

# Regional Haze Four Factor Analysis

# American Crystal Sugar Company

Crookston, MN

For Submittal to: Minnesota Pollution Control Agency 520 Lafayette Road North St. Paul, MN 55155-4194

August 28, 2020



# **Table of Contents**

| 1 | Intro | oduc  | tion   | 2 |
|---|-------|-------|--|---|
|   | 1.1   | Ana   | alysis Methodology                                     | 2 |
|   | 1.2   | CR    | K Source Parameters                                    | 2 |
| 2 | Fou   | ır Fa | ctor Analysis  | 3 |
|   | 2.1   | Арр   | licable Pollutants                                     | 3 |
|   | 2.2   | Eco   | nomic Evaluation Criteria                              | 4 |
|   | 2.3   | SO2   | 2 Analysis   | 5 |
|   | 2.3.  | 1     | Identification of SO <sub>2</sub> Control Technologies | 5 |
|   | 2.3.  | 2     | SO <sub>2</sub> Control Technology Effectiveness       | 7 |
|   | 2.3.  | 3     | Evaluation of Impacts                                  | 9 |
|   | 2.4   | NO,   | x Analysis1  | 0 |
|   | 2.4.  | 1     | Identification of NOx Control Technologies1            | 1 |
|   | 2.4.  | 2     | NO <sub>x</sub> Control Technology Effectiveness1      | 2 |
|   | 2.4.  | 3     | Evaluation of Impacts1                                 | 3 |

**Appendix A. Cost Calculations** 

# 1 Introduction

In response to the Minnesota Pollution Control Agency (MPCA) Request for Information (ROI) dated February 14, 2020, American Crystal Sugar Company (ACSC) is providing the following Four Factor Analysis to address pollutants of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>) emitted from the coal-fired boilers at the Crookston (CRK) facility.

This analysis is being provided for planning purposes and is based on budgetary cost information obtained from scaled vendor quotes for similar systems as well as methodology presented in the U.S. Environmental Protection Agency's (EPA) Air Pollution Control Cost Manual. This approach is intended to provide a study-level estimate (+/-30%) of capital and annual costs. In the event that emission reductions will be proposed for inclusion in the State Implementation Plan (SIP), it is requested that ACSC be given the opportunity to further refine the cost data to incorporate site-specific quotes reflecting current market conditions and unique site physical constraints.

# 1.1 Analysis Methodology

Following the U.S. Environmental Protection Agency (EPA) *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, the Four Factor Analysis addresses:

- The costs 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(s).

The first step in the process is identification of all available retrofit technologies for each pollutant ( $SO_2$  and  $NO_x$ ). Control options that are technically infeasible are eliminated and options are evaluated to determine their control effectiveness and economic, energy and environmental impacts.

Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction and are evaluated following a "top-down" approach similar to Best Available Control Technology (BACT) analyses.

Impacts considered for each control technology include: cost of compliance, energy impacts, non-air quality environmental impacts and the remaining useful life of the unit to be controlled.

# **1.2 CRK Source Parameters**

CRK operates three Babcock and Wilcox coal-fired stoker boilers equipped with modern overfire air (OFA) control systems. The boilers are also equipped with high-efficiency electrostatic precipitators to control particulate matter emissions. The maximum rated heat input of two identical boilers is 137 million British thermal units per hour (MMBtu/hr) each. The maximum rated heat input of the third boiler is 165 MMBtu/hr. All three boilers combust low sulfur subbituminous coal from the Powder River Basin (PRB).

The boilers are identified as EU001, EU002, and EU003 in Air Emission Permit No. 11900001-004. The operating permit limits each boiler to the maximum emission rates shown in Table 1 below.

| Pollutant       | Boiler 1 – EU001 | Boiler 2 – EU002 | Boiler 3 – EU003 |
|-----------------|------------------|------------------|------------------|
| SO <sub>2</sub> | 127              | 127 lb/hr        | 154 lb/hr        |
|                 | (0.93 lb/MMBtu)  | (0.93 lb/MMBtu)  | (0.93 lb/MMBtu)  |
| NO <sub>x</sub> | 99.8 lb/hr       | 99.8 lb/hr       | 120 lb/hr        |
|                 | (0.73 lb/MMBtu)  | (0.73 lb/MMBtu)  | (0.73 lb/MMBtu)  |

Table 1 – Permitting Emission Limits.

As indicated in the EPA's *Guidance on Regional Haze State Implementation Plans*, a state may use a source's annual emissions in tons to determine actual visibility impacts. Therefore, actual emission levels based on source test data were used to characterize emissions-related factors in this analysis. The average SO<sub>2</sub> emission rate from the two identical CRK boilers as reported in the most recent emission inventory is 0.37 lb/MMBtu and 241 tons per year (tpy) for each boiler. The SO<sub>2</sub> emission rate from the slightly larger boiler is 0.41 lb/MMBtu and 253 tpy. The average NO<sub>x</sub> emission rate from the two identical CRK boilers as reported in the most recent emission rate from the two identical CRK boilers as reported in the most recent emission rate from the two identical CRK boilers as reported in the most recent emission rate from the two identical CRK boilers as reported in the most recent emission inventory is 0.33 lb/MMBtu and 209 tpy for each boiler. The NO<sub>x</sub> emission rate from the slightly larger boiler is 0.32 lb/MMBtu and 202 tpy.

Because two of the boilers are of identical size and type, control technology costs and design features would be the same for both boilers. The third boiler is of the same type, but slightly larger. It is anticipated that the Four Factor Analysis applies to the CRK facility as a whole, and two potential control technology determinations could be made: one for the identical boilers, and one for the slightly larger single boiler at the facility. The average emission rate for the two identical boilers was used in the analysis to determine costs of compliance for those units and the individual emission rate was used for the slightly larger boiler.

# 2 Four Factor Analysis

# 2.1 Applicable Pollutants

The Four Factor Analysis addresses criteria pollutants of SO<sub>2</sub> and NO<sub>x</sub>.

<u>SO<sub>2</sub> Formation</u>. SO<sub>2</sub> emissions are formed from the oxidation of organic sulfur and pyritic sulfur in the coal during the combustion process. The majority of sulfur is oxidized to SO<sub>2</sub>, however, a small quantity may be further oxidized to form sulfur trioxide (SO<sub>3</sub>). Approximately 90% of the

sulfur present in the subbituminous coal will be emitted as sulfur oxides (SO<sub>x</sub>) compounds. Alkaline ash from some coals (including PRB coals) may cause some of the sulfur to react in the furnace to form various sulfate salts that are then retained in the fly ash. Sulfuric acid mist (H<sub>2</sub>SO<sub>4</sub>) forms when SO<sub>2</sub> emissions react with moisture and oxygen in the environment.

<u>NO<sub>x</sub> Formation</u>. There are two primary mechanisms of NO<sub>x</sub> formation in coal-fired industrial boilers: thermal production of NOx from atmospheric nitrogen and oxygen, and oxidation of nitrogen bound in the fuel. High combustion temperatures cause the nitrogen (N<sub>2</sub>) and oxygen (O<sub>2</sub>) molecules in the combustion air to react and form thermal NO<sub>x</sub>. Because thermal NO<sub>x</sub> is primarily a function of combustion temperature, NO<sub>x</sub> emission rates vary with burner and source design. Experimental measurements of thermal NO<sub>x</sub> formation have shown that the NO<sub>x</sub> concentration is exponentially dependent on temperature and is proportional to the N<sub>2</sub> concentration in the flame, the square root of the O<sub>2</sub> concentration in the flame, and the gas residence time<sup>1</sup>. The formation of fuel NO<sub>x</sub> from reactions of fuel bound nitrogen and air can account for up to 80% of total NO<sub>x</sub> from coal combustion. Subbituminous coals contain from 0.5 to 2 percent by weight fuel-bound nitrogen.

# 2.2 Economic Evaluation Criteria

Costs of compliance are directly related to the technically feasible control technology option selected and the level of emission reduction experienced from the control. Costs are expressed in terms of dollars per ton of pollutant removed, where the cost is the annualized capital and operating costs, and the tons of pollutant removed is the incremental reduction in pollutant emissions over current baseline (actual) emission levels.

Base economic criteria used in this analysis are listed in Table 2.

| Economic Parameter                     | Value                 |
|--|-----------------------|
| Interest Rate, percent                 | <b>7</b> <sup>A</sup> |
| Control Equipment Economic Life, years | 15 & 20 <sup>в</sup>  |
| Base Labor Cost, \$/hr                 | 60 <sup>c</sup>       |
| Energy Cost, \$/kW-hr                  | 0.06 <sup>D</sup>     |

### Table 2 – Economic Evaluation Criteria.

<sup>A</sup> EPA Air Pollution Control Cost Manual, Seventh Edition, January 2017, Chapter 2, Section 2.4.2.

<sup>B</sup> EPA Memorandum, Calculating Amortized Capital Costs, July 24, 1987, Robert D. Bauman, Chief, Standards and Implementation Branch.

<sup>c</sup> Loaded labor rate obtained from ACSC.

<sup>D</sup> Actual ACSC electricity cost.

Cost estimates used in the analysis have been compile from a number of data sources. In general, the cost estimates were performed following guidance provided in the EPA Air Pollution Control Cost Manual, Seventh Edition, January 2017. The EPA control cost manual data was

<sup>&</sup>lt;sup>1</sup> AP42, Chapter 1, Bituminous and Subbituminous Coal Combustion, (9/98).

supplemented with vendor supplied quotations when available and general engineering estimates. Detailed cost estimate and support data have been provided in Appendix A.

# 2.3 SO<sub>2</sub> Analysis

Because two of the coal-fired boilers at the CRK facility are identical, the analysis was prepared for one individual boiler at that capacity. The results of the analysis can be applied equally to each boiler. A separate analysis was performed for the third, slightly larger boiler.

# 2.3.1 Identification of SO<sub>2</sub> Control Technologies

Control of SO<sub>2</sub> emissions from fuel-combustion sources can be accomplished through two approaches: removal of elemental sulfur from the fuel prior to combustion, and flue gas desulfurization (FGD), which consists of removal of SO<sub>2</sub> from flue gas after combustion (post-combustion control).

Many oil refineries operate catalyst-based desulfurization units to remove organic sulfur from liquid crude oil. However, in solid fuels, such as coal, a significant fraction of the sulfur is in the form of pyrite (FeS<sub>2</sub>) or other mineral sulfates. It is possible to remove some mineral sulfates through physical processes such as washing and/or chemical processing. However, desulfurization of solid fuels is generally viewed as inefficient and expensive. Additionally, organic sulfur cannot be removed by physical cleaning. It is unlikely that sufficient desulfurization of solid fuels can be accomplished to meet anticipated emission requirements. Therefore removal of sulfur from the coal prior to combustion will not be considered a viable option for this analysis.

FGD technologies can be divided into two main categories: regenerative and throwaway processes. Regenerative processes recover sulfur in a usable form that can be sold as a reusable sulfur product. Throwaway processes remove sulfur from flue gas and scrubber byproducts are subsequently discarded. All of the FGD technologies considered can achieve  $SO_2$  removal efficiencies of 90 to 95% depending on the amount of sulfur in the coal. For relatively high sulfur coals, removal efficiencies can exceed 95%, while for lower sulfur coals (such as PRB), the achievable removal efficiency is typically less than 95%.

Regenerative processes, by nature, contain a regeneration step in the FGD process that results in higher costs than throwaway processes due to equipment and operation expenses. However, in instances where disposal options are limited and markets for recovered sulfur products are readily available, regenerative processes may be used. Potential regenerative processes that are available include the Wellman-Lord (W-L) process, magnesium oxide process, citrate scrubbing process, Flakt-Boliden process, aqueous carbonate process, Sulf-X process, Conosox process, Westvaco process and adsorption of SO<sub>2</sub> by a bed of copper oxide.

Throwaway processes such as limestone scrubbing have become widely accepted by the coalfired power industry for FGD because limestone scrubbers have overall lower costs and are simpler to operate than regenerative processes. Because the throwaway process can achieve the same removal efficiencies as regenerative processes and cost less, this analysis for SO<sub>2</sub> will focus on throwaway processes and further discussion of regenerative processes will not be considered. Throwaway processes can be divided into two categories, wet and dry. Wet or dry refers to the state of the waste by-products. Both wet and dry technologies have advantages and disadvantages with respect to initial capital and operational expenses.

### 2.3.1.1 Wet FGD Systems

Wet scrubbing (wet FGD) systems used for SO<sub>2</sub> reduction typically consist of the following operations: scrubbing or absorption, lime handling and slurry preparation, sludge processing, and flue gas handling.

Wet FGD technology is a well-established process for removing SO<sub>2</sub> from flue gas. In wet scrubbers, the flue gas enters a spray tower or absorber where it is sprayed with a water slurry, which is approximately 10 percent lime or limestone. Sodium alkali solutions can also be used in FGD systems, however these processes are considerably more expensive than lime. The preferred sorbents are limestone and lime, respectively, due to the availability and relatively low cost of limestone. Calcium in the slurry reacts with the SO<sub>2</sub> in the flue gas to form calcium sulfite or calcium sulfate. The overall chemical reaction can be simply expressed as:

$$SO_2 + CaCO_3 \rightarrow CaSO_3 + CO_2$$

Spent slurry from the reaction tank is pumped into a thickener where solids settle before being filtered for final dewatering to approximately 50 percent solids. Water removed during this process is sent to a process water holding tank, which eventually will require wastewater treatment. In a non-regenerative system, the waste sludge must also be disposed of properly. Finally, scrubbed flue gases are directed through a stack gas reheater in order to minimize corrosion downstream of the scrubber due to conversion of  $SO_2$  to  $SO_3$  and subsequently sulfuric acid (H<sub>2</sub>SO<sub>4</sub>). Reheating is sometimes needed for proper drafting and rise of exhaust gases out the stack, as well as minimizing condensation. As an alternative, the stack can be constructed of acid resistant material.

Most wet FGD systems have two stages: one for fly ash removal and one for  $SO_2$  removal. The flue gas normally passes first through a fly ash removal device, either an electrostatic precipitator (ESP) or a bag filter, and then into the  $SO_2$  absorber. There are many different types of absorbers that can be used in wet FGD systems, including: spray towers, venturis, plate towers, and mobile packed beds. However, many of these systems can result in scale buildup, plugging or erosion, which can affect the dependability and efficiency of the absorber. Therefore, simple scrubbers such as spray towers are commonly used. The chief drawback of the spray tower design is that it requires a higher liquid-to-gas ratio for equivalent removal of  $SO_2$  than other absorber designs.

### 2.3.1.2 Dry FGD Systems

In contrast to wet scrubbing systems, dry FGD (spray dryer) systems use much smaller amounts of liquid. With a spray dryer system, the flue gases enter an absorbing tower (dryer) where the hot gases are contacted with a finely atomized slurry, which is usually a calciumbased sorbent such as calcium hydroxide or calcium oxide (lime). Acid gases and SO<sub>2</sub> are absorbed by the slurry mixture and react to form solid salts. The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a non-saturated flue gas exits the absorber tower. The absorption process is also somewhat temperature dependent. Cooler flue gases allow the acid gases to more effectively react with the sorbents. The overall chemical reactions can be simply expressed as:

 $\begin{aligned} \text{Ca(OH)}_2 + \text{SO}_2 &\rightarrow \text{CaSO}_3(\text{s}) + \text{H}_2\text{O} \\ \text{Ca(OH)}_2 + 2\text{HCl} &\rightarrow \text{CaCl}_2(\text{s}) + 2\text{H}_2\text{O} \end{aligned}$ 

As can be seen above, one mole of calcium hydroxide will neutralize one mole of SO<sub>2</sub>, whereas one mole of calcium hydroxide will neutralize two moles of hydrochloric acid (HCl). A similar reaction occurs with the neutralization of hydrofluoric acid (HF). These reactions demonstrate that when using a spray dryer the HCl and HF are removed more readily than SO<sub>2</sub>. Reagent requirements should consider that the HCl and HF are removed first, followed by the reagent quantity required to remove the SO<sub>2</sub><sup>2</sup>.

The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a nonsaturated flue gas exists the absorber tower. The exhaust stream exiting the absorber contains fly ash, calcium salts, and un-reacted lime, which must be sent to a particulate control device such as a fabric filter (baghouse). The particulate control device not only is necessary to control particulate matter, but also aids in acid-gas removal. Acid gases are removed when the flue gas comes in contact with the lime-containing particles on the surface of the ESP or baghouse. Fabric filters are considered to have slightly higher residual acid gas removal levels than ESPs because the acid gases must pass through the lime-containing filter cake in a fabric filter system. Modern dry FGD systems include a loop to recycle a portion of the baghouse-collected material for re-use in the FGD module because this material contains a relatively high amount of unreacted lime.

A lower efficiency Dry FGD process that utilizes either wet or dry reagent injected directly into the furnace or flue gas duct is known as dry sorbent injection (DSI). In general, hydrated lime, lime slurry or powdered lime is injected into the existing furnace or ductwork. The constraints of the existing furnace and ductwork configuration may limit expected retrofit control efficiencies of SO<sub>2</sub>, which range from 25 to 50%. A significant drawback of this type of system is the increased maintenance costs incurred from directly injecting a sorbent into the furnace and associated duct work and the potential to significantly reduce the useful life of the boiler. Although DSI is a type of Dry FGD process, it will be referred to separately in this analysis.

### 2.3.2 SO<sub>2</sub> Control Technology Effectiveness

Effectiveness is measured by the amount of SO<sub>2</sub> removed from each control technology based on a comparison of the controlled emission rates to the baseline emission rates of the boilers. Table 3 provides a summary of the SO<sub>2</sub> control technology effectiveness.

<sup>&</sup>lt;sup>2</sup> Karl B. Schnelle, Jr. and Charles A. Brown, Air Pollution Control Technology Handbook, CRC Press, 2002.

| Control Technology         | Percent SO <sub>2</sub><br>Reduction <sup>A</sup> | Emission Rate<br>(Ib/MMBtu) | Annual<br>Emissions<br>(tpy) | Tons SO <sub>2</sub><br>Removed<br>(tpy) |  |  |
|----------------------------|---|-----------------------------|------------------------------|--|--|--|
| Two Identical Boilers (EU  | 001 & EU002)                                      |                             |                              |  |  |  |
| Baseline                   | 0   | 0.37                        | 241                          | NA                                       |  |  |
| Wet FGD                    | 80  | 0.07                        | 48                           | 193                                      |  |  |
| Dry FGD                    | 80  | 0.07                        | 48                           | 193                                      |  |  |
| DSI                        | 30  | 0.26                        | 169                          | 72                                       |  |  |
| Slightly Larger Boiler (EU | Slightly Larger Boiler (EU003)                    |                             |                              |  |  |  |
| Baseline                   | 0   | 0.41                        | 253                          | NA                                       |  |  |
| Wet FGD                    | 80  | 0.08                        | 51                           | 202                                      |  |  |
| Dry FGD                    | 80  | 0.08                        | 51                           | 202                                      |  |  |
| DSI                        | 30  | 0.29                        | 177                          | 76                                       |  |  |

### Table 3 – SO<sub>2</sub> Control Technology Effectiveness.

<sup>A</sup> Control efficiency is the lowest expected end of the range due to the combustion of low sulfur PRB coals and high relative flue gas flowrate for boiler design.

As indicated in Table 3, it is anticipated that the same level of SO<sub>2</sub> control can be achieved by the use of either Dry or Wet FGD spray dryer systems (non-DSI). This assumption is based on observation of FGD control in use on coal-fired utility boilers.

In general terms, removal of high concentrations of SO<sub>2</sub> in the flue gas is easily accomplished using either Dry or Wet FGD. Lower concentrations become more difficult to control and require greater amounts of reagent. Historically, Wet FGD systems have been used on higher-sulfur eastern coals, leading to higher efficiencies cited for Wet FGD systems, given there is much more sulfur to control. However, on lower-sulfur western coals (such as the PRB coal used at CRK) modern Dry FGD systems with better atomizer systems in conjunction with modern fabric filter technology can perform as well as Wet FGD systems. Much of the final SO<sub>2</sub> control in a Dry FGD system takes place in the reagent-rich filter cake on the fabric filter.

Because of the equivalency in anticipated SO<sub>2</sub> emission rates, only Dry FGD technology is considered in this analysis. Dry FGD technology was selected as it has lower capital and operating costs than Wet FGD and will result in a more cost-effective approach. Furthermore, use of Wet FGD to control SO<sub>2</sub> emissions from the CRK boilers would result in both higher energy penalties to the facility operations and the generation of more waste byproducts than would Dry FGD. Increased energy penalties would be due to the additional pumps and water handling equipment required for slurry preparation for the Wet FGD, which would also lead to the creation of additional waste byproducts from the spent slurry. Dewatering of the spent slurry results in the production of a wastewater stream, as well as a waste sludge that must be disposed of in a landfill. Dry FGD results only in a dry product which is easily landfilled.

The lower control efficiencies of 80 and 30% anticipated for the Dry FGD and DSI systems, respectively, are based on the fact the CRK boilers combust low sulfur PRB coal and have relatively high flue gas flow rates associated with the OFA system, resulting in lower starting SO<sub>2</sub> concentrations. Additionally, because the boilers have a smaller than typical furnace size for the type of coal combusted, boiler slagging and maintenance is higher than typical. As a

result, the introduction of large amounts of sorbent into the furnace and high temperature flue gas (such as with DSI systems) is anticipated to magnify these issues and result in a detrimental impact on operation and efficiency. Furthermore, frequent process load swings resulting from varying production demands presents difficulties with balancing sorbent injection and maintaining consistent control.

### 2.3.3 Evaluation of Impacts

The following sections present a detailed evaluation of the impacts of employing Dry FGD and DSI to control SO<sub>2</sub> emissions from the CRK boilers. The four factors assessed include: cost of compliance, energy, non-air quality environmental impacts and remaining useful life.

### 2.3.3.1 Cost of Compliance

Table 3 summarizes the capital and annual operating costs associated with retrofitting a Dry FGD and DSI system to each of the identical smaller CRK boilers (EU001 and EU002). Table 5 summarizes the same costs, adjusted for the slightly larger boiler (EU003). Detailed cost estimates indicating data sources for each cost category have been included in Appendix A.

| Description                             | Technology Option          |           |  |
|---|----------------------------|-----------|--|
|   | Dry FGD w/Fabric<br>Filter | DSI       |  |
| Emission Rate (Ib/MMBtu)                | 0.07                       | 0.26      |  |
| Emission Reduction (tpy)                | 193                        | 72        |  |
| Capital Cost (\$)                       | 14,425,400                 | 2,966,900 |  |
| Direct Annual Cost (\$)                 | 1,112,000                  | 136,300   |  |
| Indirect Annual Cost (\$)               | 2,536,500                  | 509,400   |  |
| Total Annualized Cost (\$)              | 3,648,500                  | 645,700   |  |
|   |                            |           |  |
| Cost Effectiveness, per Boiler (\$/ton) | 18,900                     | 9,000     |  |

| Table 4 – SO <sub>2</sub> Costs of Com | pliance – EU001 & | EU002 (per Boiler). |
|--|-------------------|---------------------|
|  |                   |                     |

| Description                 | Technology Option          |           |  |
|-----------------------------|----------------------------|-----------|--|
|                             | Dry FGD w/Fabric<br>Filter | DSI       |  |
| Emission Rate (Ib/MMBtu)    | 0.08                       | 0.29      |  |
| Emission Reduction (tpy)    | 202                        | 76        |  |
| Capital Cost (\$)           | 15,978,300                 | 3,306,900 |  |
| Direct Annual Cost (\$)     | 1,205,800                  | 143,700   |  |
| Indirect Annual Cost (\$)   | 2,790,900                  | 562,700   |  |
| Total Annualized Cost (\$)  | 3,996,700                  | 706,400   |  |
| Cost Effectiveness (\$/ton) | 19,800                     | 9,300     |  |

### Table 5 – SO<sub>2</sub> Costs of Compliance – EU003.

### 2.3.3.2 Energy Impact

Use of Dry FGD or DSI to control SO<sub>2</sub> emissions from the CRK boilers would result in energy penalties to facility operations in the form of the electricity demand required for operation of ancillary equipment such as the reagent preparation and atomizer equipment, as well as additional backpressure on the exhaust system that results in decreased operational efficiency.

### 2.3.3.3 Non-Air Quality Environmental Impacts

The primary detrimental non-air quality environmental impact of a Dry FGD or DSI system is the creation of a solid waste byproduct from the spent reagent. Unlike Wet FGD, there is no wastewater stream resultant from the use of Dry FGD. The solid waste that is produced from a Dry FGD system can be landfilled or possibly used as an agricultural soil supplement depending on the fly ash content.

The DSI system is anticipated to greatly increase maintenance requirements as a result of increased boiler slagging and equipment fouling. Given the age of the existing boilers, the implementation of such a system may have a significant negative impact on remaining useful life.

### 2.3.3.4 Remaining Useful Life

The remaining useful life of the CRK boilers is greater than 20 years. Therefore, the remaining useful life has no impact on the annualized estimated control technology costs.

# 2.4 NO<sub>x</sub> Analysis

Because two of the coal-fired boilers at the CRK facility are identical, the analysis was prepared for one individual boiler at that capacity. The results of the analysis can be applied equally to each boiler. A separate analysis was performed for the third, slightly larger boiler.

### 2.4.1 Identification of NOx Control Technologies

Control of  $NO_x$  emissions from boilers can be attained through either the application of combustion controls or flue gas treatment (post-combustion) technologies. Combustion control processes can reduce the quantity of  $NO_x$  formed during the combustion process. Post-combustion technologies reduce the  $NO_x$  concentrations in the flue gas steam after the  $NO_x$  has been formed in the combustion process. These methods may be used alone or in combination to achieve the various degrees of  $NO_x$  emissions required.

### 2.4.1.1 Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) systems are an add-on flue gas treatment (postcombustion control technology) to control NO<sub>x</sub> emissions. The SCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH<sub>3</sub>) or urea (CON<sub>2</sub>H<sub>4</sub>) to reduce the NO<sub>x</sub> in the flue gas to N<sub>2</sub> and H<sub>2</sub>O. The reagent is injected into the flue gas prior to passage through a catalyst bed, which accelerates the NO<sub>x</sub> reduction reaction rate. Use of SCR results in small levels of NH<sub>3</sub> emissions (NH<sub>3</sub> slip). As the catalyst degrades, NH<sub>3</sub> slip will increase, ultimately requiring catalyst replacement.

Many types of catalysts, ranging from active metals to highly porous ceramics, are available for different applications. The type of catalyst chosen depends on several operational parameters, such as reaction temperature range, flue gas flow rate, fuel chemistry, catalyst activity and selectivity, operating life, and cost. Catalyst materials include, platinum (Pt), vanadium (V), titanium (Ti), tungsten (W), titanium oxide (TiO<sub>2</sub>), zirconium oxide (ZrO<sub>2</sub>), vanadium pentoxide ( $V_2O_5$ ), silicon oxide (SiO<sub>2</sub>), and zeolites (crystalline alumina silicates).

SCR systems can utilize aqueous NH<sub>3</sub>, anhydrous NH<sub>3</sub>, or a urea solution to produce NH<sub>3</sub> on demand. Aqueous NH<sub>3</sub> is generally transported and stored in concentrations ranging from 19% to 30% and therefore requires more storage capacity than anhydrous NH<sub>3</sub>. Anhydrous NH<sub>3</sub> is nearly 100% pure in concentration and is a gas at normal atmospheric temperature and pressure. Anhydrous NH<sub>3</sub> must be stored and transported under pressure and when stored in quantities greater than 10,000 pounds, is subject to Risk Management Planning (RMP) requirements (40 CFR 68). The urea solution (urea and water at approximately 32% concentration) is used to form NH<sub>3</sub> on demand for injection into the flue gas. Generally, a specifically designed duct and decomposition chamber with a small supplemental burner is used to provide an appropriate temperature window and residence time to decompose urea to NH<sub>3</sub> and isocyanic acid (HNCO). Application of urea-based SCR systems to industrial boilers is a relatively new practice that is still under development.

Several different SCR system configurations have been used on utility boilers and are theoretically possible for use on smaller industrial boilers. In a high-dust SCR system, the reactor is located downstream of the economizer and upstream of the air heater, FGD system, and particulate control device. Low-dust SCR systems locate the reactor downstream of a particulate control device where the flue gas is relatively dust-free. Tail-end SCR systems locate the reactor downstream from all air pollution control equipment where most flue gas constituents detrimental to the SCR catalyst have been removed. However, tail-end SCR

systems can require reheating of the flue gas to minimize condensation, leading to corrosion problems.

### 2.4.1.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is another method of post-combustion control. Similar to SCR, the SNCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH<sub>3</sub>) or urea to reduce the NO<sub>x</sub> in the flue gas to N<sub>2</sub> and H<sub>2</sub>O. However, the SNCR process works without the use of a catalyst. Instead, the SNCR process occurs within a combustion unit, which acts as the reaction chamber. The heat from the boiler combustion process provides the energy for the NO<sub>x</sub> reduction reaction. Flue gas temperatures in the range of 1,500 to 1,900 °F, along with adequate reaction time within this temperature range, are required for this technology. SNCR is currently being used for NO<sub>x</sub> emission control on some utility boilers, and can achieve NO<sub>x</sub> reduction efficiencies of up to 75%. However, in typical industrial applications SNCR provides 30% to 50% NO<sub>x</sub> reduction.

### 2.4.1.3 Combustion Controls

Combustion controls such as flue gas recirculation (FGR), reducing air preheat temperature (RAP), oxygen trim (OT), low excess air (LEA), over-fire air (OFA), staged combustion air (SCA), and low NO<sub>x</sub> burners (LNB), can be used to reduce NO<sub>x</sub> emissions depending on the type of boiler, characteristics of fuel and method of firing. In practice, combustion controls have not provided the same degree of NO<sub>x</sub> controls as provided by add-on post combustion control technologies, but are generally used in conjunction with add-on controls, such as SNCR, to increase the NO<sub>x</sub> removal efficiency. The CRK boilers are currently equipped with modern OFA control systems.

## 2.4.2 NO<sub>x</sub> Control Technology Effectiveness

Effectiveness is measured by the amount of  $NO_x$  removed by each control technology based on a comparison of the controlled emission rates to the baseline emission rates of the boilers. Table 6 provides a summary of the  $NO_x$  control technology effectiveness.

| Control Technology                | Percent NO <sub>x</sub><br>Reduction | Emission Rate<br>(Ib/MMBtu) | Annual<br>Emissions<br>(tpy) | Tons NO <sub>x</sub><br>Removed<br>(tpy) |  |
|-----------------------------------|--------------------------------------|-----------------------------|------------------------------|--|--|
| <b>Two Identical Boilers (EU0</b> | 01 & EU002)                          |                             |                              |  |  |
| Baseline/OFA                      | 0                                    | 0.33                        | 209                          | NA                                       |  |
| SCR                               | 80                                   | 0.07                        | 42                           | 167                                      |  |
| SNCR                              | 30                                   | 0.23                        | 146                          | 63                                       |  |
| Slightly Larger Boiler (EU003)    |                                      |                             |                              |  |  |
| Baseline/OFA                      | 0                                    | 0.32                        | 202                          | NA                                       |  |
| SCR                               | 80                                   | 0.06                        | 40                           | 162                                      |  |
| SNCR                              | 30                                   | 0.22                        | 141                          | 61                                       |  |

### Table 6 – NO<sub>x</sub> Control Technology Effectiveness.

The lower control efficiencies of 80 and 30% anticipated for the SCR and SNCR systems, respectively, are based on the fact the CRK boilers are equipped with modern OFA control systems that work to reduce the starting NO<sub>x</sub> concentration. Furthermore, the boilers have a smaller than typical furnace size for the type of coal combusted and flue gas flow rates that are higher than typical. This operational characteristic, when combined with frequent process load swings resulting from varying production demands, results in variable flue gas temperature ranges within the boiler furnace and presents difficulties with balancing reagent injection and maintaining consistent control.

### 2.4.3 Evaluation of Impacts

The following sections present a detailed evaluation of the impacts of employing the feasible control technologies to control NO<sub>x</sub> emissions from the CRK boilers. The four factors assessed include: cost of compliance, energy, non-air quality environmental impacts and remaining useful life.

### 2.4.3.1 Cost of Compliance

Table 7 summarizes the capital and annual operating costs associated with retrofitting NO<sub>x</sub> control systems to each of the identical smaller CRK boilers (EU001 and EU002). Table 8 summarizes the same costs, adjusted for the slightly larger boiler (EU003). Detailed cost estimates indicating data sources for each cost category have been included in Appendix A.

| Description                             | Technology Option |           |  |
|---|-------------------|-----------|--|
|   | SCR               | SNCR      |  |
| Emission Rate (Ib/MMBtu)                | 0.07              | 0.23      |  |
| Emission Reduction (tpy)                | 167               | 63        |  |
|   |                   |           |  |
| Capital Cost (\$)                       | 10,975,000        | 2,685,600 |  |
| Direct Annual Cost (\$)                 | 107,900           | 46,800    |  |
| Indirect Annual Cost (\$)               | 1,504,500         | 384,000   |  |
| Total Annualized Cost (\$)              | 1,612,400         | 430,800   |  |
|   |                   |           |  |
| Cost Effectiveness, per Boiler (\$/ton) | 9,700             | 6,800     |  |

### Table 7 – NO<sub>x</sub> Cost of Compliance – EU001 & EU002 (per Boiler).

| Description                 | Technology Option |            |  |
|-----------------------------|-------------------|------------|--|
| -                           | OFA + SCR         | OFA + SNCR |  |
| Emission Rate (Ib/MMBtu)    | 0.06              | 0.22       |  |
| Emission Reduction (tpy)    | 162               | 61         |  |
| Capital Cost (\$)           | 12,499,000        | 2,890,200  |  |
| Direct Annual Cost (\$)     | 121,500           | 52,500     |  |
| Indirect Annual Cost (\$)   | 1,713,300         | 413,400    |  |
| Total Annualized Cost (\$)  | 1,834,800         | 465,900    |  |
| Cost Effectiveness (\$/ton) | 11,300            | 7,600      |  |

### Table 8 – NO<sub>x</sub> Cost of Compliance – EU003.

### 2.4.3.2 Energy Impact

The application of SCR and SNCR systems would result in energy penalties in the form of electricity demand for required operation of ancillary equipment such as reagent preparation and delivery, as well as additional backpressure on the exhaust system that results in decreased operational efficiency.

### 2.4.3.3 Non-Air Quality Environmental Impacts

SCR and SNCR both require some form of ammonia ( $NH_3$ ) source for operation. This can be stored in liquid, solid or gas, and processed on site for use. Depending on quantities stored, risk management requirements may apply. Both system are also prone to  $NH_3$  slip from unreacted  $NH_3$ . This will result in the emission of an additional pollutant.

#### 2.4.3.4 Remaining Useful Life

The remaining useful life of the CRK boilers is greater than 20 years. Therefore, the remaining useful life has no impact on the annualized estimated control technology costs.

# Appendix A Cost Calculations

# **Dry FGD Capital Cost Summary**

| Description of Cost                      | (\$) <sup>A</sup> | Remarks                                 |
|--|-------------------|---|
| Direct Capital Costs                     |                   |   |
| Dry FGD Equipment <sup>B</sup>           | 2,654,500         | Scaled Quote                            |
| Control/Instrumentation <sup>C</sup>     | 265,500           | 10% of Equipment Cost                   |
| Sales Tax                                | 159,300           | 6% of Equipment Cost                    |
| Freight <sup>C</sup>                     | 132,700           | 5% of Equipment Cost                    |
| Total Equipment Cost (TEC)               | 3,212,000         |   |
|  |                   | Based on percentage of TEC: 12%         |
|  |                   | Foundation & Supports, 40% Erection, 1% |
| Total Installation Cost                  |                   | Electrical Installation, 30% Piping, 1% |
| (TIC)/Balance of Plant Cost <sup>C</sup> | 2,730,200         | Painting, 1% Insulation                 |
| Site Preparation <sup>D</sup>            | 1,000,000         | Estimated                               |
| Total Direct Investment (TDI)            | 6,942,200         | TEC + TIC + Site Prep. = TDI            |
| Indirect Capital Cost <sup>C</sup>       |                   |   |
| Contingency                              | 96,400            | 3% of TEC                               |
| Engineering                              | 321,200           | 10% of TEC                              |
| Construction & Field Expense             | 321,200           | 10% of TEC                              |
| Contractor Fees                          | 321,200           | 10% of TEC                              |
| Start-up Assistance                      | 32,100            | 1% of TEC                               |
| Performance Test                         | 32,100            | 1% of TEC                               |
| Total Indirect Investment (TII)          | 1,124,200         |   |

# Total Turnkey Cost (TTC)

8,066,400 TDI + TII = TTC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost provided by vendor and scaled from similar projects.

<sup>c</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

# **Dry FGD Fabric Filter Capital Cost Summary**

| Description of Cost                      | (\$) <sup>A</sup> | Remarks  |
|--|-------------------|--|
| Direct Capital Costs                     |                   | ·  |
| Dry FGD Equipment <sup>B</sup>           | 2,022,400         | Scaled Quote                                     |
| Control/Instrumentation <sup>C</sup>     | 202,200           | 10% of Equipment Cost                            |
| Sales Tax                                | 121,300           | 6% of Equipment Cost                             |
| Freight <sup>C</sup>                     | 101,100           | 5% of Equipment Cost                             |
| Total Equipment Cost (TEC)               | 2,447,000         |  |
|  |                   | Based on percentage of TEC: 4%                   |
|  |                   | Foundation & Supports, 50% Erection, 8%          |
| Total Installation Cost                  |                   | Electrical Installation, 1% Piping, 4% Painting, |
| (TIC)/Balance of Plant Cost <sup>C</sup> | 1,810,800         | 7% Insulation                                    |
| Site Preparation <sup>D</sup>            | 1,000,000         | Estimated  |
| Total Direct Investment (TDI)            | 5,257,800         | TEC + TIC + Site Prep. = TDI                     |
|  |                   |  |
| Indirect Capital Cost <sup>C</sup>       |                   |  |
| Contingency                              | 73,400            | 3% of TEC  |
| Engineering                              | 244,700           | 10% of TEC                                       |
| Construction & Field Expense             | 489,400           | 20% of TEC                                       |
| Contractor Fees                          | 244,700           | 10% of TEC                                       |
| Start-up Assistance                      | 24,500            | 1% of TEC  |
| Performance Test                         | 24,500            | 1% of TEC  |

## Total Turnkey Cost (TTC)

Total Indirect Investment (TII)

6,359,000 TDI + TII = TTC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost provided by vendor and scaled from similar projects.

<sup>c</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

1,101,200

# Dry FGD/Fabric Filter Annual Cost Summary

| Description of Cost              | (\$) <sup>^</sup> | Remarks                             |
|----------------------------------|-------------------|-------------------------------------|
| Direct Annual Costs <sup>B</sup> |                   |                                     |
| Dry FGD Labor                    | 49,300            | 1 hr per shift, assumed 8 hr shifts |
| Dry FGD Supervisor               | 7,400             | 15% of labor                        |
| Fabric Filter Labor              | 65,700            | 2 hr per shift, assumed 8 hr shifts |
| Fabric Filter Supervisor         | 9,900             | 15% of labor                        |
| Solvent (Reagent)                | 256,400           | Consumption x cost                  |
| Fabric Filter Bag Replacement    | 170,700           | Labor plus bag cost                 |
| Solids Scrubber Disposal         | 56,200            | Production x cost                   |
| Solids Fly Ash Disposal          | 94,100            | Production x cost                   |
| Maintenance Labor, Dry FGD       | 49,300            | 1 hr per shift, assumed 8 hr shifts |
| Maintenance Material, Dry FGD    | 49,300            | 100% of labor                       |
| Maintenance Labor, Fabric F.     | 65,700            | 2 hr per shift, assumed 8 hr shifts |
| Maintenance Material, Fabric F.  | 65,700            | 100% of labor                       |
| Induced Draft Fan                | 129,400           | Consumption x cost                  |
| Pump                             | 42,900            | Consumption x cost                  |
| Direct Annual Costs (DAC)        | 1,112,000         |                                     |

| 000,200 |  |
|---------|--|
| 600,200 | (Capital Investment) x (CFR of 0.09439)  |
| 885,600 | (Capital Investment) x (CFR of 0.10979)  |
| 144,300 | 1% of Total Capital Investment           |
| 144,300 | 1% of Total Capital Investment           |
| 288,500 | 2% of Total Capital Investment           |
| 473,600 | 60% of O&M Labor                         |
|         | 288,500<br>144,300<br>144,300<br>885,600 |

### Total Annualized Costs (TAC) 3,648,500 DAC + IAC = TAC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Direct annual costs are based on site-specific design parameters.

<sup>C</sup> Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

<sup>D</sup> Capital Recovery Factor (CFR) based on 15 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

<sup>E</sup> Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

# **Dry Sorbent Injection Capital Cost Summary**

| Description of Cost                      | (\$) <sup>A</sup> | Remarks                                 |
|--|-------------------|---|
| Direct Capital Costs                     |                   |   |
| Dry FGD Equipment <sup>B</sup>           | 1,044,400         | Vendor Quote                            |
| Control/Instrumentation <sup>C</sup>     | 104,400           | 10% of Equipment Cost                   |
| Sales Tax                                | 62,700            | 6% of Equipment Cost                    |
| Freight <sup>C</sup>                     | 52,200            | 5% of Equipment Cost                    |
| Total Equipment Cost (TEC)               | 1,263,700         |   |
|  |                   | Based on percentage of TEC: 12%         |
|  |                   | Foundation & Supports, 40% Erection, 1% |
| Total Installation Cost                  |                   | Electrical Installation, 30% Piping, 1% |
| (TIC)/Balance of Plant Cost <sup>C</sup> | 1,074,100         | Painting, 1% Insulation                 |
| Site Preparation <sup>D</sup>            | 250,000           | Estimated (includes electrical upgrade) |
| Total Direct Investment (TDI)            | 2,587,800         | TEC + TIC + Site Prep. = TDI            |
|  |                   |   |
| Indirect Capital Cost <sup>C</sup>       |                   |   |
| Contingency                              | 37,900            | 3% of TEC                               |
| Engineering                              | 63,200            | 5% of TEC                               |
| Construction & Field Expense             | 126,400           | 10% of TEC                              |
| Contractor Fees                          | 126,400           | 10% of TEC                              |
| Start-up Assistance                      | 12,600            | 1% of TEC                               |
| Performance Test                         | 12,600            | 1% of TEC                               |
|  |                   |   |

### Total Turnkey Cost (TTC)

Total Indirect Investment (TII)

2,966,900 TDI + TII = TTC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost provided by vendor.

<sup>c</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

379,100

### **Dry Sorbent Injection Annual Cost Summary**

| Description of Cost                   | (\$) <sup>^</sup> | Remarks                                 |
|---------------------------------------|-------------------|---|
| Direct Annual Costs <sup>B</sup>      |                   | •                                       |
| DSI Labor                             | 24,600            | 1/2 hr per shift, assumed 8 hr shifts   |
| DSI Supervisor                        | 3,700             | 15% of labor                            |
| Solvent (Trona)                       | 30,800            | Consumption x cost                      |
| Solids Fly Ash Disposal               | 15,100            | Production x cost                       |
| Maintenance Labor                     | 24,600            | 1/2 hr per shift, assumed 8 hr shifts   |
| Maintenance Material, Dry FGD         | 24,600            | 100% of labor                           |
| Induced Draft Fan/Pumps               | 12,900            | Consumption x cost                      |
| Direct Annual Costs (DAC)             | 136,300           |   |
|                                       |                   |   |
| Indirect Annual Costs <sup>C</sup>    |                   |   |
| Overhead                              | 65,000            | 60% of O&M Labor                        |
| Administrative Charges                | 59,300            | 2% of Total Capital Investment          |
| Property Taxes                        | 29,700            | 1% of Total Capital Investment          |
| Insurance                             | 29,700            | 1% of Total Capital Investment          |
| Dry FGD Annualized Costs <sup>D</sup> | 325,700           | (Capital Investment) x (CFR of 0.10979) |

| Total Annualized Costs (TAC) | 645,700 | DAC + IAC = TAC |
|------------------------------|---------|-----------------|

<sup>A</sup> Values rounded to the nearest \$100.

Indirect Annual Costs (IAC)

<sup>B</sup> Direct annual costs are based on site-specific design parameters and vendor quote.

509,400

<sup>c</sup> Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

<sup>D</sup> Capital Recovery Factor (CFR) based on 15 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

# Selective Catalytic Reduction Capital Cost Summary

| Description of Cost                      | (\$) <sup>A</sup> | Remarks                         |
|--|-------------------|---------------------------------|
| Direct Capital Costs                     |                   |                                 |
| SCR Equipment <sup>B</sup>               | 4,149,800         | Control Cost Manual Spreadsheet |
| Reagent Preparation Cost <sup>B</sup>    | 1,545,200         | Control Cost Manual Spreadsheet |
| Control/Instrumentation <sup>C</sup>     | 415,000           | 10% of Equipment Cost           |
| Sales Tax                                | 249,000           | 6% of Equipment Cost            |
| Freight <sup>C</sup>                     | 207,500           | 5% of Equipment Cost            |
| Total Equipment Cost (TEC)               | 6,566,500         |                                 |
| Total Installation Cost                  |                   |                                 |
| (TIC)/Balance of Plant Cost <sup>B</sup> | 1,872,800         | Control Cost Manual Spreadsheet |
| Site Preparation <sup>D</sup>            | 500,000           | Demo and Equipment Relocation   |
| Total Direct Investment (TDI)            | 8,939,300         | TEC + TIC + Site Prep. = TDI    |

| 131,300<br>65,700 | 2% of TEC<br>1% of TEC |
|-------------------|------------------------|
| ,                 |                        |
| 050,700           | 10% 01 TEC             |
| 656 700           | 10% of TEC             |
| 328,300           | 5% of TEC              |
| 656,700           | 10% of TEC             |
| 197,000           | 3% of TEC              |
|                   | 656,700                |

| Total Turnkey Cost (TTC) | 10,975,000 | TDI + TII = TTC |
|--------------------------|------------|-----------------|
| ٨                        |            |                 |

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost obtained from EPA Air Pollution Control SCR Spreadsheet.

<sup>C</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

# Selective Catalytic Reduction Annual Cost Summary

| Description of Cost  | (\$) <sup>A</sup>  | Remarks  |
|--|--------------------|--|
| Direct Annual Costs <sup>B</sup>   |                    |  |
| Annual SCR Maintenance   | 49,200             | Control Cost Manual Spreadsheet                                  |
| Reagent (Ammonia)  | 7,300              | Control Cost Manual Spreadsheet                                  |
| SCR Electricity  | 20,700             | Control Cost Manual Spreadsheet                                  |
| Catalyst Replacment  | 30,700             | Control Cost Manual Spreadsheet                                  |
| Direct Annual Costs (DAC)  | 107,900            |  |
|  |                    |  |
| Indirect Annual Costs <sup>C</sup>   |                    |  |
| <i>Indirect Annual Costs <sup>C</sup></i><br>Overhead                                      | 29,500             | 60% of O&M Labor   |
| Overhead   | 29,500<br>219,500  | 60% of O&M Labor<br>2% of Total Capital Investment               |
| Indirect Annual Costs <sup>C</sup><br>Overhead<br>Administrative Charges<br>Property Taxes | ,                  |  |
| Overhead<br>Administrative Charges   | 219,500            | 2% of Total Capital Investment                                   |
| Overhead<br>Administrative Charges<br>Property Taxes                                       | 219,500<br>109,800 | 2% of Total Capital Investment<br>1% of Total Capital Investment |

Total Annualized Costs (TAC)1,612,400DAC + IAC = TAC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

<sup>c</sup> Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

<sup>D</sup> Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

# Selective Non-Catalytic Reduction Capital Cost Summary

| Description of Cost                      | (\$) <sup>A</sup> | Remarks                         |
|--|-------------------|---------------------------------|
| Direct Capital Costs                     |                   |                                 |
| SNCR Equipment <sup>B</sup>              | 801,200           | Control Cost Manual Spreadsheet |
| Control/Instrumentation <sup>C</sup>     | 80,100            | 10% of Equipment Cost           |
| Sales Tax                                | 48,100            | 6% of Equipment Cost            |
| Freight <sup>C</sup>                     | 40,100            | 5% of Equipment Cost            |
| Total Equipment Cost (TEC)               | 969,500           |                                 |
| Total Installation Cost                  |                   |                                 |
| (TIC)/Balance of Plant Cost <sup>B</sup> | 1,165,400         | Control Cost Manual Spreadsheet |
| Site Preparation <sup>D</sup>            | 250,000           | Demo and Equipment Relocation   |
| Total Direct Investment (TDI)            | 2,384,900         | TEC + TIC + Site Prep. = TDI    |

| ,      |                                      |
|--------|--------------------------------------|
| 9,700  | 1% of TEC                            |
| 19,400 | 2% of TEC                            |
| 97,000 | 10% of TEC                           |
| 48,500 | 5% of TEC                            |
| 97,000 | 10% of TEC                           |
| 29,100 | 3% of TEC                            |
|        | 97,000<br>48,500<br>97,000<br>19,400 |

| Total Turnke | y Cost (TTC) |   | 2,685,600 | TDI + TII = TTC |
|--------------|--------------|---|-----------|-----------------|
| Δ            |              | 4 |           |                 |

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost obtained from EPA Air Pollution Control SNCR Spreadsheet.

<sup>c</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

# Selective Non-Catalytic Reduction Annual Cost Summary

| Description of Cost                   | (\$) <sup>A</sup> | Remarks                                 |
|---------------------------------------|-------------------|---|
| Direct Annual Costs <sup>B</sup>      |                   | •                                       |
| Annual SNCR Maintenance               | 38,300            | Control Cost Manual Spreadsheet         |
| Reagent (Ammonia)                     | 7,000             | Control Cost Manual Spreadsheet         |
| Electricity                           | 400               | Control Cost Manual Spreadsheet         |
| Water                                 | 200               | Control Cost Manual Spreadsheet         |
| Additional Fuel                       | 800               | Control Cost Manual Spreadsheet         |
| Additional Ash                        | 100               | Control Cost Manual Spreadsheet         |
| Direct Annual Costs (DAC)             | 46,800            |   |
|                                       |                   |   |
| Indirect Annual Costs <sup>c</sup>    |                   |   |
| Overhead                              | 23,000            | 60% of O&M Labor                        |
| Administrative Charges                | 53,700            | 2% of Total Capital Investment          |
| Property Taxes                        | 26,900            | 1% of Total Capital Investment          |
| Insurance                             | 26,900            | 1% of Total Capital Investment          |
|                                       |                   |   |
| Dry FGD Annualized Costs <sup>D</sup> | 253,500           | (Capital Investment) x (CFR of 0.09439) |

| Total Annualized Costs (TAC) | 430,800 | DAC + IAC = TAC |
|------------------------------|---------|-----------------|

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

<sup>c</sup> Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

<sup>D</sup> Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

# **Dry FGD Capital Cost Summary**

| Description of Cost                      | (\$) <sup>A</sup> | Remarks                                 |
|--|-------------------|---|
| Direct Capital Costs                     |                   |   |
| Dry FGD Equipment <sup>B</sup>           | 2,986,300         | Scaled Quote                            |
| Control/Instrumentation <sup>C</sup>     | 298,600           | 10% of Equipment Cost                   |
| Sales Tax                                | 179,200           | 6% of Equipment Cost                    |
| Freight <sup>C</sup>                     | 149,300           | 5% of Equipment Cost                    |
| Total Equipment Cost (TEC)               | 3,613,400         |   |
|  |                   | Based on percentage of TEC: 12%         |
|  |                   | Foundation & Supports, 40% Erection, 1% |
| Total Installation Cost                  |                   | Electrical Installation, 30% Piping, 1% |
| (TIC)/Balance of Plant Cost <sup>C</sup> | 3,071,400         | Painting, 1% Insulation                 |
| Site Preparation <sup>D</sup>            | 1,000,000         | Estimated                               |
| Total Direct Investment (TDI)            | 7,684,800         | TEC + TIC + Site Prep. = TDI            |
|  |                   |   |
| Indirect Capital Cost <sup>C</sup>       |                   |   |
| Contingency                              | 108,400           | 3% of TEC                               |
| Engineering                              | 361,300           | 10% of TEC                              |
| Construction & Field Expense             | 361,300           | 10% of TEC                              |
| Contractor Fees                          | 361,300           | 10% of TEC                              |
| Start-up Assistance                      | 36,100            | 1% of TEC                               |
| Performance Test                         | 36,100            | 1% of TEC                               |
| Total Indirect Investment (TII)          | 1,264,500         |   |

# Total Turnkey Cost (TTC)

8,949,300 TDI + TII = TTC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost provided by vendor and scaled from similar projects.

<sup>c</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

# Dry FGD Fabric Filter Capital Cost Summary

| Description of Cost                      | (\$) <sup>A</sup> | Remarks  |
|--|-------------------|--|
| Direct Capital Costs                     |                   | ·  |
| Dry FGD Equipment <sup>B</sup>           | 2,275,200         | Scaled Quote                                     |
| Control/Instrumentation <sup>C</sup>     | 227,500           | 10% of Equipment Cost                            |
| Sales Tax                                | 136,500           | 6% of Equipment Cost                             |
| Freight <sup>C</sup>                     | 113,800           | 5% of Equipment Cost                             |
| Total Equipment Cost (TEC)               | 2,753,000         |  |
|  |                   | Based on percentage of TEC: 4%                   |
|  |                   | Foundation & Supports, 50% Erection, 8%          |
| Total Installation Cost                  |                   | Electrical Installation, 1% Piping, 4% Painting, |
| (TIC)/Balance of Plant Cost <sup>C</sup> | 2,037,200         | 7% Insulation                                    |
| Site Preparation <sup>D</sup>            | 1,000,000         | Estimated  |
| Total Direct Investment (TDI)            | 5,790,200         | TEC + TIC + Site Prep. = TDI                     |
|  |                   |  |
| Indirect Capital Cost <sup>C</sup>       |                   |  |
| Contingency                              | 82,600            | 3% of TEC  |
| Engineering                              | 275,300           | 10% of TEC                                       |
| Construction & Field Expense             | 550,600           | 20% of TEC                                       |
| Contractor Fees                          | 275,300           | 10% of TEC                                       |
| Start-up Assistance                      | 27,500            | 1% of TEC  |
| Performance Test                         | 27,500            | 1% of TEC  |
|  |                   |  |

### Total Turnkey Cost (TTC)

Total Indirect Investment (TII)

7,029,000 TDI + TII = TTC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost provided by vendor and scaled from similar projects.

<sup>c</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

1,238,800

# Dry FGD/Fabric Filter Annual Cost Summary

| Description of Cost              | (\$) <sup>^</sup> | Remarks                             |
|----------------------------------|-------------------|-------------------------------------|
| Direct Annual Costs <sup>B</sup> |                   | ·                                   |
| Dry FGD Labor                    | 49,300            | 1 hr per shift, assumed 8 hr shifts |
| Dry FGD Supervisor               | 7,400             | 15% of labor                        |
| Fabric Filter Labor              | 65,700            | 2 hr per shift, assumed 8 hr shifts |
| Fabric Filter Supervisor         | 9,900             | 15% of labor                        |
| Solvent (Reagent)                | 288,500           | Consumption x cost                  |
| Fabric Filter Bag Replacement    | 192,100           | Labor plus bag cost                 |
| Solids Scrubber Disposal         | 63,200            | Production x cost                   |
| Solids Fly Ash Disposal          | 105,800           | Production x cost                   |
| Maintenance Labor, Dry FGD       | 49,300            | 1 hr per shift, assumed 8 hr shifts |
| Maintenance Material, Dry FGD    | 49,300            | 100% of labor                       |
| Maintenance Labor, Fabric F.     | 65,700            | 2 hr per shift, assumed 8 hr shifts |
| Maintenance Material, Fabric F.  | 65,700            | 100% of labor                       |
| Induced Draft Fan                | 145,600           | Consumption x cost                  |
| Pump                             | 48,300            | Consumption x cost                  |
| Direct Annual Costs (DAC)        | 1,205,800         |                                     |

| Indirect Annual Costs (IAC)                 | 2,790,900 |   |
|---|-----------|---|
| Fabric Filter Annualized Costs <sup>E</sup> | 663,500   | (Capital Investment) x (CFR of 0.09439) |
| Dry FGD Annualized Costs <sup>D</sup>       | 982,500   | (Capital Investment) x (CFR of 0.10979) |
| Insurance                                   | 159,800   | 1% of Total Capital Investment          |
| Property Taxes                              | 159,800   | 1% of Total Capital Investment          |
| Administrative Charges                      | 319,600   | 2% of Total Capital Investment          |
| Overhead                                    | 505,700   | 60% of O&M Labor                        |
| Indirect Annual Costs                       | •         |   |

### Total Annualized Costs (TAC) 3,996,700 DAC + IAC = TAC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Direct annual costs are based on site-specific design parameters.

<sup>C</sup> Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

<sup>D</sup> Capital Recovery Factor (CFR) based on 15 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

<sup>E</sup> Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

# **Dry Sorbent Injection Capital Cost Summary**

| Description of Cost                      | (\$) <sup>A</sup> | Remarks                                 |
|--|-------------------|---|
| Direct Capital Costs                     |                   | •                                       |
| Dry FGD Equipment <sup>B</sup>           | 1,175,000         | Vendor Quote                            |
| Control/Instrumentation <sup>C</sup>     | 117,500           | 10% of Equipment Cost                   |
| Sales Tax                                | 70,500            | 6% of Equipment Cost                    |
| Freight <sup>C</sup>                     | 58,800            | 5% of Equipment Cost                    |
| Total Equipment Cost (TEC)               | 1,421,800         |   |
|  |                   | Based on percentage of TEC: 12%         |
|  |                   | Foundation & Supports, 40% Erection, 1% |
| Total Installation Cost                  |                   | Electrical Installation, 30% Piping, 1% |
| (TIC)/Balance of Plant Cost <sup>C</sup> | 1,208,500         | Painting, 1% Insulation                 |
| Site Preparation <sup>D</sup>            | 250,000           | Estimated (includes electrical upgrade) |
| Total Direct Investment (TDI)            | 2,880,300         | TEC + TIC + Site Prep. = TDI            |
|  |                   |   |
| Indirect Capital Cost <sup>C</sup>       |                   |   |
| Contingency                              | 42,700            | 3% of TEC                               |
| Engineering                              | 71,100            | 5% of TEC                               |
| Construction & Field Expense             | 142,200           | 10% of TEC                              |
| Contractor Fees                          | 142,200           | 10% of TEC                              |
| Start-up Assistance                      | 14,200            | 1% of TEC                               |
| Performance Test                         | 14,200            | 1% of TEC                               |
|  |                   |   |

### Total Turnkey Cost (TTC)

Total Indirect Investment (TII)

3,306,900 TDI + TII = TTC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost provided by vendor.

<sup>c</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

426,600

# **Dry Sorbent Injection Annual Cost Summary**

| Description of Cost                   | (\$) <sup>A</sup> | Remarks                                 |
|---------------------------------------|-------------------|---|
| Direct Annual Costs <sup>B</sup>      |                   | •                                       |
| DSI Labor                             | 24,600            | 1/2 hr per shift, assumed 8 hr shifts   |
| DSI Supervisor                        | 3,700             | 15% of labor                            |
| Solvent (Trona)                       | 34,700            | Consumption x cost                      |
| Solids Fly Ash Disposal               | 17,000            | Production x cost                       |
| Maintenance Labor                     | 24,600            | 1/2 hr per shift, assumed 8 hr shifts   |
| Maintenance Material, Dry FGD         | 24,600            | 100% of labor                           |
| Induced Draft Fan/Pumps               | 14,500            | Consumption x cost                      |
| Direct Annual Costs (DAC)             | 143,700           |   |
|                                       |                   |   |
| Indirect Annual Costs <sup>C</sup>    |                   |   |
| Overhead                              | 67,300            | 60% of O&M Labor                        |
| Administrative Charges                | 66,100            | 2% of Total Capital Investment          |
| Property Taxes                        | 33,100            | 1% of Total Capital Investment          |
| Insurance                             | 33,100            | 1% of Total Capital Investment          |
| Dry FGD Annualized Costs <sup>D</sup> | 363,100           | (Capital Investment) x (CFR of 0.10979) |
| Indirect Annual Costs (IAC)           | 562,700           |   |

| Total Annualized Costs (TAC) | 706,400 | DAC + IAC = TAC |
|------------------------------|---------|-----------------|

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Direct annual costs are based on site-specific design parameters and vendor quote.

<sup>c</sup> Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

<sup>D</sup> Capital Recovery Factor (CFR) based on 15 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

# Selective Catalytic Reduction Capital Cost Summary

| Description of Cost                      | (\$) <sup>^</sup> | Remarks                         |
|--|-------------------|---------------------------------|
| Direct Capital Costs                     | •                 |                                 |
| SCR Equipment <sup>B</sup>               | 4,954,500         | Control Cost Manual Spreadsheet |
| Reagent Preparation Cost <sup>B</sup>    | 1,618,800         | Control Cost Manual Spreadsheet |
| Control/Instrumentation <sup>C</sup>     | 495,500           | 10% of Equipment Cost           |
| Sales Tax                                | 297,300           | 6% of Equipment Cost            |
| Freight <sup>C</sup>                     | 247,700           | 5% of Equipment Cost            |
| Total Equipment Cost (TEC)               | 7,613,800         |                                 |
| Total Installation Cost                  |                   |                                 |
| (TIC)/Balance of Plant Cost <sup>B</sup> | 2,024,900         | Control Cost Manual Spreadsheet |
| Site Preparation <sup>D</sup>            | 500,000           | Demo and Equipment Relocation   |
| Total Direct Investment (TDI)            | 10,138,700        | TEC + TIC + Site Prep. = TDI    |

| Total Indirect Investment (TII)    | 2,360,300 |            |
|------------------------------------|-----------|------------|
| Performance Test                   | 76,100    | 1% of TEC  |
| Start-up Assistance                | 152,300   | 2% of TEC  |
| Contractor Fees                    | 761,400   | 10% of TEC |
| Construction & Field Expense       | 380,700   | 5% of TEC  |
| Engineering                        | 761,400   | 10% of TEC |
| Contingency                        | 228,400   | 3% of TEC  |
| Indirect Capital Cost <sup>C</sup> | 220.400   | 204 - 6750 |

| Total Turnkey Cost (TTC) | 12,499,000 | TDI + TII = TTC |
|--------------------------|------------|-----------------|
| A                        |            |                 |

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost obtained from EPA Air Pollution Control SCR Spreadsheet.

<sup>C</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

# Selective Catalytic Reduction Annual Cost Summary

| Description of Cost                                   | (\$)^              | Remarks  |
|---|--------------------|--|
| Direct Annual Costs <sup>B</sup>                      |                    |  |
| Annual SCR Maintenance                                | 55,900             | Control Cost Manual Spreadsheet                                  |
| Reagent (Ammonia)                                     | 9,700              | Control Cost Manual Spreadsheet                                  |
| SCR Electricity                                       | 27,600             | Control Cost Manual Spreadsheet                                  |
| Catalyst Replacment                                   | 28,300             | Control Cost Manual Spreadsheet                                  |
| Direct Annual Costs (DAC)                             | 121,500            |  |
|   |                    |  |
| Indirect Annual Costs <sup>C</sup>                    |                    |  |
| <i>Indirect Annual Costs <sup>C</sup></i><br>Overhead | 33,500             | 60% of O&M Labor   |
|   | 33,500<br>250,000  | 60% of O&M Labor<br>2% of Total Capital Investment               |
| Overhead  |                    |  |
| Overhead<br>Administrative Charges                    | 250,000            | 2% of Total Capital Investment                                   |
| Overhead<br>Administrative Charges<br>Property Taxes  | 250,000<br>125,000 | 2% of Total Capital Investment<br>1% of Total Capital Investment |

DAC + IAC = TAC

Total Annualized Costs (TAC) 1,834,800

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

<sup>c</sup> Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

<sup>D</sup> Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

# Selective Non-Catalytic Reduction Capital Cost Summary

| Description of Cost                      | (\$) <sup>^</sup> | Remarks                         |
|--|-------------------|---------------------------------|
| Direct Capital Costs                     |                   |                                 |
| SNCR Equipment <sup>B</sup>              | 866,300           | Control Cost Manual Spreadsheet |
| Control/Instrumentation <sup>C</sup>     | 86,600            | 10% of Equipment Cost           |
| Sales Tax                                | 52,000            | 6% of Equipment Cost            |
| Freight <sup>C</sup>                     | 43,300            | 5% of Equipment Cost            |
| Total Equipment Cost (TEC)               | 1,048,200         |                                 |
| Total Installation Cost                  |                   |                                 |
| (TIC)/Balance of Plant Cost <sup>B</sup> | 1,267,100         | Control Cost Manual Spreadsheet |
| Site Preparation <sup>D</sup>            | 250,000           | Demo and Equipment Relocation   |
| Total Direct Investment (TDI)            | 2,565,300         | TEC + TIC + Site Prep. = TDI    |

| Total Indirect Investment (TII) | <b>324,900</b> |            |
|---------------------------------|----------------|------------|
| Performance Test                | 10,500         | 1% of TEC  |
| Start-up Assistance             | 21,000         | 2% of TEC  |
| Contractor Fees                 | 104,800        | 10% of TEC |
| Construction & Field Expense    | 52,400         | 5% of TEC  |
| Engineering                     | 104,800        | 10% of TEC |
| Contingency                     | 31,400         | 3% of TEC  |

| Total Turnkey Cost (TTC) | 2,890,200 | TDI + TII = TTC |
|--------------------------|-----------|-----------------|
| Δ .                      |           |                 |

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost obtained from EPA Air Pollution Control SNCR Spreadsheet.

<sup>C</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

# Selective Non-Catalytic Reduction Annual Cost Summary

| Description of Cost  | (\$) <sup>A</sup> | Remarks                         |
|--|-------------------|---------------------------------|
| Direct Annual Costs <sup>B</sup>                                     |                   |                                 |
| Annual SNCR Maintenance  | 41,600            | Control Cost Manual Spreadsheet |
| Reagent (Ammonia)  | 9,000             | Control Cost Manual Spreadsheet |
| Electricity  | 600               | Control Cost Manual Spreadsheet |
| Water  | 200               | Control Cost Manual Spreadsheet |
| Additional Fuel  | 1,000             | Control Cost Manual Spreadsheet |
| Additional Ash   | 100               | Control Cost Manual Spreadsheet |
| Direct Annual Costs (DAC)  | 52,500            |                                 |
|  |                   |                                 |
| Indirect Annual Costs <sup>c</sup>                                   |                   |                                 |
| Overhead   | 25,000            | 60% of O&M Labor                |
| Administrative Charges   | 57,800            | 2% of Total Capital Investment  |
|  | 28,000            | 1% of Total Capital Investment  |
| Property Taxes   | 28,900            | 1/0 of fotal capital investment |
| , ,  | 28,900            | 1% of Total Capital Investment  |
| Property Taxes<br>Insurance<br>Dry FGD Annualized Costs <sup>D</sup> |                   | •                               |

| Total Annualized Costs (TAC) | 465,900 | DAC + IAC = TAC |
|------------------------------|---------|-----------------|
|                              | -       |                 |

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

<sup>c</sup> Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

<sup>D</sup> Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.



# Regional Haze Four Factor Analysis

# American Crystal Sugar Company

East Grand Forks, MN

For Submittal to: Minnesota Pollution Control Agency 520 Lafayette Road North St. Paul, MN 55155-4194

August 28, 2020



# **Table of Contents**

| 1 | Intro | oduc            | tion   | . 2 |
|---|-------|-----------------|--|-----|
|   | 1.1   | Ana             | alysis Methodology                                     | . 2 |
|   | 1.2   | EGI             | F Source Parameters                                    | . 2 |
| 2 | Fou   | ır Fa           | ctor Analysis  | . 3 |
|   | 2.1   | Арр             | licable Pollutants                                     | . 3 |
|   | 2.2   | Eco             | nomic Evaluation Criteria                              | . 4 |
|   | 2.3   | SO <sub>2</sub> | 2 Analysis   | . 4 |
|   | 2.3.  | .1              | Identification of SO <sub>2</sub> Control Technologies | . 4 |
|   | 2.3.  | 2               | SO <sub>2</sub> Control Technology Effectiveness       | . 7 |
|   | 2.3.  | 3               | Evaluation of Impacts                                  | . 8 |
|   | 2.4   | NO,             | x Analysis   | . 9 |
|   | 2.4.  | .1              | Identification of NO <sub>x</sub> Control Technologies | 10  |
|   | 2.4.  | 2               | NO <sub>x</sub> Control Technology Effectiveness       | 11  |
|   | 2.4.  | 3               | Evaluation of Impacts                                  | 12  |

### **Appendix A. Cost Calculations**

# 1 Introduction

In response to the Minnesota Pollution Control Agency (MPCA) Request for Information (ROI) dated February 14, 2020, American Crystal Sugar Company (ACSC) is providing the following Four Factor Analysis to address pollutants of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>) emitted from the coal-fired boilers at the East Grand Forks (EGF) facility.

This analysis is being provided for planning purposes and is based on budgetary cost information obtained from scaled vendor quotes for similar systems as well as methodology presented in the U.S. Environmental Protection Agency's (EPA) Air Pollution Control Cost Manual. This approach is intended to provide a study-level estimate (+/-30%) of capital and annual costs. In the event that emission reductions will be proposed for inclusion in the State Implementation Plan (SIP), it is requested that ACSC be given the opportunity to further refine the cost data to incorporate site-specific quotes reflecting current market conditions and unique site physical constraints.

# 1.1 Analysis Methodology

Following the EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, the Four Factor Analysis addresses:

- The costs 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(s).

The first step in the process is identification of all available retrofit technologies for each pollutant ( $SO_2$  and  $NO_x$ ). Control options that are technically infeasible are eliminated and remaining options are evaluated to determine their control effectiveness and economic, energy and environmental impacts.

Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction and are evaluated following a "top-down" approach similar to Best Available Control Technology (BACT) analyses.

Impacts considered for each control technology include: cost of compliance, energy impacts, non-air quality environmental impacts and the remaining useful life of the unit to be controlled.

# **1.2 EGF Source Parameters**

EGF operates two Babcock and Wilcox coal-fired stoker boilers equipped with modern over-fire air (OFA) control systems. The boilers are also equipped with high-efficiency electrostatic precipitators to control particulate matter emissions. The maximum rated heat input of each

boiler is 356 million British thermal units per hour (MMBtu/hr). The boilers combust low sulfur subbituminous coal from the Powder River Basin (PRB).

The boilers are identified as EU001 and EU002 in Air Emission Permit No. 11900002-006. The operating permit limits each boiler to maximum  $SO_2$  emissions of 391.8 lb/hr (1.10 lb/MMBtu) and NO<sub>x</sub> emissions of 227.9 lb/hr (0.64 lb/MMBtu).

As indicated in the EPA's *Guidance on Regional Haze State Implementation Plans*, a state may use a source's annual emissions in tons to determine actual visibility impacts. Therefore, actual emission levels based on source test data were used to characterize emissions-related factors in this analysis. The average SO<sub>2</sub> emission rate from the EGF boilers as reported in the most recent emission inventory is 0.45 lb/MMBtu and 452 tons per year (tpy) for each boiler. The average NO<sub>x</sub> emission rate from the EGF boilers as reported in the most recent emission inventory is 0.34 lb/MMBtu and 340 tpy for each boiler.

Because the boilers are of identical size and type, control technology costs and design features would be the same for both boilers. It is anticipated that the Four Factor Analysis applies to the EGF facility as a whole, and potential control technology determinations would not be made for a single boiler, but instead would apply to both boilers at the facility. Therefore, the average emission rate for the two boilers was used in the analysis to determine costs of compliance.

# 2 Four Factor Analysis

# 2.1 Applicable Pollutants

The Four Factor Analysis addresses criteria pollutants of SO<sub>2</sub> and NO<sub>x</sub>.

<u>SO<sub>2</sub> Formation</u>. SO<sub>2</sub> emissions are formed from the oxidation of organic sulfur and pyritic sulfur in the coal during the combustion process. The majority of sulfur is oxidized to SO<sub>2</sub>, however, a small quantity may be further oxidized to form sulfur trioxide (SO<sub>3</sub>). Approximately 90% of the sulfur present in the subbituminous coal will be emitted as sulfur oxides (SO<sub>x</sub>) compounds. Alkaline ash from some coals (including PRB coals) may cause some of the sulfur to react in the furnace to form various sulfate salts that are then retained in the fly ash. Sulfuric acid mist (H<sub>2</sub>SO<sub>4</sub>) forms when SO<sub>2</sub> emissions react with moisture and oxygen in the environment.

<u>NO<sub>x</sub> Formation</u>. There are two primary mechanisms of NO<sub>x</sub> formation in coal-fired industrial boilers: thermal production of NOx from atmospheric nitrogen and oxygen, and oxidation of nitrogen bound in the fuel. High combustion temperatures cause the nitrogen (N<sub>2</sub>) and oxygen (O<sub>2</sub>) molecules in the combustion air to react and form thermal NO<sub>x</sub>. Because thermal NO<sub>x</sub> is primarily a function of combustion temperature, NO<sub>x</sub> emission rates vary with burner and source design. Experimental measurements of thermal NO<sub>x</sub> formation have shown that the NO<sub>x</sub> concentration is exponentially dependent on temperature and is proportional to the N<sub>2</sub> concentration in the flame, the square root of the O<sub>2</sub> concentration in the flame, and the gas residence time<sup>1</sup>. The formation of fuel NO<sub>x</sub> from reactions of fuel bound nitrogen and air can

<sup>&</sup>lt;sup>1</sup> AP42, Chapter 1, Bituminous and Subbituminous Coal Combustion, (9/98).

account for up to 80% of total  $NO_x$  from coal combustion. Subbituminous coals contain from 0.5 to 2 percent by weight fuel-bound nitrogen.

# 2.2 Economic Evaluation Criteria

Costs of compliance are directly related to the technically feasible control technology option selected and the level of emission reduction experienced from the control. Costs are expressed in terms of dollars per ton of pollutant removed, where the cost is the annualized capital and operating costs, and the tons of pollutant removed is the incremental reduction in pollutant emissions over current baseline (actual) emission levels.

Base economic criteria used in this analysis are listed in Table 1.

| Economic Parameter                     | Value                |
|--|----------------------|
| Interest Rate, percent                 | 7 <sup>A</sup>       |
| Control Equipment Economic Life, years | 15 & 20 <sup>B</sup> |
| Base Labor Cost, \$/hr                 | 60 <sup>c</sup>      |
| Energy Cost, \$/kW-hr                  | 0.06 <sup>D</sup>    |

# Table 1 – Economic Evaluation Criteria.

<sup>A</sup> EPA Air Pollution Control Cost Manual, Seventh Edition, January 2017, Chapter 2, Section 2.4.2.

<sup>B</sup> Based on Control Equipment Type. EPA Memorandum, Calculating Amortized Capital Costs, July 24, 1987, Robert D. Bauman, Chief, Standards and Implementation Branch.

<sup>c</sup> Loaded labor rate obtained from ACSC.

<sup>D</sup> Actual ACSC electricity cost.

Cost estimates used in the analysis have been compiled from a number of data sources. In general, the cost estimates were performed following guidance provided in EPA's *Air Pollution Control Cost Manual, Seventh Edition*, January 2017. The EPA control cost manual data was supplemented with vendor supplied quotations when available and general engineering estimates. Detailed cost estimate and support data have been provided in Appendix A.

# 2.3 SO<sub>2</sub> Analysis

Because the two coal-fired boilers at the EGF facility are identical, the analysis was prepared for one individual boiler. The results of the analysis can be applied equally to each boiler.

# 2.3.1 Identification of SO<sub>2</sub> Control Technologies

Control of SO<sub>2</sub> emissions from fuel-combustion sources can be accomplished through two approaches: removal of elemental sulfur from the fuel prior to combustion, and flue gas desulfurization (FGD), which consists of removal of SO<sub>2</sub> from flue gas after combustion (post-combustion control).

Many oil refineries operate catalyst-based desulfurization units to remove organic sulfur from liquid crude oil. However, in solid fuels, such as coal, a significant fraction of the sulfur is in the

form of pyrite (FeS<sub>2</sub>) or other mineral sulfates. It is possible to remove some mineral sulfates through physical processes such as washing and/or chemical processing. However, desulfurization of solid fuels is generally viewed as inefficient and expensive. Additionally, organic sulfur cannot be removed by physical cleaning. It is unlikely that sufficient desulfurization of solid fuels can be accomplished to meet anticipated emission requirements. Therefore removal of sulfur from the coal prior to combustion will not be considered a viable option for this analysis.

FGD technologies can be divided into two main categories: regenerative and throwaway processes. Regenerative processes recover sulfur in a usable form that can be sold as a reusable sulfur product. Throwaway processes remove sulfur from flue gas and scrubber byproducts are subsequently discarded. All of the FGD technologies considered can achieve SO<sub>2</sub> removal efficiencies of 90 to 95% depending on the amount of sulfur in the coal. For relatively high sulfur coals, removal efficiencies can exceed 95%, while for lower sulfur coals (such as PRB), the achievable removal efficiency is typically less than 95%.

Regenerative processes, by nature, contain a regeneration step in the FGD process that results in higher costs than throwaway processes due to equipment and operation expenses. However, in instances where disposal options are limited and markets for recovered sulfur products are readily available, regenerative processes may be used. Potential regenerative processes that are available include the Wellman-Lord (W-L) process, magnesium oxide process, citrate scrubbing process, Flakt-Boliden process, aqueous carbonate process, Sulf-X process, Conosox process, Westvaco process and adsorption of SO<sub>2</sub> by a bed of copper oxide.

Throwaway processes such as limestone scrubbing have become widely accepted by the coalfired power industry for FGD because limestone scrubbers have overall lower costs and are simpler to operate than regenerative processes. Because the throwaway process can achieve the same removal efficiencies as regenerative processes and cost less, this analysis for SO<sub>2</sub> will focus on throwaway processes and further discussion of regenerative processes will not be considered.

Throwaway processes can be divided into two categories, wet and dry. Wet or dry refers to the state of the waste by-products. Both wet and dry technologies have advantages and disadvantages with respect to initial capital and operational expenses.

### 2.3.1.1 Wet FGD Systems

Wet scrubbing (wet FGD) systems used for SO<sub>2</sub> reduction typically consist of the following operations: scrubbing or absorption, lime handling and slurry preparation, sludge processing, and flue gas handling.

Wet FGD technology is a well-established process for removing SO<sub>2</sub> from flue gas. In wet scrubbers, the flue gas enters a spray tower or absorber where it is sprayed with a water slurry, which is approximately 10 percent lime or limestone. Sodium alkali solutions can also be used in FGD systems, however these processes are considerably more expensive than lime. The preferred sorbents are limestone and lime, respectively, due to the availability and relatively low

cost of limestone. Calcium in the slurry reacts with the  $SO_2$  in the flue gas to form calcium sulfite or calcium sulfate. The overall chemical reaction can be simply expressed as:

$$SO_2 + CaCO_3 \rightarrow CaSO_3 + CO_2$$

Spent slurry from the reaction tank is pumped into a thickener where solids settle before being filtered for final dewatering to approximately 50 percent solids. Water removed during this process is sent to a process water holding tank, which eventually will require wastewater treatment. In a non-regenerative system, the waste sludge must also be disposed of properly. Finally, scrubbed flue gases are directed through a stack gas reheater in order to minimize corrosion downstream of the scrubber due to conversion of  $SO_2$  to  $SO_3$  and subsequently sulfuric acid (H<sub>2</sub>SO<sub>4</sub>). Reheating is sometimes needed for proper drafting and rise of exhaust gases out the stack, as well as minimizing condensation. As an alternative, the stack can be constructed of acid resistant material.

Most wet FGD systems have two stages: one for fly ash removal and one for  $SO_2$  removal. The flue gas normally passes first through a fly ash removal device, either an electrostatic precipitator (ESP) or a bag filter, and then into the  $SO_2$  absorber. There are many different types of absorbers that can be used in wet FGD systems, including: spray towers, venturis, plate towers, and mobile packed beds. However, many of these systems can result in scale buildup, plugging or erosion, which can affect the dependability and efficiency of the absorber. Therefore, simple scrubbers such as spray towers are commonly used. The chief drawback of the spray tower design is that it requires a higher liquid-to-gas ratio for equivalent removal of  $SO_2$  than other absorber designs.

### 2.3.1.2 Dry FGD Systems

In contrast to wet scrubbing systems, dry FGD (spray dryer) systems use much smaller amounts of liquid. With a spray dryer system, the flue gases enter an absorbing tower (dryer) where the hot gases are contacted with a finely atomized slurry, which is usually a calciumbased sorbent such as calcium hydroxide or calcium oxide (lime). Acid gases and SO<sub>2</sub> are absorbed by the slurry mixture and react to form solid salts. The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a non-saturated flue gas exits the absorber tower. The absorption process is also somewhat temperature dependent. Cooler flue gases allow the acid gases to more effectively react with the sorbents. The overall chemical reactions can be simply expressed as:

 $Ca(OH)_2 + SO_2 \rightarrow CaSO_3(s) + H_2O$ 

 $Ca(OH)_2 + 2HCI \rightarrow CaCl_2 (s) + 2H_2O$ 

As can be seen above, one mole of calcium hydroxide will neutralize one mole of SO<sub>2</sub>, whereas one mole of calcium hydroxide will neutralize two moles of hydrochloric acid (HCI). A similar reaction occurs with the neutralization of hydrofluoric acid (HF). These reactions demonstrate that when using a spray dryer the HCI and HF are removed more readily than SO<sub>2</sub>. Reagent

requirements should consider that the HCl and HF are removed first, followed by the reagent quantity required to remove the  $SO_2^2$ .

The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a nonsaturated flue gas exists the absorber tower. The exhaust stream exiting the absorber contains fly ash, calcium salts, and un-reacted lime, which must be sent to a particulate control device such as a fabric filter (baghouse). The particulate control device not only is necessary to control particulate matter, but also aids in acid-gas removal. Acid gases are removed when the flue gas comes in contact with the lime-containing particles on the surface of the ESP or baghouse. Fabric filters are considered to have slightly higher residual acid gas removal levels than ESPs because the acid gases must pass through the lime-containing filter cake in a fabric filter system. Modern dry FGD systems include a loop to recycle a portion of the baghouse-collected material for re-use in the FGD module because this material contains a relatively high amount of unreacted lime.

A lower efficiency Dry FGD process that utilizes either wet or dry reagent injected directly into the furnace or flue gas duct is known as dry sorbent injection (DSI). In general, hydrated lime, lime slurry or powdered lime is injected into the existing furnace or ductwork. The constraints of the existing furnace and ductwork configuration may limit expected retrofit control efficiencies of SO<sub>2</sub>, which range from 25 to 50%. A significant drawback of this type of system is the increased maintenance costs incurred from directly injecting a sorbent into the furnace and associated duct work and the potential to significantly reduce the useful life of the boiler. Although DSI is a type of Dry FGD process, it will be referred to separately in this analysis.

2.3.2 SO<sub>2</sub> Control Technology Effectiveness

Effectiveness is measured by the amount of SO<sub>2</sub> removed from each control technology based on a comparison of the controlled emission rates to the baseline emission rates of the boilers. Table 2 provides a summary of the SO<sub>2</sub> control technology effectiveness.

| Control Technology | Percent SO <sub>2</sub><br>Reduction <sup>A</sup> | Emission Rate<br>(Ib/MMBtu) | Annual<br>Emissions<br>(tpy) | Tons SO <sub>2</sub><br>Removed<br>(tpy) |
|--------------------|---|-----------------------------|------------------------------|--|
| Baseline           | 0   | 0.45                        | 452                          | NA                                       |
| Wet FGD            | 80  | 0.09                        | 90                           | 362                                      |
| Dry FGD            | 80  | 0.09                        | 90                           | 362                                      |
| DSI                | 30  | 0.31                        | 316                          | 136                                      |

Table 2 –  $SO_2$  Control Technology Effectiveness.

<sup>A</sup> Control efficiency is the lowest expected end of the range due to the combustion of low sulfur PRB coals and high relative flue gas flowrate for boiler design.

As indicated in Table 2, it is anticipated that the same level of SO<sub>2</sub> control can be achieved by the use of either Dry or Wet FGD spray dryer systems (non-DSI). This assumption is based on observation of FGD control in use on coal-fired utility boilers.

<sup>&</sup>lt;sup>2</sup> Karl B. Schnelle, Jr. and Charles A. Brown, Air Pollution Control Technology Handbook, CRC Press, 2002.

In general terms, removal of high concentrations of SO<sub>2</sub> in the flue gas is easily accomplished using either Dry or Wet FGD. Lower concentrations become more difficult to control and require greater amounts of reagent. Historically, Wet FGD systems have been used on higher-sulfur eastern coals, leading to higher efficiencies cited for Wet FGD systems, given there is much more sulfur to control. However, on lower-sulfur western coals (such as the PRB coal used at EGF) modern Dry FGD systems with better atomizer systems in conjunction with modern fabric filter technology can perform nearly as well as Wet FGD systems. Much of the final SO<sub>2</sub> control in a Dry FGD system takes place in the reagent-rich filter cake on the fabric filter.

Because of the equivalency in anticipated SO<sub>2</sub> emission rates, only Dry FGD technology is considered in this analysis. Dry FGD technology was selected as it has lower capital and operating costs than Wet FGD and will result in a more cost-effective approach. Furthermore, use of Wet FGD to control SO<sub>2</sub> emissions from the EGF boilers would result in both higher energy penalties to the facility operations and the generation of more waste byproducts than would Dry FGD. Increased energy penalties would be due to the additional pumps and water handling equipment required for slurry preparation for the Wet FGD, which would also lead to the creation of additional waste byproducts from the spent slurry. Dewatering of the spent slurry results in the production of a wastewater stream, as well as a waste sludge that must be disposed of in a landfill. Dry FGD results only in a dry product which is easily landfilled.

The lower control efficiencies of 80 and 30% anticipated for the Dry FGD and DSI systems, respectively, are based on the fact the EGF boilers combust low sulfur PRB coal and have relatively high flue gas flow rates associated with the OFA system, resulting in lower starting SO<sub>2</sub> concentrations. Additionally, because the boilers have a smaller than typical furnace size for the type of coal combusted, boiler slagging and maintenance is higher than typical. As a result, the introduction of large amounts of sorbent into the furnace and high temperature flue gas (such as with DSI systems) is anticipated to magnify these issues and result in a detrimental impact on operation and efficiency. Furthermore, frequent process load swings resulting from varying production demands presents difficulties with balancing sorbent injection and maintaining consistent control.

### 2.3.3 Evaluation of Impacts

The following sections present a detailed evaluation of the impacts of employing Dry FGD and DSI to control SO<sub>2</sub> emissions from the EGF boilers. The four factors assessed include: cost of compliance, energy, non-air quality environmental impacts and remaining useful life.

### 2.3.3.1 Cost of Compliance

Table 3 summarizes the capital and annual operating costs associated with retrofitting a Dry FGD and DSI system to each EGF boiler. Detailed cost estimates indicating data sources for each cost category have been included in Appendix A.

| Description                                | Technology Option          |           |  |  |
|--|----------------------------|-----------|--|--|
| -  | Dry FGD w/Fabric<br>Filter | DSI       |  |  |
| Emission Rate (Ib/MMBtu)                   | 0.09                       | 0.31      |  |  |
| Emission Reduction (tpy)                   | 362                        | 136       |  |  |
| Capital Cost (\$)                          | 24,188,700                 | 5,302,000 |  |  |
| Direct Annual Cost (\$)                    | 1,701,200                  | 182,500   |  |  |
| Indirect Annual Cost (\$)                  | 4,135,600                  | 873,600   |  |  |
| Total Annualized Cost (\$)                 | 5,836,800                  | 1,056,100 |  |  |
| Cost Effectiveness, per Boiler<br>(\$/ton) | 16,100                     | 7,800     |  |  |

### Table 3 – SO<sub>2</sub> Costs of Compliance (per boiler).

#### 2.3.3.2 Energy Impact

Use of Dry FGD or DSI to control SO<sub>2</sub> emissions from the EGF boilers would result in energy penalties to facility operations in the form of the electricity demand required for operation of ancillary equipment such as the reagent preparation and atomizer equipment, as well as additional backpressure on the exhaust system that results in decreased operational efficiency.

#### 2.3.3.3 Non-Air Quality Environmental Impacts

The primary detrimental non-air quality environmental impact of a Dry FGD or DSI system is the creation of a solid waste byproduct from the spent reagent. Unlike Wet FGD, there is no wastewater stream resultant from the use of Dry FGD. The solid waste that is produced from a Dry FGD system can be landfilled or possibly used as an agricultural soil supplement depending on the fly ash content.

The DSI system is anticipated to greatly increase maintenance requirements as a result of increased boiler slagging and equipment fouling. Given the age of the existing boilers, the implementation of such a system may have a significant negative impact on remaining useful life.

#### 2.3.3.4 Remaining Useful Life

The remaining useful life of the EGF boilers is greater than 20 years. Therefore, the remaining useful life has no impact on the annualized estimated control technology costs.

# 2.4 NO<sub>x</sub> Analysis

Because the two coal-fired boilers at the EGF facility are identical, the analysis was prepared for one individual boiler. The results of the analysis can be applied equally to each boiler.

## 2.4.1 Identification of NO<sub>x</sub> Control Technologies

Control of  $NO_x$  emissions from boilers can be attained through either the application of combustion controls or flue gas treatment (post-combustion) technologies. Combustion control processes can reduce the quantity of  $NO_x$  formed during the combustion process. Post-combustion technologies reduce the  $NO_x$  concentrations in the flue gas steam after the  $NO_x$  has been formed in the combustion process. These methods may be used alone or in combination to achieve the various degrees of  $NO_x$  emissions required.

#### 2.4.1.1 Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) systems are an add-on flue gas treatment (postcombustion control technology) to control NO<sub>x</sub> emissions. The SCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH<sub>3</sub>) or urea (CON<sub>2</sub>H<sub>4</sub>) to reduce the NO<sub>x</sub> in the flue gas to N<sub>2</sub> and H<sub>2</sub>O. The reagent is injected into the flue gas prior to passage through a catalyst bed, which accelerates the NO<sub>x</sub> reduction reaction rate. Use of SCR results in small levels of NH<sub>3</sub> emissions (NH<sub>3</sub> slip). As the catalyst degrades, NH<sub>3</sub> slip will increase, ultimately requiring catalyst replacement.

Many types of catalysts, ranging from active metals to highly porous ceramics, are available for different applications. The type of catalyst chosen depends on several operational parameters, such as reaction temperature range, flue gas flow rate, fuel chemistry, catalyst activity and selectivity, operating life, and cost. Catalyst materials include, platinum (Pt), vanadium (V), titanium (Ti), tungsten (W), titanium oxide (TiO<sub>2</sub>), zirconium oxide (ZrO<sub>2</sub>), vanadium pentoxide ( $V_2O_5$ ), silicon oxide (SiO<sub>2</sub>), and zeolites (crystalline alumina silicates).

SCR systems can utilize aqueous NH<sub>3</sub>, anhydrous NH<sub>3</sub>, or a urea solution to produce NH<sub>3</sub> on demand. Aqueous NH<sub>3</sub> is generally transported and stored in concentrations ranging from 19% to 30% and therefore requires more storage capacity than anhydrous NH<sub>3</sub>. Anhydrous NH<sub>3</sub> is nearly 100% pure in concentration and is a gas at normal atmospheric temperature and pressure. Anhydrous NH<sub>3</sub> must be stored and transported under pressure and when stored in quantities greater than 10,000 pounds, is subject to Risk Management Planning (RMP) requirements (40 CFR 68). The urea solution (urea and water at approximately 32% concentration) is used to form NH<sub>3</sub> on demand for injection into the flue gas. Generally, a specifically designed duct and decomposition chamber with a small supplemental burner is used to provide an appropriate temperature window and residence time to decompose urea to NH<sub>3</sub> and isocyanic acid (HNCO). Application of urea-based SCR systems to industrial boilers is a relatively new practice that is still under development.

Several different SCR system configurations have been used on utility boilers and are theoretically possible for use on smaller industrial boilers. In a high-dust SCR system, the reactor is located downstream of the economizer and upstream of the air heater, FGD system, and particulate control device. Low-dust SCR systems locate the reactor downstream of a particulate control device where the flue gas is relatively dust-free. Tail-end SCR systems locate the reactor downstream from all air pollution control equipment where most flue gas constituents detrimental to the SCR catalyst have been removed. However, tail-end SCR

systems can require reheating of the flue gas to minimize condensation, leading to corrosion problems.

# 2.4.1.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is another method of post-combustion control. Similar to SCR, the SNCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH<sub>3</sub>) or urea to reduce the NO<sub>x</sub> in the flue gas to N<sub>2</sub> and H<sub>2</sub>O. However, the SNCR process works without the use of a catalyst. Instead, the SNCR process occurs within a combustion unit, which acts as the reaction chamber. The heat from the boiler combustion process provides the energy for the NO<sub>x</sub> reduction reaction. Flue gas temperatures in the range of 1,500 to 1,900 °F, along with adequate reaction time within this temperature range, are required for this technology. SNCR is currently being used for NO<sub>x</sub> emission control on some utility boilers, and can achieve NO<sub>x</sub> reduction efficiencies of up to 75%. However, in typical industrial applications SNCR provides 30% to 50% NO<sub>x</sub> reduction.

# 2.4.1.3 Combustion Controls

Combustion controls such as flue gas recirculation (FGR), reducing air preheat temperature (RAP), oxygen trim (OT), low excess air (LEA), over-fire air (OFA), staged combustion air (SCA), and low NO<sub>x</sub> burners (LNB), can be used to reduce NO<sub>x</sub> emissions depending on the type of boiler, characteristics of fuel and method of firing. In practice, combustion controls have not provided the same degree of NO<sub>x</sub> controls as provided by add-on post combustion control technologies, but are generally used in conjunction with add-on controls, such as SNCR, to increase the NO<sub>x</sub> removal efficiency. The EGF boilers are currently equipped with modern OFA control systems.

# 2.4.2 NO<sub>x</sub> Control Technology Effectiveness

Effectiveness is measured by the amount of  $NO_x$  removed by each control technology based on a comparison of the controlled emission rates to the baseline emission rates of the boilers. Table 4 provides a summary of the  $NO_x$  control technology effectiveness.

| Control Technology | Percent NO <sub>x</sub><br>Reduction | Emission Rate<br>(Ib/MMBtu) | Annual<br>Emissions<br>(tpy) | Tons NO <sub>x</sub><br>Removed<br>(tpy) |
|--------------------|--------------------------------------|-----------------------------|------------------------------|--|
| Baseline/OFA       | 0                                    | 0.34                        | 340                          | NA                                       |
| SCR                | 80                                   | 0.07                        | 68                           | 272                                      |
| SNCR               | 30                                   | 0.26                        | 238                          | 102                                      |

Table 4 – NO<sub>x</sub> Control Technology Effectiveness.

The lower control efficiencies of 80 and 30% anticipated for the SCR and SNCR systems, respectively, are based on the fact the EGF boilers are equipped with modern OFA control systems that work to reduce the starting  $NO_x$  concentration. Furthermore, the boilers have a smaller than typical furnace size for the type of coal combusted and flue gas flow rates that are higher than typical. This operational characteristic, when combined with frequent process load

swings resulting from varying production demands, results in variable flue gas temperature ranges within the boiler furnace and presents difficulties with balancing reagent injection and maintaining consistent control.

## 2.4.3 Evaluation of Impacts

The following sections present a detailed evaluation of the impacts of employing the feasible control technologies to control NO<sub>x</sub> emissions from the EGF boilers. The four factors assessed include: cost of compliance, energy, non-air quality environmental impacts and remaining useful life.

### 2.4.3.1 Cost of Compliance

Table 5 summarizes the capital and annual operating costs associated with retrofitting  $NO_x$  control systems to each EGF boiler. Detailed cost estimates indicating data sources for each cost category have been included in Appendix A.

| Description                                | Technology Option |           |  |  |
|--|-------------------|-----------|--|--|
| -  | SCR               | SNCR      |  |  |
| Emission Rate (Ib/MMBtu)                   | 0.07              | 0.26      |  |  |
| Emission Reduction (tpy)                   | 272               | 102       |  |  |
| Capital Cost (\$)                          | 21,572,000        | 4,090,400 |  |  |
| Direct Annual Cost (\$)                    | 246,200           | 89,200    |  |  |
| Indirect Annual Cost (\$)                  | 2,980,900         | 584,100   |  |  |
| Total Annualized Cost (\$)                 | 3,245,100         | 673,300   |  |  |
| Cost Effectiveness, per Boiler<br>(\$/ton) | 11,900            | 6,600     |  |  |

### Table 5 – NO<sub>x</sub> Cost of Compliance (per Boiler).

#### 2.4.3.2 Energy Impact

The application of SCR and SNCR systems would result in energy penalties in the form of electricity demand for required operation of ancillary equipment such as reagent preparation and delivery, as well as additional backpressure on the exhaust system that results in decreased operational efficiency.

### 2.4.3.3 Non-Air Quality Environmental Impacts

SCR and SNCR both require some form of ammonia (NH<sub>3</sub>) source for operation. This can be stored in liquid, solid or gas, and processed on site for use. Depending on quantities stored, risk management requirements may apply. Both systems are also prone to NH<sub>3</sub> slip from unreacted NH<sub>3</sub>. This will result in the emission of an additional pollutant.

#### 2.4.3.4 Remaining Useful Life

The remaining useful life of the EGF boilers is greater than 20 years. Therefore, the remaining useful life has no impact on the annualized estimated control technology costs.



# Appendix A Cost Calculations

# **Dry FGD Capital Cost Summary**

| Description of Cost                      | (\$) <sup>A</sup> | Remarks                                 |  |  |
|--|-------------------|---|--|--|
| Direct Capital Costs                     |                   |   |  |  |
| Dry FGD Equipment <sup>B</sup>           | 4,740,100         | Scaled Quote                            |  |  |
| Control/Instrumentation <sup>C</sup>     | 474,000           | 10% of Equipment Cost                   |  |  |
| Sales Tax                                | 284,400           | 6% of Equipment Cost                    |  |  |
| Freight <sup>C</sup>                     | 237,000           | 5% of Equipment Cost                    |  |  |
| Total Equipment Cost (TEC)               | 5,735,500         |   |  |  |
|  |                   | Based on percentage of TEC: 12%         |  |  |
|  |                   | Foundation & Supports, 40% Erection, 1% |  |  |
| Total Installation Cost                  |                   | Electrical Installation, 30% Piping, 1% |  |  |
| (TIC)/Balance of Plant Cost <sup>C</sup> | 4,875,200         | Painting, 1% Insulation                 |  |  |
| Site Preparation <sup>D</sup>            | 1,000,000         | Estimated                               |  |  |
| Total Direct Investment (TDI)            | 11,610,700        | TEC + TIC + Site Prep. = TDI            |  |  |
|  |                   |   |  |  |
| Indirect Capital Cost <sup>C</sup>       |                   |   |  |  |
| Contingency                              | 172,100           | 3% of TEC                               |  |  |
| Engineering                              | 573,600           | 10% of TEC                              |  |  |
| Construction & Field Expense             | 573,600           | 10% of TEC                              |  |  |
| Contractor Fees                          | 573,600           | 10% of TEC                              |  |  |
| Start-up Assistance                      | 57,400            | 1% of TEC                               |  |  |
| Performance Test                         | 57,400            | 1% of TEC                               |  |  |
| Total Indirect Investment (TII)          | 2,007,700         |   |  |  |

# Total Turnkey Cost (TTC)

13,618,400 TDI + TII = TTC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost provided by vendor and scaled from similar projects.

<sup>c</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

<sup>D</sup> Estimated by HDR.

# **Dry FGD Fabric Filter Capital Cost Summary**

| Description of Cost                      | (\$) <sup>A</sup> | Remarks  |  |  |
|--|-------------------|--|--|--|
| Direct Capital Costs                     |                   | •  |  |  |
| Dry FGD Equipment <sup>B</sup>           | 3,611,500         | Scaled Quote   |  |  |
| Control/Instrumentation <sup>C</sup>     | 361,200           | 10% of Equipment Cost  |  |  |
| Sales Tax                                | 216,700           | 6% of Equipment Cost   |  |  |
| Freight <sup>C</sup>                     | 180,600           | 5% of Equipment Cost   |  |  |
| Total Equipment Cost (TEC)               | 4,370,000         |  |  |  |
| Tabal Installation Cost                  |                   | Based on percentage of TEC:4%Foundation & Supports, 50% Erection, 8% |  |  |
| Total Installation Cost                  |                   | Electrical Installation, 1% Piping, 4% Painting,                     |  |  |
| (TIC)/Balance of Plant Cost <sup>C</sup> | 3,233,800         | 7% Insulation  |  |  |
| Site Preparation <sup>D</sup>            | 1,000,000         | Estimated  |  |  |
| Total Direct Investment (TDI)            | 8,603,800         | TEC + TIC + Site Prep. = TDI   |  |  |
| Indirect Capital Cost <sup>C</sup>       |                   |  |  |  |
| Contingency                              | 131,100           | 3% of TEC  |  |  |
| Engineering                              | 437,000           | 10% of TEC   |  |  |
| Construction & Field Expense             | 874,000           | 20% of TEC   |  |  |
| Contractor Fees                          | 437,000           | 10% of TEC   |  |  |
| Start-up Assistance                      | 43,700            | 1% of TEC  |  |  |
| Performance Test                         | 43,700            | 1% of TEC  |  |  |

# Total Turnkey Cost (TTC)

Total Indirect Investment (TII)

10,570,300 TDI + TII = TTC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost provided by vendor and scaled from similar projects.

<sup>c</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

1,966,500

<sup>D</sup> Estimated by HDR.

# Dry FGD/Fabric Filter Annual Cost Summary

| Description of Cost              | (\$) <sup>A</sup> | Remarks                             |  |
|----------------------------------|-------------------|-------------------------------------|--|
| Direct Annual Costs <sup>B</sup> |                   | •                                   |  |
| Dry FGD Labor                    | 49,300            | 1 hr per shift, assumed 8 hr shifts |  |
| Dry FGD Supervisor               | 7,400             | 15% of labor                        |  |
| Fabric Filter Labor              | 65,700            | 2 hr per shift, assumed 8 hr shifts |  |
| Fabric Filter Supervisor         | 9,900             | 15% of labor                        |  |
| Solvent (Reagent)                | 457,900           | Consumption x cost                  |  |
| Fabric Filter Bag Replacement    | 304,900           | Labor plus bag cost                 |  |
| Solids Scrubber Disposal         | 100,300           | Production x cost                   |  |
| Solids Fly Ash Disposal          | 168,000           | Production x cost                   |  |
| Maintenance Labor, Dry FGD       | 49,300            | 1 hr per shift, assumed 8 hr shifts |  |
| Maintenance Material, Dry FGD    | 49,300            | 100% of labor                       |  |
| Maintenance Labor, Fabric F.     | 65,700            | 2 hr per shift, assumed 8 hr shifts |  |
| Maintenance Material, Fabric F.  | 65,700            | 100% of labor                       |  |
| Induced Draft Fan                | 231,100           | Consumption x cost                  |  |
| Pump                             | 76,700            | Consumption x cost                  |  |
| Direct Annual Costs (DAC)        | 1,701,200         |                                     |  |

| Indirect Annual Costs (IAC)                 | 4,135,600 |   |
|---|-----------|---|
| Fabric Filter Annualized Costs <sup>E</sup> | 997,700   | (Capital Investment) x (CFR of 0.09439) |
| Dry FGD Annualized Costs <sup>D</sup>       | 1,495,200 | (Capital Investment) x (CFR of 0.10979) |
| Insurance                                   | 241,900   | 1% of Total Capital Investment          |
| Property Taxes                              | 241,900   | 1% of Total Capital Investment          |
| Administrative Charges                      | 483,800   | 2% of Total Capital Investment          |
| Overhead                                    | 675,100   | 60% of O&M Labor                        |
|   |           |   |

# Total Annualized Costs (TAC) 5,836,800 DAC + IAC = TAC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Direct annual costs are based on site-specific design parameters.

<sup>C</sup> Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

<sup>D</sup> Capital Recovery Factor (CFR) based on 15 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

<sup>E</sup> Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

# **Dry Sorbent Injection Capital Cost Summary**

| Description of Cost                      | (\$) <sup>A</sup> | Remarks                                 |  |  |
|--|-------------------|---|--|--|
| Direct Capital Costs                     |                   | •                                       |  |  |
| Dry FGD Equipment <sup>B</sup>           | 1,865,000         | Vendor Quote                            |  |  |
| Control/Instrumentation <sup>C</sup>     | 186,500           | 10% of Equipment Cost                   |  |  |
| Sales Tax                                | 111,900           | 6% of Equipment Cost                    |  |  |
| Freight <sup>C</sup>                     | 93,300            | 5% of Equipment Cost                    |  |  |
| Total Equipment Cost (TEC)               | 2,256,700         |   |  |  |
|  |                   | Based on percentage of TEC: 12%         |  |  |
|  |                   | Foundation & Supports, 40% Erection, 1% |  |  |
| Total Installation Cost                  |                   | Electrical Installation, 30% Piping, 1% |  |  |
| (TIC)/Balance of Plant Cost <sup>C</sup> | 1,918,200         | Painting, 1% Insulation                 |  |  |
| Site Preparation <sup>D</sup>            | 450,000           | Estimated (includes electrical upgrade) |  |  |
| Total Direct Investment (TDI)            | 4,624,900         | TEC + TIC + Site Prep. = TDI            |  |  |
|  |                   |   |  |  |
| Indirect Capital Cost <sup>C</sup>       |                   |   |  |  |
| Contingency                              | 67,700            | 3% of TEC                               |  |  |
| Engineering                              | 112,800           | 5% of TEC                               |  |  |
| Construction & Field Expense             | 225,700           | 10% of TEC                              |  |  |
| Contractor Fees                          | 225,700           | 10% of TEC                              |  |  |
| Start-up Assistance                      | 22,600            | 1% of TEC                               |  |  |
| Performance Test                         | 22,600            | 1% of TEC                               |  |  |
|  |                   |   |  |  |

# Total Turnkey Cost (TTC)

Total Indirect Investment (TII)

5,302,000 TDI + TII = TTC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost provided by vendor.

<sup>c</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

677,100

<sup>D</sup> Estimated by HDR.

# **Dry Sorbent Injection Annual Cost Summary**

| Description of Cost                   | (\$) <sup>A</sup> | Remarks                                 |  |
|---------------------------------------|-------------------|---|--|
| Direct Annual Costs <sup>B</sup>      |                   |   |  |
| DSI Labor                             | 24,600            | 1/2 hr per shift, assumed 8 hr shifts   |  |
| DSI Supervisor                        | 3,700             | 15% of labor                            |  |
| Solvent (Trona)                       | 55,000            | Consumption x cost                      |  |
| Solids Fly Ash Disposal               | 27,000            | Production x cost                       |  |
| Maintenance Labor                     | 24,600            | 1/2 hr per shift, assumed 8 hr shifts   |  |
| Maintenance Material, Dry FGD         | 24,600            | 100% of labor                           |  |
| Induced Draft Fan/Pumps               | 23,000            | Consumption x cost                      |  |
| Direct Annual Costs (DAC)             | 182,500           |   |  |
| Indirect Annual Costs <sup>C</sup>    |                   |   |  |
| Overhead                              | 79,500            | 60% of O&M Labor                        |  |
| Administrative Charges                | 106,000           | 2% of Total Capital Investment          |  |
| ŭ                                     | -                 | · · · · · · · · · · · · · · · · · · ·   |  |
| Property Taxes                        | 53,000            | 1% of Total Capital Investment          |  |
| Insurance                             | 53,000            | 1% of Total Capital Investment          |  |
| Dry FGD Annualized Costs <sup>D</sup> | 582,100           | (Capital Investment) x (CFR of 0.10979) |  |

| Total Annualized Costs (TAC) | 1 050 100 |                 |
|------------------------------|-----------|-----------------|
| Lotal Annualized Costs (TAC) | 1,056,100 | DAC + IAC = TAC |
|                              | _,        |                 |

<sup>A</sup> Values rounded to the nearest \$100.

Indirect Annual Costs (IAC)

<sup>B</sup> Direct annual costs are based on site-specific design parameters and vendor quote.

873,600

<sup>c</sup> Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

<sup>D</sup> Capital Recovery Factor (CFR) based on 15 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

# Selective Catalytic Reduction Capital Cost Summary

| Description of Cost                     | (\$) <sup>^</sup> | Remarks                         |  |
|---|-------------------|---------------------------------|--|
| Direct Capital Costs                    | •                 | •                               |  |
| SCR Equipment <sup>B</sup>              | 10,006,000        | Control Cost Manual Spreadsheet |  |
| Reagent Preparation Cost <sup>B</sup>   | 1,980,500         | Control Cost Manual Spreadsheet |  |
| Control/Instrumentation <sup>C</sup>    | 1,000,600         | 10% of Equipment Cost           |  |
| Sales Tax                               | 600,400           | 6% of Equipment Cost            |  |
| Freight <sup>C</sup>                    | 500,300           | 5% of Equipment Cost            |  |
| otal Equipment Cost (TEC)               | 14,087,800        |                                 |  |
| otal Installation Cost                  |                   |                                 |  |
| TIC)/Balance of Plant Cost <sup>B</sup> | 2,796,900         | Control Cost Manual Spreadsheet |  |
| Site Preparation <sup>D</sup>           | 500,000           | Demo and Equipment Relocation   |  |
| otal Direct Investment (TDI)            | 17,384,700        | TEC + TIC + Site Prep. = TDI    |  |

| Performance Test Total Indirect Investment (TII) | 140,900<br><b>4,367,300</b> | 1% of TEC  |
|--|-----------------------------|------------|
| Start-up Assistance                              | 281,800                     | 2% of TEC  |
| Contractor Fees                                  | 1,408,800                   | 10% of TEC |
| Construction & Field Expense                     | 704,400                     | 5% of TEC  |
| Engineering                                      | 1,408,800                   | 10% of TEC |
| Contingency                                      | 422,600                     | 3% of TEC  |

| Total Turnkey Cost (TTC) | 21,752,000 | TDI + TII = TTC |
|--------------------------|------------|-----------------|
| <b>A</b>                 |            |                 |

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost obtained from EPA Air Pollution Control SCR Spreadsheet.

<sup>c</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

<sup>D</sup> Estimated by HDR.

# Selective Catalytic Reduction Annual Cost Summary

| Description of Cost                                   | (\$) <sup>^</sup>  | Remarks  |
|---|--------------------|--|
| Direct Annual Costs <sup>B</sup>                      |                    |  |
| Annual SCR Maintenance                                | 96,100             | Control Cost Manual Spreadsheet                                  |
| Reagent (Ammonia)                                     | 28,000             | Control Cost Manual Spreadsheet                                  |
| SCR Electricity                                       | 76,600             | Control Cost Manual Spreadsheet                                  |
| Catalyst Replacment                                   | 63,500             | Control Cost Manual Spreadsheet                                  |
| Direct Annual Costs (DAC)                             | 264,200            |  |
|   |                    |  |
| Indirect Annual Costs <sup>C</sup>                    |                    |  |
| <i>Indirect Annual Costs</i> <sup>C</sup><br>Overhead | 57,700             | 60% of O&M Labor   |
| Overhead  | 57,700<br>435,000  | 60% of O&M Labor<br>2% of Total Capital Investment               |
|   |                    |  |
| Overhead<br>Administrative Charges                    | 435,000            | 2% of Total Capital Investment                                   |
| Overhead<br>Administrative Charges<br>Property Taxes  | 435,000<br>217,500 | 2% of Total Capital Investment<br>1% of Total Capital Investment |

Total Annualized Costs (TAC)3,245,100DAC + IAC = TAC

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

<sup>c</sup> Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

<sup>D</sup> Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

# Selective Non-Catalytic Reduction Capital Cost Summary

| Description of Cost                      | (\$) <sup>A</sup> | Remarks                         |
|--|-------------------|---------------------------------|
| Direct Capital Costs                     |                   |                                 |
| SNCR Equipment <sup>B</sup>              | 1,196,500         | Control Cost Manual Spreadsheet |
| Control/Instrumentation <sup>C</sup>     | 119,700           | 10% of Equipment Cost           |
| Sales Tax                                | 71,800            | 6% of Equipment Cost            |
| Freight <sup>C</sup>                     | 59,800            | 5% of Equipment Cost            |
| Total Equipment Cost (TEC)               | 1,447,800         |                                 |
| Total Installation Cost                  |                   |                                 |
| (TIC)/Balance of Plant Cost <sup>B</sup> | 1,743,700         | Control Cost Manual Spreadsheet |
| Site Preparation <sup>D</sup>            | 450,000           | Demo and Equipment Relocation   |
| Total Direct Investment (TDI)            | 3,641,500         | TEC + TIC + Site Prep. = TDI    |

| 14,500  | 1% of TEC                    |
|---------|------------------------------|
|         |                              |
| 29,000  | 2% of TEC                    |
| 144,800 | 10% of TEC                   |
| 72,400  | 5% of TEC                    |
| 144,800 | 10% of TEC                   |
| 43,400  | 3% of TEC                    |
|         | 144,800<br>72,400<br>144,800 |

| Total Turnkey Cost (TTC) | 4,090,400 | TDI + TII = TTC |
|--------------------------|-----------|-----------------|
| Δ                        |           |                 |

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Capital equipment cost obtained from EPA Air Pollution Control SNCR Spreadsheet.

<sup>c</sup> Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

<sup>D</sup> Estimated by HDR.

# Selective Non-Catalytic Reduction Annual Cost Summary

| Description of Cost                                | (\$) <sup>A</sup> | Remarks   |
|--|-------------------|---|
| Direct Annual Costs <sup>B</sup>                   |                   |   |
| Annual SNCR Maintenance                            | 57,300            | Control Cost Manual Spreadsheet   |
| Reagent (Ammonia)                                  | 26,400            | Control Cost Manual Spreadsheet   |
| Electricity  | 1,700             | Control Cost Manual Spreadsheet   |
| Water  | 600               | Control Cost Manual Spreadsheet   |
| Additional Fuel                                    | 3,000             | Control Cost Manual Spreadsheet   |
| Additional Ash                                     | 200               | Control Cost Manual Spreadsheet   |
| Direct Annual Costs (DAC)                          | 89,200            |   |
|  |                   |   |
| Indirect Annual Costs <sup>c</sup>                 |                   |   |
| Overhead   | 34,400            | 60% of O&M Labor  |
| Administrative Charges                             | 81,800            | 2% of Total Capital Investment  |
| Property Taxes                                     | 40,900            | 1% of Total Capital Investment  |
| · · ·  |                   |   |
| , ,  | 40,900            | 1% of Total Capital Investment  |
| Insurance<br>Dry FGD Annualized Costs <sup>D</sup> | 40,900<br>386,100 | 1% of Total Capital Investment<br>(Capital Investment) x (CFR of 0.09439) |

| Total Annualized Costs (TAC) | 673,300 | DAC + IAC = TAC |
|------------------------------|---------|-----------------|
| · · · ·                      |         |                 |

<sup>A</sup> Values rounded to the nearest \$100.

<sup>B</sup> Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

<sup>c</sup> Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

<sup>D</sup> Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.



May 29, 2020

Hassan M. Bouchareb Minnesota Pollution Control Agency 520 Lafayette Road North St. Paul, MN 55155-4194

#### Re: ArcelorMittal Minorca Mine Inc. Request for Information – Four Factor Analysis

Mr. Bouchareb,

ArcelorMittal Minorca Mine Inc. (Minorca) has prepared the enclosed Regional Haze Four-Factor Analysis Applicability Evaluation (Evaluation) in response to the Minnesota Pollution Control Agency's (MPCA) January 29, 2020 request for information and a Four Factor Analysis for the natural gas fired indurating machine (EQUI 38/EU 026).

Minorca respectfully requests MPCA timely withdraw its request for Minorca to prepare a fourfactor analysis for the natural gas fired indurating machine which is already equipped with Newly Engineered Site-Specific Low  $NO_X$  Burner Technology and Taconite MACT scrubbers. The Evaluation provides evidence for MPCA to exclude Minorca from the group of sources analyzed for control measures for the second implementation period and to withdraw its request for a Four Factor Analysis.

Should you have any questions or comments regarding this submittal, please contact Jaime Johnson, Environmental Manager, by telephone at 218-305-3337, or via email at Jaime.Johnson@arcelormittal.com.

Sincerely,

Robb A. Peterson Operations Manager

cc: Jaime L. Johnson (ArcelorMittal USA) Rich Zavoda (ArcelorMittal USA)



# Regional Haze Four-Factor Analysis Applicability Evaluation

Natural Gas Fired Indurating Machine Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers (EQUI 28/EU 026)

Prepared for ArcelorMittal Minorca Mine Inc.



May 29, 2020

# Regional Haze Four-Factor Analysis Applicability Evaluation

May 29, 2020

# Contents

| 1 |                                   | Exe   | ecutive            | Summary  | 1  |
|---|-----------------------------------|-------|--------------------|--|----|
| 2 |                                   | Int   | roduct             | ion  | 3  |
|   | 2.1                               |       | Regula             | tory Background  | 3  |
|   | 2                                 | 2.1.1 | Min                | nesota's Request for Information (RFI)                                   | 3  |
|   | 2                                 | 2.1.2 | SIP                | Revision Requirements  | 4  |
|   | 2                                 | 2.1.3 | USE                | PA Guidance for SIP Development  | 5  |
|   |                                   | 2.1   | .3.1               | Ambient Data Analysis  | 6  |
|   |                                   | 2.1   | .3.2               | Selection of sources for analysis  | 6  |
|   |                                   | 2.1   | .3.2.1             | Estimating Baseline Visibility Impacts for Source Selection              | 8  |
|   |                                   | 2.1   | .3.3               | Sources that Already have Effective Emission Control Technology in Place | 8  |
|   | 2.2                               |       | Facility           | Description  | 9  |
| 3 |                                   | An    | alysis o           | of Ambient Data  | 11 |
|   | 3.1                               |       | Visibili           | ty Conditions  | 11 |
|   | 3.2 Regional emissions reductions |       | 14                 |  |    |
| 4 | Visibility Impacts                |       | 16                 |  |    |
| 5 |                                   | Eva   | aluatio            | n of "Effectively Controlled" Source                                     | 18 |
|   | 5.1                               |       | NO <sub>X</sub> B  | ART-required Controls  | 18 |
|   | 5.2                               |       | SO <sub>2</sub> BA | RT-required Controls   | 20 |
| 6 |                                   | Со    | onclusio           | on   | 22 |

# List of Tables

| Table 2-1 | Identified Emission Units             | 4  |
|-----------|---------------------------------------|----|
| Table 3-1 | Notable Minnesota Emission Reductions | 15 |
| Table 5-1 | NO <sub>X</sub> Emission Limits       | 19 |
| Table 5-2 | SO <sub>2</sub> Emission Limits       | 21 |

# List of Figures

| Figure 2-1 Natu | ral Gas Fired Indurating Machine Equipped with Newly Engineered Site-Specific Low NG | Эх |
|-----------------|--|----|
|                 | Burner Technology and Taconite MACT Scrubbers Diagram                                | 10 |
| Figure 3-1      | Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)                     | 12 |
| Figure 3-2      | Visibility Trend versus URP – Voyageurs National Park (VOYA1)                        | 13 |
| Figure 3-3      | Visibility Trend versus URP – Isle Royale National Park (ISLE1)                      | 13 |
| Figure 3-4      | Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)         | 14 |

# List of Appendices

Appendix A Visibility Impacts

# 1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency (MPCA) submitted a Request for Information (RFI) Letter<sup>1</sup> to ArcelorMittal Minorca Mine, Inc. (Minorca) to consider potential emissions reduction measures of nitrogen oxides (NO<sub>X</sub>) and sulfur dioxide (SO<sub>2</sub>) from the facility's indurating furnace by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i), as explained in the August 2019 U.S. EPA Guidance (2019 Guidance)<sup>2</sup>:

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

Emission reduction evaluations addressing these factors are commonly referred to as "four-factor analyses." MPCA set a July 31, 2020 deadline for Minorca to submit a four-factor analysis. The MPCA intends to use the four-factor analyses to evaluate additional control measures as part of the development of the State Implementation Plan (SIP), which must be submitted to United States Environmental Protection Agency (USEPA) by July 31, 2021. The SIP will be prepared to address the second regional haze implementation period, which ends in 2028.

This report considers whether a four-factor analysis is warranted for Minorca because the indurating machine can be classified as an "effectively controlled" source for  $NO_x$  and  $SO_2$ . The MPCA can exclude such sources for evaluation per the regulatory requirements of the Regional Haze Rule<sup>3</sup> (RHR) and the 2019 Guidance.

This report provides evidence that it would be reasonable for MPCA to exclude Minorca from the group of sources analyzed for control measures for the second implementation period and to withdraw its request for a four-factor analysis for the indurating machine based on the following points (with additional details provided in cited report sections):

 The indurating machine meets the BART-required control equipment installation scenario and is an "effectively controlled" source for NO<sub>x</sub> and SO<sub>2</sub>. Minorca has BART emission controls and emission limits for NO<sub>x</sub> and SO<sub>2</sub> in accordance with 40 CFR 52.1235(b)(1) and 52.1235(b)(2), respectively. The associated BART analyses are provided in the August 2012<sup>4</sup> and October 2015<sup>5</sup> USEPA Federal Implementation Plan (FIP) rulemaking. (see Section 5)

<sup>&</sup>lt;sup>1</sup> January 29, 2020 letter from Hassan Bouchareb of MPCA to ArcelorMittal Minorca Mine Inc.

<sup>&</sup>lt;sup>2</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019

<sup>&</sup>lt;sup>3</sup> USEPA, Regional Haze Rule Requirements – Long Term Strategy for Regional Haze, 40 CFR 52.308(f)(2)

<sup>&</sup>lt;sup>4</sup> USEPA, Federal Register, 08/15/2012, Page 49308.

<sup>&</sup>lt;sup>5</sup> USEPA, Federal Register, 10/22/2015, Page 64160.

- The RHR and the 2019 Guidance both give states the ability to focus their analyses in one implementation period on a set of sources that differ from those analyzed in another implementation period. (see Section 2.1.3.2)
- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress. (see Section 3.1)
- The indurating machine does not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4)

Additional emission reductions from the indurating machine at Minorca will not contribute meaningfully to further reasonable progress. Therefore, Minorca respectfully requests MPCA withdraw its request for a four-factor analysis for the natural gas fired indurating machine already equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT scrubbers.

# 2 Introduction

Section 2.1 discusses the RFI provided to Minorca by MPCA, pertinent regulatory background for regional haze State Implementation Plans (SIP) development and relevant guidance issued by USEPA to assist States in preparing their SIPs, specifically regarding the selection of sources that must conduct an emissions control evaluation. Section 2.2 provides a description of Minorca's indurating furnace.

# 2.1 Regulatory Background

# 2.1.1 Minnesota's Request for Information (RFI)

"Regional haze" is defined at 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic 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 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 initial SIP was informed by best available retrofit technology (BART) analyses that were completed on all BART-subject sources. The second RHR implementation period ends in 2028 and requires development and submittal of a comprehensive SIP update by July 31, 2021.

As part of the second RHR implementation period SIP development, the MPCA sent an RFI to Minorca on January 29, 2020. The RFI stated that data from the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) 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 SO<sub>2</sub> and NO<sub>x</sub> that react with available ammonia. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan.<sup>6</sup> As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFI also stated that Minorca was identified as a significant source of NO<sub>X</sub> and SO<sub>2</sub> and is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that Minorca submit a "four-factors analysis" (herein termed as a "four-factor analysis") evaluating potential emissions control measures, pursuant to 40 CFR 51.308(f)(2)(i)<sup>7</sup>, by July 31, 2020 for the emission units identified in Table 2-1.

<sup>&</sup>lt;sup>6</sup> Although Michigan is responsible for evaluating haze in Isle Royale, it must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts.

<sup>&</sup>lt;sup>7</sup> The four statutory factors are 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts of compliance, and 4) remaining useful life of the source.

#### Table 2-1 Identified Emission Units

| Unit   | Unit ID          | Applicable Pollutants             |
|--|------------------|-----------------------------------|
| Natural Gas Fired<br>Indurating Machine<br>Equipped with Newly<br>Engineered Site-Specific Low<br>NOx Burner Technology and<br>Taconite MACT Scrubbers | (EQUI 38/EU 026) | NO <sub>x</sub> , SO <sub>2</sub> |

The RFI to Minorca specified that the "analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to USEPA guidance as issued on August 20, 2019<sup>8</sup>.

## 2.1.2 SIP Revision Requirements

The regulatory requirements for comprehensive revisions to the SIP are provided in 40 CFR 51.308(f). The next revision must be submitted to USEPA by July 31, 2021 and must include a commitment to submit periodic reports describing progress towards the reasonable progress goals as detailed in 40 CFR 51.308(g). The SIP "must address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State."

Each SIP revision is required to address several elements, including "calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress." <sup>9</sup> The baseline conditions are based on monitoring data from 2000 to 2004 while the target conditions for natural visibility are determined using USEPA guidance. The State will then determine the uniform rate of progress (URP) which compares "the baseline visibility condition for the most impaired days to the natural visibility condition for the most impaired days to the natural visibility condition for the uniform rate of visibility improvement (measured in deciviews of improvement per year) that would need to be maintained during each implementation period in order to attain natural visibility conditions by the end of 2064."<sup>10</sup>

The SIP revision must also include the "Long-term strategy for regional haze."<sup>11</sup> The strategy "must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress" towards the natural visibility goal. There are several criteria that must be considered when developing the strategy, including an evaluation of emission controls (the four-factor analysis) at selected facilities to determine emission reductions necessary to make reasonable progress. The SIP must consider other factors in developing its long-term strategy, including: emission reductions due to other air pollution control programs<sup>12</sup>, emission unit retirement and replacement

<sup>&</sup>lt;sup>8</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019 <sup>9</sup> 40 CFR 51.308(f)(1)

<sup>&</sup>lt;sup>10</sup> 40 CFR 51.308(f)(1)(vi)(A)

<sup>&</sup>lt;sup>11</sup> 40 CFR 51.308(f)(2)

<sup>&</sup>lt;sup>12</sup> 51.308(f)(2)(iv)(A)

schedules<sup>13</sup>, and the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during the implementation period<sup>14</sup>.

In addition, the SIP must include "reasonable progress goals" that reflect the visibility conditions that are anticipated to be achieved by the end of the implementation period through the implementation of the long term strategy and other requirements of the Clean Air Act (CAA)<sup>15</sup>. The reasonable progress goal is not enforceable but will be considered by USEPA in evaluating the adequacy of the SIP<sup>16</sup>.

# 2.1.3 USEPA Guidance for SIP Development

On August 20, 2019, the USEPA issued "*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*"<sup>17</sup> USEPA's primary goal in issuing the 2019 Guidance was to help states develop "approvable" SIPs. EPA also stated that the document supports key principles in SIP development, such as "leveraging emission reductions achieved through CAA and other programs that further improve visibility in protected areas."<sup>18</sup>

The 2019 Guidance says SIPs must be "consistent with applicable requirements of the CAA and EPA regulations, and are the product of reasoned decision-making"<sup>19</sup> but also emphasizes States' discretion and flexibility in the development of their SIPs. For instance, the 2019 Guidance states, "A key flexibility of the regional haze program is that a state is *not* required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures."<sup>20</sup> The 2019 Guidance notes this flexibility to not consider every emission source stems directly from CAA § 169A(b)(2) and 40 CFR § 51.308(f)(2)(i), the section of the RHR the MPCA cites in its letter.<sup>21</sup>

The 2019 Guidance lists eight key process steps that USEPA anticipates States will follow when developing their SIPs. This report focuses on the selection of sources which must conduct a four-factor analysis and references the following guidance elements which impact the selection:

- Ambient data analysis (Step 1), including the progress, degradation and URP glidepath checks (Step 7)
- Selection of sources for analysis (Step 3), with a focus on:
  - Estimating baseline visibility impacts for source selection (Step 3b)

<sup>21</sup> Ibid.

<sup>&</sup>lt;sup>13</sup> 51.308(f)(2)(iv)(C)

<sup>&</sup>lt;sup>14</sup> 51.308(f)(2)(iv)(E)

<sup>15 40</sup> CFR 51.308(f)(3)

<sup>&</sup>lt;sup>16</sup> 40 CFR 51.308(f)(3)(iii)

 <sup>&</sup>lt;sup>17</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019
 <sup>18</sup> Ibid, page 1.

<sup>&</sup>lt;sup>19</sup> Ibid.

<sup>&</sup>lt;sup>20</sup> Ibid, page 9 (emphasis added).

• Sources that already have effective emission control technology in place (Step 3f)

## 2.1.3.1 Ambient Data Analysis

As stated in Section 2.1.2, the RHR requires each state with a Class I area to calculate the baseline, current, and natural visibility conditions as well as to determine the visibility progress to date and the URP. The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). The guidance provides the following equation for calculating the Uniform Rate of Progress (URP):<sup>22</sup>

#### URP = [(2000-2004 visibility)<sub>20% most impaired</sub> - (natural visibility)<sub>20% most impaired</sub>]/60

The visibility from 2000-2004 represents the baseline period, and the natural visibility goal is in 2064, which is why the URP is calculated over a 60-year period.

At the end of the SIP development process a State must estimate the visibility conditions for the end of the implementation period and then must complete a comparison of the reasonable progress goals to the baseline visibility conditions and the URP glidepath. The guidance explains that the RHR does not define the URP as the target for "reasonable progress" and further states that if the 2028 estimate is below the URP glidepath, that does not exempt the State from considering the four-factor analysis for select sources.<sup>23</sup> However, the current visibility conditions compared to the URP glidepath will be a factor when determining the reasonable progress goal.

In Section 3, Barr evaluates the visibility improvement progress to date at BWCA, Voyageurs and Isle Royale using the IMPROVE network visibility data from MPCA's website. This analysis was conducted to document the current visibility conditions compared to the URP, which can provide insight into the amount of emission reductions necessary to have the 2028 visibility conditions below the URP.

# 2.1.3.2 Selection of sources for analysis

The 2019 Guidance emphasizes that the RHR provides flexibility in selecting sources that must conduct an emission control measures analysis:

"...a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures...."<sup>24</sup>

The 2019 Guidance goes on to justify this approach (emphasis added):

"Selecting a set of sources for analysis of control measures in each implementation period is also consistent with the Regional Haze Rule, which sets up an iterative planning process and anticipates that a state may not need to analyze control measures for all its sources in a given SIP revision. Specifically, section 51.308(f)(2)(i) of the Regional Haze Rule requires a SIP to include a

<sup>&</sup>lt;sup>22</sup> Ibid, Page 7.

<sup>&</sup>lt;sup>23</sup> Ibid, Page 50.

<sup>&</sup>lt;sup>24</sup> Ibid, Page 9.

description of the criteria the state has used to determine the sources or groups of sources it evaluated for potential controls. Accordingly, <u>it is reasonable and permissible for a state to</u> <u>distribute its own analytical work, and the compliance expenditures of source owners, over time</u> <u>by addressing some sources in the second implementation period and other sources in later</u> <u>periods</u>. For the sources that are not selected for an analysis of control measures for purposes of the second implementation period, it may be appropriate for a state to consider whether measures for such sources are necessary to make reasonable progress in later implementation periods."<sup>25</sup>

The 2019 Guidance further states that there is not a list of factors that a state must consider when selecting sources to evaluate control measures, but the state must choose factors and apply them in a reasonable way to make progress towards natural visibility. The guidance details several factors that could be considered, including:

- the in-place emission control measures and, by implication, the emission reductions that are possible to achieve at the source through additional measures<sup>26</sup>
- the four statutory factors (to the extent they have been characterized at this point in SIP development)<sup>27</sup>
- potential visibility benefits (also to the extent they have been characterized at this point in SIP development)<sup>28</sup>
- sources already having effective emissions controls in place<sup>29</sup>
- emission reductions at the source due to ongoing air pollution control programs<sup>30</sup>
- in-state emission reductions due to ongoing air pollution control programs that will result in an improvement in visibility<sup>31</sup>

Furthermore, the 2019 Guidance states that "An initial assessment of projected visibility impairment in 2028, considering growth and on-the books controls, can be a useful piece of information for states to consider as they decide how to select sources for control measure evaluation."<sup>32</sup>

<sup>&</sup>lt;sup>25</sup> Ibid, Page 9.

<sup>&</sup>lt;sup>26</sup> Ibid, Page 10.

<sup>27</sup> Ibid.

<sup>&</sup>lt;sup>28</sup> Ibid.

<sup>&</sup>lt;sup>29</sup> Ibid, Page 21.

<sup>&</sup>lt;sup>30</sup> Ibid, Page 22.

<sup>&</sup>lt;sup>31</sup> Ibid.

<sup>&</sup>lt;sup>32</sup> Ibid, Page 10.

#### 2.1.3.2.1 Estimating Baseline Visibility Impacts for Source Selection

When selecting sources to conduct an emission control evaluation, the 2019 Guidance says that the state may use a "reasonable surrogate metrics of visibility impacts." The guidance provides the following techniques to consider and says that "other reasonable techniques" may also be considered<sup>33</sup>:

- Emissions divided by distance (Q/d)
- Trajectory analyses
- Residence time analyses
- Photochemical modeling

In regard to documenting the source selection process, the 2019 Guidance states:<sup>34</sup>

"EPA recommends that this documentation and description provide both a summary of the state's source selection approach and a detailed description of how the state used technical information to select a reasonable set of sources for an analysis of control measures for the second implementation period. The state could include qualitative and quantitative information such as: the basis for the visibility impact thresholds the state used (if applicable), additional factors the state considered during its selection process, and any other relevant information."

In Section 4, Barr presents a trajectory analysis using data from the IMPROVE monitoring network as presented on MPCA's website and photochemical modeling results to demonstrate that it is not appropriate to select the taconite indurating furnaces as sources subject to the emissions control measures analysis because reducing the emissions will not have a large impact on visibility. Section 4 also presents information from the IMPROVE monitoring system which demonstrates that there was not a noticeable improvement in visibility in 2009 when the taconite plants experienced a production curtailment due to a recession which indicates that the reduction of pollutants from taconite facilities will not result in a discernable visibility improvement in the Class 1 areas.

### 2.1.3.3 Sources that Already have Effective Emission Control Technology in Place

The 2019 Guidance identified eight example scenarios and described the associated rationale for when sources should be considered "effectively controlled" and that states can exclude similar sources from needing to complete a "four-factor analysis."<sup>35</sup> One of the "effectively controlled" scenarios is for "BART-eligible units that installed and began operating controls to meet BART emission limits for the first implementation period."<sup>36</sup> USEPA caveats this scenario by clarifying that "states may not categorically exclude all BART-eligible sources, or all sources that installed BART control, as candidates for selection for

<sup>&</sup>lt;sup>33</sup> Ibid, Page 12.

<sup>&</sup>lt;sup>34</sup> Ibid, Page 27.

<sup>&</sup>lt;sup>35</sup> Ibid, Page 22.

<sup>&</sup>lt;sup>36</sup> Ibid, Page 25.

analysis of control measures."<sup>37</sup> USEPA further notes that "a state might, however, have a different, reasonable basis for not selecting such sources [BART-eligible and non-BART eligible units that implement BART controls] for control measure analysis."<sup>38</sup>

In Section 5, Barr presents an evaluation of the BART-eligible units scenario and demonstrates that the indurating machine is an "effectively controlled" source for both  $NO_X$  and  $SO_2$ . Thus, a four-factor analysis is not warranted for this source because, as USEPA notes, "it may be unlikely that there will be further available reasonable controls for such sources."<sup>39</sup>

# 2.2 Facility Description

Minorca mines iron ore (magnetite) and produces taconite pellets that are shipped to steel producers for processing in blast furnaces. The iron ore is crushed and routed through several concentration stages including grinding, magnetic separation, and thickening.

The concentrated iron ore slurry flows to a storage tank where fluxstone is added to make flux pellets. The concentrate is dewatered by vacuum disk filters, mixed with bentonite, and conveyed to balling discs. Greenballs, produced on the balling discs, are transferred to a roll conveyor for additional removal of over-and undersized material.

The greenballs are distributed evenly across pallet cars prior to entering the indurating machine. The pallet cars have a layer of fired pellets, called the hearth layer, on the bottom and sides of the car. The hearth layer acts as a buffer between the pallet car and the heat generated through the exothermic conversion of magnetite to hematite.

Minorca has one natural gas fired indurating machine, with ultra-low sulfur diesel fuel as a back-up for emergency purposes only. Natural gas has been the only fuel combusted at the indurating machine in the last 12 years. The indurating furnace is a straight grate furnace with several distinct zones. The first two stages are updraft and downdraft drying zones. The next zones are the preheat zone and firing zone. The temperature increases as the pellets pass through each zone, reaching a peak in the firing zone. The pellets enter the after-firing zone, where the conversion of magnetite to hematite is completed. The last two zones are cooling zones that allow the pellets to be discharged at a temperature of around 120 degrees Fahrenheit.

Heated air discharged from the two cooling zones is recirculated to the drying, preheat and firing zones. Off-gases from the furnace are vented primarily through two ducts, the hood exhaust that handles the updraft drying and recirculated second cooling gases, and the windbox exhaust, which handles the preheat, firing, after-firing, and downdraft drying gases. The windbox exhaust flows through a multiclone dust collector, which protects the downstream fan, and then enters a common header shared with the hood exhaust stream. The exhaust gases are subsequently divided into four streams, which lead to four

<sup>&</sup>lt;sup>37</sup> Ibid.

<sup>&</sup>lt;sup>38</sup> Ibid.

<sup>&</sup>lt;sup>39</sup> Ibid.

Taconite Maximum Achievable Control Technology (MACT) venturi rod wet scrubbers that exhaust from individual stacks. Under normal operations, the captured scrubber solids from each of the Taconite MACT four scrubbers are routed back to the concentrate thickener. An overview of the indurating machine design is provided in Figure 2-1.

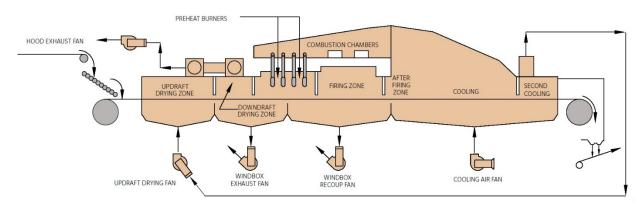


Figure 2-1 Natural Gas Fired Indurating Machine Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers Diagram

# 3 Analysis of Ambient Data

As described in Section 2.1.2, the SIP must consider visibility conditions (baseline, current, and natural visibility), progress to date, and the URP. This requirement is referred to as Step 1 on the 2019 Guidance (see Section 2.1.3.1). This information informs the State's long term strategy for regional haze, as required by 51.308(f)(2), and the reasonable progress goals, as required by 51.308(3).

Section 3.1 provides analysis of visibility conditions based on data from the IMPROVE monitoring network at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1) and Section 3.2 addresses regional emission reductions. Consistent with 51.308(f)(2)(iv), the regional emission reductions summary considers emission reductions that have occurred but are not yet reflected in the available 5-year average monitoring data set and future emission reductions that will occur prior 2028, which is the end of the second SIP implementation period.

## 3.1 Visibility Conditions

As summarized in Section 2.1.2, the RHR requires that the SIP include an analysis "of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."<sup>40</sup> This data will be used in the SIP to establish reasonable progress goals (expressed in deciviews) that reflect the visibility conditions that are projected to be achieved by the end of the implementation period (2028) as a result of the implementation of the SIP and the implementation of other regulatory requirements.<sup>41</sup> The reasonable progress goal is determined by comparing the baseline visibility conditions to natural visibility conditions and determining the uniform rate of visibility improvement needed to attain natural visibility conditions by 2064. The SIP "must consider the uniform rate of improvement in visibility and the emission-reduction measures needed to achieve it for the period covered by the implementation plan."<sup>42</sup>

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).<sup>43</sup> The available regional haze monitoring data was compared to the uniform rate of progress and to the possible reasonable progress goals for the SIP for the implementation period, which ends in 2028. As described in Section 2.1.3.1, the visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). USEPA issued guidance for tracking visibility progress, including the methods for selecting the "most impaired days," on December 20, 2018.<sup>44</sup> Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms) could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."<sup>45</sup> In

<sup>40 40</sup> CFR 51.308(f)(1)

<sup>&</sup>lt;sup>41</sup> 40 CFR 51.308(f)(3)

<sup>&</sup>lt;sup>42</sup> 40 CFR 51.308(d)(1)

<sup>&</sup>lt;sup>43</sup> <u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze visibility metrics public/Visibilityprogress</u>

<sup>&</sup>lt;sup>44</sup> https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

<sup>45</sup> USEPA, Federal Register, 05/04/2016, Page 26948

addition, the RHR allows a state to account for international emissions "to avoid any perception that a state should be aiming to compensate for impacts from international anthropogenic sources."<sup>46</sup>

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath<sup>47</sup> at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1). Regional haze impairment has been declining since 2009 for all three Class I areas that are tracked by MPCA. Impacts to the most impaired days at BWCA and Isle Royale fell below the expected 2028 URP goal in 2016 and have continued trending downward since. Voyageurs impaired days fell below the 2028 URP in 2018 and is also on a downward trend.

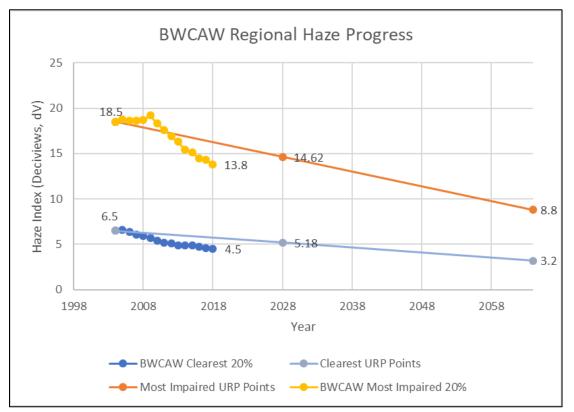


Figure 3-1 Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

<sup>&</sup>lt;sup>46</sup> USEPA, Federal Register, 01/10/2017, Page 3104

<sup>&</sup>lt;sup>47</sup><u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze visibility metrics public/Visibilitypro</u> gress

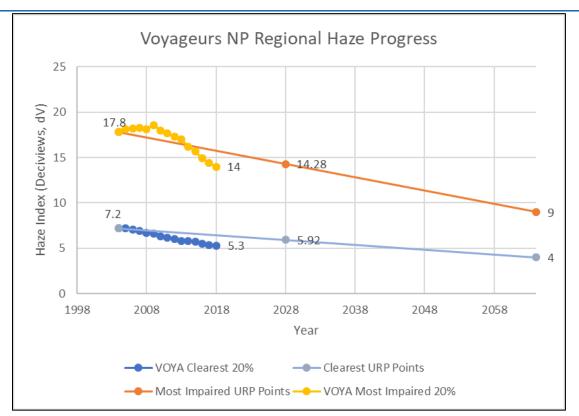


Figure 3-2 Visibility Trend versus URP – Voyageurs National Park (VOYA1)

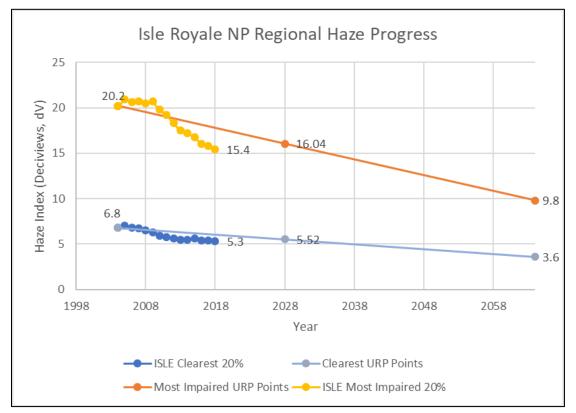


Figure 3-3 Visibility Trend versus URP – Isle Royale National Park (ISLE1)

## 3.2 Regional emissions reductions

The visibility improvement shown in Figure 3-1 through Figure 3-3 correlates with  $SO_2$  and  $NO_x$  emissions decreases from Minnesota's top twenty emission stationary sources, as shown in Figure 3-4<sup>48</sup>. These emission reductions are a result of multiple substantial efforts from the regulated community, including:

- Installation of BART controls during the first implementation period
- Emission reductions at electric utility combustion sources due to new rules and regulations, including:
  - Acid Rain Rules
  - o Cross State Air Pollution Rule (CASPR)
  - Mercury and Air Toxics Standards (MATS)
- Electric utility combustion sources undergoing fuel changes (e.g., from coal and to natural gas)
- Increased generation of renewable energy, which decreases reliance on combustion sources

Since many of these emission reduction efforts are due to federal regulations and national trends in electrical generation, similar emission reduction trends are likely occurring in other states.

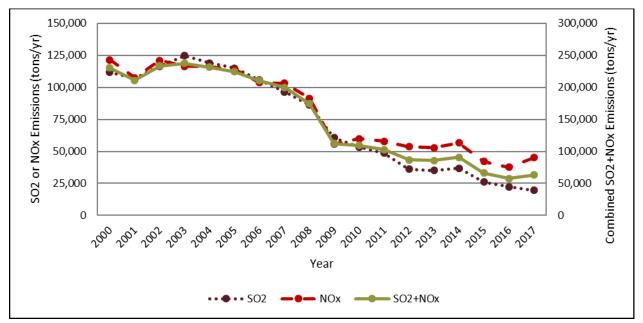


Figure 3-4 Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)

 $<sup>^{48}</sup>$  The data for NO<sub>X</sub> and SO<sub>2</sub> emissions was downloaded from the MPCA point source emissions inventory (<u>https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data</u>). The permitted facilities that had the 20 highest cumulative emissions from 2000-2017 in MN were chosen for the graphics, along with all six taconite facilities (whether or not they were in the top 20 of the state).

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath, so the emissions represented in the most recent data set (2018) is from 2014-2018. However, as shown in Table 3-1, additional emission reductions have occurred since 2014 and are not fully represented in the 5-year visibility data yet. Additionally, several stationary sources have scheduled future emission reductions which will occur prior to 2028. Combined, these current and scheduled emission reductions will further improve visibility in the Class I areas, ensuring the trend stays below the URP. Even without these planned emissions reductions, the 2018 visibility data is already below the 2028 glidepath. As such, MPCA's second SIP implementation period strategy should be commensurate with the region's visibility progress and it would be reasonable for MPCA to not include the taconite indurating furnaces when "reasonably select[ing] a set of sources for an analysis of control measures," and such decision is supported by the 2019 Guidance.

| Year | Additional Emissions Reductions Expected/Projected   |
|------|--|
| 2015 | MP Laskin: converted from coal to natural gas**  |
| 2017 | Minntac Line 6: FIP emission limit compliance date for NO <sub>X</sub> *   |
| 2018 | Minntac Line 7: FIP emission limit compliance date for NO <sub>X</sub> *<br>MP Boswell: Units 1 & 2 retired from service**   |
| 2019 | Hibtac Line 1: FIP emission limit compliance date for $NO_X^*$<br>Keetac: FIP emission limit compliance date for $NO_X^*$<br>Minntac Line 4 or 5: FIP emission limit compliance date for $NO_X^*$<br>Utac Line 1: FIP emission limit compliance date for $NO_X^*$  |
| 2020 | Hibtac Line 2: FIP emission limit compliance date for $NO_X^*$<br>Minntac Line 4 or 5: FIP emission limit compliance date for $NO_X^*$<br>Minorca: FIP emission limit compliance date for $NO_X^*$<br>Utac Line 2: FIP emission limit compliance date for $NO_X^*$ |
| 2021 | Minntac Line: FIP emission limit compliance date for NO <sub>X</sub> *<br>Hibtac Line 3: FIP emission limit compliance date for NO <sub>X</sub> *  |
| 2023 | Xcel: Sherco Unit 2 Retirement***  |
| 2026 | Xcel: Sherco Unit 1 Retirement***  |
| 2028 | Xcel: Allen S. King Plant Retirement <sup>***</sup>  |
| 2030 | Xcel: Sherco Unit 3 Retirement, Xcel target to emit 80% less carbon by 2030***   |
| 2050 | Xcel: Energy targeting carbon free generation by 2050***   |

#### Table 3-1 Notable Minnesota Emission Reductions

\* FIP is the regional haze Federal Implementation Plan detailed in 40 CFR 52.1235

\*\* Minnesota Power - Integrated Resource Plan 2015-2029

\*\*\* Xcel Energy - Upper Midwest Integrated Resource Plan 2020-2034.

# **4 Visibility Impacts**

As described in Section 2.1.3.2, the 2019 Guidance outlines criteria to evaluate when selecting sources that must complete an analysis of emission controls. The 2019 Guidance is clear that a state does not need to evaluate all sources of emissions but "may reasonably select a set of sources for an analysis of control measures" to make progress towards natural visibility.

As described in Section 2.1.3.2.1, the 2019 Guidance provides recommendations on selecting sources by estimating baseline visibility impacts. Three of the options for estimating baseline visibility impacts are analyzed below:

#### • Trajectory analyses<sup>49</sup>

In general, these analyses consider the wind direction and the location of the Class I areas to identify which sources tend to emit pollutants upwind of Class I areas. The 2019 Guidance says that a state can consider "back trajectories" which "start at the Class I area and go backwards in time to examine the path that emissions took to get to the Class I areas." Section A1.1 of Appendix A, describes the back trajectory analysis and concludes the taconite indurating furnaces were a marginal contributor to the "most impaired" days from 2009 and 2011-2015. The trajectory analysis also indicates many sources other than the taconite facilities were significant contributors to the "most impaired" days.

#### • Photochemical modeling<sup>50</sup>

The 2019 Guidance says, "states can also use a photochemical model to quantify source or source sector visibility impacts." CAMx modeling was previously conducted to identify visibility impacts in Class I areas from Minnesota taconite facilities from NOx emission reductions. This analysis is summarized in Section A1.2 of Appendix A which concludes the Class I areas near the Iron Range will not experience any observable visibility improvements from NO<sub>x</sub> emission reductions suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces.

• Other reasonable techniques<sup>51</sup>

In addition to the two analyses described above which estimate the baseline visibility impacts, Section A1.3 of Appendix A evaluates the actual visibility data against the 2009 economic recession impacts on visibility, when taconite facilities curtailed production. This curtailment resulted in a decrease in emissions from the collective group of taconite plant and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this curtailment period was compared to monitoring data during more typical production at the taconite plants to estimate the taconite facilities' actual (rather than modeled) impact on haze. This analysis concludes "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It

<sup>&</sup>lt;sup>49</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 13.

<sup>&</sup>lt;sup>50</sup> Ibid, Page 14.

<sup>&</sup>lt;sup>51</sup> Ibid, Page 12.

is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions."<sup>52</sup> The report further notes "high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states."<sup>53</sup>

<sup>&</sup>lt;sup>52</sup> AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.

<sup>&</sup>lt;sup>53</sup> Ibid, Page 12.

# 5 Evaluation of "Effectively Controlled" Source

As described in Section 2.1.3.3, the 2019 Guidance acknowledges that states may forgo requiring facilities to complete the detailed four-factor analysis if the source already has "effective emission control technology in place."<sup>54</sup> This section demonstrates that the indurating machine meets USEPA's BART-required control equipment installation scenario for NO<sub>X</sub> and SO<sub>2</sub>.

The indurating machine meets this scenario as an "effectively controlled source" because:

- The indurating machine is a BART-eligible unit, as determined by Minnesota's December 2009 Regional Haze Plan, and is regulated under 40 CFR 52.1235 (Approval and Promulgation of Implementation Plans – Subpart Y Minnesota – Regional Haze)
- The indurating machine has controls and must "meet BART emission limits for the first implementation period"<sup>55</sup> for NO<sub>X</sub> and SO<sub>2</sub>

The following sections describe USEPA's BART determinations, the associated controls that were implemented as BART, and the resulting BART emission limits for NO<sub>X</sub> and SO<sub>2</sub>.

## 5.1 NO<sub>x</sub> BART-required Controls

In the preamble to the October 2015 proposed FIP,<sup>56</sup> the USEPA concluded that BART for NO<sub>X</sub> from straight-grate furnaces is low-NO<sub>X</sub> burners with water/steam injection and pre-combustion technologies. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- External and Induced Flue Gas Recirculation Burners due to the high oxygen content of the flue gas<sup>57</sup>
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure<sup>58</sup>
- Selective Catalytic Reduction (SCR) controls because two vendors declined to bid on NO<sub>x</sub> reduction testing for a taconite facility<sup>59</sup>

<sup>&</sup>lt;sup>54</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, page 22.

<sup>&</sup>lt;sup>55</sup> Ibid, page 25.

<sup>&</sup>lt;sup>56</sup> Federal Register 80, No. 204 (October 22, 2015); 64168. Available at: <u>https://www.govinfo.gov/app/details/FR-</u> 2015-10-22/2015-25023

<sup>&</sup>lt;sup>57</sup> Federal Register 77, No. 158 (August 15, 2012); 49319. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

<sup>58</sup> Ibid.

<sup>&</sup>lt;sup>59</sup> Ibid, 49320.

• High-stoichiometric and low-stoichiometric low NO<sub>x</sub> burners (LNB) because the technology had never been used on straight-grate furnaces at the time of the determination.<sup>60</sup>

Because the technical feasibility determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for NO<sub>X</sub> emissions from taconite indurating furnaces.

In accordance with the FIP, Minorca implemented the BART NO<sub>x</sub> control measures by installing and operating newly engineered site-specific Low NOx Burner technology prior to the required FIP compliance date of January 12, 2020 and the indurating machine is subject to the FIP NO<sub>x</sub> emission limit<sup>61</sup> as shown in Table 5-1. The indurating furnace Low NOx Burners have reduced the majority of the NOx emissions. Thus, the indurating machine is considered an "effectively controlled source" in accordance with the 2019 Guidance and should be excluded from the requirement to prepare and submit a four-factor analysis. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the indurating machine from the requirement to submit a four-factor analysis.

### Table 5-1 NO<sub>x</sub> Emission Limits

| Unit   | Unit ID          | NO <sub>X</sub><br>Emission Limit <sup>(1)</sup><br>(Ib/MMBtu) | Compliance Date <sup>(2)</sup> |
|--|------------------|--|--------------------------------|
| Natural Gas Fired<br>Indurating Machine<br>Equipped with Newly<br>Engineered Site-Specific Low<br>NOx Burner Technology and<br>Taconite MACT Scrubbers | (EQUI 38/EU 026) | 1.2-1.8  | December 12, 2020              |

(1) In accordance with 40 CFR 52.1235(b)(1)(v)(A), EQUI 38/EU 026 will be limited to 1.2 to 1.8 lb NOx/MMBtu/hr beginning December 12, 2020. The specific emission limit will be established by USEPA based on available NOx CEMS data from the time period when the installed emission control technology was in operation and must be submitted by September 12, 2020.

(2) The compliance date is contingent on USEPA's approval of the final emission limit.

<sup>&</sup>lt;sup>60</sup> Federal Register 80, No. 204 (October 22, 2015); 64167. Available at: <u>https://www.govinfo.gov/app/details/FR-</u> 2015-10-22/2015-25023

<sup>&</sup>lt;sup>61</sup> 40 CFR 52.1235(b)(1)

<sup>&</sup>lt;sup>62</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 10.

## 5.2 SO<sub>2</sub> BART-required Controls

In the preamble to the August 2012 proposed FIP<sup>63</sup>, the USEPA concluded that BART for SO<sub>2</sub> emissions from the indurating machine at Minorca is existing controls. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- Dry Sorbent Injection and Spray Dryer Absorption because the high moisture content of the exhaust would lead to baghouse filter cake saturation and filter plugging
- Alternative Fuels due to Minorca being prohibited from burning solid fuel
- Coal drying/processing because the indurating machine uses natural gas
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure<sup>64</sup>
- Caustic, lime, or limestone additives to existing scrubbers operating to increase the pH of the scrubbing liquid due to corrosion concerns of the control system that were not designed to operate at a higher pH. The preamble also cited concerns with additional solids and sulfates that would be discharged to the tailing basin and would require extensive treatment to maintain water quality and/or would cause an increased blowdown and make-up water rate, which is not available<sup>65</sup>

In addition, USEPA eliminated Wet Walled Electrostatic Precipitator (WWESP) and secondary (polishing) wet scrubber technologies because they were not cost-effective.<sup>66</sup>

Because the technical feasibility and cost effectiveness determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for SO<sub>2</sub> emissions from taconite indurating furnaces.

In accordance with the FIP, Minorca has continued to operate the BART SO<sub>2</sub> control measures and is complying with the FIP SO<sub>2</sub> emission limit<sup>67</sup>, as shown in Table 5-2. Thus, the indurating machine is considered an "effectively controlled source" in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for SO<sub>2</sub>. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis,

<sup>&</sup>lt;sup>63</sup> Federal Register 77, No. 158 (August 15, 2012); 49321. Available at: <u>https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789</u>

<sup>&</sup>lt;sup>64</sup> Ibid, 49320.

<sup>65</sup> Ibid.

<sup>66</sup> Ibid, 49321.

<sup>67 40</sup> CFR 52.1235(b)(2)

which further supports eliminating the indurating machine from the requirement to submit a four-factor analysis<sup>68</sup>.

### Table 5-2 SO<sub>2</sub> Emission Limits

| Unit   | Unit ID          | SO <sub>2</sub><br>Emission Limit <sup>(1)</sup><br>(lb/hr) | Compliance<br>Date <sup>(2)</sup> |
|--|------------------|---|-----------------------------------|
| Natural Gas Fired<br>Indurating Machine<br>Equipped with Newly Engineered<br>Site-Specific Low NOx Burner<br>Technology<br>and Taconite MACT Scrubbers | (EQUI 38/EU 026) | 58.64   | April 6, 2018                     |

(1) This limit was established using one year of SO<sub>2</sub> CEMS data in accordance with the procedures outlined within 40 CFR 52.1235(b)(2)(v).

(2) Minorca submitted the revised SO<sub>2</sub> limit request on April 6, 2018 in accordance with 40 CFR 52.1235(b)(2)(v).

<sup>&</sup>lt;sup>68</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 10.

# 6 Conclusion

The preceding sections of this report support the following conclusions:

- The natural gas fired indurating machine equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT scrubbers meets the BART-required control equipment installation scenario and is an "effectively controlled" source for NO<sub>X</sub> and SO<sub>2</sub> (see Section 5). As stated in the 2019 Guidance, "it may be reasonable for a state not to select an effectively controlled source."<sup>69</sup> Therefore, it would be reasonable and compliant with USEPA requirements to exclude Minorca from further assessments of additional emission control measures.
- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress (see Section 3):
  - Visibility has improved at all three monitors (BOWA1, VOYA2, and ISLE1) compared to the baseline period
  - Visibility has been below the URP since 2012
  - The 2018 visibility data is below the URP for 2028
  - Additional emissions reductions have continued throughout the region and are not fully reflected in the available 5-year average (2014-2018) monitoring dataset
  - Additional emission reductions are scheduled to occur in the region prior to 2028, including ongoing transitions of area EGUs from coal to natural gas or renewable sources, as well as the installation of low-NO<sub>X</sub> burners throughout the taconite industry
- The indurating machine does not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4).

The combination of these factors provides sufficient justification for MPCA to justify to USEPA Minorca's exclusion from the group of sources required to conduct a four-factor analysis for this implementation period. Thus, Minorca respectfully requests that the MPCA timely withdraw its request for a four-factor analysis for the natural gas fired indurating machine already equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT scrubbers.

<sup>&</sup>lt;sup>69</sup> Ibid, Page 22

Appendix

Appendix A

Visibility Impacts

# A1 Visibility Impacts

### A1.1 Trajectory Analysis

The August 2019 U.S. EPA Guidance ("2019 Guidance" or "the Guidance")<sup>1</sup> says that the state may use a "reasonable surrogate metrics of visibility impacts" when selecting sources to conduct an four-factor analysis and cites trajectory analysis as an example of a reasonable technique. This analysis considers reverse trajectories, as provided on MPCA's website<sup>2</sup>, to determine the frequency that the trajectories on the "most impaired days"<sup>3</sup> overlapped with a specific area of influence (AOI) on the Iron Range. Data from 2011-2015 were analyzed as this was the most recent five-year period where the taconite facilities were operating under typical production rates.

A particle trajectory analysis is an analysis of the transport path of a particular air mass, including the associated particles within the air mass, to see if the air mass traveled over certain locations from specific source locations. The MPCA tracks visibility via the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area Wilderness (BWCA), Voyageurs National Park (Voyageurs) and Isle Royale National Park (Isle Royale).<sup>4</sup> MPCA's website includes a tool which analyzes reverse trajectories from BWCA and Voyageurs for the "most impaired days" and the clearest days for 2007-2016 to show the regional influence on visibility. The reverse trajectories included in the MPCA tool were developed using the NOAA Hysplit model.<sup>5</sup> The trajectories consist of a single back trajectory for each day of interest, beginning at 18:00 and running back 48 hours with a starting height of 10 meters.

The MPCA Hysplit reverse trajectories from the "most impaired days" were analyzed to identify whether trajectories overlapped with an AOI from certain taconite facilities on the Iron Range. In order to be conservative, Barr estimated an "uncertainty region" for each trajectory based on 20% of the distance traveled for every 10km along the trajectory pathway. This method is consistent with other scientific studies analyzing reverse trajectories and trajectories associated with the NOAA Hysplit model (Stohl - 1998<sup>6</sup>, Draxler - 1992<sup>7</sup>, Draxler and Hess - 1998<sup>8</sup>). For the purpose of this analysis, the Iron Range AOI was defined as a line connecting the stack at the U. S. Steel Keetac facility with the stack at the ArcelorMittal Minorca Mine and a 3-mile radius surrounding the line. This analysis considers how often the MPCA reverse trajectories overlap the Iron Range AOI on the "most impaired days" to quantitatively determine if the emissions from the Iron Range may have been a contributor to impaired visibility. Attachment 1 to Appendix A includes tables with the annual and seasonal results of this analysis as well as two example figures showing trajectories that cross, and do not cross, the Iron Range AOI.

<sup>&</sup>lt;sup>1</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019

<sup>&</sup>lt;sup>2</sup> <u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze\_visibility\_metrics\_public/Regionalinfluence</u>

<sup>&</sup>lt;sup>3</sup> "Most impaired days" is the 20% most anthropogenically impaired days on an annual basis, measured in deciviews (dv), as provided on MPCA's website.

<sup>&</sup>lt;sup>4</sup> <u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze\_visibility\_metrics\_public/Regionalinfluence</u>

<sup>&</sup>lt;sup>5</sup> https://www.arl.noaa.gov/hysplit/hysplit/

<sup>&</sup>lt;sup>6</sup> <u>http://www.kenrahn.com/DustClub/Articles/Stohl%201998%20Trajectories.pdf</u>

<sup>&</sup>lt;sup>7</sup> https://www.arl.noaa.gov/documents/reports/ARL%20TM-195.pdf

<sup>&</sup>lt;sup>8</sup> https://www.arl.noaa.gov/documents/reports/MetMag.pdf

As shown in Figure A1 and Figure A2, reverse trajectories from BWCA and Voyageurs in 2011-2015 did not overlap the Iron Range AOI on 62-80%, and 56-71% of "most impaired days", respectively. This means the taconite industry did not influence visibility at BWCA and Voyageurs on the majority of "most impaired days" and suggest that sources other than the taconite facilities are larger contributors to visibility impairment at these sites. Furthermore, the origins of many of the "most impaired day" reverse trajectories are beyond the Iron Range AOI and thus have influences, depending on the trajectory, from other sources (e.g., Boswell Energy Center, Sherburne County Generating Station) or cities such as Duluth, St. Cloud, the Twin Cities, and Rochester as shown in Figure A3.

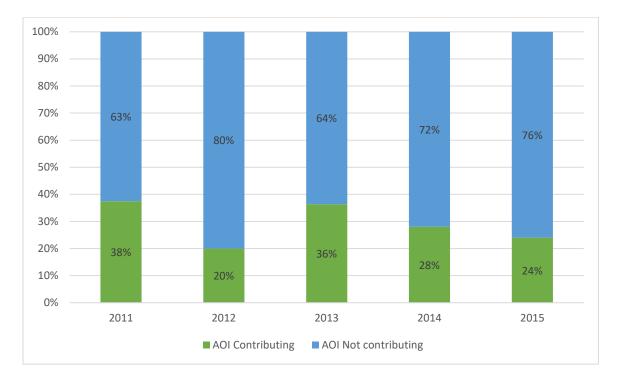


Figure A1 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at BWCA

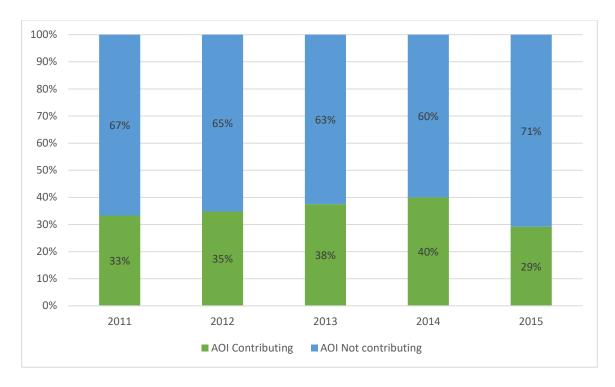


Figure A2 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at Voyageurs

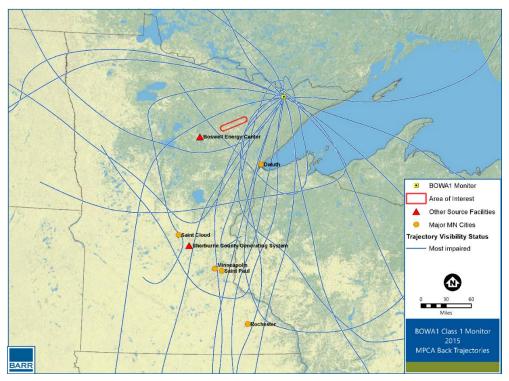


Figure A3 Reverse Trajectories and Other Sources Influencing Visibility at BWCA<sup>9</sup>

<sup>9</sup> Source: ArcGIS 10.7.1, 2020-05-14 13:31 File:

I:\Client\US\_Steel\Trajectory\_Analysis\Maps\Trajectory\_Routes\_BOWA1\_2015\_zoom.mxd User: ADS

## A1.2 Photochemical Modeling

As part of the requirement to determine the sources to include and how to determine the potential visibility improvements to consider as part of this selection, the 2019 Guidance provided some specific guidance on the use of current and previous photochemical modeling analyses (emphasis added):

"A state opting to select a set of sources to analyze must reasonably choose factors and apply them in a reasonable way given the statutory requirement to make reasonable progress toward natural visibility. Factors could include but are not limited to baseline source emissions, <u>baseline source</u> <u>visibility impacts (or a surrogate metric for the impacts)</u>, [and] the in-place emission control measures..."<sup>10</sup>

The Guidance lists options for the evaluation of source visibility impacts from least rigorous to most rigorous as: (1) emissions divided by distance (Q/d), (2) trajectory analyses, (3) residence time analyses, and (4) photochemical modeling (zero-out and/or source apportionment). It appears that MPCA selected the least rigorous (Q/d) for inclusion of sources in the four-factor analyses. The most rigorous is described below (emphases added):

"Photochemical modeling. In addition to these non-modeling techniques, states can also use a photochemical model to quantify source or source sector visibility impacts. In 2017, EPA finalized revisions to 40 CFR Part 51 Appendix W, Guideline on Air Quality Models. As part of that action, EPA stated that photochemical grid models should be the generally preferred approach for estimating source impacts on secondary PM concentrations. The existing SIP Modeling Guidance provides recommendations on model setup, including selecting air quality models, meteorological modeling, episode selection, the size of the modeling domain, the grid size and number of vertical layers, and evaluating model performance. EPA Regional offices are available to provide an informal review of a modeling protocol before a state or multijurisdictional organization begins the modeling.

The SIP Modeling Guidance focuses on the process for calculating RPGs using a photochemical grid model. The SIP Modeling Guidance does not specifically discuss using photochemical modeling outputs for estimating daily light extinction impacts for a single source or source sector. However, the approach on which the SIP Modeling Guidance is based can also be applied to a specific source or set of sources. <u>The first step in doing this is to estimate the impact of the source or set of sources</u> <u>on daily concentrations of PM species.</u>

The simplest approach to quantifying daily PM species impacts with a photochemical grid model is to perform brute force "zero-out" model runs, which involves at least two model runs: one "baseline" run with all emissions and one run with emissions of the source(s) of interest removed from the baseline simulation. The difference between these simulations provides an estimate of the PM species impact of the emissions from the source(s).

<sup>&</sup>lt;sup>10</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 10

An alternative approach to quantifying daily PM species impacts is photochemical source apportionment. Some photochemical models have been developed with a photochemical source apportionment capability, which tracks emissions from specific sources or groups of sources and/or source regions through chemical transformation, transport, and deposition processes to estimate the apportionment of predicted PM<sub>2.5</sub> species concentrations. Source apportionment can "tag" and track emissions sources by any combination of region and sector, or by individual source. For example, PM species impacts can be tracked from any particular source category in the U.S., or from individual states or counties. Individual point sources can also be tracked."<sup>11</sup>

As part of the previous regional haze planning evaluation, and to provide comments on USEPA's disapproval of the Minnesota SIP and the subsequent Regional Haze Federal Implementation Plan (FIP) (Docket EPA-R05-OAR-2010-0954 & EPA-R05-OAR-2010-0037), Barr completed photochemical modeling of ArcelorMittal and Cleveland-Cliffs' taconite operations in 2013 using CAMx source apportionment (see Attachment 2). The basis of the CAMx modeling was the Minnesota modeling analyses, which were completed as part of the regional haze SIP, including Plume in Grid (PiG) evaluations of sources included in BART analyses. This modeling included 2002 and 2005 baseline periods with projected emissions to 2018 (the first implementation planning period for the regional haze SIPs and a strong surrogate for the baseline period for the 2<sup>nd</sup> planning period). Therefore, the analysis completed is one of the best available surrogates for the potential visibility impacts from the sources that were "tagged" as part of those comments. It is important to note that the MPCA modeling analysis did not require any additional controls for taconite sources under BART. Further, the CAMx modeling that Barr conducted showed that the impact from NO<sub>X</sub> emissions from the Minnesota taconite facilities had very limited visibility impacts on the three Upper Midwest Class I areas.

Specifically, the results from executing CAMx concluded that the Class I areas near the Iron Range will not experience any observable visibility improvements from NO<sub>x</sub> emission reductions that were suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces. The modeling analysis showed that the scalar method that USEPA used to forecast the visibility improvements was inadequate to determine the visibility impacts from taconite sources. The CAMx predicted impacts for every furnace line were at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

In addition, the large amount of potential NO<sub>X</sub> emission reductions from the FIP baseline to the final FIP (>10,000 tons per year from modeled Minnesota taconite operations) was not impactful from a visibility modeling perspective. This finding provides specific source modeling evidence that additional NO<sub>X</sub> emission reductions from any or all of the taconite operations are likely not helpful for visibility improvements at the Upper Midwest Class I areas. This is particularly true given the current amount of NO<sub>X</sub> emissions generated by the taconite sources as part of the current baseline.

The 2019 Guidance addresses how states should select sources that must conduct a four-factor analysis. The RHR suggests that states can use a photochemical model to quantify facility or even stack visibility impacts. The previous CAMx modeling was conducted for the 2018 projection year and the results are

<sup>&</sup>lt;sup>11</sup> Ibid, Page 14.

especially helpful in the current visibility impact assessment to determine if the EPA's four-factor applicability analysis is necessary. Aside from the fact that the NO<sub>X</sub> reductions of taconite indurating furnaces do not result in visibility improvements, the emissions from these sources have been trending downward from 2013 to present. These reductions are related to the recent installation of low NO<sub>X</sub> burners on the taconite indurating furnaces and the overall Minnesota state reductions from the switch from coal- to natural gas-fired power plants. Thus, it is reasonable to conclude that additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility at the Class 1 areas nor is it anticipated to be necessary to reach the 2028 target visibility goal.

In summary, the exclusion of the taconite sources from the four factor analysis for NOx is reasonable, supported by the previous CAMx modeling performed for 2018 projected emissions that conclude additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility, and in line with the Guidance regarding selection of sources based on previous modeling analyses and the additional NO<sub>x</sub> reductions anticipated in Minnesota.

## A1.3 Visibility Impacts During 2009 Recession

During the economic recession in 2009, the Iron Range experienced a reduction in taconite production. This resulted in a decrease in emissions from the collective group of taconite plants and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this period was compared to monitoring data during more typical production at the taconite plants to estimate the actual (rather than modeled) impact on haze. This assessment was completed in 2012 (herein termed as "the 2012 analysis") and submitted by Cliffs as a comment to proposed Minnesota regional haze requirements (Docket: EPA-R05-OAR-2010-0037), included as Attachment 3. The 2012 analysis focused on the likely visibility impact of NO<sub>x</sub> emissions from the taconite indurating furnaces.

Observations noted in the 2012 analysis highlighted that concentrations of visibility impairing pollutants do not appear to closely track with actual emissions from taconite facilities. For example, nitrate (NO<sub>3</sub>) is a component of haze associated with NO<sub>x</sub> emissions that are emitted from a number of sources, including the indurating furnaces at the taconite facilities. As shown in Figure A4, the 2012 analysis compared taconite facility production rates to nitrate concentration for 1994-2010 at the BWCA monitor. The 2012 analysis concludes that "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions."<sup>12</sup> The report further notes that "high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states."<sup>13</sup>

<sup>&</sup>lt;sup>12</sup> AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10. <sup>13</sup> Ibid, Page 12.

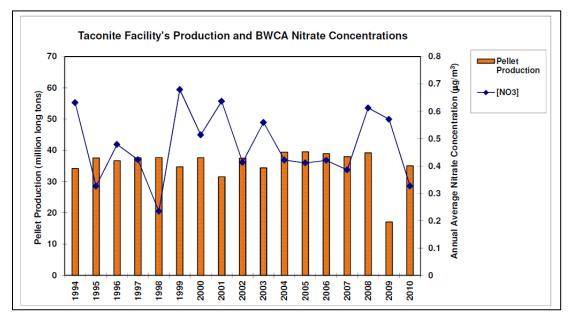


Figure A4 Minnesota Taconite Production and BWCA Nitrate Concentrations 1994-2010<sup>14</sup>

<sup>&</sup>lt;sup>14</sup> AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 9

## Attachments

# Attachment 1

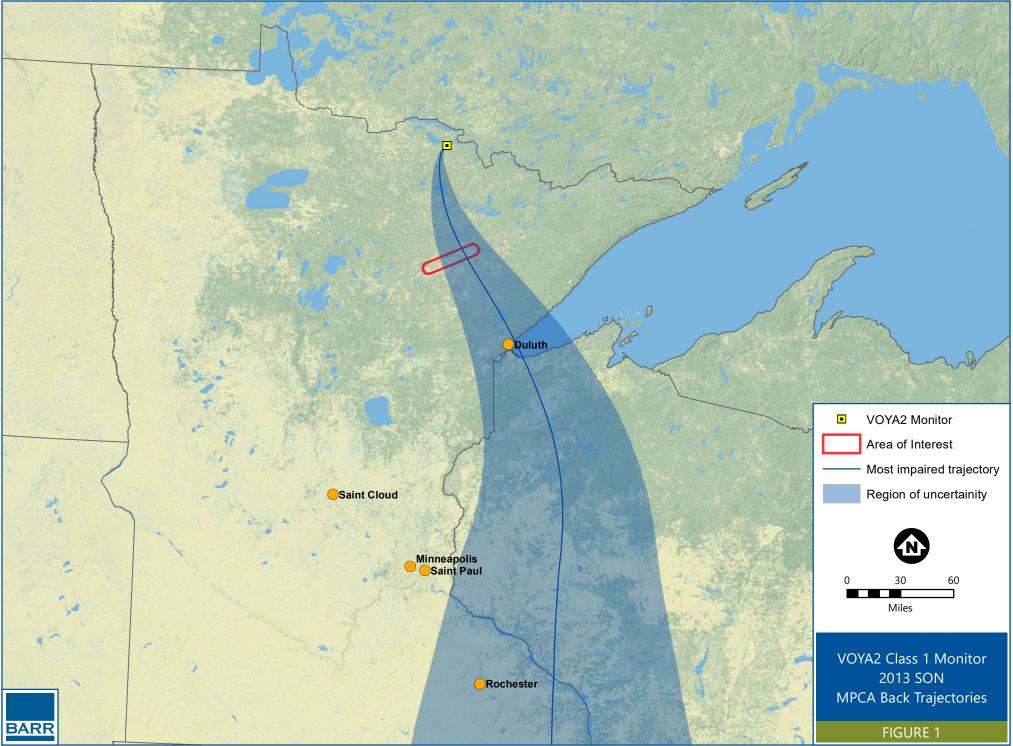
Trajectory Analysis Summary Tables and Reverse Trajectory Example Figures

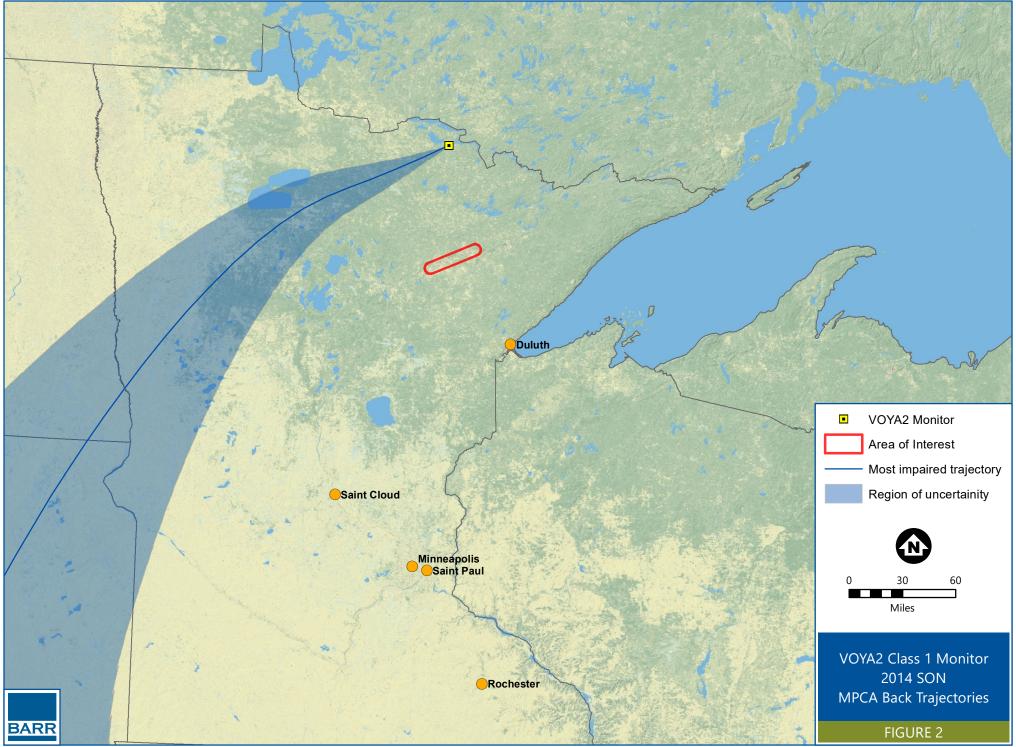
| Year | Time Period  | Most Impaired<br>Days | "Most Impaired" Trajectories<br>With Uncertainty Region<br>Crossing Iron Range AOI<br>(%) |
|------|--------------|-----------------------|---|
|      | Winter (DJF) | 9                     | 44%   |
|      | Spring (MAM) | 8                     | 38%   |
| 2011 | Summer (JJA) | 4                     | 0%  |
|      | Fall (SON)   | 3                     | 67%   |
|      | Total        | 24                    | 38%   |
|      | Winter (DJF) | 13                    | 23%   |
|      | Spring (MAM) | 4                     | 0%  |
| 2012 | Summer (JJA) | 1                     | 0%  |
|      | Fall (SON)   | 7                     | 29%   |
|      | Total        | 25                    | 20%   |
|      | Winter (DJF) | 9                     | 44%   |
|      | Spring (MAM) | 5                     | 60%   |
| 2013 | Summer (JJA) | 3                     | 0%  |
|      | Fall (SON)   | 5                     | 20%   |
|      | Total        | 22                    | 36%   |
|      | Winter (DJF) | 9                     | 33%   |
|      | Spring (MAM) | 8                     | 13%   |
| 2014 | Summer (JJA) | 2                     | 0%  |
|      | Fall (SON)   | 6                     | 50%   |
|      | Total        | 25                    | 28%   |
|      | Winter (DJF) | 13                    | 15%   |
|      | Spring (MAM) | 3                     | 67%   |
| 2015 | Summer (JJA) | 1                     | 0%  |
|      | Fall (SON)   | 8                     | 25%   |
|      | Total        | 25                    | 24%   |

Table A1 Results from MPCA Hysplit Trajectories for the BOWA1 Monitor

| Year | Months       | Most Impaired<br>Days | "Most Impaired" Trajectories<br>With Uncertainty Region<br>Crossing Iron Range AOI<br>(%) |
|------|--------------|-----------------------|---|
|      | Winter (DJF) | 8                     | 38%   |
|      | Spring (MAM) | 7                     | 29%   |
| 2011 | Summer (JJA) | 4                     | 25%   |
|      | Fall (SON)   | 5                     | 40%   |
|      | Total        | 24                    | 33%   |
|      | Winter (DJF) | 13                    | 23%   |
|      | Spring (MAM) | 3                     | 67%   |
| 2012 | Summer (JJA) | 0                     | 0%  |
|      | Fall (SON)   | 7                     | 43%   |
|      | Total        | 23                    | 35%   |
|      | Winter (DJF) | 9                     | 22%   |
|      | Spring (MAM) | 5                     | 40%   |
| 2013 | Summer (JJA) | 3                     | 0%  |
|      | Fall (SON)   | 7                     | 71%   |
|      | Total        | 24                    | 38%   |
|      | Winter (DJF) | 10                    | 50%   |
|      | Spring (MAM) | 7                     | 43%   |
| 2014 | Summer (JJA) | 2                     | 0%  |
|      | Fall (SON)   | 6                     | 33%   |
|      | Total        | 25                    | 40%   |
|      | Winter (DJF) | 14                    | 21%   |
|      | Spring (MAM) | 4                     | 50%   |
| 2015 | Summer (JJA) | 1                     | 100%  |
|      | Fall (SON)   | 5                     | 20%   |
|      | Total        | 24                    | 29%   |

 Table A2
 Results from MPCA Hysplit Trajectories for the VOYA2 Monitor





Attachment 2

CAM<sub>X</sub> Modeling Report



## **Technical Memorandum**

- From: Barr Engineering
- Subject: Summary of Comprehensive Air Quality Model with Extensions (CAM<sub>x</sub>) Analyses Performed to Evaluate the EPA Regional Haze Federal Implementation Plan for Taconite Facilities
   Date: March 6, 2013

#### **Executive Summary**

Barr Engineering conducted air modeling to predict the impact of  $NO_x$  reductions from certain taconite furnaces in Minnesota and Michigan. Using EPA's preferred Comprehensive Air Quality Model with Extensions (CAM<sub>x</sub>), the model results demonstrate that the Class I areas near these furnaces will experience no perceptible visibility improvements from  $NO_x$  emission reductions envisioned by EPA in the recent Regional Haze FIP at the furnaces. The analysis strongly suggests that the scalar method that EPA used to predict visibility improvements under significant time constraints was an inadequate substitute for CAM<sub>x</sub>, as EPA's approach over-predicted visibility impacts by factors of <u>ten to sixty</u> when compared with the proper CAM<sub>x</sub> analysis. The basis for EPA's technical analysis of the visibility improvements for their proposed emission changes must therefore be dismissed as unsupportable, and the results of this analysis should be used instead. This analysis ultimately supports the conclusions of the States of Michigan and Minnesota in their Regional Haze SIPs, that experimental low  $NO_x$  burner retrofits did not meet the criteria for BART. The imperceptible visibility improvements associated with  $NO_x$  reductions from these furnaces cannot justify the cost or the operational risks of changing burners.

#### **Discussion**

This memorandum provides a summary of the methodology and results from photochemical modeling analyses conducted to support the Cliffs Natural Resources (CNR) and Arcelor Mittal (Arcelor) response to the United States Environmental Protection Agency (EPA) final Regional Haze Federal Implementation Plan (FIP) for taconite facilities. Further, it provides a basis for comment on the proposed disapproval of the Minnesota and Michigan State Implementation Plans for taconite Best Available Retrofit Technology (BART) at the above mentioned facilities. This memorandum also includes an appendix with a summary of the BART visibility improvement requirements and a review of the EPA "scalar" method in the proposed and final FIP for determining the visibility improvement from taconite emission reductions. Further, the memorandum contrasts EPA's findings with the modeling analysis conducted and previously requested by CNR as part of its comments on the proposed FIP. The modeling evaluated emission differences at all the CNR and Arcelor taconite facilities.

Ultimately, this memorandum provides results demonstrating no perceptible visibility improvement from the  $NO_X$  emission reductions proposed and subsequently finalized by EPA in the Regional Haze FIP for the CNR and Arcelor facilities.

#### I. CAM<sub>x</sub> Modeling Methodology

The methodology utilized by Barr to complete the CAM<sub>x</sub> modeling was identical to the methods utilized by the Minnesota Pollution Control Agency (MPCA) in performing the 2002 and 2005 baseline and BART SIP modeling in 2009. This included the use of the CAM<sub>x</sub> modeling system (CAM<sub>x</sub> v5.01 - air quality model, MM5 - meteorological model, and EMS-2003 - emissions model) with meteorological data, low-level emission data, initial and boundary condition files, and other input files received directly from MPCA. Modifications to the emissions within the elevated point source input files used by MPCA were accomplished for the taconite facility furnace stacks to reflect the differences in the FIP baseline and final FIP control scenarios. In addition, the CAM<sub>x</sub> run scripts used to execute the model were provided by MPCA for each of the four calendar quarters (Jan-Mar, Apr-Jun, Jul-Sep, and Oct-Dec) along with the post-processing scripts used to estimate the visibility impacts for each scenario.

An important fact is that the results from the MPCA modeling for Minnesota's regional haze State Implementation Plan (SIP) development were also utilized by EPA in the "scalar" method proposed in the FIP. These results were subsequently defended by EPA in the final FIP stating "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."<sup>1</sup> The methods utilized by MPCA represent not only an EPA-approved approach for SIP submittal, but also formed the basis of the visibility determinations made by EPA in the proposed and final FIP. However, since EPA did not conduct its own modeling and provided only the "scalar" results, there are substantial and inherent flaws in the EPA-estimated visibility impacts. These flaws are detailed in Appendix A to this memorandum which includes a review of the EPA scalar approach. Since the modeling reported here used identical methods to the MPCA analyses, it is consistent with the underlying data that was used in

<sup>&</sup>lt;sup>1</sup> Federal Register, Volume 78, Number 25, page 8721, February 6, 2013

the EPA FIP method for estimating visibility impact. Further, this modeling provides specific technical analyses regarding the estimated effects of CNR and Arcelor taconite unit emission reductions in the final FIP on the relevant Class I areas. To effectively evaluate the impact of NOx reductions on regional haze, this level of analyses should have been conducted by EPA before publishing and finalizing the taconite BART FIP for Minnesota and Michigan.

Nonetheless, the first step in any photochemical modeling exercise is to ensure that the modeling results can be replicated to ensure no errors in the data transfer or modeling setup. Barr worked with MPCA to obtain the 2002 and 2005 modeling input files, run scripts, and post-processing files to allow for the validation of the Barr modeling system. To be clear, the modeling comparison scenario used the exact same files provided by MPCA with no adjustments. Given the length of time required to complete the modeling analyses, this step focused on the 2002 dataset and evaluated the results from the 2002 baseline and 2002 Minnesota BART SIP. The information provided by MPCA to complete this comparison was contained in the document: "Visibility Improvement Analysis of Controls Implemented due to BART Determinations on Emission Units Subject-to-BART", October 23, 2009. The results of the comparison are contained in Appendix B: Barr and MPCA CAM<sub>X</sub> Modeling Comparison of Results. As expected with any photochemical model comparison running four different quarterly simulations using two different computer systems and Fortran compilers, there are insignificant differences in the end values. The overall comparison of the results was very favorable and showed excellent agreement between the four modeled datasets (i.e. 2002 baseline and 2002 BART SIP, each from MPCA and Barr).

After successful confirmation of the consistency check of the Barr modeling system to the MPCA system, the modeling focused on the specific emission changes in the MPCA elevated point source files. As with most regional modeling applications, there were 36 "core" point source files for each scenario. This set corresponds to three files per month (Saturday, Sunday, and weekday) for all twelve months. Emission information from each file was extracted for all the CNR and Arcelor taconite facilities in Minnesota to confirm the emission totals used by MPCA in the SIP baseline and BART SIP control scenarios. The emission summary data for each unit matched the summary tables within the MPCA BART SIP modeling. Also, the emission sources from Tilden Mining Company in Michigan were identified and information extracted to allow for the same type of modeling as was conducted for the Minnesota facilities.

The next step was to include United Taconite Line 1 in the baseline and FIP modeling files. Line 1 was not originally included in the MPCA modeling because it was not operational in the 2002 base year.

Therefore, the information for that source was obtained from MPCA-provided 2018 elevated point source files and incorporated into the 36 core elevated point source files. This allowed all the CNR and Arcelor furnace lines within the FIP to be evaluated as part of this modeling analysis. To that end, each CNR and Arcelor BART-eligible source was specifically identified and labeled for processing to track modeled impacts using plume-in-grid treatment and the Particulate Source Apportionment Technology (PSAT) contained within CAM<sub>x</sub> (including Tilden Mining). A list of the sources that were included in the specific PSAT groups can be found in Appendix C: CAM<sub>x</sub> PSAT Source List.

As part of the identification and labeling process, the MPCA BART SIP elevated point source files were converted from binary input files to ascii text files using the BIN2ASC program. (NOTE: by using the BART SIP point source files, all other Minnesota BART-eligible sources were included in this modeling exercise using their BART SIP emissions to isolate the impacts of the CNR and Arcelor units.) Then, a Fortran90 program was developed to adjust the hourly emissions from each applicable source to correspond to the sum of annual emissions within each of the following scenarios: EPA FIP baseline and EPA final FIP. It is important to note that the temporal factors for each source were not modified from the original MPCA-provided inventory files (i.e. no changes to the monthly or day-of-week factors). This emission approach allowed for the exact set of emissions within each of the scenarios to be modeled. After the emissions within the text file were adjusted, the emissions were checked for accuracy. Then, each file was converted back to binary input from ASCII text using the ASC2BIN program. The emission summary for each unit/scenario combination is contained in Appendix D: Summary of  $CAM_x$ Elevated Point Source Emissions. Appendix D also provides a reference list for the emissions from the proposed FIP, Final FIP (where applicable), and calculation methodology where EPA did not provide sufficient information to calculate emissions. Table 1 contains a facility summary for all taconite furnaces under each scenario.

As stated previously, one of the outcomes of these analyses was the comparison of EPA's scalar approach to specific photochemical modeling using EPA's emission reduction assumptions within the FIP rulemakings. These modeling analyses make no judgment as to the achievability of these emission reductions. CNR and Arcelor dispute that these NOx reductions are achievable for all furnaces. These modeling analyses are, therefore, a conservative evaluation of EPA's predicted NOx reductions – not the actual NOx reductions achievable by the application of BART.

4

| Facility          | FIP Baseline (TPY) |        | Final Fl | IP (TPY) | Difference (TPY) |        |  |
|-------------------|--------------------|--------|----------|----------|------------------|--------|--|
|                   | SO2                | NOx    | SO2      | NOx      | SO2              | NOx    |  |
| Arcelor Mittal    | 179                | 3,639  | 179      | 1,092    | 0                | 2,547  |  |
| Hibbing Taconite  | 570                | 6,888  | 570      | 2,066    | 0                | 4,821  |  |
| United Taconite   | 4,043              | 5,330  | 1,969    | 1,599    | 2,074            | 3,731  |  |
| Northshore Mining | 73                 | 764    | 73       | 229      | 0                | 535    |  |
| Tilden Mining     | 1,153              | 4,613  | 231      | 1,384    | 922              | 3,229  |  |
| Total             | 6,018              | 21,233 | 3,022    | 6,370    | 2,996            | 14,863 |  |

 Table 1: Facility Taconite Furnace Emission Summary

Two other issues should be noted here.

1. The first is the nested 12-km modeling domain selected by MPCA (illustrated in Figure 1) along with the specific "receptors" used for identification of the relevant Isle Royale Class I area and their use for determination of impacts from Tilden Mining Company. The Tilden Mining source was not included in the MPCA fine grid as it was not part of the Minnesota SIP. However, the elevated point source file includes the sources in the entire 36 km domain (including Tilden). As such, the Tilden emissions were available for estimation of specific visibility impacts. The receptors selected by MPCA only included the western half of the Isle Royale Class I area because that is the portion of the area closest to the Minnesota sources. However, the size of the grid cells (e.g. 12 and 36 km) provides a large number of potential receptors at all the Class I areas and little variation among receptors is expected at the distance between Tilden and Isle Royale. Thus, the modeling data should adequately represent the visibility impact at the entire Isle Royale Class I area.

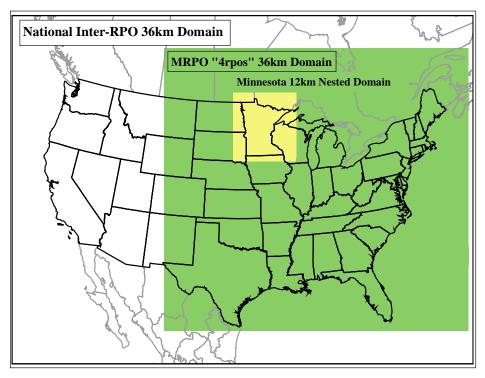


Figure 1. MPCA Modeling Domain

2. The second issue is the inconsistency between the emission reduction estimates used by EPA in the calculation of their scalar visibility benefits (i.e. Tables V-C of the proposed and final FIP) and the emission reductions calculated in the facility-specific sections of the proposed FIP. EPA's flawed calculation methodology did not use the appropriate emission reductions. In order to calculate the emissions for evaluation of the final FIP in the CAM<sub>x</sub> modeling, Barr was left with utilizing the limited information provided in the proposed and final FIP rulemaking. The lack of information and the errors and inconsistencies within the dataset were highlighted in the information request on January 31, 2013 to EPA (included in Appendix E). As of the time of this memorandum, no response by EPA has been received by Barr. Further, given the time required to complete the modeling, assumptions were made that were conservative to calculate the FIP emissions. For example, the final FIP references a 65% NO<sub>x</sub> reduction from Tilden Mining Company due to the switch to natural gas firing, but that was not consistent with the other gas-fired kilns (proposed FIP reduction was 70% with the same 1.2 lb NO<sub>x</sub>/MMBTU emission limit). Therefore, to provide the maximum emission reductions, the 70% control was utilized for all the CNR and Arcelor taconite furnaces.

#### II. Summary of CAM<sub>X</sub> Results

As mentioned above, the CAM<sub>x</sub> model was executed for each calendar quarter of 2002 and 2005 using the adjusted emissions for each scenario. The results were then post-processed to calculate visibility impacts for each scenario in deciviews (dV). All these results are provided in Appendix F: CAM<sub>x</sub> Results by Facility. For the purposes of this memorandum, the following tables compare EPA's estimates of annual average impact contained within the proposed FIP with the results generated by the CAM<sub>x</sub> modeling for this project on a facility by facility basis. The first three facilities contain emission reductions for only NO<sub>x</sub>: Arcelor Mittal, Hibbing Taconite, and Northshore Mining. These results are summarized in Tables 2-4. United Taconite and Tilden Mining, which have both SO<sub>2</sub> and NO<sub>x</sub> emission reductions, have result comparisons that require additional discussion.

The context of these results includes the following visibility impact thresholds:

<u>0.5 dV impact</u> is the BART eligibility and contribute to visibility impairment threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required)<sup>2</sup>,

1.0 dV difference is the presumed human perceptible level for visibility improvement, and

<u>0.1 dV difference</u> was defined by other agencies, such as the northeastern states MANE-VU Regional Planning Organization<sup>3</sup> as the degree of visibility improvement that is too low to justify additional emission controls. In addition, EPA's Regional Haze Rule mentions<sup>4</sup> that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

The first two columns within Tables 2-4 and 6-8 provide the difference in 98<sup>th</sup> percentile visibility improvement from the baseline to the FIP control emissions, while the third column provides a measure of over-estimation when using the EPA scalar approach (i.e. % Over Estimation by EPA = EPA Estimated Difference / CAM<sub>x</sub> Modeled Difference).

Table 2: Arcelor Mittal Visibility Impact Comparison

<sup>&</sup>lt;sup>2</sup> 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule.

<sup>&</sup>lt;sup>3</sup> As documented by various states; see, for example, <u>www.mass.gov/dep/air/priorities/hazebart.doc</u>, which indicates a visibility impact of less than 0.1 delta-dv is considered "de minimis".

<sup>&</sup>lt;sup>4</sup> 64 FR 35730.

| Class I Area    | EPA Estimated | CAM <sub>X</sub> Modeled | % Over        |
|-----------------|---------------|--------------------------|---------------|
|                 | Difference    | Difference               | Estimation by |
|                 | 98% dV        | 98% dV                   | EPA           |
| Boundary Waters | 1.7           | 0.1                      | 1500%         |
| Voyageurs       | 0.9           | 0.09                     | 1000%         |
| Isle Royale     | 1.1           | 0.03                     | 3700%         |

Table 3: Hibbing Taconite Visibility Impact Comparison

| Class I Area    | EPA Estimated | CAM <sub>x</sub> Modeled | % Over        |
|-----------------|---------------|--------------------------|---------------|
|                 | Difference    | Difference               | Estimation by |
|                 | 98% dV        | 98% dV                   | EPA           |
| Boundary Waters | 3.2           | 0.19                     | 1700%         |
| Voyageurs       | 1.7           | 0.11                     | 1500%         |
| Isle Royale     | 2.1           | 0.04                     | 5300%         |

Table 4: Northshore Mining Visibility Impact Comparison

| Class I Area    | EPA Estimated        | CAM <sub>X</sub> Modeled | % Over               |
|-----------------|----------------------|--------------------------|----------------------|
|                 | Difference<br>98% dV | Difference<br>98% dV     | Estimation by<br>EPA |
| Boundary Waters | 0.6                  | 0.01                     | 6000%                |
| Voyageurs       | 0.3                  | 0.01                     | 3000%                |
| Isle Royale     | 0.4                  | 0.01                     | 4000%                |

As pointed out in the previous comments on this proposed FIP, these results clearly demonstrate that the NOx reductions proposed in the FIP will not provide a perceptible visibility improvement. Additionally, it demonstrates that the EPA methodology using scalars severely overestimated the visibility impact from NO<sub>x</sub> emission reductions at these taconite furnaces in northeast Minnesota. Even when using maximum emission reductions from EPA's baseline, the EPA estimates grossly over predicted the potential dV improvement by over <u>10 times</u> the predicted 98<sup>th</sup> percentile visibility improvement in all cases for the Arcelor Mittal, Hibbing Taconite, and Northshore Mining facilities. The maximum 98<sup>th</sup> percentile visibility improvement predicted by the source specific tracking for any one line was 0.1 dV (Arcelor Mittal Line 1 on Boundary Waters). The minimum 98<sup>th</sup> percentile visibility improvement was 0.01 dV (Northshore Mining on Isle Royale). Further, the results presented in Table 5 for the individual furnace line impacts at Hibbing Taconite illustrate de minimis visibility improvement at all the Class I areas evaluated.

| Class I Area    | Furnace Line | CAM <sub>x</sub> Modeled<br>Difference<br>98% dV |
|-----------------|--------------|--|
| Boundary Waters | Line 1       | 0.04   |
|                 | Line 2       | 0.05   |
|                 | Line 3       | 0.08   |
| Voyageurs       | Line 1       | 0.03   |
|                 | Line 2       | 0.04   |
|                 | Line 3       | 0.04   |
| Isle Royale     | Line 1       | 0.01   |
|                 | Line 2       | 0.01   |
|                 | Line 3       | 0.01   |

Table 5: Hibbing Taconite Line-Specific Visibility Impacts

Overall, all the facilities with only  $NO_X$  emission reductions predict visibility improvement from each furnace line at or below the de minimis visibility improvement threshold of 0.1 delta-dV.

Due to the sizable change in the United Taconite SO<sub>2</sub> emission reductions from the proposed FIP to the final FIP; the visibility improvement was re-calculated using EPA's apparent methodology from the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NO<sub>X</sub> and the revised emission reduction for SO<sub>2</sub>. Then, those resultants were averaged for each of the Class I areas to obtain the "updated" EPA all pollutant estimates.

| Class I Area    | Amended EPA | CAM <sub>X</sub> Modeled | % Over        |
|-----------------|-------------|--------------------------|---------------|
|                 | Estimated   | Difference               | Estimation by |
|                 | Difference  | 98% dV                   | EPA           |
|                 | 98% dV      |                          |               |
| Boundary Waters | 1.6         | 1.40                     | 110%          |
| Voyageurs       | 0.8         | 0.85                     | N/A           |
| Isle Royale     | 1.1         | 0.35                     | 320%          |

 Table 6: United Taconite Visibility Impact Comparison (All Pollutants)

The comparison of the total modeling effort including both pollutant reductions is surprisingly similar (except for Isle Royale). However, when the individual pollutant impacts are examined, the problem with EPA's methodology is more clearly understood. The sulfate impacts are estimated more closely to the CAM<sub>x</sub> results, while the nitrate impacts are grossly overestimated similar to the first three facilities.

The methodology used to isolate the sulfate and nitrate impacts separately from the current CAM<sub>x</sub> results prioritizes the sulfate and nitrate impacts as part of three separate post-processing runs (all pollutants, sulfate, and nitrate). The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall United Taconite impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO<sub>x</sub> control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.1 dV; total = 0.15 dV) and would not show up as part of the overall visibility change. As detailed in the comments to the proposed FIP, it is also important to note the high probability that the maximum impacts from NO<sub>x</sub> emission reduction occur during the winter months when Isle Royale is closed to visitors and visitation at the other Class I areas is significantly reduced from summertime maximum conditions.<sup>5</sup>

| Table 7: United Ta | Table 7: United Taconite Visibility Impact Comparison (Suifate Impact) |  |                          |  |            |  |  |  |  |  |  |
|--------------------|--|--|--------------------------|--|------------|--|--|--|--|--|--|
| Class I Area       | Amended EPA  |  | CAM <sub>X</sub> Modeled |  | % Over     |  |  |  |  |  |  |
|                    | Estimated  |  | Difference               |  | Estimation |  |  |  |  |  |  |
|                    | Difference   |  | 98% dV                   |  | by EPA     |  |  |  |  |  |  |
|                    | 98% dV   |  |                          |  | -          |  |  |  |  |  |  |
| Boundary Waters    | 1.0  |  | 1.29                     |  | N/A        |  |  |  |  |  |  |
| Voyageurs          | 0.5  |  | 0.74                     |  | N/A        |  |  |  |  |  |  |
| Isle Royale        | 0.6  |  | 0.28                     |  | 210%       |  |  |  |  |  |  |

 Table 7: United Taconite Visibility Impact Comparison (Sulfate Impact)

Table 8: United Taconite Visibility Impact Comparison (Nitrate Impact)

| Class I Area    | Amended EPA | CAM <sub>X</sub> Modeled |  | % Over     |
|-----------------|-------------|--------------------------|--|------------|
|                 | Estimated   | Difference               |  | Estimation |
|                 | Difference  | 98% dV                   |  | by EPA     |
|                 | 98% dV      |                          |  |            |
| Boundary Waters | 2.3         | 0.18                     |  | 1300%      |
| Voyageurs       | 1.1         | 0.08                     |  | 1400%      |
| Isle Royale     | 1.6         | 0.05                     |  | 3200%      |

<sup>&</sup>lt;sup>5</sup> Cliffs Natural Resources (September 28, 2012), EPA-R05-OAR-0037-0045 Att. M

In the same manner as Hibbing Taconite, United Taconite's individual furnace lines were evaluated. As mentioned in the previous paragraph, the results in Table 9 for nitrate impact are biased toward higher nitrate impacts due to the sorting of the data to maximize nitrate impact.

| Class I Area    | Furnace Line | CAM <sub>x</sub> Modeled<br>Difference |
|-----------------|--------------|--|
| Boundary Waters | Line 1       | 98% dV<br>0.05                         |
|                 | Line 2       | 0.1                                    |
| Voyageurs       | Line 1       | 0.02                                   |
|                 | Line 2       | 0.06                                   |
| Isle Royale     | Line 1       | 0.02                                   |
|                 | Line 2       | 0.03                                   |

Table 9: United Taconite Line-Specific Nitrate Visibility Impacts

Nonetheless, as seen for all the other furnace lines, the results for United Taconite's predicted visibility impact are at or below the deminimis threshold for visibility improvement.

Since Tilden Mining Company was not evaluated using the same methodology as the Minnesota taconite facilities, there are no specific EPA data to compare with the  $CAM_X$  results. However, it is important to understand that the results are very similar to the other results regarding the impact of  $NO_X$  emission reductions on these Class I areas.

| Class I Area    | EPA Estimated  | CAM <sub>X</sub> Modeled |
|-----------------|----------------|--------------------------|
|                 | Difference 98% | Difference               |
|                 | dV             | 98% dV                   |
| Boundary Waters | N/A            | 0.08                     |
| Voyageurs       | N/A            | 0.03                     |
| Isle Royale     | N/A*           | 0.17                     |

Table 10: Tilden Mining Visibility Impact Comparison (All Pollutants)

\*EPA estimated that the proposed FIP results in 0.501 dV visibility improvement at Isle Royale from emission reduction at Tilden Mining

| Class I Area    | CAM <sub>X</sub> Sulfate |  | CAM <sub>x</sub> Nitrate |  |  |  |  |  |  |  |
|-----------------|--------------------------|--|--------------------------|--|--|--|--|--|--|--|
|                 | Modeled                  |  | Modeled                  |  |  |  |  |  |  |  |
|                 | Difference               |  | Difference               |  |  |  |  |  |  |  |
|                 | 98% dV                   |  | 98% dV                   |  |  |  |  |  |  |  |
| Boundary Waters | 0.07                     |  | 0.01                     |  |  |  |  |  |  |  |
| Voyageurs       | 0.03                     |  | 0.00                     |  |  |  |  |  |  |  |
| Isle Royale     | 0.14                     |  | 0.02                     |  |  |  |  |  |  |  |

Table 11: Tilden Mining Pollutant-Specific Impact Comparison

The visibility impacts from  $NO_X$  emission reductions at Tilden are consistent with the other modeling results and further demonstrate that significant emission reductions of NOx (3,229 tpy for Tilden) result in no visibility improvements.

#### III. Conclusions

Overall, the results from the three facilities with only  $NO_X$  emission reductions (Hibbing Taconite, Northshore Mining, and Arcelor Mittal) and the pollutant-specific comparisons for United Taconite and Tilden Mining illustrate that nearly 15,000 tons per year of  $NO_X$  reductions, even if they were technically and/or economically achievable, provide imperceptible visibility impacts at the Minnesota or nearby Michigan Class I areas. In all cases, the CAMx-predicted impacts for every furnace line are at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

The fact that NO<sub>x</sub> emission reductions do not provide perceptible visibility improvement was understood by MPCA when they proposed existing control and good combustion practices as BART for taconite furnaces in northeast Minnesota. This finding has been confirmed by this detailed modeling analysis. EPA, to its credit, does not claim that its scalar "ratio" approach for predicting visibility improvement is accurate. In the final FIP, EPA provided, "Therefore, even if the ratio approach was over-estimating visibility improvement by a factor of two or three, the expected benefits would still be significant."<sup>6</sup> Our analysis demonstrates that the ratio approach has over-estimated impacts by a factor of ten to sixty for NO<sub>x</sub> reductions. When accurately modeled, the NO<sub>x</sub> reductions do not yield discernible visibility benefits. To that end, the following pictures from WinHaze Level 1 Visual Air Quality Imaging Modeler

<sup>&</sup>lt;sup>6</sup> Federal Register, Volume 78, Number 25, page 8720, February 6, 2013

(version 2.9.9.1) provide a visual reference for the  $CAM_X$  predicted visibility impairment from the maximum nitrate impacting facility at Isle Royale and Boundary Waters<sup>7</sup>.



Isle Royale FIP Base - United Taconite



Boundary Waters FIP Base - Hibbing Taconite



Isle Royale Final FIP – United Taconite



Boundary Waters Final FIP – Hibbing Taconite

Given the size of the predicted visibility impacts (both less than 0.2 dV improvement), these pictures illustrate no discernible visibility improvement from NO<sub>X</sub> reductions at either Class I area.

Ultimately, Minnesota and Michigan reached their visibility assessments in different ways, but this modeled analysis supports their conclusion that low  $NO_X$  burner technology is not BART for the furnaces modeled at Arcelor Mittal - Minorca, Hibbing Taconite, Northshore Mining Company, United Taconite, and Tilden Mining. Therefore, EPA should approve the sections of the SIPs establishing  $NO_X$  BART on this basis.

<sup>&</sup>lt;sup>7</sup> Voyageurs National Park pictures are not contained within the WinHaze program



resourceful. naturally. engineering and environmental consultants

# APPENDIX A: Visibility Impact Requirements and EPA's Scalar Approach for Estimating Visibility Impacts within the Taconite FIP

March 6, 2013

### I. Summary of Visibility Impact Requirements

The relevant language related to the specific BART visibility impact modeling approach from 40 CFR 51 Appendix Y (herein, Appendix Y), *Guidelines for BART Determinations Under the Regional Haze Rule,* is provided here, in italics with some language underlined for emphasis:

5. Step 5: How should I determine visibility impacts in the BART determination?

• For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.

Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emission rates are calculated as a percentage of pre-control emission rates. For example, if the 24-hr pre-control emission rate is 100 lb/hr of SO[2], then the post control rate is 5 lb/hr if the control efficiency being evaluated is 95 percent.

• Make the net visibility improvement determination.

Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. You have flexibility to assess visibility improvements due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment. Suggestions for making the determination are:

• Use of a comparison threshold, as is done for determining if BART-eligible sources should be subject to a BART determination. Comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g., the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing an x percent change in improvement).

• Compare the 98th percent days for the pre- and post-control runs.

Note that each of the modeling options may be supplemented with source apportionment data or source apportionment modeling.

It should be noted that Appendix Y is a guideline for state air quality agencies to proceed with modeling of BART sources. Therefore, these are not requirements, but recommended practices for evaluation of visibility impacts. Significant discretion was given to each state regarding the use of these methods. To that end, the Minnesota Pollution Control Agency applied a different modeling system than the EPA-approved model (CALPUFF) for BART evaluations. Discussed below, the new modeling system was subsequently used by EPA as part of their FIP proposal.

Further, an excerpt from the Clean Air Act, Part C, Subpart II is provided below to establish the basis for the Appendix Y regulations related to visibility improvement.

### II. Summary of EPA's approach

Specific language from the proposed and final FIPs are provided in *italics* along with comments.

EPA relied on visibility improvement modeling conducted by the Minnesota Pollution Control Agency (MPCA) and recorded in MPCA's document "Visibility Improvement Analysis of Controls Due to BART Determinations on Emission Unit's Subject to BART", October 23, 2009 [attached]. The visibility improvement modeling conducted by MPCA utilized the Comprehensive Air Quality Model with Extensions (CAMx) air quality model with the Mesoscale Meteorological Model (MM5) and the Emission Modeling System (EMS-2003). Within the CAMx modeling system, MPCA used the Particulate Source Apportionment Tool (PSAT) and included evaluation of all the elevated point emissions<sup>1</sup> at each facility with best available retrofit technology (BART) units. The impacts from MPCA State Implementation Plan (SIP) BART controls were determined by subtracting the impact difference between the 2002/2005 base case and 2002/2005 BART control case for each facility. EPA used the impacts from four of the six facilities modeled by MPCA (Minnesota Power – Boswell Energy Center, Minnesota Power – Taconite Harbor, Northshore Mining – Silver Bay, United Taconite). The other two facilities modeled by MPCA were utility sources (Rochester Public Utilities – Silver Lake and Xcel Energy – Sherburne Generating Plant). The locations of these sources are presented below in Figure A-1 (obtained from the MPCA 2009 document).

<sup>&</sup>lt;sup>1</sup> Elevated point emissions include only sources with plume rise above 50m.

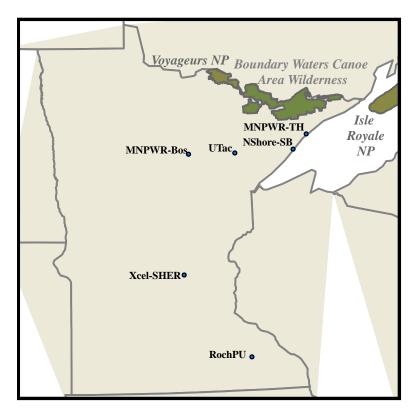


Figure A-1: Minnesota Facilities with BART-Determinations Assessed

In order to avoid the time and effort necessary for specific modeling of the units that EPA proposed to include in the FIP, EPA then used the average visibility impact from these four facilities to calculate two metrics for visibility improvement. The first metric is a ratio of number of days with greater than 0.5 deciview (dV) visibility divided separately by the change in  $SO_2$  and  $NO_x$  emissions at each facility (i.e. one ratio for change in  $SO_2$  emissions and one ratio for change in  $NO_x$  emissions). The second metric was calculated in the same fashion, but with 98<sup>th</sup> percentile visibility change divided by the change in  $SO_2$  and  $NO_x$  emissions at each facility. These ratios were then multiplied by the estimated FIP emission reductions for the taconite facilities (including UTAC and Northshore Mining). It is important to note that there were no  $NO_x$  emission reductions modeled from any of the taconite facilities and the only source of  $SO_2$  emission reductions from the taconite facilities was the UTAC facility.

Within the final FIP, EPA provided some additional statements that further clarified the agency's confidence regarding the use of the scalar approach for estimating visibility improvements.

### III. Specific Issues Regarding EPA's Visibility Impact Estimates

Clean Air Act Section 169(A)(g)(2) – "In determining the best available retrofit technology the State (or the Administrator in determining emission limitations which reflect such technology) shall 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 the source, and the <u>degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.</u>"

Proposed FIP Page 49329 – Column 1 – "The discussion below uses MPCA's emissions data and modeled visibility impact data to derive visibility impact ratios as a function of changes in emissions of NOx and SO2 at MPCA-modeled facilities. These visibility-emission ratios were then applied to the BART-based emission changes for the source subject to this BART rule to derive possible visibility impacts."

Issues – EPA's shortcut methodology does not provide an accurate assessment of potential visibility impacts from taconite emission units subject to BART, and cannot be relied upon for several reasons stated below. The use of emission change vs. visibility impact ratios is not scientifically accurate even for a single source, much less several sources in other locations, and illustrates EPA's haste for the development of the FIP without proper modeling procedures. According to a plain language reading of the Clean Air Act section above and the best-practice recommendations within Appendix Y, the state and EPA were required to conduct a thorough evaluation of the impacts associated with the changes in emissions for each BART technology at the relevant units within each taconite facilities. EPA's methodology does not result in a thorough evaluation. If such an analysis were submitted to EPA by the state, it would be rejected as inadequate. The same should apply to EPA's analysis of the visibility improvement calculations.

MPCA used an appropriate model for estimating visibility impacts from five utility sources and one taconite source, all subject to BART, in northern Minnesota. EPA took that analyses and attempted to justify its outcomes based on its flawed methodology. Alone, the differences between the emission profiles for utility sources and taconite sources and their different locations relative to the Class I areas should preclude this type of evaluation. The difference in the emissions profile relationship between  $NO_X$  and  $SO_2$  emissions is extremely important due to the interactive and competitive nature of the two pollutants for available ammonia ( $NH_3$ ) to form ammonium nitrate or ammonium sulfate.

In addition, there are important seasonal differences in the tendency for sulfates or nitrates to be important for haze formation. Nitrates are only important in winter because significant particle formation occurs only in cold weather; oxides of nitrogen react primarily to form ozone in the summer months. On the other hand, oxidation of  $SO_2$  to sulfate is most effective in summer with higher rates of photochemical and aqueous phase reactions. Due to the much different seasonal preferences for these two haze components, a one-size-fits-all scaling approach based upon annual averages that is insensitive to the season of the year is wholly inappropriate.

It is important to note that the only  $NO_x$  emission reductions used in the EPA scalar analyses were from utility sources. This occurred because the MPCA SIP did not include  $NO_x$  emission reductions from the United Taconite units. Therefore, the variation in emission profiles and stack parameters between utility boiler emission sources and taconite furnaces introduce another source of error with the EPA methodology.

Further, as shown in Figure A-1, the location of these sources with respect to the relevant Class I areas also causes significant problems with the EPA evaluation. The modeled visibility impacts from each source are a direct function of the wind direction. When two sources are not in the same direction with respect to the area, there is no possible way to accurately reflect the impact from the two different sources on receptor locations on any given day. For example, elevated impacts on the Voyageurs National Park from Northshore Mining would not happen on the same days as any of the other taconite sources in Minnesota.

Additionally, notwithstanding the inaccuracies of EPA's average scalar methodology, a review of the calculation of the visibility change to emission reduction ratios (i.e. MPCA-calculated visibility changes divided by  $SO_2$  and  $NO_X$  SIP emission reductions) was conducted. This review uncovered calculation/typographical errors in the tables that were used to develop the average visibility change metrics. These simple calculation errors were subsequently corrected in the final FIP, but another inconsistency was not. The emission reductions used for  $NO_X$  within the scalar visibility calculations (Table V-C.xx) do not match the emission reduction tables in the proposed FIP (Table V – B.yy) for each facility. In one case (Northshore Mining Company), the visibility improvement reductions are greater than the baseline emissions. The attached table provides the baseline, proposed FIP, and final FIP information contained within the EPA rulemakings and docket for each taconite furnace and facility. Ultimately, even if the scalar approach used by EPA was valid, the rulemaking record is inaccurate and incomplete for the calculation of visibility impacts due to these inconsistencies.

Further, the calculation methodology for the two facilities with  $SO_2$  and  $NO_X$  reductions (United Taconite and US Steel – Minntac) appears to utilize another invalid assumption. Also, the proposed FIP does not provide a clear explanation of the calculation of the scaled visibility impacts for these two facilities (Page 49332 – Column 1):

"To calculate the visibility impacts for the Minnesota source facilities covered by this FIP proposed rule, we multiplied the total estimated BART NOx and SO2 emission reductions for each subject facility by the appropriate visibility factor/emission change ratios in Table V-C.9 and <u>combined the results to estimate</u> the total visibility impacts that would result from the reduction of PM2.5 concentrations."

In Tables V-C.14 and V-C.16, the calculation of the visibility change with the two different pollutants is not explicitly provided within the FIP. Based on the use of the average visibility changes ("combined results") in the attached tables, one can generate "estimated visibility impacts" that are close to the values provided in the FIP tables. This pollutant averaging approach is not valid due to the previous comments regarding the interactive nature of the reaction mechanisms for ammonium nitrate and ammonium sulfate.

Proposed FIP Page 49331 – Column 1 – "The above visibility factor/emission change ratio data show significant variation from source-to-source and between impacted Class I areas. This variation is caused by differences in the relative location of the source (relative to the locations of the Class I areas), variations in background sources, variations in transport patterns on high haze factors, and other factors that we cannot assess without detailed modeling of the visibility impacts for the sources as a function of pollutant emission type."

Issue – EPA correctly establishes the significant variation in the ratio data and clearly distinguishes some (but not all) of the problems with the approach used to determine visibility impacts. Other problems include the differences in modeled utility source stack parameters vs. taconite stack parameters, the different inter-pollutant ratios at each facility, and the differences in visibility impacts due to on-going changes in emissions from 2002/2005 to current/future emission levels. Furthermore, EPA identifies the solution to solve this problem within their statement regarding "detailed modeling of the visibility impacts". This detailed modeling exercise was completed for BART-eligible Cliffs Natural Resources and Arcelor Mittal facilities in northeast Minnesota and Michigan to provide a clear record of the visibility improvements associated with the final FIP. This modeling demonstrates the lack of visibility improvement from nearly 15,000 tons per year of NO<sub>X</sub> emission reductions and provides sufficient evidence to support the Minnesota and Michigan State Implementation Plans which called for good combustion practices as BART for NO<sub>X</sub> at these facilities.

Proposed FIP Page 49333, Column 2 – "Each BART determination is a function of consideration of visibility improvement and other factors for the individual unit, but in general EPA's assessment of visibility impacts finds that technically feasible controls that are available at a reasonable cost for taconite plants can be expected to provide a visibility benefit that makes those controls warranted."

Issue – EPA's statement regarding visibility benefit from the FIP  $NO_X$  emission reductions are vastly overestimated based on updated  $CAM_X$  modeling for the Cliffs Natural Resources and Arcelor Mittal taconite furnaces. The modeling results evaluating the 98<sup>th</sup> percentile visibility improvements obtained from these emission reductions are generally less than 10% of the EPA estimates. Therefore, these  $NO_X$  controls are not warranted for visibility improvement in northeast Minnesota and Michigan.

Final FIP Page 8720, Column 2 – "EPA's analysis shows that based on all of the BART factors, including visibility, the selected controls are warranted. If highly reasonable and cost-effective controls had been available but visibility benefits were slight, EPA would have rejected those controls."

Issue – EPA describes exactly the situation with respect to "slight visibility benefits". Therefore, given the new information regarding the very slight modeled impact of  $NO_x$  emission reductions, EPA should reject those reductions as necessary under the BART program. Also, in the final FIP, EPA criticizes both MPCA and MDEQ for ignoring relevant information on Low  $NO_x$  Burner (LNB) technology. Now, given the length of time necessary and extensive effort required to generate this new visibility improvement data, EPA should reconsider its position on LNB as producing visibility benefits. This would allow EPA to support the original findings for these facilities within both the MPCA and MDEQ SIP with respect to  $NO_x$  emission limits. Final FIP Page 8720, Column 3 – "EPA's proposed rule acknowledged the uncertainty associated with the visibility impact ratio approach, but noted that despite the uncertainties, the Agency was confident that the information was adequate to assess potential visibility improvements due to emission reductions at the specific facilities."

"Given the geographic proximity of the taconite facilities to those that were modeled, EPA believes that the ratio approach provide adequate assurance of the visibility improvements that can be expected from the proposed emission reductions."

"In the proposed rule's summary of the impacts at Boundary Waters, Voyageurs, and Isle Royale, these values ranged from 1.3 to 7.1 dVs of improvement with between 17 and 93 fewer days above the 0.5 dV threshold. Therefore, even if the ratio approach was over-estimating visibility improvements by a factor of two or three, the expected benefits would still be significant."

Final FIP Page 8721, Column 3 – "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."

Issue – EPA again chose to ignore the specific technical issues discussed above regarding the use of the ratio approach and has incorrectly assumed that this approach will provide an accurate assessment of the visibility benefits from the Cliffs and Arcelor taconite facilities. Based on the refined  $CAM_x$  modeling results using a conservative estimate of EPA's final FIP emission reduction scenario, it is obvious that the ratio approach does not provide any assurance of the visibility improvements. Further, the estimates for visibility improvement are over-estimated by between a factor of ten and sixty. Therefore, the impacts are not "significant" as referenced in EPA's response to comment within the final FIP rulemaking. The lack of technical validity contained within the EPA scalar approach is alarming. Even more alarming is the agency's refusal to conduct the type of detailed analyses necessary to allow for a technically valid answer on a rulemaking that will cost the taconite industry millions of dollars.

#### **IV. Summary**

The CAM<sub>x</sub> modeling approach undertaken by Cliffs and Arcelor provides the best approximation of the visibility improvements from the emission reductions within the final FIP. This method replaces the use of the average ratio approach used by EPA with refined, photochemical modeling for the Cliffs and Arcelor facilities. The results of the analysis confirm the findings of the MPCA in its 2009 SIP that  $NO_x$  emission reductions do not have sufficient impact to warrant further consideration. At this point, we affirm that EPA's simple assessment is not credible, and any visibility improvement conclusions for  $NO_x$  are not technically sound. The visibility improvement results estimated by EPA using the ratio approach are between ten and sixty times greater than the results generated using the CAM<sub>x</sub> modeling system. In essence, the modeling conducted here provides EPA another opportunity to support the findings of the MPCA and MDEQ SIPs with respect to  $NO_x$  emissions impacts at the Cliffs and Arcelor facilities.

# Cliffs Natural Resources and Arcelor Mittal Taconite FIP Emission Summary

|                           |                   |                    |           |          | Emissions    |         | Emiss                  | ion Reductions         |         | Emissions |          |
|---------------------------|-------------------|--------------------|-----------|----------|--------------|---------|------------------------|------------------------|---------|-----------|----------|
|                           |                   |                    |           |          | Proposed FIP | ,       | Baseline -<br>Prop FIP | Baseline -<br>Prop FIP |         | Final FIP |          |
|                           |                   | Emission Unit      |           | Baseline | FIP          |         | <b>Emission Tables</b> | Visibility Calcs       |         |           |          |
| Facility                  | ModID             | Description        | Pollutant | tons/yr  | tons/yr      | Note(s) | tons/yr                | tons/yr                | Note(s) | lb/hr     | Note(s)  |
| Hibbing Taconite Company  | {3}               | Line 1             | NOx       | 2,497    | 749          | [1]     | 1,748                  |                        |         |           | [4]      |
|                           |                   |                    | SO2       | 202      | 202          | [2]     | 0                      |                        |         | 82.6      | [5]      |
|                           | {4}               | Line 2             | NOx       | 2,144    | 643          | [1]     | 1,500                  |                        |         |           | [4]      |
|                           |                   |                    | SO2       | 180      | 180          | [2]     | 0                      |                        |         | 82.6      | [5]      |
|                           | {5}               | Line 3             | NOx       | 2,247    | 674          | [1]     | 1,573                  |                        |         |           | [4]      |
|                           |                   |                    | SO2       | 188      | 188          | [2]     | 0                      |                        |         | 82.6      | [5]      |
|                           | HTC               | BART Units         | NOx       | 6,888    | 2,066        |         | 4,821                  | 5,259                  | [3]     |           |          |
|                           |                   | Combined           | SO2       | 570      | 570          |         | 0                      | 0                      | [3]     | 247.8     |          |
| Northshore Mining Company |                   | Process Boiler 1/2 | NOx       | 41       | 21           | [6]     | 21                     |                        |         |           | [10]     |
|                           |                   |                    | SO2       |          |              |         |                        |                        |         |           |          |
|                           | {24}              | Furnace 11         | NOx       | 386      | 116          | [7]     | 270                    |                        |         |           | [11]     |
|                           |                   |                    | SO2       | 38       | 38           | [8]     | 0                      |                        |         | 19.5      | [12]     |
|                           | {25}              | Furnace 12         | NOx       | 378      | 113          | [7]     | 264                    |                        |         |           | [11]     |
|                           |                   |                    | SO2       | 35       | 35           | [8]     | 0                      |                        |         | 19.5      | [12]     |
|                           | <mark>NSM</mark>  | BART Units         | NOx       | 805      | 250          |         | 555                    | 926                    | [9]     |           |          |
|                           |                   | Combined           | SO2       | 73       | 73           |         | 0                      | 0                      | [9]     | 39        |          |
| Tilden Mining Company     | {1}               | Boiler #1/2        | NOx       | 79       | 79           | [13]    | 0                      |                        |         |           |          |
|                           |                   |                    | SO2       | 0        | 0            | [14]    | 0                      |                        |         |           | [19]     |
|                           | {3}               | Ore Dryer # 1      | NOx       | 15       | 15           | [15]    | 0                      |                        |         |           |          |
|                           |                   |                    | SO2       | 34       | 34           | [15]    | 0                      |                        |         |           | [20]     |
|                           | {5}               | Furnace #1         | NOx       | 4,613    | 1,384        | [16]    | 3,229                  |                        |         |           | [21]     |
|                           |                   |                    | SO2       | 1,153    | 115          | [17]    | 1,038                  |                        |         | 55        | [22][23] |
|                           | <mark>TMC</mark>  | BART Units         | NOx       | 4,707    | 1,478        |         | 3,229                  | 3,229                  | [18]    |           |          |
|                           |                   | Combined           | SO2       | 1,187    | 150          |         | 1,038                  | 1,038                  | [18]    |           |          |
| United Taconite           | {26}              | Line 1             | NOx       | 1,643    | 493          | [24]    | 1,150                  |                        |         |           | [27]     |
|                           |                   |                    | SO2       | 1,293    | 129          | [25]    | 1,164                  |                        |         | 155       | [28]     |
|                           | {24}              | Line 2             | NOx       | 3,687    | 1,106        | [24]    | 2,581                  |                        |         |           | [27]     |
|                           |                   |                    | SO2       | 2,750    | 275          | [25]    | 2,475                  |                        |         | 374       | [28]     |
|                           | UTAC              | BART Units         | NOx       | 5,330    | 1,599        |         | 3,731                  | 3,208                  | [26]    |           |          |
|                           |                   | Combined           | SO2       | 4,043    | 404          |         | 3,639                  | 3,639                  | [26]    | 529       | [28]     |
| Arcelor Mittal            | <mark>ARC</mark>  | Line 1             | NOx       | 3,639    | 1,092        | [29]    | 2,547                  | 2,859                  | [31]    |           | [32]     |
|                           | <mark>{12}</mark> |                    | SO2       | 179      | 179          | [30]    | 0                      | 0                      | [31]    | 38.2      | [33]     |

| TOTAL BART UNIT | NOx | 21,369 6,485 |       | 14,884 | 15,481 |  |
|-----------------|-----|--------------|-------|--------|--------|--|
|                 | SO2 | 6,053        | 1,376 | 4,677  | 4,677  |  |

Facility BART Unit Summary or Overall Summary

FIP Baseline does not match reference

FIP Table B emission tables do not match Table C visibility calculation tables

#### Notes:

- [1] HTC Line 1-3 USEPA FIP NOx Baseline Emissions Proposed FIP Table V B.24; Proposed FIP NOx Emissions = 70% Control from Baseline
  - Typographical Error in Table V B.24 for Line 1 Baseline Emissions (2,143.5 TPY Proposed FIP; should have been 2,497 TPY)
- [2] HTC Line 1-3 USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V B.27
- [3] HTC USEPA Proposed BART FIP Table V C.11
- [4] HTC Furnace Lines USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
- [5] HTC Furnace Lines USEPA final BART combined limit of 247.8 lb SO2/hr [82.6 lb/hr each for Lines 1 to 3] (30-day rolling avg); can be adjusted based on CEMs data.
- [6] NSM Process Boilers 1&2 NOx Emissions from Proposed FIP Table V B.12 (p49318); LNB 50% Control from Baseline of 41.2 tons/year
- [7] NSM Furnace 11/12 NOx Emissions (Baseline and Proposed FIP Control) from Proposed FIP Table V B.8; FIP Emissions = 70% Control from Baseline
- [8] NSM Furnace 11/12 No Additional SO2 Control Applied by Proposed FIP; Baseline FIP Emission Rate from Table V B.10
- [9] NSM USEPA Proposed BART FIP Table V C.12
- [10] NSM Process Boilers 1&2 USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) [No additional control].
- [11] NSM Furnace 11/12 USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
- [12] NSM Furnace 11/12 USEPA final BART combined limit of 39.0 lb SO2/hr (30-day rolling average); must be adjusted based on CEMs data.
- [13] Tilden Process Boilers 1 & 2 NOx Baseline Emissions Proposed FIP Table V B.38
- [14] Tilden Process Boilers 1 & 2 SO2 Baseline Emissions Proposed FIP Table V B.37 (0.25 TPY)
- [15] Tilden Dryer #1 Emissions from Proposed FIP Table V B.39 (SO2) and Table V B.40 (NOx) 34.07 TPY SO2, 15.1 TPY NOx
- [16] Tilden Furnace 1 NO2 Baseline and Proposed FIP Control Emissions Proposed FIP Table V B.34 (FIP Emissions = 70% Control from Baseline)
- [17] Tilden Furnace 1 Proposed FIP SO2 Emissions Table V-B.36; Spray Dry Absorption 90%; Proposed FIP Text says 95% Control or 5 ppm; Baseline Emissions Back-calculated from 90% control
- [18] Tilden Furnace 1 USEPA did not calculate visibility improvement for Tilden (Used emission difference Baseline Proposed FIP)
- [19] Tilden USEPA Final BART limit of 1.2%S in fuel combusted by Process Boiler #1 and #2
- [20] Tilden USEPA Final BART limit of 1.5%S in fuel combusted by Ore Dryer #1
- [21] Tilden Furnace 1- USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only); NOx emissions referenced in final FIP text as 65% control from baseline (page 8721)
- [22] Tilden Furnace 1 USEPA Final BART restriction Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs; SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
- [23] Tilden Furnace 1 USEPA Final BART Modeling File (Part of Final Rulemaking Docket) Conducted by NPS 55 lb/hr SO2
- [24] UTAC Line 1-2 USEPA NOx Baseline Emissions Proposed FIP Table V B.14; Proposed FIP NOx Emissions = 70% Control from Baseline
- [25] UTAC Line 1-2 USEPA proposed FIP Baseline SO2 Emissions Table V B.17; 90% Control in Table, but 95% Control within text Proposed FIP (page 49319)
- [26] UTAC USEPA Proposed BART FIP Table V C.13
- [27] UTAC Line 1-2 USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)
- [28] UTAC Line 1-2 USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr Line 1 & 374 lb/hr Line 2).
- [29] Arcelor USEPA proposed FIP Baseline NOx Emissions Table V B.19; Proposed FIP NOx Emissions = 70% Control from Baseline
- [30] Arcelor USEPA proposed FIP Baseline SO2 Emissions Table V B.21
- [31] Arcelor USEPA Proposed BART FIP Table V C.10
- [32] Arcelor USEPA Final BART SO2 Limit of 38.16 lb/hr for Arcelor.
- [33] Arcelor USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)

EPA Furnace NOx Control % 70%



resourceful. naturally. engineering and environmental consultants

# APPENDIX B: Barr and MPCA CAM<sub>x</sub> Modeling Comparison of Results

March 6, 2013

### Minnesota Power – Taconite Harbor (BART01)

#### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| PM <sub>2.5</sub>           |          | Class I Area    |      |                 |           |      |                 |             |      |                 |  |  |
|-----------------------------|----------|-----------------|------|-----------------|-----------|------|-----------------|-------------|------|-----------------|--|--|
|                             |          | Boundary Waters |      |                 | Voyageurs |      |                 | Isle Royale |      |                 |  |  |
| Parameter                   | Met Year | Base            | BART | Differ-<br>ence | Base      | BART | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |
| Days > 0.5 dv               | 2002     | 94              | 90   | -4              | 11        | 9    | -2              | 30          | 27   | -3              |  |  |
| 98th Percentile $\Delta dv$ | 2002     | 9.2             | 8.3  | -0.9            | 0.8       | 0.7  | -0.1            | 2.2         | 1.9  | -0.3            |  |  |

#### Barr

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| $\mathbf{PM}_{2.5}$         |          | Class I Area    |      |                 |           |      |                 |             |      |                 |  |
|-----------------------------|----------|-----------------|------|-----------------|-----------|------|-----------------|-------------|------|-----------------|--|
|                             |          | Boundary Waters |      |                 | Voyageurs |      |                 | Isle Royale |      |                 |  |
| Parameter                   | Met Year | Base            | BART | Differ-<br>ence | Base      | BART | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |
| Days > 0.5 dv               | 2002     | 95              | 90   | -5              | 11        | 9    | -2              | 30          | 27   | -3              |  |
| 98th Percentile $\Delta dv$ | 2002     | 9.14            | 8.25 | -0.89           | 0.82      | 0.68 | -0.14           | 2.22        | 1.88 | -0.34           |  |

### Minnesota Power – Boswell (BART04)

#### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                       |          | Class I Area    |      |                 |           |      |                 |             |      |                 |  |
|--------------------------|----------|-----------------|------|-----------------|-----------|------|-----------------|-------------|------|-----------------|--|
| <b>PM</b> <sub>2.5</sub> |          | Boundary Waters |      |                 | Voyageurs |      |                 | Isle Royale |      |                 |  |
| Parameter                | Met Year | Base            | BART | Differ-<br>Ence | Base      | BART | Differ-<br>ence | Base        | BART | Differ-<br>Ence |  |
| Days > 0.5 dv            | 2002     | 111             | 60   | -51             | 86        | 58   | -28             | 48          | 27   | -21             |  |
| 98th Percentile<br>∆ dv  | 2002     | 4.3             | 2.4  | -1.9            | 4.4       | 2.7  | -1.8            | 2.0         | 1.0  | -1.0            |  |

Barr

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          | DM       |            |       | Class I Area    |      |      |                 |      |      |                 |  |
|-----------------------------|----------|------------|-------|-----------------|------|------|-----------------|------|------|-----------------|--|
| PM <sub>2.</sub>            | B        | oundary Wa | aters | Voyageurs       |      |      | Isle Royale     |      |      |                 |  |
| Parameter                   | Met Year | Base       | BART  | Differ-<br>Ence | Base | BART | Differ-<br>ence | Base | BART | Differ-<br>ence |  |
| Days > 0.5 dv               | 2002     | 110        | 61    | -49             | 86   | 58   | -28             | 47   | 27   | -20             |  |
| 98th Percentile $\Delta dv$ | 2002     | 4.27       | 2.37  | -1.90           | 4.43 | 2.65 | -1.78           | 1.96 | 0.98 | -0.98           |  |

# Northshore Mining – Silver Bay (BART05)

### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                                   | DM                      |      |      |                 |      | Class I Are | ea              |             |      |                 |  |  |  |  |
|--------------------------------------|-------------------------|------|------|-----------------|------|-------------|-----------------|-------------|------|-----------------|--|--|--|--|
| <b>P</b> 1 <b>V</b> 1 <sub>2</sub> . | PM <sub>2.5</sub> Bound |      |      | aters           |      | Voyageur    | s               | Isle Royale |      |                 |  |  |  |  |
| Parameter                            | Met Year                | Base | BART | Differ-<br>ence | Base | BART        | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |  |  |
| Days > 0.5 dv                        | 2002                    | 77   | 72   | -5              | 9    | 8           | -1              | 20          | 15   | -5              |  |  |  |  |
| 98th Percentile $\Delta dv$          | 2002                    | 3.96 | 3.79 | -0.17           | 0.6  | 0.5         | -0.1            | 0.9         | 0.7  | -0.2            |  |  |  |  |

#### Barr

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |            | Class I Area |      |                 |                       |      |                 |      |      |                 |  |
|-----------------------------|------------|--------------|------|-----------------|-----------------------|------|-----------------|------|------|-----------------|--|
| P1V1 <sub>2.</sub>          | $PM_{2.5}$ |              |      | aters           | Voyageurs Isle Royale |      |                 |      |      |                 |  |
| Parameter                   | Met Year   | Base         | BART | Differ-<br>ence | Base                  | BART | Differ-<br>ence | Base | BART | Differ-<br>ence |  |
| Days > 0.5 dv               | 2002       | 78           | 72   | -6              | 9                     | 8    | -1              | 20   | 15   | -5              |  |
| 98th Percentile $\Delta dv$ | 2002       | 3.96         | 3.78 | -0.18           | 0.63                  | 0.50 | -0.13           | 0.90 | 0.73 | -0.17           |  |

### **United Taconite (BART26)**

### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                      | DM       |      |            |                 | Class I Are | a    |                 |      |             |                 |  |
|-------------------------|----------|------|------------|-----------------|-------------|------|-----------------|------|-------------|-----------------|--|
| $\mathbf{PM}_{2.}$      | 5        | B    | oundary Wa | aters           | Voyageurs   |      |                 |      | Isle Royale |                 |  |
| Parameter               | Met Year | Base | BART       | Differ-<br>ence | Base        | BART | Differ-<br>ence | Base | BART        | Differ-<br>ence |  |
| Days > 0.5 dv           | 2002     | 59   | 44         | -15             | 32          | 20   | -12             | 8    | 1           | -7              |  |
| 98th Percentile<br>∆ dv | 2002     | 3.0  | 1.7        | -1.3            | 1.8         | 0.8  | -0.9            | 0.6  | 0.3         | -0.3            |  |

Barr

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                                  | DM         |      |      | Class I Area                         |      |      |                 |      |      |                 |  |
|-------------------------------------|------------|------|------|--------------------------------------|------|------|-----------------|------|------|-----------------|--|
| <b>P</b> 1 <b>V</b> 1 <sub>2.</sub> | $PM_{2.5}$ |      |      | oundary Waters Voyageurs Isle Royale |      |      |                 |      |      |                 |  |
| Parameter                           | Met Year   | Base | BART | Differ-<br>ence                      | Base | BART | Differ-<br>ence | Base | BART | Differ-<br>ence |  |
| Days > 0.5 dv                       | 2002       | 63   | 46   | -17                                  | 34   | 20   | -14             | 8    | 1    | -7              |  |
| 98th Percentile $\Delta dv$         | 2002       | 3.02 | 1.69 | -1.33                                | 1.78 | 0.85 | -0.93           | 0.59 | 0.28 | -0.31           |  |

### Xcel Sherburne (BART13)

### MPCA

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                      |          |                                       |      | Class I Area    |      |      |                 |      |      |                 |
|-------------------------|----------|---------------------------------------|------|-----------------|------|------|-----------------|------|------|-----------------|
| $\mathbf{PM}_{2.}$      | B        | Boundary Waters Voyageurs Isle Royale |      |                 |      |      |                 |      |      |                 |
| Parameter               | Met Year | Base                                  | BART | Differ-<br>ence | Base | BART | Differ-<br>ence | Base | BART | Differ-<br>ence |
| Days > 0.5 dv           | 2002     | 74                                    | 58   | -16             | 53   | 39   | -14             | 42   | 30   | -12             |
| 98th Percentile<br>∆ dv | 2002     | 2.5                                   | 1.9  | -0.6            | 2.2  | 1.7  | -0.5            | 1.4  | 1.0  | -0.4            |

#### Barr

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| PM <sub>2.5</sub>                    |          | Class I Area                          |      |                 |      |      |                 |      |      |                 |  |
|--------------------------------------|----------|---------------------------------------|------|-----------------|------|------|-----------------|------|------|-----------------|--|
| <b>P</b> 1 <b>V</b> 1 <sub>2</sub> . | B        | Boundary Waters Voyageurs Isle Royale |      |                 |      |      |                 |      | e    |                 |  |
| Parameter                            | Met Year | Base                                  | BART | Differ-<br>ence | Base | BART | Differ-<br>ence | Base | BART | Differ-<br>ence |  |
| <b>Days</b> > 0.5 dv                 | 2002     | 74                                    | 59   | -15             | 53   | 39   | -14             | 42   | 29   | -13             |  |
| 98th Percentile $\Delta dv$          | 2002     | 2.48                                  | 1.90 | -0.58           | 2.18 | 1.65 | -0.53           | 1.44 | 1.06 | -0.38           |  |

### **Rochester Public Utilities (BART07)**

### MPCA

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          | DM         |      |      | Class I Area                          |      |      |                 |      |      |                 |  |
|-----------------------------|------------|------|------|---------------------------------------|------|------|-----------------|------|------|-----------------|--|
| <b>P</b> IVI <sub>2.</sub>  | $PM_{2.5}$ |      |      | Boundary Waters Voyageurs Isle Royale |      |      |                 |      |      |                 |  |
| Parameter                   | Met Year   | Base | BART | Differ-<br>ence                       | Base | BART | Differ-<br>ence | Base | BART | Differ-<br>ence |  |
| Days > 0.5 dv               | 2002       | 0    | 0    | 0                                     | 0    | 0    | 0               | 0    | 0    | 0               |  |
| 98th Percentile $\Delta dv$ | 2002       | 0.1  | 0.1  | 0.0                                   | 0.1  | 0.0  | 0.0             | 0.1  | 0.0  | 0.0             |  |

Barr

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          | Class I Area |                 |      |                 |           |      |                 |      |             |                 |  |
|-----------------------------|--------------|-----------------|------|-----------------|-----------|------|-----------------|------|-------------|-----------------|--|
| $\mathbf{PM}_{2}$ .         | 5            | Boundary Waters |      |                 | Voyageurs |      |                 |      | Isle Royale |                 |  |
| Parameter                   | Met Year     | Base            | BART | Differ-<br>ence | Base      | BART | Differ-<br>ence | Base | BART        | Differ-<br>ence |  |
| Days > 0.5 dv               | 2002         | 0               | 0    | 0               | 0         | 0    | 0               | 0    | 0           | 0               |  |
| 98th Percentile $\Delta dv$ | 2002         | 0.10            | 0.06 | 0.04            | 0.08      | 0.04 | 0.04            | 0.09 | 0.04        | 0.05            |  |



# APPENDIX C: CAM<sub>X</sub> PSAT Source List

March 6, 2013

# 2009 MPCA Tracked, Elevated Point Sources

| RANKTRAC   | RECEPTOR      |                 |                                      |
|------------|---------------|-----------------|--------------------------------------|
| BARTSRC_ID | BARTSRC_ID    | Facility ID     | Facility Name [1]                    |
| 1          | 2             | 2703100001      | Minnesota Power - Taconite Harbor    |
| 2          | 3             | 2703700003      | XCEL - Black Dog                     |
| 3          | 4             | 2705300015      | XCEL - Riverside                     |
| 4          | 5             | 2706100004      | Minnesota Power - Boswell            |
| 5          | 6             | 2707500003      | Northshore Mining Co - Silver Bay    |
| 6          | 7             | 2709900001      | Austin Utilities - NE Power Station  |
| 7          | 8             | 2710900011      | Rochester Public Utilities           |
| 8          | 9             | 2711100002      | Otter Tail Power - Hoot Lake         |
| 9          | 10            | 2712300012      | XCEL - High Bridge                   |
| 10         | 11            | 2713700013      | Minnesota Power - Laskin             |
| 11         | 12            | 2713700027      | Hibbing Public Utilities             |
| 12         | 13            | 2713700028      | Virginia Dept of Public Utilities    |
| 13         | 14            | 2714100004      | XCEL - Sherburne Generating Plant    |
| 14         | 15            | 2716300005      | XCEL - Allen S. King                 |
| 15         | 16            | 2701700002      | Sappi - Cloquet                      |
| 16         | 17            | 2703700011      | Flint Hill Resources - Pine Bend     |
| 17         | 18            | 2706100001      | Blandin Paper / Rapids Energy        |
| 18         | 19            | 2707100002      | Boise Cascade - International Falls  |
| 19         | 20            | 2713700005      | US Steel - Minntac                   |
| 20         | 21            | 2713700015      | Minnesota Power - ML Hibbard         |
| 21         | 22            | 2713700022      | Duluth Steam Cooperative             |
| 22         | 23            | 2713700031      | Georgia Pacific - Duluth             |
| 23         | 24            | 2713700061      | Hibbing Taconite                     |
| 24         | 25            | 2713700062      | Arcelor Mittal                       |
| 25         | 26            | 2713700063      | US Steel - Keetac                    |
| 26         | 27            | 2713700113      | United Taconite - Fairlane Plant [2] |
| 27         | 28            | 2700900011      | International Paper - Sartell        |
| 28         | 29            | 2716300003      | Marathon Ashland Petroleum           |
| 29         | 30            | 2713700083      | Potlatch - Cook                      |
| 30         | 31            | 2706100010      | Potlatch - Grand Rapids              |
|            |               |                 |                                      |
|            | Included in M | IPCA BART SIP M | Iodeling Report                      |

|     | Included in MPCA BART SIP Modeling Report          |
|-----|--|
| [1] | MPCA tracked all point sources on a facility-basis |

[2] MPCA Emissions did not Include UTAC Line 1

# 2012/2013 Barr Tracked, Elevated Point Sources

| Output ID | BARTSRC ID | Facility ID | Facility / Unit Name [3]                      |
|-----------|------------|-------------|---|
| MNPWTH    | 2          | -           | Minnesota Power - Taconite Harbor             |
| XCELBD    | 3          | 2703700003  | XCEL - Black Dog                              |
| XCELRV    | 4          | 2705300015  | XCEL - Riverside                              |
| MNPWBO    | 5          | 2706100004  | Minnesota Power - Boswell                     |
| NSMSBU    | 6          | 2707500003  | Northshore Mining Co - Silver Bay (All Other) |
| AUSTIN    | 7          | 2709900001  | Austin Utilities - NE Power Station           |
| ROCHPU    | 8          | 2710900011  | Rochester Public Utilities                    |
| OTTRHL    | 9          | 2711100002  | Otter Tail Power - Hoot Lake                  |
| XCELHB    | 10         | 2712300012  | XCEL - High Bridge                            |
| MNPWLS    | 11         | 2713700013  | Minnesota Power - Laskin                      |
| HIBBPU    | 12         | 2713700027  | Hibbing Public Utilities                      |
| VIRGPU    | 13         | 2713700028  | Virginia Dept of Public Utilities             |
| XCELSB    | 14         | 2714100004  | XCEL - Sherburne Generating Plant             |
| XCELAK    | 15         | 2716300005  | XCEL - Allen S. King                          |
| SAPPIC    | 16         | 2701700002  | Sappi - Cloquet                               |
| FHRPNB    | 17         | 2703700011  | Flint Hill Resources - Pine Bend              |
| BLNPAP    | 18         | 2706100001  | Blandin Paper / Rapids Energy                 |
| BOISEC    | 19         | 2707100002  | Boise Cascade - International Falls           |
| MINNTC    | 20         | 2713700005  | US Steel - Minntac                            |
| MNPWHB    | 21         | 2713700015  | Minnesota Power - ML Hibbard                  |
| DULSTM    | 22         | 2713700022  | Duluth Steam Cooperative                      |
| GEOPAC    | 23         | 2713700031  | Georgia Pacific - Duluth                      |
| HIBTAC    | 24         | 2713700061  | Hibbing Taconite (All Other)                  |
| ARCELR    | 25         | 2713700062  | Arcelor Mittal (All Other)                    |
| KEETAC    | 26         | 2713700063  | US Steel - Keetac                             |
| UTACFP    | 27         | 2713700113  | United Taconite - Fairlane Plant (All Other)  |
| INTPAP    | 28         | 2700900011  | International Paper - Sartell                 |
| MARTHN    | 29         | 2716300003  | Marathon Ashland Petroleum                    |
| POTLTC    | 30         | 2713700083  | Potlatch - Cook                               |
| POTLTG    | 31         | 2706100010  | Potlatch - Grand Rapids                       |
| TILDEN    | 32         | 26103B4885  | Tilden Mining Company (All Other)             |
| NSMPB1    | 33         | 2707500003  | Northshore Mining - Power Boiler 1            |
| NSMPB2    | 34         | 2707500003  | Northshore Mining - Power Boiler 2            |
| NSMF11    | 35         | 2707500003  | Northshore Mining - Furnace 11                |
| NSMF12    | 36         | 2707500003  | Northshore Mining - Furnace 12                |
| UTACL1    | 37         | 2713700113  | United Taconite - Line 1                      |
| UTACL2    | 38         | 2713700113  | United Taconite - Line 2                      |
| ARCLN1    | 39         | 2713700062  | Arcelor Mittal - Line 1                       |
| HBTCF1    | 40         | 2713700061  | Hibbing Taconite - Line 1                     |
| HBTCF2    | 41         | 2713700061  | Hibbing Taconite - Line 2                     |
| HBTCF3    | 42         | 2713700061  | Hibbing Taconite - Line 3                     |
| TILDL1    | 43         | 26103B4885  | Tilden Mining - Line 1                        |

Included in Barr Output Evaluation

Barr tracked furnace stacks and other noted stacks on a unit-basis while all other stacks were included in the "All Other" stacks

[3]



# APPENDIX D: Summary of CAM<sub>x</sub> Elevated Point Source Emissions

March 6, 2013

# Summary of CAMx Elevated Point Source Emissions

|                           |                   |                    |           | Emissi         | ons      | Emiss   | sions   | Emission Reductions  |
|---------------------------|-------------------|--------------------|-----------|----------------|----------|---------|---------|----------------------|
|                           |                   |                    |           | Propose        | ed FIP   | Fina    | I FIP   | Baseline - Final FIP |
|                           |                   | Emission Unit      | Pollutant | Baseline       |          | FIP     |         |                      |
| Facility                  | ModID             | Description        |           | tons/yr        | Note(s)  | tons/yr | Note(s) | tons/yr              |
| Hibbing Taconite Company  | {3}               | Line 1             | NOx       | 2,497          | [1]      | 749     | [3]     | 1,748                |
|                           |                   |                    | SO2       | 202            | [2]      | 202     | [4]     | 0                    |
|                           | {4}               | Line 2             | NOx       | 2,144          | [1]      | 643     | [3]     | 1,500                |
|                           |                   |                    | SO2       | 180            | [2]      | 180     | [4]     | 0                    |
|                           | {5}               | Line 3             | NOx       | 2,247          | [1]      | 674     | [3]     | 1,573                |
|                           |                   |                    | SO2       | 188            | [2]      | 188     | [4]     | 0                    |
|                           | HTC               | BART Furnaces      | NOx       | 6,888          |          | 2,066   |         | 4,821                |
|                           |                   | Combined           | SO2       | 570            |          | 570     |         | 0                    |
| Northshore Mining Company |                   | Process Boiler 1/2 | NOx       | 41             | [5]      | 41      | [8]     | 0                    |
|                           |                   |                    | SO2       |                |          |         |         |                      |
|                           | {24}              | Furnace 11         | NOx       | 386            | [6]      | 116     | [9]     | 270                  |
|                           |                   |                    | SO2       | 38             | [7]      | 38      | [10]    | 0                    |
|                           | {25}              | Furnace 12         | NOx       | 378            | [6]      | 113     | [9]     | 264                  |
|                           |                   |                    | SO2       | 35             | [7]      | 35      | [10]    | 0                    |
|                           | <mark>NSM</mark>  | BART Furnaces      | NOx       | 764            |          | 229     |         | 535                  |
|                           |                   | Combined           | SO2       | 73             |          | 73      |         | 0                    |
| Tilden Mining Company     | {1}               | Boiler #1/2        | NOx       | 79             | [11]     | 79      | [16]    | 0                    |
|                           |                   |                    | SO2       | 0              | [12]     | 0       | [17]    | 0                    |
|                           | {3}               | Ore Dryer # 1      | NOx       | 15             | [13]     | 15      | [18]    | 0                    |
|                           |                   |                    | SO2       | 34             | [13]     | 34      | [19]    | 0                    |
|                           | {5}               | Furnace #1         | NOx       | 4,613          | [14]     | 1,384   | [20]    | 3,229                |
|                           |                   |                    | SO2       | 1,153          | [15]     | 231     | [21]    | 922                  |
|                           | TMC               | BART Furnace       | NOx       | 4,613          |          | 1,384   |         | 3,229                |
|                           |                   |                    | SO2       | 1,153          |          | 231     |         | 922                  |
| United Taconite           | {26}              | Line 1             | NOx       | 1,643          | [22][23] | 493     | [26]    | 1,150                |
|                           |                   |                    | SO2       | 1,293          | [25]     | 577     | [27]    | 716                  |
|                           | {24}              | Line 2             | NOx       | 3,687          | [22][24] | 1,106   | [26]    | 2,581                |
|                           |                   |                    | SO2       | 2,750          | [25]     | 1,392   | [27]    | 1,357                |
|                           | UTAC              | BART Furnaces      | NOx       | 5,330          |          | 1,599   |         | 3,731                |
|                           |                   | Combined           | SO2       | 4,043          |          | 1,969   |         | 2,074                |
| Arcelor Mittal            | ARC               | Line 1             | NOx       | 3 <i>,</i> 639 | [28]     | 1,092   | [30]    | 2,547                |
|                           | <mark>{12}</mark> |                    | SO2       | 179            | [29]     | 179     | [31]    | 0                    |

| TOTAL BART | NOx | 21,233 | 6,370 | 14,863 |
|------------|-----|--------|-------|--------|
| Furnaces   | SO2 | 6,018  | 3,022 | 2,996  |

Fac

Facility Furnace Unit Summary or Overall Summary

FIP Baseline does not match reference

#### Notes:

- [1] HTC Line 1-3 USEPA FIP NOx Baseline Emissions Proposed FIP Table V B.24
- [2] HTC Line 1-3 USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V B.27
- [3] HTC Line 1-3 USEPA Proposed FIP NOx = 70% control from Baseline Table V B.24; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
- [4] HTC Line 1-3 USEPA Final FIP no additional SO2 control (Final FIP = Baseline Emissions)
- [5] NSM Process Boilers 1&2 NOx Emissions from Proposed FIP Table V B.12 (p49318)
- [6] NSM Furnace 11/12 NOx Emissions from Proposed FIP Table V B.8
- [7] NSM Furnace 11/12 SO2 Baseline FIP Emission Rate from Proposed FIP Table V B.10
- [8] NSM Process Boilers #1 and #2 USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) No additional control.
- [9] NSM Furnace 11/12 USEPA Proposed FIP NOx = 70% control from Baseline Table V B.8; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
- [10] NSM Furnace 11/12 no Additional SO2 Control Applied by Proposed or Final FIP (Final FIP = Baseline Emissions)
- [11] Tilden Process Boilers 1 & 2 NOx Baseline Emissions Proposed FIP Table V B.38
- [12] Tilden Process Boilers 1 & 2 SO2 Baseline Emissions Proposed FIP Table V B.37 (0.25 TPY)
- [13] Tilden Dryer #1 Emissions from Proposed FIP Table V B.39 (SO2) and Table V B.40 (NOx) 34.07 TPY SO2, 15.1 TPY NOx
- [14] Tilden Furnace 1 NO2 Baseline Proposed FIP Table V B.34
- [15] Tilden Furnace 1 SO2 Baseline Proposed FIP Projected SO2 Emission Reductions Table V-B.36; Baseline Emissions Back-calculated from 90% control
- [16] Tilden Process Boilers 1 & 2 No additional NOx control (Final FIP = Baseline Emissions)
- [17] Tilden Process Boilers 1 & 2 USEPA Final BART limit of 1.2%S in fuel No additional SO2 control (Final FIP = Baseline Emissions)
- [18] Tilden Ore Dryer #1 No additional NOx control (Final FIP = Baseline Emissions)
- [19] Tilden Ore Dryer #1 USEPA Final BART limit of 1.5%S in fuel No additional SO2 control (Final FIP = Baseline Emissions)
- [20] Tilden Furnace 1 USEPA Proposed FIP NOx = 70% control from Baseline Table V B.34; Final FIP (1.2 or 1.5 lb/MMBTU) NOx emissions referenced in final FIP text at 65% control from baseline (page 8721); but that is not consistent with the remaining facilities Modeled emissions assumed 70% control to provide maximum emission reductions
- [21] Tilden USEPA Final BART restriction Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs; SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
- [22] UTAC USEPA FIP NOx Baseline Emissions Proposed FIP Table V B.14
- [23] UTAC Line 1 NOx Permit limit specified in permit 13700113-005 1,655 TPY, issued 8/19/2010, page A-49 (reference from USEPA 114 Request Question 6)
- [24] UTAC Line 2 NOx Permit limit specified in permit 13700113-005 3,692 TPY, issued 8/19/2010, page A-56 (reference from USEPA 114 Request Question 6)
- [25] UTAC Line 1&2 USEPA proposed FIP Baseline SO2 Emissions Table V B.17; 90% Control in Table, 95% Control within text Proposed FIP (page 49319) Modeled baseline emissions back-calculated from 90% Control; SO2 Reductions match Table V - C.13 in Proposed FIP
- [26] UTAC Line 1&2 USEAP Proposed FIP NOx = 70% Control from Baseline Table V B.14; Final FIP (1.2 or 1.5 lb/MMBTU) Modeled emissions assumed 70% control to provide maximum emission reductions
- [27] UTAC Line 1&2 USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr Line 1 & 374 lb/hr Line 2) 30-day rolling average. Modeled Final FIP emissions used the limits and 85% operating factor to calculate the annual emissions (designed to maximize reductions)
- [28] Arcelor Line 1 USEPA proposed FIP Baseline NOx Emissions Table V B.19
- [29] Arcelor Line 1 USEPA proposed FIP Baseline SO2 Emissions Table V B.21
- [30] Arcelor Line 1 Proposed FIP NOx = 70% Control from Baseline Table V B.19; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
- [31] Arcelor Line 1 USEPA Final FIP no additional SO2 control (Final FIP = Baseline Emissions)



# APPENDIX E: Electronic Mail Requests - Proposed and Final FIP Emission Clarifications

From:Jeffry D. BennettSent:Thursday, January 31, 2013 7:42 PMTo:'Rosenthal.steven@Epa.gov'Cc:'Long, Michael E'Subject:Clarification Regarding Emissions within the Final Taconite BART FIPAttachments:EPA\_FIP\_Emission\_Summary\_01292013.xls

Steve,

Pursuant to our conversation last week regarding the baseline and controlled emission inventories within the proposed and final BART FIP for taconite furnaces, this e-mail is designed to request clarification regarding certain information contained in the rule. To that end, attached you will find a spreadsheet that summarizes and documents (to the maximum extent possible) the emission inventory data within the FIP rulemakings.

Specifically at this time, we are requesting:

(1) verification of the UTAC baseline NOx information for Line 1 and Line 2 ('Summary' Tab, Cells E30 and E32),

(2) clarification of the differences between the information contained in Columns H and I of the spreadsheet, Column H contains the difference between the FIP baseline and proposed FIP control emissions and was calculated from information within Table V-B.xx\* - NOx or SO2 facility specific emission data. The Column I information contains the emission reductions obtained from Table V-C.yy visibility improvement estimate tables. For each facility, these two columns should match, but the NOx information does not. Ultimately, the bases for Table V-C.yy data is the component that is missing.

\*Note: for Hibbing Taconite Line 1, a typographical error was discovered in Table V-B.24 and corrected in the spreadsheet.

(3) EPA's estimates of final FIP emissions on a tons/year basis with the corresponding emission reductions (i.e. FIP baseline – final FIP control) expected by EPA. This information would replace the "?" in Columns L and M of the spreadsheet. Along with the estimates, documentation of their bases would be extremely beneficial. For example, NOx could include either a % reduction from baseline or MMBTU/hour, Hours/year, and the appropriate lb NOx/MMBTU limit.

If you have any questions regarding these requests, feel free to contact Mike Long or myself. Thank you for your time.

Jeffry D. Bennett, PE Senior Air Quality Engineer Jefferson City office: 573.638.5033 cell: 573.694.0674 JBennett@barr.com www.barr.com From: Jeffry D. Bennett
Sent: Thursday, February 14, 2013 12:02 PM
To: 'Robinson.randall@Epa.gov'
Subject: FW: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: EPA\_FIP\_Emission\_Summary\_01292013.xls

#### Randy,

I talked with Steve Rosenthal yesterday about the taconite BART FIP emissions (see e-mail below). He told me that you "wrote the section on visibility improvement" and suggested I contact you about item 2 and a portion of the information requested in item 3. Barr Engineering is contracted with Cliffs Natural Resources and Arcelor Mittal to provide their taconite facilities with technical support regarding the FIP. At this point, we are trying to summarize and document the bases for the SO2 and NOx emissions that were used in the EPA baseline, the proposed FIP, and the final FIP for all their facilities.

The attached spreadsheet that I sent Steve previously includes the summary. Item 2 is related to differences between the NOx emission reductions used in the ratio visibility improvement calculations in the proposed FIP (Table V – C.yy) and the emission reductions in Table V – B.xx for each facility. Steve thought you would have the information about the basis for the Table V – C.yy reductions.

Item 3 is requesting information about the final FIP emission reductions. Specifically, you would probably have information regarding the emissions for Tilden Mining and United Taconite (UTAC) from the CALPUFF modeling completed by Trent Wickman referenced in the final FIP rulemaking docket. Please give me a call to discuss this at your earliest convenience. We are attempting to finalize the summary by COB tomorrow. Thanks for any help you can provide.

Jeffry D. Bennett, PE Senior Air Quality Engineer Jefferson City office: 573.638.5033 cell: 573.694.0674 JBennett@barr.com www.barr.com



resourceful. naturally. engineering and environmental consultants

# APPENDIX F: CAMx Modeling Results by Facility

March 6, 2013

### Arcelor Mittal CAMx Emissions and Modeling Results

#### **Arcelor Emissions**

| Unit   | EPA FIP   | Final FIP | NOx        | EPA FIP   | Final FIP | SO2        |
|--------|-----------|-----------|------------|-----------|-----------|------------|
|        | Baseline  | NOx       | Emission   | Baseline  | SO2       | Emission   |
|        | NOx       | Emission  | Difference | SO2       | Emission  | Difference |
|        | Emission  | (TPY) [1] | (TPY)      | Emission  | (TPY)[3]  | (TPY)      |
|        | (TPY) [1] |           |            | (TPY) [2] |           |            |
| Line 1 | 3,639     | 1,092     | 2,547      | 179       | 179       | 0          |
|        |           |           |            |           |           |            |
| TOTAL  | 3,639     | 1,092     | 2,547      | 179       | 179       | 0          |

[1] FIP Baseline and Control NOx Emissions from EPA Proposed FIP Table V-B.19 – Projected Annual NOx Emission Reductions [TPY].

[2] FIP Baseline SO2 Emissions are from EPA Proposed FIP Table V-B.21 – Annual SO2 Emissions [TPY]

[3] No SO2 emission reductions in Final FIP (i.e. EPA Baseline = Final FIP control)

| Class I Area     | EPA FIP       | EPA FIP  | Proposed   | Proposed   | Difference | Difference |
|------------------|---------------|----------|------------|------------|------------|------------|
|                  | Baseline Days | Baseline | FIP Days > | FIP 98% dV | Days >0.5  | 98% dV [5] |
|                  | >0.5 dV       | 98% dV   | 0.5 dV     |            | dV [5]     | 00/00.000  |
| Boundary Waters  |               | 00,00    |            |            |            |            |
| 2002             |               |          |            |            |            |            |
| Line #1          | 30            | 0.789    | 18         | 0.713      | 12         | 0.076      |
| Facility Total   | 43            | 0.99     | 35         | 0.96       | 8          | 0.03       |
| 2005             |               |          |            |            |            |            |
| Line #1          | 7             | 0.491    | 3          | 0.326      | 4          | 0.165      |
| Facility Total   | 19            | 0.74     | 8          | 0.55       | 11         | 0.19       |
| <u>Voyageurs</u> |               |          |            |            |            |            |
| 2002             |               |          |            |            |            |            |
| Line #1          | 1             | 0.287    | 0          | 0.202      | 1          | 0.085      |
| Facility Total   | 1             | 0.34     | 0          | 0.22       | 1          | 0.12       |
| 2005             |               |          |            |            |            |            |
| Line #1          | 0             | 0.182    | 0          | 0.122      | 0          | 0.060      |
| Facility Total   | 0             | 0.22     | 0          | 0.16       | 0          | 0.06       |
| Isle Royale      |               |          |            |            |            |            |
| 2002             |               |          |            |            |            |            |
| Line #1          | 0             | 0.075    | 0          | 0.053      | 0          | 0.022      |
| Facility Total   | 0             | 0.09     | 0          | 0.06       | 0          | 0.03       |
| 2005             |               |          |            |            |            |            |
| Line #1          | 0             | 0.049    | 0          | 0.033      | 0          | 0.016      |
| Facility Total   | 0             | 0.06     | 0          | 0.04       | 0          | 0.02       |

[4] Visibility benchmarks:

<u>0.5 dV impact</u> is the BART eligibility threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required),

<u>1.0 dV difference</u> is the presumed human perceptible level for visibility improvement, and <u>0.1 dV difference</u> was defined by other agencies as the degree of visibility improvement that is too low to justify additional emission controls. Also, EPA's Regional Haze Rule mentions that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

[5] These two columns provide the difference in predicted days >0.5 dV and 98<sup>th</sup> percentile visibility improvement from the baseline to the FIP control emissions. The annual average number of days with > 0.5 dV improvement at all the Class I areas is considerably less than EPA's estimate (11 to 53). Also, the averages of the 98<sup>th</sup> percentile differences are **10 to 37 times less** than the predicted improvement by EPA. Note: the table below formed the basis for EPA's inclusion of control necessary at Arcelor Mittal.

### Arcelor Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

| Class I Area    | Area EPA Estimated EPA Estim |        |  | CAMx Modeled    | CAMx Modeled |  |  |  |
|-----------------|------------------------------|--------|--|-----------------|--------------|--|--|--|
|                 | Difference Days              |        |  | Difference Days | Difference   |  |  |  |
|                 | >0.5 dV                      | 98% dV |  | >0.5 dV[8]      | 98% dV       |  |  |  |
| Boundary Waters | 24                           | 1.7    |  | 10              | 0.11         |  |  |  |
|                 |                              |        |  |                 |              |  |  |  |
| Voyageurs       | 11                           | 0.9    |  | 1               | 0.09         |  |  |  |
|                 |                              |        |  |                 |              |  |  |  |
| Isle Royale     | 18                           | 1.1    |  | 0               | 0.03         |  |  |  |

(EPA Table C Emission Difference = 2,859 TPY NOx)[6] (EPA Table B Emission Difference = 2,547 TPY NOx)[7]

[6] Emission Difference Obtained from EPA Proposed FIP Table V-C.10 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Arcelor Mittal.

[7] Emission Difference Obtained from EPA Proposed FIP Table V-B.19.

[8] The number of days with visibility >0.5 deciviews (dV) can be a misleading indicator as illustrated by the Arcelor Mittal and Northshore Mining results (below). The 98<sup>th</sup> percentile visibility improvement at Boundary Waters during the 2002 modeled year was 0.03 dV. However, the modeling predicts this insignificant change will result in eight more days of "good visibility", defined as days with visibility at or below the 0.5 deciview threshold. Further, the Northshore Mining results at Isle Royale indicate a miniscule 0.01 deciviews, or one hundred times less than a perceptible improvement to visibility. Nonetheless, the modeling predicts this insignificant change will result in two more days of "good visibility". In both circumstances, this does not mean that the visibility change was discernible. The model gives credit for an improved day when the predicted impairment falls from 0.51 to 0.50 deciviews, but that improvement is illusory because at 0.51 deciviews people do not perceive a regional haze problem. The difference in visibility from natural background when evaluating the baseline could have several days near the 0.5 dV "contribute to visibility degradation" threshold, but well less than the 1 dV "cause visibility degradation" threshold. Then, a very small change in visibility from the baseline to the controlled emission scenario (~0.01 – 0.1 dV) could cause a large number of days to be less than the 0.5 dV benchmark without producing any real benefit to visibility.

# Hibbing Taconite (HibTac) CAMx Emissions and Modeling Results

### **HibTac Emissions**

| Unit   | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|--------|----------|-----------|------------|----------|-----------|------------|
|        | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|        | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|        | Emission | (TPY)     | (TPY)      | Emission | (TPY)     | (TPY)      |
|        | (TPY)    |           |            | (TPY)    |           |            |
| Line 1 | 2,497    | 749       | 1,748      | 202      | 202       | 0          |
| Line 2 | 2,144    | 643       | 1,500      | 180      | 180       | 0          |
| Line 3 | 2,247    | 674       | 1,573      | 188      | 188       | 0          |
|        |          |           |            |          |           |            |
| TOTAL  | 6,888    | 2,066     | 4,822      | 570      | 570       | 0          |

#### HibTac CAMx Results (By Unit)

| Class I Area           | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|------------------------|---------------|----------|-----------|-----------|------------|------------|
|                        | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Boundary Waters</u> |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line 1                 | 1             | 0.337    | 1         | 0.305     | 0          | 0.032      |
| Line 2                 | 2             | 0.287    | 0         | 0.260     | 2          | 0.027      |
| Line 3                 | 1             | 0.318    | 0         | 0.245     | 2          | 0.073      |
| Facility Total         | 33            | 1.10     | 22        | 0.96      | 11         | 0.14       |
| 2005                   |               |          |           |           |            |            |
| Line 1                 | 0             | 0.217    | 0         | 0.158     | 0          | 0.057      |
| Line 2                 | 0             | 0.203    | 0         | 0.124     | 0          | 0.079      |
| Line 3                 | 0             | 0.223    | 0         | 0.140     | 0          | 0.083      |
| Facility Total         | 14            | 0.85     | 11        | 0.62      | 3          | 0.23       |
| <u>Voyageurs</u>       |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line 1                 | 0             | 0.197    | 0         | 0.168     | 0          | 0.029      |
| Line 2                 | 0             | 0.197    | 0         | 0.159     | 0          | 0.038      |
| Line 3                 | 0             | 0.211    | 0         | 0.163     | 0          | 0.048      |
| Facility Total         | 18            | 0.67     | 10        | 0.61      | 8          | 0.06       |
| 2005                   |               |          |           |           |            |            |
| Line 1                 | 0             | 0.126    | 0         | 0.102     | 0          | 0.024      |
| Line 2                 | 0             | 0.122    | 0         | 0.085     | 0          | 0.037      |
| Line 3                 | 0             | 0.133    | 0         | 0.103     | 0          | 0.030      |
| Facility Total         | 8             | 0.51     | 5         | 0.36      | 3          | 0.15       |

| Class I Area       | EPA FIP              | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|--------------------|----------------------|----------|-----------|-----------|------------|------------|
|                    | <b>Baseline Days</b> | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                    | >0.5 dV              | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Isle Royale</u> |                      |          |           |           |            |            |
| 2002               |                      |          |           |           |            |            |
| Line 1             | 0                    | 0.053    | 0         | 0.047     | 0          | 0.006      |
| Line 2             | 0                    | 0.045    | 0         | 0.036     | 0          | 0.009      |
| Line 3             | 0                    | 0.046    | 0         | 0.037     | 0          | 0.009      |
| Facility Total     | 0                    | 0.16     | 0         | 0.13      | 0          | 0.03       |
|                    |                      |          |           |           |            |            |
| 2005               |                      |          |           |           |            |            |
| Line 1             | 0                    | 0.038    | 0         | 0.027     | 0          | 0.011      |
| Line 2             | 0                    | 0.034    | 0         | 0.022     | 0          | 0.012      |
| Line 3             | 0                    | 0.037    | 0         | 0.026     | 0          | 0.011      |
| Facility Total     | 0                    | 0.13     | 0         | 0.09      | 0          | 0.04       |

### HibTac Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 5,259 TPY NOx)[8] (EPA Table B Emission Difference = 4,822 TPY NOx)[9]

| (=              |                 |               |                    |                 |              |
|-----------------|-----------------|---------------|--------------------|-----------------|--------------|
| Class I Area    | EPA Estimated   | EPA Estimated | mated CAMx Modeled |                 | CAMx Modeled |
|                 | Difference Days | Difference    |                    | Difference Days | Difference   |
|                 | >0.5 dV         | 98% dV        |                    | >0.5 dV         | 98% dV       |
| Boundary Waters | 44              | 3.2           |                    | 7               | 0.19         |
|                 |                 |               |                    |                 |              |
| Voyageurs       | 21              | 1.7           |                    | 5               | 0.11         |
|                 |                 |               |                    |                 |              |
| Isle Royale     | 26              | 2.1           |                    | 0               | 0.04         |

[8] Emission Difference Obtained from EPA Proposed FIP Table V-C.11 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Hibbing Taconite.

[9] Emission Difference Obtained from EPA Proposed FIP Table V-B.24.

# Northshore Mining CAMx Emissions and Modeling Results

### Northshore Emissions

| Unit            | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|-----------------|----------|-----------|------------|----------|-----------|------------|
|                 | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|                 | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|                 | Emission | (TPY)     | (TPY)      | Emission | (TPY)     | (TPY)      |
|                 | (TPY)    |           |            | (TPY)    |           |            |
| Power Boiler #1 | 676      | 676       | 0          | 681      | 681       | 0          |
| Power Boiler #2 | 1,093    | 1,093     | 0          | 1,098    | 1,098     | 0          |
| Furnace 11      | 386      | 116       | 270        | 38       | 38        | 0          |
| Furnace 12      | 378      | 113       | 265        | 35       | 35        | 0          |
|                 |          |           |            |          |           |            |
| FURNACES        | 764      | 229       | 535        | 73       | 73        | 0          |
| TOTAL           | 2,533    | 1,998     | 535        | 1,852    | 1,852     | 0          |

### Northshore CAMx Results (By Unit)

| NOT LISTORE CAN        | x Results (by O |          |           |           |            |            |
|------------------------|-----------------|----------|-----------|-----------|------------|------------|
| Class I Area           | EPA FIP         | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|                        | Baseline Days   | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV         | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Boundary Waters</u> |                 |          |           |           |            |            |
| 2002                   |                 |          |           |           |            |            |
| Power Boiler #1        | 32              | 1.487    | 32        | 1.499     | 0          | -0.012     |
| Power Boiler #2        | 49              | 2.087    | 49        | 2.097     | 0          | -0.010     |
| Furnace 11             | 0               | 0.136    | 0         | 0.139     | 0          | -0.003     |
| Furnace 12             | 0               | 0.133    | 0         | 0.122     | 0          | 0.011      |
| Facility Total         | 73              | 4.16     | 72        | 4.14      | 1          | 0.02       |
|                        |                 |          |           |           |            |            |
| 2005                   |                 |          |           |           |            |            |
| Power Boiler #1        | 13              | 0.640    | 13        | 0.654     | 0          | -0.014     |
| Power Boiler #2        | 22              | 0.926    | 23        | 0.911     | 0          | 0.015      |
| Furnace 11             | 0               | 0.087    | 0         | 0.067     | 0          | 0.020      |
| Furnace 12             | 0               | 0.082    | 0         | 0.076     | 0          | 0.006      |
| Facility Total         | 51              | 1.67     | 50        | 1.68      | 1          | -0.01      |
| Voyageurs              |                 |          |           |           |            |            |
| 2002                   |                 |          |           |           |            |            |
| Power Boiler #1        | 1               | 0.196    | 1         | 0.196     | 0          | 0.000      |
| Power Boiler #2        | 1               | 0.293    | 1         | 0.293     | 0          | 0.000      |
| Furnace 11             | 0               | 0.016    | 0         | 0.013     | 0          | 0.003      |
| Furnace 12             | 0               | 0.015    | 0         | 0.013     | 0          | 0.002      |
| Facility Total         | 8               | 0.51     | 8         | 0.51      | 0          | 0.00       |

| Class I Area            | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|-------------------------|---------------|----------|-----------|-----------|------------|------------|
|                         | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                         | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Voyageurs</u>        |               |          |           |           |            |            |
| 2005                    |               |          |           |           |            |            |
| Power Boiler #1         | 0             | 0.188    | 0         | 0.193     | 0          | -0.005     |
| Power Boiler #2         | 1             | 0.244    | 1         | 0.247     | 0          | -0.003     |
| Furnace 11              | 0             | 0.020    | 0         | 0.018     | 0          | 0.002      |
| Furnace 12              | 0             | 0.021    | 0         | 0.016     | 0          | 0.004      |
| Facility Total          | 6             | 0.47     | 6         | 0.46      | 0          | 0.01       |
| Ida Davala              |               |          |           |           |            |            |
| Isle Royale             |               |          |           |           |            |            |
| 2002<br>Power Boiler #1 | 3             | 0.204    | 2         | 0.204     | 0          | 0.000      |
|                         |               | 0.294    | 3         | 0.294     | 0          | 0.000      |
| Power Boiler #2         | 6             | 0.412    | 6         | 0.408     | 0          | 0.004      |
| Furnace 11              | 0             | 0.034    | 0         | 0.028     | 0          | 0.006      |
| Furnace 12              | 0             | 0.037    | 0         | 0.029     | 0          | 0.008      |
| Facility Total          | 16            | 0.75     | 15        | 0.74      | 1          | 0.00       |
|                         |               |          |           |           |            |            |
| 2005                    |               |          |           |           |            |            |
| Power Boiler #1         | 3             | 0.180    | 3         | 0.180     | 0          | 0.000      |
| Power Boiler #2         | 4             | 0.320    | 4         | 0.322     | 0          | -0.002     |
| Furnace 11              | 0             | 0.036    | 0         | 0.023     | 0          | 0.013      |
| Furnace 12              | 0             | 0.034    | 0         | 0.022     | 0          | 0.012      |
| Facility Total          | 10            | 0.57     | 8         | 0.55      | 2          | 0.02       |

### Northshore Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 926 TPY NOx)[10] (EPA Table B Emission Difference = 535 TPY NOx)[11]

| Class I Area           | EPA Estimated   | EPA Estimated | CAMx Modeled |                 | CAMx Modeled |  |
|------------------------|-----------------|---------------|--------------|-----------------|--------------|--|
|                        | Difference Days | Difference    |              | Difference Days | Difference   |  |
|                        | >0.5 dV         | 98% dV        |              | >0.5 dV         | 98% dV       |  |
| <b>Boundary Waters</b> | 8               | 0.6           |              | 1               | 0.01         |  |
|                        |                 |               |              |                 |              |  |
| Voyageurs              | 4               | 0.3           |              | 0               | 0.01         |  |
|                        |                 |               |              |                 |              |  |
| Isle Royale            | 5               | 0.4           |              | 2               | 0.01         |  |

[10]Emission Difference Obtained from EPA Proposed FIP Table V-C.12 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Northshore Mining.

[11]Emission Difference Obtained from EPA Proposed FIP Table V-B.8; further the emission reductions in Table C exceed the FIP baseline in Table B by 142 TPY.

### United Taconite (UTAC) CAMx Emissions and Modeling Results

#### **UTAC Emissions**

| Unit   | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|--------|----------|-----------|------------|----------|-----------|------------|
|        | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|        | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|        | Emission | (TPY)     | (TPY)[12]  | Emission | (TPY)[13] | (TPY)      |
|        | (TPY)    |           |            | (TPY)    |           |            |
| Line 1 | 1,643    | 493       | 1,150      | 1,293    | 577       | 716        |
| Line 2 | 3,687    | 1,106     | 2,581      | 2,750    | 1,392     | 1,358      |
|        |          |           |            |          |           |            |
| TOTAL  | 5,330    | 1,599     | 3,731      | 4,043    | 1,969     | 2,074      |

[12]NOx emission difference was calculated using 70% emission reduction from EPA Baseline within the proposed FIP (corresponding to 1.2 lb NOx/MMBTU); to ensure maximum emission reductions were evaluated there was no change to the final FIP emissions to reflect the final FIP limit of 1.5 lb NOx/MMBTU.

[13]Final FIP SO2 Emissions were calculated using the final FIP limit of 529 lb/hr with an operating factor of 85%; this was done to maximize the emission reductions while using a reasonable operating factor

| OTAC CANA RESU         |               |          | 1         |           |            |            |
|------------------------|---------------|----------|-----------|-----------|------------|------------|
| Class I Area           | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|                        | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b> |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line #1                | 22            | 1.294    | 10        | 0.674     | 12         | 0.620      |
| Line #2                | 45            | 2.744    | 30        | 1.556     | 15         | 1.189      |
| Facility Total         | 76            | 4.22     | 55        | 2.37      | 21         | 1.85       |
|                        |               |          |           |           |            |            |
| 2005                   |               |          |           |           |            |            |
| Line #1                | 11            | 0.610    | 2         | 0.303     | 9          | 0.307      |
| Line #2                | 26            | 1.294    | 15        | 0.678     | 11         | 0.616      |
| Facility Total         | 52            | 2.52     | 34        | 1.57      | 18         | 0.95       |
| <u>Voyageurs</u>       |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line #1                | 12            | 0.606    | 2         | 0.307     | 10         | 0.299      |
| Line #2                | 26            | 1.452    | 15        | 0.771     | 11         | 0.681      |
| Facility Total         | 42            | 2.10     | 26        | 1.11      | 16         | 0.99       |
|                        |               |          |           |           |            |            |
| 2005                   |               |          |           |           |            |            |
| Line #1                | 4             | 0.331    | 1         | 0.181     | 3          | 0.150      |
| Line #2                | 17            | 0.786    | 6         | 0.446     | 11         | 0.340      |
| Facility Total         | 33            | 1.47     | 14        | 0.76      | 19         | 0.71       |

#### UTAC CAMx Results (By Unit)

| Class I Area       | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|--------------------|---------------|----------|-----------|-----------|------------|------------|
|                    | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                    | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Isle Royale</u> |               |          |           |           |            |            |
| 2002               |               |          |           |           |            |            |
| Line #1            | 0             | 0.255    | 0         | 0.117     | 0          | 0.138      |
| Line #2            | 8             | 0.518    | 0         | 0.266     | 8          | 0.252      |
| Facility Total     | 13            | 0.81     | 3         | 0.41      | 10         | 0.40       |
|                    |               |          |           |           |            |            |
| 2005               |               |          |           |           |            |            |
| Line #1            | 0             | 0.163    | 0         | 0.080     | 0          | 0.083      |
| Line #2            | 1             | 0.322    | 0         | 0.184     | 1          | 0.138      |
| Facility Total     | 10            | 0.57     | 0         | 0.28      | 10         | 0.29       |

#### UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 3,208 TPY NOx and 3,639 TPY SO2)[14] (EPA Table B Emission Difference = 3,731 TPY NOx and 3,639 TPY SO2)[15]

| Class I Area    | EPA Estimated   | EPA Estimated |  | CAMx Modeled    | CAMx Modeled |  |  |
|-----------------|-----------------|---------------|--|-----------------|--------------|--|--|
|                 | Difference Days | Difference    |  | Difference Days | Difference   |  |  |
|                 | >0.5 dV         | 98% dV        |  | >0.5 dV[16]     | 98% dV[16]   |  |  |
| Boundary Waters | 29              | 1.9           |  | 20              | 1.40         |  |  |
|                 |                 |               |  |                 |              |  |  |
| Voyageurs       | 12              | 0.99          |  | 18              | 0.85         |  |  |
|                 |                 |               |  |                 |              |  |  |
| Isle Royale     | 14              | 1.16          |  | 10              | 0.35         |  |  |

[14]Emission Difference Obtained from EPA Proposed FIP Table V-C.13 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for United Taconite.

[15]Emission Difference Obtained from EPA Proposed FIP Table V-B.14 (SO2) and V-B.17 (NOx) – NOx reductions are not consistent

[16]Baseline – final FIP Emission Reductions -> 3,731 TPY NOx and 2,074 TPY SO2

The United Taconite comparison table above does not provide an "apples to apples" comparison. As noted, the EPA estimated visibility benefits include more SO2 emission reductions (proposed FIP) than are included in the final FIP. This table was amended to include the revised SO2 emission reductions using EPA's apparent methodology within the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NOx and the revised emission reduction for SO2. Then, those resultants were averaged for each of the Class I areas to obtain the amended EPA estimates below to provide for the appropriate comparison of EPA's method.

| Amended UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with |
|---|
| CAMx Modeling Analyses  |

| Class I Area    | EPA Estimated   | EPA Estimated |  | CAMx Modeled    | CAMx Modeled |  |  |  |
|-----------------|-----------------|---------------|--|-----------------|--------------|--|--|--|
|                 | Difference Days | Difference    |  | Difference Days | Difference   |  |  |  |
|                 | >0.5 dV         | 98% dV        |  | >0.5 dV         | 98% dV       |  |  |  |
| Boundary Waters | 22              | 1.6           |  | 20              | 1.40         |  |  |  |
|                 |                 |               |  |                 |              |  |  |  |
| Voyageurs       | 10              | 0.8           |  | 18              | 0.85         |  |  |  |
|                 |                 |               |  |                 |              |  |  |  |
| Isle Royale     | 14              | 1.1           |  | 10              | 0.35         |  |  |  |

Final FIP Emission Difference = 3,731 TPY NOx and 2,074 TPY SO2

As discussed above, the SO4 and NO3 visibility benefits were combined by EPA. The following tables provide a modeled comparison of the impacts sorted by SO4 and NO3 on a line-specific basis, then combined for both lines. The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall UTAC impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO<sub>x</sub> control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.15 dV; total = 0.20 dV) and would not show up as part of the overall visibility change (see Line 2 – 2002 Boundary Waters results).

| Class I Area                   | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|--------------------------------|---------------|----------|-----------|-----------|------------|------------|
|                                | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                                | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b>         |               |          |           |           |            |            |
| 2002                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.106    | 0         | 0.059     | 0          | 0.047      |
| Line #1 – SO4                  | 22            | 1.294    | 10        | 0.674     | 12         | 0.620      |
| Line #1 – All                  | 22            | 1.294    | 10        | 0.674     | 12         | 0.620      |
|                                |               |          |           |           |            |            |
| 2005                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.136    | 0         | 0.083     | 0          | 0.053      |
| Line #1 – SO4                  | 8             | 0.571    | 2         | 0.280     | 6          | 0.291      |
| Line #1 – All                  | 11            | 0.610    | 2         | 0.303     | 9          | 0.307      |
| Voyageurs                      |               |          |           |           |            |            |
| 2002                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.040    | 0         | 0.017     | 0          | 0.023      |
| Line #1 – SO4                  | 11            | 0.582    | 2         | 0.301     | 9          | 0.281      |
| Line #1 – All                  | 12            | 0.606    | 2         | 0.307     | 10         | 0.299      |
|                                |               |          |           |           |            |            |
| 2005                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.048    | 0         | 0.027     | 0          | 0.021      |
| Line #1 – SO4                  | 4             | 0.330    | 1         | 0.155     | 3          | 0.175      |
| Line #1 – All                  | 4             | 0.331    | 1         | 0.181     | 3          | 0.150      |
| Isle Royale                    |               |          |           |           |            |            |
| 2002                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.033    | 0         | 0.015     | 0          | 0.018      |
| Line #1 – SO4                  | 0             | 0.216    | 0         | 0.104     | 0          | 0.112      |
| Line #1 – All                  | 0             | 0.255    | 0         | 0.117     | 0          | 0.138      |
| 2005                           |               |          |           |           |            |            |
| <b>2005</b><br>Line #1 – NO3   | 0             | 0.026    | 0         | 0.011     | 0          | 0.015      |
| Line #1 – NO3                  | 0             | 0.026    | 0         | 0.011     | 0          | 0.015      |
| Line #1 – SO4<br>Line #1 – All | 0             |          |           |           |            |            |
| Line #1 – All                  | U             | 0.163    | 0         | 0.080     | 0          | 0.083      |

UTAC Line 1 – Pollutant Specific Modeling Results

| Class I Area           | EPA FIP              | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|------------------------|----------------------|----------|-----------|-----------|------------|------------|
|                        | <b>Baseline Days</b> | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV              | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b> |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 1                    | 0.237    | 0         | 0.090     | 1          | 0.147      |
| Line #2 – SO4          | 44                   | 2.679    | 28        | 1.547     | 16         | 1.132      |
| Line #2 – All          | 45                   | 2.744    | 30        | 1.556     | 15         | 1.189      |
|                        |                      |          |           |           |            |            |
| 2005                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 1                    | 0.195    | 0         | 0.091     | 1          | 0.104      |
| Line #2 – SO4          | 25                   | 1.196    | 15        | 0.659     | 10         | 0.539      |
| Line #2 – All          | 26                   | 1.294    | 15        | 0.678     | 11         | 0.616      |
| Voyageurs              |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.104    | 0         | 0.031     | 0          | 0.073      |
| Line #2 – SO4          | 25                   | 1.446    | 15        | 0.768     | 10         | 0.678      |
| Line #2 – All          | 26                   | 1.452    | 15        | 0.771     | 11         | 0.681      |
| 2005                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.083    | 0         | 0.033     | 0          | 0.050      |
| Line #2 – NOS          | 16                   | 0.773    | 6         | 0.436     | 10         | 0.337      |
| Line #2 – All          | 10                   | 0.775    | 6         | 0.430     | 10         | 0.340      |
|                        |                      |          |           |           |            |            |
| <u>Isle Royale</u>     |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.054    | 0         | 0.018     | 0          | 0.036      |
| Line #2 – SO4          | 7                    | 0.469    | 0         | 0.245     | 7          | 0.224      |
| Line #2 – All          | 8                    | 0.518    | 0         | 0.266     | 8          | 0.252      |
| 2005                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.046    | 0         | 0.016     | 0          | 0.030      |
| Line #2 – SO4          | 1                    | 0.319    | 0         | 0.166     | 1          | 0.153      |
| Line #2 – All          | 1                    | 0.322    | 0         | 0.184     | 1          | 0.138      |

UTAC Line 2 – Pollutant Specific Modeling Results

# UTAC Comparison of Sulfate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

|                 | Difference = $2,07$ + | 111302        |                 |              |
|-----------------|-----------------------|---------------|-----------------|--------------|
| Class I Area    | EPA Estimated         | EPA Estimated | CAMx Modeled    | CAMx Modeled |
|                 | Difference Days       | Difference    | Difference Days | Difference   |
|                 | >0.5 dV               | 98% dV        | >0.5 dV         | 98% dV       |
| Boundary Waters | 14                    | 1.0           | 22              | 1.29         |
|                 |                       |               |                 |              |
| Voyageurs       | 6                     | 0.5           | 16              | 0.74         |
|                 |                       |               |                 |              |
| Isle Royale     | 8                     | 0.6           | 4               | 0.28         |

Final FIP Emission Difference = 2,074 TPY SO2

# UTAC Comparison of Nitrate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 3,731 TPY NOx

| Class I Area    | EPA Estimated   | EPA Estimated | CAMx Modeled    | CAMx Modeled |
|-----------------|-----------------|---------------|-----------------|--------------|
|                 | Difference Days | Difference    | Difference Days | Difference   |
|                 | >0.5 dV         | 98% dV        | >0.5 dV         | 98% dV       |
| Boundary Waters | 31              | 2.3           | 1               | 0.18         |
|                 |                 |               |                 |              |
| Voyageurs       | 15              | 1.1           | 0               | 0.08         |
|                 |                 |               |                 |              |
| Isle Royale     | 20              | 1.6           | 0               | 0.05         |

The maximum 98<sup>th</sup> percentile NO3 impact when combining both line emission reductions is <u>0.18 dV</u>, while the maximum 98<sup>th</sup> percentile SO4 impact for both lines is <u>1.29 dV</u>. Based on these results, it is evident that the SO4 impact on the Class I areas provides the vast majority of the predicted CAMx estimates of visibility improvement. This finding is consistent with MPCA's original finding for BART in the 2009 SIP that NOx emission reductions do not provide substantive visibility improvement.

# Tilden Mining CAMx Emissions and Modeling Results

## **Tilden Emissions**

| Unit   | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|--------|----------|-----------|------------|----------|-----------|------------|
|        | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|        | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|        | Emission | (TPY)     | (TPY)      | Emission | (TPY)     | (TPY)      |
|        | (TPY)    |           |            | (TPY)    |           |            |
| Line 1 | 4,613    | 1,384     | 3,229      | 1,153    | 231       | 922        |
|        |          |           |            |          |           |            |
| TOTAL  | 4,613    | 1,384     | 3,229      | 1,153    | 231       | 922        |

## Tilden CAMx Results (By Unit)

| Class I Area           | EPA FIP       | EPA FIP  | Final FIP  | Final FIP | Difference | Difference |
|------------------------|---------------|----------|------------|-----------|------------|------------|
|                        | Baseline Days | Baseline | Days > 0.5 | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV       | 98% dV   | dV         |           | dV         |            |
| <b>Boundary Waters</b> |               |          |            |           |            |            |
| 2002                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.141    | 0          | 0.037     | 0          | 0.104      |
|                        |               |          |            |           |            |            |
| 2005                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.097    | 0          | 0.042     | 0          | 0.055      |
|                        |               |          |            |           |            |            |
| <u>Voyageurs</u>       |               |          |            |           |            |            |
| 2002                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.042    | 0          | 0.011     | 0          | 0.031      |
|                        |               |          |            |           |            |            |
| 2005                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.041    | 0          | 0.010     | 0          | 0.031      |
|                        |               |          |            |           |            |            |
| Isle Royale            |               |          |            |           |            |            |
| 2002                   |               |          |            |           |            |            |
| Line #1                | 1             | 0.300    | 0          | 0.094     | 1          | 0.206      |
|                        |               |          |            |           |            |            |
| 2005                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.211    | 0          | 0.070     | 0          | 0.141      |

| Class I Area           | EPA FIP              | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|------------------------|----------------------|----------|-----------|-----------|------------|------------|
|                        | <b>Baseline Days</b> | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV              | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b> |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.031    | 0         | 0.013     | 0          | 0.018      |
| Line #1 – SO4          | 0                    | 0.102    | 0         | 0.022     | 0          | 0.080      |
| Line #1 – All          | 0                    | 0.141    | 0         | 0.037     | 0          | 0.104      |
| 2005                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.045    | 0         | 0.042     | 0          | 0.003      |
| Line #1 – SO4          | 0                    | 0.087    | 0         | 0.019     | 0          | 0.068      |
| Line #1 – All          | 0                    | 0.097    | 0         | 0.042     | 0          | 0.055      |
| Mauggaura              |                      |          |           |           |            |            |
| Voyageurs<br>2002      |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.002    | 0         | 0.001     | 0          | 0.001      |
| Line #1 – SO4          | 0                    | 0.041    | 0         | 0.011     | 0          | 0.030      |
| Line #1 – All          | 0                    | 0.042    | 0         | 0.011     | 0          | 0.031      |
| 2005                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.005    | 0         | 0.003     | 0          | 0.002      |
| Line #1 – SO4          | 0                    | 0.039    | 0         | 0.008     | 0          | 0.031      |
| Line #1 – All          | 0                    | 0.041    | 0         | 0.010     | 0          | 0.031      |
| Isle Royale            |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.084    | 0         | 0.038     | 0          | 0.046      |
| Line #1 – SO4          | 1                    | 0.197    | 0         | 0.052     | 1          | 0.145      |
| Line #1 – All          | 1                    | 0.300    | 0         | 0.094     | 1          | 0.206      |
| 2005                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.043    | 0         | 0.047     | 0          | -0.004     |
| Line #1 – SO4          | 0                    | 0.176    | 0         | 0.040     | 0          | 0.136      |
| Line #1 – All          | 0                    | 0.211    | 0         | 0.070     | 0          | 0.141      |

Tilden Line 1 – Pollutant Specific Modeling Results

Attachment 3

2012 AECOM Report



# Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

Robert Paine and David Heinold, AECOM

September 28, 2012

#### Executive Summary

This report reviews several aspects of the visibility assessment that is part of any Best Available Retrofit Technology (BART) assessment. The crux of this analysis focuses upon two opportunistic emission reductions that have resulted in no perceptible visibility benefits, while a straightforward application of EPA's modeling procedures would predict a substantial visibility benefit. These actual emission reduction cases include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in Minnesota in 2009.

There are several reasons why there is an inconsistency between the real world and the modeling results:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clean, which exaggerates the impact of emission sources. Overly clean natural conditions can erroneously indicate that some states are missing the 2018 milestone for achieving progress toward an impossible goal by the year 2064.
- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations that are detailed in this report. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.
- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.
- The modeled base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

September 2012



Impacts of the taconite plants' NO<sub>x</sub> emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5  $\frac{1}{2}$  months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO<sub>x</sub> controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to increases in haze due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, as well as the impacts of Michigan sources on Minnesota's Class I areas indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.



#### Introduction

Best Available Retrofit Technology (BART) is part of the Clean Air Act (Appendix Y of 40 CFR Part 51) as a requirement related to visibility and the 1999 Regional Haze Rule (RHR)<sup>1</sup> that applies to existing stationary sources. Sources eligible for BART were those from 26 source categories with a potential to emit over 250 tons per year of any air pollutant, and that were placed into operation between August 1962 and August 1977. Final BART implementation guidance for regional haze was published in the Federal Register on July 6, 2005<sup>2</sup>.

The United States Environmental Protection Agency (EPA) has issued a proposed rule<sup>3</sup> to address BART requirements for taconite plants in Minnesota and Michigan that involves emission controls for SO<sub>2</sub> and NO<sub>x</sub>. This document addresses the likely visibility impact of taconite plant emissions, specifically NO<sub>x</sub> emissions, for impacts at Prevention of Significant Deterioration (PSD) Class I areas that the RHR addresses.

#### Locations of Emission Sources and PSD Class I Areas

Figure 1 shows the location of BART-eligible taconite plants in Minnesota and Michigan addressed in EPA's proposed rule, as well as Class I areas within 500 km of these sources. In most applications of EPA's preferred dispersion model for visibility impacts, CALPUFF<sup>4</sup>, the distance limitation is 200-300 km because of the overprediction tendencies<sup>5</sup> for further distances. The overprediction occurs because of extended travel times that often involve at least a full day, during which there can be significant wind shear influences on plume spreading that the model and the meteorological wind field does not accommodate. With larger travel distances, there are higher uncertainties in the predictions of any model, either CALPUFF or a regional photochemical model. Therefore, a reasonable upper limit for establishing the impact of the taconite sources would be 500 km, with questionable results beyond 200-300 km from the source. In this case, the Class I areas involved are those shown in Figure 1. All other PSD Class I areas are much further away. It is noteworthy that EPA's visibility improvement assessment considered only three Class I areas: Voyageurs National Park, Boundary Waters Canoe Area Wilderness, and Isle Royale National Park.

September 2012

<sup>&</sup>lt;sup>1</sup> Regional Haze Regulations; Final Rule. *Federal Register*, *64*, 35713-35774. (July 1, 1999).

<sup>&</sup>lt;sup>2</sup> Federal Register. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, Vol. 70. (July 6, 2005)

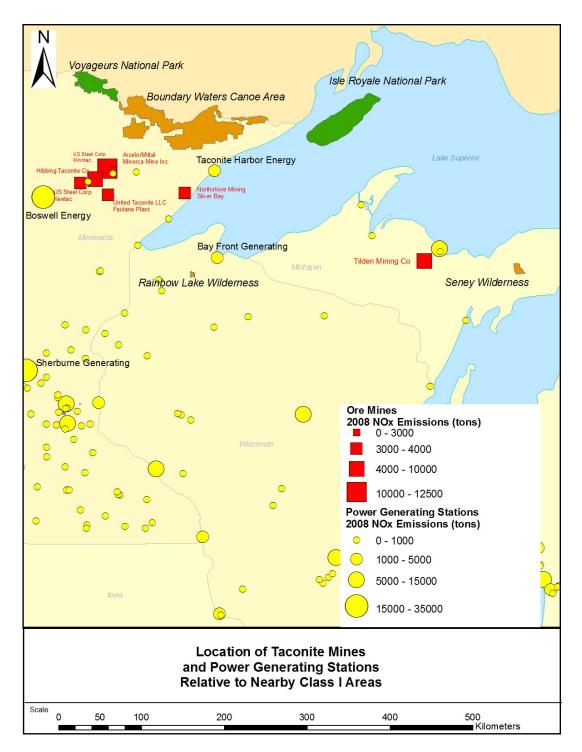
<sup>&</sup>lt;sup>3</sup> 77FR49308, August 15, 2012.

<sup>&</sup>lt;sup>4</sup> CALPUFF Dispersion Model, 2000. <u>http://www.epa.gov/scram001</u> (under 7th Modeling Conference link to Earth Tech web site).

<sup>&</sup>lt;sup>5</sup> As documented in Appendix D of the IWAQM Phase 2 document, available at www.epa.gov/scram001/7thconf/calpuff/phase2.pdf.



Figure 1 Location of Emission Sources Relative To PSD Class I Areas in Minnesota and Michigan





#### Overprediction Tendency of Visibility Assessment Modeling for BART Emission Reductions

A particularly challenging part of the BART process is the lack of well-defined criteria for determining whether a proposed emission reduction is sufficient, because the criteria for determining BART are somewhat subjective in several aspects, such as what controls are cost-effective and the degree to which the related modeled reductions in haze are sufficient. In addition, the calculations of the visibility improvements, which are intrinsic to establishing the required BART controls, are subject to considerable uncertainty due both to the inherent uncertainty in model predictions and model input parameters. Alternative approaches for applying for technical options and chemistry algorithms in the United States Environmental Protection Agency's (EPA's) preferred CALPUFF model can result in a large range in the modeled visibility improvement. The degree of uncertainty is especially large when NO<sub>x</sub> emission controls are considered as a BART option because modeling secondary formation of ammonium nitrate is quite challenging. Accurately modeling the effects of NO<sub>x</sub> controls on visibility is very important because they are often very expensive to install and operate. As a collateral effect that needs to be taken into account for BART decisions, such controls can also complicate energy efficiency objectives and strategies to control greenhouse gases and other pollutants. In this paper we discuss why EPA's preferred application of CALPUFF would likely overestimate the predicted visibility impact of emissions, especially NO<sub>x</sub>, and the associated effectiveness of NO<sub>x</sub> emission controls. Overestimates of the benefits of emissions reduction are evident from the following observations, which are discussed in this document:

- Natural background extinction used in CALPOST to calculate a source's haze impacts is underestimated, which has the effect of exaggerating the impact, which is computed relative to these defined conditions. Natural conditions also dictate how well each state is adhering to the 2018 milestone for achieving progress toward this goal by the year 2064. If the specification of natural conditions is underestimated to the extent that it is not attainable regardless of contributions from U.S. anthropogenic sources, then some states will be penalized for not achieving sufficient progress toward an impossible goal. Appendix A discusses this point in more detail.
- The chemistry in the current EPA-approved version of CALPUFF overestimates winter nitrate haze, especially in conjunction with the specification of high ammonia background concentrations. This conservatism is exacerbated by CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, CALPUFF modeling will credit BART emission reductions with more visibility improvements than will really occur.
- There are examples where actual significant emission reductions have occurred, where CALPUFF modeling as conducted for BART would predict significant visibility improvements, but no perceptive changes in haze occurred.

#### Visibility Impact of NO<sub>x</sub> Emissions – Unique Aspects and Seasonality

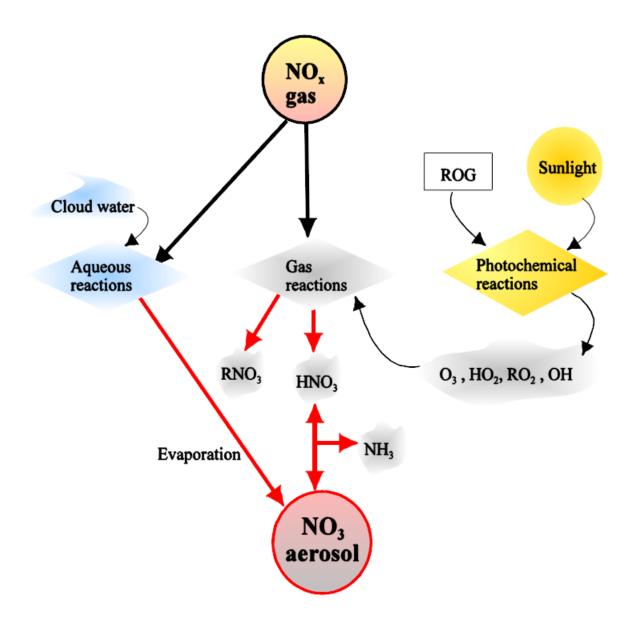
The oxidation of NO<sub>X</sub> to total nitrate (TNO<sub>3</sub>) depends on the NO<sub>X</sub> concentration, ambient ozone concentration, and atmospheric stability. Some of the TNO<sub>3</sub> is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state with HNO<sub>3</sub> gas that is a function

September 2012



of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 2<sup>6</sup>. It is important to realize that both CALPUFF and regional photochemical models tend to overpredict nitrate formation, especially in winter. A more detailed discussion of this issue is provided in Appendix B.

#### Figure 2 CALPUFF II NO<sub>x</sub> Oxidation



<sup>6</sup> Figure 2-32 from CALPUFF Users Guide, available at <u>http://www.src.com/calpuff/download/CALPUFF\_UsersGuide.pdf</u>.

Page 6 of 45



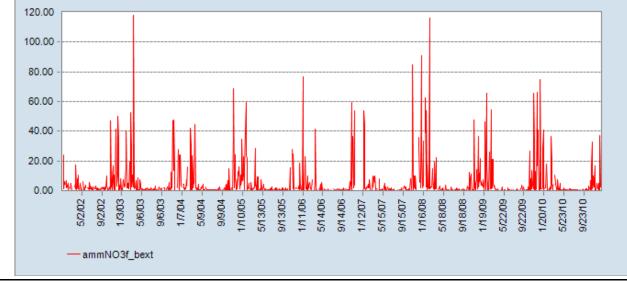
In CALPUFF, total nitrate  $(TNO_3 = HNO_3 + NO_3)$  is partitioned into each species according to the equilibrium relationship between gaseous  $HNO_3$  and  $NO_3$  aerosol. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate strongly depends on availability of  $NH_3$  to form ammonium nitrate. A summary of the conditions affecting nitrate formation is provided below:

- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium nitrate is formed;
- Sulfate preferentially scavenges ammonia over nitrates.

For this BART analysis, the effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various  $NO_X$  control options. For parts of the country where sulfate concentrations are relatively high and ammonia emissions are quite low, the atmosphere is likely to be in an ammonia-limited regime relative to nitrate formation. Therefore,  $NO_X$  emission controls are not very effective in improving regional haze, especially if there is very little ambient ammonia available.

In many cases, the BART visibility assessments ignore the haze increases that occur due to the additional power generation required to operate the control equipment. For  $NO_x$  controls, for example, the warm season emissions have minimal visibility impact, but the associated  $SO_2$  emissions from the power generation required to run the controls will increase sulfate haze. These effects have not been considered in the visibility assessment modeling.

It is evident from haze composition plots available from Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors that nitrate haze is confined to winter months. This is clearly shown in Figure 3, which is a timeline of nitrate haze extinction from Boundary Waters Canoe Area Wilderness. Similar patterns are evident for the other Class I areas plotted in Figure 1. The impact of NO<sub>X</sub> emissions during the non-winter months (e.g., April through October) is very low.



#### Figure 3 Boundary Water Canoe Area Wilderness Ammonium Nitrate Extinction, 2002-2010

September 2012

Page 7 of 45



The occurrence of significant nitrate haze only in the winter months has implications for the effectiveness of haze reductions relative to park attendance. The BART Rule addresses the seasonal issue as follows: "Other ways that visibility improvement may be assessed to inform the control decisions would be to examine distributions of the daily impacts, determine if the time of year is important (e.g., high impacts are occurring during tourist season) . . . "

In this case, the high nitrate impacts are not occurring during the tourist season, especially for the waterdominant Class I areas in Minnesota (Voyageurs and Boundary Waters) that freeze in winter. In fact, for Voyageurs National Park, the typical monthly attendance<sup>7</sup> for an off-season month (November) is only 0.2% that of a peak-season month (July). This is obviously due in part to the brutal winter weather in northern Minnesota (and Michigan) and the lack of boating access to frozen water bodies.

Operations at the Michigan Class I areas in winter are even more restricted. Isle Royale National Park is one of the few national parks to <u>totally close</u><sup>8</sup> during the winter (generally, during the period of November 1 through April 15). The closure is due to the extreme winter weather conditions and difficulty of access from the mainland across a frozen Lake Superior, for the protection of wildlife, and for the safety and protection of potential visitors. Due to this total closure, there is very little nitrate haze impact in this park during the seasons of the year that it is open, and haze issues for Isle Royale National Park will not be further considered in this report.

The Seney Wilderness Area Visitor Center is open<sup>9</sup> only during the period of May 15th to mid-October. Various trails are generally only open during the same period. The tour loops are closed in the fall, winter, and spring to allow migrating and nesting birds a place to rest or nest undisturbed, and because of large amounts of snow. Although portions of the park are open in the winter, the visitation is greatly reduced due to no visitor center access, no trail or tour loop access, and the severe weather.

#### Effect of 2009 Recession on Haze in Affected PSD Class I Areas

The effect on haze of a significant (50%) emission reduction from the taconite plants that actually occurred in early 2009 and lasted throughout calendar year 2009 is discussed in this section. This emission reduction was not due to environmental regulations, but rather economic conditions, and affected all pollutants being emitted by the collective group of Minnesota taconite plants, as well as regional power production that is needed to operate the taconite plants.

The annual taconite production<sup>10</sup> from the Minnesota taconite plants in recent years is plotted in Figure 4, along with annual average nitrate concentrations at the nearest Class I area, Boundary Waters Canoe Area (BWCA). The figure shows that the nitrate measured in the park did not respond to the reduction in emissions from the taconite plants. Figures 5 and 6 show the time series<sup>11</sup> of nitrate and sulfate haze in

<sup>&</sup>lt;sup>7</sup> As documented at <u>http://www.gorp.com/parks-guide/voyageurs-national-park-outdoor-pp2-guide-cid9423.html</u>.

<sup>&</sup>lt;sup>8</sup> As noted at <u>http://www.nps.gov/isro/planyourvisit/hours.htm</u>.

<sup>&</sup>lt;sup>9</sup> As noted at <u>http://www.fws.gov/midwest/seney/visitor\_info.html</u>.

<sup>&</sup>lt;sup>10</sup> Production data is available from taxes levied on taconite production, and the data was supplied by BARR Engineering through a personal communication with Robert Paine of AECOM.

<sup>&</sup>lt;sup>11</sup> Available from the VIEWS web site at http://views.cira.colostate.edu/web/.



the BWCA over the past several years. Figures for other affected Class I areas (Voyageurs, Seney, and Isle Royale) are shown in Appendix C.

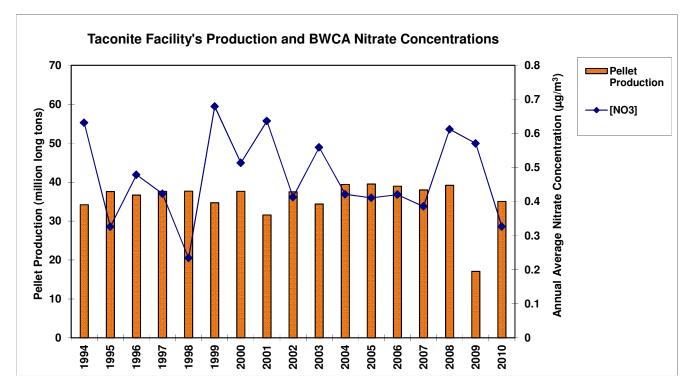
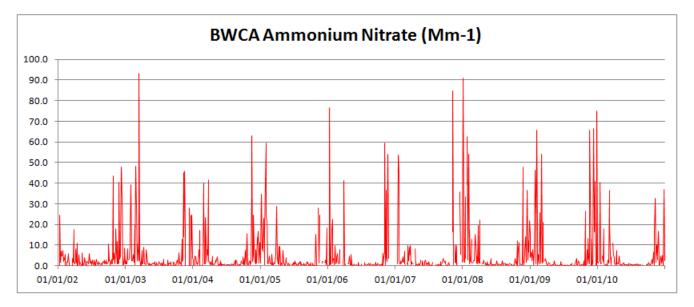




Figure 5 Time Series of Nitrate Haze at Boundary Waters Canoe Area (2002-2010)



September 2012



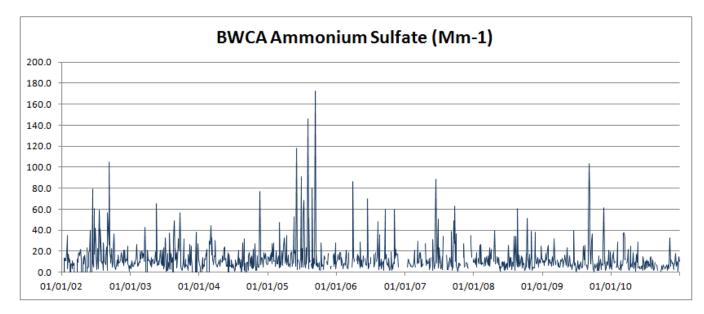


Figure 6 Time Series of Sulfate Haze at Boundary Waters Canoe Area (2002-2010)

It is evident from this information that the haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions.

It is instructive to review the haze composition time series plots for BWCA for 2008, 2009, and 2010, as shown in Figures 7, 8, and 9.

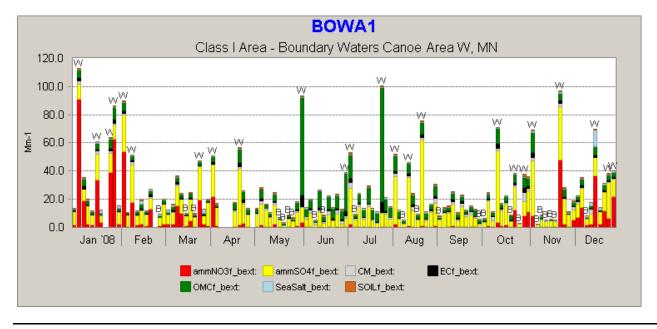


Figure 7 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2008

September 2012



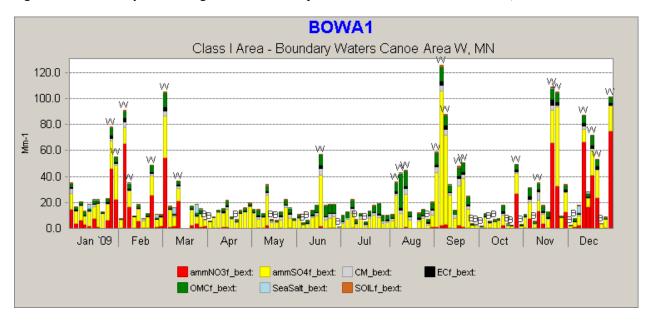
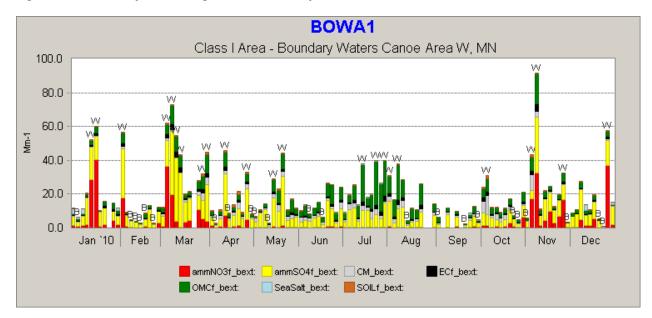




Figure 9 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2010



As has been mentioned above, it is evident that the nitrate haze (red bars) is only important during the colder months (November through March). It is also evident that haze from forest fires (green bars) is predominant in the warm weather months, but varies from year to year according to the frequency of wildfires. For example, 2008 was a year of high occurrences of wildfires, while 2009 saw a low frequency, and 2010 was more normal.

September 2012



The curtailment of taconite plant activity lasted from early 2009 through December 2009, peaking in the summer of 2009. Even so, we see the highest sulfate haze days (yellow bars) in September 2009 when taconite production was half of normal activity. Also, we note high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states.

These findings suggest that reduction of emissions from the taconite plants will likely have minimal effects on haze in the nearby Class I areas. The fact that the various plants are distributed over a large area means that individual plumes are isolated and generally do not combine with others.

At least one other emission reduction opportunity to determine the effect on visibility improvement has occurred; this is related to the shutdown of the Mohave Generating Station in 2005, and its effect upon visibility in the Grand Canyon National Park. The discussion in Appendix D indicates that although CALPUFF modeling predicted substantial visibility benefits, very little change has occurred since 2005.

Other reasons that visibility assessment models such as CALPUFF could overpredict impacts are listed below.

- 1) The CALPUFF base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.
- 2) The way that the predicted concentrations are accounted for in the CALPOST output overstate the impact for even the case where the CALPUFF predictions are completely accurate. The way that CALPOST works is that the peak 24-hour prediction <u>anywhere</u> in a Class I area is the only information saved for each predicted day. The predicted impact for each day is effectively assumed to be a) always in the same place; and b) in all portions of the Class I area. Therefore, the 98<sup>th</sup> percentile day's prediction could be comprised of impacts in 8 different places that are all erroneously assumed to be co-located.
- 3) CALPUFF does not simulate dispersion and transport accurately over a full diurnal cycle, during which significant wind direction shear can occur (and is not properly accounted for by CALPUFF). This can result in plumes that are more cohesive than actually occur.
- 4) As discussed above, it is well established that nitrate predictions are often overstated by CALPUFF v. 5.8, especially in winter.
- 5) Natural conditions as input to CALPOST are not attainable, and their use will exaggerate the simulated visibility impacts of modeled emissions.

#### Interstate Non-Interference with Regional Haze Rule SIPs from Taconite Plant Emissions

An issue that is a recurring one for a number of state implementation plans (SIPs) is whether emissions from one state can interfere with haze reduction plans for downwind states. For Minnesota, it would be expected that emission reductions undertaken to reduce haze in Minnesota Class I areas (Voyageurs and Boundary Waters) would also act to reduce haze in other Class I areas. In the case of Minnesota's

September 2012



taconite plant emissions, earlier discussions of the potentially affected Class I areas indicated that only the Class I areas in northern Michigan (Isle Royale National Park and Seney Wilderness Area) are close enough and in a general predominant wind direction to merit consideration. The closer of these two parks, Isle Royale, is closed to the public from November 1 through April 15, and haze effects there would not be affected by NO<sub>X</sub> emissions because those effects are only important in the winter. Since Minnesota's Class I areas are located generally upwind of Michigan sources, the impact of Michigan sources on these Class I areas is expected to be small. This is confirmed in the Particulate Matter Source Apportionment Technology (PSAT) plots shown below.

Regional photochemical modeling studies<sup>12</sup> conducted by the CENRAP Regional Planning Organization, of which Minnesota is a part, shows contributions of various states as well as international contributions for haze impacts in the Michigan Class I areas. Relevant figures from the Iowa RHR SIP report for 2018 emission inventory haze impacts are reproduced below for Isle Royale National Park (Figure 10) and Seney Wilderness Area (Figure 11).

The modeling conducted for this analysis, using CAMx, shows that the relative contribution to haze for all Minnesota sources to sulfate haze in Isle Royale National Park is low, consisting of only 10% of the sulfate haze. The effect of 2018 emissions from Minnesota sources at the more distant Seney Wilderness Area is even lower, with the state's emissions ranking 9<sup>th</sup> among other jurisdictions analyzed for this Class I area. Therefore, it is apparent that Minnesota sources, and certainly the subset including taconite plants, would not be expected to interfere with other state's progress toward the 2018 milestone associated with the Regional Haze Rule.

Figures 12 and 13, reproduced from the Iowa RHR SIP report for Boundary Waters and Voyageurs, respectively, indicate that Michigan sources rank 11<sup>th</sup> and 12<sup>th</sup>, respectively, for haze impacts in these two areas for projected 2018 emissions. Therefore, as expected, Michigan sources are not expected to interfere with Minnesota's RHR SIP for progress in 2018.

<sup>&</sup>lt;sup>12</sup> See, for example, the Iowa State Implementation Plan for Regional Haze report at <u>http://www.iowadnr.gov/portals/idnr/uploads/air/insidednr/rulesandplanning/rh\_sip\_final.pdf</u>, Figures 11.3 and 11.4.

AECOM

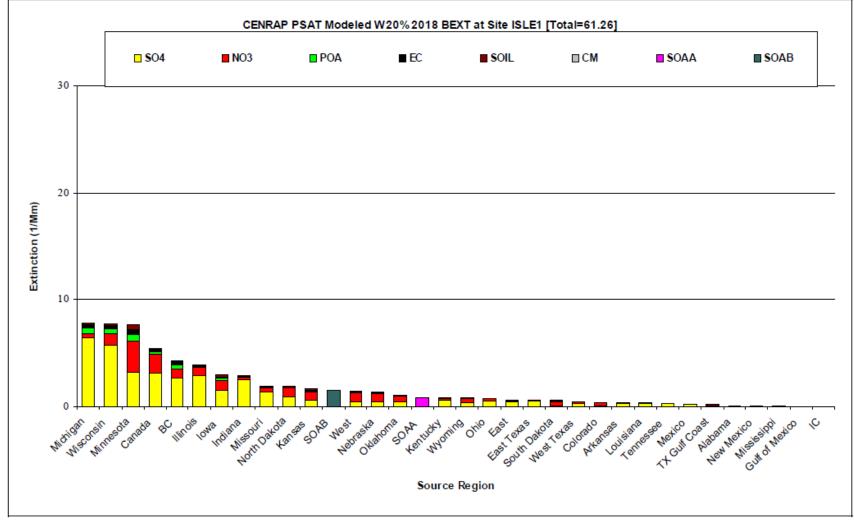


Figure 10 PSAT Results from CENRAP CAMx Modeling for Isle Royale National Park

Figure 11.3. Source apportion contributions by region and pollutant to ISLE in 2018.

September 2012

Page 14 of 45

www.aecom.com

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas



Figure 11 PSAT Results from CENRAP CAMx Modeling for Seney Wilderness Area

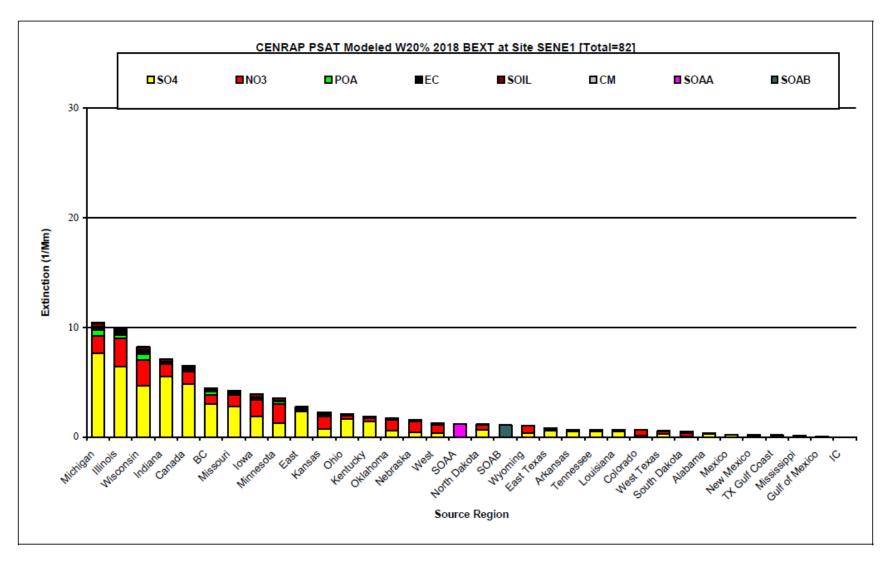


Figure 11.4. Source apportion contributions by region and pollutant to SENE in 2018.

September 2012

Page 15 of 45



Figure 12 PSAT Results from CENRAP CAMx Modeling for Boundary Waters Canoe Area Wilderness

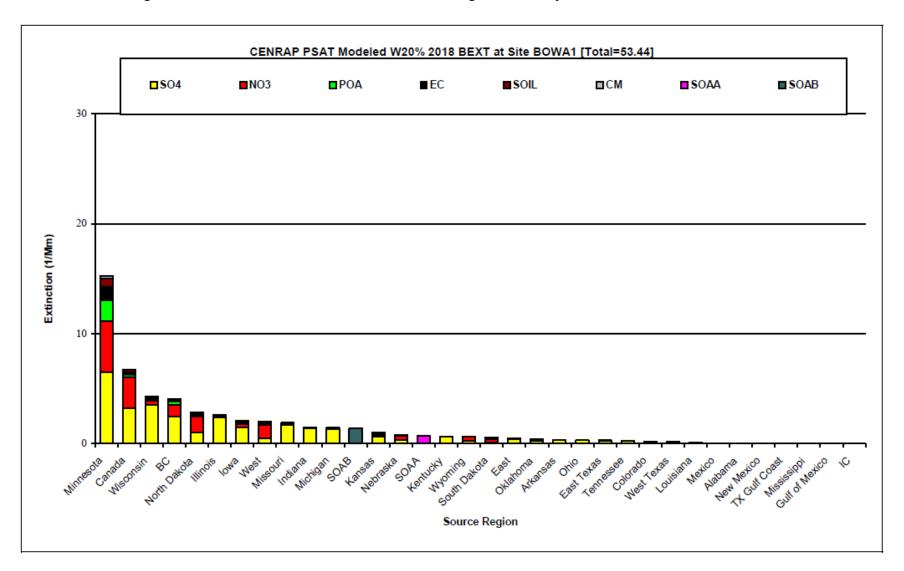


Figure 11.1. Source apportion contributions by region and pollutant to BOWA in 2018.

September 2012

Page 16 of 45



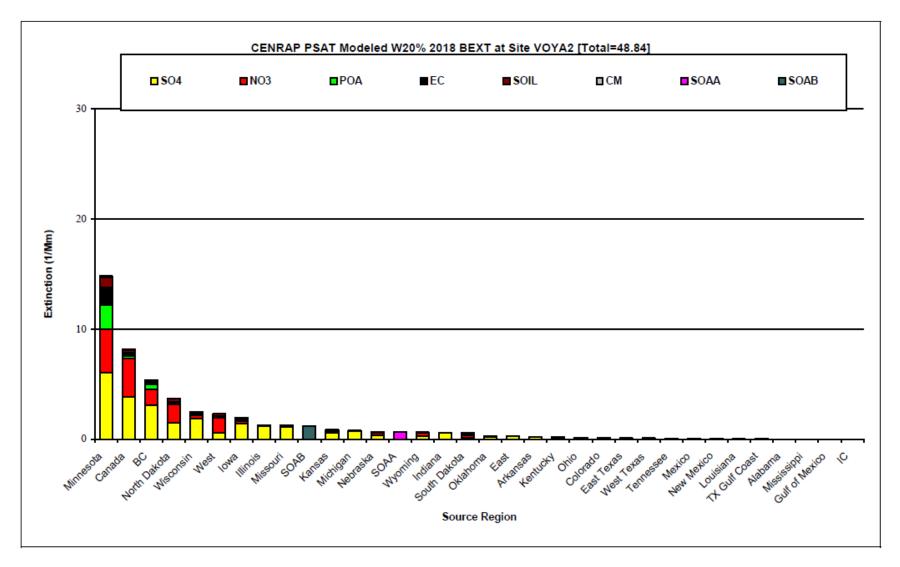


Figure 11.2. Source apportion contributions by region and pollutant to VOYA in 2018.

September 2012

Page 17 of 45

#### CONCLUSIONS

EPA's preferred modeling tools to assess the visibility improvement from BART controls will likely overestimate the predicted visibility improvement. While this is expected for all pollutants, it is especially true for  $NO_X$  emission controls. This occurs for several reasons:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clear, which exaggerates the impact of emission sources. Overly clean natural conditions can lead to the erroneous conclusion that some states are not adhering to the 2018 milestone because they need to achieve progress toward an impossible goal by the year 2064.
- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.
- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.
- The modeled base case scenario is always a worst-case emission rate, assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

Impacts of the taconite plants' NO<sub>x</sub> emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5  $\frac{1}{2}$  months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO<sub>x</sub> controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to visibility disbenefits due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

Evidence of models' tendency for overprediction are provided in examples of actual significant emission reductions that have resulted in virtually no perceptive changes in haze, while visibility assessment modeling as conducted for BART would predict significant visibility improvements. These examples include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in 2009.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, and vice versa indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

# **APPENDIX A**

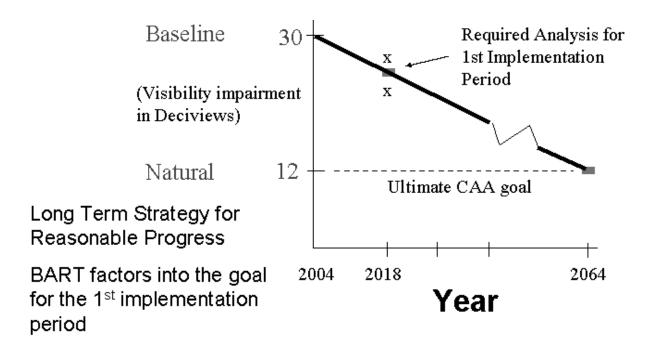
# THE REGIONAL HAZE RULE GOAL OF NATURAL CONDITIONS

An important consideration in the ability for a state to meet the 2018 Uniform Rate of Progress (URP) goal is the definition of the end point goal of "natural conditions" for the worst 20% haze days; see Figure A-1, which illustrates this concept). Note that while achieving improved visibility for the worst 20% haze days, the RHR also stipulates that there should not be deterioration of visibility for the best 20%, or clearest, days. One way to define that goal would be the elimination of all man-made emissions. This raises some other questions, such as:

- To what categories of emissions does the RHR pertain?
- Does the current definition of natural conditions include non-anthropogenic or uncontrollable emissions?

The default natural background assumed by EPA in their 2003 guidance document<sup>13</sup> is not realistic. The discussion in this section explains why EPA's default natural conditions significantly understate the true level of natural haze, including the fact that there are contributors of haze that are not controllable (and that are natural) that should be included in the definition of natural visibility conditions. In addition, one important aspect of the uncontrollable haze, wildfires, is further discussed regarding the biased quantification of its contribution to natural haze due to suppression of wildfires during the 20<sup>th</sup> century.

#### Figure A-1: Illustration of the Uniform Rate of Progress Goal



Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

September 2012

<sup>&</sup>lt;sup>13</sup> Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule, (U.S. Environmental Protection Agency, September 2003). <u>http://www.epa.gov/ttncaaa1/t1/memoranda/rh\_envcurhr\_gd.pdf</u>.

In its RHR SIP, North Dakota<sup>14</sup> noted in Section 9.7 that,

"Achieving natural conditions will require the elimination of all anthropogenic sources of emissions. Given current technology, achieving natural conditions is an impossibility. Any estimate of the number of years necessary to achieve natural visibility conditions would require assumptions about future energy sources, technology improvements for sources of emissions, and every facet of human behavior that causes visibility impairing emissions. The elimination of all SO<sub>2</sub> and NO<sub>x</sub> emissions in North Dakota will not achieve the uniform rate of progress for this [2018], or any future planning period. Any estimate of the number of years to achieve natural conditions is questionable because of the influence of out-of-state sources."

It will be extremely difficult, if not impossible, to eliminate all anthropogenic emissions, even if natural conditions are accurately defined. It will be even more daunting to try to reach the goal if natural conditions are significantly understated, and as a result, states are asked to control sources that are simply not controllable. It is clear that the use of EPA default natural conditions leads to unworkable and absurd results for one state's (North Dakota's) ability to determine the rate of progress toward an unattainable goal. The definition of natural conditions that can be reasonably attained for a reasonable application of USEPA's Regional Haze Rule should be revised for all states.

The objective of the following discussion is to summarize recent modeling studies of natural visibility conditions and to suggest how such studies can be used in evaluating the uniform rate of progress in reducing haze to attain natural visibility levels. In addition, the distinction between natural visibility and policy relevant background visibility is discussed. Treatment of this issue by other states, such as Texas, is also discussed.

#### **Regional Haze Issues for Border States**

There are similarities between the Regional Haze Rule (RHR) challenges for border states such as North Dakota and Texas in that both states have significant international and natural contributions to regional haze in Class I areas in their states. The Texas Commission on Environmental Quality (TCEQ) has introduced alternative RHR glide paths to illustrate the State's rate of progress toward the RHR goals. Since TCEQ has gone through the process of a RHR State Implementation Plan (SIP) development and comment period, it is instructive to look at the TCEQ approach, the comments provided by the Federal Land Managers to TCEQ, and TCEQ's reaction to the comments.

Similarities to be considered for the RHR SIP development in border states, such as North Dakota and Texas, include the items listed below.

• These states have Class I areas for which a considerable fraction of the regional haze is due to international transport or transport from other regions of the United States.

21

<sup>&</sup>lt;sup>14</sup> North Dakota Dep. of Health, 2010. North Dakota State Implementation Plan for Regional Haze. <u>http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Main%20SIP%20Sections%201-12.pdf</u>.

- As a result, there is a substantial reduction in SO<sub>2</sub> and NO<sub>x</sub> emissions from the BART-eligible sources in each state, but this reduction results in a relatively small impact on regional haze mitigation. Additional emission reductions would, therefore, have a minimal benefit on visibility improvement at substantial cost.
- In the Regional Haze SIP development, these states have attempted to account for the effects of anthropogenic emissions that they can control in alternative analyses. These analysis result in a finding that the in-state emission reductions come closer to meeting the Uniform Rate of Progress glide path goals for 2018. However, due to the low probability of impact of these sources on the worst 20% days, the effectiveness of in-state emission controls on anthropogenic sources subject to controls is inherently limited.

TCEQ decided that coarse and fine PM measured at the Class I areas were due to natural causes (especially on the worst 20% days), and adjusted the natural conditions endpoint accordingly. The Federal Land Managers (FLMs) agreed with this approach for the most part<sup>15</sup>, but suggested that 80% of these concentrations would be due to natural causes, and 20% would be due to anthropogenic causes. TCEQ determined from a sensitivity analysis that the difference in these two approaches was too small to warrant a re-run of their analysis, but it is important that the FLMs agreed to a state-specific modification of the natural conditions endpoint, and this substantially changed the perceived rate of progress of the SIP plan toward the altered natural conditions endpoint.

Although the TCEQ did not address other particulate matter components in this same way, a review of air parcel back trajectories previously available from the IMPROVE web site (<u>http://views.cira.colostate.edu/web/</u>) suggests that other components, such as organic matter due to wildfires, could be substantially due to natural causes, so that this component should also be considered as at least partially natural.

The TCEQ discussed the issue of how emissions from Mexico could interfere with progress on the RHR, but they did not appear to adjust the glide path based upon Mexican emissions. On the other hand, in its weight of evidence analysis, North Dakota did evaluate adjustments based upon anthropogenic emissions that could not be controlled from Canadian sources, but did not take into account any specific particulate species that are generally not emitted by major anthropogenic sources of SO<sub>2</sub> and NO<sub>x</sub>.

#### **Natural Haze Levels**

The Regional Haze Rule establishes the goal that natural visibility conditions should be attained in Federal Class I areas by the year 2064. Additionally, the states are required to determine the uniform rate of progress (URP) of visibility improvement necessary to attain the natural visibility goal by 2064. Finally, each state must develop a SIP identifying reasonable control measures that will be adopted well before 2018 to reduce source emissions of visibility-impairing particulate matter (PM) and its precursors (SO<sub>2</sub> and NO<sub>x</sub>).

Estimates of natural haze levels have been developed by the EPA for visibility planning purposes and are described in the above-referenced EPA 2003 document. The natural haze estimates were based on ambient data analysis of selected PM species for days with good visibility and are shown in Table A-1.

<sup>&</sup>lt;sup>15</sup> See Appendix 2-2 at <u>http://www.tceq.state.tx.us/implementation/air/sip/bart/haze\_appendices.html</u>.

These estimates were derived from Trijonis<sup>16</sup> and use two different sets of natural concentrations for the eastern and western U.S. Tombach<sup>17</sup> provides a detailed review and discussion of uncertainty in the USEPA natural PM estimates. Natural visibility can be calculated using the IMPROVE equation which calculates the light scattering caused by each

# Table A-1: Average Natural Levels of Aerosol Components from Table 2-1 of Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (EPA, 2003)

|                               | Average Natura | l Concentration | - <u>-</u>        | Dry   |  |
|-------------------------------|----------------|-----------------|-------------------|---|--|
|                               | West (µg/m³)   | East (µg/m³)    | – Error<br>Factor | Extinction<br>Efficiency<br>(m <sup>2</sup> /g) |  |
| Ammonium sulfate <sup>b</sup> | 0.12           | 0.23            | 2                 | 3   |  |
| Ammonium nitrate              | 0.10           | 0.10            | 2                 | 3   |  |
| Organic carbon mass °         | 0.47           | 1.40            | 2                 | 4   |  |
| Elemental carbon              | 0.02           | 0.02            | 2-3               | 10  |  |
| Soil                          | 0.50           | 0.50            | 1½ - 2            | 1   |  |
| Coarse Mass                   | 3.0            | 3.0             | 1½ - 2            | 0.6   |  |

a: After Trijonis, see footnote 12

b: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.1  $\mu$ g/m<sup>3</sup> and 0.2  $\mu$ g/m<sup>3</sup> of ammonium bisulfate.

c: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.5 µg/m<sup>3</sup> and 1.5 µg/m<sup>3</sup> of organic compounds.

component of PM. After much study, changes in the IMPROVE equation and in the method for calculating natural visibility were developed in 2005 and are described by Pitchford et al.<sup>18</sup>

The EPA guidance also makes provision for refined estimates of site-specific natural haze that differ from the default values using either data analysis or model simulations. However, most states have continued to use the default natural haze levels for calculating the progress toward natural visibility conditions.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>16</sup> Trijonis, J. C. Characterization of Natural Background Aerosol Concentrations. Appendix A in Acidic Deposition: State of Science and Technology. Report 24. Visibility: Existing and Historical Conditions -- Causes and Effects. J. C. Trijonis, lead author. National Acid Precipitation Assessment Program: Washington, DC, 1990.

<sup>&</sup>lt;sup>17</sup> Tombach, I., (2008) *Natural Haze Levels Sensitivity -- Assessment of Refinements to Estimates of Natural Conditions,* Report to the Western Governors Association, January 2008, available at <a href="http://www.wrapair.org/forums/aamrf/projects/NCB/index.html">http://www.wrapair.org/forums/aamrf/projects/NCB/index.html</a>.

<sup>&</sup>lt;sup>18</sup> Pitchford, M., Malm, W., Schichtel, B., Kumar, N., Lowenthal, D., Hand, J., Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data, J. Air & Waste Manage, Assoc. 57: 1326 – 1336, 2007.

Tombach and Brewer<sup>19</sup> reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach<sup>8</sup> also reviewed estimates of natural haze levels and proposed that, instead of using two sets of default natural PM concentrations for the eastern and western US, a large number of sensitivity zones should be developed that reflect regional variability in natural PM sources. Tombach<sup>8</sup> also suggested that modeling studies are a possible approach to further revise estimates of natural PM concentrations.

Previous modeling studies have shown that the estimates of natural visibility described above for "clean" days will differ from the results of model simulations when United States anthropogenic emissions are totally eliminated (Tonnesen et al., 2006<sup>20</sup>; Koo et al., 2010<sup>21</sup>), especially when natural wild fire emissions are included in the model simulation. Because the URP is calculated using model simulations of PM on the 20% of days with the worst visibility, wild fires and other extreme events can result in estimated levels of natural haze (even without any contribution of US anthropogenic sources) that can be significantly greater than the natural levels used in the EPA guidance for URP calculation. This could make it difficult or impossible for states to identify emissions control measures sufficient to demonstrate the URP toward attaining visibility goals because the endpoint is unachievable even if all US anthropogenic emissions are eliminated, as North Dakota has already determined even for the interim goal in 2018.

#### Previous Suppression of Wildfire Activity and its Effect upon the EPA Default Natural Conditions

Throughout history, except for the past few decades, fires have been used to clear land, change plant and tree species, sterilize land, maintain certain types of habitat, among other purposes. Native Americans used fires as a technique to maintain certain pieces of land or to improve habitats. Although early settlers often used fires in the same way as the Native Americans, major wildfires on public domain land were largely ignored and were often viewed as an opportunity to open forestland for grazing.

Especially large fires raged in North America during the 1800s and early 1900s. The public was becoming slowly aware of fire's potential for life-threatening danger. Federal involvement in trying to control forest fires began in the late 1890s with the hiring of General Land Office rangers during the fire season. When the management of the forest reserves (now called national forests) was transferred to the newly formed Forest Service in 1905, the agency took on the responsibility of creating professional standards for firefighting, including having more rangers and hiring local people to help put out fires.

Since the beginning of the 20<sup>th</sup> century, fire suppression has resulted in a buildup of vegetative "fuels" and catastrophic wildfires. Recent estimates of background visual range, such as Trijonis<sup>16</sup>, have underestimated the role of managed fire on regional haze. Since about 1990, various government agencies have increased prescribed burning to reduce the threat of dangerous wildfires, and the

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>19</sup> Tombach, I., and Brewer, P. (2005). Natural Background Visibility and Regional Haze Goals in the Southeastern United States. *J. Air & Waste Manage. Assoc. 55*, 1600-1620.

<sup>&</sup>lt;sup>20</sup> Tonnesen, G., Omary, M., Wang, Z., Jung, C.J., Morris, R., Mansell, G., Jia, Y., Wang, B., and Z. Adelman (2006) Report for the Western Regional Air Partnership Regional Modeling Center, University of California Riverside, Riverside, California, November. (<u>http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC 2006 report FINAL.pdf</u>).

<sup>&</sup>lt;sup>21</sup> Koo B., C.J. Chien, G. Tonnesen, R. Morris , J. Johnson, T. Sakulyanontvittaya, P. Piyachaturawat, and G.Yarwood, 2010. Natural emissions for regional modeling of background ozone and particulate matter and impacts on emissions control strategies. <u>Atm. Env.</u>, 44, 2372-2382.

increased haze due to these fires is often more of an impairment to visibility than industrial sources, especially for  $NO_X$  reductions that are only effective in winter, the time of the lowest tourist visitation in most cases.

The National Park Service indicates at <u>http://www.nps.gov/thro/parkmgmt/firemanagement.htm</u> for the Theodore Roosevelt National Park that:

"For most of the 20<sup>th</sup> Century, wildfires were extinguished immediately with the assumption that doing so would protect lives, property, and natural areas. However, following the unusually intense fire season of 1988, agencies including the National Park Service began to rethink their policies." Even this policy is not always successful, as experienced by the USDA Forest Service<sup>22</sup> in their management of wildfires near the Boundary Waters Canoe Area that can contribute significantly to visibility degradation during the peak tourist season. In this case, even small fires, if left unchecked, have been known to evolve into uncontrollable fires and then require substantial resources to extinguish.

EPA's 2003 "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" acknowledges that wildfires are a contributor to natural visibility conditions, but the data used in estimates of natural conditions were taken during a period of artificial fire suppression so that the true impact of natural wildfires is understated. The report notes that "data should be available for EPA and States to develop improved estimates of the contribution of fire emissions to natural visibility conditions in mandatory Federal Class I areas over time." As noted by several studies noted above, the impact due to natural fire levels is underestimated in the EPA natural visibility conditions include the distortion of Reasonable Progress analyses and also to BART modeling results that overestimate the visibility improvement achievable from NO<sub>X</sub> emission reductions due to the use of inaccurate natural visibility conditions.

#### **Recommendations for an Improved Estimate of Visibility Natural Conditions**

A reasonable approach would be to combine the effects of the uncontrollable particulate matter components and the emissions from international sources to determine a new glide path endpoint that is achievable by controlling (only) U.S. anthropogenic emissions. To compute this new endpoint, regional photochemical modeling using CMAQ or CAMx could be conducted for the base case (already done) and then for a future endpoint case that has no U.S. anthropogenic emissions, but with natural particulate matter emissions (e.g., dust, fires, organic matter) as well as fine particulate, SO<sub>2</sub> and NO<sub>x</sub> emissions associated with all non-U.S. sources set to the current baseline levels. The simulation should include an higher level of wildfire activity than in the recent past to reflect a truer level of fire activity before manmade suppression in the 20<sup>th</sup> century. Then, states could use a relative reduction factor (RRF) approach to determine the ratio of the haze impacts between the base case and the reasonable future case, and then apply the RRF values to the baseline haze to obtain a much more reasonable "natural conditions" haze endpoint. The more accurate natural background would also result in a reduction in the degree to which CALPUFF modeling overstates visibility improvement from emission reductions.

<sup>&</sup>lt;sup>22</sup> See explanation at <u>http://www.msnbc.msn.com/id/48569985/ns/us\_news-environment/t/forest-service-gets-more-aggressive-small-fires/</u>.

## **APPENDIX B**

## MODEL OVERPREDICTION ISSUES FOR WINTERTIME NITRATE HAZE

This appendix includes a discussion of CALPUFF predictions for nitrate haze, followed by more general issues with CALPUFF predictions.

#### **CALPUFF Predictions of Nitrate Haze**

Secondary pollutants such as nitrates and sulfates contribute to light extinction in Class I areas. The CALPUFF model was approved by EPA for use in BART determinations to evaluate the effect of these pollutants on visibility in Class I areas. CALPUFF version 5.8 (the current guideline version) uses the EPA-approved MESOPUFF II chemical reaction mechanism to convert SO<sub>2</sub> and NO<sub>x</sub> emissions to secondary sulfate and nitrate. This section describes how secondary pollutants, specifically nitrate, are formed and the factors affecting their formation, especially as formulated in CALPUFF.

In the CALPUFF model, the oxidation of NO<sub>x</sub> to nitric acid (HNO<sub>3</sub>) depends on the NO<sub>x</sub> concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration. In CALPUFF, total nitrate (TNO<sub>3</sub> = HNO<sub>3</sub> + NO<sub>3</sub>) is partitioned into gaseous HNO<sub>3</sub> and NO<sub>3</sub> particles according to the equilibrium relationship between the two species. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate particles *strongly* depends on availability of NH<sub>3</sub> to form ammonium nitrate, as shown in Figure 6<sup>23</sup>. The figure on the left shows that with 1 ppb of available ammonia and fixed temperature and humidity (for example, 275 K and 80% humidity), only 50% of the total nitrate is in the form of particulate matter. When the available ammonia is increased to 2 ppb, as shown in the figure on the right, as much as 80% of the total nitrate is in the particulate form. Figure B-1 also shows that colder temperatures and higher relative humidity favor particulate nitrate formation. A summary of the conditions affecting nitrate formation are listed below:

- Colder temperature and higher relative humidity create more favorable conditions to form nitrate particulate matter in the form of ammonium nitrate;
- Warmer temperatures and lower relative humidity create less favorable conditions for nitrate particulate matter resulting in a small fraction of total nitrate in the form of ammonium nitrate;
- Ammonium sulfate formation preferentially scavenges available atmospheric ammonia over ammonium nitrate formation. In air parcels where sulfate concentrations are high and ambient ammonia concentrations are low, there is less ammonia available to react with nitrate, and less ammonium nitrate is formed.

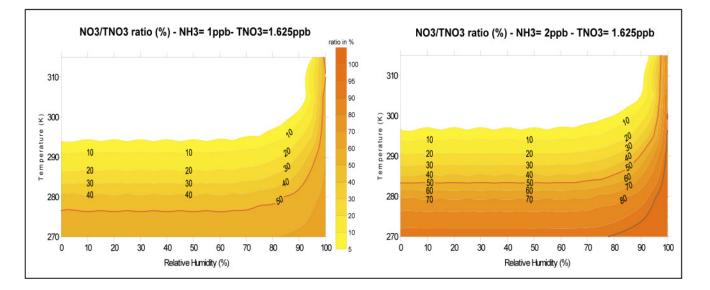
The effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various  $NO_x$  control options. For the reasons discussed above, the seasons with lower temperatures are the most likely to be most important for ammonium nitrate formation when regional haze is more effectively reduced by controlling  $NO_x$ .

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

September 2012

27

<sup>&</sup>lt;sup>23</sup> Scire, Joseph. CALPUFF MODELING SYSTEM. CALPUFF course presented at Chulalongkorn University, Bangkok, Thailand. May 16-20, 2005; slide 40 available at <u>http://aqnis.pcd.go.th/tapce/plan/4CALPUFF%20slides.pdf</u>, accessed March 2011.



#### Figure B-1: NO<sub>3</sub>/HNO<sub>3</sub> Equilibrium Dependency on Temperature and Humidity

#### Sensitivity of CALPUFF Haze Calculations to Background Ammonia Concentration

In an independent analysis, the Colorado Department of Public Health and Environment (CDPHE) performed a sensitivity modeling analysis to explore the effect of the specified ammonia concentration applied in CALPUFF on the predicted visibility impacts for a source with high NO<sub>x</sub> emissions relative to SO<sub>2</sub> emissions<sup>24</sup>. The results of the sensitivity modeling are shown in Figure B-2. It is noteworthy that the largest sensitivity occurs for specified ammonia input between 1 and 0.1 ppb. In that factor-of-ten range, the difference in the peak visibility impact predicted by CALPUFF is slightly more than a factor of three. This sensitivity analysis shows that the specification of background ammonia is very important in terms of the magnitude of visibility impacts predicted by CALPUFF. The fact that regional, diurnal and seasonal variations of ambient ammonia concentrations are not well-characterized and mechanisms not well-understood effectively limits the effectiveness of CALPUFF in modeling regional haze, especially in terms of the contribution of ammonium nitrate.

It is also noteworthy that CALPUFF version 5.8's demonstrated over-predictions of wintertime nitrate can be mitigated to some extent by using lower winter ammonia background values, although there is not extensive measurement data to determine the ambient ammonia concentrations. This outcome showing the superiority of the monthly-varying background ammonia concentrations was found by Salt River

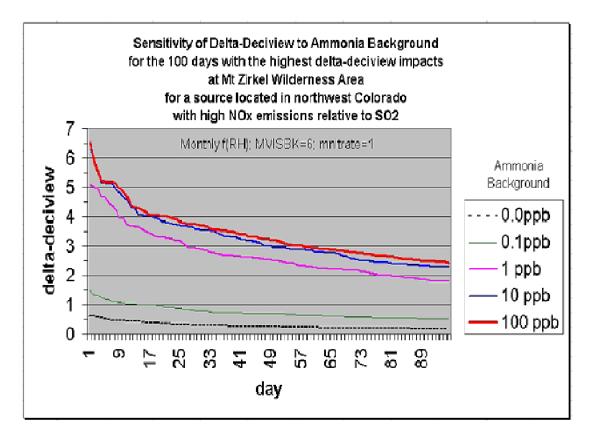
September 2012 Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>24</sup> Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at <u>http://www.colorado.gov/airquality/documents/Draft-</u> ColoradoSupplementalBARTAnalysisCALPUFFProtocol-25June2010.pdf. (2010)

Project in case studies of the Navajo Generating Station impacts on Grand Canyon monitors, as presented<sup>25</sup> to EPA in 2010.

It is important to note that 14 years ago in 1998, when the IWAQM Phase 2 guidance<sup>26</sup> was issued, CALPUFF did not even have the capability of accommodating monthly ammonia background concentrations; only a single value was allowed. Since then, CALPUFF has evolved to be able to receive as input monthly varying ammonia concentrations. EPA's guidance on the recommended input values that are constant all year has not kept pace with the CALPUFF's capability. The weight of evidence clearly indicates that the use of monthly varying ammonia concentrations with lower wintertime values will result in more accurate predictions.

# Figure B-2: CDPHE Plot of Sensitivity of Visibility Impacts Modeled by CALPUFF for Different Ammonia Backgrounds.



<sup>&</sup>lt;sup>25</sup> Salt River Project, 2010. Measurements of Ambient Background Ammonia on the Colorado Plateau and Visibility Modeling Implications. Salt River Project, P.O. Box 52025 PAB352, Phoenix, Arizona 85072.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>26</sup> IWAQM Phase 2 Summary Report and Recommendations (EPA-454/R-98-019), EPA OAQPS, December 1998). <u>http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf</u>.

### Independent Studies of the Effect of Model Chemistry on Nitrate Predictions

The Regional Haze BART Rule acknowledged that CALPUFF tends to overestimate the amount of nitrate that is produced. In particular, the overestimate of ammonium nitrate concentrations on visibility at Class I areas is the greatest in the winter, when temperatures (and visitation) are lowest, the nitrate concentrations are the greatest, and the sulfate concentrations tend to be the least due to reduced oxidation rates of SO<sub>2</sub> to sulfate.

On page 39121, the BART rule<sup>27</sup> stated that: "...the simplified chemistry in the [CALPUFF] model tends to magnify the actual visibility effects of that source."

On page 39123, the BART rule stated that: "We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. In its next review of the Guideline on Air Quality Models, EPA will evaluate these and other newer approaches<sup>28</sup>."

EPA did not conduct such an evaluation, but the discussion below reports on the efforts of other investigators.

A review of independent evaluations of the CALPUFF model is reported here, with a focus on identifying studies that address the nitrate chemistry used in the model. Morris et al.<sup>29</sup> reported that the CALPUFF MESOPUFF II transformation rates were developed using temperatures of 86, 68 and 50 °F. Therefore, the 50 °F minimum temperature used in development of the model could result in overestimating sulfate and nitrate formation in colder conditions. These investigators found that CALPUFF tended to overpredict nitrate concentrations during winter by a factor of about three.

A recent independent study of the CALPUFF performance by Karamchandani et al (referred to here as the KCBB study) is highly relevant to this issue<sup>30</sup>. The KCBB study presented several improvements to the Regional Impacts on Visibility and Acid Deposition (RIVAD) chemistry option in CALPUFF, an alternative treatment that was more amenable to an upgrade than the MESOPUFF II chemistry option. Among other items, the improvements included the replacement of the original CALPUFF secondary particulate matter (PM) modules by newer algorithms that are used in current state-of-the-art regional air quality models such as CMAQ, CMAQ-MADRID, CAMx and REMSAD, and in advanced puff models

<sup>29</sup> Morris, R., Steven Lau and Bonyoung Koo. Evaluation of the CALPUFF Chemistry Algorithms. Presented at A&WMA 98th Annual Conference and Exhibition, June 21-25, 2005 Minneapolis, Minnesota. (2005)

<sup>30</sup> Karamchandani, P., S. Chen, R. Bronson, and D. Blewitt. Development of an Improved Chemistry Version of CALPUFF and Evaluation Using the 1995 SWWYTAF Data Base. Presented at the Air & Waste Management Association Specialty Conference on Guideline on Air Quality Models: Next Generation of Models, October 28-30, 2009, Raleigh, NC. (2009)

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>27</sup> July 6, 2005 Federal Register publication of the Regional Haze BART rule.

<sup>&</sup>lt;sup>28</sup> The next (9<sup>th</sup>) EPA modeling conference was held in 2008, during which the concepts underlying the chemistry upgrades in CALPUFF 6.42 were presented. However, EPA failed to conduct the promised evaluation in its review of techniques at that conference held 4 years ago. As a result of the 10<sup>th</sup> EPA modeling conference held in March 2012, EPA appears to be continuing to rely upon CALPUFF version 5.8, which it admitted in the July 6, 2005 BART rule has serious shortcomings.

such as SCICHEM. In addition, the improvements included the incorporation of an aqueous-phase chemistry module based on the treatment in CMAQ. Excerpts from the study papers describing each of the improvements made to CALPUFF in the KCBB study are repeated below.

#### Gas-Phase Chemistry Improvements

The KCBB study applied a correction to CALPUFF in that the upgraded model was modified to keep track of the puff ozone concentrations between time steps. The authors also updated the oxidation rates of  $SO_2$  and nitrogen dioxide (NO<sub>2</sub>) by the hydroxide ion (OH<sup>-</sup>) to the rates employed in contemporary photochemical and regional PM models.

#### Treatment of Inorganic Particulate Matter

The KCBB study scientists noted that the EPA-approved version of CALPUFF currently uses a simple approach to simulate the partitioning of nitrate and sulfate between the gas and particulate phases. In this approach, sulfate is appropriately assumed to be entirely present in the particulate phase, while nitrate is assumed to be formed by the reaction between nitric acid and ammonia.

The KCBB study implemented an additional treatment for inorganic gas-particle equilibrium, based upon an advanced aerosol thermodynamic model referred to as the ISORROPIA model<sup>31</sup>. This model is currently used in several state-of-the-art regional air quality models. With this new module, the improved CALPUFF model developed in the KCBB study includes a treatment of inorganic PM formation that is consistent with the state of the science in air quality modeling, and is critical for the prediction of regional haze due to secondary nitrate formation from NO<sub>X</sub> emissions.

#### Treatment of Organic Particulate Matter

The KCBB study added a treatment for secondary organic aerosols (SOA) that is coupled with the corrected RIVAD scheme described above. The treatment is based on the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID)<sup>32,33</sup>, which treats SOA formation from both anthropogenic and biogenic volatile organic compound emissions.

#### Aqueous-Phase Chemistry

The current aqueous-phase formation of sulfate in both CALPUFF's RIVAD and MESOPUFF II schemes is currently approximated with a simplistic treatment that uses an arbitrary pseudo-first order rate in the presence of clouds (0.2% per hour), which is added to the gas-phase rate. There is no explicit treatment

<sup>33</sup> Pun, B., C. Seigneur, J. Pankow, R. Griffin, and E. Knipping. An upgraded absorptive secondary organic aerosol partitioning module for three-dimensional air quality applications, 24th Annual American Association for Aerosol Research Conference, Austin, TX, October 17-21, 2005. (2005)

September 2012

www.aecom.com

<sup>&</sup>lt;sup>31</sup> Nenes A., Pilinis C., and Pandis S.N. Continued Development and Testing of a New Thermodynamic Aerosol Module for Urban and Regional Air Quality Models, *Atmos. Env.* **1998**, 33, 1553-1560.

<sup>&</sup>lt;sup>32</sup>Zhang, Y., B. Pun, K. Vijayaraghavan, S.-Y. Wu, C. Seigneur, S. Pandis, M. Jacobson, A. Nenes and J.H. Seinfeld. Development and Application of the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID), *J. Geophys. Res.* **2004**, 109, D01202, doi:10.1029/2003JD003501.

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

of aqueous-phase SO<sub>2</sub> oxidation chemistry. The KCBB study incorporated into CALPUFF a treatment of sulfate formation in clouds that is based on the treatment that is used in EPA's CMAQ model.

#### CALPUFF Model Evaluation and Sensitivity Tests

The EPA-approved version of CALPUFF and the version with the improved chemistry options were evaluated using the 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database<sup>34</sup>, available from the Wyoming Department of Environmental Quality. The database includes MM5 output for 1995, CALMET and CALPUFF codes and control files, emissions for the Southwest Wyoming Regional modeling domain, and selected outputs from the CALPUFF simulations. Several sensitivity studies were also conducted to investigate the effect of background NH<sub>3</sub> concentrations on model predictions of PM nitrate. Twice-weekly background NH<sub>3</sub> concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH<sub>3</sub> concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

- MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH<sub>3</sub> concentration of 1 ppb for arid land. As discussed previously, the MESOPUFF II algorithm is the basis for the currently approved version of CALPUFF that is being used for BART determinations throughout the United States.
- 2. Improved CALPUFF RIVAD/ARM3 chemistry using background values of NH<sub>3</sub> concentrations based on measurements in the Pinedale, Wyoming area, as described above.

PM sulfate and nitrate were predicted by the two models and compared with actual measured values obtained at the Bridger Wilderness Area site from the IMPROVE network and the Pinedale site from the Clean Air Status and Trends Network (CASTNET). For the two model configurations evaluated in this study, the results for PM sulfate were very similar, which was expected since the improvements to the CALPUFF chemistry were anticipated to have the most impact on PM nitrate predictions. Therefore, the remaining discussion focuses on the performance of each model with respect to PM nitrate.

The EPA-approved CALPUFF model was found to significantly overpredict PM nitrate concentrations at the two monitoring locations, by a factor of two to three. The performance of the version of CALPUFF with the improved RIVAD chemistry was much better, with an overprediction of about 4% at the Pinedale CASTNET site and of about 28% at the Bridger IMPROVE site.

In an important sensitivity analysis conducted within the KCBB study, both the EPA-approved version of CALPUFF and the improved version were run with a constant ammonia background of 1 ppb, as recommended by IWAQM Phase II<sup>35</sup>. The results were similar to those noted above: the improved

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>34</sup> Wyoming Department of Environmental Quality. 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database. Background and database description are available at http://deq.state.wy.us/aqd/prop/2003AppF.pdf. (2010)

<sup>&</sup>lt;sup>35</sup> Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Long-Range Transport Modeling, EPA-454/R-98-019. (1998)

CALPUFF predictions were about two to three times lower than those from the EPA-approved version of CALPUFF. This result is similar to the results using the seasonal observed values of ammonia, and indicates that the sensitivity of the improved CALPUFF model to the ammonia input value is potentially less than that of the current EPA-approved model.

Similar sensitivity was noted by Scire et al. in their original work in the SWWYATF study<sup>36</sup>, in which they tested seasonally varying levels of background ammonia in CALPUFF (using 0.23 ppb in winter, for example; see Figure B-3. The sensitivity modeling for predicting levels of nitrate formation shows very similar results to those reported in the KCBB study.

These findings indicate that to compensate for the tendency of the current EPA-approved version of CALPUFF to overpredict nitrates, the background ammonia values that should be used as input in CALPUFF modeling should be representative of isolated areas (e.g., Class I areas).

On November 3, 2010, TRC released a new version (6.42) of CALPUFF to fix certain coding "bugs" in EPA-approved version 5.8 and to improve the chemistry module. Additional enhancements to CALPUFF version 6.42 have been reported at EPA's 10<sup>th</sup> modeling conference in March 2012 by Scire<sup>37</sup>, who also has conducted recent evaluations of this version in comparison to the regulatory version (5.8). Despite the evidence that this CALPUFF version is a generation ahead of the currently approved version for modeling secondary particulate formation, EPA has not acted to adopt it as a guideline model. Even with evidence provided by independent investigators<sup>29,30</sup> that also indicate that wintertime nitrate estimated by CALPUFF version 5.8 is generally overpredicted by a factor between 2 and 4, EPA has not taken steps to adopt the improved CALPUFF model, noting that extensive peer review, evaluations, and rulemaking are still needed for this adoption to occur. In the meantime, EPA, in retaining CALPUFF version 5.8 as the regulatory model for regional haze predictions, is ignoring the gross degree of overestimation of particulate nitrate and is thus ensuring that regional haze modeling conducted for BART is overly conservative. EPA's delay in adopting CALPUFF version 6.42 will thus result in falsely attributing regional haze mitigation to NO<sub>X</sub> emission reductions.

September 2012 Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas 33

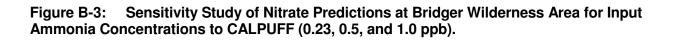
<sup>&</sup>lt;sup>36</sup> Scire, J.S., Z-X Wu, D.G. Strimaitis and G.E. Moore. The Southwest Wyoming Regional CALPUFF Air Quality Modeling Study – Volume I. Prepared for the Wyoming Dept of Environmental Quality. (2001)

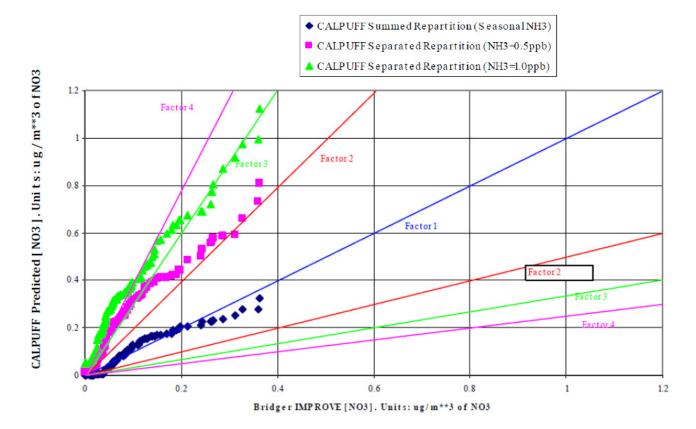
<sup>&</sup>lt;sup>37</sup> Scire, J., 2012. New Developments and Evaluations of the CALPUFF Model. <u>http://www.epa.gov/ttn/scram/10thmodconf/presentations/3-5-CALPUFF Improvements Final.pdf</u>.

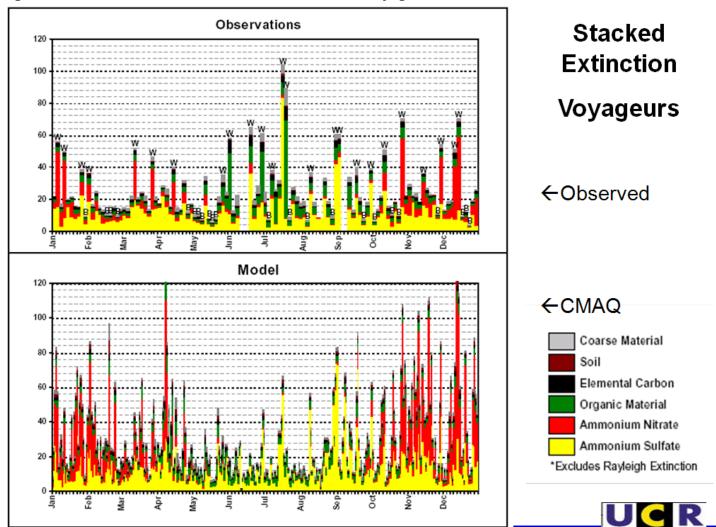
#### **OVERPREDICTIONS OF NITRATE HAZE BY REGIONAL PHOTOCHEMICAL MODELS**

The overprediction tendency for modeling of wintertime nitrate haze is not limited to CALPUFF. Even the state-of-the-art regional photochemical models are challenged in getting the right ammonium nitrate concentrations. This is evident in a presentation<sup>38</sup> made by Environ to the CENRAP Regional Planning Organization in 2006. The relevant figures from the Ralph Morris presentation (shown in Figures B-4 and B-5 below) indicate that both CMAQ and CAMx significantly overpredict nitrate haze in winter at Voyageurs National Park, by about a factor of 2. This is shown by the height of the red portion of the composition plot stacked bars between the observed and predicted timelines. It is noteworthy that Minnesota and EPA have relied upon this modeling approach for their BART determinations. Similar to CALPUFF, as discussed above, the agency modeling is prone to significantly overpredicting wintertime nitrate haze, leading to an overestimate of visibility improvement with NO<sub>x</sub> emission reductions.

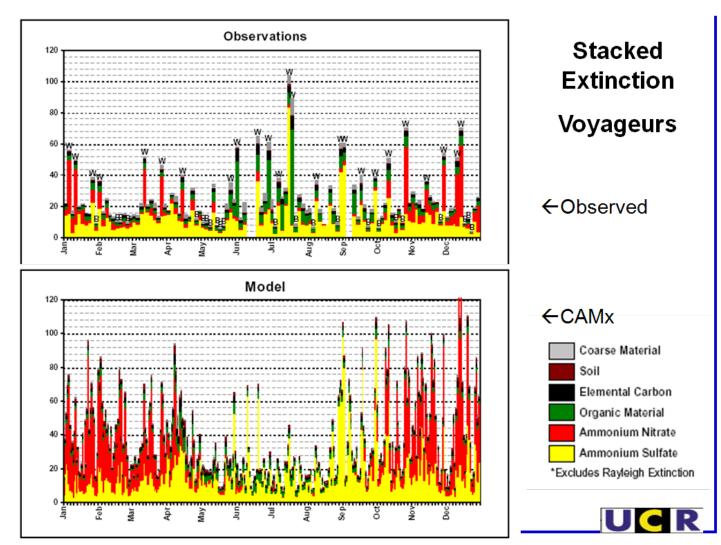
<sup>&</sup>lt;sup>38</sup> <u>http://pah.cert.ucr.edu/aqm/cenrap/meetings.shtml</u>, under "MPE", slides 9 and 10.







### Figure B-4 CMAQ vs. Observed Haze Predictions at Voyageurs National Park



### Figure B-5 CAMx vs. Observed Haze Predictions at Voyageurs National Park

### **APPENDIX C**

Haze Time Series Plots for Voyageurs National Park, Seney Wilderness Area, and Isle Royale National Park

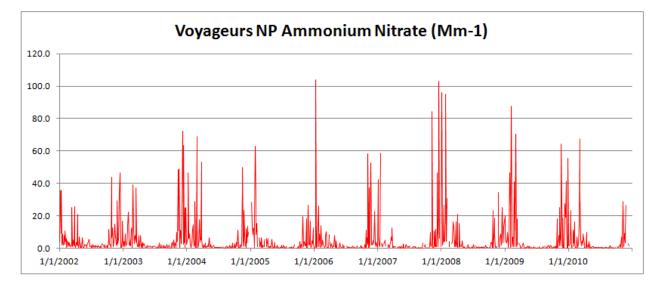
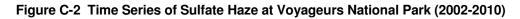
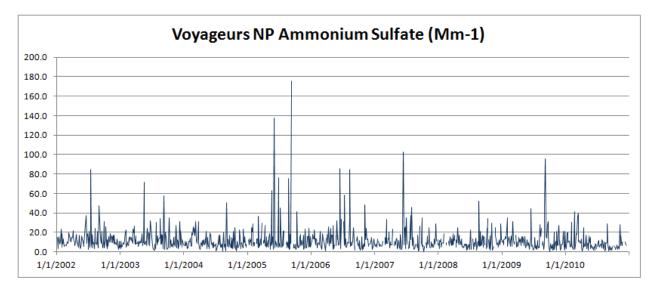
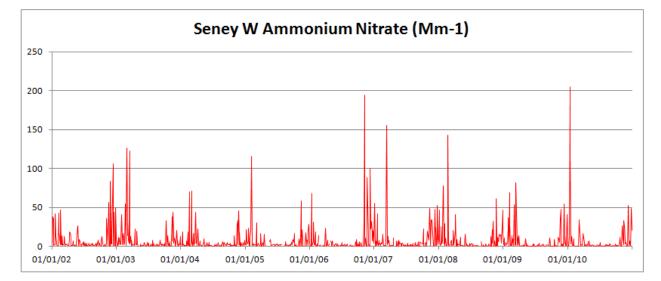


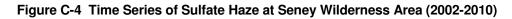
Figure C-1 Time Series of Nitrate Haze at Voyageurs National Park (2002-2010)

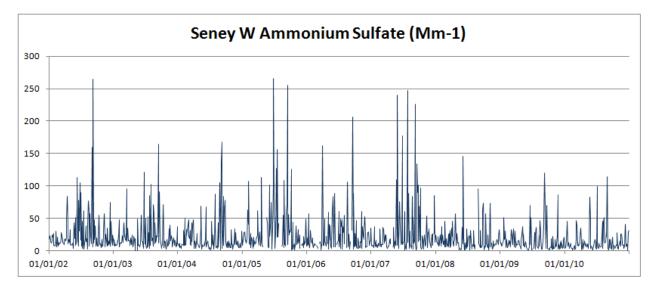


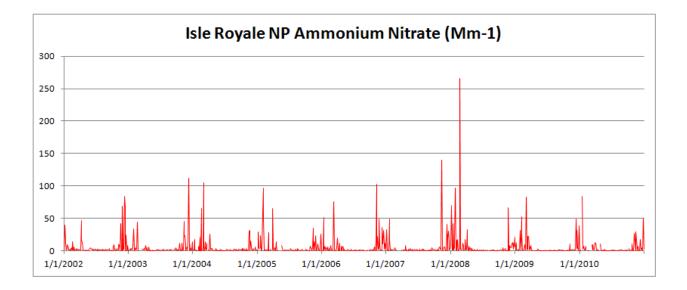




### Figure C-3 Time Series of Nitrate Haze at Seney Wilderness Area (2002-2010)

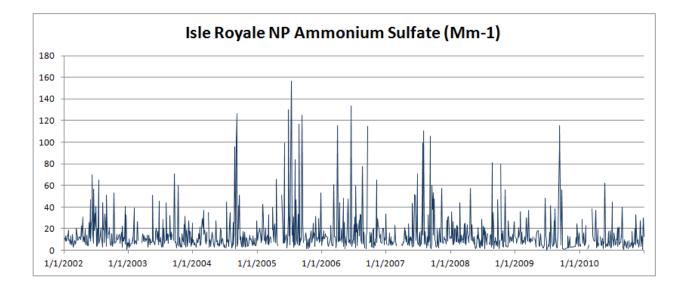






#### Figure C-5 Time Series of Nitrate Haze at Isle Royale National Park (2002-2010)

#### Figure C-6 Time Series of Sulfate Haze at Isle Royale National Park (2002-2010)



### APPENDIX D

### EXAMPLE OF VISIBILITY CHANGES AFTER ACTUAL EMISSION REDUCTIONS: SHUTDOWN OF THE MOHAVE GENERATING STATION

The Mohave Generating Station (MGS) shut down at the end of 2005, which should have had a large, beneficial effect (over 2 dv, according to CALPUFF) upon Grand Canyon visibility on the 98<sup>th</sup> percentile worst days. The MGS was a large (1590 MW) coal-fired plant located near the southern tip of Nevada (Laughlin, NV). MGS was placed in operation in the early 1970s, and was retired at the end of 2005 as a result of a consent agreement with the United States Environmental Protection Agency (EPA). The agreement had provided MGS with the option of continued operation if state-of-the-art emissions controls were installed for SO<sub>2</sub> and NOx emissions, but the owners determined that the cost of controls was too high to justify the investment. As a result, the plant was shut down on December 31, 2005 and has not been in operation since then.

As shown in Figure C-1, the MGS location is about 115 km away from the closest point of the Grand Canyon National Park, for which a southwesterly wind is needed to carry the emissions from MGS to most of the park. A multi-year study<sup>39</sup> completed by the EPA in 1999 (Project MOHAVE) indicated that MGS could be a significant contributor to haze in the Grand Canyon. In fact, typical annual emissions from MGS during the last several years of operation were approximately 40,000 tons per year (TPY) of SO<sub>2</sub> and 20,000 TPY of NOx. EPA noted in their Project MOHAVE conclusions that due to this level of emissions of haze precursors and its proximity to the Grand Canyon, MGS was the single largest emission source that could cause regional haze within the Grand Canyon.

Haze observations at three locations in the Grand Canyon (Meadview, Indian Garden, and Hance Camp monitors are available every third day for periods both before and after the plant shut down at the end of 2005. By comparing haze measurements before and after plant shutdown, it may be possible to determine whether the haze in the Grand Canyon has perceptibly changed since 2005 by reviewing the data from these three monitors. The Meadview monitor is at the western edge of the Park, and is relatively close to MGS. The other two IMPROVE monitors are located near some of the most heavily visited areas of the park (Hance Camp, on the South Rim, and Indian Garden, about 1,100 feet lower near the bottom of the canyon).

A 2010 *Atmospheric Environment* paper by Terhorst and Berkman<sup>40</sup> studied the effects of the opportunistic "experiment" afforded by the abrupt shutdown of the largest source affecting the Grand Canyon (according to EPA). The paper noted that Project MOHAVE's conclusions about the effects of MGS on the Grand Canyon visibility were ambiguous. The project's tracer studies revealed that while the MGS emissions did reach the park, particularly in the summer, there was no evidence linking these elevated concentrations with actual visibility impairment; indeed, "correlation between measured tracer concentration and both particulate sulfur and light extinction were virtually nil."

On the other hand, dispersion models produced results inconsistent with the observations. Noting the disconnect between the measurements and model predictions, EPA noted the disparity between the measurements and modeling results, but still appeared to favor the models when it concluded that MGS was the largest sole contributor to visibility impairment in the Grand Canyon.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>39</sup> Pitchford, M., Green, M., Kuhns, H., Scruggs, M., Tombach, I., Malm, W., Farber, R., Mirabella, V., 1999. Project MOHAVE: Final Report. Tech. Rep., U.S. Environmental Protection Agency (EPA).

<sup>&</sup>lt;sup>40</sup> Jonathan Terhorst and Mark Berkman. "Effect of Coal-Fired Power Generation on Visibility in a Nearby National Park," Atmospheric Environment, 44(2010) 2544-2531. This publication is available by request from Mark Berkman at <u>mark.berkman@berkeleyeconomics.com</u>.

According to the authors, the Project Mohave observations were consistent with observations during temporary outages of MGS, for which there were no reports of substantial changes to visibility in the Grand Canyon.

Best Available Retrofit Technology (BART) studies evaluated a possible conversion of MGS to natural gas firing in 2008. These studies used the CALPUFF dispersion model in a manner prescribed by EPA to determine the change in visibility between the baseline emissions associated with coal firing to the natural gas firing alternative. The BART analyses conducted by the Nevada Department of Environmental Protection indicated that large differences in haze would result: an improvement of about 2.4 deciviews for the 98<sup>th</sup> percentile peak day, and a haze reduction to below 0.5 deciview on 186 days over 3 years modeled. Since natural gas firing would eliminate nearly all of the SO<sub>2</sub> emissions (although not all of the NOx emissions) this modeled result would tend to underestimate the visibility improvement that would be anticipated with a total plant shutdown.

Terhorst and Berkman analyzed several statistics to determine the change in sulfate concentrations and visibility in the Grand Canyon between the period 2003-2005 (pre-shutdown) and the period 2006-2008 (post-shutdown). They also considered other areas to determine how other regional and environmental effects might be reflected in changes at the Grand Canyon. Terhorst and Berkman calculated the average visibility over all IMPROVE monitoring days between 2003-2005 and 2006-2008, and determined that the average visibility was unchanged at Meadview, slightly improved on the South Rim (Hance Camp), and slightly worse at Indian Garden. Consistent with the observations of minimal visibility impact of MGS during Project MOHAVE, they concluded that the closure of MGS had a relatively minor effect on visibility in the Grand Canyon. These authors questioned the veracity of CALPUFF modeling (e.g., for BART) in that it predicts relatively large improvements in the Grand Canyon visibility that are not borne out by observations.

Emissions reductions associated with the shutdown of the Mohave Generating Station at the end of 2005 have provided an opportunistic means to discern the effect of retrofitting emission controls on coal-fired power plants in the western United States. In the case of MGS, although EPA had determined that this facility was the single most important contributor to haze in the Grand Canyon National Park and CALPUFF modeling using EPA's BART procedures provided predictions of significant improvements in haze, actual particulate and haze measurements taken before and after the shutdown do not reflect the large reductions that would be anticipated from these studies. This may be due in part to the fact that there are several aspects to the CALPUFF modeling procedures that greatly inflate the predicted haze (as noted below), and therefore, the predicted improvements due to emission reductions.

# AECOM

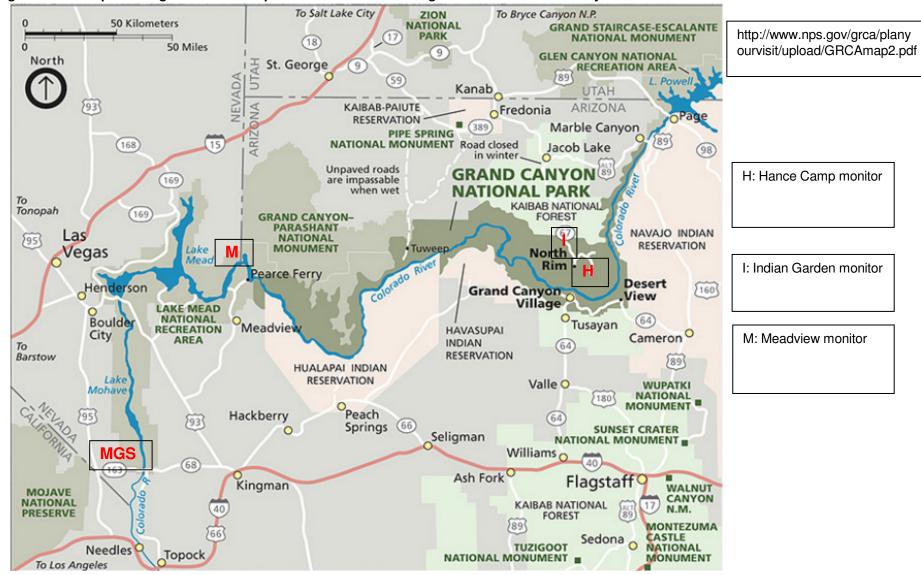


Figure D-1 : Map Showing the Relationship of the Mohave Generating Station to the Grand Canyon National Park

September 2012

Page 45 of 45

www.aecom.com

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

# **Regional Haze Four-Factor Analysis**

Boiler #1 (EQUI 15 / EU 420) Boiler #2 (EQUI 16 / EU 430) Recovery Furnace (EQUI 9 / EU 320)

Prepared for Boise White Paper LLC

July 15, 2020



# **Regional Haze Four-Factor Analysis**

Boiler #1 (EQUI 15 / EU 420) Boiler #2 (EQUI 16 / EU 430) Recovery Furnace (EQUI 9 / EU 320)

Prepared for Boise White Paper LLC

July 15, 2020

325 South Lake Avenue Duluth, MN 55802 218.529.8200 www.barr.com

# Regional Haze Four-Factor Analysis

July 15, 2020

# Contents

| 1      | Executive Summary1   |
|--------|--|
| 2      | Introduction1  |
| 2.1    | Four-factor Analysis Regulatory Background1                                |
| 2.2    | Emission Unit Description2   |
| 2.3    | Boiler #2 and Recovery Furnace: Effective Controls3                        |
| 2.4    | Boiler #1: Permit Limits4  |
| 3      | Boiler #1: Four-factor Analysis for NO <sub>x</sub> 5                      |
| 3.1    | Emission Control Options5  |
| 3.2    | Baseline Emission Rates7   |
| 3.3    | Factor 1 – Cost of Compliance7   |
| 3.4    | Factor 2 – Time Necessary for Compliance8                                  |
| 3.5    | Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance9 |
| 3.6    | Factor 4 – Remaining Useful Life of the Source9                            |
| 3.7    | Proposed NO <sub>x</sub> Controls and Emissions Rates9                     |
| Append | dices1   |

## List of Tables

| Table 2-1  | Identified Emission Units                                      | 2 |
|------------|--|---|
| Table 2-2  | Boiler #1 (EQUI 15) Permit Limits                              | 4 |
| Table 3-1: | Natural Gas Power Boiler RBLC Summary – NO <sub>x</sub>        | 6 |
| Table 3-2: | Projected 2028 NO <sub>X</sub> Emissions (tons per year)       | 7 |
| Table 3-3: | Boiler #1 NO <sub>x</sub> Control Cost Summary, per Unit Basis | 8 |

### List of Appendices

- Appendix A.1: Four-Factor Analysis Applicability for Boiler #2 and Recovery Furnace
- Appendix A.2: Regional Haze Correspondence with Hassan Bouchareb dated May 29, 2020
- Appendix B: RACT/BACT/LAER Clearinghouse (RBLC) Review Summary for Natural Gas Boilers for NO<sub>X</sub>
- Appendix C.1: Boiler #1 Cost Calculations for NO<sub>X</sub> Control Measures (SCR)
- Appendix C.2: Boiler #1 Cost Calculations for NO<sub>X</sub> Control Measures (LNB with FGR and OFA)

# **1 Executive Summary**

On January 29, 2020 the Minnesota Pollution Control Agency's (MPCA's) submitted a Request for Information (RFI)<sup>1</sup> to Boise Paper LLC (Boise) regarding an analysis of emission reductions to support the development of the State Implementation Plan (SIP) for the Regional Haze Rule (RHR)<sup>2</sup>. The RFI requested that the facility evaluate potential emissions reduction measures for sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>X</sub>) for Boiler #2 (EQUI 16 / EU430), Recovery Furnace (EQUI 9 / EU 320), and for NO<sub>X</sub> only for Boiler #1 (EQUI 15 / EU 420). The request said that the analysis must address the four statutory factors laid out in 40 CFR 51.308(f)(2)(i) and pursuant to the final U.S. Environmental Protection Agency (EPA) RHR State Implementation Plan (SIP) guidance<sup>3</sup> (2019 SIP Guidance):

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

The 2019 SIP Guidance was reviewed to determine if either Boiler #2 or Recovery Furnace were "effectively controlled" sources. Appendix A.1 demonstrates that Boiler #2 and Recovery Furnace are "effectively controlled" and does not need to conduct a four-factor analysis for those emission units as required in the January 29, 2020 RFI letter. Concurrence of this demonstration was provided by Hassan Bouchareb on May 29, 2020, which is included as in Appendix A.2.

This report evaluates potential NO<sub>X</sub> control technologies and feasibility for Boiler #1, as required in the January 29, 2020 RFI. Boise has concluded that new emission controls are not warranted because the cost of compliance of technically feasible retrofit emission control technologies is not cost effective. As such, Boise proposes to maintain the existing NO<sub>X</sub> permit limits for Boiler #1 as presented in Table 2-2.

<sup>&</sup>lt;sup>1</sup> January 29, 2020 letter from Hassan Bouchareb of MPCA to Boise Paper LLC.

<sup>&</sup>lt;sup>2</sup> The U.S. Environmental Protection Agency (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>&</sup>lt;sup>3</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

# 2 Introduction

This section discussed the pertinent regulatory background information and a description of the emission sources at Boise which were identified by MPCA for analysis.

### 2.1 Four-factor Analysis Regulatory Background

The RHR published on July 15, 2005 by the 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 SIPs in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. Each SIP must be developed to make reasonable progress towards the ultimate goal of achieving natural background visibility by 2064. The initial SIPs, which were informed by best available retrofit technology (BART) analyses that were completed on all subject-to-BART sources, were due on December 17, 2007. The second RHR planning period requires development and submittal of updated state SIPs by July 31, 2021.

On January 29, 2020, the MPCA sent an RFI to Boise. The RFI stated that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) 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 SO<sub>2</sub> and NO<sub>x</sub>. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze in Isle Royale, Michigan must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts. As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFIs also stated that the facility was identified as a significant source of  $NO_X$  and  $SO_2$  which is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that Boise submit a "four factors analysis" (herein termed as a four-factor analysis) by July 31, 2020 for the emission units identified in Table 2-1 as part of the State's regional haze reasonable progress.

 Table 2-1
 Identified Emission Units

| Unit             | Unit ID          | Applicable Pollutants             | Effectively<br>Controlled <sup>4</sup> | Four Factor Analysis<br>Required <sup>5</sup> |
|------------------|------------------|-----------------------------------|--|---|
| Boiler #1        | EQUI 15 / EU 420 | NO <sub>X</sub>                   | Not Applicable                         | Yes   |
| Boiler #2        | EQUI 16 / EU 430 | NO <sub>X</sub> , SO <sub>2</sub> | Yes                                    | No  |
| Recovery Furnace | EQUI 9 / EU 320  | NO <sub>X</sub>                   | Yes                                    | No  |

The MPCA stated that the analysis must consider potential emissions reduction measures by addressing the four statutory factors which are laid out in 40 CFR 51.308(f)(2)(i):

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

The RFI letter to the Boise specified that the "analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to the final 2019 SIP Guidance.

This report describes the background and analysis for conducting a four-factor analysis for  $NO_X$  and  $SO_2$  for the emission units identified in Table 2-1.

### 2.2 Emission Unit Description

Boise is wholly owned by Packaging Corporation of America (PCA). The facility in International Falls, Minnesota is an integrated kraft pulp and paper mill that produces commodity and specialty paper. The three emission units included in MPCA's RFI are:

• **Boiler #1 (EQUI 15):** This emission unit was originally commissioned as a coal-fired boiler and has been converted to only burn natural gas. The boiler produces steam to generate electricity and provide heat for other processes at the plant. Exhaust from the sludge dryer (EQUI 24) may also vent to Boiler #1. The boiler is also a backup combustion source for non-condensable gases (NCG) which are the exhaust gases from the pulp digestion and black liquor solids (BLS) evaporation processes. The amount of NCG burned in Boiler #1 is limited by the facility air permit. Good combustion practices are utilized for Boiler #1 through a combination of several efforts, including control strategy, boiler monitoring, and training.

<sup>&</sup>lt;sup>4</sup> See Section 2.3 Boiler #2 and Recovery Furnace: Effective Controls

<sup>&</sup>lt;sup>5</sup> Four-Factor Analysis applicability for Boiler #2 and Recovery Furnace is included in Appendix A.1

- **Boiler #2 (EQUI 16):** This emission unit was originally commissioned as a coal-fired boiler This emission unit is a stoker grate design which produces steam to generate electricity and provide heat for other processes at the plant. The boiler burns primarily hog fuel (biomass which is primarily bark and wood refuse from the facility de-barking process) and is also permitted to burn wastewater treatment plant sludge, paper, and natural gas. The boiler is also a backup combustion source for NCG. The amount of NCG burned in Boiler #2 is limited by the facility air permit. Particulate matter emissions from the power boiler are controlled by multiclones and a high-efficiency electrostatic precipitator (ESP). Boiler #2 does not have add-on NO<sub>x</sub> controls, but does use staged and overfire air to manage the generation of NO<sub>x</sub> The boiler does not have add-on SO<sub>2</sub> controls but burns low sulfur fuels and the wood ash provides some dry scrubbing of SO<sub>2</sub> when NCGs are burned concurrently.
- **Recovery Furnace (EQUI 9):** This emission unit burns strong BLS that are generated in the kraft pulp mill chemical recovery process. Weak BLS, which is generated as part of the pulping and washing processes, are concentrated in evaporators to make strong BLS. The strong BLS is then charged to the Recovery Furnace where the organic portion of the BLS is burned to produce steam to generate electricity and provide heat for other processes at the plant. The cooking chemicals collect as molten smelt at the bottom of the boiler. The amount of BLS burned in the Recovery Furnace is limited by the facility air permit. The Recovery Furnace is a primary source of all criteria pollutant emissions, as well as sulfuric acid (H<sub>2</sub>SO<sub>4</sub>), total reduced sulfur (TRS), and Hazardous Air Pollutants (HAP). Particulate matter emissions from the Recovery Furnace are controlled by a high-efficiency ESP. The Recovery Furnace does not have add-on NO<sub>x</sub> controls but does use staged air injection to manage the generation of NO<sub>x</sub>.

### 2.3 Boiler #2 and Recovery Furnace: Effective Controls

The 2019 SIP Guidance states that it "may be reasonable for a state not to select an effectively controlled source"<sup>6</sup> for the four-factor analysis with the rationale that "it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls necessary."<sup>7</sup> EPA identified potential scenarios that "EPA believes it may be reasonable for a state not to select a particular source for further analysis." However, EPA clarified that the associated scenarios are not a comprehensive list but are merely to illustrate examples for the state to consider.

Boise submitted a letter to MPCA on May 8, 2020 requesting the RFI be withdrawn for Boiler #2 (EQUI 15) and the Recovery Furnace (EQUI 9) because these sources are already "effectively controlled" as defined in the 2019 SIP Guidance. MPCA responded via email on May 29, 2020 and confirmed that these sources are

<sup>&</sup>lt;sup>6</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, Page 22.

<sup>&</sup>lt;sup>7</sup> Ibid, Page 23.

"effectively controlled," and, therefore, a four-factor analysis is not required. Boise's request letter and MPCA's response email are presented in Appendix A.1 and Appendix A.2, respectively.

### 2.4 Boiler #1: Permit Limits

Boise's current Title V Operating Permit #0170002-101 limits Boiler #1 NO<sub>X</sub> emissions in Conditions 5.13.1-5.14.5. In addition, the emissions of NO<sub>X</sub> from this source are also subject to the NO<sub>X</sub> Cap Group limits as presented in Conditions 5.2.1-5.2.7. Boiler #1 does not have add-on NO<sub>X</sub> controls but the generation of NO<sub>X</sub> is managed by good combustion practices and NO<sub>X</sub> emissions are measured by a continuous emission monitoring system (CEMS). The numeric emission limits are presented in Table 2-2. It is noteworthy that the individual NO<sub>X</sub> emission limit is based on modeling and the NO<sub>X</sub> Cap Group limits are based on a visibility impacts analysis. Additionally, the NO<sub>X</sub> modeling will soon be updated as the air permit Condition 6.1.10 states "The Permittee shall submit a computer dispersion modeling protocol for 1-hour and annual NO2 NAAQS due by 6/6/2021. This protocol will describe the proposed modeling methodology and input data, in accordance with the current version of the MPCA Air Dispersion Modeling Guidance."

| Pollutant       | Condition | Limit  | Basis of Limit   |
|-----------------|-----------|--|--|
| NOx             | 5.14.3    | Nitrogen Dioxide <= 0.20 pounds per million Btu heat input 30-<br>day rolling average.   | Title I Condition: 40 CFR<br>52.21(k) (modeling) &<br>Minn. R. 7007.3000   |
| NO <sub>X</sub> | 5.2.1     | The Permittee shall limit emission of Nitrogen Oxides <= 3.67<br>tons per day from combustion sources (EQUI 9, EQUI 15, EQUI<br>16, EQUI 17, and EQUI 18).   | Title I Condition: 40 CFR<br>52.21(o) (visibility) &<br>Minn. R. 7007.3000 |
| NOx             | 5.2.3     | The Permittee shall limit emissions of Nitrogen Oxides <= 4.18 tons per day. This limit is the total NOx cap for the combustion sources (Boilers #1, #2, #3, #9, and the recovery furnace) (EQUI 15, EQUI 16, EQUI 17, EQUI 18, EQUI 9, respectively) as well as the lime kiln and smelt dissolving tank (EQUI 13 and EQUI 945). | Title I Condition: 40 CFR<br>52.21(o) (visibility) &<br>Minn. R. 7007.3000 |

### Table 2-2 Boiler #1 (EQUI 15) Permit Limits

# 3 Boiler #1: Four-factor Analysis for NO<sub>X</sub>

This section identifies baseline emission rates and evaluates the four statutory factors for NO<sub>X</sub> emissions from Boiler #1.

### 3.1 Emission Control Options

The 2019 SIP Guidance states that the "first step in characterizing control measures for a source is the identification of technically feasible control measures for those pollutants that contribute to visibility impairment."<sup>8</sup> However, EPA recognized that a "state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures."<sup>9</sup> This section addresses the selection of emission control options for NO<sub>X</sub> from Boiler #1.

The following methodology was used to determine which emission control technologies should be considered in the four-factor analysis:

- 1. Search the RACT/BACT/LAER Clearinghouse (RBLC)<sup>10</sup> for available control technologies with the following search criteria:
  - Similar emission unit type (process name)
  - Similar fuel
  - 10-year look back
- 2. Eliminate technologies that would not would not apply to the specific emission unit under consideration
- 3. Advance the remaining technologies for consideration in the four-factor analysis

The RBLC search for natural gas fueled boilers for NO<sub>x</sub> is presented in Appendix B and a summary is provided in Table 3-1.

<sup>&</sup>lt;sup>8</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 28.

<sup>&</sup>lt;sup>9</sup> Ibid, Page 29.

<sup>&</sup>lt;sup>10</sup> RACT/BACT/LAER Clearinghouse (RBLC) as maintained by USEPA (link to RBLC website)

#### Table 3-1: Natural Gas Power Boiler RBLC Summary – NOx

| RBLC ID  | Technology   |
|--|--|
| TN-0162<br>TN-0164   | Selective Catalytic Reduction<br>Low NO <sub>X</sub> Burners<br>Flue Gas Recirculation |
| TX-0811  | Selective Catalytic Reduction<br>Low NO <sub>X</sub> Burners                           |
| TX-0731  | Selective Catalytic Reduction  |
| IN-0179  | Ultra Low NO <sub>X</sub> Burners  |
| WV-00025   | Flue Gas Recirculation   |
| PA-0306<br>LA-0314<br>OH-0363<br>AK-0083<br>VA-0325<br>TX-0712 | Ultra Low NO <sub>x</sub> Burners  |
| LA-0272<br>AR-0121<br>IN-0263<br>MI-0423<br>OH-0374            | Low NO <sub>x</sub> Burners<br>Flue Gas Recirculation                                  |
| MI-0427  | Low $NO_X$ Burners with internal (within the burner) Flue Gas Recirculation            |
| LA-0307<br>TX-0641<br>VA-0328<br>OH-0354<br>TX-0708            | Low NO <sub>X</sub> Burners  |
| TX-0576  | Good Combustion Practice   |

Good combustion practices were not considered in the four-factor analysis because these are already implemented through a combination of several efforts, including control strategy, boiler monitoring, and training.

As shown in Table 3-1, the majority of the control technologies presented in the RBLC include LNB or ULNB, with or without FGR. The specific technology selected for these projects was likely dependent on the targeted emission rate. For the purposes of the four-factor analysis, Boise has combined these technologies into a single category titled "LNB/ULNB with or without FGR" and then contacted a vendor to provide a technically feasible solution for the target emission rate (additional detail is provided in Section 3.3).

Based on this information, the technologies that were considered in the four-factor analysis are:

- SCR
- LNB/ULNB with or without FGR

### 3.2 Baseline Emission Rates

The 2019 SIP Guidance states that 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."<sup>11</sup> Thus, Boise anticipates flat growth in the paper industry and projects that emissions in 2028 will be equivalent to 2019 actual emissions.

### Table 3-2:Projected 2028 NOx Emissions (tons per year)

| Year                     | Boiler #1      |
|--------------------------|----------------|
| 2019 actual emissions    | 90.9 tons/year |
| 2028 Projected Emissions | 90.9 tons/year |

### 3.3 Factor 1 – Cost of Compliance

Boise has completed compliance cost estimates for the selected NO<sub>X</sub> emission control measures following EPA's Control Cost Manual as recommended in the 2019 SIP Guidance.<sup>12</sup> The SCR cost estimate were based on spreadsheet templates provided by EPA. The LNB/ULNB cost estimate is based on a vendor cost estimate for which the vendor was asked to provide a technically feasible solution to reduce emissions from the current emission rate (0.131 lb/MMBtu) to 0.050 lb/MMBtu which is the emission limit for Boise's Boiler #3 (EQUI 17) as shown in permit condition 5.16.1. The conceptual design provided by the vendor is LNB with FGR and over-fire air (OFA).

The capital cost estimates were confirmed by Boise's plant engineering staff as reasonable, based on their considerable experience with projects at Boise and their informal conversations with other companies that have completed similar types of projects at other facilities. A more detailed cost estimate is likely to increase the costs for installing and implementing either of the projects. Cost calculation spreadsheets for the NO<sub>x</sub> emission control measures are provided in Appendix C.

The cost effectiveness analysis compares the annualized cost of the technology per ton of pollutant removed and is evaluated on a 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.

The resulting cost effectiveness calculations are summarized in Table 3-3.

<sup>&</sup>lt;sup>11</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 29.

<sup>&</sup>lt;sup>12</sup> Ibid, Page 21.

| Additional<br>Emissions Control<br>Measure | Total Capital<br>Investment<br>(\$) | Total Annualized<br>Costs<br>(\$/year) | Control Efficiency<br>(%) | Annual Emissions<br>Reduction<br>(tpy) | Pollution Control<br>Cost Effectiveness<br>(\$/ton) |
|--|-------------------------------------|--|---------------------------|--|---|
| SCR  | \$7,828,245                         | \$970,836                              | 69%                       | 63.1                                   | \$15,375  |
| LNB with<br>FGR and OFA                    | \$11,144,531                        | \$1,557,544                            | 62.0%                     | 56.2                                   | \$27,707  |

 Table 3-3:
 Boiler #1 NOx Control Cost Summary, per Unit Basis

Based on the information provided in Table 3-3 and in consideration of RHR analyses conducted in other states, the emission control measures were not considered cost effective.

Sections 3.4 through 3.6 provide a screening-level summary of the remaining three factors evaluated for the NO<sub>X</sub> emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

### 3.4 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, the time for compliance considers the time needed to develop and approve the new emissions limit into the 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.

The technologies would require significant resources and time of at least two to three years design, engineer, procure, and install the equipment. The facility would attempt to complete the construction during a regularly scheduled outage but recognizes that the outage may need to be extended to install all required equipment.

The SIP is scheduled to be submitted in 2021 with the anticipated approval in 2022 (approximately one year after submittal). Once the SIP is approved, the design, engineer, procurement, and installation schedule would begin. This would put the anticipated date of installation in 2024 or 2025.

# 3.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified  $NO_X$  control measures are summarized below.

- SCR
  - o Increased truck and/or train traffic (reagent and catalyst deliveries)
  - o Possible ammonia slip (unreacted reagent that is emitted to the atmosphere)
  - o Catalyst regeneration
  - o Catalyst disposal
  - Electricity consumption (fans and pumps)
- LNB with SCR and OFA
  - Electricity consumption (fans)
  - Possible increase in carbon monoxide (CO) emissions)

### 3.6 Factor 4 – Remaining Useful Life of the Source

Because Boiler #1 is expected to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life) was used to calculate emission reductions, amortized costs, and cost effectiveness on a dollar per ton basis.

### 3.7 Proposed NO<sub>X</sub> Controls and Emissions Rates

This four-factor analysis does not support the installation of additional NO<sub>X</sub> emission control measures at Boiler #1 beyond those described in Section 2.3. As such, Boise proposes to maintain the existing NO<sub>X</sub> permit limits presented in Table 2-2.

Appendices

# Appendix A.1

Four-Factor Analysis Applicability

For Boiler #2 and Recovery Furnace

May 8, 2020

Hassan M. Bouchareb Minnesota Pollution Control Agency 520 Lafayette Road North St. Paul, MN 55155-4194

#### Re: Request for Information – Regional Haze Rule, Reasonable Progress, Four-Factor Analysis

Dear Mr. Bouchareb:

This letter is in response to your January 29, 2020, request for information (RFI) to Boise White Paper LLC (Boise) regarding the Regional Haze Rule (RHR). The RFI requested that Boise submit a "four-factor analysis" of control equipment for three emission units at our International Falls facility. The analysis would be used by the Minnesota Pollution Control Agency (MPCA) to develop a comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the RHR (40 CFR 51.308). The RFI stated that the analysis should be prepared following guidance<sup>1</sup> provided by the U. S. Environmental Protection Agency (EPA).

EPA's guidance recognizes that the states have flexibility in deciding which sources must conduct a fourfactor analysis. For example, the guidance states that it "may be reasonable for a state not to select an effectively controlled source"<sup>2</sup> and that, for such sources, a state should explain "why it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary."<sup>3</sup>

This letter requests that MPCA withdraw the RFI for the Recovery Furnace (EQUI 9 / EU 320) and Boiler #2 (EQUI 15 / EU 420) because these sources are already "effectively controlled" as defined in EPA's guidance<sup>4</sup>. The following supporting rationale explains why this determination is consistent with MPCA's requirement to make reasonable progress.

## **1** Background

The MPCA is required to develop and implement air quality protection plans to reduce pollution that causes haze at national parks and wilderness areas, known as Class I areas. The RHR requirements are found in 40 CFR 51.308. The state of Minnesota includes two Class I areas: Boundary Waters Canoe Area Wilderness (BWCAW) and Voyageurs National Park (Voyageurs). In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states—namely, Isle Royale National Park

<sup>&</sup>lt;sup>1</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019.

<sup>&</sup>lt;sup>2</sup> Ibid, Page 22.

<sup>&</sup>lt;sup>3</sup> Ibid, Page 23

<sup>&</sup>lt;sup>4</sup> Ibid, Page 22.

(Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze at Isle Royale, it must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts.

The goal of the RHR is to return the Class I areas to natural visibility conditions by 2064. To that end, the RHR requires states to develop a state implementation plan (SIP) and to provide comprehensive updates every 10 years. MPCA submitted its Regional Haze SIP in December 2009, updated it in May 2012, and must submit a comprehensive update by July 31, 2021, to address reasonable progress in the second implementation period, 2018-2028. Progress is tracked by the EPA and the MPCA based on the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at the BWCAW (BOWA1), Voyageurs (VOYA2) and Isle Royale (ISLE1).

Each SIP revision is required to address several elements, including:

- Calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress (40 CFR 51.308(f)(1))
- Long-term strategy for regional haze (40 CFR 51.308(f)(2))
- Reasonable progress goals (40 CFR 51.308(f)(3))
- Monitoring strategy and other implementation plan requirements (40 CFR 51.308(f)(6))

On January 29, 2020, MPCA sent an RFI to Boise which stated that our facility was identified as a significant source of  $NO_X$  and  $SO_2$  and is located close enough to the BWCAW or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requested that we submit a "four-factor analysis"<sup>5</sup> by July 31, 2020, for the emission units identified in Table 1.

| Unit             | Unit ID          | Applicable Pollutants             |
|------------------|------------------|-----------------------------------|
| Recovery Furnace | EQUI 9 / EU 320  | NOx                               |
| Boiler #1        | EQUI 15 / EU 420 | NO <sub>x</sub>                   |
| Boiler #2        | EQUI 16 / EU 430 | NO <sub>X</sub> , SO <sub>2</sub> |

**Table 1: Identified Emission Units** 

The RFI stated that the "analysis should be prepared using the U.S. Environmental Protection Agency guidance<sup>6</sup> that provides recommendations for how each of the factors should be determined." The results of the four-factor analysis would be incorporated into the long term strategy which must "include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress."<sup>7</sup>

<sup>&</sup>lt;sup>5</sup> The four factors are presented in 40 CFR 51.308(f)(2)(i): cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance and remaining useful life of the source.

<sup>&</sup>lt;sup>6</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019

<sup>&</sup>lt;sup>7</sup> 40 CFR 51.308(f)(3)

The reasonable progress goals are determined based on several criteria, including an evaluation of the "rate of progress needed to attain natural visibility conditions by the year 2064.... In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction measures needed to achieve it for the period covered by the implementation plan."<sup>8</sup>

# 2 Current Visibility in BWCAW, Voyageurs, and Isle Royale

The data from the IMPROVE monitoring network for BWCAW, Voyageurs, and Isle Royale are available on MPCA's website<sup>9</sup>. As shown in figures 1 through 3, the visibility at each Class I area has been improving since 2009 and is already below the 2028 uniform rate of progress (URP)<sup>10</sup>. The observed visibility improvement could be attributed to emission reductions from regulated stationary sources due to a variety of reasons, including:

- installation of best available retrofit technology (BART) during the first RHR implementation period,
- emission reductions from a variety of industries, including the pulp and paper sources, due to updated rules and regulations, and
- transition of power generation systems from coal to natural gas and renewables (wind and solar).

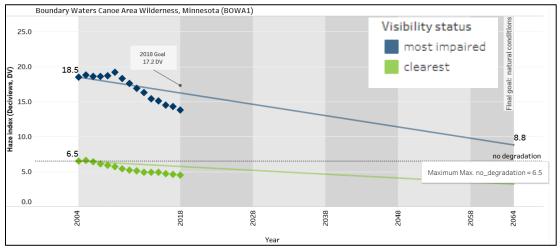


Figure 1: BWCAW Current Visibility Conditions

<sup>&</sup>lt;sup>8</sup> 40 CFR 51.308(d)(1)(i)(B) <sup>9</sup><u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze visibility metrics public/Visibility progress</u> progress

<sup>&</sup>lt;sup>10</sup> The URP is determined based on the slope of the line from baseline conditions (2000-2004) to the natural visibility conditions in 2064

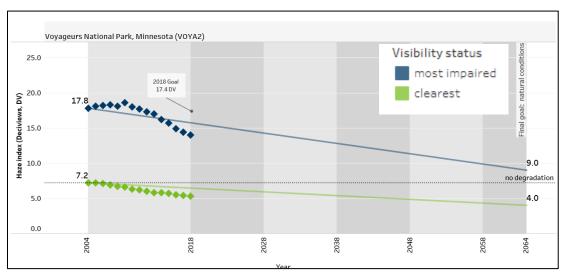


Figure 2: Voyageurs Current Visibility Conditions

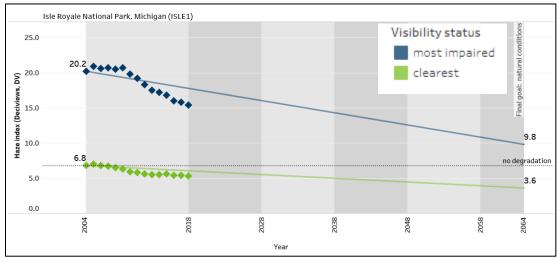


Figure 3: Isle Royale Current Visibility Conditions

Some of these emission reductions have recently occurred but are not fully reflected in the 5-year average monitoring data presented in figures 1 through 3. For example, Minnesota Power retired two coal-fired boilers at the Boswell Energy Center in Cohasset at the end of 2018. In addition, the compliance schedule is still in progress for the NO<sub>x</sub> emission reductions required by the Taconite Federal Implementation Plan (FIP) Establishing BART for Taconite Plants (40 CFR 52.1235). Furthermore, there are others emission reduction projects that are scheduled to occur in Minnesota prior to 2028, the end of the second RHR implementation period (e.g., Xcel Energy boiler retirements as detailed in their Upper Midwest Integrated Resource Plan, 2020-2034). These emission reductions will further improve the visibility in the Class I areas.

# **3** EPA Guidance for State Implementation Plans

MPCA's January 29, 2020, RFI stated that the four-factor analysis should follow EPA's guidance<sup>11</sup> that provides recommendations for how each of the factors should be determined. Additionally, EPA also provides states guidance on selecting sources which must conduct a four-factor analysis.

The guidance says that the state will determine which emission control measures are necessary to make reasonable progress in the affected Class I areas<sup>12</sup>. However, as discussed in Section 2, the current sustained progress towards visibility goals in BWCAW, Voyageurs, and Isle Royale is such that the MPCA may tolerate the current reduction trajectory of emission reductions during the second implementation period. The MPCA would be warranted to further consider the flexibility allowed in the RHR to *"reasonably select a set of sources for an analysis of control measures."*<sup>13</sup> The monitoring information will help MPCA *"explain why the decision is consistent with the requirement to make reasonable progress."*<sup>14</sup>

# 4 EPA Guidance for Effectively Controlled Sources

EPA guidance states that it "may be reasonable for a state not to select an effectively controlled source"<sup>15</sup> for the four-factor analysis with the rationale that "*it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls necessary.*"<sup>16</sup> EPA identified potential scenarios that "*EPA believes it may be reasonable for a state not to select a particular source for further analysis.*" However, EPA clarified that the associated scenarios are not a comprehensive list but are merely to illustrate examples for the state to consider.

One of the "effectively controlled" scenarios is for sources that went through a best available control technology (BACT) review with a construction permit issued on or after July 31, 2013.<sup>17</sup> EPA notes that the BACT control equipment review methodologies are "*similar to, if not more stringent than, the four statutory factors for reasonable progress.*" As presented below, an extension of the BACT review scenario is for sources that have existing permit limits, independent of the statutory basis (e.g., air dispersion modeling, PSD avoidance limit, etc.), which are consistent or sufficiently similar to recent BACT determinations for similar sources. Because the limits are similar to BACT, this extension is consistent with EPA's conclusion that a four-factor analysis "would likely result in the conclusion that no *further controls are necessary.*"

- <sup>13</sup> Ibid.
- <sup>14</sup> Ibid, Page 23.
- <sup>15</sup> Ibid, Page 22.
- <sup>16</sup> Ibid, Page 23.
- <sup>17</sup> Ibid.

<sup>&</sup>lt;sup>11</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019

<sup>&</sup>lt;sup>12</sup> Ibid, Page 9.

# 4.1 Recovery Furnace (EQUI 9 / EU 320)

The RFI requested a four-factor analysis for  $NO_x$  emissions from the Recovery Furnace which is a combustion unit that burns black liquor solids (BLS) from the Kraft pulping process to recover spent cooking chemicals. The combustion process generates heat which is recovered by steam generation. The combustion process results in  $NO_x$  and other emissions.

The Recovery Furnace has not undergone a NO<sub>x</sub> BACT review since July 31, 2013, so this unit does not directly meet this scenario. However, the current NO<sub>x</sub> limit<sup>18</sup> (100 lb/hr per 30-day rolling average, which is equivalent to 80 ppm at 8% oxygen (O<sub>2</sub>)) was compared to recent determinations in EPA's RBLC database (Attachment A) and the limit is consistent with NO<sub>x</sub> limits from recent BACT determinations (e.g., 85 ppm at 8%  $O_2^{19}$ , 120 ppm at 8%  $O_2^{20}$ ).

Because the current NO<sub>x</sub> emission limit is similar to recent BACT determinations and BACT control equipment reviews are "*similar to if not more stringent than*" the four-factor analysis methodology, it is unlikely that additional controls would be available to further reduce emissions. Therefore, this unit is sufficiently similar BACT scenario and MPCA can justify that a four-factor analysis need not be completed.

# 4.2 Boiler #2 (EQUI 16 / EU 430)

The RFI requested a four-factor analysis for  $NO_x$  and  $SO_2$  emissions Boiler #2 which is an industrial boiler that is permitted to burn the following fuels: <sup>21</sup>

- Biomass (commonly referred to as "hog fuel")
- WWTP Sludge
- Natural Gas
- Non-Condensable Gas (NCG)

The associated combustion results in NO<sub>X</sub> and SO<sub>2</sub> emissions, among other emissions.

**NO**<sub>x</sub>: Boiler #2's current NO<sub>x</sub> limit<sup>22</sup> (100.2 lb/hr, which is equivalent to 0.25 lb/MMBtu at the maximum firing rate) was compared to recent determinations in EPA's RBLC database (Attachment B) and the limit is consistent with NO<sub>x</sub> limits from recent BACT determinations (e.g., two determinations<sup>23,24</sup> with 0.3 lb/MMBtu limits).

Because the current NO<sub>x</sub> emission limit is similar to recent BACT determinations and BACT control equipment reviews are *"similar to if not more stringent than"* the four-factor analysis methodology, it is unlikely that additional controls would be available to further reduce emissions. Therefore, this unit is

<sup>&</sup>lt;sup>18</sup> Title V Operating Permit (TVOP) Condition 5.13.7

<sup>&</sup>lt;sup>19</sup> 2019 BACT determination for Sun Bio Materials Company (AR-0161)

<sup>&</sup>lt;sup>20</sup> 2015 BACT determination for Rocktenn CP, LLC (AL-0302)

Permit 07100002-014 Condition 5.17.14 limits fuel burned to "bark, wood refuse, wastewater treatment sludge, paper, and natural gas. Non-condensable gas (NCG) is also oxidized in Boiler #2."

<sup>&</sup>lt;sup>22</sup> TVOP Condition 5.17.7

<sup>&</sup>lt;sup>23</sup> 2010 BACT determination for Boise White Paper (AL-0250)

<sup>&</sup>lt;sup>24</sup> 2014 BACT determination for Abengoa Bioenergy Biomass of Kansas (KS-0034)

sufficiently similar BACT scenario and MPCA can justify that a four-factor analysis need not be completed.

**SO**<sub>2</sub>: When considering the SO2 emissions from Boiler #2, it is important to note:

- The primary fuel is hog fuel, a biomass which is primarily bark from the facility de-barking process. This fuel is inherently low in sulfur.
- Natural gas is a supplemental fuel and is also a low-sulfur fuel.
- Most of the SO<sub>2</sub> emissions from the boiler are a direct result of Non-Condensable Gas (NCG) combustion. However, Boiler #2 is the secondary NCG combustion source<sup>25</sup> and is only utilized when the primary NCG combustion source (Lime Kiln (EQUI 13 / EU 340)) is unavailable; Boiler #1 (EQUI 15 / EU 420) is the tertiary NCG combustion device<sup>26</sup>.
- Boiler #2 has an SO<sub>2</sub> emission limit (9.4 lb/hr as a 12-hr rolling average, which is equivalent to 0.024 lb/MMBtu at the maximum firing rate) which applies when NCG is not being combusted.<sup>27</sup>
- Boiler #1 and Boiler #2 have a combined SO<sub>2</sub> emission limit (115 tons per rolling 12-month period) which applies when burning NCG in either of the backup combustion sources.<sup>28</sup>
- Maintaining the ability to combust the NCG in the backup combustion sources is part of the overall strategy for limiting emissions of hazardous air pollutants because 40 CFR Part 63 Subpart S (National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry) limits the amount of time that NCG can be vented to the atmosphere without combustion.
- Additionally, maintaining the ability to combust NCG in the backup combustion sources is an engineered control to maintain the continued safe operation of the Kraft pulping equipment and process.

Boiler #2's current SO<sub>2</sub> limit, which applies when NCG is not being combusted (9.4 lb/hr as a 12-hr rolling average, which is equivalent to 0.024 lb/MMBtu at the maximum firing rate)<sup>29</sup>, was compared to recent determinations in EPA's RBLC database (Attachment C). The limit is consistent with SO<sub>2</sub> limits from recent BACT determinations for similar sources (e.g., 0.025 lb/MMBtu<sup>30</sup>, 0.21 lb/MMBtu<sup>31</sup>).

The TVOP limits the SO<sub>2</sub> emissions from the backup NCG combustion sources (Boiler #1 and Boiler 2) to 115 tons per rolling 12-month period.<sup>32</sup> As stated above, maintaining the ability to combust the NCG in the backup combustion sources is part of the overall strategy for limiting emissions of hazardous air pollutants as required by 40 CFR Part 63 Subpart S. Boise works diligently to maintain the availability of the primary NCG combustion source (Lime Kiln) which limits the actual emissions from the facility. For

<sup>&</sup>lt;sup>25</sup> TVOP Condition 5.3.3

<sup>&</sup>lt;sup>26</sup> Ibid.

<sup>&</sup>lt;sup>27</sup> TVOP Condition 5.17.6

<sup>&</sup>lt;sup>28</sup> TVOP Condition 5.3.6

<sup>&</sup>lt;sup>29</sup> TVOP Condition 5.17.6

<sup>&</sup>lt;sup>30</sup> 2019 BACT determination for Sun Bio Materials Company (AR-0161)

<sup>&</sup>lt;sup>31</sup> 2014 BACT determination for Abengoa Bioenergy Biomass of Kansas (KS-0034)

<sup>&</sup>lt;sup>32</sup> TVOP Condition 5.3.6

example, the maximum annual SO<sub>2</sub> emissions from Boiler #2 in the past five years was 35.4 tons which resulted from 436 hours (18.2 days) of NCG combustion. Although the actual emissions provide for a large margin of compliance, Boise could not take a more stringent limit because the existing limit could be necessary if an unanticipated downtime or failure of the primary combustion source were to occur.

In regards to the installation of SO<sub>2</sub> controls on Boiler #2 for the NCG combustion scenario, it is unlikely that any controls would be cost effective. This conclusion is based on designing the SO<sub>2</sub> controls to treat the full volume of Boiler #2 flue gas (i.e., a large annualized capital expenditure) but only operating the equipment when NCG is being combusted (e.g., the maximum SO<sub>2</sub> emissions from Boiler #2 in the past five years resulted from 18.2 days of NCG combustion). The annualized cost will be high but the low utilization of the control equipment will not result in large actual emission reductions and the cost would therefore not be cost-effective.

The SO<sub>2</sub> emission limit when NCG is not being combusted is similar to recent BACT determinations and BACT control equipment reviews are "*similar to if not more stringent than*" the four-factor analysis methodology, it is unlikely that additional controls would be available to further reduce emissions. In addition, the SO<sub>2</sub> emission limit when NCG is being burned is necessary for the backup combustion sources to ensure control of HAP emissions but the installation of control equipment to operate only when combustion NCG would not be cost effective. Therefore, the MPCA can justify that a four-factor analysis need not be completed.

# **5** Conclusion

As described in Section 2, the current visibility in the nearby Class I areas is already below the 2028 glidepath, so MPCA does not need to consider an excessive reasonable progress goal for the SIP revision that is due in 2021. Furthermore, as described in Section 4, there is sufficient justification to consider the Recovery Furnace and Boiler #2 as "effectively controlled" sources. Thus, it "*may be reasonable for a state not to select an effectively controlled source*" to conduct a four-factor analysis because "*there will be only a low likelihood of a significant technological advancement that could provide further reasonable emission reductions*."<sup>33</sup> Therefore, Boise requests that your RFI dated January 29, 2020, be withdrawn for the Recovery Furnace and Boiler #2. We will continue to proceed with a four factor analysis for Boiler #1 as directed in the RFI dated January 29, 2020.

We are available at your convenience to discuss this request in detail. Please advise if a telephone conference is desired. You may contact Kara Huziak at <u>karahuziak@boisepaper.com</u> with questions or to request a meeting.

Thank you for considering our request.

Sincerely,

Mike Wagner Mill Manager

Attachments:

- A. RBLC Summary: NO<sub>X</sub> from Recovery Furnaces
- B. RLBC Summary: NO<sub>x</sub> from Hog Fuel Boilers
- C. RBLC Summary: SO<sub>2</sub> from Hog Fuel Boilers

<sup>&</sup>lt;sup>33</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 23.

# Boise White Paper LLC Regional Haze "Effectively Controlled" Source Scenario Comparison Analysis Attachment A: Recovery Furnace NOx RBLC Search

Pollutant Name: NOx NOTE: Draft determinations are marked with a " \* " beside the RBLC ID.

| NOTE: Dran | determinations are marked with a " *             | beside the RBLC ID.                              |                   |               |               |                |  |  |                              |                |                        | 1                        |                                  |                     |                |                |                           |                     |               |               |                               |                         |                            |
|------------|--|--|-------------------|---------------|---------------|----------------|--|--|------------------------------|----------------|------------------------|--------------------------|----------------------------------|---------------------|----------------|----------------|---------------------------|---------------------|---------------|---------------|-------------------------------|-------------------------|----------------------------|
| RBLCID     | FACILITY NAME                                    | CORPORATE OR COMPANY NAME                        | FACILITY<br>STATE | PERMIT NUM    | NAICS<br>CODE | PERMIT DATE    | FACILITY DESCRIPTION   | Process<br>Name  | Fuel                         | Through<br>put | UNITS                  | Pollutant                | Emission Control Description     | Emission<br>Limit 1 | Limits Units 1 | Avg Time       | CASE-BY-<br>CASE<br>BASIS | Emission<br>Limit 2 | Limits Units2 | Avg Time2     | Standard<br>Emission<br>Limit | Standard Limit<br>Units | t Standard Lim<br>Avg Time |
| L-0266     | GEORGIA PACIFIC BREWTON LLC                      | GEORGIA PACIFIC LLC                              | AL                | 502-0001-X044 | 322130        | 06/11/2014 ACT | Kraft Pulp & Paper mdu   | No.4 Recovery &<br>Smelt Tank                              | Black Liquor                 | 1355           | MMBTU/ hr              | Nitrogen Oxides<br>(NOx) | Staged air combustion            | 90                  | PPM@8%O2       | 3HRS AVG       | BACT-PSD                  | 221                 | LB/H          | 3HRS AVG      | 0                             |                         |                            |
| 1-0266     | GEORGIA PACIFIC BREWTON LLC                      | GEORGIA PACIFIC LLC                              | AL                | 502-0001-X044 | 322130        | 06/11/2014 ACT | Kraft Pulp & Paper mdu   | No. 4 REC &<br>Smelt                                       | Natural Gas                  | 1355           | mmbtu                  | Nitrogen Oxides<br>(NOx) | Gas Combustion                   | 0.2                 | LB/MMBTU       | 3 HRS AVG      | BACT-PSD                  | 145.12              | LB/H          | 3 HRS AVG     | 0                             |                         |                            |
| L-0274     | BOISE WHITE PAPER, LLC                           | BOISE WHITE PAPER, LLC                           | AL                | 102-0001-X011 | 322121        | 02/04/2015 ACT | Paper mill   | Recovery<br>Furnace - Non-<br>Direct Contact<br>with Dry - | Black Liquor<br>Solids (BLS) | 2.88           | million lbs. of<br>BLS | Nitrogen Oxides<br>(NOx) |                                  | 90                  | PPMDV          | @8% O2         | BACT-PSD                  | 105.8               | LB/H          | 3-HR. ROLLING | 0                             |                         |                            |
| L-0302     | ROCKTENN STEVENSON                               | ROCKTENN CP, LLC                                 | AL                | 705-0014-X014 | 322130        | 04/29/2015 ACT | Pulp & Paper Mill  | Recovery Boiler  | Black Liquid                 | 58334          | LB/LB BL               | Nitrogen Oxides<br>(NOx) |                                  | 120                 | PPM@8%O2       | 30 DAYS AVG    | BACT-PSD                  | 72.92               | LB/H          | 3 HRS AVG     | 0                             |                         |                            |
| AL-0320    | GP BREWTON                                       | GEORGIA-PACIFIC BREWTON LLC                      | AL                | 502-0001-X044 | 322130        | 01/03/2018 ACT |  | No. 4 Recovery<br>Furnace                                  | Black Liqour                 | 1355           | MMBtu/hr               | Nitrogen Oxides<br>(NOx) |                                  | 90                  | PPMV @8% O2    |                | BACT-PSD                  | 221.9               | LB/HR         | 3 HR          | 0                             |                         |                            |
| R-0156     | GREEN BAY PACKAGING - ARKANSAS KRAFT<br>DIVISION | GREEN BAY PACKAGING - ARKANSAS KRAFT<br>DIVISION | AR                | 0224-AOP-R21  | 322130        | 02/08/2019 ACT | paperboard mill  | Recovery Boiler  | black liquor<br>solids       | 401400         | T/YR                   | Nitrogen Oxides<br>(NOx) |                                  | 80                  | LB/H           |                | OTHER CASE-<br>BY-CASE    | 313.1               | T/YR          |               | 0                             |                         |                            |
| AR-0161    | SUN BIO MATERIAL COMPANY                         | SUN BIO MATERIAL COMPANY                         | AR                | 2384-AOP-R0   | 322110        |                | A kraft paper mill designed with one high yield Kraft softwood<br>Fiberline and two linerboard machiens. The plant is initially sized to<br>support an approximate, nominal linerboard production capacity of<br>4,400 machine dry tons per day at varying base weights.   | Recovery Boiler  | Black Liquor<br>Solids       | 2900           | MMBtu/hr               | Nitrogen Oxides<br>(NOx) | Quaternary Air/Staged Combustion | 85                  | PPMVD @ 8% O2  | 3 1-HOUR TESTS | BACT-PSD                  | 0                   |               |               | 0                             |                         |                            |
| AR-0161    | SUN BIO MATERIAL COMPANY                         | SUN BIO MATERIAL COMPANY                         | AR                | 2384-AOP-R0   | 322110        | 09/23/2019 ACT | Avoid interime by toring be used at varying use vergins.<br>A kraft paper mill designed with one high yield Kraft softwood<br>Fiberline and two linerboard machiens. The plant is initially sized to<br>support an approximate, nominal linerboard production capacity of<br>4,400 machine dry tons per day at varying base weights. | Lime Kiln  | Natural Gas                  | 225            | MMBtu/hr               | Nitrogen Oxides<br>(NOx) | Good Combustion Practices        | 180                 | PPMVD @ 10% O2 | 3 1-HOUR TESTS | BACT-PSD                  | 0                   |               |               | 0                             |                         |                            |
| *AR-0161   | SUN BIO MATERIAL COMPANY                         | SUN BIO MATERIAL COMPANY                         | AR                | 2384-AOP-R0   | 322110        | 09/23/2019 ACT | A kraft paper mill designed with one high yield Kraft softwood<br>Fiberline and two linerboard machiens. The plant is initially sized to<br>support an approximate, nominal linerboard production capacity of<br>4,400 machine dry tons per day at varying base weights.   | Power Boiler   | Biomass                      | 1200           | MMBtu/hr               | Nitrogen Oxides<br>(NOx) | Selective Catalytic Reduction    | 0.06                | LB/MMBTU       | 3-HOUR         | BACT-PSD                  | 0                   |               |               | 0                             |                         |                            |

# Boise White Paper LLC Regional Haze "Effectively Controlled" Source Scenario Comparison Analysis Attachment B: Hog Fuel Boiler NOx RBLC Search

Pollutant Name: NOx NOTE: Draft determinations are marked with a " \* " beside the RBLC ID.

| RBLCID   | FACILITY NAME                                  | CORPORATE OR COMPANY NAME                     | FACILITY | PERMIT NUM               | NAICS  | PERMIT DATE    | FACILITY DESCRIPTION   | Process<br>Name  | Fuel                             | Through- | UNITS    | Pollutant                | Emission Control Description  | Emission<br>Limit 1 | Limits Units 1 | Avg Time                           | CASE-BY-<br>CASE | Emission<br>Limit 2 | Limits Units2 | Avg Time2                                     | Standard<br>Emission | Standard Limit<br>Units | Standard Limit<br>Avg Time |
|----------|--|---|----------|--------------------------|--------|----------------|--|--|----------------------------------|----------|----------|--------------------------|---|---------------------|----------------|------------------------------------|------------------|---------------------|---------------|---|----------------------|-------------------------|----------------------------|
|          |  |   | STATE    |                          | CODE   |                |  | Name   |                                  | put      |          |                          |   | Limit 1             |                |                                    | BASIS            | Limit 2             |               | -   | Limit                | Units                   | Avg i ime                  |
| AL-0250  | BOISE WHITE PAPER                              | BOISE WHITE PAPER, LLC                        | AL       | 102-0001                 | 322121 | 03/23/2010 ACT |  | COMBINATION<br>BOILER  | WOOD                             | 435      | MMBTU/H  | Nitrogen Oxides<br>(NOx) | LOW NOX BURNERS   | 0.3                 | LB/MMBTU       | 3 H                                | BACT-PSD         | 130.5               | LB/H          | 3 Н   | 0                    |                         |                            |
| *AR-0161 | SUN BIO MATERIAL COMPANY                       | SUN BIO MATERIAL COMPANY                      | AR       | 2384-AOP-R0              | 322110 | 09/23/2019 ACT | A kraft paper mill designed with one high yield Kraft softwood<br>Fiberline and two linerboard machiens. The plant is initially sized to<br>support an approximate, nominal linerboard production capacity of<br>4,400 machine dry tons per day at varying base weights.       | Power Boiler   | Biomass                          | 1200     | MMBtu/hr | Nitrogen Oxides<br>(NOx) | Selective Catalytic Reduction   | 0.06                | LB/MMBTU       | 3-HOUR                             | BACT-PSD         | 0                   |               |   | 0                    |                         |                            |
| CA-1203  | SIERRA PACIFIC INDUSTRIES-LOYALTON             | SIERRA PACIFIC INDUSTRIES                     | CA       | SAC 87-01-A              | 221119 | 08/30/2010 ACT | 20 MW COGENERATION POWER PLANT   | RILEY SPREADER<br>STOKER BOILER -<br>Transient Period<br>(see notes) | WOOD                             | 335.7    | MMBTU/H  | Nitrogen Oxides<br>(NOx) | SELECTIVE NON-CATALYTIC REDUCTION<br>(SNCR)                                 | 102                 | РРМ            | @12% CO2, 8-HR<br>ROLLING AVG      | BACT-PSD         | 65                  | lb/H          | 8-HR ROLLING AVG                              | 0                    |                         |                            |
| CA-1203  | SIERRA PACIFIC INDUSTRIES-LOYALTON             | SIERRA PACIFIC INDUSTRIES                     | CA       | SAC 87-01-A              | 221119 | 08/30/2010 ACT | 20 MW COGENERATION POWER PLANT   | RILEY SPREADER<br>STOKER BOILER                                      | WOOD                             | 335.7    | MMBTU/H  | Nitrogen Oxides<br>(NOx) | SELECTIVE NON-CATALYTIC REDUCTION<br>(SNCR)                                 | 80                  | РРМ            | @12% CO2, 8-HR<br>ROLLING AVG      | BACT-PSD         | 50.75               | LB/H          | 8-HR ROLLING AVG                              | 0                    |                         |                            |
| CA-1225  | SIERRA PACIFIC INDUSTRIES-ANDERSON<br>DIVISION | SIERRA PACIFIC INDUSTRIES                     | CA       | SAC 12-01                | 321113 | 04/25/2014 ACT | 31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY   | STOKER BOILER<br>(NORMAL<br>OPERATION)                               | BIOMASS                          | 468      | MMBTU/H  | Nitrogen Oxides<br>(NOx) | SNCR  | 0.13                | lb/MMBTU       | 12-MONTH<br>ROLLING BASIS          | BACT-PSD         | 0.15                | lb/MMBTU      | 3-HOUR BLOCK<br>AVERAGE                       | 0                    |                         |                            |
| CA-1225  | SIERRA PACIFIC INDUSTRIES-ANDERSON<br>DIVISION | SIERRA PACIFIC INDUSTRIES                     | CA       | SAC 12-01                | 321113 | 04/25/2014 ACT | 31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY   | STOKER BOILER<br>(STARTUP &<br>SHUTDOWN<br>PERIODS)                  | BIOMASS                          | 468      | MMBTU/H  | Nitrogen Oxides<br>(NOx) | SNCR  | 70.2                | LB/H           | 8-HR AVG<br>(STARTUP<br>PERIODS)   | BACT-PSD         | 70.2                | LB/H          | 8-HR AVG<br>(SHUTDOWN<br>PERIODS)             | 0                    |                         |                            |
| CT-0156  | MONTVILLE POWER LLC                            | NRG ENERGY                                    | СТ       | 107-0056                 | 221119 | 04/06/2010 ACT | 43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED<br>NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL<br>CAPACITY FACTOR)   | 42 MW Biomass<br>utility boiler                                      | Clean wood                       | 600      | MMBTU/H  | Nitrogen Oxides<br>(NOx) | Regenerative SCR  | 0.06                | LB/MMBTU       | 24 HR BLOCK                        | LAER             | 0                   |               |   | 0                    |                         |                            |
| CT-0162  | PLAINFIELD RENEWABLE ENERGY, LLC               | PLAINFIELD RENEWABLE ENERGY, LLC              | СТ       | 145-0049                 | 221119 | 12/29/2010 ACT | 37.5 MW Biomass Power Plant  | Fluidized Bed<br>Gasification  | Wood                             | 523.1    | MMBtu/hr | Nitrogen Oxides<br>(NOx) | SNCR  | 0.075               | LB/MMBTU       |                                    | LAER             | 45.3                | PPMVD @7% O2  | 24 HR BLOCK                                   | 0                    |                         |                            |
| GA-0141  | WARREN COUNTY BIOMASS ENERGY<br>FACILITY       | OGETHORPE POWER CORPERATION                   | GA       | 4911-301-0016-P-<br>01-0 | 221119 | 12/17/2010 ACT | The proposed project will include: a bubbling fluidized bed boiler<br>with a maximum total heat input capacity of 1,399 MMBTU/H, 2 fire<br>water pump emergency engines; a raw material handling & storage<br>area; a sorbent storage silo; a boiler bed sand silo, a sand day | Boiler, Biomass<br>Wood  | Biomass<br>wood                  | 100      | MW       | Nitrogen Oxides<br>(NOx) | Selective non-catalytic reduction system<br>(SNCR)                          | 0.1                 | LB/MMBTU       | 30 D ROLLING AV /<br>CONDITION 2.9 | BACT-PSD         | 648                 | TONS          | 12 MONTH<br>ROLLING TOTAL /<br>CONDITION 2.18 | 0                    |                         |                            |
| *KS-0034 | ABENGOA BIOENERGY BIOMASS OF KANSAS<br>(ABBK)  | ABENGOA BIOENERGY BIOMASS OF KANSAS<br>(ABBK) | KS       | C-11396                  | 325193 | 05/27/2014 ACT | Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and<br>operate a biomass-to-ethanol and biomass-to-energy production<br>facility near Hugoton, Kansas.   | biomass to<br>energy<br>cogeneration<br>bioler                       | different<br>types of<br>biomass | 500      | MMBtu/hr | Nitrogen Oxides<br>(NOx) | Selective Catalytic Reduction System (SCR)<br>and an over-fire system (OFA) | 0.3                 | LB/MMBTU       | 30-DAY ROLLING,<br>INCLUDES SSM    | BACT-PSD         | 157.5               | LB/HR         | 1-HR AVE,<br>INCLUDES SSM                     | 0                    |                         |                            |
| ME-0037  | VERSO BUCKSPORT LLC                            | VERSO BUCKSPORT LLC                           | ME       | A-22-77-4-A              | 322121 | 11/29/2010 ACT | Existing pulp (groundwood and thermomechanical) and paper<br>making facility.  | Biomass Boiler 8   | Biomass                          | 814      | MMBTU/H  | Nitrogen Oxides<br>(NOx) | SNCR  | 0.15                | LB/MMBTU       | 30 DAY ROLLING                     | BACT-PSD         | 244.2               | LB/H          |   | 0                    |                         |                            |

#### Boise White Paper LLC Regional Haze "Effectively Controlled" Source Scenario Comparison Analysis Attachment C: Hog Fuel Boiler SO2 RBLC Search

Pollutant Name: SO2

#### NOTE: Draft determinations are marked with a " \* " beside the RBLC ID. CASE-BY CASE BASIS FACILITY STATE NAICS CODE Process Name Through-put Emission Limit 1 RBLCID FACILITY NAME CORPORATE OR COMPANY NAM PERMIT NUM PERMIT DATE FACILITY DESCRIPTION Fuel UNITS Pollutant Emission Control Description Avg Time Limits Units 1 BACT-PSD UN BIO MATERIAL COMPANY SUN BIO MATERIAL COMPAN 322110 09/23/2019 ACT A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to AR 384-AOP-R0 wer Boiler 1200 /MBtu/h Sulfur Dioxide (SO2) GD/Dry Sorbent Injection 0.025 LB/MMBTU 3 1-HOUR TEST mass 04/06/2010 ACT 43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED MONTVILLE POWER LLC BACT-PSD 3 HR BLOCK CT-0156 NRG ENERGY MMBTU/H Sulfur Oxides (SOx) СТ 107-0056 221119 42 MW Biomass ean woo 600 Low sulfur fuels 0.025 LB/MMBTU NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL tility boiler CAPACITY FACTOR) CT-0162 12/29/2010 ACT 37.5 MW Biomass Power Plant OTHER CASI BY-CASE PLAINFIELD RENEWABLE ENERGY, LLC PLAINFIELD RENEWABLE ENERGY, LLC 221119 Fluidized Bed Gasification MMBtu/hr Sulfur Dioxide (SO2) Spray Dryer, Bed Injection 0.035 LB/MMBTU CT 145-0049 Wood 523.1 WARREN COUNTY BIOMASS ENERGY FACILITY 12/17/2010 ACT The proposed project will include: a bubbling fluidized bed boiler with a maximum total heat input capacity of 1,399 MMBTU/H, 2 fire Wi water pump emergency engines; a raw material handling & storage area; a sorbent storage silo; a boiler bed sand silo, a sand day 05/27/2014 ACT Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and bio operate a biomass-to-ethanol and biomass-to-energy production for the submarke Verse. BACT-PSD GA-0141 OGETHORPE POWER CORPERATION 4911-301-0016-01-0 Boiler, Bion Nood 30 D ROLLING AV / CONDITION 2.12 GA 221119 100 MW Sulfur Oxides (SOx) Dust sorbent injection system 0.01 LB/MMBTU Biomass wood different types of biomass \*KS-0034 ABENGOA BIOENERGY BIOMASS OF KANSAS ABENGOA BIOENERGY BIOMASS OF KANSA KS C-11396 325193 500 ulfur Dioxide (SO2 Injection of sorbent (lime) in combination with a dry flue gas desulfurization (FGD) 0.21 LB/MMI 30-DAY ROLLING, INCLUDES SSM BACT-PSD iomass to BBK) nergy acility near Hugoton. Kansas. eneration 05/09/2011 ACT KRAFT PULP MILL WHICH PRODUCES UNBLEACHED LINERBOA HOURLY LA-0249 RED RIVER MILL FERNATIONAL PAPER CO 322130 MMBTU/H Sulfur Dioxide (SO2) USE OF LOW SULFUR FUELS BACT-PSD LA D-LA-562(M-HOGGED 992.43 LB/H O. 2 HOGGED JEL BOILER 60 UEL/BAR VERSO BUCKSPORT LLC VERSO BUCKSPORT LLC 11/29/2010 ACT Existing pulp (groundwood and thermomechanical) and paper making facility. 0.7% sulfur when firing oil BACT-PSD ME 0027 ME A-22-77-4-A 322121 814 MMBTU/H Sulfur Dioxide (SO2) 0.8 LB/MMBTU 3-HR AVERAGE Biomass nass Boiler

| 8Y-<br>5 | Emission<br>Limit 2 | Limits Units2 | Avg Time2   | Standard<br>Emission<br>Limit | Standard Limit<br>Units | Standard Limit<br>Avg Time |
|----------|---------------------|---------------|---|-------------------------------|-------------------------|----------------------------|
| Ð        | 0                   |               |   | 0                             |                         |                            |
| D        | 0                   |               |   | 0                             |                         |                            |
| SE-      | 15.4                | PPMVD @7% O2  | 3 HR BLOCK  | 0                             |                         |                            |
| D        | 56                  | TONS          | 12 MONTH<br>ROLLING TOTAL /<br>CONDITION 2.20     | 0                             |                         |                            |
| D        | 110.25              | LB/HR         | MAX 1-HR,<br>INCLUDES SS,<br>EXCLUDES<br>MALFUNCT | 0                             |                         |                            |
| D        | 262.8               | T/YR          | ANNUAL<br>MAXIMUM                                 | 0.06                          | LB/MMBTU                |                            |
| D        | 651.2               | LB/H          |   | 0                             |                         |                            |

# Appendix A.2

Regional Haze Correspondence with Hassan Bouchareb

Dated May 29, 2020

------ Original message ------From: "Bouchareb, Hassan (MPCA)" <<u>hassan.bouchareb@state.mn.us</u>> Date: 5/29/20 12:12 PM (GMT-06:00) To: "Huziak, Kara" <<u>KaraHuziak@BoisePaper.com</u>> Cc: "Rein, Patrick" <<u>PatrickRein@boisepaper.com</u>> Subject: [EXTERNAL] RE: Regional Haze Request - NOx question

Ms. Huziak,

Thank you for providing this information. Based on this information and information included in your request, I agree that the recovery furnace and boiler #2 qualify as effectively controlled and Boise White Paper does not need to conduct a four factor analysis for those emission units as requested in the January 29, 2020 RFI letter. Please note that I may have additional questions for you regarding these units as I work on preparing Minnesota's regional haze SIP; potentially in describing the units and expected operations for various portions of the regional haze rules.

I have one request for you that would be helpful for me. Eventually, I will be working to post the collection of fourfactor analyses and facility responses to the MPCA's external website to facilitate review by interested, external folks. Would you please include your request to withdraw the four factor analysis for the recovery furnace and boiler #2 with your response to the RFI letter for Boiler #1?

It would be helpful to have everything in one package so I can provide it to our publication/web support teams when we get to that point.

Please let me know if you have any questions.

Thank you!

Hassan M. Bouchareb | Engineer Minnesota Pollution Control Agency (MPCA) Office: (651) 757-2653 | Fax: (651) 296-8324 Pronouns: he/him/his Hassan.Bouchareb@state.mn.us | www.pca.state.mn.us

NOTICE: This email (including attachments) is covered by the Electronic Communications Privacy Act, 18 U.S.C. 2510-2521. This email may be confidential and may be legally privileged. If you are not the intended recipient, you are hereby notified that any retention, dissemination, distribution, or copying of this communication is strictly prohibited. Please reply back to the sender that you have received this message in error, then delete it. Thank you.

From: Huziak, Kara <<u>KaraHuziak@BoisePaper.com</u>>
Sent: Thursday, May 21, 2020 3:45 PM
To: Bouchareb, Hassan (MPCA) <<u>hassan.bouchareb@state.mn.us</u>>
Subject: Regional Haze Request - NOx question

Mr. Bouchareb,

Thank you for the update. Regarding the history of the BACT analysis for the Recovery Furnace, we've prepared the following table which provides the history of the permitting for the Recovery Furnace with a focus on the NO<sub>x</sub> emissions limit changes. It is important to note that the existing permit limit (*110*)

*lbs/hour using 30-day Rolling Average; This is equivalent to 80 ppm on a dry basis, corrected to 8% oxygen*) is the result of a BACT analysis. It is also important to note that the Recovery Furnace utilizes a two-stage tertiary air system (i.e., quaternary overfire air) which is the control system listed as BACT in the RBLC and in Sappi's 2017 major air permit amendment (<u>Air Permit Number 01700002-101</u> – see the BACT analysis in Section 3.3.3 of the TSD).

| Permit # | Issued Date | Description  |
|----------|-------------|--|
| 001      | 09/1990     | <ul> <li>The NO<sub>x</sub> permit limit in the first Title V permit was:</li> <li>Nitrogen Oxides: less than or equal to 86.9 lbs/hour using 30-day Rolling<br/>Average. This is equivalent to 80 ppm on a dry basis, corrected to 8% oxygen.</li> <li>Title I Condition: 40 CFR Section 52.21 (modeling and netting); Minn. R.<br/>7007.3000</li> </ul>  |
| 003      | 10/2000     | <ul> <li>This permit was for the Efficiency Improvement Project which was permitted under PSD. The TSD describes the NO<sub>x</sub> limit as follows:</li> <li>NO<sub>x</sub> limit increased from 86.9 to 94.5 lbs/hour and identified as BACT limit; the previous limit was not a BACT limit. Although the NO<sub>x</sub> limit on this emission unit has been increased, the NO<sub>x</sub> emission cap for the facility has not been increased. The NO<sub>x</sub> emission rate on a pound per ton of black liquor solids basis is the same as what it was previously, but since the black liquor production will be increasing, the lbs/hour emission rate will increase.</li> <li>The permit limit was listed as follows: <ul> <li>Nitrogen Oxides: less than or equal to 94.5 lbs/hour using 30-day Rolling Average.</li> <li>Title I Condition: 40 CFR Section 52.21(j) (BACT limit); Minn. R. 7007.3000</li> </ul> </li> </ul>                |
| 006      | 11/2004     | <ul> <li>This permit amendment included an increase in the NO<sub>x</sub> emission limit for the Recovery Furnace. The NO<sub>x</sub> emission limit increase was based on an update to the NO<sub>x</sub> BACT analysis because the existing permit limit was a BACT limit. The permit limit was listed as follows: <ul> <li>Nitrogen Oxides: less than or equal to 102 lbs/hour using 30-day Rolling Average. This is equivalent to 80 ppm on a dry basis, corrected to 8% oxygen.</li> <li>Title I Condition: 40 CFR Section 52.21(j) (BACT limit); Minn. R. 7007.3000</li> </ul> </li> </ul>   |
| 009      | 10/2008     | <ul> <li>This permit amendment included increase to the Total Facility black liquor solids (BLS) production limit from 41,000 to 44,200 tons/month and the NO<sub>x</sub> emission limit. The permit amendment also increased the NO<sub>x</sub> emission limit which included an update to the NO<sub>x</sub> BACT analysis because the existing permit limit was a BACT limit. As described in the TSD, <i>"the requested NOx and CO emission limits increase is necessary to maintain the mass emission limits (lb/hr) in proper proportion to the maximum permitted annual BLS rate"</i> (Air Permit 07100002-009 – see page 16 of the TSD). The permit limit was listed as follows:</li> <li>Nitrogen Oxides: less than or equal to 110 lbs/hour using 30-day Rolling Average. This is equivalent to 80 ppm on a dry basis, corrected to 8% oxygen.</li> <li>Title I Condition: 40 CFR Section 52.21(j) (BACT limit); Minn. R. 7007.3000</li> </ul> |
| 010      | 03/2009     | This Major Amendment was requested by the facility to allow for the blending of distillate oil (#1 and #2) with the black liquor solids (BLS) to provide the facility with additional fuel flexibility for the Recovery Furnace (Emission Unit 320). However, there was no change to the NO <sub>x</sub> emission limit.   |

| 014 | 06/2017 | This permit action is the reissuance of the Part 70 operating permit. In addition to the reissuance, a major permit amendment was incorporated into the permit to increase the total facility BLS production limit from 44,200 to 46,410 tons per month using a 12-month rolling average. However, the facility did not request a change to the NO <sub>X</sub> emission limit. |
|-----|---------|---|
| 101 | 04/2020 | This permit action is a Major Amendment for an increase in BLS throughput to $49,890$ tons/month. However, the facility did not request a change to the NO <sub>x</sub> emission limit.   |

Please let me know if you have questions or need additional assistance for your review.

Thank you,

Kara Huziak

Environmental, Air 400 2<sup>nd</sup> Street International Falls, MN 56649

218.285.5449 Office 218.417.0624 Cell



From: Bouchareb, Hassan (MPCA) <<u>hassan.bouchareb@state.mn.us</u>>
Sent: Wednesday, May 20, 2020 2:12 PM
To: Huziak, Kara <<u>KaraHuziak@BoisePaper.com</u>>
Cc: Rein, Patrick <<u>PatrickRein@boisepaper.com</u>>
Subject: [EXTERNAL] RE: Regional Haze Request

Hello Kara,

Thanks for your patience so far! I'm currently reviewing your request and so far it looks like we'll likely be able to grant the request. One thing you could help me with is the history of the BACT analysis for the Recovery Furnace (i.e., when it was first completed, updates since then, etc.). I was looking through the previous permits for Boise and I noticed the lb/hr NO<sub>X</sub> values have changed while the equivalent ppm concentration has remained the same. From my review so far, it looks like that is due to production/capacity increases that allowed the furnace to process more BLS but it would be helpful if you could provide the history of the changes to help clarify how the ppm value from the previous BACT analysis has remained while the hourly emission rates have increased.

Additionally, It's not clear to me if controls are implemented to allow Boise to meet these NO<sub>x</sub> limits or if it is managed through other methods. I see that CEMS are used to demonstrate compliance with the limits, but if you could help clarify what, if any, controls are implemented for NO<sub>x</sub> that would be helpful as well.

Let me know if you have any questions.

Thanks again!

Hassan M. Bouchareb | Engineer Minnesota Pollution Control Agency (MPCA) Office: (651) 757-2653 | Fax: (651) 296-8324 Pronouns: he/him/his Hassan.Bouchareb@state.mn.us | www.pca.state.mn.us

NOTICE: This email (including attachments) is covered by the Electronic Communications Privacy Act, 18 U.S.C. 2510-2521. This email may be confidential and may be legally privileged. If you are not the intended recipient, you are hereby notified that any retention, dissemination, distribution, or copying of this communication is strictly prohibited. Please reply back to the sender that you have received this message in error, then delete it. Thank you.

From: Huziak, Kara <<u>KaraHuziak@BoisePaper.com</u>> Sent: Wednesday, May 20, 2020 9:09 AM To: Bouchareb, Hassan (MPCA) <<u>hassan.bouchareb@state.mn.us</u>> Cc: Rein, Patrick <<u>PatrickRein@boisepaper.com</u>> Subject: RE: Regional Haze Request

This message may be from an external email source. Do not select links or open attachments unless verified. Report all suspicious emails to Minnesota IT Services Security Operations Center.

Hello Mr. Bouchareb,

I am writing to follow up on our recent 4-Factor analysis request. Do you have any questions or require clarification regarding the request? We are happy to meet with you by phone to discuss further.

Thank you,

Kara Huziak

Environmental, Air 400 2<sup>nd</sup> Street International Falls, MN 56649

218.285.5449 Office 218.417.0624 Cell



From: Huziak, Kara
Sent: Tuesday, May 12, 2020 12:36 PM
To: Hassan.Bouchareb@State.mn.us
Cc: Rein, Patrick <<u>PatrickRein@boisepaper.com</u>>
Subject: Regional Haze Request

Mr. Bouchareb,

Please find attached a digital copy of a letter mailed to your attention requesting further consideration for EQUI 09 and EQUI 16 at the International Falls, MN (Air Permit 07100002-101, agency interest #443).

We look forward to discussing this request with you.

Thank you,

Kara Huziak

Environmental, Air 400 2<sup>nd</sup> Street International Falls, MN 56649

218.285.5449 Office 218.417.0624 Cell



# Appendix B

RACT/BACT/LAER Clearinghouse (RBLC) Review

Summary for Natural Gas Boilers for NO<sub>X</sub>

# Boise White Paper LLC Appendix B: Natural Gas Boiler NOx RBLC Search

Pollutant Name: NOx NOTE: Draft determinations are marked with a " \* " beside the RBLC ID.

| RBLCID   | FACILITY NAME                                  | CORPORATE OR COMPANY<br>NAME           | FACILITY<br>STATE | PERMIT NUM              | NAICS<br>CODE | PERMIT DATE    | FACILITY DESCRIPTION  | Process<br>Name  | Fuel                    | Through-<br>put | UNITS                    | Pollutant                | Emission Control Description   | Emission<br>Limit 1 | Limits Units 1 | Avg Time   | CASE-BY-<br>CASE<br>BASIS | Emission<br>Limit 2 | Limits Units2         | Avg Time2                                    | Standard<br>Emission<br>Limit | Standard Limit<br>Units | Standard Limit<br>Avg Time |
|----------|--|--|-------------------|-------------------------|---------------|----------------|---|--|-------------------------|-----------------|--------------------------|--------------------------|--|---------------------|----------------|--|---------------------------|---------------------|-----------------------|--|-------------------------------|-------------------------|----------------------------|
| VA-0328  | C4GT, LLC                                      | NOVI ENERGY                            | VA                | 52588                   | 221112        | 04/26/2018 ACT | Natural gas-fired combined cycle power plant  | Auxiliary Boiler   | Natural Gas             | 902             | mmcf/y                   | Nitrogen Oxides<br>(NOx) | Low NOx burners  | 0.011               | LB/MMBTU       | CORRECTED TO 3%<br>O2                            | BACT-PSD                  | 1.2                 | LB/H                  |  | 0                             |                         |                            |
| TN-0162  | JOHNSONVILLE COGENERATION                      | TENNESSEE VALLEY AUTHORITY             | TN                | 970816F                 | 221112        | 04/19/2016 ACT | Existing gas-fired combustion turbine with new heat recovery steam<br>generator (HRSG) with duct burner and two new gas-fired auxiliary<br>boilers.   | Two Natural Gas-<br>Fired Auxiliary<br>Boilers             | Natural Gas             | 450             | MMBtu/hr                 | Nitrogen Oxides<br>(NOx) | Good combustion design and practices,<br>selective catalytic reduction (SCR), low-NOX<br>burners with flue gas recirculation                       | 0.013               | LB/MMBTU       |  | BACT-PSD                  | 0                   |                       |  | 0                             |                         |                            |
| TX-0576  | PIPE MANUFACTURING STEEL MINI MILL             | TPCO AMERICA INC                       | ТХ                | PSDTX1188 AND<br>86860  | 331513        | 04/19/2010 ACT | converts scrap steel into seamless pipe   | vacuum<br>degasser boiler                                  | natural gas             | 40              | MMBTU/H                  | Nitrogen Oxides<br>(NOx) | good combustion practice   | 0.1                 | LB/MMBTU       |  | BACT-PSD                  | 0                   |                       |  | 0                             |                         |                            |
|          | TENASKA PA PARTNERS/WESTMORELAND<br>GEN FAC    | TENASKA PA PARTNERS LLC                | PA                | 65-00990 C/E            | 221112        | 02/12/2016 ACT |   | 245 MMBtu<br>natural gas fired<br>Auxiliary boiler         | Natural Gas             | 1052            | MMscf/yr                 | Nitrogen Oxides<br>(NOx) | Good combustion practices and ULNOx<br>burners   | 0.011               | LB/MMBTU       |  | LAER                      | 9                   | PPMDV @ 15% O2        |  | 0                             |                         |                            |
| LA-0314  | INDORAMA LAKE CHARLES FACILITY                 | INDORAMA VENTURES OLEFINS, LLC         | LA                | PSD-LA-813              | 325199        | 08/03/2016 ACT | modify and restart-up a mothballed facility to produce 1,009 million  | boiler A and B<br>(010 and 011)                            | natural<br>gas/fuel gas | 248             |                          | Nitrogen Oxides<br>(NOx) | good combustion practices; fueled by natural<br>gas or process fuel gas; ULNB (FGR and<br>economizer)  | 0.06                | LB/MM BTU      | THREE ONE-HOUR<br>TEST AVERAGE                   | BACT-PSD                  | 0                   |                       |  | 0                             |                         |                            |
| LA-0314  | INDORAMA LAKE CHARLES FACILITY                 | INDORAMA VENTURES OLEFINS, LLC         | LA                | PSD-LA-813              | 325199        | 08/03/2016 ACT | modify and restart-up a mothballed facility to produce 1,009 million<br>lbs/yr of ethylene  | boiler B-201   | natural<br>gas/fuel gas | 229             | mm btu                   | Nitrogen Oxides<br>(NOx) | good combustion practices; fueled by natural<br>gas or process fuel gas; ULNB (FGR and<br>economizer)  | 0.06                | LB/MM BTU      | THREE ONE-HOUR<br>TEST AVERAGE                   | BACT-PSD                  | 0                   |                       |  | 0                             |                         |                            |
| *TN-0164 | TVA - JOHNSONVILLE COGENERATION                | TENNESSEE VALLEY AUTHORITY             | TN                | 972969                  | 221112        | 02/01/2018 ACT | Combustion turbines and combined cycle plant  | Two Auxiliary<br>Boilers                                   | Natural Gas             | 450             | MMBtu/hr,<br>each boiler | Nitrogen Oxides<br>(NOx) | SCR, low-NOX burners, flue gas recirculation,<br>good combustion design & practices  | 0.013               | LB/MMBTU       | 30-DAY AVG<br>EXCLUDING<br>STARTUP &<br>SHUTDOWN | BACT-PSD                  | 0.2                 | , .                   | 30-DAY AVG,<br>APPLIES AT ALL<br>TIMES       | 0                             |                         |                            |
| OH-0354  | KRATON POLYMERS U.S. LLC                       | KRATON POLYMERS U.S. LLC               | ОН                | P0108853                | 325212        | 01/15/2013 ACT | Thermoplastic elastomer manufacturing facility  | Two 249<br>MMBtu/H<br>boilers                              | Natural Gas             | 249             | MMBtu/H                  | Nitrogen Oxides<br>(NOx) | Low-NOx burners  | 0.12                | LB/MMBTU       | BURNING<br>DISTILLATE OIL                        | N/A                       | 392.83              | T/YR                  |  | 0.1                           | LB/MMBTU                | BURNING NATURAL<br>GAS     |
| AK-0083  | KENAI NITROGEN OPERATIONS                      | AGRIUM U.S. INC.                       | AK                | AQ0083CPT06             | 325311        | 01/06/2015 ACT | The Kenai Nitrogen Operations Facility is located at Mile 21 of the<br>Kenai Spur Highway, near Kenai Alaska. It is classified as a<br>nitrogenous fertilizer manufacturing facility under Standard<br>Industrial Classification code 2873 and under North American             | Three (3)<br>Package Boilers                               | Natural Gas             | 243             | MMBTU/H                  | Nitrogen Oxides<br>(NOx) | Ultra Low NOx Burners  | 0.01                | LB/MMBTU       | 30-DAY AVERAGE                                   | BACT-PSD                  | 0                   |                       |  | 0                             |                         |                            |
| AR-0121  | EL DORADO CHEMICAL COMPANY                     | LSB INDUSTRIES, INC.                   | AR                | 0573-AOP-R16            | 325311        | 11/18/2013 ACT | CHEMICAL MANUFACTURING, INCLUDING NITRIC ACID   | START-UP<br>BOILER   | NATURAL<br>GAS          | 240             | MMBTU/H                  | Nitrogen Oxides<br>(NOx) | LOW NOX BURNERS AND FLUE GAS<br>RECIRCULATION  | 4.32                | LB/H           | ROLLING 3 HOUR<br>AVERAGE                        | BACT-PSD                  | 0.018               | lb/MMBTU              | ROLLING 3 HOUR<br>AVERAGE                    | 0                             |                         |                            |
| IN-0263  | MIDWEST FERTILIZER COMPANY LLC                 | MIDWEST FERTILIZER COMPANY LLC         | IN                | 129-36943-00059         | 325311        | 03/23/2017 ACT | STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY   | NATURAL GAS<br>AUXILIARY<br>BOILERS (EU-<br>012A, EU-012B, | NATURAL<br>GAS          | 218.6           | MMBTU/H                  | Nitrogen Oxides<br>(NOx) | LOW NOX BURNERS WITH FLUE GAS<br>RECIRCULATION AND GOOD COMBUSTION<br>PRACTICES  | 20.4                | LB/MMCF EACH   | 3 HOUR AVERAGE                                   | BACT-PSD                  | 1877.39             | MMCF/12 MONTH<br>EACH | ROLLING AVERAGE                              | 0                             |                         |                            |
| IN-0179  | OHIO VALLEY RESOURCES, LLC                     | OHIO VALLEY RESOURCES, LLC             | IN                | 147-32322-00062         | 325311        | 09/25/2013 ACT | NITROGENOUS FERTILIZER PRODUCTION PLANT   | FOUR (4)<br>NATURAL GAS-<br>FIRED BOILERS                  | NATURAL<br>GAS          | 218             | MMBTU/HR,<br>EACH        | Nitrogen Oxides<br>(NOx) | ULTRA LOW NOX BURNERS FLUE GAS<br>RECIRCULATION  | 20.4                | LB/MMCF        | 24-HR AVERAGE                                    | BACT-PSD                  | 0                   |                       |  | 0                             |                         |                            |
| LA-0272  | AMMONIA PRODUCTION FACILITY                    | DYNO NOBEL LOUISIANA AMMONIA, LLC      | LA                | (225) 219-3417"         | 2873          | 10/08/2012 ACT | 2780 TON PER DAY AMMONIA PRODUCTION FACILITY  | COMMISSIONIN<br>G BOILERS 1 & 2<br>(CB-1 & CB-2)           |                         | 217.5           | MM BTU/HR                | Nitrogen Oxides<br>(NOx) | FLUE GAS RECIRCULATION, LOW NOX<br>BURNERS, AND GOOD COMBUSTION<br>PRACTICES (I.E., PROPER DESIGN OF BURNER<br>AND FIREBOX COMPONENTS; MAINTAINING | 11.92               | LB/H           | HOURLY<br>MAXIMUM                                | BACT-PSD                  | 21.86               |                       | ANNUAL<br>MAXIMUM                            | 0.05                          | LB/MM BTU               | ANNUAL AVERAGE             |
| TX-0811  | LINEAR ALPHA OLEFINS PLANT                     | INEOS OLIGOMERS USA LLC                | ТХ                | 136130 AND N250         | 325110        | 11/03/2016 ACT | Manufactures linear alpha olefins (LAO) from ethylene   | Industrial-Sized<br>Furnaces,<br>Natural Gas-fired         |                         | 217             | MM BTU / H               | Nitrogen Oxides<br>(NOx) | Low-NOX burners and Selective Catalytic<br>Reduction (SCR). Ammonia slip limited to 10<br>ppmv (corrected to 3% O2) on a 1-hr block<br>average.    | 0.006               | LB / MM BTU    | HHV BASIS,<br>ANNUAL AVERAGE                     |                           | 0.014               |                       | HHV BASIS, 1-HR<br>AVERAGE                   | 0                             |                         |                            |
| OH-0374  | GUERNSEY POWER STATION LLC                     | GUERNSEY POWER STATION LLC             | он                | P0122594                | 221112        | 10/23/2017 ACT | 1,650 MW combined cycle combustion turbine electrical generating<br>facility  | Auxiliary Boiler<br>(B001)                                 | Natural gas             | 185             | MMBTU/H                  | Nitrogen Oxides<br>(NOx) | low-NOx burners and flue gas recirculation   | 3.7                 | LB/H           |  | BACT-PSD                  | 9.25                |                       | PER ROLLING 12<br>MONTH PERIOD               | 0.02                          | LB/MMBTU                |                            |
| VA-0325  | GREENSVILLE POWER STATION                      | VIRGINIA ELECTRIC AND POWER COMPANY    | VA                | 52525                   | 221112        |                | The proposed project will be a new, nominal 1,600 MW combined-<br>cycle electrical power generating facility utilizing three combustion<br>turbines each with a duct-fired heat recovery steam generator<br>(HRSG) with a common reheat condensing steam turbine generator      | BOILER (1) AND<br>FUEL GAS                                 | NATURAL<br>GAS          | 185             | MMBTU/HR                 | Nitrogen Oxides<br>(NOx) | ultra low-NO,, burners   | 0.011               | LB/MMBTU       |  | N/A                       | 0                   |                       |  | 0                             |                         |                            |
|          | FILER CITY STATION                             | FILER CITY STATION LIMITED PARTNERSHIP | МІ                | 66-17                   | 221112        | 11/17/2017 ACT | New natural gas combined heat and power plant proposed at<br>existing cogenerating power plant permitted to burn wood, coal and<br>tire derived fuel.   | EUAUXBOILER<br>(Auxiliary boiler)                          | Natural gas             | 182             | MMBTU/H                  | Nitrogen Oxides<br>(NOx) | LNB that incorporate internal (within the<br>burner) FGR and good combustion practices.  | 0.04                | LB/MMBTU       | 30 DAY ROLLING<br>AVERAGE                        | BACT-PSD                  | 0                   |                       |  | 0                             |                         |                            |
| MI-0423  | INDECK NILES, LLC                              | INDECK NILES, LLC                      | MI                | 75-16                   | 221112        | 01/04/2017 ACT | Natural gas combined cycle power plant.   | EUAUXBOILER<br>(Auxiliary Boiler)                          | natural gas             | 182             | MMBTU/H                  | Nitrogen Oxides<br>(NOx) | Low NOx burners/Flue gas recirculation and<br>good combustion practices.   | 0.04                | LB/MMBTU       | 30 DAY ROLLING<br>AVG TIME PERIOD                | BACT-PSD                  | 0                   |                       |  | 0                             |                         |                            |
| TX-0641  | PINECREST ENERGY CENTER                        | PINECREST ENERGY CENTER LLC            | тх                | PSDTX1298               | 221122        | 11/12/2013 ACT | Combinec Cycle Electric Generating Plant  | Auxiliary boiler   | natural gas             | 150             | MMBTU/H                  | Nitrogen Oxides<br>(NOx) | low NOx burners  | 16                  | PPMVD          | INITIAL STACK<br>TEST, 3% OXYGEN                 | BACT-PSD                  | 0                   |                       |  | 0                             |                         |                            |
| TX-0708  | LA PALOMA ENERGY CENTER                        | LA PALOMA ENERGY CENTER, LLC           | ТХ                | 101542<br>PSDTX1288     | 221112        | 02/07/2013 ACT | The proposed project is a new electric power plant, fueled by<br>pipeline quality natural gas. The design of the plant is standard<br>combined cycle (CC) technology.   | boiler   | natural gas             | 150             | MMBTU/H                  | Nitrogen Oxides<br>(NOx) | low-NOx burners, limited use   | 0.02                | LB/MMBTU       | 3-HR ROLLING<br>AVERAGE                          | BACT-PSD                  | 0                   |                       |  | 0                             |                         |                            |
|          | NTE OHIO, LLC                                  |  | ОН                | P0116610                | 221112        | 11/05/2014 ACT | Combined-cycle, natural gas-fired power plant   | Auxiliary Boiler<br>(B001)                                 | Natural gas             | 150             | MMBTU/H                  | Nitrogen Oxides<br>(NOx) | Ultra low NOx burner   | 1.65                | LB/H           |  | BACT-PSD                  | 3.3                 |                       | PER ROLLING 12<br>MONTH PERIOD               | 0.011                         | LB/MMBTU                |                            |
| TX-0712  | TRINIDAD GENERATING FACILITY                   | SOUTHERN POWER COMPANY                 | тх                | 111393<br>PSDTX1368     | 221112        | 11/20/2014 ACT | Southern Power Company (SPC) is proposing to construct an electric<br>generating facility near Trinidad, Henderson County, Texas. The<br>Trinidad Generating Facility (TGF) will include a natural gas-fired<br>combined cycle combustion turbine generator (CTG) equipped with | boiler   | natural gas             | 110             | MMBTU/H                  | Nitrogen Oxides<br>(NOx) | ultra-low NOx burners, limited use   | 9                   | PPMVD          | @15% O2  | BACT-PSD                  | 0                   |                       |  | 0                             |                         |                            |
|          | MOUNDSVILLE COMBINED CYCLE POWER<br>PLANT      | MOUNDSVILLE POWER, LLC                 | wv                | R14-0030                | 221112        | 11/21/2014 ACT | Nominal 549 mW(output) natural gas-fired combined cycle power<br>plant.   | Auxiliary Boiler   | Natural Gas             | 100             | mmBtu/hr                 | Nitrogen Oxides<br>(NOx) | Ultra Low-NOx Burners, Flue-Gas<br>Recirculation, & Good Combustion Practices  | 2                   | LB/H           |  | BACT-PSD                  | 0                   |                       |  | 0.02                          | LB/MMBTU                |                            |
|          | CORPUS CHRISTI TERMINAL CONDENSATE<br>SPLITTER | MAGELLAN PROCESSING LP                 | ТХ                | 118270 AND<br>PSDTX1398 | 324110        | 04/10/2015 ACT |   | Industrial-Size<br>Boilers/Furnaces                        | natural gas             | 0               |                          | Nitrogen Oxides<br>(NOx) | Selective catalytic reduction (SCR)  | 0.006               | LB/MMBTU       | 12-MONTH AVG                                     | BACT-PSD                  | 0.01                | lb/MMBTU              | BLOCK 1-HR AVG                               | 0                             |                         |                            |
|          | STOCKTON COGEN COMPANY                         | APMC STOCKTON COGEN                    | CA                | SJ 85-04                | 221112        |                | PRODUCTS MANUFACTURING CORPORATION (APMC) STOCKTON<br>COGEN AND LOCATED IN STOCKTON, CALIFORNIA   | AUXILIARY<br>BOILER  | NATURAL<br>GAS          | 178             |                          | Nitrogen Oxides<br>(NOx) |  | 7                   | PPMVD          | @3% O2   | BACT-PSD                  | 0.0085              | LB/MMBTU              |  | 0                             |                         |                            |
| CA-1212  | PALMDALE HYBRID POWER PROJECT                  | CITY OF PALMDALE                       | CA                | SE 09-01                | 221112        | 10/18/2011 ACT |   | AUXILIARY<br>BOILER  | NATURAL<br>GAS          | 110             | MMBTU/H                  | Nitrogen Oxides<br>(NOx) |  | 9                   | PPMVD          | @3% O2, 3-HR AVG                                 | i BACT-PSD                | 0                   |                       |  | 0                             |                         |                            |
| OH-0336  | CAMPBELL SOUP COMPANY                          | CAMPBELL SOUP COMPANY                  | ОН                | P0106678                | 311422        | 12/14/2010 ACT | Canned food maufacturing facility.  | Boilers (3)  | Natural Gas             | 0               |                          | Nitrogen Oxides<br>(NOx) |  | 0.04                | LB/MMBTU       | BASED ON MFG.<br>GUARANTEE                       | OTHER CASE-<br>BY-CASE    | 63.08               |                       | ROLLING 12 MO.<br>FROM 3 BOILERS<br>TOGETHER | 0                             |                         |                            |

# Appendix C.1

Boiler #1 Cost Calculations for NO<sub>X</sub> Control (SCR)

# Boise - International Falls, MN #1 Boiler NO<sub>x</sub> SNCR Calculations

|                               |             | Boiler 1                 | Comment                                     |
|-------------------------------|-------------|--------------------------|---|
| Max                           | 398         | MMBtu/hr                 | PTE Calculations for Boiler 1.              |
| Firing Rate                   |             |                          |   |
| NO <sub>x</sub> Emission Rate | 0.1310      | lb/MMBtu                 | Air emission inventory (see "Data Inputs")  |
| (Uncontrolled)                |             |                          |   |
| NO <sub>x</sub> Controls      | 0.0622      | lb/MMBtu                 | Target (see "Data Inputs")                  |
| Emission Rate                 |             |                          |   |
| System Capacity Factor        |             | 39.8%                    | Actual fuel per year / Maxium fuel per year |
| (Actuall rate vs. max         |             |                          | (See "SNCR Design Parameters")              |
| firing rate at 8760)          |             |                          |   |
|                               |             |                          |   |
| Uncontrolled                  | 90.9        | ton/year                 | Calculated from Above                       |
| Emissions                     |             |                          |   |
| Control                       |             | 53%                      | Based on target emission rate above         |
| Efficiency                    |             |                          | (mid-point of pulp and paper in Table 1.2)  |
| Controlled                    | 43.2        | ton/year                 | Calculated from Above                       |
| Emissions                     |             |                          |   |
| Total Capital Investment      | \$ <i>.</i> | 4,228,677                | From "Cost Estimate"                        |
| (TCI)                         |             |                          |   |
|                               |             |                          |   |
| Total Annual Cost (TAC)       | \$475,742   | per year in 2020 dollars | From "Cost Estimate"                        |
| =                             |             |                          |   |
| NOx Removed =                 | 47.7        | tons/year                | From "Cost Estimate"                        |
| Cost Effectiveness =          | \$9,969     | per ton of NOx removed   | From "Cost Estimate"                        |
|                               |             | in 2020 dollars          |   |
|                               |             |                          |   |

| Data Inputs  |  |  |  |  |  |  |  |  |  |  |
|--|--|--|--|--|--|--|--|--|--|--|
| Enter the following data for your combustion unit:   |  |  |  |  |  |  |  |  |  |  |
| Is the combustion unit a utility or industrial boiler?   | Industrial   | What type of fuel does the unit burn?  |  |  |  |  |  |  |  |  |
| Is the SNCR for a new boiler or retrofit of an existing boiler?  | trofit   |  |  |  |  |  |  |  |  |  |
| Please enter a retrofit factor equal to or greater than 0.84 based on difficulty. Enter 1 for projects of average retrofit difficulty.   | the level of 1.6   |  |  |  |  |  |  |  |  |  |
| Complete all of the highlighted data fields:   |  |  |  |  |  |  |  |  |  |  |
|  | 200.0 10101 //   |  |  |  |  |  |  |  |  |  |
| What is the maximum heat input rate (QB)?  | 398.0 MMBtu/hour   | Type of coal burned: Not Applicable  |  |  |  |  |  |  |  |  |
| What is the higher heating value (HHV) of the fuel?  | 1,020 Btu/scf  | Enter the sulfur content (%S) = percent by weight  |  |  |  |  |  |  |  |  |
| What is the estimated actual annual fuel consumption?<br>Is the boiler a fluid-bed boiler?   | 1,414,842,703 scf/year   | Ash content (%Ash):  |  |  |  |  |  |  |  |  |
|  |  | Not applicable to units buring fuel oil or natural gas   |  |  |  |  |  |  |  |  |
| Enter the net plant heat input rate (NPHR)   | 8.2 MMBtu/MW   | 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.  |  |  |  |  |  |  |  |  |
| If the NPHR is not known, use the default NPHR value:  | Fuel TypeDefault NPHRCoal10 MMBtu/MWFuel Oil11 MMBtu/MWNatural Gas8.2 MMBtu/MW   | Fraction in<br>Coal Blend%S%AshHHV (Btu/lb)Fuel Cost<br>(\$/MMBtu)Bituminous01.849.2311,8412.4Sub-Bituminous00.415.848,8261.89Lignite00.8213.66,6261.74Please click the calculate button to calculate weighted<br>values based on the data in the table above.   |  |  |  |  |  |  |  |  |
| What is the maximum heat input rate (QB)?<br>What is the higher heating value (HHV) of the fuel?<br>What is the estimated actual annual fuel consumption?<br>Is the boiler a fluid-bed boiler?<br>Enter the net plant heat input rate (NPHR) | 1,414,842,703       scf/year         No          8.2       MMBtu/MW         Fuel Type       Default NPHR         Coal       10 MMBtu/MW         Fuel Oil       11 MMBtu/MW | or<br>Select the appropriate SO <sub>2</sub> emission rate:<br>Ash content (%Ash):<br>Percent by weight<br>Not applicable to units buring fuel oil or natural gas<br>Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please<br>enter the actual values for these parameters in the table below. If the actual value for any<br>parameter is not known, you may use the default values provided.<br>Fraction in Koal State Sta |  |  |  |  |  |  |  |  |

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates  $(t_{SNCR})$ 

351 days

Plant Elevation

1129 Feet above sea level

| Inlet NO <sub>x</sub> Emissions (NOx <sub>in</sub> ) to SNCR    | 0.131 lb/MMBtu        |  |
|---|-----------------------|--|
| Oulet NO <sub>x</sub> Emissions (NOx <sub>out</sub> ) from SNCR | 0.06 lb/MMBtu         | ]  |
| Estimated Normalized Stoichiometric Ratio (NSR)                 | 1.22                  | *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 <sub>stored</sub> )       | 50 Percent            | 1  |
| Density of reagent as stored ( $\rho_{stored}$ )                | 71 lb/ft <sup>3</sup> |  |
| Concentration of reagent injected (C <sub>inj</sub> )           | 50 percent            | Densities of typical SNCR reagents:  |
| Number of days reagent is stored (t <sub>storage</sub> )        | 14 days               | 50% urea solution 71 lbs/ft <sup>3</sup>   |
| Estimated equipment life  | 20 Years              | 29.4% aqueous $NH_3$ 56 $Ibs/ft^3$   |
|   |                       |  |
| Select the reagent used   | Urea 🔻                |  |

#### Enter the cost data for the proposed SNCR:

| Desired dollar-year<br>CEPCI for 2020   | 2020           592.1         Enter the CEPCI value for 2020         541.7         2016 CEPCI                                 | CEPCI = Chemical Engineering Plant Cost Index   |
|---|--|---|
| Annual Interest Rate (i)<br>Fuel (Cost <sub>fuel</sub> )  | 5.5     Percent*       2.13     \$/MMBtu   | * 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at<br>https://www.federalreserve.gov/releases/h15/.) |
| Reagent (Cost <sub>reag</sub> )<br>Water (Cost <sub>water</sub> )<br>Electricity (Cost <sub>elect</sub> ) | 1.81         \$/gallon for a 50 percent solution of urea           0.0051         \$/gallon           0.0676         \$/kWh* | _   |
| Ash Disposal (for coal-fired boilers only) ( $Cost_{ash}$ )   | \$/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) = Administrative Charges Factor (ACF) =



#### Data Sources for Default Values Used in Calculations:

|                          |                  |  | If you used your own site-specific values, please enter the value used |
|--------------------------|------------------|--|--|
| Data Element             | Default Value    | Sources for Default Value  | and the reference source   |
| Reagent Cost (\$/gallon) | \$1.66/gallon of | U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector   |  |
|                          | 50% urea         | Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and |  |
|                          | solution         | Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5,    |  |
|                          |                  | Attachment 5-4, January 2017. Available at:  |  |
|                          |                  | https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-         |  |
|                          |                  | 4_sncr_cost_development_methodology.pdf.   |  |

| 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 http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf. |                |
|--|---------|---|----------------|
| Electricity Cost (\$/kWh)                  | 0.0676  | U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published<br>December 2017. Available at:<br>https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.   |                |
| Fuel Cost (\$/MMBtu)                       | 2.87    | U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4.<br>Published December 2017. Available at:<br>https://www.eia.gov/electricity/annual/pdf/epa.pdf.   |                |
| Ash Disposal Cost (\$/ton)                 | -       | Not applicable  | Not Applicable |
| Percent sulfur content for Coal (% weight) |         | Not applicable  | Not Applicable |
| Percent ash content for Coal (% weight)    |         | Not applicable  | Not Applicable |
| Higher Heating Value (HHV) (Btu/lb)        | 1,033   | 2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S.<br>Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power<br>Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.           |                |
| Interest Rate (%)                          | 5.5     | Default bank prime rate   |                |

## **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 <sub>B</sub> ) =         | HHV x Max. Fuel Rate =   | 398              | MMBtu/hour |   |
| Maximum Annual fuel consumption (mfuel) =                  | (QB x 1.0E6 Btu/MMBtu x 8760)/HHV =  | 3,418,117,647    | scf/year   |   |
| Actual Annual fuel consumption (Mactual) =                 |  | 1,414,842,703    | scf/year   |   |
| Heat Rate Factor (HRF) =                                   | NPHR/10 =  | 0.82             |            |   |
| Total System Capacity Factor (CF <sub>total</sub> ) =      | (Mactual/Mfuel) x (tSNCR/365) =  | 0.40             | fraction   |   |
| Total operating time for the SNCR $(t_{op})$ =             | CF <sub>total</sub> x 8760 =   | 3487             | hours      |   |
| NOx Removal Efficiency (EF) =                              | (NOx <sub>in</sub> - NOx <sub>out</sub> )/NOx <sub>in</sub> =  | 53               | percent    |   |
| NOx removed per hour =                                     | $NOx_{in} \times EF \times Q_B =$  | 27.37            | lb/hour    |   |
| Total NO <sub>x</sub> removed per year =                   | (NOx <sub>in</sub> x EF x Q <sub>B</sub> x t <sub>op</sub> )/2000 =                                    | 47.72            | 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) |                  |            | Not applicable; factor applies only to coal-<br>fired boilers |
| SO <sub>2</sub> Emission rate =                            | (%S/100)x(64/32)*(1x10 <sup>6</sup> )/HHV =  |                  |            | Not applicable; factor applies only to coal-<br>fired boilers |
| Elevation Factor (ELEVF) =                                 | 14.7 psia/P =  | 1.04             |            |   |
| Atmospheric pressure at 1129 feet above sea level<br>(P) = | 2116x[(59-(0.00356xh)+459.7)/518.6] <sup>5.256</sup> x (1/144)*<br>=                                   | 14.1             | psia       |   |
| Retrofit Factor (RF) =                                     | Retrofit to existing boiler  | 1.60             |            |   |

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at

Urea

https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

#### Reagent Data:

Type of reagent used

60.06 g/mole Molecular Weight of Reagent (MW) = Density =

71 lb/gallon

| Parameter  | Equation  | Calculated Value | Units   |
|--|---|------------------|---|
| Reagent consumption rate (m <sub>reagent</sub> ) = | $(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR) =$     | 42               | lb/hour   |
|  | (whre SR = 1 for $NH_3$ ; 2 for Urea)                                     |                  |   |
| Reagent Usage Rate (m <sub>sol</sub> ) =           | $m_{reagent}/C_{sol} =$   | 83               | lb/hour   |
|  | (m <sub>sol</sub> x 7.4805)/Reagent Density =                             | 8.7              | gal/hour  |
| Estimated tank volume for reagent storage =        | (m <sub>sol</sub> x 7.4805 x t <sub>storage</sub> x 24 hours/day)/Reagent | 2 000            | gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons) |
|  | Density =   | 3,000            | rounded up to the nearest 100 gallons)  |

### **Capital Recovery Factor:**

| Parameter                       | Equation                                      | Calculated Value |
|---------------------------------|---|------------------|
| Capital Recovery Factor (CRF) = | $i(1+i)^{n}/(1+i)^{n} - 1 =$                  | 0.0837           |
|                                 | Where n = Equipment Life and i= Interest Rate |                  |

| Parameter   | Equation  | Calculated Value | Units        |               |
|---|---|------------------|--------------|---------------|
| Electricity Usage:  |   |                  |              |               |
| Electricity Consumption (P) =   | (0.47 x NOx <sub>in</sub> x NSR x Q <sub>B</sub> )/NPHR =         | 3.6              | kW/hour      |               |
| Water Usage:  |   |                  |              |               |
| Nater consumption (q <sub>w</sub> ) =                                       | ( $m_{sol}$ /Density of water) x (( $C_{stored}/C_{inj}$ ) - 1) = | 0                | gallons/hour |               |
| Fuel Data:  |   |                  |              |               |
| Additional Fuel required to evaporate water in<br>njected reagent (ΔFuel) = | Hv x $m_{reagent}$ x ((1/ $C_{inj}$ )-1) =                        | 0.04             | MMBtu/hour   |               |
|   |   |                  |              | _             |
| Ash Disposal:<br>Additional ash produced due to increased fuel              |   |                  |              | Not applicab  |
| consumption ( $\Delta$ ash) =   | $(\Delta fuel x \% Ash x 1x10^{6})/HHV =$                         | 0.0              | llh/hour     | to coal-fired |
| consumption ( $\Delta ash$ ) =  | (Δtuel x %Ash x 1x10°)/HHV =                                      | 0.0              | nour/di      | to            |

Iot applicable - Ash disposal cost applies only o coal-fired boilers

## **Cost Estimate**

## Total Capital Investment (TCI)

| For Coal-Fired Boilers:   |   |
|---|---|
| For Fuel Oil and Natural Gas-Fired Boilers:   | $TCI = 1.3 x (SNCR_{cost} + APH_{cost} + BOP_{cost})$ |
|   | TCI = $1.3 \times (SNCR_{cost} + BOP_{cost})$         |
|   |   |
|   |   |
| Capital costs for the SNCR (SNCR <sub>cost</sub> ) =  | \$1,257,491 in 2020 dollars                           |
| 1   | \$1,257,491 in 2020 dollars<br>\$0 in 2020 dollars    |
| Capital costs for the SNCR (SNCR <sub>cost</sub> ) =<br>Air Pre-Heater Costs ( $APH_{cost}$ )* =<br>Balance of Plant Costs ( $BOP_{cost}$ ) = |   |

 Total Capital Investment (TCI) =
 \$4,228,677 in 2020 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 <sub>cost</sub> )  |  |  |
|--|---|--|--|
| For Coal-Fired Utility Boilers:  |   |  |  |
| ,<br>SNCR <sub>cost</sub> = 220,000 x ( $B_{MW}$ x HRF) <sup>0.42</sup> x CoalF x BTF x ELEVF x RF |   |  |  |
| For Fuel Oil and Natural Gas-Fired Utility Boil  |   |  |  |
| SI   | $NCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$                             |  |  |
| For Coal-Fired Industrial Boilers:   |   |  |  |
| SNCR <sub>cost</sub> =   | 220,000 x (0.1 x Q <sub>B</sub> x HRF) <sup>0.42</sup> x CoalF x BTF x ELEVF x RF                           |  |  |
| For Fuel Oil and Natural Gas-Fired Industrial  | Boilers:  |  |  |
| SNCI   | R <sub>cost</sub> = 147,000 x ((Q <sub>B</sub> /NPHR)x HRF) <sup>0.42</sup> x ELEVF x RF                    |  |  |
|  |   |  |  |
| SNCR Capital Costs (SNCR <sub>cost</sub> ) =   | \$1,257,491 in 2020 dollars   |  |  |
|  |   |  |  |
|  |   |  |  |
|  | Air Pre-Heater Costs (APH <sub>cost</sub> )*  |  |  |
| For Coal-Fired Utility Boilers:  |   |  |  |
|  | $H_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$                     |  |  |
| For Coal-Fired Industrial Boilers:   | co oco (o t. o. 1107, o. 15 <sup>0,78</sup> , t.15, o.  |  |  |
| APH  | <sub>cost</sub> = 69,000 x (0.1 x Q <sub>B</sub> x HRF x CoalF) <sup>0.78</sup> x AHF x RF                  |  |  |
| Air Pre-Heater Costs (APH <sub>cost</sub> ) =  | \$0 in 2020 dollars   |  |  |
|  | boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of                            |  |  |
| sulfur dioxide.  |   |  |  |
|  | Balance of Plant Costs (BOP <sub>cost</sub> )   |  |  |
| For Coal-Fired Utility Boilers:  |   |  |  |
| •  | = 320,000 x (B <sub>MW</sub> ) <sup>0.33</sup> x (NO <sub>x</sub> Removed/hr) <sup>0.12</sup> x BTF x RF    |  |  |
| For Fuel Oil and Natural Gas-Fired Utility Boil  |   |  |  |
|  | $_{ost} = 213,000 \times (B_{MW})^{0.33} \times (NO_{x} \text{Removed/hr})^{0.12} \times \text{RF}$         |  |  |
| For Coal-Fired Industrial Boilers:   |   |  |  |
|  | 320,000 x (0.1 x Q <sub>B</sub> ) <sup>0.33</sup> x (NO <sub>x</sub> Removed/hr) <sup>0.12</sup> x BTF x RF |  |  |
| For Fuel Oil and Natural Gas-Fired Industrial  |   |  |  |
|  |   |  |  |

 $BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$ 

Balance of Plant Costs (BOP<sub>cost</sub>) =

\$1,995,337 in 2020 dollars

### **Annual Costs**

### **Total Annual Cost (TAC)**

TAC = Direct Annual Costs + Indirect Annual Costs

| Direct Annual Costs (DAC) =           | \$119,899 in 2020 dollars |
|---------------------------------------|---------------------------|
| Indirect Annual Costs (IDAC) =        | \$355,843 in 2020 dollars |
| Total annual costs (TAC) = DAC + IDAC | \$475,742 in 2020 dollars |

### Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

| Annual Maintenance Cost = | 0.015 x TCI =  | \$63,430 in 2020 dollars  |
|---------------------------|--|---------------------------|
| Annual Reagent Cost =     | $q_{sol} x Cost_{reag} x t_{op} =$                             | \$55,332 in 2020 dollars  |
| Annual Electricity Cost = | P x Cost <sub>elect</sub> x t <sub>op</sub> =                  | \$859 in 2020 dollars     |
| Annual Water Cost =       | q <sub>water</sub> x Cost <sub>water</sub> x t <sub>op</sub> = | \$0 in 2020 dollars       |
| Additional Fuel Cost =    | $\Delta$ Fuel x Cost <sub>fuel</sub> x t <sub>op</sub> =       | \$277 in 2020 dollars     |
| Additional Ash Cost =     | $\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$                | \$0 in 2020 dollars       |
| Direct Annual Cost =      |  | \$119,899 in 2020 dollars |

### Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

| Administrative Charges (AC) = | 0.03 x Annual Maintenance Cost = | \$1,903 in 2020 dollars   |
|-------------------------------|----------------------------------|---------------------------|
| Capital Recovery Costs (CR)=  | CRF x TCI =                      | \$353,940 in 2020 dollars |
| Indirect Annual Cost (IDAC) = | AC + CR =                        | \$355,843 in 2020 dollars |

### **Cost Effectiveness**

### Cost Effectiveness = Total Annual Cost/ NOx Removed/year

| Total Annual Cost (TAC) = | \$475,742 per year in 2020 dollars             |
|---------------------------|--|
| NOx Removed =             | 48 tons/year                                   |
| Cost Effectiveness =      | \$9,969 per ton of NOx removed in 2020 dollars |

|   | % Reduction   |            |  |
|---|---------------|------------|--|
| Industry and Units  | Ammonia-Based | Urea-Based |  |
| Cement Kilns  | 12-77         | 25-90      |  |
| Chemical Industry   | NAª           | 35-80      |  |
| Circulating Fluidized and Bubbling Bed Boilers                      | 76–80         | NA         |  |
| Coal, Wood and Tire Fired Industrial and IPP/Co-Generations Boilers | NA            | 20-75      |  |
| Coal-Fired Boilers  | 38-83         | 20-66      |  |
| Gas- and Oil-Fired Industrial Boilers                               | 30–75         | NA         |  |
| Glass Melting Furnaces  | 51–70         | NA         |  |
| Steel Products Industry   | NA            | 42.9-90    |  |
|   |               |            |  |
| Municipal Waste Combustors  | 45-70         | 16–87      |  |
| Oil- and Gas-Fired Heaters  | 45–76         | NA         |  |
| Process Units   | NA            | 40-85      |  |
| Pulp and Paper Industry   | NA            | 20-62      |  |
| Refinery Process Units and Industrial Boilers                       | NA            | 20–75      |  |
| Stoker-Fired and Pulverized Coal-Fired Boilers                      | 50-83         | NA         |  |
| Stoker-Fired Wood-Fueled Boilers                                    | 40–75         | NA         |  |
|   |               |            |  |
| Vapor, Sludge and Hazardous Waste Incinerators                      | 65–91         | NA         |  |

# Table 1.2: SNCR NO<sub>x</sub> Reduction Efficiency by Industry and Reagent Type [2, 4]

<sup>a</sup>NA means not available.

# Appendix C.2

Boiler #1 Cost Calculations for NO<sub>X</sub> Control (LNB with FGR and OFA)

# Low-NOx Burner (LNB) with Flue Gas Recirculation (FGR) and Overfire Air (OFA) Cost Estimate for Boise Paper LLC Jun 23, 2020

As we talked on last Monday with a few assumptions, this is a high level estimate to support your order of magnitude request:

- General comments:
  - With your described emissions requirements we expect need of FGR to obtain the NOx limits. Unit operating data and a study/test could confirm this need.
  - Budget pricing is not an offer to sell.
  - Estimate is based on past work, future interface with sub vendors could be impacted by COVID 19 issues, or other business impacting conditions,
    - Examples, but not limited to (all of which could impact price and lead time)
      - price impacts (raw materials costs, labor rates...),
      - vendors out of business,
      - transportation disruptions,
      - manufacturing disruptions.
  - Asbestos mitigation is not considered in estimate and could be considerable if abatement is necessary.
  - Lead paint abatement is also not considered in estimate and also could be significant impact to cost.
  - Past installations were reviewed to accommodate best installation designs. With description of site and no drawings, budget price could be impacted due to unknown routing/obstructions.
  - No modifications are considered to radiant or convective heating surface or temperature control of final steam conditions.
- Scope boundaries would be:
  - Gas at inlet/outlet to main gas skid (not sure of your gas piping into the mill or capacity)
  - Gas at inlet/outlet to individual burners gas skids
  - Electrical at fan (no supply of electrical- BUS/Breakers wiring to fan, etc.)
  - Controls (no hardware/software for control system). Subs to supply logic for combustion control, and burner management
  - Existing windbox with modifications; repairs to existing windbox are not considered (physical conditions need to be evaluated)
  - FGR fan conceptual ducting (this is a wildcard based on unfamiliar described difficult routing)
- Base scope would typically include:
  - o Engineering
  - T fired burner gas/air buckets/lighters scope
  - Overfire air scope (assume FGR/COFA due to short furnace)
  - Gas skids
    - Main gas header valve train
    - Header vent spool
    - Burner gas valve train (one per burner)
    - Main flame scanners
  - o FGR fan
  - FGR flue/dampers

- Other scope not supplied includes:
  - Field Service.
    - Installation, demolition, field testing, or construction management of the proposed equipment.
    - Load analysis of existing structural steel or any required re-enforcement
    - Engineering, Material, or Installation of any required modifications to existing structural support steel to accommodate new burner access platform addition if required, fan platform, valve rack supports or piping supports.
    - Modifications to the Combustion control system (DCS) software, configuration, review of existing loop diagrams, etc.
    - Modifications to the Combustion control system (DCS) equipment such as IO cards or other hardware necessary for the system to accept the new proposed burner and ignitor equipment.
    - Wiring design or material supply including site specific wiring diagrams, loop sheets, interconnection drawings, raceway layout drawings, wire, conduit, or cable trays.
    - Permits, licenses, and other Governmental Agency permission required to construct and operate the proposed equipment.
    - Spare or replacement parts.
    - Federal, state, or local sales and use taxes.
    - Baseline or Acceptance testing.
    - Damper control logic changes (if required).
    - Fees associated with any onsite approval agencies.
    - Boise Inc. to provide natural gas regulated to approximately 100 to 150 psig to the gas header inlet, with a maximum design pressure of 200 psig.
    - Fuel/Air piping beyond supplied valve racks (piping supply to main header valve rack, piping between valve racks or to/from burners and local valve racks).
    - Vent piping from valve racks to atmosphere.
    - Training Manual & Training.
    - Existing Primary Outlet header (temperature monitoring recommended).
    - Modifications to FD or ID fans.
    - Windbox interior compartment plates, windbox modifications or any repair or refurbishment which will be by others.
- Installation is based on a high level factor estimate and is subject to the above factors.

## Pricing:

- Material \$3.5M (see above)
- Installation \$5M
  - o General mechanical
  - o Electrical
  - o Piping
  - Controls (swag based on no information available to understand existing)

## Schedule:

Based on historic information a typical project span from receipt of order to delivery of equipment could be roughly 40-50 weeks. Thus added time for purchasing process along with staging materials and installation could add approximately 20 -30 weeks.

Other developmental cost typically provided by an Architectural Engineering firm and/or others are not included and could be required to support balance of plant aspects of this project. This could include but is not limited to:

- Controls integration of new equipment (factors of available space in existing electrical system and I/O points in control system for example)
- Stack monitoring equipment or data management systems for new emission reporting
- Structural aspect of new equipment integrated into the existing steel.
- Instrument air requirements as taxed to existing systems
- Existing equipment conditions (integration of new systems into old equipment can require significant investment to improve conditions of existing equipment to support intended integration of the new systems if existing is damaged or modified).

# Boise - International Falls, MN #1 Boiler Table 1: LNB-FGR Summary

|                               |             | Boiler 1                 | Comment                                   |
|-------------------------------|-------------|--------------------------|---|
| Max                           | 398         | MMBtu/hr                 | PTE Calculations for Boiler 1             |
| Firing Rate                   |             |                          |   |
| NO <sub>x</sub> Emission Rate | 0.131       | lb/MMBtu                 | 2019 Air emission inventory (see Table 2) |
| (Uncontrolled)                |             |                          |   |
| NO <sub>x</sub> Controls      | 0.050       | lb/MMBtu                 | Target                                    |
| Emission Rate                 |             |                          |   |
| Utilization Rate              |             | 41.4%                    | 2019 Air emission inventory (see Table 2) |
| Uncontrolled                  | 90.9        | ton/year                 | Calculated from Above                     |
| Emissions                     |             |                          |   |
| Control                       |             | 62%                      | Calculated from Above                     |
| Efficiency                    |             |                          |   |
| Controlled                    | 34.7        | ton/year                 | Calculated from Above                     |
| Emissions                     |             |                          |   |
| Total Capital Investment      | \$1         | 1,144,531                | From Table 3 - NOx Control - LNB with FGR |
| (TCI)                         |             |                          |   |
|                               |             |                          |   |
| Total Annual Cost (TAC)       | \$1,557,544 | per year in 2020 dollars | From Table 3 - NOx Control - LNB with FGR |
| =                             |             |                          |   |
| NOx Removed =                 | 56.2        | tons/year                | Calculated from Above                     |
| Cost Effectiveness =          | \$27,707    | per ton of NOx removed   | Calculated from Above                     |
|                               |             | in 2020 dollars          |   |
|                               |             |                          |   |

# Boise White Paper LLC International Falls, MN Table 2: Summary of Utility, Chemical, and Supply Costs

| Operating Unit:   | Boiler 1      |                            | Study Year | 2020          | Boise International Falls Site Specific Data                         |   |
|---|---------------|----------------------------|------------|---------------|--|---|
|   | EQUI17        |                            | otauj roa. | 2020          | EPA Default Scaled Value or Other Public Source                      |   |
|   | STRU25        |                            |            |               |  | ce  |
| Stack/vent Number   | 2020          |                            |            |               | Other Barr Project (public or not client specific)                   |   |
| ltem  | Unit Cost     | Units                      | Cost       | Year          | Data Source  | Notes   |
| Operating Labor   | 67.53         |                            | 60         | 2016          | EPA SCR Cost Manual Spreadsheet                                      |   |
| Maintenance Labor   | 67.53         |                            |            |               |  | Assumed to be equivalent to operating labor   |
| Installation Labor  | 67.53         |                            |            |               |  | Assumed to be equivalent to operating labor   |
| Electricity   |               | \$/kwh                     |            |               | 2015-2019 EIA Average prices for the                                 |   |
| Lioothony   | 0.00          | ¢, i ci i i                |            |               | commerical sector  |   |
| Natural Gas   | 3.90          | \$/kscf                    |            |               | 2015-2019 EIA Average prices for the                                 |   |
|   | 0.00          | φποσι                      |            |               | commerical sector  |   |
| Water   | 0.42          | \$/mgal                    | 0.20       | 1995          |  |   |
| Cooling Water   |               | \$/mgal                    | 0.23       |               | Hbbing Taconite BART 2006 Study                                      |   |
| Compressed Air  |               | \$/kscf                    | 0.38       |               | Taconite FIP Docket - Control cost estimate for                      |   |
| Compressed 74   | 0.40          | ¢/K301                     | 0.00       | 2012          | UTAC   |   |
| Chemicals & Supplies  |               |                            |            |               |  |   |
| Lime  | 183.68        | \$/ton                     | 145.00     | 2012          | Taconite FIP Docket - Control cost estimate for                      |   |
|   |               |                            |            |               | UTAC   |   |
| Trona   | 285.00        | \$/ton                     |            |               | Reagent cost for trona from another Barr                             |   |
|   |               |                            |            |               | Engineering Co. Project.   |   |
| Urea 50% Solution   | 1.81          | \$/gallon                  | 1.66       | 2017          | EPA SCR Cost Manual Spreadsheet                                      |   |
| Estimated operating life of the catalyst (H <sub>catalyst</sub> ) | 20,000        | hours                      |            |               | EPA Control Cost Manual for SCR suggests                             |   |
|   |               |                            |            |               | 16,000 - 24,000 hours  |   |
| SCR Catalyst cost (CC replace)                                    | 255           | \$/cubic foot              | 227        | 2016          | EPA SCR Cost Manual Spreadsheet                                      | Cost includes removal and disposal/regeneration of existing catalyst and installation of new catalyst   |
| Fabric Filter Bags  | 228.02        | ¢/haa                      | 180        | 2010          | Taconite FIP Docket - Control cost estimate for                      |   |
| Fabric Filter Bags  | 228.02        | \$/bag                     | 180        | 2012          | UTAC   |   |
|   |               |                            |            |               |  |   |
| Other   |               |                            |            |               |  |   |
| Sales Tax   | 6.875%        |                            |            |               |  | Minnesota specific sales tax, not including local tax   |
| Interest Rate   | 5.50%         |                            |            |               | EPA SCR Cost Manual Spreadsheet                                      |   |
| Solid Waste Disposal  | 63.34         | \$/ton                     | 50         | 2012          | Taconite FIP Docket - Control cost estimate for UTAC                 |   |
| Contingencies   | 10%           | of purchased equip cost (B | 3)         |               | EPA Cost Control Cost Manual Chapter 2                               | Suggested contingency range of 5% to 15% of total capital investment  |
| Markup on capital investment (retrofit factor)                    | 25%           |                            |            |               | EPA Cost Control Cost Manual Chapter 2                               | Use retrofit factor of 25% (add 25% to installation cost to account for items not Covered by vendor cost<br>estimate such as (1) Structural aspect of new equipment integrated into the existing steel. and (2) Existing<br>equipment conditions (integration of new systems into old equipment can require significant investment to<br>improve conditions of existing equipment to support intended integration of the new systems if existing is<br>damaged or modified).) |
| Operating Information   |               |                            |            |               |  |   |
| Annual Op. Hrs  | 8 101         | Hours                      |            |               | 2019 Operating Data  |   |
| Utilization Rate  | 6,424         |                            |            |               | Assumed  |   |
| Design Capacity   |               | MMBTU/hr                   |            |               | PTE Calculations for Boiler 9  |   |
| Equipment Life  |               | VIND I U/III<br>Vrs        |            |               | Assumed  |   |
| Temperature   |               | yis<br>Dea F               |            |               | SMBSC CEMs Stack Temperature Data                                    | 2018-2020 Average, excluding periods of boiler shutdown/startup   |
| Moisture Content  | 370           | Degr                       |            |               | 2014 Boiler 1 Hg Stack Temperature Data                              | 2010-2020 Average, excluding periods of boller shuldown/startup   |
| Actual Flow Rate  | 209.000       | a af m                     |            |               | 2014 Boller 1 Hg Stack Test Data<br>2014 Boiler 1 Hg Stack Test Data |   |
| Standardized Flow Rate  |               | acrm<br>scfm @ 68º F       | 100.000    | scfm @ 32º F  | Calculated Value   |   |
| Standardized Flow Rate  |               | dscfm @ 68º F              | 123,889    | SUIII @ 32° F | Calculated Value   |   |
| Fuel higher heating value (HHV)                                   |               | btu/scf                    |            |               | Standard value   |   |
| Plant Elevation   |               | Feet above sea level       |            |               | otanuaru value   | International Falls. MN elevation   |
| # days boiler operates  |               | days                       |            |               | 2019 AEI   |   |
| # days boller operates  | 351           | uays                       |            |               | ZUI9 AEI   |   |
|   | Baseline Emis | sions                      |            |               |  |   |
| Pollutant   | Lb/Hr         | Ton/Year                   |            |               | Unit: lb/mmbtu   |   |
|   |               |                            |            |               |  |   |
| Nitrous Oxides (NOx)  | 21.6          | 90.9                       |            |               | 0.131  | 2019 CEMS lb/MMBtu average. Use "utilization rate" to adjust to match ton/year from emission inventory  |

### **Boise White Paper LLC** International Falls, MN Table 3 NO<sub>x</sub> Control - Low NOx Burners (LNB) with Flue Gas Recirculation (FGR)

**Operating Unit:** 

Boiler 1

| Emission Unit Number               | EQUI17 |          | Stack/Vent Number      | STRU25  |               |
|------------------------------------|--------|----------|------------------------|---------|---------------|
| Desgin Capacity                    | 398    | MMBtu/hr | Standardized Flow Rate | 123,889 | scfm @ 32º F  |
| Expected Utiliztion Rate           | 41%    |          | Temperature            | 370     | Deg F         |
| Expected Annual Hours of Operation | 8,424  | Hours    | Moisture Content       | 11.8%   |               |
| Annual Interest Rate               | 5.5%   |          | Actual Flow Rate       | 209,000 | acfm          |
| Expected Equipment Life            | 20     | yrs      | Standardized Flow Rate | 132,954 | scfm @ 68º F  |
|                                    |        |          | Dry Std Flow Rate      | 117,332 | dscfm @ 68º F |

#### CONTROL EQUIPMENT COSTS

| CONTROL EQUIPMENT COSTS                     |                                       |                        |   |               |                 |                    |                    |               |
|---|---------------------------------------|------------------------|---|---------------|-----------------|--------------------|--------------------|---------------|
| Capital Costs                               |                                       |                        |   |               |                 |                    |                    |               |
| Direct Capital Costs                        |                                       |                        |   |               |                 |                    |                    |               |
| Purchased Equipment (A)                     |                                       | Vendor provided co     | st estimate                                     |               |                 |                    |                    | 3,500,000.00  |
| Purchased Equipment Total (B)               | 11.9%                                 | increase to control    | device cost (A)                                 | to include MN | Sales Tax and   | d Freight          |                    | 3,915,625.00  |
|   |                                       |                        |   |               |                 |                    |                    |               |
| Installation - Standard Costs               |                                       | Vendor provided co     | st estimate                                     |               |                 |                    |                    | 5,000,000.00  |
| Installation - Site Specific Costs          |                                       |                        |   |               |                 |                    |                    | 0.00          |
| Installation Total                          |                                       |                        |   |               |                 |                    |                    | 5,000,000.00  |
| Total Direct Capital Cost, DC               |                                       |                        |   |               |                 |                    |                    | 8,915,625.00  |
| Total Indirect Capital Costs, IC            | 0%                                    | of purchased equip     | cost (B)  |               |                 |                    |                    | 0.00          |
| Total Capital Investment (TCI) with         | 25%                                   | retrofit factor to acc | ount for issues                                 | not addressed | by vendor su    | ch as structural s | teel, condition of | 11,144,531.25 |
| retrofit factor = (DC + IC) * (1 + retrofit |                                       | existing equipment,    | asbestos, etc.                                  |               |                 |                    |                    |               |
| factor)                                     |                                       |                        |   |               |                 |                    |                    |               |
|   |                                       |                        |   |               |                 |                    |                    |               |
| Operating Costs                             |                                       |                        |   |               |                 |                    |                    |               |
| Total Annual Direct Operating Costs         |                                       | Labor, supervision,    | materials, repla                                | cement parts, | utilities, etc. |                    |                    | 111,997.69    |
| Total Annual Indirect Operating Costs       | Total Annual Indirect Operating Costs |                        | Sum indirect oper costs + capital recovery cost |               |                 |                    |                    | 1,445,546.77  |
| Total Annual Cost (Annualized Capital Cos   | t + Operating                         | g Cost)                |   |               |                 |                    |                    | 1,557,544.47  |

#### **Emission Control Cost Calculation**

| Pollutant            | Baseline   | Cont. Emis. | Cont. Emis. | Cont Emis | Reduction | Cont Cost  |
|----------------------|------------|-------------|-------------|-----------|-----------|------------|
|                      | Emis. T/yr | Ib/hr       | Ib/MMBtu    | T/yr      | T/yr      | \$/Ton Rem |
| Nitrous Oxides (NOx) | 90.9       | 19.9        | 0.05        | 34.7      | 56.2      | 27,707     |

Notes & Assumptions <sup>1</sup> Total installed capital cost estimate from vendor

2 Assumed 0.5 hr/shift operatior and maintenance labor for LNB

<sup>3</sup> Controlled emission factor based on vendor estimated burner/OFA performance

4 Installation costs do not account for the following:

Controls integration of new equipment (factors of available space in existing electrical system and I/O points in control system for example) Stack monitoring equipment or data management systems for new emission reporting Instrument air requirements as taxed to existing systems

Permits, licenses, and other Governmental Agency permission required to construct and operate the proposed equipment.

### Boise White Paper LLC International Falls, MN Table 3 NOx Control - Low NOx Burners (LNB) with Flue Gas Recirculation (FGR)

| Purchased Equipment (A) (1)       Vendor provided cost estimate         Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC         Instrumentation       Costs included in vendor provided estimate         MN Sales Taxes       6.9% of control device cost (A)         Freight       5% of control device cost (A)         Purchased Equipment Total (B)       12%         Installation [1]       Foundations & supports         Handling & erection       Electrical         Piping       Installation         Installation Total       Vendor provided cost estimate         Indirect Capital Costs       Engineering, supervision         Construction & field expenses       0% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contractor fees       0% Costs included in vendor provided estimate         Model Stud                        | \$3,500,000.0<br>\$0.0<br>\$240,625.0<br>\$175,000.0<br>\$3,915,625.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0       |
|---|---|
| MN Sales Taxes       6.9% of control device cost (A)         Freight       5% of control device cost (A)         Purchased Equipment Total (B)       12%         Installation [1]       Foundations & supports         Handling & erection       Electrical         Piping       Installation Total         Installation Total       Vendor provided cost estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Contractor fees       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Model Studies   | \$240,625.0<br>\$175,000.0<br>\$3,915,625.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0                |
| Freight       5% of control device cost (Å)         Purchased Equipment Total (B)       12%         Installation [1]       Foundations & supports         Handling & erection       Electrical         Piping       Insulation         Installation Total       Vendor provided cost estimate         Indirect Capital Costs       0% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Otal Indirect Capital Costs, IC       0% of purchased equip cost (B)  | \$175,000.0<br>\$3,915,625.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0 |
| Purchased Equipment Total (B)       12%         Installation [1]       Foundations & supports         Handling & erection       Electrical         Piping       Insulation         Insulation       Painting         Installation Total       Vendor provided cost estimate         Indirect Capital Costs       0% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Contractor fees       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Of Costs included in vendor provided estimate       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Of Costs included in vendor provided estimate       0% Costs included in vendor pr       | \$3,915,625.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0             |
| Installation [1]         Foundations & supports         Handling & erection         Electrical         Piping         Installation         Painting         Installation Total         Vendor provided cost estimate         Installation Total         Total Direct Capital Costs         Engineering, supervision         0% Costs included in vendor provided estimate         Construction & field expenses         0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         0% Costs included in vendor provided estimate       0% Costs included in vendor provided estimate         0% Costs included in vendor provided estimate       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         O% Costs included in vendor provided estimate       0% Costs included in vendor provided estimate   | \$0.0<br>\$0.0<br>\$0.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$8,915,625.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$   |
| Foundations & supports         Handling & erection         Electrical         Piping         Insulation         Painting         Installation Total         Vendor provided cost estimate         Installation Total         Vendor provided cost estimate         Installation Total         Total Direct Capital Costs         Engineering, supervision         0% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Contractor fees       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       0% of purchased equip cost (B)   | \$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$8,915,625.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0          |
| Handling & erection         Electrical         Piping         Insulation         Painting         Installation Total         Vendor provided cost estimate         Installation Total         Vendor provided cost estimate         Installation Total         Installation Total         Vendor provided cost estimate         Indirect Capital Costs         Engineering, supervision         O% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       0% of purchased equip cost (B)   | \$0.0<br>\$0.0<br>\$0.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$8,915,625.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$  |
| Electrical         Piping         Installation         Painting         Installation Total         Vendor provided cost estimate         Installation Total         Total Direct Capital Costs, DC         Indirect Capital Costs         Engineering, supervision         0% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Contractor fees       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       0% of purchased equip cost (B)  | \$0.0<br>\$0.0<br>\$0.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$8,915,625.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$  |
| Piping<br>Insulation<br>Painting       Vendor provided cost estimate         Installation Total<br>Total Direct Capital Cost, DC       Vendor provided cost estimate         Indirect Capital Costs<br>Engineering, supervision       0% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       0% of purchased equip cost (B)   | \$0.0<br>\$0.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0          |
| Insulation       Painting         Installation Total       Vendor provided cost estimate         Indirect Capital Costs       Vendor provided in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Contractor fees       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       0% of purchased equip cost (B)  | \$0.0<br>\$0.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0         |
| Painting<br>Installation Total       Vendor provided cost estimate         Installation Total<br>Total Direct Capital Cost, DC       Vendor provided cost estimate         Indirect Capital Costs<br>Engineering, supervision       0% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         O% Costs included in vendor provided estimate       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         O% Costs included in vendor provided estimate       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         O% Costs included in vendor provided estimate       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         O% of purchased equip cost (B)       0% of purchased equip cost (B) | \$0.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$5,000,000.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0         |
| Installation Total       Vendor provided cost estimate         Installation Total       Vendor provided cost estimate         Installation Total       Office Capital Cost, DC         Indirect Capital Costs       O% Costs included in vendor provided estimate         Construction & field expenses       O% Costs included in vendor provided estimate         Construction & field expenses       O% Costs included in vendor provided estimate         Start-up       O% Costs included in vendor provided estimate         Performance test       O% Costs included in vendor provided estimate         Model Studies       O% Costs included in vendor provided estimate         Contingencies       O% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       O% of purchased equip cost (B)   | \$5,000,000.0<br>\$5,000,000.0<br>\$8,915,625.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0         |
| Total Direct Capital Cost, DC         Indirect Capital Costs         Engineering, supervision       0% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Contractor fees       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       0% of purchased equip cost (B)   | \$8,915,625.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$  |
| Total Direct Capital Cost, DC         Indirect Capital Costs<br>Engineering, supervision       0% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Contractor fees       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       0% of purchased equip cost (B)  | \$8,915,625.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$  |
| Indirect Capital Costs       0% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Contractor fees       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       0% of purchased equip cost (B)  | \$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0   |
| Engineering, supervision       0% Costs included in vendor provided estimate         Construction & field expenses       0% Costs included in vendor provided estimate         Contractor fees       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       0% of purchased equip cost (B)  | \$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0  |
| Construction & field expenses0% Costs included in vendor provided estimateContractor fees0% Costs included in vendor provided estimateStart-up0% Costs included in vendor provided estimatePerformance test0% Costs included in vendor provided estimateModel Studies0% Costs included in vendor provided estimateContingencies0% Costs included in vendor provided estimateTotal Indirect Capital Costs, IC0% of purchased equip cost (B)  | \$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0  |
| Contractor fees       0% Costs included in vendor provided estimate         Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       0% of purchased equip cost (B)   | \$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0<br>\$0.0  |
| Contractor fees0% Costs included in vendor provided estimateStart-up0% Costs included in vendor provided estimatePerformance test0% Costs included in vendor provided estimateModel Studies0% Costs included in vendor provided estimateContingencies0% Costs included in vendor provided estimateTotal Indirect Capital Costs, IC0% of purchased equip cost (B)  | \$0.<br>\$0.<br>\$0.<br>\$0.<br>\$0.<br>\$0.  |
| Start-up       0% Costs included in vendor provided estimate         Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       0% of purchased equip cost (B)   | \$0. <br>\$0. <br>\$0. <br>\$0.   |
| Performance test       0% Costs included in vendor provided estimate         Model Studies       0% Costs included in vendor provided estimate         Contingencies       0% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       0% of purchased equip cost (B)  | \$0.0<br>\$0.0<br>\$0.0   |
| Contingencies       0% Costs included in vendor provided estimate         Total Indirect Capital Costs, IC       0% of purchased equip cost (B)   | \$0.0   |
| Total Indirect Capital Costs, IC     0% of purchased equip cost (B)   |   |
|   | ¢0.0  |
| Total Capital Investment (TCI) = DC + IC  | \$0.0   |
|   | \$8,915,625.0   |
| Site Preparation, as required Site Specific (see retrofit factor)   | NA  |
| Buildings, as required Site Specific  | NA  |
| Site Specific - Other Site Specific (see retrofit factor)   |   |
| Total Site Specific Costs<br>Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost  | \$0.0<br>\$8,915,625.0  |
|   |   |
| Total Capital Investment (TCI) with Retrofit Factor 25% retrofit factor to account for issues not addressed by vendor<br>such as structural steel, condition of existing equipment,<br>asbestos, etc.   | \$11,144,531.2  |
| DPERATING COSTS   |   |
| Direct Annual Operating Costs, DC   |   |
| Operating Labor   | ¢05 554 1   |
| Operator         67.53 \$/Hr, 0.5 hr/8 hr shift, 8424 hr/yr           Supervisor         15% of Operator Costs  | \$35,554.8<br>\$5,333.2   |
| Maintenance (2)   | ψ0,000.2  |
| Maintenance Labor 67.53 \$/Hr, 0.5 hr/8 hr shift, 8424 hr/yr  | \$35,554.8  |
| Maintenance Materials 100% of maintenance labor costs   | \$35,554.8  |
| Utilities, Supplies, Replacements & Waste Management  |   |
| NA NA   | \$111.997.6   |
| Total Annual Direct Operating Costs   | \$111,997.0   |
| Indirect Operating Costs Overhead 60% of total labor and material costs   | \$67,198.6  |
| Administration (2% total capital costs) 2% of total capital costs (TCI)   | \$222,890.6   |
| Property tax (1% total capital costs) 2% of total capital costs (TCI)   |   |
| Insurance (1% total capital costs) 1% of total capital costs (TCI)  | \$111,445.3<br>\$111,445.3  |
| Capital Recovery 8% for a 20- year equipment life and a 5.5% interest rate  | \$932,566.9   |
| Total Annual Indirect Operating Costs         Sum indirect oper costs + capital recovery cost   | \$1,445,546.7   |
|   | ψ1,740,040.1  |

Total Annual Cost (Annualized Capital Cost + Operating Cost)

\$1,557,544.47

### Boise White Paper LLC International Falls, MN Table 3 NOx Control - Low NOx Burners (LNB) with Flue Gas Recirculation (FGR)

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

Replacement Parts & Equipment: N/A

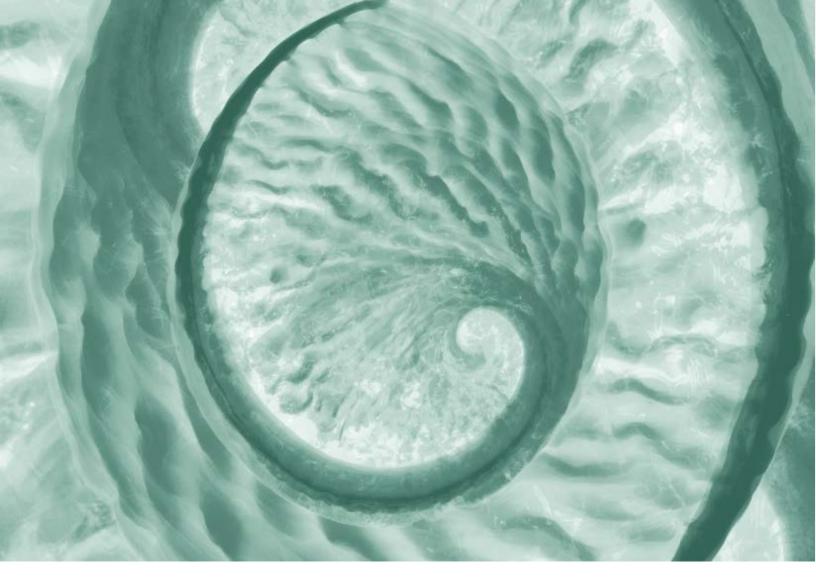
Replacement Parts & Equipment: N/A

Electrical Use

Reagent Use & Other Operating Costs

Operating Cost Calculations

Annual hours of operation: Utilization Rate: 8,424 41%



# Four Factor Analysis

Hibbing Public Utilities Commission Hibbing, Minnesota

28 July 2020 Project No.: 0560921



| Document details  | This document documents the four factor analysis of the sulfur dioxide (SO2) emissions from EQUI 1 and EQUI 3, as well as nitrogen oxide (NOx) emissions from EQUI 1, EQUI 3, and EQUI 7. Hibbing Public Utilities Commission is located in Hibbing, Minnesota. |
|-------------------|---|
| Document title    | Four Factor Analysis  |
| Document subtitle | Hibbing Public Utilities Commission   |
| Project No.       | 0560921   |
| Date              | 28 July 2020  |
| Version           | Final   |
| Author            | Curnow  |
| Client Name       | City of Hibbing   |

# CONTENTS

| 1. | INTR                      | ODUCTIO             | ON  | 1  |
|----|---------------------------|---------------------|---|----|
| 2. | <b>PLAN</b><br>2.1<br>2.2 | SO <sub>2</sub> and | RIPTION.<br>d NO <sub>x</sub> Emissions<br>al SO <sub>2</sub> and NO <sub>x</sub> Emissions | 2  |
|    |                           |                     |   |    |
| 3. | FOU                       | K-FACIO             | OR ANALYSIS   | 4  |
|    | 3.1                       | SO <sub>2</sub> Co  | ntrol Technology  | 4  |
|    | 3.2                       | NO <sub>x</sub> Co  | ntrol Technology  | 5  |
|    |                           | 3.2.1               | Coal-Fired Boilers EQUI 1 and EQUI 3 NOx Control Technology                                 | 5  |
|    |                           | 3.2.2               | Wood-fired Boiler NO <sub>x</sub> Control Technology  | 6  |
|    | 3.3                       | Cost Su             | ımmary  | 9  |
|    |                           | 3.3.1               | Coal-Fired Boilers EQUI 1A and 3A   | 9  |
|    |                           | 3.3.2               | Wood-Fired Boiler EQUI 7 Additional NOx Control   | 11 |
|    | 3.4                       | Time to             | Implement Controls  | 13 |
|    | 3.5                       | Non-Air             | Quality Impacts   | 13 |
|    | 3.6                       | Remain              | ing Useful Life   | 14 |
| 4. | SUM                       | MARY                |   | 14 |
|    | 4.1                       | Coal-Fir            | red Boiler – EQUI 1 and EQUI 3 SO <sub>2</sub> Control                                      | 14 |
|    | 4.2                       |                     | red Boiler – EQUI 1 and EQUI 3 NO <sub>x</sub> Control                                      |    |
|    | 4.3                       | Wood B              | Boiler - EQUI 7 NO <sub>x</sub> Control   | 14 |

# List of Appendices

| APPENDIX A | SITE LOCATION MAP                             |
|------------|---|
| APPENDIX B | RACT/BACT/LAER SUMMARY                        |
| APPENDIX C | USEPA AIR CONTROL TECHNOLOGY SNCR FACT SHEET  |
| APPENDIX D | USEPA AIR CONTROL TECHNOLOGY SCR FACT SHEET   |
| APPENDIX E | EXCERPTS FROM FOSTER WHEELER OPERATORS MANUAL |
| APPENDIX F | USEPA AIR CONTROL TECHNOLOGY FGD FACT SHEET   |

# List of Tables

| Table 1: Continuous Emission Monitor  | 3  |
|---|----|
| Table 2: Historical SO <sub>2</sub> Emissions                                 | 3  |
| Table 3: Historical NO <sub>x</sub> Emissions                                 | 4  |
| Table 4: EQUI 1 and EQUI 3 SO <sub>2</sub> Control Cost Estimate Summary      | 9  |
| Table 5: EQUI 1 and EQUI 3 SNCR NO <sub>x</sub> Control Cost Estimate Summary | 10 |
| Table 6: EQUI 1 and EQUI 3 SCR NO <sub>x</sub> Control Cost Estimate Summary  | 11 |
| Table 7: EQUI 7 SCR NO <sub>x</sub> Control Cost Estimate Summary             | 12 |
| Table 8: Impacts of Potential SO <sub>x</sub> Control Technologies            | 13 |
| Table 9: Impacts of Potential NO <sub>x</sub> Control Technologies            | 13 |

# Acronyms and Abbreviations

| Name            | Description                          |
|-----------------|--------------------------------------|
| °F              | degrees Fahrenheit                   |
| BACT            | Best Available Control Technology    |
| CEM             | continuous emission monitor          |
| CFR             | Code of Federal Regulations          |
| СО              | carbon monoxide                      |
| DSI             | dry sorbent injection                |
| ESP             | electrostatic precipitator           |
| FGD             | Flue Gas Desulfurization             |
| HPUC            | Hibbing Public Utilities Commission  |
| hr              | hour                                 |
| ICAC            | Institute of Clean Air Companies     |
| kW              | kilow atts                           |
| LAER            | Low est Achievable Emission Rate     |
| lb              | pounds                               |
| LNB             | Low NO <sub>x</sub> Burner           |
| LSD             | Lime Spray Dryer                     |
| LSFO            | Limestone Forced Oxidation           |
| MMBtu           | million British thermal units        |
| MPCA            | Minnesota Pollution Control Agency   |
| MW              | megaw atts                           |
| NO <sub>x</sub> | nitrogen oxide                       |
| NSR             | New Source Review                    |
| O&M             | operation and maintenance            |
| OFA             | over-fire air                        |
| RBLC            | RACT/BACT/LAER Clearinghouse         |
| SCR             | Selective Catalytic Reduction        |
| SDA             | spray dyer absorber                  |
| SNCR            | selective non-catalytic reduction    |
| SO <sub>2</sub> | sulfur dioxide                       |
| tpy             | tons per year                        |
| USEPA           | U.S. Environmental Protection Agency |
| WFGD            | Wet Flue Gas Desulfurization         |

# 1. INTRODUCTION

Under 40 Code of Federal Regulations Part 52 (40 CFR 52) Subpart P Section 51.308, states are required to develop a long-term strategy for regional haze. Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for those areas located outside the State that may be affected by emissions from within the State. The long-term strategy must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress toward achieving natural visibility conditions in the affected Class I Federal area.

40 CFR 52 Subpart P, Section 51.308(f)(2)(i) requires the State to evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering four factors:

- 1. Cost of compliance,
- 2. Time necessary for compliance,
- 3. Energy and non-air quality environmental impacts of compliance, and
- 4. Remaining useful life of any potentially affected emission unit.

The State Implementation Plan must include a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress. Revisions to the Minnesota Regional Haze Implementation Plan are due to the U.S. Environmental Protection Agency (USEPA) by July 31, 2021, and the implementation period is 10 years to demonstrate progress toward attaining the visibility goals.

In a letter dated February 14, 2020, the Minnesota Pollution Control Agency (MPCA) requested that the Hibbing Public Utilities Commission (HPUC) conduct a four-factor analysis of the nitrogen oxide (NO<sub>x</sub>) and sulfur dioxide (SO<sub>2</sub>) emissions from Boiler 1A (EQUI 1 / EU 001), Boiler 3A (EQUI 3 / EU 003) and Wood-Fired Boiler EQUI 7 (EU007). Boiler 2A (EQUI 2 / EU002) has a common stack with Boiler 1A but was not part of the Four Factor Analysis request. In a telephone conversation with the MPCA Regional Haze contact, Mr. Hassan Bouchareb, ERM was informed that Boiler 2A was not in the request because the base year triggering the review was 2016, and Boiler 2A did not operate in 2016.

The Class 1 areas in proximity to HPUC are Boundary Waters Canoe Area Wilderness and Voyageurs National Park. The center of the Boundary Waters Canoe Area Wilderness is approximately 75 miles from HPUC, and its closest point is approximately 43 miles from HPUC. The center of Voyageurs National Park is approximately 73 miles from HPUC, and its closest point is approximately 64 miles from HPUC. A site location map showing HPUC relative to the two Class 1 areas is provided in Appendix A.

This report documents the four-factor analysis for controlling  $SO_2$  and  $NO_x$  from Boiler 1A and Boiler 3A as well as controlling  $NO_x$  emissions from the Wood Fired Boiler (EQUI 7) at HPUC. For the rest of this analysis, references to Boiler 1A and 3A will be based on the MPCA air permit identification of these sources, which are EQUI 1 and EQUI 3, respectively. A brief description of HPUC and boiler actual

emissions is provided in Section 2 of this report. Section 3 of this report includes the four-factor analysis. The following information is included in Section 3.

- Technically feasible control technology available for NO<sub>x</sub> reductions and the cost of control.
- The time schedule necessary for implementing a control strategy is described in general terms accounting for project approval, engineering design, bidding, procurement/contracting, construction, and commissioning.
- The non-air quality impacts of compliance are identified and costs estimated to the extent possible. These include truck traffic, electrical use, solid waste generation, and water use.
- The remaining useful life of the boilers is discussed in terms of the maintenance of the unit and projects for the remaining life of the unit before a major overhaul or replacement is due.
- A general discussion of cost effectiveness is included in the summary section. This discussion is based on a review of published information on the reasonableness cost per ton of SO<sub>2</sub> and NO<sub>x</sub> removed as related to visibility improvement.

# 2. PLANT DESCRIPTION

The HPUC operates a co-generation facility for the city of Hibbing. The facility has the ability to generate electricity and steam. Currently, the facility is not generating electricity and solely providing steam to their steam distribution system for space heating and industrial purposes to nearby businesses, schools, and residences. The HPUC is considered a district heating plant and is located in downtown Hibbing, in close proximity to its steam customers.

HPUC operates in accordance with a federal 40 CFR Part 70 Permit number 13700027-101, issued on May 8, 2018. The combustion emission units at the facility consist of three coal-fired boilers EQUI 1, EQUI 2, EQUI 3, and wood-fired boiler EQUI 7. Attached to the steam distribution system, but not at the main HPUC facility, are two small natural gas fired boilers capable of serving the Hibbing High School. The high school boilers have not been operated in years.

EQUI 7 was permitted in 2005 and was required to demonstrate Best Available Control Technology (BACT) and compliance with the National Ambient Air Quality Standards in place at that time (Permit No. 13700027-003). A gas burner was permitted (Permit No. 13700027-009) and installed in 2015 to assist in stabilizing combustion to lower carbon monoxide (CO) emissions. The natural gas burners were needed to counteract the fluctuation of the moisture content of the wood fuel being received, which was causing swings that led to CO emissions exceeding permit limits too frequently.

EQUI 7 uses selective non-catalytic reduction (SNCR) for NO<sub>x</sub> control and a multi-cyclone followed by an electrostatic precipitator (ESP) for particulate matter control. The boiler is also equipped with an opacity monitor, NO<sub>x</sub> monitor, and CO monitor. The boiler design includes over-fire air (OFA), which will reduce the formation of NO<sub>x</sub> but was not specifically included for NO<sub>x</sub> control and is not listed in the air permit as control for NO<sub>x</sub>. Additional information on the existing OFA system is in subsequent paragraphs.

HPUC no longer holds a power purchase agreement with Xcel Energy. Currently, HPUC has no intention of generating electricity. Going forward, HPUC will operate in a similar manner as how the facility was operated in the past year, which is not operating the wood boiler, limiting coal to one trainload a season (14,000 tons), and burning natural gas as needed to satisfy district steam loads.

# 2.1 SO<sub>2</sub> and NO<sub>x</sub> Emissions

A summary of recent continuous emission monitor information is listed in Table 1.

| Value Description  | EQUI 1 and EQUI 2 SO <sub>2</sub><br>(Ib/MMBtu) | EQUI 3 SO <sub>2</sub><br>(Ib/M M Btu) | EQUI 7 NO <sub>x</sub><br>(Ib/MMBtu) |
|--------------------|---|--|--------------------------------------|
| Minimum            | 0   | 0                                      | 0                                    |
| Maximum            | 0.47 <sup>a</sup>                               | 0.52 <sup>a</sup>                      | 0.155 <sup>b</sup>                   |
| Range <sup>c</sup> | 0.47  | 0.52                                   | 0.155                                |
| Average            | 0.10  | 0.17                                   | 0.0.03                               |

Abbreviations: Ib = pounds; MMBtu = million British thermal units

<sup>a</sup> Permit limit for each coal-fired boiler (EQUI 1, EQUI 2, and EQUI 3) is 4.0 lbs/MMBtu when combusting coal.

<sup>b</sup> Permit limit for EQUI 7 is 0.15 lb/MMBtu based on a 30-day average. The value shown for EQUI 7 in this table is one instance in time, not a 30-day average.

<sup>c</sup> Range is the difference between the highest (maximum) and the lowest (minimum) within a set of numbers.

The potential emissions of SO<sub>2</sub> from EQUI 1 and EQUI 2 are 194 pounds per hour (lb/hr) and 851 tons per year (tpy) each. The potential emissions of SO<sub>2</sub> from EQUI 3 are 223 lb/hr and 978 tpy.

The potential emissions of NO<sub>x</sub> from EQUI 1 and EQUI 2 are 140 lb/hr and 612 tpy each. The potential emissions of NO<sub>x</sub> from EQUI 3 are 160 lb/hr and 703 tpy. The potential emissions of NO<sub>x</sub> for EQUI 7 while burning wood are 34.5 lb/hr and 151.11 tpy.

# 2.2 Historical SO<sub>2</sub> and NO<sub>x</sub> Emissions

Historical emissions were taken from the actual air emission reports HPUC submitted to the MPCA for last 4 years. EQUI 2 was not requested to be included in the analysis by the MPCA, but the boiler shares a common stack with EQUI 1 and so was included for informational purposes. The actual emission rates are based on the continuous emission monitors and are the values reported to the MPCA for the annual actual emission reports.

The actual annual SO<sub>2</sub> emissions have decreased each year from 2016 to 2019. Table 2 provides the actual annual SO<sub>2</sub> emission rates from 2016 to 2019 for each of the coal boilers. The wood boiler EQUI 7 is not included because the amount of sulfur in wood is minimal, which results in minor emissions of SO<sub>2</sub> from the combustion reaction.

| Year    | EQUI 1<br>(tpy) | EQUI 2<br>(tpy) | EQUI 3 (tpy) |
|---------|-----------------|-----------------|--------------|
| 2016    | 167.5           | 37.3            | 168.3        |
| 2017    | 181.7           | 1.2             | 158.0        |
| 2018    | 83.1            | 2.15E-14        | 78.6         |
| 2019    | 3.3             | 2.15E-14        | 36.2         |
| Average | 108.90          | 9.63            | 110.28       |

# Table 2: Historical SO<sub>2</sub> Emissions

The actual annual  $NO_x$  emissions have decreased each year from 2016 to 2019. Table 3 provides the actual annual  $NO_x$  emission rates from 2016 to 2019 as reported to the MPCA for the three coal boilers and the wood-fired boiler at HPUC.

| Year    | EQUI 1<br>(tpy) | EQUI 2<br>(tpy) | EQUI 3<br>(tpy) | EQUI 7<br>(tpy) |
|---------|-----------------|-----------------|-----------------|-----------------|
| 2016    | 157.8           | 39              | 193.6           | 87.0            |
| 2017    | 118.9           | 1.1             | 167.1           | 86.8            |
| 2018    | 111.8           | 1.9E-14         | 133.3           | 31.9            |
| 2019    | 43.2            | 1.9E-14         | 82.2            | 15.2            |
| Average | 107.93          | 10.03           | 144.05          | 55.23           |

# Table 3: Historical NO<sub>x</sub> Emissions

# 3. FOUR-FACTOR ANALYSIS

The following is the four-factor analysis. The following subsections present information on the cost of  $SO_2$  and  $NO_x$  control for EQUI 1 and EQUI 3 and supplemental  $NO_x$  control for EQUI 7. Boiler EQUI 7 already has  $NO_x$  control, so the analysis is based on the incremental reduction of changing the control system already in place. The analysis includes the time necessary to implement controls, the energy and non-air quality environmental impacts of implementing controls, and the remaining useful life of the boilers.

# 3.1 SO<sub>2</sub> Control Technology

A literature review of available control technology for coal fired boilers was conducted and two commercially available Flue Gas Desulfurization (FGD) technology options are available for removing SO<sub>2</sub> produced by coal-fired boilers. The two technologies identified as commercially available that could be applied to EQUI 1 and EQUI 2 are:

- 1. Limestone Forced Oxidation (LSFO) Scrubber, and
- 2. Lime Spray Dryer (LSD) Scrubber.

**LSFO** – LSFO is a wet FGD technology. In a wet system the exhaust gas is mixed with a liquid alkaline sorbent (typically limestone). The mixing is achieved by forcing the exhaust stream through a pool off liquid slurry or by spraying the exhaust with a liquid. This technology is commonly simply referred to as wet scrubbing. According to vendor information, a new wet scrubber can routinely achieve SO<sub>2</sub> removal efficiencies of 95% (Institute of Clean Air Companies [ICAC] Acid Gas/SO<sub>2</sub> Controls), <u>https://www.icac.com/page/Acid Gas SO2 Control.</u>

**LSD** – LSD is a semi-dry FGD technology that uses a spray dyer absorber. In dry FGD systems, the exhaust stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer. The removal efficiency is dependent on the amount of sulfur in the coal. This technology is often referred to as dry scrubbing or dry sorbent injection. A fabric filter/baghouse is required downstream of the scrubber to collect the sorbent used to absorb the SO<sub>2</sub>. This technology is commonly referred to as a spray dryer.

In addition to the literature review, a search of the USEPA RACT/BACT/LAER Clearinghouse (RBLC) database for Process Type 12.110 Industrial Boiler firing coal and Process Type 11.110 Utility and Large Industrial Boiler firing coal for January 1, 2010 through June 30, 2020 was conducted on June 30, 2020 to identify what SO<sub>2</sub> control strategies are in place and what emission levels represent the BACT. BACT limits are emission rates and are determined on a case-by-case basis. The BACT emission rates are used in this report for comparison purposes only and do not represent an applicable standard.

Eleven plants were listed in the RBLC database; all but one had add-on  $SO_2$  control listed. The only facility with a coal boiler to not list  $SO_2$  control, only an  $SO_2$  limit, was Miller Brewing Company in Ohio. A

summary of the RBLC entries for boilers firing coal is attached as Appendix B, the entries specific to SO<sub>2</sub> are in table B-1.

Of the FGD systems installed, 85% are wet systems and 12% are spray dryers. Wet scrubbers can achieve the highest removal efficiencies at greater than 90%, whereas dry scrubbers typically achieve less than 80% (USEPA Fact Sheet).

# 3.2 NO<sub>x</sub> Control Technology

In August 2010 the USEPA published "Documentation for Integrated Planning Model Base Case" that included NO<sub>x</sub> emission control information prepared by engineering firm Sargent and Lundy (USEPA 2020) <u>https://www.epa.gov/airmarkets/documentation-integrated-planning-model-ipm-base-case-v410</u>. Sargent and Lundy performed a complete bottom-up engineering reassessment of the cost and performance assumptions NO<sub>x</sub> emission controls for large utility boilers.

Available control options identified are:

- Low NO<sub>x</sub> Burner (LNB) without OFA,
- LNB with OFA,
- OFA,
- Selective Catalytic Reduction (SCR), and
- SNCR.

# 3.2.1 Coal-Fired Boilers EQUI 1 and EQUI 3 NO<sub>x</sub> Control Technology

The coal-fired boilers at HPUC do not employ any add on control technologies for NO<sub>x</sub> reduction. None of the coal-fired boilers have been subject to federal New Source Review (NSR) permitting, which would have required review and installation of BACT.

A search of the RBLC was conducted on June 30, 2020 to identify what NO<sub>x</sub> control strategies are in place for coal-fired/natural gas boilers around the country and what emission levels represent the BACT. BACT limits are emission rates and are determined on a case-by-case basis. The BACT emission rates are used in this report for comparison purposes only and do not represent an applicable standard.

An RBLC search for Process Type 12.110 Industrial Boiler firing coal and Process Type 11.110 Utility and Large Industrial Boiler firing coal for January 1, 2010 through June 30, 2020 found 15 entries, which were all for NO<sub>x</sub>. Of the 15 entries found, 5 were noted as having SNCR and 3 indicated SCR. A summary of the RBLC entries for boilers firing coal is attached as Appendix B; entries specific to NO<sub>x</sub> are in table B-2.

<u>LNB</u> – LNBs control the fuel and air mixture in order to create larger and more branched flames. This reduces the peak flame temperature and in turn reduces  $NO_x$  formation.

<u>**OFA Systems**</u> – Additional NO<sub>x</sub> reduction can be achieved by integrating staged combustion (OFA) into the overall system. OFA can be used by itself but is most often used in conjunction with other NO<sub>x</sub> reduction systems.

<u>SCR</u> – SCR uses a liquid reducing agent in combination with a catalyst to convert  $NO_x$  into nitrogen and water. The reducing agent most commonly used is ammonia.

<u>SNCR</u> – Like the SCR system, SNCR also converts  $NO_x$  into nitrogen and water. However, no catalyst is used; instead, the reagent is injected at a high temperature.

# 3.2.1.1 LNB

EQUI 1 and EQUI 3 are stoker boilers, which means a solid fuel (in this case coal) is mechanically fed into the combustion chamber and the fuel sits on top of a grate during combustion. LNB is not a fuel delivery option for this type of a solid fuel. LNB is not technically feasible and was eliminated from additional discussion for combustion of a solid fuel.

# 3.2.1.2 OFA

An OFA system is a design feature of boilers to ensure adequate air to promote combustion efficiency. The coal-fired boilers were designed with OFA for proper combustion efficiency. Since OFA is an inherent part of the boiler design, it was not specifically identified as a pollution control technology.

# 3.2.1.3 SNCR

SNCR reduces the formation of NO<sub>x</sub> by injecting an ammonia type reactant into the furnace at a properly determined location. SNCR is used on a wide-range of industrial boilers. SNCR can also accommodate seasonal or year-round boiler operation. Reported SNCR reduction efficiencies vary depending on temperature, residence time, reducing reagent, reagent injection rate, uncontrolled NO<sub>x</sub> level, distribution of the reagent in the flue gas, and CO and oxygen concentrations. USEPA "Air Pollution Control Technology Fact Sheet" EPA-452/F-03-031 states that achievable NO<sub>x</sub> reduction levels range from 30 to 50% (USEPA 2002). A copy of the USEPA fact sheet is provided in Appendix C.

SCR is the highest-performing control option currently available. According to the USEPA "Air Pollution Control Technology Fact Sheet" for SCR (EPA-452/F-03-032), SCR is capable of NO<sub>x</sub> reduction efficiencies in the range of 70 to 90% (ICAC 2000). A copy of the USEPA fact sheet is provided in Appendix D.

# 3.2.2 Wood-fired Boiler NO<sub>x</sub> Control Technology

A BACT analysis was completed for EQUI 7 when it was initially permitted in 2005. That analysis indicated that SNCR and a NO<sub>x</sub> emission rate of 0.15 lb per million British thermal units (MMBtu) was BACT. An excerpt from the technical support document that was attached to the operating permit is provided below.

# MPCA Technical Support Document, Permit Action Number: 13700028-005 Page 17 of 64, 7/11/2005

Nitrogen oxide controls from the RBLC database records indicate a wide range of technologies as BACT, including no control, combustion control, SNCR and SCR. Again the most stringent control, SCR appears in the permit for RBLC record OH-0269, however that facility has not been constructed and the permit has expired. BACT emission rates range from 0.15 to 0.40 pounds per million Btu, excluding OH-0269 which has not been constructed. The lowest BACT emission rate for a constructed and operating facility is 0.15 lbs/MMBtu from the District Energy St. Paul facility, which employs SNCR technology.

In August 2010, the USEPA published "Documentation for Integrated Planning Model Base Case," which included NO<sub>x</sub> emission control information prepared by engineering firm Sargent and Lundy (USEPA 2020) <u>https://www.epa.gov/airmarkets/documentation-integrated-planning-model-ipm-base-case-v410</u>. Sargent and Lundy performed a complete bottom-up engineering reassessment of the cost and performance assumptions NO<sub>x</sub> emission controls for large utility coal fired boilers. The study is not directly relatable to smaller wood boilers, but the identified control technologies available for NO<sub>x</sub> control would be the same.

Available control options identified are:

- LNB without OFA,
- LNB with OFA,
- OFA,
- SCR, and
- SNCR.

A new search of the RBLC was conducted on June 30, 2020, to identify what NO<sub>x</sub> control strategies are in place for wood-fired/natural gas boilers around the country and what emission levels represent the BACT. BACT limits are emission rates and are determined on a case-by-case basis. The BACT emission rates are used in this report for comparison purposes only and do not represent an applicable standard.

An RBLC search for Process Type 12.120 Industrial Boiler Firing Biomass (includes wood and wood waste) and Process Type 11.120 Utility and Large Industrial Boiler firing Biomass (includes wood and wood waste) for January 1, 2010 through June 30, 2020 found 19 entries. Of the 19 entries found, 10 were noted as having SNCR and 7 indicated SCR. Of the seven entries that indicated SCR was being used for control, only one—Berlin Station LLC, which has a rated capacity of 1,013 MMBtu/hr (over four times larger than EQUI 7)—has been built and is operating. The Berlin Station boiler was the only boiler able to be confirmed to have been built with SCR. The boiler was required to comply with the Lowest Achievable Emission Rate (LAER) requirements. The boiler is noted as having SCR much larger in capacity (464 to 1,200 MMBtu/hr) than EQUI 7 (230 MMBtu/hr). The other entries found were listed as having LNBs. Some boilers also indicated OFA as part of the boiler design. A summary of the RBLC entries is attached as Appendix B, with specific entries for wood-fired boilers listed in table B-3.

**LNB** – LNBs control the fuel and air mixture in order to create larger and more branched flames. This reduces the peak flame temperature and in turn reduces NO<sub>x</sub> formation.

<u>**OFA**</u> – Additional NO<sub>x</sub> reduction can be achieved by integrating staged combustion (OFA) into the overall system. OFA can be used by itself but is most often used in conjunction with other NO<sub>x</sub> reduction systems.

**<u>SCR</u>** – SCR uses a liquid reducing agent in combination with a catalyst to convert NO<sub>x</sub> into nitrogen and water. The reducing agent most commonly used is ammonia.

<u>SNCR</u> – Like the SCR system, SNCR also converts  $NO_x$  into nitrogen and water. However, no catalyst is used; instead the reagent is injected at a high temperature.

# 3.2.2.1 LNB

The wood-fired boiler is a stoker boiler which means a solid fuel (in this case wood) is mechanically fed into the combustion chamber and the fuel sits on top of a grate during combustion. The wood that is added is in chip form which is around 3 inches in size. LNB is not a fuel delivery option for this type of a solid fuel. LNB is not technically feasible and was eliminated from additional discussion for wood combustion.

The natural gas burners, installed in 2015 to stabilize combustion, are LNB. Combustion stabilization is necessary due to the variability in the moisture content of the wood, which was causing large swings in CO emissions. Natural gas is not the primary fuel, and as such not the focus of this analysis.

# 3.2.2.2 OFA

An OFA system is a design feature of boilers to ensure adequate air to promote combustion efficiency. In boiler EQUI7, air for combustion is supplied from two separate sources: undergate air and OFA. The undergate air supplies 60% of the required combustion air, while the OFA makes up the remaining 40%. The OFA system provides combustion air to a serious of fixed nozzles that penetrate the furnace front and rear walls. There are three elevations of nozzles on the front wall and four elevations of nozzles on the rear wall. The nozzles are optimized to inject air above the grate into a zone where suspension burning takes place. Different nozzle elevations are used to optimize combustion while minimizing emissions from combustion. Both systems are required to be operating when wood is being combusted.

A portion of the operator's manual provided by Foster Wheeler, which provides a detailed description of the OFA system, is provided in Appendix E. The air permit for EQUI7 does not list OFA as a pollution control device because it is considered a factor of boiler design, not an add-on control system.

Compliance with 40 CFR 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters—more commonly referred to as "Boiler MACT"—requires EQUI 7 to be tuned annually. The tune-ups focus on boiler efficiency, which would have an impact on improving air emissions.

# 3.2.2.3 SNCR

EQUI 7 has an SNCR system for NO<sub>x</sub> reduction and, as such, no additional discussion on this technology is provided since it is already in use.

# 3.2.2.4 SCR

SCR is the highest-performing control option currently available. According to the USEPA "Air Pollution Control Technology Fact Sheet" for SCR (EPA-452/F-03-032), SCR is capable of NO<sub>x</sub> reduction efficiencies in the range of 70 to 90% (ICAC 2000). A copy of the USEPA fact sheet is provided in Appendix D. Higher reductions are noted by the USEPA as possible but generally not cost-effective. SCR makes use of a catalyst with ammonia injection. The catalyst improves the efficiency of the chemical reduction of NO<sub>x</sub> by ammonia. The SCR is designed to evenly distribute the flow of NO<sub>x</sub> across a catalyst surface, and provide thorough mixing of the injected ammonia to facilitate reduction and thus removal of NO<sub>x</sub>. The catalyst requires gas at a sufficient temperature for the chemical reaction to occur. The boiler exhaust gas also requires particulate removal prior to the SCR to prevent fouling of the catalyst.

The potential use of SCR for control of NO<sub>x</sub> from the EQUI 7 was evaluated as BACT when the boiler was originally permitted in 2005. The BACT analysis completed as part of the 2005 permit action indicated that SCR was an infeasible NO<sub>x</sub> control option for a wood-fired boiler. The reason the technology was considered infeasible was because of the higher levels of silicates and other constituents found in biomass fuels, which lead to rapid fouling of the catalyst bed, greatly reducing the effectiveness of the SCR system and leading to significant downtime and expense in replacing the catalyst.

The RBLC did note some wood-fired boilers that have been permitted with SCR. The boilers listed as using SCR for NO<sub>x</sub> control are all much larger than EQUI 7 and, most likely, operate at a higher capacity factor. Two of the entries that cited SCR noted the basis for the technology as a requirement to permit at LAER. EQUI 7's primary function at HPUC is to serve the district heating system. HPUC does have some demand for steam in the summer but the majority of the steam production is during the heating season. The HPUC steam customer base continues to decrease as some former entities are relocating outside of the service area or transitioning to their own on-site steam production/heat production.

# 3.3 Cost Summary

# 3.3.1 Coal-Fired Boilers EQUI 1A and 3A

# 3.3.1.1 SO<sub>2</sub> Control Costs

The costs for SO<sub>2</sub> control are based on USEPA published information taken from the USEPA "Air Pollution Control Technology Fact Sheet" EPA-452/F-03-034 for FGD, a copy of which is in Appendix F. The cost information from the fact sheet is contained in table 1b – Summary of Cost Information in \$/kilowatts (kW) (2001 Dollars). The table entry for Industrial Coal Boilers was used for EQUI 1 and EQUI 3. Where cost values have been provided as ranges, the average of the range has been used for estimating purposes.

If a spray dryer technology is used a fabric filter will need to be added downstream of the scrubber to remove the sorbent that was injected in to the exhaust stream. The particulate collector is designed and operated as an integral part of the removal process as the solids continue to react with SO<sub>2</sub>,

The level of SO<sub>2</sub> reductions are based on the actual annual emissions over the past 4 years. Because the facility is no longer producing electricity and district heating customers continue to decline, the operation of the boilers has trended downward. HPUC expects that the trend for decreased operation will become the normal operating mode going forward. As stated earlier, HPUC is only expecting to purchase one unit train of coal for winter operation. The results of the cost estimating for both wet and spray dry technology are shown in Table 4.

| Parameter   | EQUI 1<br>(17.8 MW, 178,000 kW) |                          | EQUI 3<br>(21.4 MW, 214,000 kW) |                          |
|---|---------------------------------|--------------------------|---------------------------------|--------------------------|
|   | Wet                             | Spray Dry                | Wet                             | Spray Dry                |
| Capital Cost<br>(875 \$/kW for wet and 675 \$/KW for spray dry) | \$155,750,000                   | \$120,150,000            | \$187,250,000                   | \$144,450,000            |
| O&M Cost<br>(14 \$/kW for wet and 155 \$/KW for spray dry)      | \$2,492,000                     | \$27,590,000             | \$2,996,000                     | \$33,170,000             |
| Annual Cost<br>(125 \$/kW for wet and 275 \$/KW for spray dry)  | \$22,250,000                    | \$48,950,000             | \$26,750,000                    | \$58,850,000             |
| Subtotal (2001 \$)  | \$180,492,000                   | \$196,690,000            | \$216,996,000                   | \$236,470,000            |
| Subtotal Adjusted for 2020 \$ <sup>a</sup>                      | \$265,738,372                   | \$289,586,687            | \$319,483,211                   | \$348,154,781            |
| Emission Reduction Percent                                      | 90%                             | 80%                      | 90%                             | 80%                      |
| Emission Reduction <sup>b</sup> (tpy)                           | 98.01                           | 87.12                    | 99.25                           | 88.22                    |
| Cost of Emission Reduction (\$/ton)<br>°                        | \$2,711,339                     | \$3,323,998 <sup>d</sup> | \$3,218,974                     | \$3,946,438 <sup>d</sup> |

# Table 4: EQUI 1 and EQUI 3 SO<sub>2</sub> Control Cost Estimate Summary

Abbreviations: MW = megawatts; O&M = operation and maintenance

<sup>c</sup> Cost of emission reduction is rounded to the nearest whole dollar.

<sup>d</sup> Cost of emission reduction does not include the addition of a fabric filter down stream of the spray dryer.

<sup>&</sup>lt;sup>a</sup> The inflation rate in the United States between 2001 and today is 47.23%, (U.S. Bureau of Labor Statistics), <u>https://www.bls.gov/data/inflation\_calculator.htm</u>, July 2020.

<sup>&</sup>lt;sup>b</sup> Emission reduction is based on a 4-year average of actual emissions reported from 2016–2019. Emissions of 108.90 tons of SO<sub>2</sub> are from EQUI 1 and 110.28 tons of SO<sub>2</sub> are from EQUI 3.

# 3.3.1.2 NOx Control SNCR Cost

Table 5 summarizes the cost of retrofitting EQUI 1 and EQUI 3 with an SNCR NO<sub>x</sub> control system. Costs are based on the USEPA "Air Pollution Control Technology Fact Sheet" for SNCR, EPA-452/F-03-031, page 2, a copy of which is in Appendix C. Information is in \$/MMBtu/hr and \$/megawatts (MW) (1999 Dollars). The excerpt from the fact sheet concerning SNCR costs for industrial boilers greater than 100 MMBtu/hr is presented below.

- 1. Capital Cost: 900 to 2,500 \$/MMBtu/hr (9,000 to 25,000 \$/MW)
- 2. Operation and Maintenance (O&M) Cost: 100 to 500 \$/MMBtu/hr (1,000 to 5,000 \$/MW)
- 3. Annualized Cost: 300 to 1,000 \$/MMBtu/hr (3,000 to 10,000 \$/MW)

EQUI 1 is 17.8 MW and EQUI 3 is 21.4 MW. SNCR is applicable to boilers operated full time as well as boilers only operated on a seasonal basis.

# Table 5: EQUI 1 and EQUI 3 SNCR NO<sub>x</sub> Control Cost Estimate Summary

| Parameter  | EQUI 1<br>(17.8 MW/216 MMBtu/hr) | EQUI 3<br>(21.4 MW/248 MMBtu/hr) |  |
|--|----------------------------------|----------------------------------|--|
| Capital Cost (17,000 \$/MW)                      | \$302,600                        | \$363,800                        |  |
| O&M Cost (3,000 \$/MW)                           | \$103,500                        | \$64,200                         |  |
| Annual Cost (6,500 \$/MW)                        | \$115,700                        | \$139,100                        |  |
| SNCR Subtotal (1999 \$)                          | \$521,800                        | \$567,100                        |  |
| SNCR Subtotal Adjusted for 2020 \$ <sup>a</sup>  | \$818,756                        | \$889,837                        |  |
| Emission Reduction Percent                       | 40%                              | 40%                              |  |
| Emission Reduction <sup>b</sup> (tpy)            | 43.17                            | 57.62                            |  |
| Cost of Emission Reduction <sup>c</sup> (\$/ton) | \$18,966                         | \$15,443                         |  |

<sup>a</sup> The inflation rate in the United States between 1999 and today is 56.91%, (U.S. Bureau of Labor Statistics, <u>https://www.bls.gov/data/inflation\_calculator.htm</u>, July 2020.

<sup>b</sup> Emission reduction is based on a 4-year actual average of 2016–2019 emissions of 107.93 tons of NO<sub>x</sub> from EQUI 1 and 144.05 tons of NO<sub>x</sub> from EQUI 3.

<sup>c</sup> Cost of emission reduction is rounded to the nearest whole dollar.

The cost to retrofit EQUI 1 and EQUI 3 with SNCR would be about \$19,000 and \$15,500 per ton of NO<sub>x</sub> removed. Since the dissolution of the Xcel Power Purchase Agreement and the decline in steam customers, HPUC has seen a reduction in use of all the boilers on site, as evident in the summary of historical NO<sub>x</sub> actual emissions contained in Table 3.

# 3.3.1.3 NOx Control SCR Cost

The costs for NO<sub>x</sub> control are based on USEPA published information taken from the USEPA "Air Pollution Control Technology Fact Sheet" for SCR, EPA-452/F-03-032, a copy of which is in Appendix D. The cost information from the fact sheet is contained in table 1a – Summary of Cost Information in \$/MMBtu/hr (1999 Dollars). The table entry for Industrial Coal Boilers was used for EQUI 1 and EQUI 3. Where cost values have been provided as ranges, the average of the range has been used for estimating purposes. The control efficiency of SCR is based on an 85% capacity factor and annual control of NO<sub>x</sub>. Table 6 summarizes the costs associated with retrofitting EQUI 1 and EQUI 3 with SCR for NO<sub>x</sub> Control.

| Parameter  | EQUI 1<br>(216 MMBtu/hr) | EQUI 3<br>(248 MMBtu/hr) |
|--|--------------------------|--------------------------|
| Capital Cost (12,500 \$/MMBtu)                   | \$2,700,000              | \$3,100,000              |
| 30% Retrofit Add-on                              | \$810,000                | \$930,000                |
| O&M Cost (300 \$/MMBtu)                          | \$64,800                 | \$74,400                 |
| Annual Cost (1,600 \$/MMBtu)                     | \$345,600                | \$396,800                |
| SCR Subtotal (1999 \$)                           | \$3,920,400              | \$4,501,200              |
| SCR Subtotal Adjusted for 2020 \$ <sup>a</sup>   | \$6,151,500              | \$7,062,833              |
| Pre-heater for Exhaust                           | Cost Not Available b     | Not Applicable           |
| Emission Reduction Percent                       | 85%                      | 85%                      |
| Emission Reduction <sup>c</sup> (tpy)            | 91.74                    | 122.44                   |
| Cost of Emission Reduction <sup>d</sup> (\$/ton) | \$67,054                 | \$57,684                 |

# Table 6: EQUI 1 and EQUI 3 SCR NO<sub>x</sub> Control Cost Estimate Summary

<sup>a</sup> The inflation rate in the United States between 1999 and today is 56.91%, (U.S. Bureau of Labor Statistics), <u>https://www.bls.gov/data/inflation\_calculator.htm</u>, July 2020.

<sup>b</sup> EQUI 1 would require a preheater for exhaust in lieu of a hot side ESP. The cost for the preheater was not available but is listed in the table in order to identify it as another cost with both capital and operating impacts.

<sup>c</sup> Emission reduction is based on actual average emissions from 2016–2019 of 107.93 tons of NO<sub>x</sub> from EQUI 1 and 144.05 tons of NO<sub>x</sub> from EQUI 3.

<sup>d</sup> Cost of emission reduction is rounded to the nearest whole dollar.

The cost to retrofit EQUI 1 with SCR would be about \$67,068 per ton of NO<sub>x</sub> removed. That value does not include the cost to increase the heat of the ESP exhaust to a sufficient temperature for the catalyst. The cost to retrofit EQUI 3 with SCR would be about \$57,684 per ton of NO<sub>x</sub> removed. EQUI 3 uses a hot side ESP, which means the exhaust temperature may be high enough without additional heating for the catalyst reaction.

USEPA directly states that capital costs for SCR are significantly higher than other types of NO<sub>x</sub> controls due to the large volume of catalyst that is required. The cost of the catalyst is listed as \$283/cubic foot. In addition, retrofitting SCR to an existing unit can increase costs by over 30% (USEPA 2002). The space constraints at HPUC would also add costs due to the requirement to relocate items and demolish structures in order to find the space for additional pollution control equipment.

Since the dissolution of the Xcel Power Purchase Agreement for renewable power, all the boilers on site have seen a reduction in use, as evident in the summary of historical actual NO<sub>x</sub> emissions contained in Table 3.

# 3.3.2 Wood-Fired Boiler EQUI 7 Additional NO<sub>x</sub> Control

SCR is the only  $NO_x$  reduction technology reviewed for cost since EQUI 7 already uses SNCR and the design includes OFA. LNBs are not applicable to wood. The natural gas fired combustion stabilization burners are low  $NO_x$ , but the combustion stabilizing burners are not part of this assessment. No other technology was found for application to this boiler system.

In order for an SCR to work on EQUI7, the current ESP system would need to be replaced with a hot side ESP or, as an alternative, the air stream could be reheated to achieve sufficient temperature for the catalyst reaction. Catalysts require temperatures ranging from 480 degrees Fahrenheit (°F) to 800°F (ICAC 1997). The exhaust temperature entering the existing ESP is at about 400°F and would not be expected to change significantly upon the exit of the ESP.

As indicated earlier, SCR is typically applied to large coal and natural gas fired electrical utility boilers sized larger than what HPUC operates. The fact sheet does say SCR can be effective for large industrial boilers if the capacity factor is high enough. USEPA only refers to applying SCR technology to coal and natural gas fired boilers.

The USEPA directly states that capital costs for SCR are significantly higher than other types of NO<sub>x</sub> controls due to the large volume of catalyst that is required. The cost of the catalyst is listed as \$283/cubic foot. In addition, retrofitting SCR to an existing unit can increase costs by over 30% (USEPA 2002).

Table 7 summarizes the cost of retrofitting EQUI 7 with an SCR NO<sub>x</sub> control system. Costs are based on the USEPA "Air Pollution Control Technology Fact Sheet" for SCR, EPA-452/F-03-032, table 1a – Summary of Cost Information in \$/MMBtu/hr (1999 Dollars) for Industrial Oil, Gas, and Wood boilers. EQUI 7 has a rated capacity of 230 MMBtu/hr. The fact sheet is included as Appendix D.

#### Parameter EQUI 7 (230 MMBtu/hr) Capital Cost (5,000 \$/MMBtu) \$1,150,000 30% Retrofit Add-on \$345,000 O&M Cost (450 \$/MMBtu) \$103,500 Annual Cost (700 \$/MMBtu) \$161,000 SCR Subtotal (1999 \$) \$1,759,500 SCR Subtotal Adjusted for 2020 \$ a \$2,760,831 Pre-heater for Exhaust b Cost Not Available Emission Reduction 53.2% (85% total which is 53.2% above the existing SNCR system at 31.8%) Emission Reduction <sup>c</sup>(tpy) 40.72

# Table 7: EQUI 7 SCR NOx Control Cost Estimate Summary

<sup>a</sup> The inflation rate in the United States between 1999 and today is 56.91%, (U.S. Bureau of Labor Statistics), <u>https://www.bls.gov/data/inflation\_calculator.htm</u>, July 2020)

<sup>b</sup> Preheater for exhaust in lieu of a hot side ESP. The cost for the preheater was not available but is listed in the table in order to identify it as another cost with both capital and operating impacts.

<sup>c</sup> Emission reduction is based on 2016 emissions of 87.0 tons of NO<sub>x</sub>, which could be reduced by an additional 53.2% by retrofitting EQUI 7 with SCR for NO<sub>x</sub> reduction.

<sup>d</sup> Cost of emission reduction is rounded to the nearest whole dollar.

Cost of Emission Reduction <sup>d</sup> (\$/ton)

The cost to retrofit EQUI 7 with SCR would be about 67,800 per ton of NO<sub>x</sub> removed. That value does not include the cost to increase the heat of the ESP exhaust to a sufficient temperature for the catalyst. Since the dissolution of the Xcel Power Purchase Agreement for renewable power, the wood boiler has seen a reduction in use, as evident in the summary of historical actual NO<sub>x</sub> emissions contained in Table 3. It is also the intent of HPUC to not operate the wood boiler going forward. At this time, there are no plans to remove boiler EQUI 7 from the operating permit.

\$67,800

# 3.4 Time to Implement Controls

To implement any of the controls discussed the following steps, and their duration, would need to be completed by HPUC:

- Budgetary design and project approval (12 months);
- Detailed engineering design and bid documents (6 to 9 months);
- Bid solicitation, evaluation, and selection (3 to 4 months);
- Procurement/contracting (3 to 4 months);
- Construction (6 to 10 months); and
- Commissioning (2 to 3 months).

This leads to an overall schedule of 32 to 42 months from concept to operation. HPUC is a governmental institution that requires formal approval from commission for any funding to occur.

# 3.5 Non-Air Quality Impacts

This section outlines in general terms the non-air quality related impacts that would result from implementing control technologies on the boilers. Table 8 and 9 show the impacts in general terms. For example, SCR for NO<sub>x</sub> control (Table 6) uses a catalyst that is made from various ceramic materials, such as titanium oxide or oxides of base metals (such as vanadium, molybdenum, and tungsten), zeolites, or various precious metals. Mining to obtain catalyst materials has environmental implications.

| Technology                       | EQUI 1 | EQUI 3 |
|----------------------------------|--------|--------|
| Electrical Energy<br>Consumption | Yes    | Yes    |
| Transportation Impacts           | Yes    | Yes    |
| Solid Waste Generation           | Yes    | Yes    |
| Increased Water<br>Consumption   | Yes    | Yes    |

#### Table 8: Impacts of Potential SO<sub>x</sub> Control Technologies

# Table 9: Impacts of Potential NO<sub>x</sub> Control Technologies

| Technology                       | EQUI 1 – SNCR or SCR | EQUI 3 – SNCR or SCR | EQUI 7 - SCR |
|----------------------------------|----------------------|----------------------|--------------|
| Electrical Energy<br>Consumption | Yes                  | Yes                  | Yes          |
| Transportation Impacts           | Yes                  | Yes                  | Yes          |
| Solid Waste Generation           | Yes                  | Yes                  | Yes          |
| Increased Water<br>Consumption   | Yes                  | Yes                  | Yes          |

In addition, retrofitting any of the boilers with additional emission control equipment will result in greenhouse gas emissions from construction, truck traffic, material manufacturing, and electrical use. Assuming that the electricity to power the control systems is from some fossil fuel-fired generation, then the increased electrical demand would result in greenhouse gas emissions.

# 3.6 Remaining Useful Life

EQUI 7 began operating in 2006, and the expectation is that it will last about 25 to 30 years with proper maintenance. That means the remaining useful life of EQUI 7 is greater than 10 years. EQUI 1 and EQUI 2 were installed in 1953, and EQUI 3 was installed around 1972. All three of the coal-fired boilers on site are well past what is deemed as a typical useful life. The boilers are continuously maintained with periodic replacement of components on as needed basis. Based on the years of service of the coal-fired boilers at HPUC, they are well beyond the conventional useful life age typically associated with boilers.

# 4. SUMMARY

The review of available information suggests that the cost criteria for visibility improvement is less than that for BACT; however, the target values for economic feasibility are generally not published and are evaluated on a case-by-case basis. The USEPA "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) provides guidance for states to establish control evaluation criteria, such as:

"...measures that cost less than \$X/ton and that result in either (1) a visibility benefit greater than Y deciview at the most impacted Class I area or (2) cumulative visibility benefits across multiple affected Class I areas greater than Z deciview."

# 4.1 Coal-Fired Boiler – EQUI 1 and EQUI 3 SO<sub>2</sub> Control

Adding SO<sub>2</sub> control to EQUI 1 and/or EQUI 3 at HPUC could be achieved by either installing a wet scrubber or spray dry scrubber. The cost of FGD technology has been calculated at \$2,711,339 per ton of SO<sub>2</sub> removed for EQUI 1 and \$3,323,998 per ton of SO<sub>2</sub> removed for EQUI 3. The cost of a spray dryer system not included the downstream fabric filter has been calculated to be over \$3,218,974 per ton of SO<sub>2</sub> removed for EQUI 1 and over \$3,946,438 per ton of SO<sub>2</sub> removed for EQUI 3. Both technologies, based on how the boilers are currently being operated, should be considered cost-prohibitive for visibility protection.

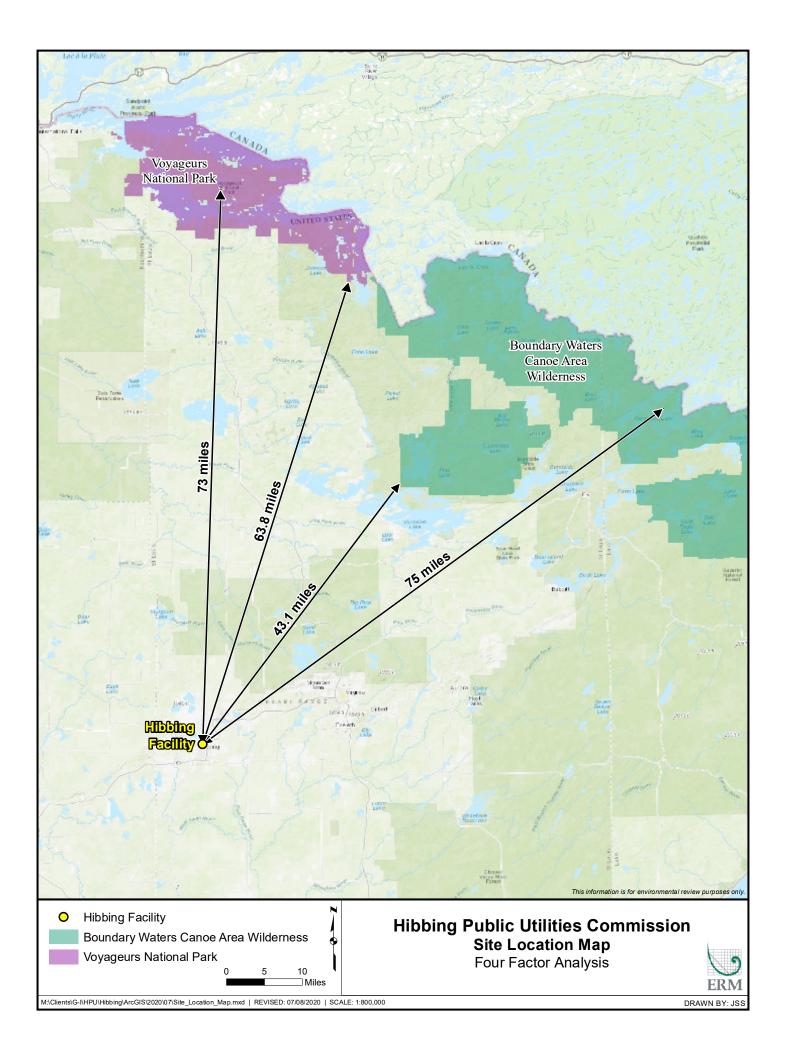
# 4.2 Coal-Fired Boiler – EQUI 1 and EQUI 3 NO<sub>x</sub> Control

Reducing NO<sub>x</sub> emissions from the EQUI 1 and/or EQUI 3 at HPUC could be achieved by either installing SNCR or SCR. The cost of SNCR technology has been calculated at \$18,966 per ton of NO<sub>x</sub> removed for EQUI 1 and \$15,443 per ton of NO<sub>x</sub> removed for EQUI 3. The cost of an SCR system has been calculated to be over \$67,054 per ton of NO<sub>x</sub> removed for EQUI 1 and over \$57,684 per ton of NO<sub>x</sub> removed for EQUI 3. Both technologies, based on how the boilers are currently being operated, should be considered cost-prohibitive for visibility protection.

# 4.3 Wood Boiler - EQUI 7 NO<sub>x</sub> Control

In the case of further reducing NO<sub>x</sub> emissions from the EQUI7 at HPUC, the only available technology would be to replace the SNCR system with SCR. The cost of an SCR system has been calculated to be over \$67,800 per ton of NO<sub>x</sub> removed. This level of cost effectiveness would not be considered cost-effective for BACT control, and should be considered cost-prohibitive for visibility protection.

# APPENDIX A SITE LOCATION MAP



# APPENDIX B RACT/BACT/LAER SUMMARY

#### Appendix B-1 Reasonably Available Control Technology, Best Available Control Technology, Lowest Available Emission Rate Clearinghouse RBLC Database Summary - EPA Database Accessed on June 30, 2020

#### Coal-Fired Boilers – SO<sub>2</sub>

| RBLC ID | Company  | Boiler Size<br>(MMBtu/hr) | Pollutant       | Limit | Units    | Technology   | Basis For<br>Limit | Permit<br>Issuance<br>Date | Process<br>Type <sup>1</sup> |
|---------|--|---------------------------|-----------------|-------|----------|--|--------------------|----------------------------|------------------------------|
| CA-1206 | APMC Stockton Cogen<br>Stockton Cogen Company                                  | 730                       | SO <sub>2</sub> | 59    | lb/hr    | Limestone injection with 70% minimum removal efficiency  | BACT               | 9/16/2010                  | 11.110                       |
| NE-0037 | Cargill, Inc   | 1500                      | SO <sub>2</sub> | 0.11  | lb/MMBtu | Limestone injection  | BACT               | 9/8/2006                   | 12.110                       |
| OH-0241 | Miller Brewing Company   | 238                       | SO <sub>2</sub> | 1.6   | lb/MMBtu |  | BACT               | 5/27/2004                  | 12.110                       |
| VA-0267 | VPI University<br>VPI Power Station  | 146.7                     | SO <sub>2</sub> | 23.6  | lb/hr    | Dry scrubber flue gas desulfurization system, continuous emissions monitoring system (CEMS)                    | BACT               | 8/30/2001                  | 12.110                       |
| NC-0092 | International Paper Company<br>Riegelwood Mill                                 | 249                       | SO <sub>2</sub> | 0.8   | lb/MMBtu | Multiclone, variable throat venturi-type wet scrubber  | BACT               | 5/10/2001                  | 12.110                       |
| AZ-0055 | Salt River Project Agricultural and Power District<br>Navajo Generator Station | 7725                      | SO <sub>2</sub> | 0     |          | Flue gas desulfurization   | BART               | 6/6/2012                   | 11.110                       |
| MI-0400 | Wolverine Power Supply Cooperative, Inc.                                       | 3030                      | SO <sub>2</sub> | 303   | lb/hr    | Dry flue gas desulfurization (spray dry absorber<br>or polishing scrubber)                                     | BACT               | 6/29/2011                  | 11.110                       |
| TX-0595 | Tenaska Trailblazer Partners, LLC  | 8307                      | SO <sub>2</sub> | 0.06  | lb/MMBtu | Wet limestone scrubber   | BACT               | 12/30/2010                 | 11.110                       |
| MI-0399 | Detroit Edison   | 7624                      | SO <sub>2</sub> | 0.107 | lb/MMBtu | Wet flue gas desulfurization   | BACT               | 12/21/2010                 | 11.110                       |
| TX-0554 | Coleto Creek   | 6670                      | SO <sub>2</sub> | 0.06  | lb/MMBtu | Spray Dry Adsorber / Fabric Filter   | BACT               | 5/3/2010                   | 11.110                       |
| КҮ-0100 | East Kentucky Power Cooperative, LLC<br>J.K. Smith Generating Station          | 3000                      | SO <sub>2</sub> | 0.075 | lb/MMBtu | Limestone Injection (circulating fluidized bed<br>[CFB]) and flash dryer absorber with fresh lime<br>injection | BACT               | 4/9/2010                   | 11.110                       |

EPA Website: https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en

<sup>1</sup> The process codes searched were 12.100 Industrial-size boilers/furnaces - Solid Fuel & Solid Fuel Mixes (> 100 MMBtu/hr to 250 MMBtu/hr) and 11.120 - Utility - and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr) - Biomass (includes wood, wood waste, bagasse, and other biomass).

Notes:

The terms "RACT," "BACT," and "LAER" are acronyms for different program requirements under the NSR program.

RACT, or Reasonably Available Control Technology, is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas).

BACT, or Best Available Control Technology, is required on major new or modified sources in clean areas (i.e., attainment areas).

LAER, or Lowest Achievable Emission Rate, is required on major new or modified sources in non-attainment areas.

#### Appendix B-2 Reasonably Available Control Technology, Best Available Control Technology, Lowest Available Emission Rate Clearinghouse RBLC Database Summary - EPA Database Accessed on June 30, 2020

#### Coal-Fired Boilers – NO<sub>x</sub>

| RBLC ID | Company  | Boiler Size<br>(MMBtu/hr) | Pollutant       | Limit | Units    | Technology   | Basis For<br>Limit | Permit<br>Issuance<br>Date | Process<br>Type <sup>1</sup> |
|---------|--|---------------------------|-----------------|-------|----------|--|--------------------|----------------------------|------------------------------|
| CA-1206 | APMC Stockton Cogen<br>Stockton Cogen Company                                  | 730                       | NO <sub>x</sub> | 50    | ppm      | Low bed temperature staged combustion, selective non-catalytic reduction (SNCR)        | BACT               | 9/16/2010                  | 11.110                       |
| NE-0037 | Cargill, Inc   | 1500                      | NO <sub>x</sub> | 0.08  | lb/MMBtu | Combustion control, SNCR   | BACT               | 9/8/2006                   | 12.110                       |
| ND-0020 | Red Trail Energy, LLC<br>Richardton Plant                                      | 250                       | NO <sub>x</sub> | 0.1   | lb/MMBtu | SNCR   | BACT               | 8/4/2004                   | 12.110                       |
| OH-0241 | Miller Brewing Company   | 238                       | NO <sub>x</sub> | 0.7   | lb/MMBtu | Overfire air (OFA) and side fire air to reduce flame temperature                       | BACT               | 5/27/2004                  | 12.110                       |
| NC-0092 | International Paper Company<br>Riegelwood Mill                                 | 249                       | NO <sub>x</sub> | 0.4   | lb/MMBtu | Good combustion practices  | BACT               | 5/10/2001                  | 12.110                       |
| OK-0152 | O G and E<br>Muskogee Generating Station                                       | 1875.5                    | NO <sub>x</sub> | 0.15  | lb/MMbtu | Low NO <sub>x</sub> burners (LNB) and OFA  | BART               | 1/30/2013                  | 11.110                       |
| OK-0151 | O G and E<br>Muskogee Generating Station                                       | 1875.5                    | NO <sub>x</sub> | 0.15  | lb/MMbtu | LNBs and OFA   | BACT               | 1/17/2013                  | 11.110                       |
| AZ-0055 | Salt River Project Agricultural and Power District<br>Navajo Generator Station | 7725                      | NO <sub>x</sub> | 0.24  | lb/MMBtu | LNBs and OFA   | BACT               | 2/6/2012                   | 11.110                       |
| MI-0400 | Wolverine Power Supply Cooperative, Inc.                                       | 3030                      | NO <sub>x</sub> | 1     | lb/MW-hr | SNCR   | BACT               | 6/29/2011                  | 11.110                       |
| TX-0595 | Tenaska Trailblazer Partners, LLC  | 8307                      | NO <sub>x</sub> | 0.05  | lb/MMBtu | selective catalytic reduction (SCR)  | BACT               | 12/30/2010                 | 11.110                       |
| MI-0399 | Detroit Edison   | 7624                      | NO <sub>x</sub> | 0.08  | lb/MMBtu | Staged combustion, LNBs, OFA, SCR  | BACT               | 12/21/2010                 | 11.110                       |
| TX-0554 | Coleto Creek   | 6670                      | NO <sub>x</sub> | 0.06  | lb/MMBtu | LNBs with OFA system, SCR  | BACT               | 5/3/2010                   | 11.110                       |
| КҮ-0100 | East Kentucky Power Cooperative, LLC<br>J.K. Smith Generating Station          | 3000                      | NO <sub>x</sub> | 0.07  | lb/MMBtu | SNCR   | BACT               | 4/9/2010                   | 11.110                       |
| TX-0557 | NRG Texas Power LLC<br>Limestone Electric Generating Station                   | 9061                      | NO <sub>x</sub> | 0.25  | lb/MMBtu | Tuning of existing low NO <sub>x</sub> firing system to induce deeper state combustion | ВАСТ               | 2/1/2010                   | 11.110                       |
| TX-0556 | Southwestern Public Service Company<br>Harrington Station Unit 1 Boiler        | 3630                      | NO <sub>x</sub> | 1452  | lb/hr    | Separated OFA windbox system; LNB tips and additional control to the burners           | BACT               | 1/15/2010                  | 11.110                       |

EPA Website: https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en

<sup>1</sup> The process codes searched were 12.110 Industrial-size boilers/furnaces - Solid Fuel & Solid Fuel Mixes (> 100 MMBtu/hr to 250 MMBtu/hr) Coal (includes bituminous, subbituminous, anthracite, and lignite) and 11.110 - Utility - and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr) - Coal (includes bituminous, subbituminous, anthracite, and lignite).

Notes:

The terms "RACT," "BACT," and "LAER" are acronyms for different program requirements under the NSR program.

RACT, or Reasonably Available Control Technology, is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas).

BACT, or Best Available Control Technology, is required on major new or modified sources in clean areas (i.e., attainment areas).

LAER, or Lowest Achievable Emission Rate, is required on major new or modified sources in non-attainment areas.

#### Appendix B-3 Reasonably Available Control Technology, Best Available Control Technology, Lowest Available Emission Rate Clearinghouse RBLC Database Summary - EPA Database Accessed on June 30, 2020

Wood-Fired Boilers – NO<sub>x</sub>

| RBLC ID | Company   | Boiler Size<br>(MMBtu/hr) | Pollutant       | Limit | Units    | Technology   | Basis For<br>Limit | Permit<br>Issuance<br>Date | Process<br>Type <sup>1</sup> |
|---------|---|---------------------------|-----------------|-------|----------|--|--------------------|----------------------------|------------------------------|
| ME-0040 | Robbins Lumber, Inc.  | 167.3                     | NO <sub>x</sub> | 25.1  | lb/hr    | Flue gas recirculation (FGR) / Selective non-<br>catalytic reduction (SNCR)  | BACT               | 6/30/2017                  | 12.120                       |
| MI-0425 | Arauco North America Grayling Particleboard   | 110                       | NO <sub>x</sub> | 95    | lb/hr    | Good combustion practices, low NO <sub>x</sub> burners (LNB)   | BACT               | 5/9/2017                   | 12.120                       |
| MI-0421 | Arauco North America Grayling Particleboard   | 110                       | NO <sub>x</sub> | 95    | lb/hr    | Good combustion practices, LNB   | BACT               | 8/26/2016                  | 12.120                       |
| SC-0149 | Klausner Holding USA, Inc.  | 120                       | NO <sub>x</sub> | 0.14  | lb/MMBtu | SNCR   | Other              | 1/3/2013                   | 12.120                       |
| FL-0332 | Highlands Envirofuels (HEF), LLC<br>Highlands Biorefinery and Cogeneration Plant      | 458.5                     | NO <sub>x</sub> | 0.1   | lb/MMBtu | SNCR with urea or $NH_3$ injection, LNB  | BACT               | 9/23/2011                  | 12.120                       |
| FL-0322 | Southeast Renewable Fuels (SRF), LLC<br>Sweet Sorghum-to-Ethanol Advanced Biorefinery | 536                       | NO <sub>x</sub> | 0.1   | lb/MMBtu | Good combustion practices, SNCR, selective catalytic reduction (SCR), or combination with urea or $NH_3$ injection | BACT               | 12/23/2010                 | 12.120                       |
| AR-0161 | Sun Bio Material Company  | 1,200                     | NO <sub>x</sub> | 0.06  | lb/MMBtu | SCR  | BACT               | 9/23/2019                  | 11.120                       |
| FL-0359 | US Sugar Corporation  | 1,077                     | NO <sub>x</sub> | 0.1   | lb/MMBtu | SNCR (NH <sub>3</sub> injection)   | BACT               | 11/29/2016                 | 11.120                       |
| KS-0034 | Abengoa Bioenergy Biomass of Kansas (ABBK)  | 500                       | NO <sub>x</sub> | 0.3   | lb/MMBtu | SCR and overfire air (OFA) system  | BACT               | 5/27/2014                  | 11.120                       |
| CA-1225 | Sierra Pacific Industries   | 468                       | NO <sub>x</sub> | 0.13  | lb/MMBtu | SNCR   | BACT               | 4/25/2014                  | 11.120                       |
| VT-0039 | North Springfield Sustainable Energy Project, LLC                                     | 464                       | NO <sub>x</sub> | 0.03  | lb/MMBtu | Bubbling fluidized bed boiler design and SCR   | BACT               | 4/19/2013                  | 11.120                       |
| GA-0141 | Ogethorpe Power Corporation<br>Warren County Biomass Energy Facility                  | 341                       | NO <sub>x</sub> | 0.1   | lb/MMBtu | SNCR   | BACT               | 12/17/2010                 | 11.120                       |
| VT-0037 | Beaver Wood Energy Fair Haven, LLC  | 482                       | NO <sub>x</sub> | 0.03  | lb/MMBtu | Good combustion control and SCR  | BACT               | 2/10/2012                  | 11.120                       |
| ME-0037 | Verso Bucksport, LLC  | 817                       | NO <sub>x</sub> | 0.15  | lb/MMBtu | SNCR   | BACT               | 11/29/2010                 | 11.120                       |
| CA-1203 | Sierra Pacific Industries   | 335.7                     | NO <sub>x</sub> | 80    | ppm      | SNCR   | BACT               | 8/30/2010                  | 11.120                       |
| NH-0018 | Berlin Station, LLC<br>Burgess Biopower   | 1,013                     | NO <sub>x</sub> | 0.06  | lb/MMBtu | SCR with NH <sub>3</sub> injection <sup>2</sup>  | LAER               | 7/26/2010                  | 11.120                       |
| CT-0156 | NRG Energy  | 600                       | NO <sub>x</sub> | 0.06  | lb/MMBtu | Regenerative SCR   | LAER               | 4/6/2010                   | 11.120                       |
| AL-0250 | Boise White Paper, LLC  | 435                       | NO <sub>x</sub> | 0.3   | lb/MMBtu | LNB  | BACT               | 3/23/2010                  | 11.120                       |
| TX-0553 | Lindale Renewable Energy, LLC   | 1,256                     | NO <sub>x</sub> | 0.15  | lb/MMBtu | SNCR   | BACT               | 1/8/2010                   | 11.120                       |

EPA Website: https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en

<sup>1</sup>The process codes searched were 12.100 Industrial-size boilers/furnaces - Solid Fuel & Solid Fuel Mixes (> 100 MMBtu/hr to 250 MMBtu/hr) and 11.120 - Utility - and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr) - Biomass (includes wood, wood waste, bagasse, and other biomass).

<sup>2</sup>This entry is the only facility listed in the RBLC database under the process categories searched, that has been confirmed to have been built and is using an SCR for NO<sub>x</sub> control.

Notes:

The terms "RACT," "BACT," and "LAER" are acronyms for different program requirements under the NSR program.

RACT, or Reasonably Available Control Technology, is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas).

BACT, or Best Available Control Technology, is required on major new or modified sources in clean areas (i.e., attainment areas).

LAER, or Lowest Achievable Emission Rate, is required on major new or modified sources in non-attainment areas.

APPENDIX C USEPA AR CONTROL TECHNOLOGY SNCR FACT SHEET



# Air Pollution Control Technology Fact Sheet

Name of Technology: Selective Non -Catalytic Reduction (SNCR)

Type of Technology: Control Device - Chemical reduction of a pollutant via a reducing agent.

Applicable Pollutants: Nitrogen Oxides (NO<sub>x</sub>)

#### Achievable Emission Limits/Reductions:

 $NO_x$  reduction levels range from 30% to 50% (EPA, 2002). For SNCR applied in conjunction with combustion controls, such as low  $NO_x$  burners, reductions of 65% to 75% can be achieved (ICAC 2000).

Applicable Source Type: Point

#### **Typical Industrial Applications:**

There are hundreds of commercially installed SNCR systems on a wide range of boiler configurations including: dry bottom wall fired and tangentially fired units, wet bottom units, stokers, and fluidized bed units. These units fire a variety of fuels such as coal, oil, gas, biomass, and waste. Other applications include thermal incinerators, municipal and hazardous solid waste combustion units, cement kilns, process heaters, and glass furnaces.

#### **Emission Stream Characteristics:**

- a. Combustion Unit Size: In the United States, SNCR has been applied to boilers and other combustion units ranging in size from 50 to 6,000 MMBtu/hr (5 to 600MW/hr) (EPA, 2002). Until recently, it was difficult to get high levels of NOx reduction on units greater than 3,000 MMBtu (300 MW) due to limitations in mixing. Improvements in SNCR injection and control systems have resulted in high NO<sub>x</sub> reductions (> 60%) on utility boilers greater than 6,000 MMBtu/hr (600MW). (ICAC, 2000).
- **b. Temperature:** The NO<sub>X</sub> reduction reaction occurs at temperatures between 1600°F to 2100°F (870°C to 1150°C) (EPA, 2002). Proprietary chemicals, referred to as enhancers or additives, can be added to the reagent to lower the temperature range at which the NO<sub>X</sub> reduction reactions occur.
- **c. Pollutant Loading:** SNCR tends to be less effective at lower levels of uncontrolled  $NO_x$ . Typical uncontrolled  $NO_x$  levels vary from 200 ppm to 400 ppm (NESCAUM, 2000). SNCR is better suited for applications with high levels of PM in the waste gas stream than SCR.
- **d. Other Considerations:** Ammonia slip refers to emissions of unreacted ammonia that result from incomplete reaction of the  $NO_x$  and the reagent. Ammonia slip may cause: 1) formation of ammonium sulfates, which can plug or corrode downstream components, 2) ammonia absorption into fly ash, which may affect disposal or reuse of the ash, and 3) increased plume

visibility. In the U.S., permitted ammonia slip levels are typically 2 to 10 ppm (EPA, 2002). Ammonia slip at these levels do not result in plume formation or pose human health hazards. Process optimization after installation can lower slip levels.

Nitrous Oxide ( $N_2O$ ) is a by-product formed during SNCR. Urea based reduction generates more  $N_2O$  than ammonia-based systems. At most, 10% of the  $NO_x$  reduced in urea-based SNCR is converted to  $N_2O$ . Nitrous oxide does not contribute to ground level ozone or acid formation. (ICAC,2000)

#### Emission Stream Pretreatment Requirements: None

Cost Information: All costs are in year 1999 dollars. (NESCAUM, 2000; ICAC, 2000; and EPA, 2002)

The difficulty of SNCR retrofit on existing large coal-fired boilers is considered to be minimal. However, the difficulty significantly increases for smaller boilers and packaged units. The primary concern is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required. In addition, adequate space adjacent to the boiler must be available for distribution system equipment and for performing maintenance. This may require modifications to ductwork and other boiler equipment.

A typical breakdown of annual costs for industrial boilers will be 15% to 35% for capital recovery and 65% to-85% for operating expense (ICAC,2000). Since SNCR is an operating expense-driven technology, its cost varies directly with  $NO_x$  reduction requirements and reagent usage. Optimization of the injection system after start up can reduce reagent usage and, subsequently, operating costs. Recent improvements in SNCR injection systems have also lowered operating costs.

There is a wide range of cost effectiveness for SNCR due to the different boiler configurations and sitespecific conditions, even within a given industry. Cost effectiveness is impacted primarily by uncontrolled  $NO_x$  level, required emissions reduction, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty. The cost effectiveness of SNCR is less sensitive to capacity factor than SCR. Control of  $NO_x$  is often only required during the ozone season, typically June through August. Since SNCR costs are a function of operating costs, SNCR is an effective control option for seasonal  $NO_x$ reductions.

Costs are presented below for industrial boilers greater than 100 MMBtu/hr.

- a. Capital Cost: 900 to 2,500 \$/MMBtu/hr (9,000 to 25,000 \$/MW)
- b. O&M Cost: 100 to 500 \$/MMBtu/hr (1,000 to 5,000 \$/MW)
- c. Annualized Cost: 300 to 1000 \$/MMBtu/hr (3,000 to 10,000 \$/MW)
- d. Cost per Ton of Pollutant Removed:

Annual Control:400 to 2,500 \$/ton of NO\_x removedSeasonal Control:2,000 to 3,000 \$/ton of NO\_x removed

#### Theory of Operation:

SNCR is based on the chemical reduction of the  $NO_X$  molecule into molecular nitrogen ( $N_2$ ) and water vapor ( $H_2O$ ). A nitrogen based reducing agent (reagent), such as ammonia or urea, is injected into the

post combustion flue gas. The reduction reaction with NO<sub>x</sub> is favored over other chemical reaction processes at temperatures ranging between 1600°F and 2100°F (870°C to 1150°C), therefore, it is considered a selective chemical process (EPA, 2002).

Both ammonia and urea are used as reagents. Urea-based systems have advantages over ammonia based systems. Urea is non-toxic, less volatile liquid that can be stored and handled more safely. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing the mixing with the flue gas which is difficult in large boilers. However, urea is more expensive than ammonia. The Normalized Stoichiometric Ratio (NSR) defines the ratio of reagent to NO<sub>x</sub> required to achieve the targeted NO<sub>x</sub> reduction. 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.

In the SNCR process, the combustion unit acts as the reactor chamber. The reagent is generally injected within the boiler superheater and reheater radiant and convective regions, where the combustion gas temperature is at the required temperature range. The injection system is designed to promote mixing of the reagent with the flue gas. The number and location of injection points is determined by the temperature profiles and flow patterns within the combustion unit.

Certain application are more suited for SNCR due to the combustion unit design. Units with furnace exit temperatures of 1550°F to 1950°F (840°C to 1065°C), residence times of greater than one second, and high levels of uncontrolled  $NO_x$  are good candidates.

During low-load operation, the location of the optimum temperature region shifts upstream within the boiler. Additional injection points are required to accommodate operations at low loads. Enhancers can be added to the reagent to lower the temperature range at which the  $NO_X$  reduction reaction occurs. The use of enhancers reduces the need for additional injection locations.

#### Advantages:

- Capital and operating costs are among the lowest of all  $NO_{\chi}$  reduction methods.
- Retrofit of SNCR is relatively simple and requires little downtime for large and medium size units.
- Cost effective for seasonal or variable load applications.
- Waste gas streams with high levels of PM are acceptable.
- Can be applied with combustion controls to provide higher NO<sub>X</sub> reductions.

#### Disadvantages:

- The waste gas stream must be within a specified temperature range.
- Not applicable to sources with low NO<sub>x</sub> concentrations such as gas turbines.
- Lower NO<sub>x</sub> reductions than Selective Catalytic Reduction (SCR).
- May require downstream equipment cleaning.
- Results in ammonia in the waste gas stream which may impact plume visibility, and resale or disposal of ash.

#### References:

EPA, 1998. U.S. Environmental Protection Agency, Innovative Strategies and Economics Group, "Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis", Prepared by Pechan-Avanti Group, Research Triangle Park, NC. 1998.

EPA, 1999. US Environmental Protection Agency, Clean Air Technology Center. "Technical Bulletin: Nitrogen Oxides ( $NO_x$ ), Why and How They Are Controlled". Research Triangle Park, NC. 1998.

EPA, 2002. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. *EPA Air Pollution Control Cost Manual*, Section 4 Chapter 1. EPA 452/B-02-001. 2002. http://www.epa.gov/ttn/catc/dir1/cs4-2ch1.pdf

ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling  $NO_x$  Emissions". Washington, D.C. 2000.

NESCAUM, 2000. Northeast States for Coordinated Air Use Management. "Status Reports on  $NO_X$  Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines: Technologies & Cost Effectiveness". Boston, MA. 2002.

APPENDIX D USEPA AIR CONTROL TECHNOLOGY SCR FACT SHEET



# Air Pollution Control Technology Fact Sheet

Name of Technology: Selective Catalytic Reduction (SCR)

Type of Technology: Control Device - Chemical reduction via a reducing agent and a catalyst.

Applicable Pollutants: Nitrogen Oxides (NOx)

**Achievable Emission Limits/Reductions:** SCR is capable of NOx reduction efficiencies in the range of 70% to 90% (ICAC, 2000). Higher reductions are possible but generally are not cost-effective.

#### Applicable Source Type: Point

**Typical Industrial Applications:** Stationary fossil fuel combustion units such as electrical utility boilers, industrial boilers, process heaters, gas turbines, and reciprocating internal combustion engines. In addition, SCR has been applied to nitric acid plants. (ICAC, 1997)

#### **Emission Stream Characteristics:**

- a. Combustion Unit Size: In the United States, SCR has been applied to coal- and natural gasfired electrical utility boilers ranging in size from 250 to 8,000 MMBtu/hr (25 to 800 MW) (EPA, 2002). SCR can be cost effective for large industrial boilers and process heaters operating at high to moderate capacity factors (>100 MMBtu/hr or >10MW for coal-fired and >50 MMBtu/hr or >5MW for gas-fired boilers). SCR is a widely used technology for large gas turbines.
- b. Temperature: The NOx reduction reaction is effective only within a given temperature range. The optimum temperature range depends on the type of catalyst used and the flue gas composition. Optimum temperatures vary from 480°F to 800°F (250°C to 427°C) (ICAC, 1997). Typical SCR systems tolerate temperature fluctuations of ± 200°F (± 90°C) (EPA, 2002).
- c. Pollutant Loading: SCR can achieve high reduction efficiencies (>70%) on NOx concentrations as low as 20 parts per million (ppm). Higher NOx levels result in increased performance; however, above 150 ppm, the reaction rate does not increase significantly (Environex, 2000). High levels of sulfur and particulate matter (PM) in the waste gas stream will increase the cost of SCR.
- d. Other Considerations: Ammonia slip refers to emissions of unreacted ammonia that result from incomplete reaction of the NOx and the reagent. Ammonia slip may cause: 1) formation of ammonium sulfates, which can plug or corrode downstream components, and 2) ammonia absorption into fly ash, which may affect disposal or reuse of the ash. In the U.S., permitted ammonia slip levels are typically 2 to 10 ppm. Ammonia slip at this levels do not result in plume formation or human health hazards. Process optimization after installation can lower slip levels.

Waste gas streams with high levels of PM may require a sootblower. Sootblowers are installed in the SCR reactor to reduce deposition of particulate onto the catalyst. It also reduces fouling of downstream equipment by ammonium sulfates.

The pressure of the waste gas decreases significantly as it flows across the catalyst. Application of SCR generally requires installation a new or upgraded induced draft fan to recover pressure.

**Emission Stream Pretreatment Requirements:** The flue gas may require heating to raise the temperature to the optimum range for the reduction reaction. Sulfur and PM may be removed from the waste gas stream to reduce catalyst deactivation and fouling of downstream equipment.

#### **Cost Information:**

Capital costs are significantly higher than other types of NOx controls due to the large volume of catalyst that is required. The cost of catalyst is approximately  $10,000 \text{ s/m}^3$  (283 s/ft<sup>3</sup>). A 350 MMBtu/hr natural gas-fired boiler operating at 85% capacity requires approximately  $17 \text{ m}^3$  (600 ft<sup>3</sup>). For the same sized coal-fired boiler, the required catalyst is on the order of 42 m<sup>3</sup> (1,500 ft<sup>3</sup>). (NESCAUM 2000).

SCR is a proprietary technology and designs on large combustion units are site specific. Retrofit of SCR on an existing unit can increase costs by over 30% (EPA, 2002). The increase in cost is primarily due to ductwork modification, the cost of structural steel, and reactor construction. Significant demolition and relocation of equipment may be required to provide space for the reactor.

The O&M costs of using SCR are driven by the reagent usage, catalyst replacement, and increased electrical power usage. SCR applications on large units (>100 MMBtu/hr) generally require 20,000 to 100,000 gallons of reagent per week (EPA, 2002). The catalyst operating life is on the order of 25,000 hours for coal-fired units and 40,000 hours for oil- and gas-fired units (EPA, 2002). A catalyst management plan can be developed so that only a fraction of the total catalyst inventory, rather than the entire volume, is replaced at any one time. This distributes the catalyst replacement and disposal costs more evenly over the lifetime of the system. O&M costs are greatly impacted by the capacity factor of the unit and annual versus seasonal control of  $NO_x$ .

O&M cost and the cost per ton of pollutant removed is greatly impacted by the capacity factor and whether SCR is utilized seasonally or year round.

| Unit Type                              | Capital Cost    | O&M Cost <sup>d</sup> | Annual Cost <sup>d</sup> | Cost per Ton of<br>Pollutant Removed |  |
|--|-----------------|-----------------------|--------------------------|--------------------------------------|--|
|  | (\$/MMBtu)      | (\$/MMBtu)            | (\$/MMBtu)               | (\$/ton)                             |  |
| Industrial Coal Boiler                 | 10,000 - 15,000 | 300                   | 1,600                    | 2,000 - 5,000                        |  |
| Industrial Oil, Gas, Wood <sup>c</sup> | 4,000 - 6,000   | 450                   | 700                      | 1,000 - 3,000                        |  |
| Large Gas Turbine                      | 5,000 - 7,500   | 3,500                 | 8,500                    | 3,000 - 6,000                        |  |
| Small Gas Turbine                      | 17,000 - 35,000 | 1,500                 | 3,000                    | 2,000 - 10,000                       |  |

| Table 1a: Summary of Cost Information in \$/MMBtu/hr | (1999 Dollars) a, b |
|--|---------------------|
|--|---------------------|

|                                      | Capital Cost  | O&M Cost <sup>d</sup> | Annual Cost <sup>d</sup> | Cost per Ton of<br>Pollutant Removed |
|--------------------------------------|---------------|-----------------------|--------------------------|--------------------------------------|
| Unit Type                            | (\$/MW)       | (\$/MW)               | (\$/MW)                  | (\$/ton)                             |
| Industrial Coal Boiler               | 1,000 - 1,500 | 30                    | 160                      | 2,000 - 5,000                        |
| Industrial Oil, Gas, Wood $^{\circ}$ | 400 - 600     | 45                    | 70                       | 1,000 - 3,000                        |
| Large Gas Turbine                    | 500 - 750     | 350                   | 850                      | 3,000 - 6,000                        |
| Small Gas Turbine                    | 1,700- 3,500  | 150                   | 300                      | 2,000 - 10,000                       |

Table 1b: Summary of Cost Information in \$/MW (1999 Dollars)<sup>a, b</sup>

<sup>a</sup> (ICAC, 1997; NESCAUM, 2000; EPA, 2002)

<sup>b</sup> Assumes 85% capacity factor and annual control of NOx

° SCR installed on wood fired boiler assumes a hot side electrostatic precipitator for PM removal

<sup>d</sup> Coal and oil O&M and annual costs are based on 350MMBtu boiler, and gas turbine O&M and annual costs are based on 75 MW and 5 MW turbine

# Theory of Operation:

The SCR process chemically reduces the NOx molecule into molecular nitrogen and water vapor. A nitrogen based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and reagent diffuse through the catalyst. The reagent reacts selectively with the NOx within a specific temperature range and in the presence of the catalyst and oxygen.

Temperature, the amount of reducing agent, injection grid design and catalyst activity are the main factors that determine the actual removal efficiency. The use of a catalyst results in two primary advantages of the SCR process over the SNCR: higher NOx control efficiency and reactions within a lower and broader temperature range. The benefits are accompanied by a significant increase in capital and operating costs. The catalyst is composed of active metals or ceramics with a highly porous structure. Catalysts configurations are generally ceramic honeycomb and pleated metal plate (monolith) designs. The catalyst composition, type, and physical properties affect performance, reliability, catalyst quantity required, and cost. The SCR system supplier and catalyst supplier generally guarantee the catalyst life and performance. Newer catalyst designs increase catalyst activity, surface area per unit volume, and the temperature range for the reduction reaction.

Catalyst activity is a measure of the NOx reduction reaction rate. Catalyst activity is a function of many variables including catalyst composition and structure, diffusion rates, mass transfer rates, gas temperature, and gas composition. Catalyst deactivation is caused by:

- poisoning of active sites by flue gas constituents,
- thermal sintering of active sites due to high temperatures within reactor,
- blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter, and
- erosion due to high gas velocities.

As the catalyst activity decreases, NOx removal decreases and ammonia slip increases. When the ammonia slip reaches the maximum design or permitted level, new catalyst must be installed. There are several different locations downstream of the combustion unit where SCR systems can be installed. Most coal-fired applications locate the reactor downstream of the economizer and upstream of the air heater and particulate control devices (hot-side). The flue gas in this location is usually within the optimum temperature window for NOx reduction reactions using metal oxide catalysts. SCR may be applied after PM and sulfur removal

equipment (cold-side), however, reheating of the flue gas may be required, which significantly increases the operational costs.

SCR is very cost-effective for natural gas fired units. Less catalyst is required since the waste gas stream has lower levels of NOx, sulfur, and PM. Combined-cycle natural gas turbines frequently use SCR technology for NOx reduction. A typical combined-cycle SCR design places the reactor chamber after the superheater within a cavity of the heat recovery steam generator system (HRSG). The flue gas temperature in this area is within the operating range for base metal-type catalysts.

SCR can be used separately or in combination with other NOx combustion control technologies such as low NOx burners (LNB) and natural gas reburn (NGR). SCR can be designed to provide NOx reductions year-round or only during ozone season.

#### Advantages:

- Higher NOx reductions than low-NOx burners and Selective Non-Catalytic Reduction (SNCR)
- Applicable to sources with low NOx concentrations
- Reactions occur within a lower and broader temperature range than SNCR.
- Does not require modifications to the combustion unit

#### Disadvantages:

- Significantly higher capital and operating costs than low-NOx burners and SNCR
- Retrofit of SCR on industrial boilers is difficult and costly
- Large volume of reagent and catalyst required.
- May require downstream equipment cleaning.
- Results in ammonia in the waste gas stream which may impact plume visibility, and resale or disposal of ash.

#### **References:**

EPA, 1998. U.S. Environmental Protection Agency, Innovative Strategies and Economics Group, "Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis", Prepared by Pechan-Avanti Group, Research Triangle Park, NC. 1998.

EPA, 1999. US Environmental Protection Agency, Clean Air Technology Center. "Technical Bulletin: Nitrogen Oxides (NOx), Why and How They Are Controlled". Research Triangle Park, NC. 1998.

EPA, 2002. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. *EPA Air Pollution Control Cost Manual Section 4 Chapter 2*. EPA 452/B-02-001. 2002. http://www.epa.gov/ttn/catc/dir1/cs4-2ch2.pdf

Gaikwad, 2000. Gaikwad, Kurtides, and DePriest. "Optimizing SCR Reactor Design for Future Operating Flexibility". Presented at the Institute of Clean Air Companies Forum 2000. Washington D.C.

ICAC, 1997. Institute of Clean Air Companies, Inc. "White Paper: Selective Catalytic Reduction (SCR) Control of NOx Emissions". Washington, D.C. 1997.

ICAC, 2000. Institute of Clean Air Companies. "Optimizing SCR Reactor Design for Future Operating Flexibility". Washington, D.C. 2000.

NESCAUM, 2002. Northeast States for Coordinated Air Use Management. "Status Reports on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines: Technologies & Cost Effectiveness". Boston, MA. 2002.

OTAG 1998. OTAG Emissions Inventory Workgroup. "OTAG Technical Supporting Document: Chapter 5." Raleigh, North Carolina, US Environmental Protection Agency. 1998.

APPENDIX E EXCERPTS FROM FOSTER WHEELER OPERATORS MANUAL



The grate is fed onto the grate by means of two pneumatic fuel distributors situated on the furnace front wall. These are located above the grate and are evenly spaced across the width of the boiler. Each distributor receives litter from a metering feeder and blows it into the furnace using a variable pressure air stream.

The feeders are set up using a pulse air, rotating damper to regulate the front to back fuel trajectory onto the grate. Conveying air used by the feeders is supplied by a separate distributor air fan.

#### **1) Fuel Feeders**

The boiler is equipped with two variable speed twin screw feeders that are used to regulate fuel feed to each pneumatic distributor. These are located above and in close proximity to each fuel distributor.

Biomass fuel is metered into the boiler at a controlled rate set by load demand. The feeders are supplied with integral fuel bins that receive biomass from the plant conveyor.

#### m) Primary Air System (HTUsee Air & Flue Gas System DescriptionUTH)

A single variable speed motor driven FD fan provides combustion air to the grate. The fan is furnished with an inlet filter, venturi metering section and inlet silencer. Airflow control is split ranged using variable speed with inlet damper control at low load. The output of the fan is regulated from load demand from the combustion control system.

Air discharged from the fan is heated in the undergrate air heater prior to entering the undergrate air plenums.

#### n) Secondary Air System (JUsee Air & Flue Gas System DescriptionUTH)

A single variable speed motor driven FD fan provides combustion air to the overfire air nozzles above the grate. The fan is furnished with an inlet duct, venturi metering section, intake silencer and inlet control damper. Airflow control is split ranged using variable speed with inlet damper control at low load. The output of the fan is regulated from load demand from the combustion control system.

Discharge air is heated and directed to a series of overfire air nozzles on the front and rear furnace walls.

#### o) Distributor Air Fan

A single, constant speed distributor air fan is furnished to supply ambient air to the fuel distributors. The fan is set up to supply a constant amount of air and is unregulated by the operator.



#### General

The following description should be read in conjunction with drawing No. <u>113925V-</u> <u>0202</u> Air & Flue Gas P&ID.

#### Note:

FWL terminal points are designated as "TP FWL".

#### **Combustion Air System**

Air for combustion is supplied from two separate sources, undergrate air and overfire air. Each system is sized to deliver approximately 60% and 40% respectively of the required total combustion air. It is necessary that both systems be in operation to operate the boiler when firing biomass fuel.

#### Undergrate air

The undergrate air system provides combustion air to the under the grate air zones. A forced draft fan delivers ambient air to the grate taken from inside the building via an intake duct. The incoming air stream to the fan is metered through a venturi section 11FE-510, equipped with flow transmitter 11FT 510 (by others) and flow switch 11FSH 510 (by others). An intake silencer 11EDS 511 is furnished for noise attenuation downstream of the metering venturi.

An inlet louver damper 11EJM 511is furnished for low load control of airflow. This is driven by air operated actuator 11FY 510 in response to a 4-20mA control signal from the DCS combustion controls. The actuator is provided with open/closed limit switches 11ZSL510/ZSH 510 for proof of closed and purge positions.

The variable speed undergrate air fan is driven by an electric motor, 11MV 510 equipped with winding temperature thermostats. The fan is also equipped with bearing temperature monitors 11TE 510A/B.

The FD fan is equipped with a variable speed drive for discharge capacity control that is spilt ranged for operation with the inlet louver control damper. Fan speed is controlled from the characterized 4-20mA combustion control signal.

Pressure at the FD fan discharge is monitored by pressure transmitter 11PT 510 prior to being directed through a tubular air heater 11ESE 510 that is utilised to preheat the undergrate air. This is necessary with all high moisture fuels for optimum combustion conditions. The temperature of air leaving the air heater is unregulated and varies with load. Temperature is measured by transmitter 11TT 512.

The grate is divided into three separate air zones from front to back. These, in turn are subdivided into LH and RH sections for a total of six independent zones. Air to each zone can be biased by individual manual inlet dampers. Control of these dampers allows the

operator to manually bias the air split, front to back and side to side for optimum burning and emissions control.

WHEELER

Thermocouples 11TE 721A/B/C & 11TE 722 A/B/C are provided on the underside of the grate for temperature monitoring and alarm purposes.

#### **Overfire Air**

FOSTE

The overfire air system provides combustion air to a series of fixed nozzles that penetrate the furnace front and rear walls. There are three elevations of nozzles on the front wall and four elevations on the rear wall (see DSCo. Manual for details). These are optimized during commissioning and set up to inject air above the grate into a zone where suspension burning takes place. Different nozzle elevations are selected in order to provide optimum combustion conditions with minimum emissions.

Secondary air is drawn from inside the boiler building through an intake duct. The duct is equipped with a venturi section 11FE 515 and transmitter 11FT 515 (by others) for flow metering purposes. A silencer 11EDS 510 is provided on the fan intake for noise attenuation purposes.

An inlet louver damper 11EJM 510 is furnished for low load control of airflow. This is driven by air operated actuator 11FY 515 in response to a 4-20mA control signal from the DCS combustion controls. The actuator is provided with open/closed limit switches 11ZSL 515/ZSH 515 for proof of closed and purge positions.

The overfire air fan is driven by a variable speed electric motor 11MV 515 equipped with winding temperature thermostats. The motor is also equipped with bearing temperature detectors TE-A-09-006A/006B.

The fan is equipped with inboard and outboard bearing temperature detectors 11TE 515A/B.

The overfire air fan is equipped with a variable speed drive for discharge capacity control that is spilt ranged for operation with the inlet louver control damper. Fan speed is controlled from the characterized 4-20mA combustion control signal.

Pressure at the overfire air fan discharge is monitored by pressure transmitter 11PT 515 prior to being directed through a tubular air heater 11ESE 511 that is utilised to preheat the overfire air. The temperature of air leaving the air heater is unregulated and varies with load. Temperature is measured by transmitter 11TT 517.

Preheated air is routed through a series of ducts to the front and rear overfire air nozzles into the furnace. Isolation dampers are provided on the nozzles for operational flexibility since some nozzles, or complete nozzle elevations may not be used during normal operation.

APPENDIX F USEPA AIR CONTROL TECHNOLOGY FGD FACT SHEET



## Air Pollution Control Technology Fact Sheet

Name of Technology: Flue Gas Desulfurization (FGD) - Wet, Spray Dry, and Dry Scrubbers

**Type of Technology:** Control Device - absorption and reaction using an alkaline reagent to produce a solid compound.

Applicable Pollutants: Sulfur dioxide (SO<sub>2</sub>)

Achievable Emission Limits/Reductions: Scrubbers are capable of reduction efficiencies in the range of 50% to 98%. The highest removal efficiencies are achieved by wet scrubbers, greater than 90% and the lowest by dry scrubbers, typically less than 80%. Newer dry scrubber designs are capable of higher control efficiencies, on the order of 90%.

### Applicable Source Type: Point

**Typical Industrial Applications:** Stationary coal- and oil-fired combustion units such as utility and industrial boilers, as well as other industrial combustion units such as municipal and medical waste incinerators, cement and lime kilns, metal smelters, petroleum refineries, glass furnaces, and  $H_2SO_4$  manufacturing facilities. Approximately 85% of the FGD systems installed in the US are wet systems, 12% are spray dry and 3% are dry systems.

### **Emission Stream Characteristics:**

- **a. Combustion Unit Size:** SO<sub>2</sub> scrubbers have been applied combustion units firing coal and oil ranging in size from 5 MW to over 1,500 MW (50 MMBtu/hr to 15,000 MMBut/hr). Dry and spray scrubbers are generally applied to units less than 3,000 MMBtu/hr (300 MW) (EPA, 2000).
- b. Temperature: For wet scrubbers, typical inlet gas temperatures are 150°C to 370°C (300°F to 700°F) (FETC, 1996). For spray dry systems, the temperature of the flue gas exiting the absorber must be 10°C to 15°C (20°F to 30°F) above the adiabatic saturation temperature. Optimal temperatures for SO<sub>2</sub> removal for dry sorbent injection systems range from 150°C to 180°C (300°F to 350°F). Optimal temperatures for SO<sub>2</sub> removal when applying dry sorbent injection systems vary between 150°C to 1000°C (300°F to 1830°F) depending on the sorbent properties (Joseph, 1998)
- **c. Pollutant Loading:** SO<sub>2</sub> scrubbers are limited to dilute SO<sub>2</sub> waste gas streams of approximately 2000 ppm.(Cooper, 2002).
- **d. Other Considerations:** The amount of chlorine in the flue gas affects the amount of water evaporated by the system due to the formation of salts. Chlorine content improves the SO<sub>2</sub> removal but also results in salt deposition on the absorber and downstream equipment (Schnelle, 2002).

An additional or upgraded induced draft (ID) fan may be required to compensate for flue gas pressure drop across the absorber.

Many wet systems reheat the flue gas downstream of the absorber to prevent corrosion caused by condensation inside the ducts and stack and reduce plume visibility.

**Emission Stream Pretreatment Requirements:** In spray dry and dry injection systems, the flue gas must be cooled to a temperature range of 10°C to 15°C (20°F to 30°F) above adiabatic saturation. This temperature range avoids wet solids deposition on downstream equipment and plugging of the baghouse. A heat recovery boiler, an evaporative cooler or a heat exchanger is typically used to cool the gas.

### **Cost Information:**

Capital costs for SO<sub>2</sub> scrubbers have decreased by over 30% since the beginning of the 1990's. Current costs for SO<sub>2</sub> scrubbers applied to electric utilities are reported to be approximately \$100/kW (Smith, 2001). Retrofit of scrubbers on existing units can increase the capital cost up to 30%. Retrofit costs vary significantly between sites and depend on space limitations, major modifications to existing equipment (e.g., ductwork and stack) and the operating condition of the units (e.g., temperature, flowrate).

O&M costs increase with increasing sulfur content since more reagent is required to treat the same volume of gas. Typical reagents such as lime and limestone are inexpensive; however, the use of proprietary reagents or reagent enhancers or additives that can significantly increase the O&M cost. Limestone is generally available for 10 to 20 \$/ton and lime is available for 60 to 80 \$/ton (Smith, 2001). Waste product disposal costs vary from \$10/ton to \$30/ton and byproduct saleable prices vary from 0 to 15 \$/ton (Smith, 2001). The addition of a scrubbers causes a loss of energy available for generating steam due to evaporation of water and the energy required to drive the reaction. New scrubber designs result in an energy penalty of less than 1% of the total plant energy (Srivastava, 2001).

|               | Unit Size  | Capital Cost        | O&M Cost <sup>b</sup> | Annual Cost     | Cost per Ton of   |
|---------------|------------|---------------------|-----------------------|-----------------|-------------------|
| Scrubber Type | Unit Size  | Capital Cost        | Odivi Cost            | Annual Cost     | Pollutant Removed |
|               | (MMBtu/hr) | (\$/MMBtu)          | (\$/MMBtu)            | (\$/MMBtu)      | (\$/ton)          |
| Wet           | > 4,000    | 10,000 -25,000      | 200 - 800             | 25 - 40         | 200 - 500         |
|               | < 4,000    | 25,000 -<br>150,000 | 800 - 1,800           | 60 - 600        | 500 - 5,000       |
| Spray Dry     | > 2,000    | 4,000 - 15,000      | 600 - 1,000           |                 | 150 - 300         |
|               | < 2,000    | 30,000 -<br>150,000 | 1,000 - 30,000        | 10,000 - 50,000 | 500 - 4,000       |

Table 1a: Summary of Cost Information in \$/MMBtu/hr (2001 Dollars) <sup>a</sup>

Table 1b: Summary of Cost Information in \$/MW (2001 Dollars) <sup>a</sup>

| Scrubber  | Unit Size | Capital Cost | O&M Cost <sup>b</sup> | Annual Cost | Cost per Ton of<br>Pollutant Removed |
|-----------|-----------|--------------|-----------------------|-------------|--------------------------------------|
| Туре      | (MW)      | (\$/kW)      | (\$/kW)               | (\$/kW)     | (\$/ton)                             |
| Wet       | > 400     | 100 - 250    | 2 - 8                 | 20 - 50     | 200 - 500                            |
|           | < 400     | 250 - 1,500  | 8 - 20                | 50 - 200    | 500 - 5,000                          |
| Spray Dry | > 200     | 40 - 150     | 4 - 10                | 20 -50      | 150 - 300                            |
|           | < 200     | 150 - 1,500  | 10 - 300              | 50 - 500    | 500 - 4,000                          |

<sup>a</sup> (EIA, 2002; EPA, 2000; Srivastava, 2001)

<sup>b</sup> Assumes capacity factor > 80%

### Theory of Operation:

The FDG or  $SO_2$  scrubbing process typically uses a calcium or sodium based alkaline reagent. The reagent is injected in the flue gas in a spray tower or directly into the duct. The  $SO_2$  is absorbed, neutralized and/or oxidized by the alkaline reagent into a solid compound, either calcium or sodium sulfate. The solid is removed from the waste gas stream using downstream equipment.

Scrubbers are classified as "once-through" or "regenerable", based on how the solids generated by the process are handled. Once-through systems either dispose of the spent sorbent as a waste or utilize it as a byproduct. Regenerable systems recycle the sorbent back into the system. At the present time, regenerable processes have higher costs than once-through processes; however, regenerable processes might be chosen if space or disposal options are limited and markets for byproducts (gypsum) are available (Cooper, 2002). In 1998, approximately 3% of FDG systems installed in the US were regenerable.

Both types of systems, once-through and regenerable, can be further categorized as wet, dry, or semi-dry. Each of these processes is described in the following sections.

### Wet Systems

In a wet scrubber system, flue gas is ducted to a spray tower where an aqueous slurry of sorbent is injected into the flue gas. To provide good contact between the waste gas and sorbent, the nozzles and injection locations are designed to optimize the size and density of slurry droplets formed by the system. A portion of the water in the slurry is evaporated and the waste gas stream becomes saturated with water vapor. Sulfur dioxide dissolves into the slurry droplets where it reacts with the alkaline particulates. The slurry falls to the bottom of the absorber where it is collected. Treated flue gas passes through a mist eliminator before exiting the absorber which removes any entrained slurry droplets. The absorber effluent is sent to a reaction tank where the  $SO_2$ -alkali reaction is completed forming a neutral salt. In a regenerable system, the spent slurry is recycled back to the absorber. Once through systems dewater the spent slurry for disposal or use as a by-product.

Typical sorbent material is limestone, or lime. Limestone is very inexpensive but control efficiencies for limestone systems are limited to approximately 90%. Lime is easier to manage on-site and has control efficiencies up to 95% but is significantly more costly (Cooper 2002). Proprietary sorbents with reactivity-enhancing additives provide control efficiencies greater than 95% but are very costly. Electrical utilities store large volumes of limestone or lime on site and prepare the sorbent for injection, but this is generally not cost effective for smaller industrial applications.

The volume ratio of reagent slurry to waste gas is referred to as the liquid to gas ratio (L/G). The L/G ratio determines the amount of reagent available for reaction with  $SO_2$ . Higher L/G ratios result in higher control efficiencies. Higher L/G also increases oxidation of the  $SO_2$ , which results in a decrease of the formation of scale in the absorber. O&M costs are a direct function of reagent usage, so increasing the L/G increases annual costs. L/G ratios are approximately 1:1 for wet scrubbers and are expressed as gallons of slurry per 1000 ft<sup>3</sup> of flue gas (liters of slurry/1000Nm<sup>3</sup> of flue gas).

Oxidation of the slurry sorbent causes gypsum (calcium sulfate) scale to form in the absorber. Limestone forced oxidation (LSFO) is a newer process based on wet limestone scrubbing which reduces scale. In LSFO, air is added to the reaction tank which oxidizes the spent slurry to gypsum. The gypsum is removed from the reaction tank prior to the slurry being recycled to the absorber. The recycle slurry has a lower concentration of gypsum and scale formation in the absorber is significantly reduced. Gypsum can be commercially sold, eliminating the need for landfilling of the waste product (Srivastava, 2001). In addition to scale control, the larger size gypsum crystals formed in LSFO settle and dewater

more efficiently, reducing the size of the byproduct handling equipment (EPA, 2002). However, LSFO requires additional blowers which increase the capital and annual costs of the system.

Wet limestone scrubbing has high capital and operating cost due to the handling of liquid reagent and waste. Nonetheless, it is the preferred process for coal-fired electric utility power plants burning coal due to the low cost of limestone and  $SO_2$  control efficiencies from 90% up to 98% (Schnelle, 2002).

### Semi-Dry Systems

Semi-dry systems, or spray dryers, inject an aqueous sorbent slurry similar to a wet system, however, the slurry has a higher sorbent concentration. As the hot flue gas mixes with the slurry solution, water from the slurry is evaporated. The water that remains on the solid sorbent enhances the reaction with  $SO_2$ . The process forms a dry waste product which is collected with a standard particulate matter (PM) collection device such as a baghouse or ESP. The waste product can be disposed, sold as a byproduct or recycled to the slurry.

Various calcium and sodium based reagents can be utilized as sorbent. Spray dry scrubbers typically inject lime since it is more reactive than limestone and less expensive than sodium based reagents. The reagent slurry is injected through rotary atomizers or dual-fluid nozzles to create a finer droplet spray than wet scrubber systems (Srivastava, 2000).

The performance of a lime spray dry scrubber is more sensitive to operating conditions. A "close approach" to adiabatic saturation temperature is required to maximize the removal of  $SO_2$ . However, excess moisture causes the wet solids to deposit on the absorber and downstream equipment. The optimum temperature is 10°C to 15°C (20°F to 50°F) below saturation temperature (Srivastava, 2000). Lower L/G ratios, approximately 1:3, must be utilized do to the limitation on flue gas moisture (Schnelle, 2002). Flue gas with high  $SO_2$  concentrations or temperatures reduce the performance of the scrubber (Schnelle, 2002).

 $SO_2$  control efficiencies for spray dry scrubbers are slightly lower than wet systems, between 80% and 90% due to its lower reactivity and L/G ratios. Application of a single spray dry absorber is limited to combustion units less than 200 MW (2,000 MMBtu/hr) (IEA, 2001). Larger combustion units require multiple absorber systems. The capital and operating cost for spray dry scrubbers are lower than for wet scrubbing because equipment for handling wet waste products is not required. In addition, carbon steel can be used to manufacture the absorber since the flue gas is less humid. Typically applications include electric utility units burning low- to medium- sulfur coal, industrial boilers, and municipal waste incinerators that require 80%  $SO_2$  control efficiency (Schnelle, 2002).

### Dry systems

Dry sorbent injection systems, pneumatically inject powdered sorbent directly into the furnace, the economizer, or downstream ductwork. The dry waste product is removed using particulate control equipment such as a baghouse or electrostatic precipitator (ESP). The flue gas is generally cooled prior to the entering the PM control device. Water can be injected upstream of the absorber to enhance SO<sub>2</sub> removal (Srivastava, 2001).

Furnace injection requires flue gas temperatures between 950°C to 1000°C (1740°F to 1830°F) in order to decompose the sorbent into porous solids with high surface area (Srivastava 2001). Injection into the economizer requires temperatures of 500°C to 570°C (930°F to 1060°F) (Srivastava 2001). Duct injection requires the dispersion of a fine sorbent spray into the flue gas downstream of the air preheater. The injection must occur at flue gas temperatures between 150°C to 180°C (300°F to 350°F) (Joseph, 1998).

Dry sorbent systems typically use calcium and sodium based alkaline reagents. A number of proprietary reagents are also available. A typical injection system uses several injection lances protruding from the furnace or duct walls. Injection of water downstream of the sorbent injection increases  $SO_2$  removal by the sorbent.

An even distribution of sorbent across the reactor and adequate residence time at the proper temperature are critical for high  $SO_2$  removal rates (Srivastava 2001). Flue gas must be kept 10°C to 15°C (20°F to 50°F) below saturation temperature to minimize deposits on the absorber and downstream equipment.

Dry scrubbers have significantly lower capital and annual costs than wet systems because they are simpler, demand less water and waste disposal is less complex. Dry injection systems install easily and use less space, therefore, they are good candidates retrofit applications.  $SO_2$  removal efficiencies are significantly lower than wet systems, between 50% and 60% for calcium based sorbents. Sodium based dry sorbent injection into the duct can achieve up to 80% control efficiencies (Srivastava 2001). Dry sorbent injection is viewed as an emerging  $SO_2$  control technology for medium to small industrial boiler applications. Newer applications of dry sorbent injection on small coal-fired industrial boilers have achieved greater than 90%  $SO_2$  control efficiencies.

### Advantages:

- High  $SO_2$  removal efficiencies, from 50% up to 98%.
- Products of reaction may be reusable
- Difficulty of retrofit is moderate to low
- Inexpensive and readily available reagents

#### Disadvantages:

- High capital and O&M costs
- Scaling and deposit of wet solids on absorber and downstream equipment
- Wet systems generate a wet waste product and may result in a visible plume
- Cannot be used for waste gas SO<sub>2</sub> concentrations greater than 2,000 ppm
- Disposal of waste products significantly increases O&M costs

### **References:**

Cooper, 2002. Cooper, C.D. and Alley, F.C. *Air Pollution Control : A Design Approach*. Waveland Press, Inc. Prospect Heights, IL, 2002.

EPA, 2000. Srivastava Ravi K. *Controlling SO*<sub>2</sub> *Emissions: A Review of Technologies.* US Environmental Protection Agency, Office of Research and Development. EPA/600/R-00/093. Washington, D.C. 2002. http://www.epa.gov/ordntrnt/ORD/WebPubs/so2/index.html

FETC, 1996. *Electric Utility Engineer's FGD Manual, Volume 1: FGD Process Design.* Department of Energy, Federal Energy Technology Center. Morgantown, WV, 1996.

IEA, 2001. "Coal Research, Sorbent Injection Systems for SO<sub>2</sub> Control", Clean Coal Technologies Database. <u>http://ww.iea-coal.org.uk/CCTdatabase/sorbing.htm.</u>

Joseph, 1998. Joseph, G. T. and Beachler, D.S. "Scrubber Systems Operation Review APTI Course". Developed by North Carolina State University under EPA Cooperative Assistance Agreement. Raleigh, N.C 1998.

Schenelle, 2002. Schenelle, K.B. Jr and Brown, C.A. *Air Pollution Control Technology Handbook*. CRC Press LLC. Boca Raton, FL. 2002.

Smith 2001. Smith, Douglas. "SO<sub>2</sub> Controls: Cost of Scrubbers down to \$100/kW". Power Engineering, September, 2001.

Srivastava, 2001. Srivastava R. K., and W. Josewicz.. "Flue Gas Desulfurization: The State of the Art". Air and Waste Management Assoc., 51:1676-1688, 2001.

EIA, 2002. EIA-767 Database; Annual Steam-Electric Plant Operation and Design Data, 2001. Energy Information Administration, Department of Energy. November 26, 2002. http://www.eia.doe.gov/cneaf/electricity/page/eia767.html

# ERM has over 160 offices across the following countries and territories worldwide

Argentina Australia Belgium Brazil Canada Chile China Colombia France Germany Ghana Guyana Hong Kong India Indonesia Ireland Italy Japan Kazakhstan Kenya Malaysia Mexico Mozambique Myanmar

The Netherlands New Zealand Norw ay Panama Peru Poland Portugal Puerto Rico Romania Russia Senegal Singapore South Africa South Korea Spain Sw eden Sw itzerland Taiw an Tanzania Thailand UAE UK US Vietnam

#### ERM's Minneapolis Office

222 South 9<sup>th</sup> Street Suite 2900 Minneapolis, MN

T: 612.347.6789

www.erm.com



# **Hibbing Taconite Company**

Managed by ArcelorMittal Hibbing Management LLC

May 29, 2020

Hassan M. Bouchareb Minnesota Pollution Control Agency 520 Lafayette Road North St. Paul, MN 55155-4194

### Re: ArcelorMittal Hibbing Taconite Company Request for Information – Four Factor Analysis

Mr. Bouchareb,

ArcelorMittal Hibbing Taconite Company (HTC) has prepared the enclosed Regional Haze Four-Factor Analysis Applicability Evaluation (Evaluation) in response to the Minnesota Pollution Control Agency's (MPCA) January 29, 2020 request for information and a Four Factor Analysis for the natural gas fired indurating furnace Lines 1-3 (EQUI 95-97/EU 020-022).

HTC respectfully requests MPCA timely withdraw its request for HTC to prepare a four-factor analysis for the natural gas fired indurating furnace Lines 1-3 which are already equipped with Newly Engineered Site-Specific Low  $NO_X$  Burner Technology and Taconite MACT scrubbers. The Evaluation provides evidence for MPCA to exclude HTC from the group of sources analyzed for control measures for the second implementation period and to withdraw its request for a Four Factor Analysis.

Should you have any questions or comments regarding this submittal, please contact Julie Lucas, Environmental Manager, by telephone at 218-262-6856 or via email at julie.lucas@arcelormittal.com

Sincerely,

Edward h LaTert

Edward M. LaTendresse General Manager

cc: Julie C. Lucas (ArcelorMittal USA) Rich Zavoda (ArcelorMittal USA)



# Regional Haze Four-Factor Analysis Applicability Evaluation

Natural Gas Fired Indurating Furnace Lines 1-3 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers (EQUI 95-97/EU 020-022)

Prepared for Hibbing Taconite Company

May 29, 2020

325 South Lake Avenue Duluth, MN 55802 218.529.8200 www.barr.com

## Regional Haze Four-Factor Analysis Applicability Evaluation

May 29, 2020

# Contents

| 1 |     | Exe   | ecutive            | Summary  | 1  |
|---|-----|-------|--------------------|--|----|
| 2 |     | Int   | roduct             | ion  | 3  |
|   | 2.1 |       | Regula             | tory Background  | 3  |
|   | 2   | 2.1.1 | Min                | nesota's Request for Information (RFI)                                   | 3  |
|   | 2   | 2.1.2 | SIP                | Revision Requirements  | 4  |
|   | 2   | 2.1.3 | USE                | PA Guidance for SIP Development  | 5  |
|   |     | 2.1   | .3.1               | Ambient Data Analysis  | 6  |
|   |     | 2.1   | .3.2               | Selection of sources for analysis  | 6  |
|   |     | 2.1   | .3.2.1             | Estimating Baseline Visibility Impacts for Source Selection              | 8  |
|   |     | 2.1   | .3.3               | Sources that Already have Effective Emission Control Technology in Place | 8  |
|   | 2.2 |       | Facility           | Description  | 9  |
| 3 |     | An    | alysis o           | of Ambient Data  | 11 |
|   | 3.1 |       | Visibili           | ty Conditions  | 11 |
|   | 3.2 |       | Regior             | al emissions reductions  | 14 |
| 4 |     | Vis   | sibility           | mpacts   | 16 |
| 5 |     | Eva   | aluatio            | n of "Effectively Controlled" Source                                     | 18 |
|   | 5.1 |       | NO <sub>X</sub> B  | ART-required Controls  | 18 |
|   | 5.2 |       | SO <sub>2</sub> BA | RT-required Controls   | 20 |
| 6 |     | Со    | onclusio           | on   | 22 |

### List of Tables

| Table 2-1 | Identified Emission Units             | 4  |
|-----------|---------------------------------------|----|
| Table 3-1 | Notable Minnesota Emission Reductions | 15 |
| Table 5-1 | NO <sub>x</sub> Emission Limits       | 20 |
| Table 5-2 | SO <sub>2</sub> Emission Limits       | 21 |

### List of Figures

| Figure 2-1 | Natural Gas Fired Straight Grate Furnace Equipped with Newly Engineered Site-Specific |    |
|------------|---|----|
|            | Low NOx Burner Technology and Taconite MACT Scrubbers Diagram                         | 10 |
| Figure 3-1 | Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)                      | 12 |
| Figure 3-2 | Visibility Trend versus URP – Voyageurs National Park (VOYA1)                         | 13 |
| Figure 3-3 | Visibility Trend versus URP – Isle Royale National Park (ISLE1)                       | 13 |
| Figure 3-4 | Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)          | 14 |

### List of Appendices

Appendix A Visibility Impacts

# 1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency (MPCA) submitted a Request for Information (RFI) Letter<sup>1</sup> to Hibbing Taconite Company (HTC) to consider potential emissions reduction measures of nitrogen oxides (NO<sub>X</sub>) and sulfur dioxide (SO<sub>2</sub>) from the facility's indurating furnaces by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i), as explained in the August 2019 U.S. EPA Guidance (2019 Guidance)<sup>2</sup>:

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

Emission reduction evaluations addressing these factors are commonly referred to as "four-factor analyses." MPCA set a July 31, 2020 deadline for HTC to submit a four-factor analysis. The MPCA intends to use the four-factor analyses to evaluate additional control measures as part of the development of the State Implementation Plan (SIP), which must be submitted to United States Environmental Protection Agency (USEPA) by July 31, 2021. The SIP will be prepared to address the second regional haze implementation period, which ends in 2028.

This report considers whether a four-factor analysis is warranted for HTC because the indurating furnace Lines 1-3 can be classified as "effectively controlled" sources for  $NO_x$  and  $SO_2$ . The MPCA can exclude such sources for evaluation per the regulatory requirements of the Regional Haze Rule<sup>3</sup> (RHR) and the 2019 Guidance.

This report provides evidence that it would be reasonable for MPCA to exclude HTC from the group of sources analyzed for control measures for the second implementation period and to withdraw its request for a four-factor analysis for the indurating furnace Lines 1-3 based on the following points (with additional details provided in cited report sections):

The indurating furnace Lines 1-3 meet the BART-required control equipment installation scenario and are "effectively controlled" sources for NO<sub>x</sub> and SO<sub>2</sub>. HTC has BART emission controls and emission limits for NO<sub>x</sub> and SO<sub>2</sub> in accordance with 40 CFR 52.1235(b)(1) and 52.1235(b)(2), respectively. The associated BART analyses are provided in the August 2012<sup>4</sup> and October 2015<sup>5</sup> USEPA Federal Implementation Plan (FIP) rulemaking. (see Section 5)

<sup>&</sup>lt;sup>1</sup> January 29, 2020 letter from Hassan Bouchareb of MPCA to Hibbing Taconite Company.

<sup>&</sup>lt;sup>2</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019

<sup>&</sup>lt;sup>3</sup> USEPA, Regional Haze Rule Requirements – Long Term Strategy for Regional Haze, 40 CFR 52.308(f)(2)

<sup>&</sup>lt;sup>4</sup> USEPA, Federal Register, 08/15/2012, Page 49308.

<sup>&</sup>lt;sup>5</sup> USEPA, Federal Register, 10/22/2015, Page 64160.

- The RHR and the 2019 Guidance both give states the ability to focus their analyses in one implementation period on a set of sources that differ from those analyzed in another implementation period. (see Section 2.1.3.2)
- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress. (see Section 3.1)
- The indurating furnace Lines 1-3 do not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4)

Additional emission reductions from the indurating furnace Lines 1-3 at HTC will not contribute meaningfully to further reasonable progress. Therefore, HTC respectfully requests that the MPCA timely withdraw its request for a four-factor analysis for the natural gas fired indurating furnace Lines 1-3 already equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT scrubbers.

# 2 Introduction

Section 2.1 discusses the RFI provided to HTC by MPCA, pertinent regulatory background for regional haze State Implementation Plans (SIP) development and relevant guidance issued by USEPA to assist States in preparing their SIPs, specifically regarding the selection of sources that must conduct an emissions control evaluation. Section 2.2 provides a description of HTC's indurating furnaces.

### 2.1 Regulatory Background

### 2.1.1 Minnesota's Request for Information (RFI)

"Regional haze" is defined at 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic 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 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 initial SIP was informed by best available retrofit technology (BART) analyses that were completed on all BART-subject sources. The second RHR implementation period ends in 2028 and requires development and submittal of a comprehensive SIP update by July 31, 2021.

As part of the second RHR implementation period SIP development, the MPCA sent an RFI to HTC on January 29, 2020. The RFI stated that data from the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) 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 SO<sub>2</sub> and NO<sub>x</sub> that react with available ammonia. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan.<sup>6</sup> As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFI also stated that HTC was identified as a significant source of  $NO_X$  and  $SO_2$  and is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that HTC submit a "four-factors analysis" (herein termed as a "four-factor analysis") evaluating potential emissions control measures, pursuant to 40 CFR 51.308(f)(2)(i)<sup>7</sup>, by July 31, 2020 for the emission units identified in Table 2-1.

<sup>&</sup>lt;sup>6</sup> Although Michigan is responsible for evaluating haze in Isle Royale, it must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts.

<sup>&</sup>lt;sup>7</sup> The four statutory factors are 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts of compliance, and 4) remaining useful life of the source.

### Table 2-1 Identified Emission Units

| Unit  | Unit ID        | Applicable Pollutants             |
|---|----------------|-----------------------------------|
| Natural Gas Fired Indurating Furnace Line No 1<br>Equipped with Newly Engineered Site-Specific Low<br>NOx Burner Technology and Taconite MACT Scrubbers | EQUI 95/EU 020 | NO <sub>x</sub> , SO <sub>2</sub> |
| Natural Gas Fired Indurating Furnace Line No 2<br>Equipped with Newly Engineered Site-Specific Low<br>NOx Burner Technology and Taconite MACT Scrubbers | EQUI 96/EU 021 | NOx, SO2                          |
| Natural Gas Fired Indurating Furnace Line No 3<br>Equipped with Newly Engineered Site-Specific Low<br>NOx Burner Technology and Taconite MACT Scrubbers | EQUI 97/EU 022 | NO <sub>X</sub> , SO <sub>2</sub> |

The RFI to HTC specified that the "analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to USEPA guidance as issued on August 20, 2019<sup>8</sup>.

### 2.1.2 SIP Revision Requirements

The regulatory requirements for comprehensive revisions to the SIP are provided in 40 CFR 51.308(f). The next revision must be submitted to USEPA by July 31, 2021 and must include a commitment to submit periodic reports describing progress towards the reasonable progress goals as detailed in 40 CFR 51.308(g). The SIP "must address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State."

Each SIP revision is required to address several elements, including "calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress." <sup>9</sup> The baseline conditions are based on monitoring data from 2000 to 2004 while the target conditions for natural visibility are determined using USEPA guidance. The State will then determine the uniform rate of progress (URP) which compares "the baseline visibility condition for the most impaired days to the natural visibility condition for the most impaired days to the natural visibility condition for the most impaired days of improvement (measured in deciviews of improvement per year) that would need to be maintained during each implementation period in order to attain natural visibility conditions by the end of 2064."<sup>10</sup>

The SIP revision must also include the "Long-term strategy for regional haze."<sup>11</sup> The strategy "must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress" towards the natural visibility goal. There are several criteria that must be considered when developing the strategy, including an evaluation of emission controls (the four-factor analysis) at selected facilities to determine emission reductions necessary to make reasonable

<sup>&</sup>lt;sup>8</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019

<sup>&</sup>lt;sup>9</sup> 40 CFR 51.308(f)(1)

<sup>&</sup>lt;sup>10</sup> 40 CFR 51.308(f)(1)(vi)(A)

<sup>&</sup>lt;sup>11</sup> 40 CFR 51.308(f)(2)

progress. The SIP must consider other factors in developing its long-term strategy, including: emission reductions due to other air pollution control programs<sup>12</sup>, emission unit retirement and replacement schedules<sup>13</sup>, and the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during the implementation period<sup>14</sup>.

In addition, the SIP must include "reasonable progress goals" that reflect the visibility conditions that are anticipated to be achieved by the end of the implementation period through the implementation of the long term strategy and other requirements of the Clean Air Act (CAA)<sup>15</sup>. The reasonable progress goal is not enforceable but will be considered by USEPA in evaluating the adequacy of the SIP<sup>16</sup>.

### 2.1.3 USEPA Guidance for SIP Development

On August 20, 2019, the USEPA issued "*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*"<sup>17</sup> USEPA's primary goal in issuing the 2019 Guidance was to help states develop "approvable" SIPs. EPA also stated that the document supports key principles in SIP development, such as "leveraging emission reductions achieved through CAA and other programs that further improve visibility in protected areas."<sup>18</sup>

The 2019 Guidance says SIPs must be "consistent with applicable requirements of the CAA and EPA regulations, and are the product of reasoned decision-making"<sup>19</sup> but also emphasizes States' discretion and flexibility in the development of their SIPs. For instance, the 2019 Guidance states, "A key flexibility of the regional haze program is that a state is *not* required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures."<sup>20</sup> The 2019 Guidance notes this flexibility to not consider every emission source stems directly from CAA § 169A(b)(2) and 40 CFR § 51.308(f)(2)(i), the section of the RHR the MPCA cites in its letter.<sup>21</sup>

The 2019 Guidance lists eight key process steps that USEPA anticipates States will follow when developing their SIPs. This report focuses on the selection of sources which must conduct a four-factor analysis and references the following guidance elements which impact the selection:

• Ambient data analysis (Step 1), including the progress, degradation and URP glidepath checks (Step 7)

<sup>&</sup>lt;sup>12</sup> 51.308(f)(2)(iv)(A)

<sup>&</sup>lt;sup>13</sup> 51.308(f)(2)(iv)(C)

<sup>&</sup>lt;sup>14</sup> 51.308(f)(2)(iv)(E)

<sup>15 40</sup> CFR 51.308(f)(3)

<sup>&</sup>lt;sup>16</sup> 40 CFR 51.308(f)(3)(iii)

 <sup>&</sup>lt;sup>17</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019
 <sup>18</sup> Ibid, page 1.

<sup>&</sup>lt;sup>19</sup> Ibid.

<sup>&</sup>lt;sup>20</sup> Ibid, page 9 (emphasis added).

<sup>&</sup>lt;sup>21</sup> Ibid.

- Selection of sources for analysis (Step 3), with a focus on:
  - Estimating baseline visibility impacts for source selection (Step 3b)
  - o Sources that already have effective emission control technology in place (Step 3f)

### 2.1.3.1 Ambient Data Analysis

As stated in Section 2.1.2, the RHR requires each state with a Class I area to calculate the baseline, current, and natural visibility conditions as well as to determine the visibility progress to date and the URP. The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). The guidance provides the following equation for calculating the Uniform Rate of Progress (URP):<sup>22</sup>

URP = [(2000-2004 visibility)<sub>20% most impaired</sub> – (natural visibility)<sub>20% most impaired</sub>]/60

The visibility from 2000-2004 represents the baseline period, and the natural visibility goal is in 2064, which is why the URP is calculated over a 60-year period.

At the end of the SIP development process a State must estimate the visibility conditions for the end of the implementation period and then must complete a comparison of the reasonable progress goals to the baseline visibility conditions and the URP glidepath. The guidance explains that the RHR does not define the URP as the target for "reasonable progress" and further states that if the 2028 estimate is below the URP glidepath, that does not exempt the State from considering the four-factor analysis for select sources.<sup>23</sup> However, the current visibility conditions compared to the URP glidepath will be a factor when determining the reasonable progress goal.

In Section 3, Barr evaluates the visibility improvement progress to date at BWCA, Voyageurs and Isle Royale using the IMPROVE network visibility data from MPCA's website. This analysis was conducted to document the current visibility conditions compared to the URP, which can provide insight into the amount of emission reductions necessary to have the 2028 visibility conditions below the URP.

### 2.1.3.2 Selection of sources for analysis

The 2019 Guidance emphasizes that the RHR provides flexibility in selecting sources that must conduct an emission control measures analysis:

"...a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures...."<sup>24</sup>

<sup>&</sup>lt;sup>22</sup> Ibid, Page 7.

<sup>&</sup>lt;sup>23</sup> Ibid, Page 50.

<sup>&</sup>lt;sup>24</sup> Ibid, Page 9.

The 2019 Guidance goes on to justify this approach (emphasis added):

"Selecting a set of sources for analysis of control measures in each implementation period is also consistent with the Regional Haze Rule, which sets up an iterative planning process and anticipates that a state may not need to analyze control measures for all its sources in a given SIP revision. Specifically, section 51.308(f)(2)(i) of the Regional Haze Rule requires a SIP to include a description of the criteria the state has used to determine the sources or groups of sources it evaluated for potential controls. Accordingly, <u>it is reasonable and permissible for a state to distribute its own analytical work, and the compliance expenditures of source owners, over time by addressing some sources in the second implementation period and other sources in later <u>periods</u>. For the sources that are not selected for an analysis of control measures for purposes of the second implementation period, it may be appropriate for a state to consider whether measures for such sources are necessary to make reasonable progress in later implementation periods."<sup>25</sup></u>

The 2019 Guidance further states that there is not a list of factors that a state must consider when selecting sources to evaluate control measures, but the state must choose factors and apply them in a reasonable way to make progress towards natural visibility. The guidance details several factors that could be considered, including:

- the in-place emission control measures and, by implication, the emission reductions that are possible to achieve at the source through additional measures<sup>26</sup>
- the four statutory factors (to the extent they have been characterized at this point in SIP development)<sup>27</sup>
- potential visibility benefits (also to the extent they have been characterized at this point in SIP development)<sup>28</sup>
- sources already having effective emissions controls in place<sup>29</sup>
- emission reductions at the source due to ongoing air pollution control programs<sup>30</sup>
- in-state emission reductions due to ongoing air pollution control programs that will result in an improvement in visibility<sup>31</sup>

- 27 Ibid.
- <sup>28</sup> Ibid.

<sup>31</sup> Ibid.

<sup>&</sup>lt;sup>25</sup> Ibid, Page 9.

<sup>&</sup>lt;sup>26</sup> Ibid, Page 10.

<sup>&</sup>lt;sup>29</sup> Ibid, Page 21.

<sup>&</sup>lt;sup>30</sup> Ibid, Page 22.

Furthermore, the 2019 Guidance states that "An initial assessment of projected visibility impairment in 2028, considering growth and on-the books controls, can be a useful piece of information for states to consider as they decide how to select sources for control measure evaluation."<sup>32</sup>

### 2.1.3.2.1 Estimating Baseline Visibility Impacts for Source Selection

When selecting sources to conduct an emission control evaluation, the 2019 Guidance says that the state may use a "reasonable surrogate metrics of visibility impacts." The guidance provides the following techniques to consider and says that "other reasonable techniques" may also be considered<sup>33</sup>:

- Emissions divided by distance (Q/d)
- Trajectory analyses
- Residence time analyses
- Photochemical modeling

In regard to documenting the source selection process, the 2019 Guidance states:<sup>34</sup>

"EPA recommends that this documentation and description provide both a summary of the state's source selection approach and a detailed description of how the state used technical information to select a reasonable set of sources for an analysis of control measures for the second implementation period. The state could include qualitative and quantitative information such as: the basis for the visibility impact thresholds the state used (if applicable), additional factors the state considered during its selection process, and any other relevant information."

In Section 4, Barr presents a trajectory analysis using data from the IMPROVE monitoring network as presented on MPCA's website and photochemical modeling results to demonstrate that it is not appropriate to select the taconite indurating furnaces as sources subject to the emissions control measures analysis because reducing the emissions will not have a large impact on visibility. Section 4 also presents information from the IMPROVE monitoring system which demonstrates that there was not a noticeable improvement in visibility in 2009 when the taconite plants experienced a production curtailment due to a recession which indicates that the reduction of pollutants from taconite facilities will not result in a discernable visibility improvement in the Class 1 areas.

### 2.1.3.3 Sources that Already have Effective Emission Control Technology in Place

The 2019 Guidance identified eight example scenarios and described the associated rationale for when sources should be considered "effectively controlled" and that states can exclude similar sources from needing to complete a "four-factor analysis."<sup>35</sup> One of the "effectively controlled" scenarios is for "BART-

<sup>&</sup>lt;sup>32</sup> Ibid, Page 10.

<sup>&</sup>lt;sup>33</sup> Ibid, Page 12.

<sup>&</sup>lt;sup>34</sup> Ibid, Page 27.

<sup>&</sup>lt;sup>35</sup> Ibid, Page 22.

eligible units that installed and began operating controls to meet BART emission limits for the first implementation period."<sup>36</sup> USEPA caveats this scenario by clarifying that "states may not categorically exclude all BART-eligible sources, or all sources that installed BART control, as candidates for selection for analysis of control measures."<sup>37</sup> USEPA further notes that "a state might, however, have a different, reasonable basis for not selecting such sources [BART-eligible and non-BART eligible units that implement BART controls] for control measure analysis."<sup>38</sup>

In Section 5, Barr presents an evaluation of the BART-eligible units scenario and demonstrates that the indurating furnace Lines 1-3 are "effectively controlled" sources for both NO<sub>X</sub> and SO<sub>2</sub>. Thus, a four-factor analysis is not warranted for this source because, as USEPA notes, "it may be unlikely that there will be further available reasonable controls for such sources."<sup>39</sup>

### 2.2 Facility Description

HTC mines iron ore (magnetite) and produces taconite pellets that are shipped to steel producers for processing in blast furnaces. The iron ore is crushed and routed through several concentration stages including grinding, magnetic separation, and thickening.

A concentrated iron ore slurry is dewatered by vacuum disk filters, mixed with bentonite, and conveyed to balling drums. Greenballs produced on the balling drums are distributed evenly across pallet cars prior to entry into the pellet furnace. The pallet cars have a layer of fired pellets, called the hearth layer, on the bottom and sides of the car. The hearth layer acts as a buffer between the pallet car and the heat generated through the exothermic conversion of magnetite to hematite.

HTC operates three natural gas fired indurating furnace lines, with fuel oil as a back-up for emergency purposes. Natural gas has been the only fuel combusted at the indurating furnaces in the last 20 years. Each Line is a straight-grate induration furnace design. The first two zones are updraft and downdraft drying zones. The next zones are the preheat zone and firing zone. The temperature increases as the pellets pass through each zone, reaching a peak in the firing zone. The conversion of magnetite to hematite is completed in the firing zone. The last two zones are cooling zones that allow the pellets to be safely discharged.

Heated air discharged from the two cooling zones is recirculated to the drying, preheat and firing zones. Flue gas from the furnaces are vented primarily through two ducts, the hood exhaust that handles the drying and recirculated cooling gases, and the windbox exhaust, which handles the preheat and firing gases. The windbox flue gas flows through the multiclones, and then enters a common header shared with the hood flue gas stream. The flue gases are subsequently divided into four streams which lead to

<sup>&</sup>lt;sup>36</sup> Ibid, Page 25.

<sup>37</sup> Ibid.

<sup>&</sup>lt;sup>38</sup> Ibid.

<sup>&</sup>lt;sup>39</sup> Ibid.

four Taconite Maximum Achievable Control Technology (MACT) venturi rod wet scrubbers and exit from four individual stacks. An overview of the furnace design is provided on Figure 2-1.

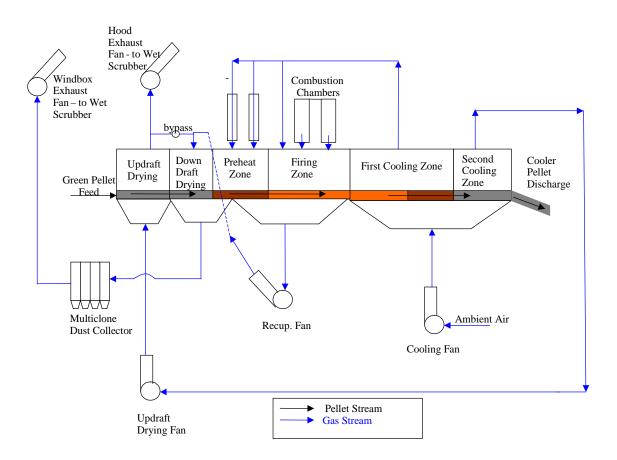


Figure 2-1 Natural Gas Fired Straight Grate Furnace Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers Diagram

# 3 Analysis of Ambient Data

As described in Section 2.1.2, the SIP must consider visibility conditions (baseline, current, and natural visibility), progress to date, and the URP. This requirement is referred to as Step 1 on the 2019 Guidance (see Section 2.1.3.1). This information informs the State's long term strategy for regional haze, as required by 51.308(f)(2), and the reasonable progress goals, as required by 51.308(3).

Section 3.1 provides analysis of visibility conditions based on data from the IMPROVE monitoring network at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1) and Section 3.2 addresses regional emission reductions. Consistent with 51.308(f)(2)(iv), the regional emission reductions summary considers emission reductions that have occurred but are not yet reflected in the available 5-year average monitoring data set and future emission reductions that will occur prior 2028, which is the end of the second SIP implementation period.

### 3.1 Visibility Conditions

As summarized in Section 2.1.2, the RHR requires that the SIP include an analysis "of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."<sup>40</sup> This data will be used in the SIP to establish reasonable progress goals (expressed in deciviews) that reflect the visibility conditions that are projected to be achieved by the end of the implementation period (2028) as a result of the implementation of the SIP and the implementation of other regulatory requirements.<sup>41</sup> The reasonable progress goal is determined by comparing the baseline visibility conditions to natural visibility conditions and determining the uniform rate of visibility improvement needed to attain natural visibility conditions by 2064. The SIP "must consider the uniform rate of improvement in visibility and the emission-reduction measures needed to achieve it for the period covered by the implementation plan."<sup>42</sup>

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).<sup>43</sup> The available regional haze monitoring data was compared to the uniform rate of progress and to the possible reasonable progress goals for the SIP for the implementation period, which ends in 2028. As described in Section 2.1.3.1, the visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). USEPA issued guidance for tracking visibility progress, including the methods for selecting the "most impaired days," on December 20, 2018.<sup>44</sup> Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms) could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."<sup>45</sup> In

<sup>40 40</sup> CFR 51.308(f)(1)

<sup>&</sup>lt;sup>41</sup> 40 CFR 51.308(f)(3)

<sup>&</sup>lt;sup>42</sup> 40 CFR 51.308(d)(1)

<sup>&</sup>lt;sup>43</sup> https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze visibility metrics public/Visibilityprogress

<sup>&</sup>lt;sup>44</sup> https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

<sup>45</sup> USEPA, Federal Register, 05/04/2016, Page 26948

addition, the RHR allows a state to account for international emissions "to avoid any perception that a state should be aiming to compensate for impacts from international anthropogenic sources."<sup>46</sup>

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath<sup>47</sup> at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1). Regional haze impairment has been declining since 2009 for all three Class I areas that are tracked by MPCA. Impacts to the most impaired days at BWCA and Isle Royale fell below the expected 2028 URP goal in 2016 and have continued trending downward since. Voyageurs impaired days fell below the 2028 URP in 2018 and is also on a downward trend.

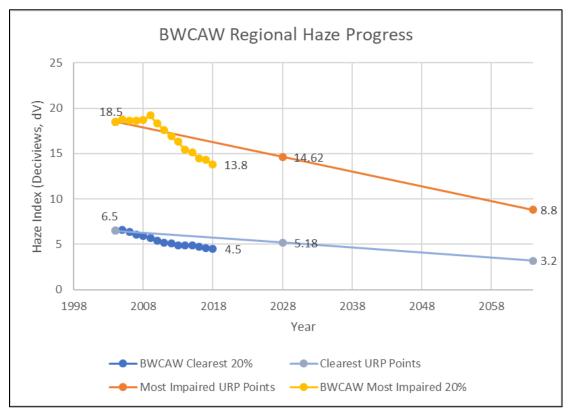


Figure 3-1 Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

<sup>&</sup>lt;sup>46</sup> USEPA, Federal Register, 01/10/2017, Page 3104

<sup>&</sup>lt;sup>47</sup><u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze visibility metrics public/Visibilitypro</u> gress

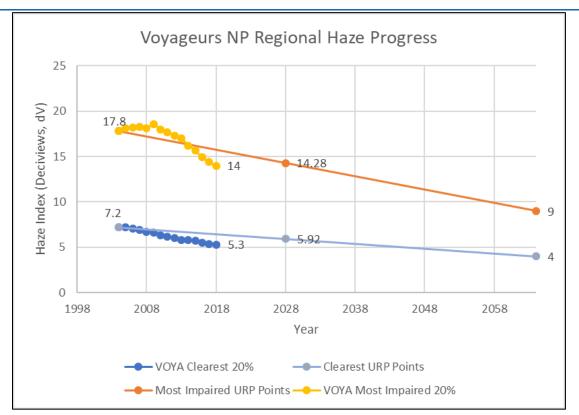


Figure 3-2 Visibility Trend versus URP – Voyageurs National Park (VOYA1)

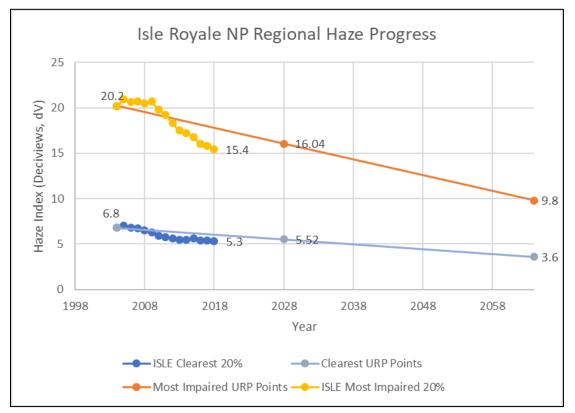


Figure 3-3 Visibility Trend versus URP – Isle Royale National Park (ISLE1)

### 3.2 Regional emissions reductions

The visibility improvement shown in Figure 3-1 through Figure 3-3 correlates with  $SO_2$  and  $NO_x$  emissions decreases from Minnesota's top twenty emission stationary sources, as shown in Figure 3-4<sup>48</sup>. These emission reductions are a result of multiple substantial efforts from the regulated community, including:

- Installation of BART controls during the first implementation period
- Emission reductions at electric utility combustion sources due to new rules and regulations, including:
  - Acid Rain Rules
  - o Cross State Air Pollution Rule (CASPR)
  - Mercury and Air Toxics Standards (MATS)
- Electric utility combustion sources undergoing fuel changes (e.g., from coal and to natural gas)
- Increased generation of renewable energy, which decreases reliance on combustion sources

Since many of these emission reduction efforts are due to federal regulations and national trends in electrical generation, similar emission reduction trends are likely occurring in other states.

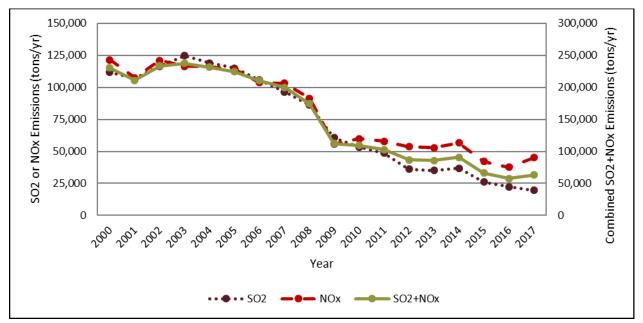


Figure 3-4 Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)

 $<sup>^{48}</sup>$  The data for NO<sub>X</sub> and SO<sub>2</sub> emissions was downloaded from the MPCA point source emissions inventory (<u>https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data</u>). The permitted facilities that had the 20 highest cumulative emissions from 2000-2017 in MN were chosen for the graphics, along with all six taconite facilities (whether or not they were in the top 20 of the state).

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath, so the emissions represented in the most recent data set (2018) is from 2014-2018. However, as shown in Table 3-1, additional emission reductions have occurred since 2014 and are not fully represented in the 5-year visibility data yet. Additionally, several stationary sources have scheduled future emission reductions which will occur prior to 2028. Combined, these current and scheduled emission reductions will further improve visibility in the Class I areas, ensuring the trend stays below the URP. Even without these planned emissions reductions, the 2018 visibility data is already below the 2028 glidepath. As such, MPCA's second SIP implementation period strategy should be commensurate with the region's visibility progress and it would be reasonable for MPCA to not include the taconite indurating furnaces when "reasonably select[ing] a set of sources for an analysis of control measures," and such decision is supported by the 2019 Guidance.

| Year | Additional Emissions Reductions Expected/Projected   |  |  |  |
|------|--|--|--|--|
| 2015 | MP Laskin: converted from coal to natural gas**  |  |  |  |
| 2017 | Minntac Line 6: FIP emission limit compliance date for NO <sub>X</sub> *   |  |  |  |
| 2018 | Minntac Line 7: FIP emission limit compliance date for NO <sub>X</sub> *<br>MP Boswell: Units 1 & 2 retired from service**   |  |  |  |
| 2019 | Hibtac Line 1: FIP emission limit compliance date for $NO_X^*$<br>Keetac: FIP emission limit compliance date for $NO_X^*$<br>Minntac Line 4 or 5: FIP emission limit compliance date for $NO_X^*$<br>Utac Line 1: FIP emission limit compliance date for $NO_X^*$  |  |  |  |
| 2020 | Hibtac Line 2: FIP emission limit compliance date for $NO_X^*$<br>Minntac Line 4 or 5: FIP emission limit compliance date for $NO_X^*$<br>Minorca: FIP emission limit compliance date for $NO_X^*$<br>Utac Line 2: FIP emission limit compliance date for $NO_X^*$ |  |  |  |
| 2021 | Minntac Line: FIP emission limit compliance date for NO <sub>X</sub> *<br>Hibtac Line 3: FIP emission limit compliance date for NO <sub>X</sub> *  |  |  |  |
| 2023 | Xcel: Sherco Unit 2 Retirement***  |  |  |  |
| 2026 | Xcel: Sherco Unit 1 Retirement***  |  |  |  |
| 2028 | Xcel: Allen S. King Plant Retirement <sup>***</sup>  |  |  |  |
| 2030 | Xcel: Sherco Unit 3 Retirement, Xcel target to emit 80% less carbon by 2030***   |  |  |  |
| 2050 | Xcel: Energy targeting carbon free generation by 2050***   |  |  |  |

### Table 3-1 Notable Minnesota Emission Reductions

\* FIP is the regional haze Federal Implementation Plan detailed in 40 CFR 52.1235

\*\* Minnesota Power - Integrated Resource Plan 2015-2029

\*\*\* Xcel Energy - Upper Midwest Integrated Resource Plan 2020-2034.

# **4 Visibility Impacts**

As described in Section 2.1.3.2, the 2019 Guidance outlines criteria to evaluate when selecting sources that must complete an analysis of emission controls. The 2019 Guidance is clear that a state does not need to evaluate all sources of emissions but "may reasonably select a set of sources for an analysis of control measures" to make progress towards natural visibility.

As described in Section 2.1.3.2.1, the 2019 Guidance provides recommendations on selecting sources by estimating baseline visibility impacts. Three of the options for estimating baseline visibility impacts are analyzed below:

### • Trajectory analyses<sup>49</sup>

In general, these analyses consider the wind direction and the location of the Class I areas to identify which sources tend to emit pollutants upwind of Class I areas. The 2019 Guidance says that a state can consider "back trajectories" which "start at the Class I area and go backwards in time to examine the path that emissions took to get to the Class I areas." Section A1.1 of Appendix A, describes the back trajectory analysis and concludes the taconite indurating furnaces were a marginal contributor to the "most impaired" days from 2009 and 2011-2015. The trajectory analysis also indicates many sources other than the taconite facilities were significant contributors to the "most impaired" days.

### • Photochemical modeling<sup>50</sup>

The 2019 Guidance says, "states can also use a photochemical model to quantify source or source sector visibility impacts." CAMx modeling was previously conducted to identify visibility impacts in Class I areas from Minnesota taconite facilities from NOx emission reductions. This analysis is summarized in Section A1.2 of Appendix A which concludes the Class I areas near the Iron Range will not experience any observable visibility improvements from NO<sub>x</sub> emission reductions suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces.

• Other reasonable techniques<sup>51</sup>

In addition to the two analyses described above which estimate the baseline visibility impacts, Section A1.3 of Appendix A evaluates the actual visibility data against the 2009 economic recession impacts on visibility, when taconite facilities curtailed production. This curtailment resulted in a decrease in emissions from the collective group of taconite plant and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this curtailment period was compared to monitoring data during more typical production at the taconite plants to estimate the taconite facilities' actual (rather than modeled) impact on haze. This analysis concludes "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It

<sup>&</sup>lt;sup>49</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 13.

<sup>&</sup>lt;sup>50</sup> Ibid, Page 14.

<sup>&</sup>lt;sup>51</sup> Ibid, Page 12.

is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions."<sup>52</sup> The report further notes "high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states."<sup>53</sup>

<sup>&</sup>lt;sup>52</sup> AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.

<sup>&</sup>lt;sup>53</sup> Ibid, Page 12.

# 5 Evaluation of "Effectively Controlled" Source

As described in Section 2.1.3.3, the 2019 Guidance acknowledges that states may forgo requiring facilities to complete the detailed four-factor analysis if the source already has "effective emission control technology in place."<sup>54</sup> This section demonstrates that the indurating furnace Lines 1-3 meet USEPA's BART-required control equipment installation scenario for NO<sub>X</sub> and SO<sub>2</sub>.

The indurating furnace Lines 1-3 meet this scenario as "effectively controlled" sources because:

- The indurating furnace Lines 1-3 are BART-eligible units, as determined by Minnesota's December 2009 Regional Haze Plan, and are regulated under 40 CFR 52.1235 (Approval and Promulgation of Implementation Plans Subpart Y Minnesota Regional Haze)
- The indurating furnace Lines 1-3 have controls and must "meet BART emission limits for the first implementation period"<sup>55</sup> for NO<sub>X</sub> and SO<sub>2</sub>

The following sections describe USEPA's BART determinations, the associated controls that were implemented as BART, and the resulting BART emission limits for  $NO_X$  and  $SO_2$ .

### 5.1 NO<sub>x</sub> BART-required Controls

In the preamble to the October 2015 proposed FIP,<sup>56</sup> the USEPA concluded that BART for NO<sub>X</sub> from straight-grate furnaces is low-NO<sub>X</sub> burners with water/steam injection and pre-combustion technologies. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- External and Induced Flue Gas Recirculation Burners due to the high oxygen content of the flue gas<sup>57</sup>
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure<sup>58</sup>
- Selective Catalytic Reduction (SCR) controls because two vendors declined to bid on NO<sub>x</sub> reduction testing for a taconite facility<sup>59</sup>

59 Ibid.

<sup>&</sup>lt;sup>54</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, page 22.

<sup>&</sup>lt;sup>55</sup> Ibid, page 25.

<sup>&</sup>lt;sup>56</sup> Federal Register 80, No. 204 (October 22, 2015); 64168. Available at: <u>https://www.govinfo.gov/app/details/FR-</u> 2015-10-22/2015-25023

<sup>&</sup>lt;sup>57</sup> Federal Register 77, No. 158 (August 15, 2012); 49321. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

<sup>58</sup> Ibid.

• High-stoichiometric and low-stoichiometric low NO<sub>x</sub> burners (LNB) because the technology had never been used on straight-grate furnaces at the time of the determination.<sup>60</sup>

Because the technical feasibility determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for NO<sub>X</sub> emissions from taconite indurating furnaces.

In accordance with the FIP, HTC implemented the BART NO<sub>x</sub> control measures by installing and operating newly engineered site specific Low NOx Burner technology at the indurating furnace Lines 1-3 prior to the required FIP compliance dates of July 12, 2018, January 12, 2020 and July 12, 2020, respectively, and the indurating furnace Lines 1-3 are subject to the FIP NO<sub>x</sub> emission limits<sup>61</sup> as shown in Table 5-1. Installation and startup of the Low NOx Burners on indurating furnace Line 3 was timely completed on April 27, 2020, prior to the indefinite idling of all 3 lines as of May 3, 2020. The indurating furnace Low NOx Burners have reduced the majority of the NOx emissions. Thus, the indurating furnace Lines 1-3 are considered "effectively controlled" sources in accordance with the 2019 Guidance and should be excluded from the requirement to prepare and submit a four-factor analysis. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the indurating furnace Lines 1-3 from the requirement to submit a four-factor analysis.

<sup>&</sup>lt;sup>60</sup> Federal Register 80, No. 204 (October 22, 2015); 64167. Available at: <u>https://www.govinfo.gov/app/details/FR-</u> 2015-10-22/2015-25023

<sup>&</sup>lt;sup>61</sup> 40 CFR 52.1235(b)(1)

<sup>&</sup>lt;sup>62</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 10.

### Table 5-1NOx Emission Limits

| Unit   | Unit ID        | NO <sub>X</sub><br>Emission Limit <sup>(1)</sup><br>(Ib/MMBtu) | Compliance Date <sup>(2)</sup> |
|--|----------------|--|--------------------------------|
| Natural Gas Fired<br>Indurating Furnace Line No 1<br>Equipped with Newly Engineered Site-<br>Specific Low NOx Burner Technology<br>and Taconite MACT Scrubbers | EQUI 95/EU 020 | 1.2-1.8  | June 12, 2019                  |
| Natural Gas Fired<br>Indurating Furnace Line No 2<br>Equipped with Newly Engineered Site-<br>Specific Low NOx Burner Technology<br>and Taconite MACT Scrubbers | EQUI 96/EU 021 | 1.2-1.8  | December 12, 2020              |
| Natural Gas Fired<br>Indurating Furnace Line No 3<br>Equipped with Newly Engineered Site-<br>Specific Low NOx Burner Technology<br>and Taconite MACT Scrubbers | EQUI 97/EU 022 | 1.2-1.8  | May 12, 2021                   |

(1) In accordance with 40 CFR 52.1235(b)(1)(ii), the indurating furnace Lines 1-3 will be limited between 1.2 and 1.8 lb NOx/MMBtu beginning in the months listed above. The specific emission limit will be established by USEPA based on available NOx CEMS data from the time period when the installed emission control technology was in operation and must be submitted to USEPA for approval.

(2) The compliance date is contingent on USEPA's approval of the final emission limit.

### 5.2 SO<sub>2</sub> BART-required Controls

In the preamble to the August 2012 proposed FIP<sup>63</sup>, the USEPA concluded that BART for SO<sub>2</sub> emissions from the indurating furnace Lines 1-3 at HTC is existing controls. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- Dry Sorbent Injection and Spray Dryer Absorption because the high moisture content of the exhaust would lead to baghouse filter cake saturation and filter plugging
- Alternative Fuels due to HTC being prohibited from burning solid fuel
- Coal drying/processing because the indurating furnace Lines 1-3 do not burn coal
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure<sup>64</sup>

In addition, USEPA eliminated Wet Walled Electrostatic Precipitator (WWESP) and secondary (polishing) wet scrubber technologies because they were not cost-effective.<sup>65</sup> HTC also considered and eliminated

<sup>&</sup>lt;sup>63</sup> Federal Register 77, No. 158 (August 15, 2012); 49323. Available at: <u>https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789</u>

<sup>&</sup>lt;sup>64</sup> Ibid, 49322.

<sup>65</sup> Ibid, 49323.

the addition of caustic, lime, or limestone to the scrubber water to improve SO<sub>2</sub> removal but determine it to be not practical.

Because the technical feasibility and cost effectiveness determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for SO<sub>2</sub> emissions from taconite indurating furnaces.

In accordance with the FIP, HTC has continued to operate the BART SO<sub>2</sub> control measures and is complying with the FIP SO<sub>2</sub> emission limits<sup>66</sup>, as shown in Table 5-2. Thus, the indurating furnace Lines 1-3 are considered "effectively controlled" sources in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for SO<sub>2</sub>. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the indurating furnace Lines 1-3 from the requirement to submit a four-factor analysis<sup>67</sup>.

### Table 5-2 SO<sub>2</sub> Emission Limits

| Unit  | Unit ID        | SO <sub>2</sub><br>Emission Limit <sup>(1)</sup><br>(lb/hr) | Compliance Date <sup>(2)</sup> |
|---|----------------|---|--------------------------------|
| Natural Gas Fired<br>Indurating Furnace Line No 1 Equipped<br>with Newly Engineered Site-Specific<br>Low NOx Burner Technology<br>and Taconite MACT Scrubbers | EQUI 95/EU 020 |   |                                |
| Natural Gas Fired<br>Indurating Furnace Line No 2 Equipped<br>with Newly Engineered Site-Specific<br>Low NOx Burner Technology<br>and Taconite MACT Scrubbers | EQUI 96/EU 021 | 279.3   | April 11, 2018                 |
| Natural Gas Fired<br>Indurating Furnace Line No 3 Equipped<br>with Newly Engineered Site-Specific<br>Low NOx Burner Technology<br>and Taconite MACT Scrubbers | EQUI 97/EU 022 |   |                                |

(1) This limit was established using one year of SO<sub>2</sub> CEMS data, in accordance with the procedures outlined within 40 CFR 52.1235(b)(2)(v).

(2) HTC submitted the revised SO<sub>2</sub> limit request on April 11, 2018, in accordance with 40 CFR 52.1235(b)(2)(v).

<sup>66 40</sup> CFR 52.1235(b)(2)

<sup>&</sup>lt;sup>67</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 10.

# 6 Conclusion

The preceding sections of this report support the following conclusions:

- The natural gas fired indurating furnace Lines 1-3 equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT scrubbers meet the BART-required control equipment installation scenario and are "effectively controlled" sources for NO<sub>X</sub> and SO<sub>2</sub> (see Section 5). As stated in the 2019 Guidance, "it may be reasonable for a state not to select an effectively controlled source."<sup>68</sup> Therefore, it would be reasonable and compliant with USEPA requirements to exclude HTC from further assessments of additional emission control measures.
- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress (see Section 3):
  - Visibility has improved at all three monitors (BOWA1, VOYA2, and ISLE1) compared to the baseline period
  - Visibility has been below the URP since 2012
  - The 2018 visibility data is below the URP for 2028
  - Additional emissions reductions have continued throughout the region and are not fully reflected in the available 5-year average (2014-2018) monitoring dataset
  - Additional emission reductions are scheduled to occur in the region prior to 2028, including ongoing transitions of area EGUs from coal to natural gas or renewable sources, as well as the installation of low-NO<sub>X</sub> burners throughout the taconite industry
- The indurating furnace Lines 1-3 do not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4).

The combination of these factors provides sufficient justification for MPCA to justify to USEPA HTC's exclusion from the group of sources required to conduct a four-factor analysis for this implementation period. Thus, HTC respectfully requests that the MPCA timely withdraw its request for a four-factor analysis for the natural gas fired indurating furnace Lines 1-3 already equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT scrubbers.

<sup>&</sup>lt;sup>68</sup> Ibid, Page 22

Appendix

Appendix A

Visibility Impacts

# A1 Visibility Impacts

### A1.1 Trajectory Analysis

The August 2019 U.S. EPA Guidance ("2019 Guidance" or "the Guidance")<sup>1</sup> says that the state may use a "reasonable surrogate metrics of visibility impacts" when selecting sources to conduct an four-factor analysis and cites trajectory analysis as an example of a reasonable technique. This analysis considers reverse trajectories, as provided on MPCA's website<sup>2</sup>, to determine the frequency that the trajectories on the "most impaired days"<sup>3</sup> overlapped with a specific area of influence (AOI) on the Iron Range. Data from 2011-2015 were analyzed as this was the most recent five-year period where the taconite facilities were operating under typical production rates.

A particle trajectory analysis is an analysis of the transport path of a particular air mass, including the associated particles within the air mass, to see if the air mass traveled over certain locations from specific source locations. The MPCA tracks visibility via the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area Wilderness (BWCA), Voyageurs National Park (Voyageurs) and Isle Royale National Park (Isle Royale).<sup>4</sup> MPCA's website includes a tool which analyzes reverse trajectories from BWCA and Voyageurs for the "most impaired days" and the clearest days for 2007-2016 to show the regional influence on visibility. The reverse trajectories included in the MPCA tool were developed using the NOAA Hysplit model.<sup>5</sup> The trajectories consist of a single back trajectory for each day of interest, beginning at 18:00 and running back 48 hours with a starting height of 10 meters.

The MPCA Hysplit reverse trajectories from the "most impaired days" were analyzed to identify whether trajectories overlapped with an AOI from certain taconite facilities on the Iron Range. In order to be conservative, Barr estimated an "uncertainty region" for each trajectory based on 20% of the distance traveled for every 10km along the trajectory pathway. This method is consistent with other scientific studies analyzing reverse trajectories and trajectories associated with the NOAA Hysplit model (Stohl - 1998<sup>6</sup>, Draxler - 1992<sup>7</sup>, Draxler and Hess - 1998<sup>8</sup>). For the purpose of this analysis, the Iron Range AOI was defined as a line connecting the stack at the U. S. Steel Keetac facility with the stack at the ArcelorMittal Minorca Mine and a 3-mile radius surrounding the line. This analysis considers how often the MPCA reverse trajectories overlap the Iron Range AOI on the "most impaired days" to quantitatively determine if the emissions from the Iron Range may have been a contributor to impaired visibility. Attachment 1 to Appendix A includes tables with the annual and seasonal results of this analysis as well as two example figures showing trajectories that cross, and do not cross, the Iron Range AOI.

<sup>&</sup>lt;sup>1</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019

<sup>&</sup>lt;sup>2</sup> <u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze\_visibility\_metrics\_public/Regionalinfluence</u>

<sup>&</sup>lt;sup>3</sup> "Most impaired days" is the 20% most anthropogenically impaired days on an annual basis, measured in deciviews (dv), as provided on MPCA's website.

<sup>&</sup>lt;sup>4</sup> <u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze\_visibility\_metrics\_public/Regionalinfluence</u>

<sup>&</sup>lt;sup>5</sup> https://www.arl.noaa.gov/hysplit/hysplit/

<sup>&</sup>lt;sup>6</sup> <u>http://www.kenrahn.com/DustClub/Articles/Stohl%201998%20Trajectories.pdf</u>

<sup>&</sup>lt;sup>7</sup> https://www.arl.noaa.gov/documents/reports/ARL%20TM-195.pdf

<sup>&</sup>lt;sup>8</sup> https://www.arl.noaa.gov/documents/reports/MetMag.pdf

As shown in Figure A1 and Figure A2, reverse trajectories from BWCA and Voyageurs in 2011-2015 did not overlap the Iron Range AOI on 62-80%, and 56-71% of "most impaired days", respectively. This means the taconite industry did not influence visibility at BWCA and Voyageurs on the majority of "most impaired days" and suggest that sources other than the taconite facilities are larger contributors to visibility impairment at these sites. Furthermore, the origins of many of the "most impaired day" reverse trajectories are beyond the Iron Range AOI and thus have influences, depending on the trajectory, from other sources (e.g., Boswell Energy Center, Sherburne County Generating Station) or cities such as Duluth, St. Cloud, the Twin Cities, and Rochester as shown in Figure A3.

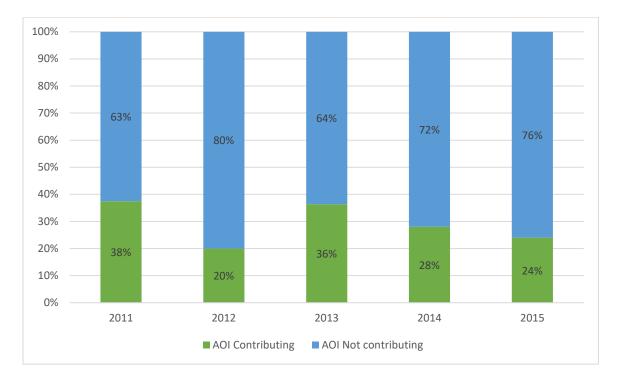


Figure A1 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at BWCA

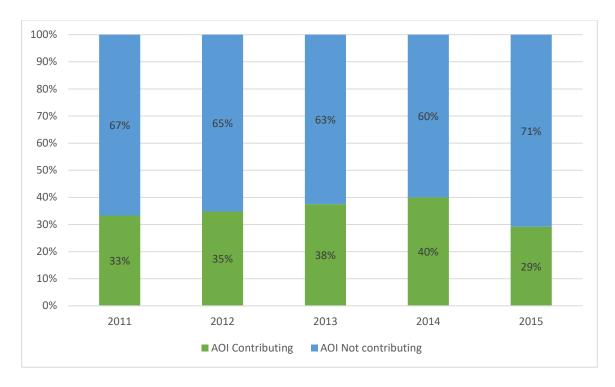


Figure A2 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at Voyageurs

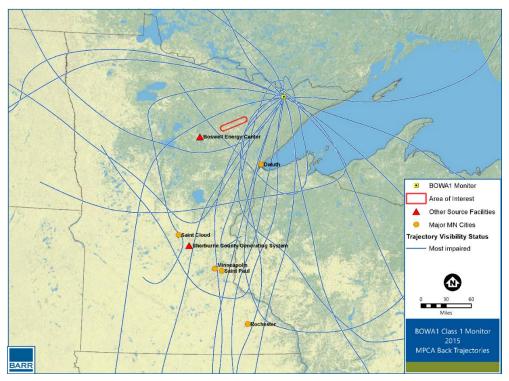


Figure A3 Reverse Trajectories and Other Sources Influencing Visibility at BWCA<sup>9</sup>

<sup>9</sup> Source: ArcGIS 10.7.1, 2020-05-14 13:31 File:

I:\Client\US\_Steel\Trajectory\_Analysis\Maps\Trajectory\_Routes\_BOWA1\_2015\_zoom.mxd User: ADS

## A1.2 Photochemical Modeling

As part of the requirement to determine the sources to include and how to determine the potential visibility improvements to consider as part of this selection, the 2019 Guidance provided some specific guidance on the use of current and previous photochemical modeling analyses (emphasis added):

"A state opting to select a set of sources to analyze must reasonably choose factors and apply them in a reasonable way given the statutory requirement to make reasonable progress toward natural visibility. Factors could include but are not limited to baseline source emissions, <u>baseline source</u> <u>visibility impacts (or a surrogate metric for the impacts)</u>, [and] the in-place emission control measures..."<sup>10</sup>

The Guidance lists options for the evaluation of source visibility impacts from least rigorous to most rigorous as: (1) emissions divided by distance (Q/d), (2) trajectory analyses, (3) residence time analyses, and (4) photochemical modeling (zero-out and/or source apportionment). It appears that MPCA selected the least rigorous (Q/d) for inclusion of sources in the four-factor analyses. The most rigorous is described below (emphases added):

"Photochemical modeling. In addition to these non-modeling techniques, states can also use a photochemical model to quantify source or source sector visibility impacts. In 2017, EPA finalized revisions to 40 CFR Part 51 Appendix W, Guideline on Air Quality Models. As part of that action, EPA stated that photochemical grid models should be the generally preferred approach for estimating source impacts on secondary PM concentrations. The existing SIP Modeling Guidance provides recommendations on model setup, including selecting air quality models, meteorological modeling, episode selection, the size of the modeling domain, the grid size and number of vertical layers, and evaluating model performance. EPA Regional offices are available to provide an informal review of a modeling protocol before a state or multijurisdictional organization begins the modeling.

The SIP Modeling Guidance focuses on the process for calculating RPGs using a photochemical grid model. The SIP Modeling Guidance does not specifically discuss using photochemical modeling outputs for estimating daily light extinction impacts for a single source or source sector. However, the approach on which the SIP Modeling Guidance is based can also be applied to a specific source or set of sources. <u>The first step in doing this is to estimate the impact of the source or set of sources</u> <u>on daily concentrations of PM species.</u>

The simplest approach to quantifying daily PM species impacts with a photochemical grid model is to perform brute force "zero-out" model runs, which involves at least two model runs: one "baseline" run with all emissions and one run with emissions of the source(s) of interest removed from the baseline simulation. The difference between these simulations provides an estimate of the PM species impact of the emissions from the source(s).

<sup>&</sup>lt;sup>10</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 10

An alternative approach to quantifying daily PM species impacts is photochemical source apportionment. Some photochemical models have been developed with a photochemical source apportionment capability, which tracks emissions from specific sources or groups of sources and/or source regions through chemical transformation, transport, and deposition processes to estimate the apportionment of predicted PM<sub>2.5</sub> species concentrations. Source apportionment can "tag" and track emissions sources by any combination of region and sector, or by individual source. For example, PM species impacts can be tracked from any particular source category in the U.S., or from individual states or counties. Individual point sources can also be tracked."<sup>11</sup>

As part of the previous regional haze planning evaluation, and to provide comments on USEPA's disapproval of the Minnesota SIP and the subsequent Regional Haze Federal Implementation Plan (FIP) (Docket EPA-R05-OAR-2010-0954 & EPA-R05-OAR-2010-0037), Barr completed photochemical modeling of ArcelorMittal and Cleveland-Cliffs' taconite operations in 2013 using CAMx source apportionment (see Attachment 2). The basis of the CAMx modeling was the Minnesota modeling analyses, which were completed as part of the regional haze SIP, including Plume in Grid (PiG) evaluations of sources included in BART analyses. This modeling included 2002 and 2005 baseline periods with projected emissions to 2018 (the first implementation planning period for the regional haze SIPs and a strong surrogate for the baseline period for the 2<sup>nd</sup> planning period). Therefore, the analysis completed is one of the best available surrogates for the potential visibility impacts from the sources that were "tagged" as part of those comments. It is important to note that the MPCA modeling analysis did not require any additional controls for taconite sources under BART. Further, the CAMx modeling that Barr conducted showed that the impact from NO<sub>X</sub> emissions from the Minnesota taconite facilities had very limited visibility impacts on the three Upper Midwest Class I areas.

Specifically, the results from executing CAMx concluded that the Class I areas near the Iron Range will not experience any observable visibility improvements from NO<sub>x</sub> emission reductions that were suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces. The modeling analysis showed that the scalar method that USEPA used to forecast the visibility improvements was inadequate to determine the visibility impacts from taconite sources. The CAMx predicted impacts for every furnace line were at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

In addition, the large amount of potential NO<sub>X</sub> emission reductions from the FIP baseline to the final FIP (>10,000 tons per year from modeled Minnesota taconite operations) was not impactful from a visibility modeling perspective. This finding provides specific source modeling evidence that additional NO<sub>X</sub> emission reductions from any or all of the taconite operations are likely not helpful for visibility improvements at the Upper Midwest Class I areas. This is particularly true given the current amount of NO<sub>X</sub> emissions generated by the taconite sources as part of the current baseline.

The 2019 Guidance addresses how states should select sources that must conduct a four-factor analysis. The RHR suggests that states can use a photochemical model to quantify facility or even stack visibility impacts. The previous CAMx modeling was conducted for the 2018 projection year and the results are

<sup>&</sup>lt;sup>11</sup> Ibid, Page 14.

especially helpful in the current visibility impact assessment to determine if the EPA's four-factor applicability analysis is necessary. Aside from the fact that the NO<sub>X</sub> reductions of taconite indurating furnaces do not result in visibility improvements, the emissions from these sources have been trending downward from 2013 to present. These reductions are related to the recent installation of low NO<sub>X</sub> burners on the taconite indurating furnaces and the overall Minnesota state reductions from the switch from coal- to natural gas-fired power plants. Thus, it is reasonable to conclude that additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility at the Class 1 areas nor is it anticipated to be necessary to reach the 2028 target visibility goal.

In summary, the exclusion of the taconite sources from the four factor analysis for NOx is reasonable, supported by the previous CAMx modeling performed for 2018 projected emissions that conclude additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility, and in line with the Guidance regarding selection of sources based on previous modeling analyses and the additional NO<sub>x</sub> reductions anticipated in Minnesota.

## A1.3 Visibility Impacts During 2009 Recession

During the economic recession in 2009, the Iron Range experienced a reduction in taconite production. This resulted in a decrease in emissions from the collective group of taconite plants and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this period was compared to monitoring data during more typical production at the taconite plants to estimate the actual (rather than modeled) impact on haze. This assessment was completed in 2012 (herein termed as "the 2012 analysis") and submitted by Cliffs as a comment to proposed Minnesota regional haze requirements (Docket: EPA-R05-OAR-2010-0037), included as Attachment 3. The 2012 analysis focused on the likely visibility impact of NO<sub>x</sub> emissions from the taconite indurating furnaces.

Observations noted in the 2012 analysis highlighted that concentrations of visibility impairing pollutants do not appear to closely track with actual emissions from taconite facilities. For example, nitrate (NO<sub>3</sub>) is a component of haze associated with NO<sub>x</sub> emissions that are emitted from a number of sources, including the indurating furnaces at the taconite facilities. As shown in Figure A4, the 2012 analysis compared taconite facility production rates to nitrate concentration for 1994-2010 at the BWCA monitor. The 2012 analysis concludes that "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions."<sup>12</sup> The report further notes that "high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states."<sup>13</sup>

<sup>&</sup>lt;sup>12</sup> AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10. <sup>13</sup> Ibid, Page 12.

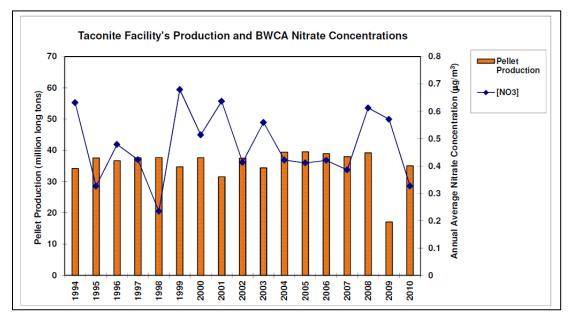


Figure A4 Minnesota Taconite Production and BWCA Nitrate Concentrations 1994-2010<sup>14</sup>

<sup>&</sup>lt;sup>14</sup> AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 9

# Attachments

# Attachment 1

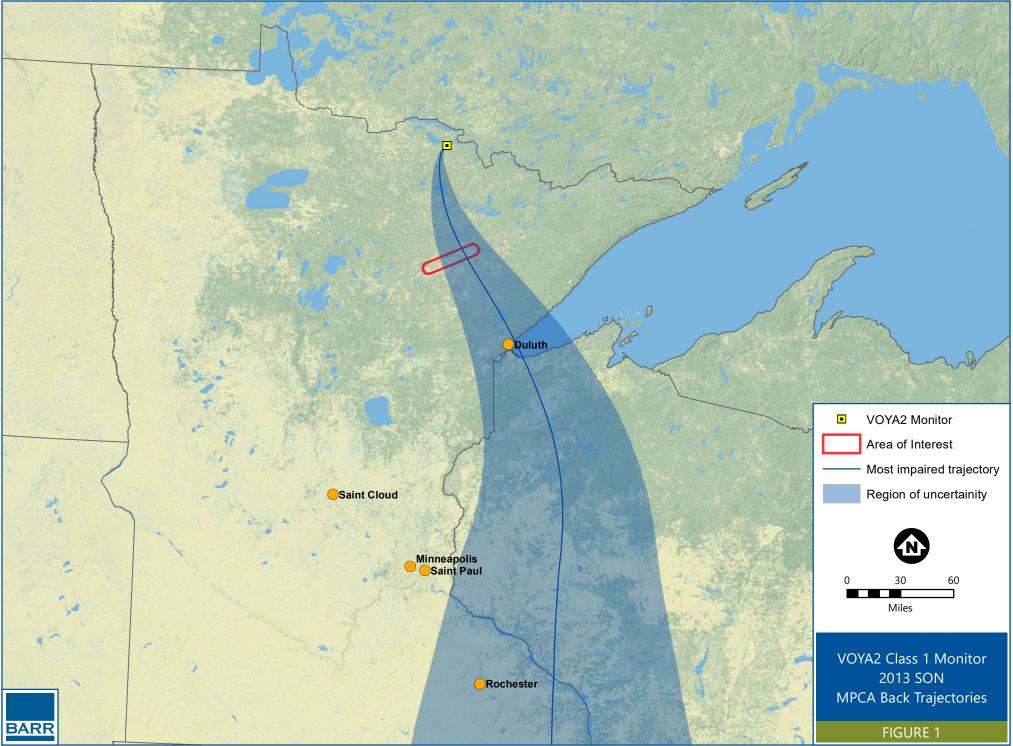
Trajectory Analysis Summary Tables and Reverse Trajectory Example Figures

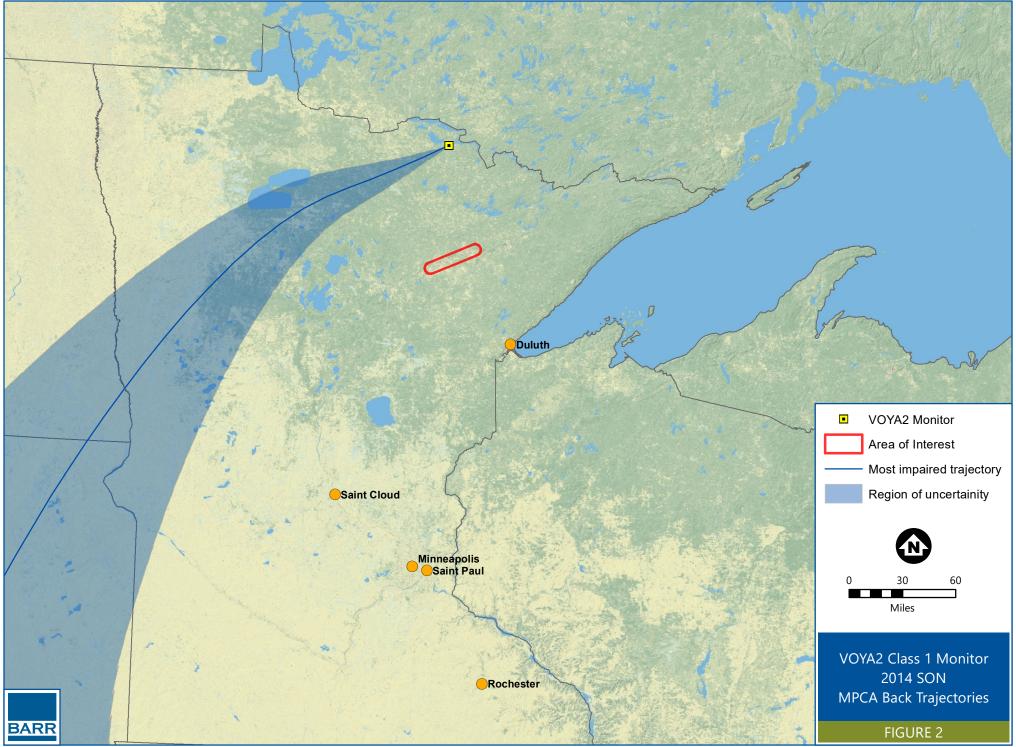
| Year | Time Period  | Most Impaired<br>Days | "Most Impaired" Trajectories<br>With Uncertainty Region<br>Crossing Iron Range AOI<br>(%) |
|------|--------------|-----------------------|---|
|      | Winter (DJF) | 9                     | 44%   |
|      | Spring (MAM) | 8                     | 38%   |
| 2011 | Summer (JJA) | 4                     | 0%  |
|      | Fall (SON)   | 3                     | 67%   |
|      | Total        | 24                    | 38%   |
|      | Winter (DJF) | 13                    | 23%   |
|      | Spring (MAM) | 4                     | 0%  |
| 2012 | Summer (JJA) | 1                     | 0%  |
|      | Fall (SON)   | 7                     | 29%   |
|      | Total        | 25                    | 20%   |
|      | Winter (DJF) | 9                     | 44%   |
|      | Spring (MAM) | 5                     | 60%   |
| 2013 | Summer (JJA) | 3                     | 0%  |
|      | Fall (SON)   | 5                     | 20%   |
|      | Total        | 22                    | 36%   |
|      | Winter (DJF) | 9                     | 33%   |
|      | Spring (MAM) | 8                     | 13%   |
| 2014 | Summer (JJA) | 2                     | 0%  |
|      | Fall (SON)   | 6                     | 50%   |
|      | Total        | 25                    | 28%   |
|      | Winter (DJF) | 13                    | 15%   |
|      | Spring (MAM) | 3                     | 67%   |
| 2015 | Summer (JJA) | 1                     | 0%  |
|      | Fall (SON)   | 8                     | 25%   |
|      | Total        | 25                    | 24%   |

Table A1 Results from MPCA Hysplit Trajectories for the BOWA1 Monitor

| Year | Months       | Most Impaired<br>Days | "Most Impaired" Trajectories<br>With Uncertainty Region<br>Crossing Iron Range AOI<br>(%) |
|------|--------------|-----------------------|---|
|      | Winter (DJF) | 8                     | 38%   |
|      | Spring (MAM) | 7                     | 29%   |
| 2011 | Summer (JJA) | 4                     | 25%   |
|      | Fall (SON)   | 5                     | 40%   |
|      | Total        | 24                    | 33%   |
|      | Winter (DJF) | 13                    | 23%   |
|      | Spring (MAM) | 3                     | 67%   |
| 2012 | Summer (JJA) | 0                     | 0%  |
|      | Fall (SON)   | 7                     | 43%   |
|      | Total        | 23                    | 35%   |
|      | Winter (DJF) | 9                     | 22%   |
|      | Spring (MAM) | 5                     | 40%   |
| 2013 | Summer (JJA) | 3                     | 0%  |
|      | Fall (SON)   | 7                     | 71%   |
|      | Total        | 24                    | 38%   |
|      | Winter (DJF) | 10                    | 50%   |
|      | Spring (MAM) | 7                     | 43%   |
| 2014 | Summer (JJA) | 2                     | 0%  |
|      | Fall (SON)   | 6                     | 33%   |
|      | Total        | 25                    | 40%   |
|      | Winter (DJF) | 14                    | 21%   |
|      | Spring (MAM) | 4                     | 50%   |
| 2015 | Summer (JJA) | 1                     | 100%  |
|      | Fall (SON)   | 5                     | 20%   |
|      | Total        | 24                    | 29%   |

 Table A2
 Results from MPCA Hysplit Trajectories for the VOYA2 Monitor





Attachment 2

CAM<sub>X</sub> Modeling Report



## **Technical Memorandum**

- From: Barr Engineering
- Subject: Summary of Comprehensive Air Quality Model with Extensions (CAM<sub>x</sub>) Analyses Performed to Evaluate the EPA Regional Haze Federal Implementation Plan for Taconite Facilities
   Date: March 6, 2013

#### **Executive Summary**

Barr Engineering conducted air modeling to predict the impact of  $NO_x$  reductions from certain taconite furnaces in Minnesota and Michigan. Using EPA's preferred Comprehensive Air Quality Model with Extensions (CAM<sub>x</sub>), the model results demonstrate that the Class I areas near these furnaces will experience no perceptible visibility improvements from  $NO_x$  emission reductions envisioned by EPA in the recent Regional Haze FIP at the furnaces. The analysis strongly suggests that the scalar method that EPA used to predict visibility improvements under significant time constraints was an inadequate substitute for CAM<sub>x</sub>, as EPA's approach over-predicted visibility impacts by factors of <u>ten to sixty</u> when compared with the proper CAM<sub>x</sub> analysis. The basis for EPA's technical analysis of the visibility improvements for their proposed emission changes must therefore be dismissed as unsupportable, and the results of this analysis should be used instead. This analysis ultimately supports the conclusions of the States of Michigan and Minnesota in their Regional Haze SIPs, that experimental low  $NO_x$  burner retrofits did not meet the criteria for BART. The imperceptible visibility improvements associated with  $NO_x$  reductions from these furnaces cannot justify the cost or the operational risks of changing burners.

#### **Discussion**

This memorandum provides a summary of the methodology and results from photochemical modeling analyses conducted to support the Cliffs Natural Resources (CNR) and Arcelor Mittal (Arcelor) response to the United States Environmental Protection Agency (EPA) final Regional Haze Federal Implementation Plan (FIP) for taconite facilities. Further, it provides a basis for comment on the proposed disapproval of the Minnesota and Michigan State Implementation Plans for taconite Best Available Retrofit Technology (BART) at the above mentioned facilities. This memorandum also includes an appendix with a summary of the BART visibility improvement requirements and a review of the EPA "scalar" method in the proposed and final FIP for determining the visibility improvement from taconite emission reductions. Further, the memorandum contrasts EPA's findings with the modeling analysis conducted and previously requested by CNR as part of its comments on the proposed FIP. The modeling evaluated emission differences at all the CNR and Arcelor taconite facilities.

Ultimately, this memorandum provides results demonstrating no perceptible visibility improvement from the  $NO_X$  emission reductions proposed and subsequently finalized by EPA in the Regional Haze FIP for the CNR and Arcelor facilities.

#### I. CAM<sub>x</sub> Modeling Methodology

The methodology utilized by Barr to complete the CAM<sub>x</sub> modeling was identical to the methods utilized by the Minnesota Pollution Control Agency (MPCA) in performing the 2002 and 2005 baseline and BART SIP modeling in 2009. This included the use of the CAM<sub>x</sub> modeling system (CAM<sub>x</sub> v5.01 - air quality model, MM5 - meteorological model, and EMS-2003 - emissions model) with meteorological data, low-level emission data, initial and boundary condition files, and other input files received directly from MPCA. Modifications to the emissions within the elevated point source input files used by MPCA were accomplished for the taconite facility furnace stacks to reflect the differences in the FIP baseline and final FIP control scenarios. In addition, the CAM<sub>x</sub> run scripts used to execute the model were provided by MPCA for each of the four calendar quarters (Jan-Mar, Apr-Jun, Jul-Sep, and Oct-Dec) along with the post-processing scripts used to estimate the visibility impacts for each scenario.

An important fact is that the results from the MPCA modeling for Minnesota's regional haze State Implementation Plan (SIP) development were also utilized by EPA in the "scalar" method proposed in the FIP. These results were subsequently defended by EPA in the final FIP stating "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."<sup>1</sup> The methods utilized by MPCA represent not only an EPA-approved approach for SIP submittal, but also formed the basis of the visibility determinations made by EPA in the proposed and final FIP. However, since EPA did not conduct its own modeling and provided only the "scalar" results, there are substantial and inherent flaws in the EPA-estimated visibility impacts. These flaws are detailed in Appendix A to this memorandum which includes a review of the EPA scalar approach. Since the modeling reported here used identical methods to the MPCA analyses, it is consistent with the underlying data that was used in

<sup>&</sup>lt;sup>1</sup> Federal Register, Volume 78, Number 25, page 8721, February 6, 2013

the EPA FIP method for estimating visibility impact. Further, this modeling provides specific technical analyses regarding the estimated effects of CNR and Arcelor taconite unit emission reductions in the final FIP on the relevant Class I areas. To effectively evaluate the impact of NOx reductions on regional haze, this level of analyses should have been conducted by EPA before publishing and finalizing the taconite BART FIP for Minnesota and Michigan.

Nonetheless, the first step in any photochemical modeling exercise is to ensure that the modeling results can be replicated to ensure no errors in the data transfer or modeling setup. Barr worked with MPCA to obtain the 2002 and 2005 modeling input files, run scripts, and post-processing files to allow for the validation of the Barr modeling system. To be clear, the modeling comparison scenario used the exact same files provided by MPCA with no adjustments. Given the length of time required to complete the modeling analyses, this step focused on the 2002 dataset and evaluated the results from the 2002 baseline and 2002 Minnesota BART SIP. The information provided by MPCA to complete this comparison was contained in the document: "Visibility Improvement Analysis of Controls Implemented due to BART Determinations on Emission Units Subject-to-BART", October 23, 2009. The results of the comparison are contained in Appendix B: Barr and MPCA CAM<sub>X</sub> Modeling Comparison of Results. As expected with any photochemical model comparison running four different quarterly simulations using two different computer systems and Fortran compilers, there are insignificant differences in the end values. The overall comparison of the results was very favorable and showed excellent agreement between the four modeled datasets (i.e. 2002 baseline and 2002 BART SIP, each from MPCA and Barr).

After successful confirmation of the consistency check of the Barr modeling system to the MPCA system, the modeling focused on the specific emission changes in the MPCA elevated point source files. As with most regional modeling applications, there were 36 "core" point source files for each scenario. This set corresponds to three files per month (Saturday, Sunday, and weekday) for all twelve months. Emission information from each file was extracted for all the CNR and Arcelor taconite facilities in Minnesota to confirm the emission totals used by MPCA in the SIP baseline and BART SIP control scenarios. The emission summary data for each unit matched the summary tables within the MPCA BART SIP modeling. Also, the emission sources from Tilden Mining Company in Michigan were identified and information extracted to allow for the same type of modeling as was conducted for the Minnesota facilities.

The next step was to include United Taconite Line 1 in the baseline and FIP modeling files. Line 1 was not originally included in the MPCA modeling because it was not operational in the 2002 base year.

Therefore, the information for that source was obtained from MPCA-provided 2018 elevated point source files and incorporated into the 36 core elevated point source files. This allowed all the CNR and Arcelor furnace lines within the FIP to be evaluated as part of this modeling analysis. To that end, each CNR and Arcelor BART-eligible source was specifically identified and labeled for processing to track modeled impacts using plume-in-grid treatment and the Particulate Source Apportionment Technology (PSAT) contained within CAM<sub>x</sub> (including Tilden Mining). A list of the sources that were included in the specific PSAT groups can be found in Appendix C: CAM<sub>x</sub> PSAT Source List.

As part of the identification and labeling process, the MPCA BART SIP elevated point source files were converted from binary input files to ascii text files using the BIN2ASC program. (NOTE: by using the BART SIP point source files, all other Minnesota BART-eligible sources were included in this modeling exercise using their BART SIP emissions to isolate the impacts of the CNR and Arcelor units.) Then, a Fortran90 program was developed to adjust the hourly emissions from each applicable source to correspond to the sum of annual emissions within each of the following scenarios: EPA FIP baseline and EPA final FIP. It is important to note that the temporal factors for each source were not modified from the original MPCA-provided inventory files (i.e. no changes to the monthly or day-of-week factors). This emission approach allowed for the exact set of emissions within each of the scenarios to be modeled. After the emissions within the text file were adjusted, the emissions were checked for accuracy. Then, each file was converted back to binary input from ASCII text using the ASC2BIN program. The emission summary for each unit/scenario combination is contained in Appendix D: Summary of  $CAM_x$ Elevated Point Source Emissions. Appendix D also provides a reference list for the emissions from the proposed FIP, Final FIP (where applicable), and calculation methodology where EPA did not provide sufficient information to calculate emissions. Table 1 contains a facility summary for all taconite furnaces under each scenario.

As stated previously, one of the outcomes of these analyses was the comparison of EPA's scalar approach to specific photochemical modeling using EPA's emission reduction assumptions within the FIP rulemakings. These modeling analyses make no judgment as to the achievability of these emission reductions. CNR and Arcelor dispute that these NOx reductions are achievable for all furnaces. These modeling analyses are, therefore, a conservative evaluation of EPA's predicted NOx reductions – not the actual NOx reductions achievable by the application of BART.

4

| Facility          | FIP Basel | line (TPY) | Final FIP (TPY) |       | Difference (TPY) |        |  |
|-------------------|-----------|------------|-----------------|-------|------------------|--------|--|
|                   | SO2       | NOx        | SO2             | NOx   | SO2              | NOx    |  |
| Arcelor Mittal    | 179       | 3,639      | 179             | 1,092 | 0                | 2,547  |  |
| Hibbing Taconite  | 570       | 6,888      | 570             | 2,066 | 0                | 4,821  |  |
| United Taconite   | 4,043     | 5,330      | 1,969           | 1,599 | 2,074            | 3,731  |  |
| Northshore Mining | 73        | 764        | 73              | 229   | 0                | 535    |  |
| Tilden Mining     | 1,153     | 4,613      | 231             | 1,384 | 922              | 3,229  |  |
| Total             | 6,018     | 21,233     | 3,022           | 6,370 | 2,996            | 14,863 |  |

 Table 1: Facility Taconite Furnace Emission Summary

Two other issues should be noted here.

1. The first is the nested 12-km modeling domain selected by MPCA (illustrated in Figure 1) along with the specific "receptors" used for identification of the relevant Isle Royale Class I area and their use for determination of impacts from Tilden Mining Company. The Tilden Mining source was not included in the MPCA fine grid as it was not part of the Minnesota SIP. However, the elevated point source file includes the sources in the entire 36 km domain (including Tilden). As such, the Tilden emissions were available for estimation of specific visibility impacts. The receptors selected by MPCA only included the western half of the Isle Royale Class I area because that is the portion of the area closest to the Minnesota sources. However, the size of the grid cells (e.g. 12 and 36 km) provides a large number of potential receptors at all the Class I areas and little variation among receptors is expected at the distance between Tilden and Isle Royale. Thus, the modeling data should adequately represent the visibility impact at the entire Isle Royale Class I area.

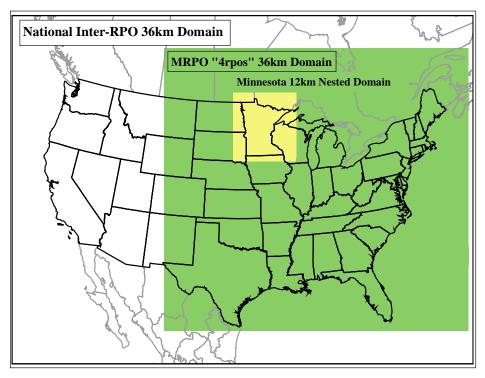


Figure 1. MPCA Modeling Domain

2. The second issue is the inconsistency between the emission reduction estimates used by EPA in the calculation of their scalar visibility benefits (i.e. Tables V-C of the proposed and final FIP) and the emission reductions calculated in the facility-specific sections of the proposed FIP. EPA's flawed calculation methodology did not use the appropriate emission reductions. In order to calculate the emissions for evaluation of the final FIP in the CAM<sub>x</sub> modeling, Barr was left with utilizing the limited information provided in the proposed and final FIP rulemaking. The lack of information and the errors and inconsistencies within the dataset were highlighted in the information request on January 31, 2013 to EPA (included in Appendix E). As of the time of this memorandum, no response by EPA has been received by Barr. Further, given the time required to complete the modeling, assumptions were made that were conservative to calculate the FIP emissions. For example, the final FIP references a 65% NO<sub>x</sub> reduction from Tilden Mining Company due to the switch to natural gas firing, but that was not consistent with the other gas-fired kilns (proposed FIP reduction was 70% with the same 1.2 lb NO<sub>x</sub>/MMBTU emission limit). Therefore, to provide the maximum emission reductions, the 70% control was utilized for all the CNR and Arcelor taconite furnaces.

#### II. Summary of CAM<sub>X</sub> Results

As mentioned above, the CAM<sub>x</sub> model was executed for each calendar quarter of 2002 and 2005 using the adjusted emissions for each scenario. The results were then post-processed to calculate visibility impacts for each scenario in deciviews (dV). All these results are provided in Appendix F: CAM<sub>x</sub> Results by Facility. For the purposes of this memorandum, the following tables compare EPA's estimates of annual average impact contained within the proposed FIP with the results generated by the CAM<sub>x</sub> modeling for this project on a facility by facility basis. The first three facilities contain emission reductions for only NO<sub>x</sub>: Arcelor Mittal, Hibbing Taconite, and Northshore Mining. These results are summarized in Tables 2-4. United Taconite and Tilden Mining, which have both SO<sub>2</sub> and NO<sub>x</sub> emission reductions, have result comparisons that require additional discussion.

The context of these results includes the following visibility impact thresholds:

<u>0.5 dV impact</u> is the BART eligibility and contribute to visibility impairment threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required)<sup>2</sup>,

1.0 dV difference is the presumed human perceptible level for visibility improvement, and

<u>0.1 dV difference</u> was defined by other agencies, such as the northeastern states MANE-VU Regional Planning Organization<sup>3</sup> as the degree of visibility improvement that is too low to justify additional emission controls. In addition, EPA's Regional Haze Rule mentions<sup>4</sup> that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

The first two columns within Tables 2-4 and 6-8 provide the difference in 98<sup>th</sup> percentile visibility improvement from the baseline to the FIP control emissions, while the third column provides a measure of over-estimation when using the EPA scalar approach (i.e. % Over Estimation by EPA = EPA Estimated Difference / CAM<sub>x</sub> Modeled Difference).

Table 2: Arcelor Mittal Visibility Impact Comparison

<sup>&</sup>lt;sup>2</sup> 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule.

<sup>&</sup>lt;sup>3</sup> As documented by various states; see, for example, <u>www.mass.gov/dep/air/priorities/hazebart.doc</u>, which indicates a visibility impact of less than 0.1 delta-dv is considered "de minimis".

<sup>&</sup>lt;sup>4</sup> 64 FR 35730.

| Class I Area    | EPA Estimated | CAM <sub>X</sub> Modeled | % Over        |
|-----------------|---------------|--------------------------|---------------|
|                 | Difference    | Difference               | Estimation by |
|                 | 98% dV        | 98% dV                   | EPA           |
| Boundary Waters | 1.7           | 0.1                      | 1500%         |
| Voyageurs       | 0.9           | 0.09                     | 1000%         |
| Isle Royale     | 1.1           | 0.03                     | 3700%         |

Table 3: Hibbing Taconite Visibility Impact Comparison

| Class I Area    | EPA Estimated | CAM <sub>x</sub> Modeled | % Over        |
|-----------------|---------------|--------------------------|---------------|
|                 | Difference    | Difference               | Estimation by |
|                 | 98% dV        | 98% dV                   | EPA           |
| Boundary Waters | 3.2           | 0.19                     | 1700%         |
| Voyageurs       | 1.7           | 0.11                     | 1500%         |
| Isle Royale     | 2.1           | 0.04                     | 5300%         |

Table 4: Northshore Mining Visibility Impact Comparison

| Class I Area    | EPA Estimated        | CAM <sub>X</sub> Modeled | % Over               |
|-----------------|----------------------|--------------------------|----------------------|
|                 | Difference<br>98% dV | Difference<br>98% dV     | Estimation by<br>EPA |
| Boundary Waters | 0.6                  | 0.01                     | 6000%                |
| Voyageurs       | 0.3                  | 0.01                     | 3000%                |
| Isle Royale     | 0.4                  | 0.01                     | 4000%                |

As pointed out in the previous comments on this proposed FIP, these results clearly demonstrate that the NOx reductions proposed in the FIP will not provide a perceptible visibility improvement. Additionally, it demonstrates that the EPA methodology using scalars severely overestimated the visibility impact from NO<sub>x</sub> emission reductions at these taconite furnaces in northeast Minnesota. Even when using maximum emission reductions from EPA's baseline, the EPA estimates grossly over predicted the potential dV improvement by over <u>10 times</u> the predicted 98<sup>th</sup> percentile visibility improvement in all cases for the Arcelor Mittal, Hibbing Taconite, and Northshore Mining facilities. The maximum 98<sup>th</sup> percentile visibility improvement predicted by the source specific tracking for any one line was 0.1 dV (Arcelor Mittal Line 1 on Boundary Waters). The minimum 98<sup>th</sup> percentile visibility improvement was 0.01 dV (Northshore Mining on Isle Royale). Further, the results presented in Table 5 for the individual furnace line impacts at Hibbing Taconite illustrate de minimis visibility improvement at all the Class I areas evaluated.

| Class I Area    | Furnace Line | CAM <sub>x</sub> Modeled<br>Difference<br>98% dV |
|-----------------|--------------|--|
| Boundary Waters | Line 1       | 0.04   |
|                 | Line 2       | 0.05   |
|                 | Line 3       | 0.08   |
| Voyageurs       | Line 1       | 0.03   |
|                 | Line 2       | 0.04   |
|                 | Line 3       | 0.04   |
| Isle Royale     | Line 1       | 0.01   |
|                 | Line 2       | 0.01   |
|                 | Line 3       | 0.01   |

Table 5: Hibbing Taconite Line-Specific Visibility Impacts

Overall, all the facilities with only  $NO_X$  emission reductions predict visibility improvement from each furnace line at or below the de minimis visibility improvement threshold of 0.1 delta-dV.

Due to the sizable change in the United Taconite SO<sub>2</sub> emission reductions from the proposed FIP to the final FIP; the visibility improvement was re-calculated using EPA's apparent methodology from the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NO<sub>X</sub> and the revised emission reduction for SO<sub>2</sub>. Then, those resultants were averaged for each of the Class I areas to obtain the "updated" EPA all pollutant estimates.

| Class I Area    | Amended EPA | CAM <sub>X</sub> Modeled | % Over        |
|-----------------|-------------|--------------------------|---------------|
|                 | Estimated   | Difference               | Estimation by |
|                 | Difference  | 98% dV                   | EPA           |
|                 | 98% dV      |                          |               |
| Boundary Waters | 1.6         | 1.40                     | 110%          |
| Voyageurs       | 0.8         | 0.85                     | N/A           |
| Isle Royale     | 1.1         | 0.35                     | 320%          |

 Table 6: United Taconite Visibility Impact Comparison (All Pollutants)

The comparison of the total modeling effort including both pollutant reductions is surprisingly similar (except for Isle Royale). However, when the individual pollutant impacts are examined, the problem with EPA's methodology is more clearly understood. The sulfate impacts are estimated more closely to the CAM<sub>x</sub> results, while the nitrate impacts are grossly overestimated similar to the first three facilities.

The methodology used to isolate the sulfate and nitrate impacts separately from the current CAM<sub>x</sub> results prioritizes the sulfate and nitrate impacts as part of three separate post-processing runs (all pollutants, sulfate, and nitrate). The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall United Taconite impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO<sub>x</sub> control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.1 dV; total = 0.15 dV) and would not show up as part of the overall visibility change. As detailed in the comments to the proposed FIP, it is also important to note the high probability that the maximum impacts from NO<sub>x</sub> emission reduction occur during the winter months when Isle Royale is closed to visitors and visitation at the other Class I areas is significantly reduced from summertime maximum conditions.<sup>5</sup>

| Table 7: United Taconite Visibility Impact Comparison (Suifate Impact) |             |  |                          |  |            |
|--|-------------|--|--------------------------|--|------------|
| Class I Area   | Amended EPA |  | CAM <sub>X</sub> Modeled |  | % Over     |
|  | Estimated   |  | Difference               |  | Estimation |
|  | Difference  |  | 98% dV                   |  | by EPA     |
|  | 98% dV      |  |                          |  | -          |
| Boundary Waters  | 1.0         |  | 1.29                     |  | N/A        |
| Voyageurs  | 0.5         |  | 0.74                     |  | N/A        |
| Isle Royale  | 0.6         |  | 0.28                     |  | 210%       |

 Table 7: United Taconite Visibility Impact Comparison (Sulfate Impact)

Table 8: United Taconite Visibility Impact Comparison (Nitrate Impact)

| Class I Area    | Amended EPA | CAM <sub>X</sub> Modeled | % Over     |
|-----------------|-------------|--------------------------|------------|
|                 | Estimated   | Difference               | Estimation |
|                 | Difference  | 98% dV                   | by EPA     |
|                 | 98% dV      |                          |            |
| Boundary Waters | 2.3         | 0.18                     | 1300%      |
| Voyageurs       | 1.1         | 0.08                     | 1400%      |
| Isle Royale     | 1.6         | 0.05                     | 3200%      |

<sup>&</sup>lt;sup>5</sup> Cliffs Natural Resources (September 28, 2012), EPA-R05-OAR-0037-0045 Att. M

In the same manner as Hibbing Taconite, United Taconite's individual furnace lines were evaluated. As mentioned in the previous paragraph, the results in Table 9 for nitrate impact are biased toward higher nitrate impacts due to the sorting of the data to maximize nitrate impact.

| Class I Area    | Furnace Line | CAM <sub>x</sub> Modeled<br>Difference |
|-----------------|--------------|--|
| Boundary Waters | Line 1       | 98% dV<br>0.05                         |
|                 | Line 2       | 0.1                                    |
| Voyageurs       | Line 1       | 0.02                                   |
|                 | Line 2       | 0.06                                   |
| Isle Royale     | Line 1       | 0.02                                   |
|                 | Line 2       | 0.03                                   |

Table 9: United Taconite Line-Specific Nitrate Visibility Impacts

Nonetheless, as seen for all the other furnace lines, the results for United Taconite's predicted visibility impact are at or below the deminimis threshold for visibility improvement.

Since Tilden Mining Company was not evaluated using the same methodology as the Minnesota taconite facilities, there are no specific EPA data to compare with the  $CAM_X$  results. However, it is important to understand that the results are very similar to the other results regarding the impact of  $NO_X$  emission reductions on these Class I areas.

| Class I Area    | <b>EPA</b> Estimated | CAM <sub>X</sub> Modeled |
|-----------------|----------------------|--------------------------|
|                 | Difference 98%       | Difference               |
|                 | dV                   | 98% dV                   |
| Boundary Waters | N/A                  | 0.08                     |
| Voyageurs       | N/A                  | 0.03                     |
| Isle Royale     | N/A*                 | 0.17                     |

Table 10: Tilden Mining Visibility Impact Comparison (All Pollutants)

\*EPA estimated that the proposed FIP results in 0.501 dV visibility improvement at Isle Royale from emission reduction at Tilden Mining

| SPeene impact companys |                          |  |                          |
|------------------------|--------------------------|--|--------------------------|
| Class I Area           | CAM <sub>X</sub> Sulfate |  | CAM <sub>x</sub> Nitrate |
|                        | Modeled                  |  | Modeled                  |
|                        | Difference               |  | Difference               |
|                        | 98% dV                   |  | 98% dV                   |
| Boundary Waters        | 0.07                     |  | 0.01                     |
| Voyageurs              | 0.03                     |  | 0.00                     |
| Isle Royale            | 0.14                     |  | 0.02                     |

Table 11: Tilden Mining Pollutant-Specific Impact Comparison

The visibility impacts from  $NO_X$  emission reductions at Tilden are consistent with the other modeling results and further demonstrate that significant emission reductions of NOx (3,229 tpy for Tilden) result in no visibility improvements.

#### III. Conclusions

Overall, the results from the three facilities with only  $NO_X$  emission reductions (Hibbing Taconite, Northshore Mining, and Arcelor Mittal) and the pollutant-specific comparisons for United Taconite and Tilden Mining illustrate that nearly 15,000 tons per year of  $NO_X$  reductions, even if they were technically and/or economically achievable, provide imperceptible visibility impacts at the Minnesota or nearby Michigan Class I areas. In all cases, the CAMx-predicted impacts for every furnace line are at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

The fact that NO<sub>x</sub> emission reductions do not provide perceptible visibility improvement was understood by MPCA when they proposed existing control and good combustion practices as BART for taconite furnaces in northeast Minnesota. This finding has been confirmed by this detailed modeling analysis. EPA, to its credit, does not claim that its scalar "ratio" approach for predicting visibility improvement is accurate. In the final FIP, EPA provided, "Therefore, even if the ratio approach was over-estimating visibility improvement by a factor of two or three, the expected benefits would still be significant."<sup>6</sup> Our analysis demonstrates that the ratio approach has over-estimated impacts by a factor of ten to sixty for NO<sub>x</sub> reductions. When accurately modeled, the NO<sub>x</sub> reductions do not yield discernible visibility benefits. To that end, the following pictures from WinHaze Level 1 Visual Air Quality Imaging Modeler

<sup>&</sup>lt;sup>6</sup> Federal Register, Volume 78, Number 25, page 8720, February 6, 2013

(version 2.9.9.1) provide a visual reference for the  $CAM_X$  predicted visibility impairment from the maximum nitrate impacting facility at Isle Royale and Boundary Waters<sup>7</sup>.



Isle Royale FIP Base - United Taconite



Boundary Waters FIP Base - Hibbing Taconite



Isle Royale Final FIP – United Taconite



Boundary Waters Final FIP – Hibbing Taconite

Given the size of the predicted visibility impacts (both less than 0.2 dV improvement), these pictures illustrate no discernible visibility improvement from NO<sub>X</sub> reductions at either Class I area.

Ultimately, Minnesota and Michigan reached their visibility assessments in different ways, but this modeled analysis supports their conclusion that low  $NO_X$  burner technology is not BART for the furnaces modeled at Arcelor Mittal - Minorca, Hibbing Taconite, Northshore Mining Company, United Taconite, and Tilden Mining. Therefore, EPA should approve the sections of the SIPs establishing  $NO_X$  BART on this basis.

<sup>&</sup>lt;sup>7</sup> Voyageurs National Park pictures are not contained within the WinHaze program



resourceful. naturally. engineering and environmental consultants

## APPENDIX A: Visibility Impact Requirements and EPA's Scalar Approach for Estimating Visibility Impacts within the Taconite FIP

March 6, 2013

### I. Summary of Visibility Impact Requirements

The relevant language related to the specific BART visibility impact modeling approach from 40 CFR 51 Appendix Y (herein, Appendix Y), *Guidelines for BART Determinations Under the Regional Haze Rule,* is provided here, in italics with some language underlined for emphasis:

5. Step 5: How should I determine visibility impacts in the BART determination?

• For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.

Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emission rates are calculated as a percentage of pre-control emission rates. For example, if the 24-hr pre-control emission rate is 100 lb/hr of SO[2], then the post control rate is 5 lb/hr if the control efficiency being evaluated is 95 percent.

• Make the net visibility improvement determination.

Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. You have flexibility to assess visibility improvements due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment. Suggestions for making the determination are:

• Use of a comparison threshold, as is done for determining if BART-eligible sources should be subject to a BART determination. Comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g., the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing an x percent change in improvement).

• Compare the 98th percent days for the pre- and post-control runs.

Note that each of the modeling options may be supplemented with source apportionment data or source apportionment modeling.

It should be noted that Appendix Y is a guideline for state air quality agencies to proceed with modeling of BART sources. Therefore, these are not requirements, but recommended practices for evaluation of visibility impacts. Significant discretion was given to each state regarding the use of these methods. To that end, the Minnesota Pollution Control Agency applied a different modeling system than the EPA-approved model (CALPUFF) for BART evaluations. Discussed below, the new modeling system was subsequently used by EPA as part of their FIP proposal.

Further, an excerpt from the Clean Air Act, Part C, Subpart II is provided below to establish the basis for the Appendix Y regulations related to visibility improvement.

### II. Summary of EPA's approach

Specific language from the proposed and final FIPs are provided in *italics* along with comments.

EPA relied on visibility improvement modeling conducted by the Minnesota Pollution Control Agency (MPCA) and recorded in MPCA's document "Visibility Improvement Analysis of Controls Due to BART Determinations on Emission Unit's Subject to BART", October 23, 2009 [attached]. The visibility improvement modeling conducted by MPCA utilized the Comprehensive Air Quality Model with Extensions (CAMx) air quality model with the Mesoscale Meteorological Model (MM5) and the Emission Modeling System (EMS-2003). Within the CAMx modeling system, MPCA used the Particulate Source Apportionment Tool (PSAT) and included evaluation of all the elevated point emissions<sup>1</sup> at each facility with best available retrofit technology (BART) units. The impacts from MPCA State Implementation Plan (SIP) BART controls were determined by subtracting the impact difference between the 2002/2005 base case and 2002/2005 BART control case for each facility. EPA used the impacts from four of the six facilities modeled by MPCA (Minnesota Power – Boswell Energy Center, Minnesota Power – Taconite Harbor, Northshore Mining – Silver Bay, United Taconite). The other two facilities modeled by MPCA were utility sources (Rochester Public Utilities – Silver Lake and Xcel Energy – Sherburne Generating Plant). The locations of these sources are presented below in Figure A-1 (obtained from the MPCA 2009 document).

<sup>&</sup>lt;sup>1</sup> Elevated point emissions include only sources with plume rise above 50m.

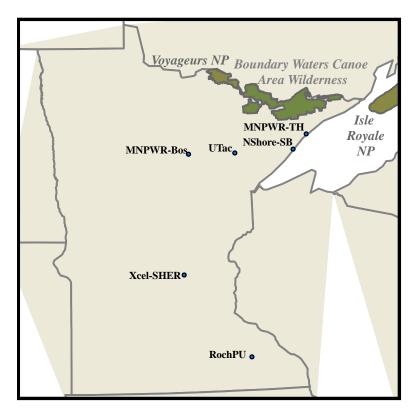


Figure A-1: Minnesota Facilities with BART-Determinations Assessed

In order to avoid the time and effort necessary for specific modeling of the units that EPA proposed to include in the FIP, EPA then used the average visibility impact from these four facilities to calculate two metrics for visibility improvement. The first metric is a ratio of number of days with greater than 0.5 deciview (dV) visibility divided separately by the change in  $SO_2$  and  $NO_x$  emissions at each facility (i.e. one ratio for change in  $SO_2$  emissions and one ratio for change in  $NO_x$  emissions). The second metric was calculated in the same fashion, but with 98<sup>th</sup> percentile visibility change divided by the change in  $SO_2$  and  $NO_x$  emissions at each facility. These ratios were then multiplied by the estimated FIP emission reductions for the taconite facilities (including UTAC and Northshore Mining). It is important to note that there were no  $NO_x$  emission reductions modeled from any of the taconite facilities and the only source of  $SO_2$  emission reductions from the taconite facilities was the UTAC facility.

Within the final FIP, EPA provided some additional statements that further clarified the agency's confidence regarding the use of the scalar approach for estimating visibility improvements.

### III. Specific Issues Regarding EPA's Visibility Impact Estimates

Clean Air Act Section 169(A)(g)(2) – "In determining the best available retrofit technology the State (or the Administrator in determining emission limitations which reflect such technology) shall 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 the source, and the <u>degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.</u>"

Proposed FIP Page 49329 – Column 1 – "The discussion below uses MPCA's emissions data and modeled visibility impact data to derive visibility impact ratios as a function of changes in emissions of NOx and SO2 at MPCA-modeled facilities. These visibility-emission ratios were then applied to the BART-based emission changes for the source subject to this BART rule to derive possible visibility impacts."

Issues – EPA's shortcut methodology does not provide an accurate assessment of potential visibility impacts from taconite emission units subject to BART, and cannot be relied upon for several reasons stated below. The use of emission change vs. visibility impact ratios is not scientifically accurate even for a single source, much less several sources in other locations, and illustrates EPA's haste for the development of the FIP without proper modeling procedures. According to a plain language reading of the Clean Air Act section above and the best-practice recommendations within Appendix Y, the state and EPA were required to conduct a thorough evaluation of the impacts associated with the changes in emissions for each BART technology at the relevant units within each taconite facilities. EPA's methodology does not result in a thorough evaluation. If such an analysis were submitted to EPA by the state, it would be rejected as inadequate. The same should apply to EPA's analysis of the visibility improvement calculations.

MPCA used an appropriate model for estimating visibility impacts from five utility sources and one taconite source, all subject to BART, in northern Minnesota. EPA took that analyses and attempted to justify its outcomes based on its flawed methodology. Alone, the differences between the emission profiles for utility sources and taconite sources and their different locations relative to the Class I areas should preclude this type of evaluation. The difference in the emissions profile relationship between  $NO_X$  and  $SO_2$  emissions is extremely important due to the interactive and competitive nature of the two pollutants for available ammonia ( $NH_3$ ) to form ammonium nitrate or ammonium sulfate.

In addition, there are important seasonal differences in the tendency for sulfates or nitrates to be important for haze formation. Nitrates are only important in winter because significant particle formation occurs only in cold weather; oxides of nitrogen react primarily to form ozone in the summer months. On the other hand, oxidation of  $SO_2$  to sulfate is most effective in summer with higher rates of photochemical and aqueous phase reactions. Due to the much different seasonal preferences for these two haze components, a one-size-fits-all scaling approach based upon annual averages that is insensitive to the season of the year is wholly inappropriate.

It is important to note that the only  $NO_x$  emission reductions used in the EPA scalar analyses were from utility sources. This occurred because the MPCA SIP did not include  $NO_x$  emission reductions from the United Taconite units. Therefore, the variation in emission profiles and stack parameters between utility boiler emission sources and taconite furnaces introduce another source of error with the EPA methodology.

Further, as shown in Figure A-1, the location of these sources with respect to the relevant Class I areas also causes significant problems with the EPA evaluation. The modeled visibility impacts from each source are a direct function of the wind direction. When two sources are not in the same direction with respect to the area, there is no possible way to accurately reflect the impact from the two different sources on receptor locations on any given day. For example, elevated impacts on the Voyageurs National Park from Northshore Mining would not happen on the same days as any of the other taconite sources in Minnesota.

Additionally, notwithstanding the inaccuracies of EPA's average scalar methodology, a review of the calculation of the visibility change to emission reduction ratios (i.e. MPCA-calculated visibility changes divided by  $SO_2$  and  $NO_X$  SIP emission reductions) was conducted. This review uncovered calculation/typographical errors in the tables that were used to develop the average visibility change metrics. These simple calculation errors were subsequently corrected in the final FIP, but another inconsistency was not. The emission reductions used for  $NO_X$  within the scalar visibility calculations (Table V-C.xx) do not match the emission reduction tables in the proposed FIP (Table V – B.yy) for each facility. In one case (Northshore Mining Company), the visibility improvement reductions are greater than the baseline emissions. The attached table provides the baseline, proposed FIP, and final FIP information contained within the EPA rulemakings and docket for each taconite furnace and facility. Ultimately, even if the scalar approach used by EPA was valid, the rulemaking record is inaccurate and incomplete for the calculation of visibility impacts due to these inconsistencies.

Further, the calculation methodology for the two facilities with  $SO_2$  and  $NO_X$  reductions (United Taconite and US Steel – Minntac) appears to utilize another invalid assumption. Also, the proposed FIP does not provide a clear explanation of the calculation of the scaled visibility impacts for these two facilities (Page 49332 – Column 1):

"To calculate the visibility impacts for the Minnesota source facilities covered by this FIP proposed rule, we multiplied the total estimated BART NOx and SO2 emission reductions for each subject facility by the appropriate visibility factor/emission change ratios in Table V-C.9 and <u>combined the results to estimate</u> the total visibility impacts that would result from the reduction of PM2.5 concentrations."

In Tables V-C.14 and V-C.16, the calculation of the visibility change with the two different pollutants is not explicitly provided within the FIP. Based on the use of the average visibility changes ("combined results") in the attached tables, one can generate "estimated visibility impacts" that are close to the values provided in the FIP tables. This pollutant averaging approach is not valid due to the previous comments regarding the interactive nature of the reaction mechanisms for ammonium nitrate and ammonium sulfate.

Proposed FIP Page 49331 – Column 1 – "The above visibility factor/emission change ratio data show significant variation from source-to-source and between impacted Class I areas. This variation is caused by differences in the relative location of the source (relative to the locations of the Class I areas), variations in background sources, variations in transport patterns on high haze factors, and other factors that we cannot assess without detailed modeling of the visibility impacts for the sources as a function of pollutant emission type."

Issue – EPA correctly establishes the significant variation in the ratio data and clearly distinguishes some (but not all) of the problems with the approach used to determine visibility impacts. Other problems include the differences in modeled utility source stack parameters vs. taconite stack parameters, the different inter-pollutant ratios at each facility, and the differences in visibility impacts due to on-going changes in emissions from 2002/2005 to current/future emission levels. Furthermore, EPA identifies the solution to solve this problem within their statement regarding "detailed modeling of the visibility impacts". This detailed modeling exercise was completed for BART-eligible Cliffs Natural Resources and Arcelor Mittal facilities in northeast Minnesota and Michigan to provide a clear record of the visibility improvements associated with the final FIP. This modeling demonstrates the lack of visibility improvement from nearly 15,000 tons per year of NO<sub>X</sub> emission reductions and provides sufficient evidence to support the Minnesota and Michigan State Implementation Plans which called for good combustion practices as BART for NO<sub>X</sub> at these facilities.

Proposed FIP Page 49333, Column 2 – "Each BART determination is a function of consideration of visibility improvement and other factors for the individual unit, but in general EPA's assessment of visibility impacts finds that technically feasible controls that are available at a reasonable cost for taconite plants can be expected to provide a visibility benefit that makes those controls warranted."

Issue – EPA's statement regarding visibility benefit from the FIP  $NO_X$  emission reductions are vastly overestimated based on updated  $CAM_X$  modeling for the Cliffs Natural Resources and Arcelor Mittal taconite furnaces. The modeling results evaluating the 98<sup>th</sup> percentile visibility improvements obtained from these emission reductions are generally less than 10% of the EPA estimates. Therefore, these  $NO_X$  controls are not warranted for visibility improvement in northeast Minnesota and Michigan.

Final FIP Page 8720, Column 2 – "EPA's analysis shows that based on all of the BART factors, including visibility, the selected controls are warranted. If highly reasonable and cost-effective controls had been available but visibility benefits were slight, EPA would have rejected those controls."

Issue – EPA describes exactly the situation with respect to "slight visibility benefits". Therefore, given the new information regarding the very slight modeled impact of  $NO_x$  emission reductions, EPA should reject those reductions as necessary under the BART program. Also, in the final FIP, EPA criticizes both MPCA and MDEQ for ignoring relevant information on Low  $NO_x$  Burner (LNB) technology. Now, given the length of time necessary and extensive effort required to generate this new visibility improvement data, EPA should reconsider its position on LNB as producing visibility benefits. This would allow EPA to support the original findings for these facilities within both the MPCA and MDEQ SIP with respect to  $NO_x$  emission limits. Final FIP Page 8720, Column 3 – "EPA's proposed rule acknowledged the uncertainty associated with the visibility impact ratio approach, but noted that despite the uncertainties, the Agency was confident that the information was adequate to assess potential visibility improvements due to emission reductions at the specific facilities."

"Given the geographic proximity of the taconite facilities to those that were modeled, EPA believes that the ratio approach provide adequate assurance of the visibility improvements that can be expected from the proposed emission reductions."

"In the proposed rule's summary of the impacts at Boundary Waters, Voyageurs, and Isle Royale, these values ranged from 1.3 to 7.1 dVs of improvement with between 17 and 93 fewer days above the 0.5 dV threshold. Therefore, even if the ratio approach was over-estimating visibility improvements by a factor of two or three, the expected benefits would still be significant."

Final FIP Page 8721, Column 3 – "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."

Issue – EPA again chose to ignore the specific technical issues discussed above regarding the use of the ratio approach and has incorrectly assumed that this approach will provide an accurate assessment of the visibility benefits from the Cliffs and Arcelor taconite facilities. Based on the refined  $CAM_x$  modeling results using a conservative estimate of EPA's final FIP emission reduction scenario, it is obvious that the ratio approach does not provide any assurance of the visibility improvements. Further, the estimates for visibility improvement are over-estimated by between a factor of ten and sixty. Therefore, the impacts are not "significant" as referenced in EPA's response to comment within the final FIP rulemaking. The lack of technical validity contained within the EPA scalar approach is alarming. Even more alarming is the agency's refusal to conduct the type of detailed analyses necessary to allow for a technically valid answer on a rulemaking that will cost the taconite industry millions of dollars.

### **IV. Summary**

The CAM<sub>x</sub> modeling approach undertaken by Cliffs and Arcelor provides the best approximation of the visibility improvements from the emission reductions within the final FIP. This method replaces the use of the average ratio approach used by EPA with refined, photochemical modeling for the Cliffs and Arcelor facilities. The results of the analysis confirm the findings of the MPCA in its 2009 SIP that  $NO_x$  emission reductions do not have sufficient impact to warrant further consideration. At this point, we affirm that EPA's simple assessment is not credible, and any visibility improvement conclusions for  $NO_x$  are not technically sound. The visibility improvement results estimated by EPA using the ratio approach are between ten and sixty times greater than the results generated using the CAM<sub>x</sub> modeling system. In essence, the modeling conducted here provides EPA another opportunity to support the findings of the MPCA and MDEQ SIPs with respect to  $NO_x$  emissions impacts at the Cliffs and Arcelor facilities.

# Cliffs Natural Resources and Arcelor Mittal Taconite FIP Emission Summary

|                           |                   |                    |           |          | Emissions    |         | Emiss                  | ion Reductions         |         | Emissions |          |
|---------------------------|-------------------|--------------------|-----------|----------|--------------|---------|------------------------|------------------------|---------|-----------|----------|
|                           |                   |                    |           |          | Proposed FIP | ,       | Baseline -<br>Prop FIP | Baseline -<br>Prop FIP |         | Final FIP |          |
|                           |                   | Emission Unit      |           | Baseline | FIP          |         | <b>Emission Tables</b> | Visibility Calcs       |         |           |          |
| Facility                  | ModID             | Description        | Pollutant | tons/yr  | tons/yr      | Note(s) | tons/yr                | tons/yr                | Note(s) | lb/hr     | Note(s)  |
| Hibbing Taconite Company  | {3}               | Line 1             | NOx       | 2,497    | 749          | [1]     | 1,748                  |                        |         |           | [4]      |
|                           |                   |                    | SO2       | 202      | 202          | [2]     | 0                      |                        |         | 82.6      | [5]      |
|                           | {4}               | Line 2             | NOx       | 2,144    | 643          | [1]     | 1,500                  |                        |         |           | [4]      |
|                           |                   |                    | SO2       | 180      | 180          | [2]     | 0                      |                        |         | 82.6      | [5]      |
|                           | {5}               | Line 3             | NOx       | 2,247    | 674          | [1]     | 1,573                  |                        |         |           | [4]      |
|                           |                   |                    | SO2       | 188      | 188          | [2]     | 0                      |                        |         | 82.6      | [5]      |
|                           | HTC               | BART Units         | NOx       | 6,888    | 2,066        |         | 4,821                  | 5,259                  | [3]     |           |          |
|                           |                   | Combined           | SO2       | 570      | 570          |         | 0                      | 0                      | [3]     | 247.8     |          |
| Northshore Mining Company |                   | Process Boiler 1/2 | NOx       | 41       | 21           | [6]     | 21                     |                        |         |           | [10]     |
|                           |                   |                    | SO2       |          |              |         |                        |                        |         |           |          |
|                           | {24}              | Furnace 11         | NOx       | 386      | 116          | [7]     | 270                    |                        |         |           | [11]     |
|                           |                   |                    | SO2       | 38       | 38           | [8]     | 0                      |                        |         | 19.5      | [12]     |
|                           | {25}              | Furnace 12         | NOx       | 378      | 113          | [7]     | 264                    |                        |         |           | [11]     |
|                           |                   |                    | SO2       | 35       | 35           | [8]     | 0                      |                        |         | 19.5      | [12]     |
|                           | <mark>NSM</mark>  | BART Units         | NOx       | 805      | 250          |         | 555                    | 926                    | [9]     |           |          |
|                           |                   | Combined           | SO2       | 73       | 73           |         | 0                      | 0                      | [9]     | 39        |          |
| Tilden Mining Company     | {1}               | Boiler #1/2        | NOx       | 79       | 79           | [13]    | 0                      |                        |         |           |          |
|                           |                   |                    | SO2       | 0        | 0            | [14]    | 0                      |                        |         |           | [19]     |
|                           | {3}               | Ore Dryer # 1      | NOx       | 15       | 15           | [15]    | 0                      |                        |         |           |          |
|                           |                   |                    | SO2       | 34       | 34           | [15]    | 0                      |                        |         |           | [20]     |
|                           | {5}               | Furnace #1         | NOx       | 4,613    | 1,384        | [16]    | 3,229                  |                        |         |           | [21]     |
|                           |                   |                    | SO2       | 1,153    | 115          | [17]    | 1,038                  |                        |         | 55        | [22][23] |
|                           | <mark>TMC</mark>  | BART Units         | NOx       | 4,707    | 1,478        |         | 3,229                  | 3,229                  | [18]    |           |          |
|                           |                   | Combined           | SO2       | 1,187    | 150          |         | 1,038                  | 1,038                  | [18]    |           |          |
| United Taconite           | {26}              | Line 1             | NOx       | 1,643    | 493          | [24]    | 1,150                  |                        |         |           | [27]     |
|                           |                   |                    | SO2       | 1,293    | 129          | [25]    | 1,164                  |                        |         | 155       | [28]     |
|                           | {24}              | Line 2             | NOx       | 3,687    | 1,106        | [24]    | 2,581                  |                        |         |           | [27]     |
|                           |                   |                    | SO2       | 2,750    | 275          | [25]    | 2,475                  |                        |         | 374       | [28]     |
|                           | UTAC              | BART Units         | NOx       | 5,330    | 1,599        |         | 3,731                  | 3,208                  | [26]    |           |          |
|                           |                   | Combined           | SO2       | 4,043    | 404          |         | 3,639                  | 3,639                  | [26]    | 529       | [28]     |
| Arcelor Mittal            | <mark>ARC</mark>  | Line 1             | NOx       | 3,639    | 1,092        | [29]    | 2,547                  | 2,859                  | [31]    |           | [32]     |
|                           | <mark>{12}</mark> |                    | SO2       | 179      | 179          | [30]    | 0                      | 0                      | [31]    | 38.2      | [33]     |

| TOTAL BART UNIT | NOx | 21,369 | 6,485 | 14,884 | 15,481 |
|-----------------|-----|--------|-------|--------|--------|
|                 | SO2 | 6,053  | 1,376 | 4,677  | 4,677  |

Facility BART Unit Summary or Overall Summary

FIP Baseline does not match reference

FIP Table B emission tables do not match Table C visibility calculation tables

### Notes:

- [1] HTC Line 1-3 USEPA FIP NOx Baseline Emissions Proposed FIP Table V B.24; Proposed FIP NOx Emissions = 70% Control from Baseline
  - Typographical Error in Table V B.24 for Line 1 Baseline Emissions (2,143.5 TPY Proposed FIP; should have been 2,497 TPY)
- [2] HTC Line 1-3 USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V B.27
- [3] HTC USEPA Proposed BART FIP Table V C.11
- [4] HTC Furnace Lines USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
- [5] HTC Furnace Lines USEPA final BART combined limit of 247.8 lb SO2/hr [82.6 lb/hr each for Lines 1 to 3] (30-day rolling avg); can be adjusted based on CEMs data.
- [6] NSM Process Boilers 1&2 NOx Emissions from Proposed FIP Table V B.12 (p49318); LNB 50% Control from Baseline of 41.2 tons/year
- [7] NSM Furnace 11/12 NOx Emissions (Baseline and Proposed FIP Control) from Proposed FIP Table V B.8; FIP Emissions = 70% Control from Baseline
- [8] NSM Furnace 11/12 No Additional SO2 Control Applied by Proposed FIP; Baseline FIP Emission Rate from Table V B.10
- [9] NSM USEPA Proposed BART FIP Table V C.12
- [10] NSM Process Boilers 1&2 USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) [No additional control].
- [11] NSM Furnace 11/12 USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
- [12] NSM Furnace 11/12 USEPA final BART combined limit of 39.0 lb SO2/hr (30-day rolling average); must be adjusted based on CEMs data.
- [13] Tilden Process Boilers 1 & 2 NOx Baseline Emissions Proposed FIP Table V B.38
- [14] Tilden Process Boilers 1 & 2 SO2 Baseline Emissions Proposed FIP Table V B.37 (0.25 TPY)
- [15] Tilden Dryer #1 Emissions from Proposed FIP Table V B.39 (SO2) and Table V B.40 (NOx) 34.07 TPY SO2, 15.1 TPY NOx
- [16] Tilden Furnace 1 NO2 Baseline and Proposed FIP Control Emissions Proposed FIP Table V B.34 (FIP Emissions = 70% Control from Baseline)
- [17] Tilden Furnace 1 Proposed FIP SO2 Emissions Table V-B.36; Spray Dry Absorption 90%; Proposed FIP Text says 95% Control or 5 ppm; Baseline Emissions Back-calculated from 90% control
- [18] Tilden Furnace 1 USEPA did not calculate visibility improvement for Tilden (Used emission difference Baseline Proposed FIP)
- [19] Tilden USEPA Final BART limit of 1.2%S in fuel combusted by Process Boiler #1 and #2
- [20] Tilden USEPA Final BART limit of 1.5%S in fuel combusted by Ore Dryer #1
- [21] Tilden Furnace 1- USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only); NOx emissions referenced in final FIP text as 65% control from baseline (page 8721)
- [22] Tilden Furnace 1 USEPA Final BART restriction Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs; SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
- [23] Tilden Furnace 1 USEPA Final BART Modeling File (Part of Final Rulemaking Docket) Conducted by NPS 55 lb/hr SO2
- [24] UTAC Line 1-2 USEPA NOx Baseline Emissions Proposed FIP Table V B.14; Proposed FIP NOx Emissions = 70% Control from Baseline
- [25] UTAC Line 1-2 USEPA proposed FIP Baseline SO2 Emissions Table V B.17; 90% Control in Table, but 95% Control within text Proposed FIP (page 49319)
- [26] UTAC USEPA Proposed BART FIP Table V C.13
- [27] UTAC Line 1-2 USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)
- [28] UTAC Line 1-2 USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr Line 1 & 374 lb/hr Line 2).
- [29] Arcelor USEPA proposed FIP Baseline NOx Emissions Table V B.19; Proposed FIP NOx Emissions = 70% Control from Baseline
- [30] Arcelor USEPA proposed FIP Baseline SO2 Emissions Table V B.21
- [31] Arcelor USEPA Proposed BART FIP Table V C.10
- [32] Arcelor USEPA Final BART SO2 Limit of 38.16 lb/hr for Arcelor.
- [33] Arcelor USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)

EPA Furnace NOx Control % 70%



resourceful. naturally. engineering and environmental consultants

# APPENDIX B: Barr and MPCA CAM<sub>x</sub> Modeling Comparison of Results

March 6, 2013

# Minnesota Power – Taconite Harbor (BART01)

### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          | PM <sub>2.5</sub> |                 | Class I Area |                 |      |          |                 |             |      |                 |  |  |
|-----------------------------|-------------------|-----------------|--------------|-----------------|------|----------|-----------------|-------------|------|-----------------|--|--|
| P1V12.5                     |                   | Boundary Waters |              |                 |      | Voyageur | <b>S</b>        | Isle Royale |      |                 |  |  |
| Parameter                   | Met Year          | Base            | BART         | Differ-<br>ence | Base | BART     | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |
| Days > 0.5 dv               | 2002              | 94              | 90           | -4              | 11   | 9        | -2              | 30          | 27   | -3              |  |  |
| 98th Percentile $\Delta dv$ | 2002              | 9.2             | 8.3          | -0.9            | 0.8  | 0.7      | -0.1            | 2.2         | 1.9  | -0.3            |  |  |

### Barr

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          | <b>PM</b> <sub>2.5</sub> |      | Class I Area |                 |      |          |                 |             |      |                 |  |  |  |
|-----------------------------|--------------------------|------|--------------|-----------------|------|----------|-----------------|-------------|------|-----------------|--|--|--|
| PINI <sub>2.5</sub>         |                          | B    | oundary Wa   | aters           |      | Voyageur | s               | Isle Royale |      |                 |  |  |  |
| Parameter                   | Met Year                 | Base | BART         | Differ-<br>ence | Base | BART     | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |  |
| Days > 0.5 dv               | 2002                     | 95   | 90           | -5              | 11   | 9        | -2              | 30          | 27   | -3              |  |  |  |
| 98th Percentile $\Delta dv$ | 2002                     | 9.14 | 8.25         | -0.89           | 0.82 | 0.68     | -0.14           | 2.22        | 1.88 | -0.34           |  |  |  |

### Minnesota Power – Boswell (BART04)

### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                       |          |                 |      |                 |      | Class I Are | ea              |             |      |                 |  |
|--------------------------|----------|-----------------|------|-----------------|------|-------------|-----------------|-------------|------|-----------------|--|
| <b>PM</b> <sub>2.5</sub> |          | Boundary Waters |      |                 |      | Voyageur    | s               | Isle Royale |      |                 |  |
| Parameter                | Met Year | Base            | BART | Differ-<br>Ence | Base | BART        | Differ-<br>ence | Base        | BART | Differ-<br>Ence |  |
| Days > 0.5 dv            | 2002     | 111             | 60   | -51             | 86   | 58          | -28             | 48          | 27   | -21             |  |
| 98th Percentile<br>∆ dv  | 2002     | 4.3             | 2.4  | -1.9            | 4.4  | 2.7         | -1.8            | 2.0         | 1.0  | -1.0            |  |

Barr

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |      |            |                 |      | Class I Are | a               |             |      |                 |  |
|-----------------------------|----------|------|------------|-----------------|------|-------------|-----------------|-------------|------|-----------------|--|
| PM <sub>2.</sub>            | 5        | B    | oundary Wa | aters           |      | Voyageur    | s               | Isle Royale |      |                 |  |
| Parameter                   | Met Year | Base | BART       | Differ-<br>Ence | Base | BART        | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |
| Days > 0.5 dv               | 2002     | 110  | 61         | -49             | 86   | 58          | -28             | 47          | 27   | -20             |  |
| 98th Percentile $\Delta dv$ | 2002     | 4.27 | 2.37       | -1.90           | 4.43 | 2.65        | -1.78           | 1.96        | 0.98 | -0.98           |  |

# Northshore Mining – Silver Bay (BART05)

### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |      | Class I Area |                 |      |          |                 |             |      |                 |  |  |
|-----------------------------|----------|------|--------------|-----------------|------|----------|-----------------|-------------|------|-----------------|--|--|
| <b>PM</b> <sub>2</sub> .    | 5        | B    | oundary Wa   | aters           |      | Voyageur | s               | Isle Royale |      |                 |  |  |
| Parameter                   | Met Year | Base | BART         | Differ-<br>ence | Base | BART     | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |
| Days > 0.5 dv               | 2002     | 77   | 72           | -5              | 9    | 8        | -1              | 20          | 15   | -5              |  |  |
| 98th Percentile $\Delta dv$ | 2002     | 3.96 | 3.79         | -0.17           | 0.6  | 0.5      | -0.1            | 0.9         | 0.7  | -0.2            |  |  |

### Barr

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          | $PM_{2.5}$ |                 | Class I Area |                 |      |          |                 |             |      |                 |  |  |  |
|-----------------------------|------------|-----------------|--------------|-----------------|------|----------|-----------------|-------------|------|-----------------|--|--|--|
| P1V1 <sub>2.</sub>          | 5          | Boundary Waters |              |                 |      | Voyageur | s               | Isle Royale |      |                 |  |  |  |
| Parameter                   | Met Year   | Base            | BART         | Differ-<br>ence | Base | BART     | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |  |
| Days > 0.5 dv               | 2002       | 78              | 72           | -6              | 9    | 8        | -1              | 20          | 15   | -5              |  |  |  |
| 98th Percentile $\Delta dv$ | 2002       | 3.96            | 3.78         | -0.18           | 0.63 | 0.50     | -0.13           | 0.90        | 0.73 | -0.17           |  |  |  |

### **United Taconite (BART26)**

### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                      |          |                 | Class I Area |                 |      |          |                 |             |      |                 |  |  |  |
|-------------------------|----------|-----------------|--------------|-----------------|------|----------|-----------------|-------------|------|-----------------|--|--|--|
| PM <sub>2.5</sub>       |          | Boundary Waters |              |                 |      | Voyageur | <b>S</b>        | Isle Royale |      |                 |  |  |  |
| Parameter               | Met Year | Base            | BART         | Differ-<br>ence | Base | BART     | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |  |
| Days > 0.5 dv           | 2002     | 59              | 44           | -15             | 32   | 20       | -12             | 8           | 1    | -7              |  |  |  |
| 98th Percentile<br>∆ dv | 2002     | 3.0             | 1.7          | -1.3            | 1.8  | 0.8      | -0.9            | 0.6         | 0.3  | -0.3            |  |  |  |

Barr

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          | $PM_{2.5}$ |      | Class I Area |                 |      |          |                 |             |      |                 |  |  |  |
|-----------------------------|------------|------|--------------|-----------------|------|----------|-----------------|-------------|------|-----------------|--|--|--|
| P1N12.5                     |            | B    | oundary Wa   | aters           |      | Voyageur | 5               | Isle Royale |      |                 |  |  |  |
| Parameter                   | Met Year   | Base | BART         | Differ-<br>ence | Base | BART     | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |  |
| Days > 0.5 dv               | 2002       | 63   | 46           | -17             | 34   | 20       | -14             | 8           | 1    | -7              |  |  |  |
| 98th Percentile $\Delta dv$ | 2002       | 3.02 | 1.69         | -1.33           | 1.78 | 0.85     | -0.93           | 0.59        | 0.28 | -0.31           |  |  |  |

# Xcel Sherburne (BART13)

### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| <b>PM</b> <sub>2.5</sub>   |          |      | Class I Area |                 |      |          |                 |             |      |                 |  |  |  |
|----------------------------|----------|------|--------------|-----------------|------|----------|-----------------|-------------|------|-----------------|--|--|--|
| <b>P</b> IVI <sub>2.</sub> | 5        | B    | oundary Wa   | aters           |      | Voyageur | s               | Isle Royale |      |                 |  |  |  |
| Parameter                  | Met Year | Base | BART         | Differ-<br>ence | Base | BART     | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |  |
| Days > 0.5 dv              | 2002     | 74   | 58           | -16             | 53   | 39       | -14             | 42          | 30   | -12             |  |  |  |
| 98th Percentile<br>∆ dv    | 2002     | 2.5  | 1.9          | -0.6            | 2.2  | 1.7      | -0.5            | 1.4         | 1.0  | -0.4            |  |  |  |

### Barr

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          | PM <sub>2.5</sub> |                 |      |                 |      | Class I Are | ea              |             |      |                 |  |
|-----------------------------|-------------------|-----------------|------|-----------------|------|-------------|-----------------|-------------|------|-----------------|--|
| PINI <sub>2.5</sub>         |                   | Boundary Waters |      |                 |      | Voyageur    | s               | Isle Royale |      |                 |  |
| Parameter                   | Met Year          | Base            | BART | Differ-<br>ence | Base | BART        | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |
| <b>Days</b> > 0.5 dv        | 2002              | 74              | 59   | -15             | 53   | 39          | -14             | 42          | 29   | -13             |  |
| 98th Percentile $\Delta dv$ | 2002              | 2.48            | 1.90 | -0.58           | 2.18 | 1.65        | -0.53           | 1.44        | 1.06 | -0.38           |  |

### **Rochester Public Utilities (BART07)**

### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |                        |      |                 |                    | Class I Are | a               |             |      |                 |
|-----------------------------|----------|------------------------|------|-----------------|--------------------|-------------|-----------------|-------------|------|-----------------|
| $\mathbf{PM}_{2.}$          | 5        | <b>Boundary Waters</b> |      |                 | y Waters Voyageurs |             |                 | Isle Royale |      |                 |
| Parameter                   | Met Year | Base                   | BART | Differ-<br>ence | Base               | BART        | Differ-<br>ence | Base        | BART | Differ-<br>ence |
| Days > 0.5 dv               | 2002     | 0                      | 0    | 0               | 0                  | 0           | 0               | 0           | 0    | 0               |
| 98th Percentile $\Delta dv$ | 2002     | 0.1                    | 0.1  | 0.0             | 0.1                | 0.0         | 0.0             | 0.1         | 0.0  | 0.0             |

Barr

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |                 |      |                 |           | Class I Are | ea              |             |      |                 |
|-----------------------------|----------|-----------------|------|-----------------|-----------|-------------|-----------------|-------------|------|-----------------|
| $\mathbf{PM}_{2}$ .         | 5        | Boundary Waters |      |                 | Voyageurs |             |                 | Isle Royale |      |                 |
| Parameter                   | Met Year | Base            | BART | Differ-<br>ence | Base      | BART        | Differ-<br>ence | Base        | BART | Differ-<br>ence |
| Days > 0.5 dv               | 2002     | 0               | 0    | 0               | 0         | 0           | 0               | 0           | 0    | 0               |
| 98th Percentile $\Delta dv$ | 2002     | 0.10            | 0.06 | 0.04            | 0.08      | 0.04        | 0.04            | 0.09        | 0.04 | 0.05            |



# APPENDIX C: CAM<sub>X</sub> PSAT Source List

March 6, 2013

# 2009 MPCA Tracked, Elevated Point Sources

| RANKTRAC   | RECEPTOR      |                 |                                      |
|------------|---------------|-----------------|--------------------------------------|
| BARTSRC_ID | BARTSRC_ID    | Facility ID     | Facility Name [1]                    |
| 1          | 2             | 2703100001      | Minnesota Power - Taconite Harbor    |
| 2          | 3             | 2703700003      | XCEL - Black Dog                     |
| 3          | 4             | 2705300015      | XCEL - Riverside                     |
| 4          | 5             | 2706100004      | Minnesota Power - Boswell            |
| 5          | 6             | 2707500003      | Northshore Mining Co - Silver Bay    |
| 6          | 7             | 2709900001      | Austin Utilities - NE Power Station  |
| 7          | 8             | 2710900011      | Rochester Public Utilities           |
| 8          | 9             | 2711100002      | Otter Tail Power - Hoot Lake         |
| 9          | 10            | 2712300012      | XCEL - High Bridge                   |
| 10         | 11            | 2713700013      | Minnesota Power - Laskin             |
| 11         | 12            | 2713700027      | Hibbing Public Utilities             |
| 12         | 13            | 2713700028      | Virginia Dept of Public Utilities    |
| 13         | 14            | 2714100004      | XCEL - Sherburne Generating Plant    |
| 14         | 15            | 2716300005      | XCEL - Allen S. King                 |
| 15         | 16            | 2701700002      | Sappi - Cloquet                      |
| 16         | 17            | 2703700011      | Flint Hill Resources - Pine Bend     |
| 17         | 18            | 2706100001      | Blandin Paper / Rapids Energy        |
| 18         | 19            | 2707100002      | Boise Cascade - International Falls  |
| 19         | 20            | 2713700005      | US Steel - Minntac                   |
| 20         | 21            | 2713700015      | Minnesota Power - ML Hibbard         |
| 21         | 22            | 2713700022      | Duluth Steam Cooperative             |
| 22         | 23            | 2713700031      | Georgia Pacific - Duluth             |
| 23         | 24            | 2713700061      | Hibbing Taconite                     |
| 24         | 25            | 2713700062      | Arcelor Mittal                       |
| 25         | 26            | 2713700063      | US Steel - Keetac                    |
| 26         | 27            | 2713700113      | United Taconite - Fairlane Plant [2] |
| 27         | 28            | 2700900011      | International Paper - Sartell        |
| 28         | 29            | 2716300003      | Marathon Ashland Petroleum           |
| 29         | 30            | 2713700083      | Potlatch - Cook                      |
| 30         | 31            | 2706100010      | Potlatch - Grand Rapids              |
|            |               |                 |                                      |
|            | Included in M | IPCA BART SIP M | Iodeling Report                      |

|     | Included in MPCA BART SIP Modeling Report          |
|-----|--|
| [1] | MPCA tracked all point sources on a facility-basis |

[2] MPCA Emissions did not Include UTAC Line 1

# 2012/2013 Barr Tracked, Elevated Point Sources

| Output ID | BARTSRC ID | Facility ID | Facility / Unit Name [3]                      |
|-----------|------------|-------------|---|
| MNPWTH    | 2          | -           | Minnesota Power - Taconite Harbor             |
| XCELBD    | 3          | 2703700003  | XCEL - Black Dog                              |
| XCELRV    | 4          | 2705300015  | XCEL - Riverside                              |
| MNPWBO    | 5          | 2706100004  | Minnesota Power - Boswell                     |
| NSMSBU    | 6          | 2707500003  | Northshore Mining Co - Silver Bay (All Other) |
| AUSTIN    | 7          | 2709900001  | Austin Utilities - NE Power Station           |
| ROCHPU    | 8          | 2710900011  | Rochester Public Utilities                    |
| OTTRHL    | 9          | 2711100002  | Otter Tail Power - Hoot Lake                  |
| XCELHB    | 10         | 2712300012  | XCEL - High Bridge                            |
| MNPWLS    | 11         | 2713700013  | Minnesota Power - Laskin                      |
| HIBBPU    | 12         | 2713700027  | Hibbing Public Utilities                      |
| VIRGPU    | 13         | 2713700028  | Virginia Dept of Public Utilities             |
| XCELSB    | 14         | 2714100004  | XCEL - Sherburne Generating Plant             |
| XCELAK    | 15         | 2716300005  | XCEL - Allen S. King                          |
| SAPPIC    | 16         | 2701700002  | Sappi - Cloquet                               |
| FHRPNB    | 17         | 2703700011  | Flint Hill Resources - Pine Bend              |
| BLNPAP    | 18         | 2706100001  | Blandin Paper / Rapids Energy                 |
| BOISEC    | 19         | 2707100002  | Boise Cascade - International Falls           |
| MINNTC    | 20         | 2713700005  | US Steel - Minntac                            |
| MNPWHB    | 21         | 2713700015  | Minnesota Power - ML Hibbard                  |
| DULSTM    | 22         | 2713700022  | Duluth Steam Cooperative                      |
| GEOPAC    | 23         | 2713700031  | Georgia Pacific - Duluth                      |
| HIBTAC    | 24         | 2713700061  | Hibbing Taconite (All Other)                  |
| ARCELR    | 25         | 2713700062  | Arcelor Mittal (All Other)                    |
| KEETAC    | 26         | 2713700063  | US Steel - Keetac                             |
| UTACFP    | 27         | 2713700113  | United Taconite - Fairlane Plant (All Other)  |
| INTPAP    | 28         | 2700900011  | International Paper - Sartell                 |
| MARTHN    | 29         | 2716300003  | Marathon Ashland Petroleum                    |
| POTLTC    | 30         | 2713700083  | Potlatch - Cook                               |
| POTLTG    | 31         | 2706100010  | Potlatch - Grand Rapids                       |
| TILDEN    | 32         | 26103B4885  | Tilden Mining Company (All Other)             |
| NSMPB1    | 33         | 2707500003  | Northshore Mining - Power Boiler 1            |
| NSMPB2    | 34         | 2707500003  | Northshore Mining - Power Boiler 2            |
| NSMF11    | 35         | 2707500003  | Northshore Mining - Furnace 11                |
| NSMF12    | 36         | 2707500003  | Northshore Mining - Furnace 12                |
| UTACL1    | 37         | 2713700113  | United Taconite - Line 1                      |
| UTACL2    | 38         | 2713700113  | United Taconite - Line 2                      |
| ARCLN1    | 39         | 2713700062  | Arcelor Mittal - Line 1                       |
| HBTCF1    | 40         | 2713700061  | Hibbing Taconite - Line 1                     |
| HBTCF2    | 41         | 2713700061  | Hibbing Taconite - Line 2                     |
| HBTCF3    | 42         | 2713700061  | Hibbing Taconite - Line 3                     |
| TILDL1    | 43         | 26103B4885  | Tilden Mining - Line 1                        |

Included in Barr Output Evaluation

Barr tracked furnace stacks and other noted stacks on a unit-basis while all other stacks were included in the "All Other" stacks

[3]



# APPENDIX D: Summary of CAM<sub>x</sub> Elevated Point Source Emissions

March 6, 2013

# Summary of CAMx Elevated Point Source Emissions

|                           |                   |                    |           | Emissi         | ons      | Emiss   | sions   | Emission Reductions  |
|---------------------------|-------------------|--------------------|-----------|----------------|----------|---------|---------|----------------------|
|                           |                   |                    |           | Propose        | ed FIP   | Fina    | I FIP   | Baseline - Final FIP |
|                           |                   | Emission Unit      | Pollutant | Baseline       |          | FIP     |         |                      |
| Facility                  | ModID             | Description        |           | tons/yr        | Note(s)  | tons/yr | Note(s) | tons/yr              |
| Hibbing Taconite Company  | {3}               | Line 1             | NOx       | 2,497          | [1]      | 749     | [3]     | 1,748                |
|                           |                   |                    | SO2       | 202            | [2]      | 202     | [4]     | 0                    |
|                           | {4}               | Line 2             | NOx       | 2,144          | [1]      | 643     | [3]     | 1,500                |
|                           |                   |                    | SO2       | 180            | [2]      | 180     | [4]     | 0                    |
|                           | {5}               | Line 3             | NOx       | 2,247          | [1]      | 674     | [3]     | 1,573                |
|                           |                   |                    | SO2       | 188            | [2]      | 188     | [4]     | 0                    |
|                           | HTC               | BART Furnaces      | NOx       | 6,888          |          | 2,066   |         | 4,821                |
|                           |                   | Combined           | SO2       | 570            |          | 570     |         | 0                    |
| Northshore Mining Company |                   | Process Boiler 1/2 | NOx       | 41             | [5]      | 41      | [8]     | 0                    |
|                           |                   |                    | SO2       |                |          |         |         |                      |
|                           | {24}              | Furnace 11         | NOx       | 386            | [6]      | 116     | [9]     | 270                  |
|                           |                   |                    | SO2       | 38             | [7]      | 38      | [10]    | 0                    |
|                           | {25}              | Furnace 12         | NOx       | 378            | [6]      | 113     | [9]     | 264                  |
|                           |                   |                    | SO2       | 35             | [7]      | 35      | [10]    | 0                    |
|                           | <mark>NSM</mark>  | BART Furnaces      | NOx       | 764            |          | 229     |         | 535                  |
|                           |                   | Combined           | SO2       | 73             |          | 73      |         | 0                    |
| Tilden Mining Company     | {1}               | Boiler #1/2        | NOx       | 79             | [11]     | 79      | [16]    | 0                    |
|                           |                   |                    | SO2       | 0              | [12]     | 0       | [17]    | 0                    |
|                           | {3}               | Ore Dryer # 1      | NOx       | 15             | [13]     | 15      | [18]    | 0                    |
|                           |                   |                    | SO2       | 34             | [13]     | 34      | [19]    | 0                    |
|                           | {5}               | Furnace #1         | NOx       | 4,613          | [14]     | 1,384   | [20]    | 3,229                |
|                           |                   |                    | SO2       | 1,153          | [15]     | 231     | [21]    | 922                  |
|                           | TMC               | BART Furnace       | NOx       | 4,613          |          | 1,384   |         | 3,229                |
|                           |                   |                    | SO2       | 1,153          |          | 231     |         | 922                  |
| United Taconite           | {26}              | Line 1             | NOx       | 1,643          | [22][23] | 493     | [26]    | 1,150                |
|                           |                   |                    | SO2       | 1,293          | [25]     | 577     | [27]    | 716                  |
|                           | {24}              | Line 2             | NOx       | 3,687          | [22][24] | 1,106   | [26]    | 2,581                |
|                           |                   |                    | SO2       | 2,750          | [25]     | 1,392   | [27]    | 1,357                |
|                           | UTAC              | BART Furnaces      | NOx       | 5,330          |          | 1,599   |         | 3,731                |
|                           |                   | Combined           | SO2       | 4,043          |          | 1,969   |         | 2,074                |
| Arcelor Mittal            | ARC               | Line 1             | NOx       | 3 <i>,</i> 639 | [28]     | 1,092   | [30]    | 2,547                |
|                           | <mark>{12}</mark> |                    | SO2       | 179            | [29]     | 179     | [31]    | 0                    |

| TOTAL BART | NOx | 21,233 | 6,370 | 14,863 |
|------------|-----|--------|-------|--------|
| Furnaces   | SO2 | 6,018  | 3,022 | 2,996  |

Fac

Facility Furnace Unit Summary or Overall Summary

FIP Baseline does not match reference

#### Notes:

- [1] HTC Line 1-3 USEPA FIP NOx Baseline Emissions Proposed FIP Table V B.24
- [2] HTC Line 1-3 USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V B.27
- [3] HTC Line 1-3 USEPA Proposed FIP NOx = 70% control from Baseline Table V B.24; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
- [4] HTC Line 1-3 USEPA Final FIP no additional SO2 control (Final FIP = Baseline Emissions)
- [5] NSM Process Boilers 1&2 NOx Emissions from Proposed FIP Table V B.12 (p49318)
- [6] NSM Furnace 11/12 NOx Emissions from Proposed FIP Table V B.8
- [7] NSM Furnace 11/12 SO2 Baseline FIP Emission Rate from Proposed FIP Table V B.10
- [8] NSM Process Boilers #1 and #2 USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) No additional control.
- [9] NSM Furnace 11/12 USEPA Proposed FIP NOx = 70% control from Baseline Table V B.8; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
- [10] NSM Furnace 11/12 no Additional SO2 Control Applied by Proposed or Final FIP (Final FIP = Baseline Emissions)
- [11] Tilden Process Boilers 1 & 2 NOx Baseline Emissions Proposed FIP Table V B.38
- [12] Tilden Process Boilers 1 & 2 SO2 Baseline Emissions Proposed FIP Table V B.37 (0.25 TPY)
- [13] Tilden Dryer #1 Emissions from Proposed FIP Table V B.39 (SO2) and Table V B.40 (NOx) 34.07 TPY SO2, 15.1 TPY NOx
- [14] Tilden Furnace 1 NO2 Baseline Proposed FIP Table V B.34
- [15] Tilden Furnace 1 SO2 Baseline Proposed FIP Projected SO2 Emission Reductions Table V-B.36; Baseline Emissions Back-calculated from 90% control
- [16] Tilden Process Boilers 1 & 2 No additional NOx control (Final FIP = Baseline Emissions)
- [17] Tilden Process Boilers 1 & 2 USEPA Final BART limit of 1.2%S in fuel No additional SO2 control (Final FIP = Baseline Emissions)
- [18] Tilden Ore Dryer #1 No additional NOx control (Final FIP = Baseline Emissions)
- [19] Tilden Ore Dryer #1 USEPA Final BART limit of 1.5%S in fuel No additional SO2 control (Final FIP = Baseline Emissions)
- [20] Tilden Furnace 1 USEPA Proposed FIP NOx = 70% control from Baseline Table V B.34; Final FIP (1.2 or 1.5 lb/MMBTU) NOx emissions referenced in final FIP text at 65% control from baseline (page 8721); but that is not consistent with the remaining facilities Modeled emissions assumed 70% control to provide maximum emission reductions
- [21] Tilden USEPA Final BART restriction Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs; SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
- [22] UTAC USEPA FIP NOx Baseline Emissions Proposed FIP Table V B.14
- [23] UTAC Line 1 NOx Permit limit specified in permit 13700113-005 1,655 TPY, issued 8/19/2010, page A-49 (reference from USEPA 114 Request Question 6)
- [24] UTAC Line 2 NOx Permit limit specified in permit 13700113-005 3,692 TPY, issued 8/19/2010, page A-56 (reference from USEPA 114 Request Question 6)
- [25] UTAC Line 1&2 USEPA proposed FIP Baseline SO2 Emissions Table V B.17; 90% Control in Table, 95% Control within text Proposed FIP (page 49319) Modeled baseline emissions back-calculated from 90% Control; SO2 Reductions match Table V - C.13 in Proposed FIP
- [26] UTAC Line 1&2 USEAP Proposed FIP NOx = 70% Control from Baseline Table V B.14; Final FIP (1.2 or 1.5 lb/MMBTU) Modeled emissions assumed 70% control to provide maximum emission reductions
- [27] UTAC Line 1&2 USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr Line 1 & 374 lb/hr Line 2) 30-day rolling average. Modeled Final FIP emissions used the limits and 85% operating factor to calculate the annual emissions (designed to maximize reductions)
- [28] Arcelor Line 1 USEPA proposed FIP Baseline NOx Emissions Table V B.19
- [29] Arcelor Line 1 USEPA proposed FIP Baseline SO2 Emissions Table V B.21
- [30] Arcelor Line 1 Proposed FIP NOx = 70% Control from Baseline Table V B.19; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
- [31] Arcelor Line 1 USEPA Final FIP no additional SO2 control (Final FIP = Baseline Emissions)



# APPENDIX E: Electronic Mail Requests - Proposed and Final FIP Emission Clarifications

From:Jeffry D. BennettSent:Thursday, January 31, 2013 7:42 PMTo:'Rosenthal.steven@Epa.gov'Cc:'Long, Michael E'Subject:Clarification Regarding Emissions within the Final Taconite BART FIPAttachments:EPA\_FIP\_Emission\_Summary\_01292013.xls

Steve,

Pursuant to our conversation last week regarding the baseline and controlled emission inventories within the proposed and final BART FIP for taconite furnaces, this e-mail is designed to request clarification regarding certain information contained in the rule. To that end, attached you will find a spreadsheet that summarizes and documents (to the maximum extent possible) the emission inventory data within the FIP rulemakings.

Specifically at this time, we are requesting:

(1) verification of the UTAC baseline NOx information for Line 1 and Line 2 ('Summary' Tab, Cells E30 and E32),

(2) clarification of the differences between the information contained in Columns H and I of the spreadsheet, Column H contains the difference between the FIP baseline and proposed FIP control emissions and was calculated from information within Table V-B.xx\* - NOx or SO2 facility specific emission data. The Column I information contains the emission reductions obtained from Table V-C.yy visibility improvement estimate tables. For each facility, these two columns should match, but the NOx information does not. Ultimately, the bases for Table V-C.yy data is the component that is missing.

\*Note: for Hibbing Taconite Line 1, a typographical error was discovered in Table V-B.24 and corrected in the spreadsheet.

(3) EPA's estimates of final FIP emissions on a tons/year basis with the corresponding emission reductions (i.e. FIP baseline – final FIP control) expected by EPA. This information would replace the "?" in Columns L and M of the spreadsheet. Along with the estimates, documentation of their bases would be extremely beneficial. For example, NOx could include either a % reduction from baseline or MMBTU/hour, Hours/year, and the appropriate lb NOx/MMBTU limit.

If you have any questions regarding these requests, feel free to contact Mike Long or myself. Thank you for your time.

Jeffry D. Bennett, PE Senior Air Quality Engineer Jefferson City office: 573.638.5033 cell: 573.694.0674 JBennett@barr.com www.barr.com From: Jeffry D. Bennett
Sent: Thursday, February 14, 2013 12:02 PM
To: 'Robinson.randall@Epa.gov'
Subject: FW: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: EPA\_FIP\_Emission\_Summary\_01292013.xls

#### Randy,

I talked with Steve Rosenthal yesterday about the taconite BART FIP emissions (see e-mail below). He told me that you "wrote the section on visibility improvement" and suggested I contact you about item 2 and a portion of the information requested in item 3. Barr Engineering is contracted with Cliffs Natural Resources and Arcelor Mittal to provide their taconite facilities with technical support regarding the FIP. At this point, we are trying to summarize and document the bases for the SO2 and NOx emissions that were used in the EPA baseline, the proposed FIP, and the final FIP for all their facilities.

The attached spreadsheet that I sent Steve previously includes the summary. Item 2 is related to differences between the NOx emission reductions used in the ratio visibility improvement calculations in the proposed FIP (Table V – C.yy) and the emission reductions in Table V – B.xx for each facility. Steve thought you would have the information about the basis for the Table V – C.yy reductions.

Item 3 is requesting information about the final FIP emission reductions. Specifically, you would probably have information regarding the emissions for Tilden Mining and United Taconite (UTAC) from the CALPUFF modeling completed by Trent Wickman referenced in the final FIP rulemaking docket. Please give me a call to discuss this at your earliest convenience. We are attempting to finalize the summary by COB tomorrow. Thanks for any help you can provide.

Jeffry D. Bennett, PE Senior Air Quality Engineer Jefferson City office: 573.638.5033 cell: 573.694.0674 JBennett@barr.com www.barr.com



resourceful. naturally. engineering and environmental consultants

# APPENDIX F: CAMx Modeling Results by Facility

March 6, 2013

### Arcelor Mittal CAMx Emissions and Modeling Results

### **Arcelor Emissions**

| Unit   | EPA FIP   | Final FIP | NOx        | EPA FIP   | Final FIP | SO2        |
|--------|-----------|-----------|------------|-----------|-----------|------------|
|        | Baseline  | NOx       | Emission   | Baseline  | SO2       | Emission   |
|        | NOx       | Emission  | Difference | SO2       | Emission  | Difference |
|        | Emission  | (TPY) [1] | (TPY)      | Emission  | (TPY)[3]  | (TPY)      |
|        | (TPY) [1] |           |            | (TPY) [2] |           |            |
| Line 1 | 3,639     | 1,092     | 2,547      | 179       | 179       | 0          |
|        |           |           |            |           |           |            |
| TOTAL  | 3,639     | 1,092     | 2,547      | 179       | 179       | 0          |

[1] FIP Baseline and Control NOx Emissions from EPA Proposed FIP Table V-B.19 – Projected Annual NOx Emission Reductions [TPY].

[2] FIP Baseline SO2 Emissions are from EPA Proposed FIP Table V-B.21 – Annual SO2 Emissions [TPY]

[3] No SO2 emission reductions in Final FIP (i.e. EPA Baseline = Final FIP control)

| Class I Area     | EPA FIP       | EPA FIP  | Proposed   | Proposed   | Difference | Difference |
|------------------|---------------|----------|------------|------------|------------|------------|
|                  | Baseline Days | Baseline | FIP Days > | FIP 98% dV | Days >0.5  | 98% dV [5] |
|                  | >0.5 dV       | 98% dV   | 0.5 dV     |            | dV [5]     | 00/00.000  |
| Boundary Waters  |               | 00,00    |            |            |            |            |
| 2002             |               |          |            |            |            |            |
| Line #1          | 30            | 0.789    | 18         | 0.713      | 12         | 0.076      |
| Facility Total   | 43            | 0.99     | 35         | 0.96       | 8          | 0.03       |
| 2005             |               |          |            |            |            |            |
| Line #1          | 7             | 0.491    | 3          | 0.326      | 4          | 0.165      |
| Facility Total   | 19            | 0.74     | 8          | 0.55       | 11         | 0.19       |
| <u>Voyageurs</u> |               |          |            |            |            |            |
| 2002             |               |          |            |            |            |            |
| Line #1          | 1             | 0.287    | 0          | 0.202      | 1          | 0.085      |
| Facility Total   | 1             | 0.34     | 0          | 0.22       | 1          | 0.12       |
| 2005             |               |          |            |            |            |            |
| Line #1          | 0             | 0.182    | 0          | 0.122      | 0          | 0.060      |
| Facility Total   | 0             | 0.22     | 0          | 0.16       | 0          | 0.06       |
| Isle Royale      |               |          |            |            |            |            |
| 2002             |               |          |            |            |            |            |
| Line #1          | 0             | 0.075    | 0          | 0.053      | 0          | 0.022      |
| Facility Total   | 0             | 0.09     | 0          | 0.06       | 0          | 0.03       |
| 2005             |               |          |            |            |            |            |
| Line #1          | 0             | 0.049    | 0          | 0.033      | 0          | 0.016      |
| Facility Total   | 0             | 0.06     | 0          | 0.04       | 0          | 0.02       |

[4] Visibility benchmarks:

<u>0.5 dV impact</u> is the BART eligibility threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required),

<u>1.0 dV difference</u> is the presumed human perceptible level for visibility improvement, and <u>0.1 dV difference</u> was defined by other agencies as the degree of visibility improvement that is too low to justify additional emission controls. Also, EPA's Regional Haze Rule mentions that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

[5] These two columns provide the difference in predicted days >0.5 dV and 98<sup>th</sup> percentile visibility improvement from the baseline to the FIP control emissions. The annual average number of days with > 0.5 dV improvement at all the Class I areas is considerably less than EPA's estimate (11 to 53). Also, the averages of the 98<sup>th</sup> percentile differences are **10 to 37 times less** than the predicted improvement by EPA. Note: the table below formed the basis for EPA's inclusion of control necessary at Arcelor Mittal.

### Arcelor Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

| (EPA Table B Emission Difference – 2,347 TPF NOX)[7] |                             |            |              |                 |            |  |  |
|--|-----------------------------|------------|--------------|-----------------|------------|--|--|
| Class I Area   | EPA Estimated EPA Estimated |            | CAMx Modeled | CAMx Modeled    |            |  |  |
|  | Difference Days             | Difference |              | Difference Days | Difference |  |  |
|  | >0.5 dV                     | 98% dV     |              | >0.5 dV[8]      | 98% dV     |  |  |
| Boundary Waters                                      | 24                          | 1.7        |              | 10              | 0.11       |  |  |
|  |                             |            |              |                 |            |  |  |
| Voyageurs  | 11                          | 0.9        |              | 1               | 0.09       |  |  |
|  |                             |            |              |                 |            |  |  |
| Isle Royale  | 18                          | 1.1        |              | 0               | 0.03       |  |  |

(EPA Table C Emission Difference = 2,859 TPY NOx)[6] (EPA Table B Emission Difference = 2,547 TPY NOx)[7]

[6] Emission Difference Obtained from EPA Proposed FIP Table V-C.10 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Arcelor Mittal.

[7] Emission Difference Obtained from EPA Proposed FIP Table V-B.19.

[8] The number of days with visibility >0.5 deciviews (dV) can be a misleading indicator as illustrated by the Arcelor Mittal and Northshore Mining results (below). The 98<sup>th</sup> percentile visibility improvement at Boundary Waters during the 2002 modeled year was 0.03 dV. However, the modeling predicts this insignificant change will result in eight more days of "good visibility", defined as days with visibility at or below the 0.5 deciview threshold. Further, the Northshore Mining results at Isle Royale indicate a miniscule 0.01 deciviews, or one hundred times less than a perceptible improvement to visibility. Nonetheless, the modeling predicts this insignificant change will result in two more days of "good visibility". In both circumstances, this does not mean that the visibility change was discernible. The model gives credit for an improved day when the predicted impairment falls from 0.51 to 0.50 deciviews, but that improvement is illusory because at 0.51 deciviews people do not perceive a regional haze problem. The difference in visibility from natural background when evaluating the baseline could have several days near the 0.5 dV "contribute to visibility degradation" threshold, but well less than the 1 dV "cause visibility degradation" threshold. Then, a very small change in visibility from the baseline to the controlled emission scenario (~0.01 – 0.1 dV) could cause a large number of days to be less than the 0.5 dV benchmark without producing any real benefit to visibility.

# Hibbing Taconite (HibTac) CAMx Emissions and Modeling Results

### **HibTac Emissions**

| Unit   | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|--------|----------|-----------|------------|----------|-----------|------------|
|        | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|        | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|        | Emission | (TPY)     | (TPY)      | Emission | (TPY)     | (TPY)      |
|        | (TPY)    |           |            | (TPY)    |           |            |
| Line 1 | 2,497    | 749       | 1,748      | 202      | 202       | 0          |
| Line 2 | 2,144    | 643       | 1,500      | 180      | 180       | 0          |
| Line 3 | 2,247    | 674       | 1,573      | 188      | 188       | 0          |
|        |          |           |            |          |           |            |
| TOTAL  | 6,888    | 2,066     | 4,822      | 570      | 570       | 0          |

### HibTac CAMx Results (By Unit)

| Class I Area           | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|------------------------|---------------|----------|-----------|-----------|------------|------------|
|                        | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Boundary Waters</u> |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line 1                 | 1             | 0.337    | 1         | 0.305     | 0          | 0.032      |
| Line 2                 | 2             | 0.287    | 0         | 0.260     | 2          | 0.027      |
| Line 3                 | 1             | 0.318    | 0         | 0.245     | 2          | 0.073      |
| Facility Total         | 33            | 1.10     | 22        | 0.96      | 11         | 0.14       |
| 2005                   |               |          |           |           |            |            |
| Line 1                 | 0             | 0.217    | 0         | 0.158     | 0          | 0.057      |
| Line 2                 | 0             | 0.203    | 0         | 0.124     | 0          | 0.079      |
| Line 3                 | 0             | 0.223    | 0         | 0.140     | 0          | 0.083      |
| Facility Total         | 14            | 0.85     | 11        | 0.62      | 3          | 0.23       |
| <u>Voyageurs</u>       |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line 1                 | 0             | 0.197    | 0         | 0.168     | 0          | 0.029      |
| Line 2                 | 0             | 0.197    | 0         | 0.159     | 0          | 0.038      |
| Line 3                 | 0             | 0.211    | 0         | 0.163     | 0          | 0.048      |
| Facility Total         | 18            | 0.67     | 10        | 0.61      | 8          | 0.06       |
| 2005                   |               |          |           |           |            |            |
| Line 1                 | 0             | 0.126    | 0         | 0.102     | 0          | 0.024      |
| Line 2                 | 0             | 0.122    | 0         | 0.085     | 0          | 0.037      |
| Line 3                 | 0             | 0.133    | 0         | 0.103     | 0          | 0.030      |
| Facility Total         | 8             | 0.51     | 5         | 0.36      | 3          | 0.15       |

| Class I Area       | EPA FIP              | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|--------------------|----------------------|----------|-----------|-----------|------------|------------|
|                    | <b>Baseline Days</b> | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                    | >0.5 dV              | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Isle Royale</u> |                      |          |           |           |            |            |
| 2002               |                      |          |           |           |            |            |
| Line 1             | 0                    | 0.053    | 0         | 0.047     | 0          | 0.006      |
| Line 2             | 0                    | 0.045    | 0         | 0.036     | 0          | 0.009      |
| Line 3             | 0                    | 0.046    | 0         | 0.037     | 0          | 0.009      |
| Facility Total     | 0                    | 0.16     | 0         | 0.13      | 0          | 0.03       |
|                    |                      |          |           |           |            |            |
| 2005               |                      |          |           |           |            |            |
| Line 1             | 0                    | 0.038    | 0         | 0.027     | 0          | 0.011      |
| Line 2             | 0                    | 0.034    | 0         | 0.022     | 0          | 0.012      |
| Line 3             | 0                    | 0.037    | 0         | 0.026     | 0          | 0.011      |
| Facility Total     | 0                    | 0.13     | 0         | 0.09      | 0          | 0.04       |

### HibTac Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 5,259 TPY NOx)[8] (EPA Table B Emission Difference = 4,822 TPY NOx)[9]

| 1217110010 2 211100 |                 |               |                 |              |
|---------------------|-----------------|---------------|-----------------|--------------|
| Class I Area        | EPA Estimated   | EPA Estimated | CAMx Modeled    | CAMx Modeled |
|                     | Difference Days | Difference    | Difference Days | Difference   |
|                     | >0.5 dV         | 98% dV        | >0.5 dV         | 98% dV       |
| Boundary Waters     | 44              | 3.2           | 7               | 0.19         |
|                     |                 |               |                 |              |
| Voyageurs           | 21              | 1.7           | 5               | 0.11         |
|                     |                 |               |                 |              |
| Isle Royale         | 26              | 2.1           | 0               | 0.04         |

[8] Emission Difference Obtained from EPA Proposed FIP Table V-C.11 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Hibbing Taconite.

[9] Emission Difference Obtained from EPA Proposed FIP Table V-B.24.

# Northshore Mining CAMx Emissions and Modeling Results

### Northshore Emissions

| Unit            | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|-----------------|----------|-----------|------------|----------|-----------|------------|
|                 | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|                 | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|                 | Emission | (TPY)     | (TPY)      | Emission | (TPY)     | (TPY)      |
|                 | (TPY)    |           |            | (TPY)    |           |            |
| Power Boiler #1 | 676      | 676       | 0          | 681      | 681       | 0          |
| Power Boiler #2 | 1,093    | 1,093     | 0          | 1,098    | 1,098     | 0          |
| Furnace 11      | 386      | 116       | 270        | 38       | 38        | 0          |
| Furnace 12      | 378      | 113       | 265        | 35       | 35        | 0          |
|                 |          |           |            |          |           |            |
| FURNACES        | 764      | 229       | 535        | 73       | 73        | 0          |
| TOTAL           | 2,533    | 1,998     | 535        | 1,852    | 1,852     | 0          |

### Northshore CAMx Results (By Unit)

| NOT LISTOPE CAN        | x Results (by O |          |           |           |            |            |
|------------------------|-----------------|----------|-----------|-----------|------------|------------|
| Class I Area           | EPA FIP         | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|                        | Baseline Days   | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV         | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Boundary Waters</u> |                 |          |           |           |            |            |
| 2002                   |                 |          |           |           |            |            |
| Power Boiler #1        | 32              | 1.487    | 32        | 1.499     | 0          | -0.012     |
| Power Boiler #2        | 49              | 2.087    | 49        | 2.097     | 0          | -0.010     |
| Furnace 11             | 0               | 0.136    | 0         | 0.139     | 0          | -0.003     |
| Furnace 12             | 0               | 0.133    | 0         | 0.122     | 0          | 0.011      |
| Facility Total         | 73              | 4.16     | 72        | 4.14      | 1          | 0.02       |
|                        |                 |          |           |           |            |            |
| 2005                   |                 |          |           |           |            |            |
| Power Boiler #1        | 13              | 0.640    | 13        | 0.654     | 0          | -0.014     |
| Power Boiler #2        | 22              | 0.926    | 23        | 0.911     | 0          | 0.015      |
| Furnace 11             | 0               | 0.087    | 0         | 0.067     | 0          | 0.020      |
| Furnace 12             | 0               | 0.082    | 0         | 0.076     | 0          | 0.006      |
| Facility Total         | 51              | 1.67     | 50        | 1.68      | 1          | -0.01      |
| Voyageurs              |                 |          |           |           |            |            |
| 2002                   |                 |          |           |           |            |            |
| Power Boiler #1        | 1               | 0.196    | 1         | 0.196     | 0          | 0.000      |
| Power Boiler #2        | 1               | 0.293    | 1         | 0.293     | 0          | 0.000      |
| Furnace 11             | 0               | 0.016    | 0         | 0.013     | 0          | 0.003      |
| Furnace 12             | 0               | 0.015    | 0         | 0.013     | 0          | 0.002      |
| Facility Total         | 8               | 0.51     | 8         | 0.51      | 0          | 0.00       |

| Class I Area            | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|-------------------------|---------------|----------|-----------|-----------|------------|------------|
|                         | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                         | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Voyageurs</u>        |               |          |           |           |            |            |
| 2005                    |               |          |           |           |            |            |
| Power Boiler #1         | 0             | 0.188    | 0         | 0.193     | 0          | -0.005     |
| Power Boiler #2         | 1             | 0.244    | 1         | 0.247     | 0          | -0.003     |
| Furnace 11              | 0             | 0.020    | 0         | 0.018     | 0          | 0.002      |
| Furnace 12              | 0             | 0.021    | 0         | 0.016     | 0          | 0.004      |
| Facility Total          | 6             | 0.47     | 6         | 0.46      | 0          | 0.01       |
| Ida Davala              |               |          |           |           |            |            |
| Isle Royale             |               |          |           |           |            |            |
| 2002<br>Power Boiler #1 | 3             | 0.204    | 2         | 0.204     | 0          | 0.000      |
|                         |               | 0.294    | 3         | 0.294     | 0          | 0.000      |
| Power Boiler #2         | 6             | 0.412    | 6         | 0.408     | 0          | 0.004      |
| Furnace 11              | 0             | 0.034    | 0         | 0.028     | 0          | 0.006      |
| Furnace 12              | 0             | 0.037    | 0         | 0.029     | 0          | 0.008      |
| Facility Total          | 16            | 0.75     | 15        | 0.74      | 1          | 0.00       |
|                         |               |          |           |           |            |            |
| 2005                    |               |          |           |           |            |            |
| Power Boiler #1         | 3             | 0.180    | 3         | 0.180     | 0          | 0.000      |
| Power Boiler #2         | 4             | 0.320    | 4         | 0.322     | 0          | -0.002     |
| Furnace 11              | 0             | 0.036    | 0         | 0.023     | 0          | 0.013      |
| Furnace 12              | 0             | 0.034    | 0         | 0.022     | 0          | 0.012      |
| Facility Total          | 10            | 0.57     | 8         | 0.55      | 2          | 0.02       |

### Northshore Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 926 TPY NOx)[10] (EPA Table B Emission Difference = 535 TPY NOx)[11]

| Class I Area           | EPA Estimated   | EPA Estimated | CAMx Modeled    | CAMx Modeled |
|------------------------|-----------------|---------------|-----------------|--------------|
|                        | Difference Days | Difference    | Difference Days | Difference   |
|                        | >0.5 dV         | 98% dV        | >0.5 dV         | 98% dV       |
| <b>Boundary Waters</b> | 8               | 0.6           | 1               | 0.01         |
|                        |                 |               |                 |              |
| Voyageurs              | 4               | 0.3           | 0               | 0.01         |
|                        |                 |               |                 |              |
| Isle Royale            | 5               | 0.4           | 2               | 0.01         |

[10]Emission Difference Obtained from EPA Proposed FIP Table V-C.12 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Northshore Mining.

[11]Emission Difference Obtained from EPA Proposed FIP Table V-B.8; further the emission reductions in Table C exceed the FIP baseline in Table B by 142 TPY.

### United Taconite (UTAC) CAMx Emissions and Modeling Results

### **UTAC Emissions**

| Unit   | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|--------|----------|-----------|------------|----------|-----------|------------|
|        | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|        | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|        | Emission | (TPY)     | (TPY)[12]  | Emission | (TPY)[13] | (TPY)      |
|        | (TPY)    |           |            | (TPY)    |           |            |
| Line 1 | 1,643    | 493       | 1,150      | 1,293    | 577       | 716        |
| Line 2 | 3,687    | 1,106     | 2,581      | 2,750    | 1,392     | 1,358      |
|        |          |           |            |          |           |            |
| TOTAL  | 5,330    | 1,599     | 3,731      | 4,043    | 1,969     | 2,074      |

[12]NOx emission difference was calculated using 70% emission reduction from EPA Baseline within the proposed FIP (corresponding to 1.2 lb NOx/MMBTU); to ensure maximum emission reductions were evaluated there was no change to the final FIP emissions to reflect the final FIP limit of 1.5 lb NOx/MMBTU.

[13]Final FIP SO2 Emissions were calculated using the final FIP limit of 529 lb/hr with an operating factor of 85%; this was done to maximize the emission reductions while using a reasonable operating factor

| OTAC CANA RESU         |               |          | 1         |           |            |            |
|------------------------|---------------|----------|-----------|-----------|------------|------------|
| Class I Area           | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|                        | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b> |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line #1                | 22            | 1.294    | 10        | 0.674     | 12         | 0.620      |
| Line #2                | 45            | 2.744    | 30        | 1.556     | 15         | 1.189      |
| Facility Total         | 76            | 4.22     | 55        | 2.37      | 21         | 1.85       |
|                        |               |          |           |           |            |            |
| 2005                   |               |          |           |           |            |            |
| Line #1                | 11            | 0.610    | 2         | 0.303     | 9          | 0.307      |
| Line #2                | 26            | 1.294    | 15        | 0.678     | 11         | 0.616      |
| Facility Total         | 52            | 2.52     | 34        | 1.57      | 18         | 0.95       |
| <u>Voyageurs</u>       |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line #1                | 12            | 0.606    | 2         | 0.307     | 10         | 0.299      |
| Line #2                | 26            | 1.452    | 15        | 0.771     | 11         | 0.681      |
| Facility Total         | 42            | 2.10     | 26        | 1.11      | 16         | 0.99       |
|                        |               |          |           |           |            |            |
| 2005                   |               |          |           |           |            |            |
| Line #1                | 4             | 0.331    | 1         | 0.181     | 3          | 0.150      |
| Line #2                | 17            | 0.786    | 6         | 0.446     | 11         | 0.340      |
| Facility Total         | 33            | 1.47     | 14        | 0.76      | 19         | 0.71       |

### UTAC CAMx Results (By Unit)

| Class I Area       | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|--------------------|---------------|----------|-----------|-----------|------------|------------|
|                    | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                    | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Isle Royale</u> |               |          |           |           |            |            |
| 2002               |               |          |           |           |            |            |
| Line #1            | 0             | 0.255    | 0         | 0.117     | 0          | 0.138      |
| Line #2            | 8             | 0.518    | 0         | 0.266     | 8          | 0.252      |
| Facility Total     | 13            | 0.81     | 3         | 0.41      | 10         | 0.40       |
|                    |               |          |           |           |            |            |
| 2005               |               |          |           |           |            |            |
| Line #1            | 0             | 0.163    | 0         | 0.080     | 0          | 0.083      |
| Line #2            | 1             | 0.322    | 0         | 0.184     | 1          | 0.138      |
| Facility Total     | 10            | 0.57     | 0         | 0.28      | 10         | 0.29       |

### UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 3,208 TPY NOx and 3,639 TPY SO2)[14] (EPA Table B Emission Difference = 3,731 TPY NOx and 3,639 TPY SO2)[15]

|                 | $\frac{1}{2} = \frac{1}{2}$ |               | 0,00 |                 |              |
|-----------------|-----------------------------|---------------|------|-----------------|--------------|
| Class I Area    | EPA Estimated               | EPA Estimated |      | CAMx Modeled    | CAMx Modeled |
|                 | Difference Days             | Difference    |      | Difference Days | Difference   |
|                 | >0.5 dV                     | 98% dV        |      | >0.5 dV[16]     | 98% dV[16]   |
| Boundary Waters | 29                          | 1.9           |      | 20              | 1.40         |
|                 |                             |               |      |                 |              |
| Voyageurs       | 12                          | 0.99          |      | 18              | 0.85         |
|                 |                             |               |      |                 |              |
| Isle Royale     | 14                          | 1.16          |      | 10              | 0.35         |

[14]Emission Difference Obtained from EPA Proposed FIP Table V-C.13 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for United Taconite.

[15]Emission Difference Obtained from EPA Proposed FIP Table V-B.14 (SO2) and V-B.17 (NOx) – NOx reductions are not consistent

[16]Baseline – final FIP Emission Reductions -> 3,731 TPY NOx and 2,074 TPY SO2

The United Taconite comparison table above does not provide an "apples to apples" comparison. As noted, the EPA estimated visibility benefits include more SO2 emission reductions (proposed FIP) than are included in the final FIP. This table was amended to include the revised SO2 emission reductions using EPA's apparent methodology within the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NOx and the revised emission reduction for SO2. Then, those resultants were averaged for each of the Class I areas to obtain the amended EPA estimates below to provide for the appropriate comparison of EPA's method.

| Amended UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with |
|---|
| CAMx Modeling Analyses  |

| Class I Area    | EPA Estimated   | EPA Estimated |  | CAMx Modeled    | CAMx Modeled |  |  |
|-----------------|-----------------|---------------|--|-----------------|--------------|--|--|
|                 | Difference Days | Difference    |  | Difference Days | Difference   |  |  |
|                 | >0.5 dV         | 98% dV        |  | >0.5 dV         | 98% dV       |  |  |
| Boundary Waters | 22              | 1.6           |  | 20              | 1.40         |  |  |
|                 |                 |               |  |                 |              |  |  |
| Voyageurs       | 10              | 0.8           |  | 18              | 0.85         |  |  |
|                 |                 |               |  |                 |              |  |  |
| Isle Royale     | 14              | 1.1           |  | 10              | 0.35         |  |  |

Final FIP Emission Difference = 3,731 TPY NOx and 2,074 TPY SO2

As discussed above, the SO4 and NO3 visibility benefits were combined by EPA. The following tables provide a modeled comparison of the impacts sorted by SO4 and NO3 on a line-specific basis, then combined for both lines. The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall UTAC impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO<sub>x</sub> control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.15 dV; total = 0.20 dV) and would not show up as part of the overall visibility change (see Line 2 – 2002 Boundary Waters results).

| Class I Area                   | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|--------------------------------|---------------|----------|-----------|-----------|------------|------------|
|                                | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                                | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b>         |               |          |           |           |            |            |
| 2002                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.106    | 0         | 0.059     | 0          | 0.047      |
| Line #1 – SO4                  | 22            | 1.294    | 10        | 0.674     | 12         | 0.620      |
| Line #1 – All                  | 22            | 1.294    | 10        | 0.674     | 12         | 0.620      |
|                                |               |          |           |           |            |            |
| 2005                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.136    | 0         | 0.083     | 0          | 0.053      |
| Line #1 – SO4                  | 8             | 0.571    | 2         | 0.280     | 6          | 0.291      |
| Line #1 – All                  | 11            | 0.610    | 2         | 0.303     | 9          | 0.307      |
| Voyageurs                      |               |          |           |           |            |            |
| 2002                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.040    | 0         | 0.017     | 0          | 0.023      |
| Line #1 – SO4                  | 11            | 0.582    | 2         | 0.301     | 9          | 0.281      |
| Line #1 – All                  | 12            | 0.606    | 2         | 0.307     | 10         | 0.299      |
|                                |               |          |           |           |            |            |
| 2005                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.048    | 0         | 0.027     | 0          | 0.021      |
| Line #1 – SO4                  | 4             | 0.330    | 1         | 0.155     | 3          | 0.175      |
| Line #1 – All                  | 4             | 0.331    | 1         | 0.181     | 3          | 0.150      |
| Isle Royale                    |               |          |           |           |            |            |
| 2002                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.033    | 0         | 0.015     | 0          | 0.018      |
| Line #1 – SO4                  | 0             | 0.216    | 0         | 0.104     | 0          | 0.112      |
| Line #1 – All                  | 0             | 0.255    | 0         | 0.117     | 0          | 0.138      |
| 2005                           |               |          |           |           |            |            |
| <b>2005</b><br>Line #1 – NO3   | 0             | 0.026    | 0         | 0.011     | 0          | 0.015      |
| Line #1 – NO3                  | 0             | 0.026    | 0         | 0.011     | 0          | 0.015      |
| Line #1 – SO4<br>Line #1 – All | 0             |          |           |           |            |            |
| Line #1 – All                  | U             | 0.163    | 0         | 0.080     | 0          | 0.083      |

UTAC Line 1 – Pollutant Specific Modeling Results

| Class I Area           | EPA FIP              | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|------------------------|----------------------|----------|-----------|-----------|------------|------------|
|                        | <b>Baseline Days</b> | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV              | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b> |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 1                    | 0.237    | 0         | 0.090     | 1          | 0.147      |
| Line #2 – SO4          | 44                   | 2.679    | 28        | 1.547     | 16         | 1.132      |
| Line #2 – All          | 45                   | 2.744    | 30        | 1.556     | 15         | 1.189      |
|                        |                      |          |           |           |            |            |
| 2005                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 1                    | 0.195    | 0         | 0.091     | 1          | 0.104      |
| Line #2 – SO4          | 25                   | 1.196    | 15        | 0.659     | 10         | 0.539      |
| Line #2 – All          | 26                   | 1.294    | 15        | 0.678     | 11         | 0.616      |
| Voyageurs              |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.104    | 0         | 0.031     | 0          | 0.073      |
| Line #2 – SO4          | 25                   | 1.446    | 15        | 0.768     | 10         | 0.678      |
| Line #2 – All          | 26                   | 1.452    | 15        | 0.771     | 11         | 0.681      |
| 2005                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.083    | 0         | 0.033     | 0          | 0.050      |
| Line #2 – NOS          | 16                   | 0.083    | 6         | 0.436     | 10         | 0.337      |
| Line #2 – 304          | 10                   | 0.786    | 6         | 0.430     | 10         | 0.337      |
|                        |                      |          |           |           |            |            |
| <u>Isle Royale</u>     |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.054    | 0         | 0.018     | 0          | 0.036      |
| Line #2 – SO4          | 7                    | 0.469    | 0         | 0.245     | 7          | 0.224      |
| Line #2 – All          | 8                    | 0.518    | 0         | 0.266     | 8          | 0.252      |
| 2005                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.046    | 0         | 0.016     | 0          | 0.030      |
| Line #2 – SO4          | 1                    | 0.319    | 0         | 0.166     | 1          | 0.153      |
| Line #2 – All          | 1                    | 0.322    | 0         | 0.184     | 1          | 0.138      |

UTAC Line 2 – Pollutant Specific Modeling Results

# UTAC Comparison of Sulfate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

|                 | Difference = $2,07$ + | 111302        |                 |              |
|-----------------|-----------------------|---------------|-----------------|--------------|
| Class I Area    | EPA Estimated         | EPA Estimated | CAMx Modeled    | CAMx Modeled |
|                 | Difference Days       | Difference    | Difference Days | Difference   |
|                 | >0.5 dV               | 98% dV        | >0.5 dV         | 98% dV       |
| Boundary Waters | 14                    | 1.0           | 22              | 1.29         |
|                 |                       |               |                 |              |
| Voyageurs       | 6                     | 0.5           | 16              | 0.74         |
|                 |                       |               |                 |              |
| Isle Royale     | 8                     | 0.6           | 4               | 0.28         |

Final FIP Emission Difference = 2,074 TPY SO2

# UTAC Comparison of Nitrate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 3,731 TPY NOx

| Class I Area    | EPA Estimated   | EPA Estimated | CAMx Modeled    | CAMx Modeled |
|-----------------|-----------------|---------------|-----------------|--------------|
|                 | Difference Days | Difference    | Difference Days | Difference   |
|                 | >0.5 dV         | 98% dV        | >0.5 dV         | 98% dV       |
| Boundary Waters | 31              | 2.3           | 1               | 0.18         |
|                 |                 |               |                 |              |
| Voyageurs       | 15              | 1.1           | 0               | 0.08         |
|                 |                 |               |                 |              |
| Isle Royale     | 20              | 1.6           | 0               | 0.05         |

The maximum 98<sup>th</sup> percentile NO3 impact when combining both line emission reductions is <u>0.18 dV</u>, while the maximum 98<sup>th</sup> percentile SO4 impact for both lines is <u>1.29 dV</u>. Based on these results, it is evident that the SO4 impact on the Class I areas provides the vast majority of the predicted CAMx estimates of visibility improvement. This finding is consistent with MPCA's original finding for BART in the 2009 SIP that NOx emission reductions do not provide substantive visibility improvement.

# Tilden Mining CAMx Emissions and Modeling Results

### **Tilden Emissions**

| Unit   | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|--------|----------|-----------|------------|----------|-----------|------------|
|        | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|        | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|        | Emission | (TPY)     | (TPY)      | Emission | (TPY)     | (TPY)      |
|        | (TPY)    |           |            | (TPY)    |           |            |
| Line 1 | 4,613    | 1,384     | 3,229      | 1,153    | 231       | 922        |
|        |          |           |            |          |           |            |
| TOTAL  | 4,613    | 1,384     | 3,229      | 1,153    | 231       | 922        |

### Tilden CAMx Results (By Unit)

| Class I Area           | EPA FIP       | EPA FIP  | Final FIP  | Final FIP | Difference | Difference |
|------------------------|---------------|----------|------------|-----------|------------|------------|
|                        | Baseline Days | Baseline | Days > 0.5 | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV       | 98% dV   | dV         |           | dV         |            |
| <b>Boundary Waters</b> |               |          |            |           |            |            |
| 2002                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.141    | 0          | 0.037     | 0          | 0.104      |
|                        |               |          |            |           |            |            |
| 2005                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.097    | 0          | 0.042     | 0          | 0.055      |
|                        |               |          |            |           |            |            |
| <u>Voyageurs</u>       |               |          |            |           |            |            |
| 2002                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.042    | 0          | 0.011     | 0          | 0.031      |
|                        |               |          |            |           |            |            |
| 2005                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.041    | 0          | 0.010     | 0          | 0.031      |
|                        |               |          |            |           |            |            |
| Isle Royale            |               |          |            |           |            |            |
| 2002                   |               |          |            |           |            |            |
| Line #1                | 1             | 0.300    | 0          | 0.094     | 1          | 0.206      |
|                        |               |          |            |           |            |            |
| 2005                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.211    | 0          | 0.070     | 0          | 0.141      |

| Class I Area           | EPA FIP              | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|------------------------|----------------------|----------|-----------|-----------|------------|------------|
|                        | <b>Baseline Days</b> | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV              | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b> |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.031    | 0         | 0.013     | 0          | 0.018      |
| Line #1 – SO4          | 0                    | 0.102    | 0         | 0.022     | 0          | 0.080      |
| Line #1 – All          | 0                    | 0.141    | 0         | 0.037     | 0          | 0.104      |
| 2005                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.045    | 0         | 0.042     | 0          | 0.003      |
| Line #1 – SO4          | 0                    | 0.087    | 0         | 0.019     | 0          | 0.068      |
| Line #1 – All          | 0                    | 0.097    | 0         | 0.042     | 0          | 0.055      |
| Vouggourg              |                      |          |           |           |            |            |
| Voyageurs<br>2002      |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.002    | 0         | 0.001     | 0          | 0.001      |
| Line #1 – SO4          | 0                    | 0.041    | 0         | 0.011     | 0          | 0.030      |
| Line #1 – All          | 0                    | 0.042    | 0         | 0.011     | 0          | 0.031      |
| 2005                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.005    | 0         | 0.003     | 0          | 0.002      |
| Line #1 – SO4          | 0                    | 0.039    | 0         | 0.008     | 0          | 0.031      |
| Line #1 – All          | 0                    | 0.041    | 0         | 0.010     | 0          | 0.031      |
| Isle Royale            |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.084    | 0         | 0.038     | 0          | 0.046      |
| Line #1 – SO4          | 1                    | 0.197    | 0         | 0.052     | 1          | 0.145      |
| Line #1 – All          | 1                    | 0.300    | 0         | 0.094     | 1          | 0.206      |
| 2005                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.043    | 0         | 0.047     | 0          | -0.004     |
| Line #1 – SO4          | 0                    | 0.176    | 0         | 0.040     | 0          | 0.136      |
| Line #1 – All          | 0                    | 0.211    | 0         | 0.070     | 0          | 0.141      |

Tilden Line 1 – Pollutant Specific Modeling Results

Attachment 3

2012 AECOM Report



# Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

Robert Paine and David Heinold, AECOM

September 28, 2012

### Executive Summary

This report reviews several aspects of the visibility assessment that is part of any Best Available Retrofit Technology (BART) assessment. The crux of this analysis focuses upon two opportunistic emission reductions that have resulted in no perceptible visibility benefits, while a straightforward application of EPA's modeling procedures would predict a substantial visibility benefit. These actual emission reduction cases include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in Minnesota in 2009.

There are several reasons why there is an inconsistency between the real world and the modeling results:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clean, which exaggerates the impact of emission sources. Overly clean natural conditions can erroneously indicate that some states are missing the 2018 milestone for achieving progress toward an impossible goal by the year 2064.
- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations that are detailed in this report. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.
- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.
- The modeled base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

September 2012

www.aecom.com



Impacts of the taconite plants' NO<sub>x</sub> emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5  $\frac{1}{2}$  months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO<sub>x</sub> controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to increases in haze due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, as well as the impacts of Michigan sources on Minnesota's Class I areas indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.



### Introduction

Best Available Retrofit Technology (BART) is part of the Clean Air Act (Appendix Y of 40 CFR Part 51) as a requirement related to visibility and the 1999 Regional Haze Rule (RHR)<sup>1</sup> that applies to existing stationary sources. Sources eligible for BART were those from 26 source categories with a potential to emit over 250 tons per year of any air pollutant, and that were placed into operation between August 1962 and August 1977. Final BART implementation guidance for regional haze was published in the Federal Register on July 6, 2005<sup>2</sup>.

The United States Environmental Protection Agency (EPA) has issued a proposed rule<sup>3</sup> to address BART requirements for taconite plants in Minnesota and Michigan that involves emission controls for SO<sub>2</sub> and NO<sub>x</sub>. This document addresses the likely visibility impact of taconite plant emissions, specifically NO<sub>x</sub> emissions, for impacts at Prevention of Significant Deterioration (PSD) Class I areas that the RHR addresses.

### Locations of Emission Sources and PSD Class I Areas

Figure 1 shows the location of BART-eligible taconite plants in Minnesota and Michigan addressed in EPA's proposed rule, as well as Class I areas within 500 km of these sources. In most applications of EPA's preferred dispersion model for visibility impacts, CALPUFF<sup>4</sup>, the distance limitation is 200-300 km because of the overprediction tendencies<sup>5</sup> for further distances. The overprediction occurs because of extended travel times that often involve at least a full day, during which there can be significant wind shear influences on plume spreading that the model and the meteorological wind field does not accommodate. With larger travel distances, there are higher uncertainties in the predictions of any model, either CALPUFF or a regional photochemical model. Therefore, a reasonable upper limit for establishing the impact of the taconite sources would be 500 km, with questionable results beyond 200-300 km from the source. In this case, the Class I areas involved are those shown in Figure 1. All other PSD Class I areas are much further away. It is noteworthy that EPA's visibility improvement assessment considered only three Class I areas: Voyageurs National Park, Boundary Waters Canoe Area Wilderness, and Isle Royale National Park.

September 2012

<sup>&</sup>lt;sup>1</sup> Regional Haze Regulations; Final Rule. *Federal Register*, *64*, 35713-35774. (July 1, 1999).

<sup>&</sup>lt;sup>2</sup> Federal Register. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, Vol. 70. (July 6, 2005)

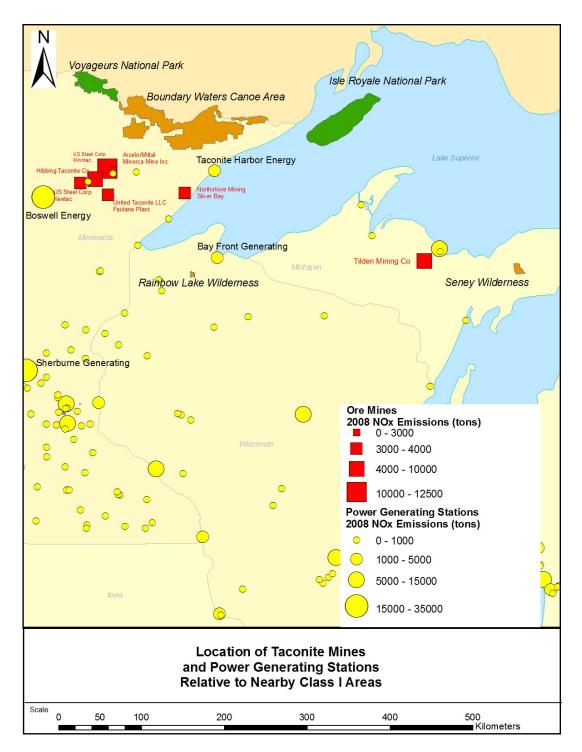
<sup>&</sup>lt;sup>3</sup> 77FR49308, August 15, 2012.

<sup>&</sup>lt;sup>4</sup> CALPUFF Dispersion Model, 2000. <u>http://www.epa.gov/scram001</u> (under 7th Modeling Conference link to Earth Tech web site).

<sup>&</sup>lt;sup>5</sup> As documented in Appendix D of the IWAQM Phase 2 document, available at www.epa.gov/scram001/7thconf/calpuff/phase2.pdf.



Figure 1 Location of Emission Sources Relative To PSD Class I Areas in Minnesota and Michigan





### Overprediction Tendency of Visibility Assessment Modeling for BART Emission Reductions

A particularly challenging part of the BART process is the lack of well-defined criteria for determining whether a proposed emission reduction is sufficient, because the criteria for determining BART are somewhat subjective in several aspects, such as what controls are cost-effective and the degree to which the related modeled reductions in haze are sufficient. In addition, the calculations of the visibility improvements, which are intrinsic to establishing the required BART controls, are subject to considerable uncertainty due both to the inherent uncertainty in model predictions and model input parameters. Alternative approaches for applying for technical options and chemistry algorithms in the United States Environmental Protection Agency's (EPA's) preferred CALPUFF model can result in a large range in the modeled visibility improvement. The degree of uncertainty is especially large when NO<sub>x</sub> emission controls are considered as a BART option because modeling secondary formation of ammonium nitrate is quite challenging. Accurately modeling the effects of NO<sub>x</sub> controls on visibility is very important because they are often very expensive to install and operate. As a collateral effect that needs to be taken into account for BART decisions, such controls can also complicate energy efficiency objectives and strategies to control greenhouse gases and other pollutants. In this paper we discuss why EPA's preferred application of CALPUFF would likely overestimate the predicted visibility impact of emissions, especially NO<sub>x</sub>, and the associated effectiveness of NO<sub>x</sub> emission controls. Overestimates of the benefits of emissions reduction are evident from the following observations, which are discussed in this document:

- Natural background extinction used in CALPOST to calculate a source's haze impacts is underestimated, which has the effect of exaggerating the impact, which is computed relative to these defined conditions. Natural conditions also dictate how well each state is adhering to the 2018 milestone for achieving progress toward this goal by the year 2064. If the specification of natural conditions is underestimated to the extent that it is not attainable regardless of contributions from U.S. anthropogenic sources, then some states will be penalized for not achieving sufficient progress toward an impossible goal. Appendix A discusses this point in more detail.
- The chemistry in the current EPA-approved version of CALPUFF overestimates winter nitrate haze, especially in conjunction with the specification of high ammonia background concentrations. This conservatism is exacerbated by CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, CALPUFF modeling will credit BART emission reductions with more visibility improvements than will really occur.
- There are examples where actual significant emission reductions have occurred, where CALPUFF modeling as conducted for BART would predict significant visibility improvements, but no perceptive changes in haze occurred.

### Visibility Impact of NO<sub>x</sub> Emissions – Unique Aspects and Seasonality

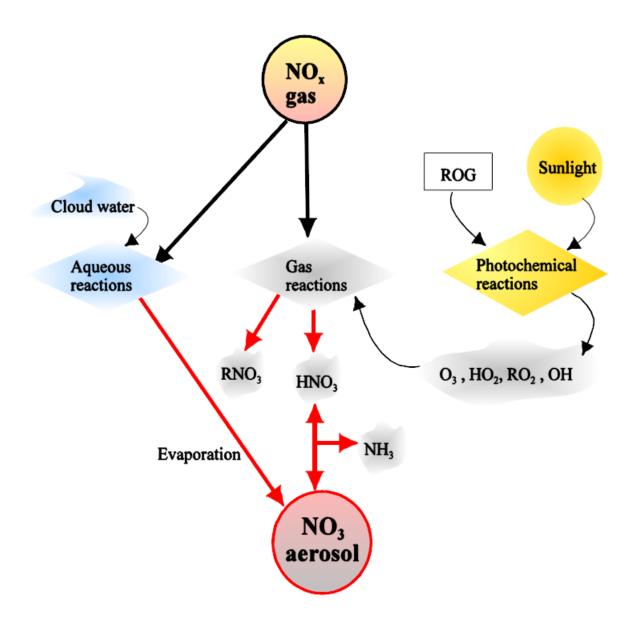
The oxidation of NO<sub>X</sub> to total nitrate (TNO<sub>3</sub>) depends on the NO<sub>X</sub> concentration, ambient ozone concentration, and atmospheric stability. Some of the TNO<sub>3</sub> is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state with HNO<sub>3</sub> gas that is a function

September 2012



of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 2<sup>6</sup>. It is important to realize that both CALPUFF and regional photochemical models tend to overpredict nitrate formation, especially in winter. A more detailed discussion of this issue is provided in Appendix B.

### Figure 2 CALPUFF II NO<sub>x</sub> Oxidation



<sup>6</sup> Figure 2-32 from CALPUFF Users Guide, available at <u>http://www.src.com/calpuff/download/CALPUFF\_UsersGuide.pdf</u>.

Page 6 of 45



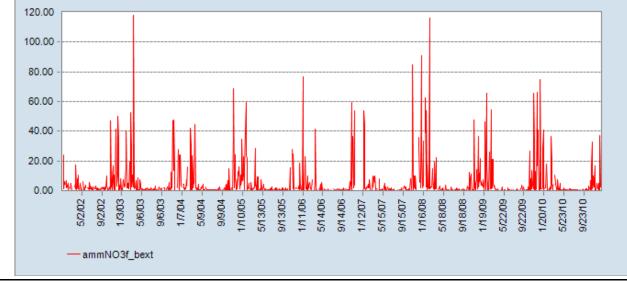
In CALPUFF, total nitrate  $(TNO_3 = HNO_3 + NO_3)$  is partitioned into each species according to the equilibrium relationship between gaseous  $HNO_3$  and  $NO_3$  aerosol. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate strongly depends on availability of  $NH_3$  to form ammonium nitrate. A summary of the conditions affecting nitrate formation is provided below:

- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium nitrate is formed;
- Sulfate preferentially scavenges ammonia over nitrates.

For this BART analysis, the effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various  $NO_X$  control options. For parts of the country where sulfate concentrations are relatively high and ammonia emissions are quite low, the atmosphere is likely to be in an ammonia-limited regime relative to nitrate formation. Therefore,  $NO_X$  emission controls are not very effective in improving regional haze, especially if there is very little ambient ammonia available.

In many cases, the BART visibility assessments ignore the haze increases that occur due to the additional power generation required to operate the control equipment. For  $NO_x$  controls, for example, the warm season emissions have minimal visibility impact, but the associated  $SO_2$  emissions from the power generation required to run the controls will increase sulfate haze. These effects have not been considered in the visibility assessment modeling.

It is evident from haze composition plots available from Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors that nitrate haze is confined to winter months. This is clearly shown in Figure 3, which is a timeline of nitrate haze extinction from Boundary Waters Canoe Area Wilderness. Similar patterns are evident for the other Class I areas plotted in Figure 1. The impact of NO<sub>X</sub> emissions during the non-winter months (e.g., April through October) is very low.



#### Figure 3 Boundary Water Canoe Area Wilderness Ammonium Nitrate Extinction, 2002-2010

September 2012

Page 7 of 45



The occurrence of significant nitrate haze only in the winter months has implications for the effectiveness of haze reductions relative to park attendance. The BART Rule addresses the seasonal issue as follows: "Other ways that visibility improvement may be assessed to inform the control decisions would be to examine distributions of the daily impacts, determine if the time of year is important (e.g., high impacts are occurring during tourist season) . . . "

In this case, the high nitrate impacts are not occurring during the tourist season, especially for the waterdominant Class I areas in Minnesota (Voyageurs and Boundary Waters) that freeze in winter. In fact, for Voyageurs National Park, the typical monthly attendance<sup>7</sup> for an off-season month (November) is only 0.2% that of a peak-season month (July). This is obviously due in part to the brutal winter weather in northern Minnesota (and Michigan) and the lack of boating access to frozen water bodies.

Operations at the Michigan Class I areas in winter are even more restricted. Isle Royale National Park is one of the few national parks to <u>totally close</u><sup>8</sup> during the winter (generally, during the period of November 1 through April 15). The closure is due to the extreme winter weather conditions and difficulty of access from the mainland across a frozen Lake Superior, for the protection of wildlife, and for the safety and protection of potential visitors. Due to this total closure, there is very little nitrate haze impact in this park during the seasons of the year that it is open, and haze issues for Isle Royale National Park will not be further considered in this report.

The Seney Wilderness Area Visitor Center is open<sup>9</sup> only during the period of May 15th to mid-October. Various trails are generally only open during the same period. The tour loops are closed in the fall, winter, and spring to allow migrating and nesting birds a place to rest or nest undisturbed, and because of large amounts of snow. Although portions of the park are open in the winter, the visitation is greatly reduced due to no visitor center access, no trail or tour loop access, and the severe weather.

### Effect of 2009 Recession on Haze in Affected PSD Class I Areas

The effect on haze of a significant (50%) emission reduction from the taconite plants that actually occurred in early 2009 and lasted throughout calendar year 2009 is discussed in this section. This emission reduction was not due to environmental regulations, but rather economic conditions, and affected all pollutants being emitted by the collective group of Minnesota taconite plants, as well as regional power production that is needed to operate the taconite plants.

The annual taconite production<sup>10</sup> from the Minnesota taconite plants in recent years is plotted in Figure 4, along with annual average nitrate concentrations at the nearest Class I area, Boundary Waters Canoe Area (BWCA). The figure shows that the nitrate measured in the park did not respond to the reduction in emissions from the taconite plants. Figures 5 and 6 show the time series<sup>11</sup> of nitrate and sulfate haze in

<sup>&</sup>lt;sup>7</sup> As documented at <u>http://www.gorp.com/parks-guide/voyageurs-national-park-outdoor-pp2-guide-cid9423.html</u>.

<sup>&</sup>lt;sup>8</sup> As noted at <u>http://www.nps.gov/isro/planyourvisit/hours.htm</u>.

<sup>&</sup>lt;sup>9</sup> As noted at <u>http://www.fws.gov/midwest/seney/visitor\_info.html</u>.

<sup>&</sup>lt;sup>10</sup> Production data is available from taxes levied on taconite production, and the data was supplied by BARR Engineering through a personal communication with Robert Paine of AECOM.

<sup>&</sup>lt;sup>11</sup> Available from the VIEWS web site at http://views.cira.colostate.edu/web/.



the BWCA over the past several years. Figures for other affected Class I areas (Voyageurs, Seney, and Isle Royale) are shown in Appendix C.

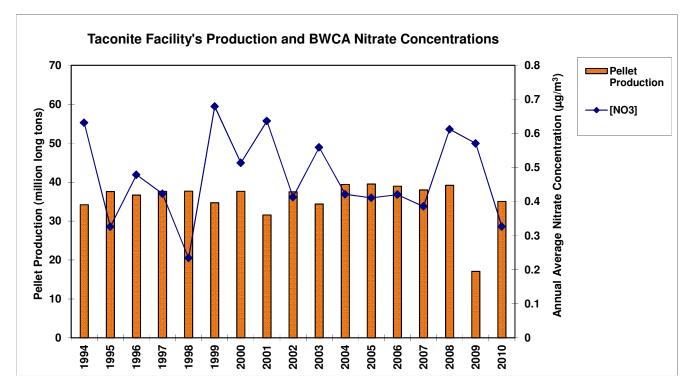
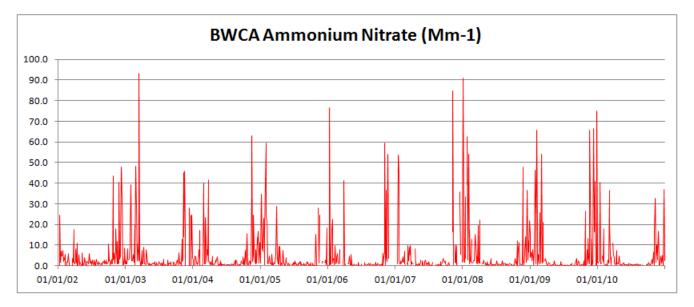




Figure 5 Time Series of Nitrate Haze at Boundary Waters Canoe Area (2002-2010)



September 2012



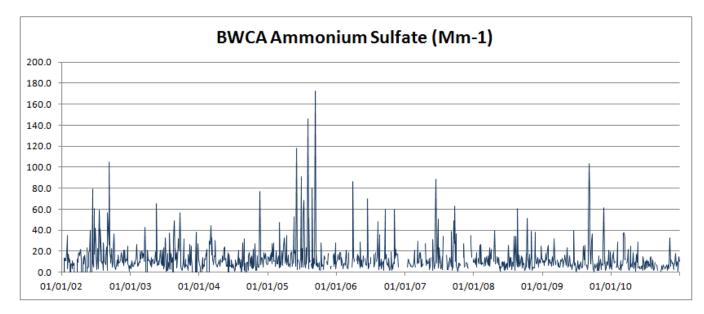


Figure 6 Time Series of Sulfate Haze at Boundary Waters Canoe Area (2002-2010)

It is evident from this information that the haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions.

It is instructive to review the haze composition time series plots for BWCA for 2008, 2009, and 2010, as shown in Figures 7, 8, and 9.

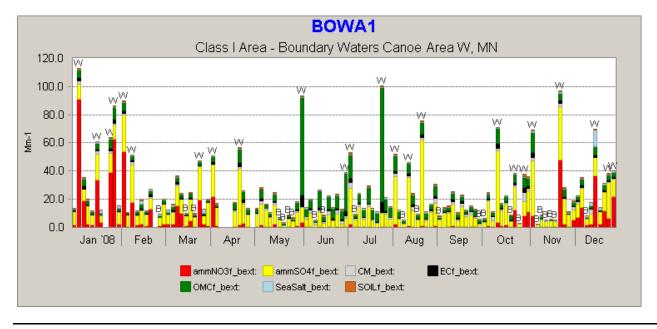


Figure 7 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2008

September 2012



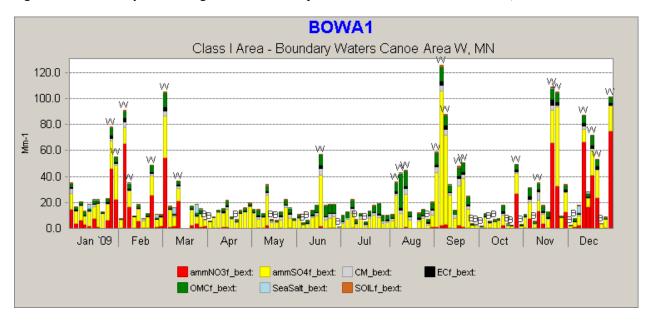
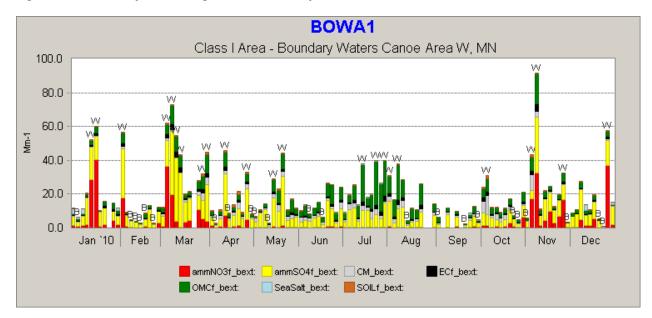




Figure 9 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2010



As has been mentioned above, it is evident that the nitrate haze (red bars) is only important during the colder months (November through March). It is also evident that haze from forest fires (green bars) is predominant in the warm weather months, but varies from year to year according to the frequency of wildfires. For example, 2008 was a year of high occurrences of wildfires, while 2009 saw a low frequency, and 2010 was more normal.

September 2012



The curtailment of taconite plant activity lasted from early 2009 through December 2009, peaking in the summer of 2009. Even so, we see the highest sulfate haze days (yellow bars) in September 2009 when taconite production was half of normal activity. Also, we note high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states.

These findings suggest that reduction of emissions from the taconite plants will likely have minimal effects on haze in the nearby Class I areas. The fact that the various plants are distributed over a large area means that individual plumes are isolated and generally do not combine with others.

At least one other emission reduction opportunity to determine the effect on visibility improvement has occurred; this is related to the shutdown of the Mohave Generating Station in 2005, and its effect upon visibility in the Grand Canyon National Park. The discussion in Appendix D indicates that although CALPUFF modeling predicted substantial visibility benefits, very little change has occurred since 2005.

Other reasons that visibility assessment models such as CALPUFF could overpredict impacts are listed below.

- 1) The CALPUFF base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.
- 2) The way that the predicted concentrations are accounted for in the CALPOST output overstate the impact for even the case where the CALPUFF predictions are completely accurate. The way that CALPOST works is that the peak 24-hour prediction <u>anywhere</u> in a Class I area is the only information saved for each predicted day. The predicted impact for each day is effectively assumed to be a) always in the same place; and b) in all portions of the Class I area. Therefore, the 98<sup>th</sup> percentile day's prediction could be comprised of impacts in 8 different places that are all erroneously assumed to be co-located.
- 3) CALPUFF does not simulate dispersion and transport accurately over a full diurnal cycle, during which significant wind direction shear can occur (and is not properly accounted for by CALPUFF). This can result in plumes that are more cohesive than actually occur.
- 4) As discussed above, it is well established that nitrate predictions are often overstated by CALPUFF v. 5.8, especially in winter.
- 5) Natural conditions as input to CALPOST are not attainable, and their use will exaggerate the simulated visibility impacts of modeled emissions.

### Interstate Non-Interference with Regional Haze Rule SIPs from Taconite Plant Emissions

An issue that is a recurring one for a number of state implementation plans (SIPs) is whether emissions from one state can interfere with haze reduction plans for downwind states. For Minnesota, it would be expected that emission reductions undertaken to reduce haze in Minnesota Class I areas (Voyageurs and Boundary Waters) would also act to reduce haze in other Class I areas. In the case of Minnesota's

September 2012



taconite plant emissions, earlier discussions of the potentially affected Class I areas indicated that only the Class I areas in northern Michigan (Isle Royale National Park and Seney Wilderness Area) are close enough and in a general predominant wind direction to merit consideration. The closer of these two parks, Isle Royale, is closed to the public from November 1 through April 15, and haze effects there would not be affected by NO<sub>X</sub> emissions because those effects are only important in the winter. Since Minnesota's Class I areas are located generally upwind of Michigan sources, the impact of Michigan sources on these Class I areas is expected to be small. This is confirmed in the Particulate Matter Source Apportionment Technology (PSAT) plots shown below.

Regional photochemical modeling studies<sup>12</sup> conducted by the CENRAP Regional Planning Organization, of which Minnesota is a part, shows contributions of various states as well as international contributions for haze impacts in the Michigan Class I areas. Relevant figures from the Iowa RHR SIP report for 2018 emission inventory haze impacts are reproduced below for Isle Royale National Park (Figure 10) and Seney Wilderness Area (Figure 11).

The modeling conducted for this analysis, using CAMx, shows that the relative contribution to haze for all Minnesota sources to sulfate haze in Isle Royale National Park is low, consisting of only 10% of the sulfate haze. The effect of 2018 emissions from Minnesota sources at the more distant Seney Wilderness Area is even lower, with the state's emissions ranking 9<sup>th</sup> among other jurisdictions analyzed for this Class I area. Therefore, it is apparent that Minnesota sources, and certainly the subset including taconite plants, would not be expected to interfere with other state's progress toward the 2018 milestone associated with the Regional Haze Rule.

Figures 12 and 13, reproduced from the Iowa RHR SIP report for Boundary Waters and Voyageurs, respectively, indicate that Michigan sources rank 11<sup>th</sup> and 12<sup>th</sup>, respectively, for haze impacts in these two areas for projected 2018 emissions. Therefore, as expected, Michigan sources are not expected to interfere with Minnesota's RHR SIP for progress in 2018.

<sup>&</sup>lt;sup>12</sup> See, for example, the Iowa State Implementation Plan for Regional Haze report at <u>http://www.iowadnr.gov/portals/idnr/uploads/air/insidednr/rulesandplanning/rh\_sip\_final.pdf</u>, Figures 11.3 and 11.4.

AECOM

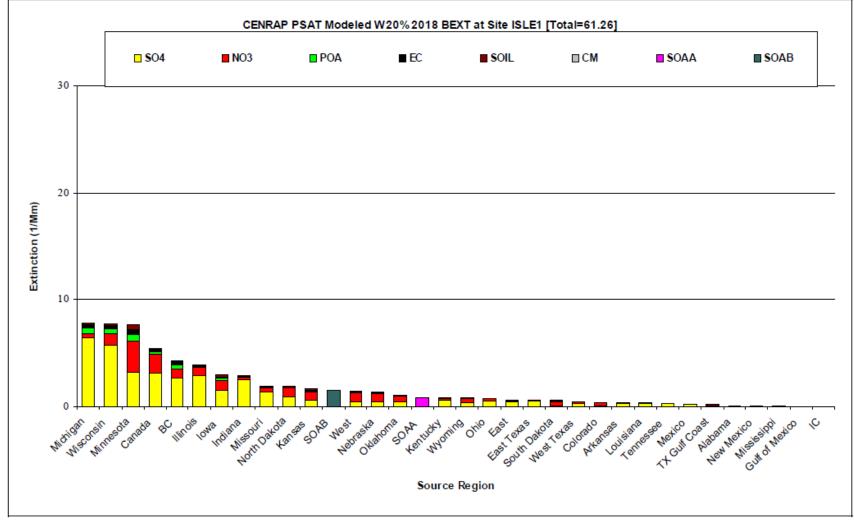


Figure 10 PSAT Results from CENRAP CAMx Modeling for Isle Royale National Park

Figure 11.3. Source apportion contributions by region and pollutant to ISLE in 2018.

September 2012

Page 14 of 45

www.aecom.com

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas



Figure 11 PSAT Results from CENRAP CAMx Modeling for Seney Wilderness Area

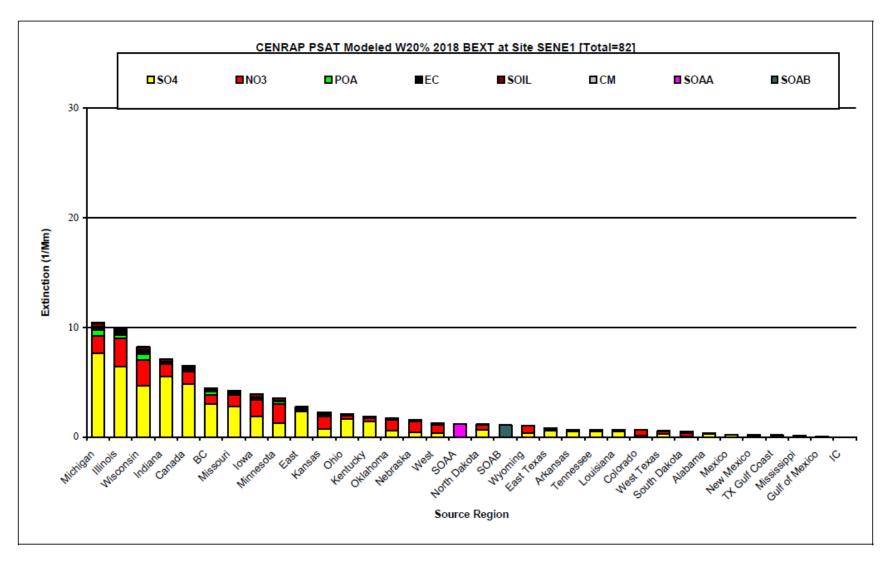


Figure 11.4. Source apportion contributions by region and pollutant to SENE in 2018.

September 2012

Page 15 of 45



Figure 12 PSAT Results from CENRAP CAMx Modeling for Boundary Waters Canoe Area Wilderness

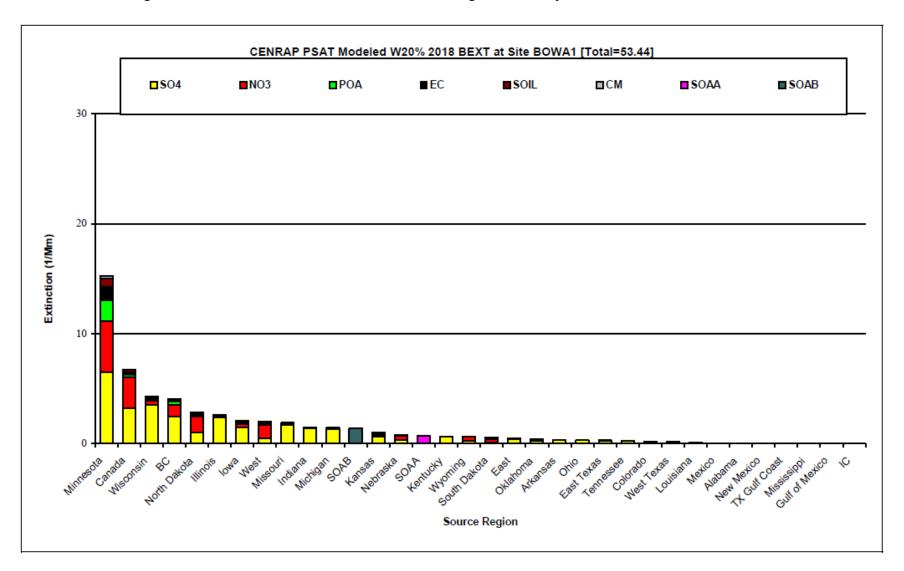


Figure 11.1. Source apportion contributions by region and pollutant to BOWA in 2018.

September 2012

Page 16 of 45



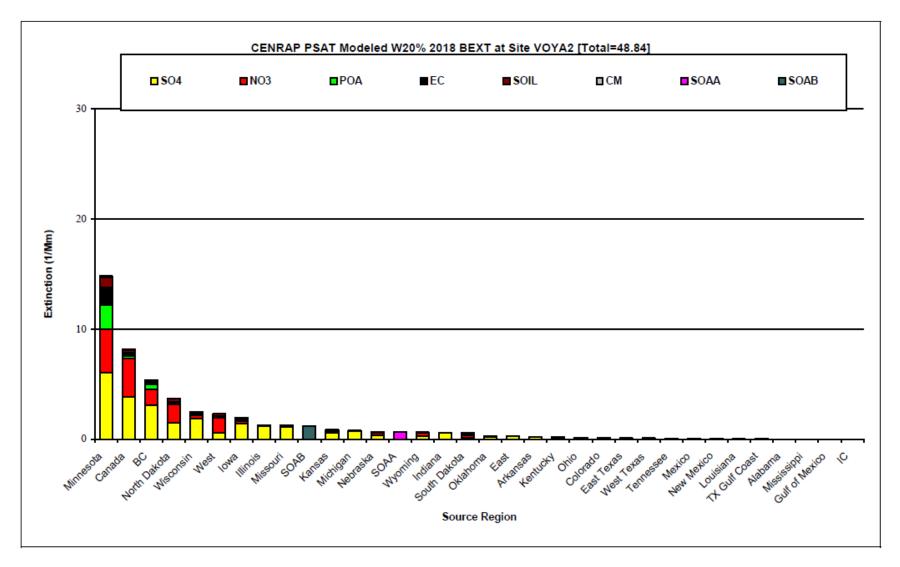


Figure 11.2. Source apportion contributions by region and pollutant to VOYA in 2018.

September 2012

Page 17 of 45

#### CONCLUSIONS

EPA's preferred modeling tools to assess the visibility improvement from BART controls will likely overestimate the predicted visibility improvement. While this is expected for all pollutants, it is especially true for  $NO_X$  emission controls. This occurs for several reasons:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clear, which exaggerates the impact of emission sources. Overly clean natural conditions can lead to the erroneous conclusion that some states are not adhering to the 2018 milestone because they need to achieve progress toward an impossible goal by the year 2064.
- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.
- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.
- The modeled base case scenario is always a worst-case emission rate, assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

Impacts of the taconite plants' NO<sub>x</sub> emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5  $\frac{1}{2}$  months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO<sub>x</sub> controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to visibility disbenefits due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

Evidence of models' tendency for overprediction are provided in examples of actual significant emission reductions that have resulted in virtually no perceptive changes in haze, while visibility assessment modeling as conducted for BART would predict significant visibility improvements. These examples include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in 2009.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, and vice versa indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

# **APPENDIX A**

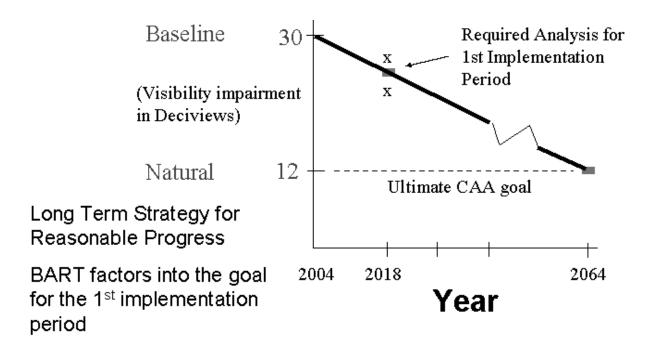
# THE REGIONAL HAZE RULE GOAL OF NATURAL CONDITIONS

An important consideration in the ability for a state to meet the 2018 Uniform Rate of Progress (URP) goal is the definition of the end point goal of "natural conditions" for the worst 20% haze days; see Figure A-1, which illustrates this concept). Note that while achieving improved visibility for the worst 20% haze days, the RHR also stipulates that there should not be deterioration of visibility for the best 20%, or clearest, days. One way to define that goal would be the elimination of all man-made emissions. This raises some other questions, such as:

- To what categories of emissions does the RHR pertain?
- Does the current definition of natural conditions include non-anthropogenic or uncontrollable emissions?

The default natural background assumed by EPA in their 2003 guidance document<sup>13</sup> is not realistic. The discussion in this section explains why EPA's default natural conditions significantly understate the true level of natural haze, including the fact that there are contributors of haze that are not controllable (and that are natural) that should be included in the definition of natural visibility conditions. In addition, one important aspect of the uncontrollable haze, wildfires, is further discussed regarding the biased quantification of its contribution to natural haze due to suppression of wildfires during the 20<sup>th</sup> century.

## Figure A-1: Illustration of the Uniform Rate of Progress Goal



Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

September 2012

<sup>&</sup>lt;sup>13</sup> Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule, (U.S. Environmental Protection Agency, September 2003). <u>http://www.epa.gov/ttncaaa1/t1/memoranda/rh\_envcurhr\_gd.pdf</u>.

In its RHR SIP, North Dakota<sup>14</sup> noted in Section 9.7 that,

"Achieving natural conditions will require the elimination of all anthropogenic sources of emissions. Given current technology, achieving natural conditions is an impossibility. Any estimate of the number of years necessary to achieve natural visibility conditions would require assumptions about future energy sources, technology improvements for sources of emissions, and every facet of human behavior that causes visibility impairing emissions. The elimination of all SO<sub>2</sub> and NO<sub>x</sub> emissions in North Dakota will not achieve the uniform rate of progress for this [2018], or any future planning period. Any estimate of the number of years to achieve natural conditions is questionable because of the influence of out-of-state sources."

It will be extremely difficult, if not impossible, to eliminate all anthropogenic emissions, even if natural conditions are accurately defined. It will be even more daunting to try to reach the goal if natural conditions are significantly understated, and as a result, states are asked to control sources that are simply not controllable. It is clear that the use of EPA default natural conditions leads to unworkable and absurd results for one state's (North Dakota's) ability to determine the rate of progress toward an unattainable goal. The definition of natural conditions that can be reasonably attained for a reasonable application of USEPA's Regional Haze Rule should be revised for all states.

The objective of the following discussion is to summarize recent modeling studies of natural visibility conditions and to suggest how such studies can be used in evaluating the uniform rate of progress in reducing haze to attain natural visibility levels. In addition, the distinction between natural visibility and policy relevant background visibility is discussed. Treatment of this issue by other states, such as Texas, is also discussed.

#### **Regional Haze Issues for Border States**

There are similarities between the Regional Haze Rule (RHR) challenges for border states such as North Dakota and Texas in that both states have significant international and natural contributions to regional haze in Class I areas in their states. The Texas Commission on Environmental Quality (TCEQ) has introduced alternative RHR glide paths to illustrate the State's rate of progress toward the RHR goals. Since TCEQ has gone through the process of a RHR State Implementation Plan (SIP) development and comment period, it is instructive to look at the TCEQ approach, the comments provided by the Federal Land Managers to TCEQ, and TCEQ's reaction to the comments.

Similarities to be considered for the RHR SIP development in border states, such as North Dakota and Texas, include the items listed below.

• These states have Class I areas for which a considerable fraction of the regional haze is due to international transport or transport from other regions of the United States.

21

<sup>&</sup>lt;sup>14</sup> North Dakota Dep. of Health, 2010. North Dakota State Implementation Plan for Regional Haze. <u>http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Main%20SIP%20Sections%201-12.pdf</u>.

- As a result, there is a substantial reduction in SO<sub>2</sub> and NO<sub>x</sub> emissions from the BART-eligible sources in each state, but this reduction results in a relatively small impact on regional haze mitigation. Additional emission reductions would, therefore, have a minimal benefit on visibility improvement at substantial cost.
- In the Regional Haze SIP development, these states have attempted to account for the effects of anthropogenic emissions that they can control in alternative analyses. These analysis result in a finding that the in-state emission reductions come closer to meeting the Uniform Rate of Progress glide path goals for 2018. However, due to the low probability of impact of these sources on the worst 20% days, the effectiveness of in-state emission controls on anthropogenic sources subject to controls is inherently limited.

TCEQ decided that coarse and fine PM measured at the Class I areas were due to natural causes (especially on the worst 20% days), and adjusted the natural conditions endpoint accordingly. The Federal Land Managers (FLMs) agreed with this approach for the most part<sup>15</sup>, but suggested that 80% of these concentrations would be due to natural causes, and 20% would be due to anthropogenic causes. TCEQ determined from a sensitivity analysis that the difference in these two approaches was too small to warrant a re-run of their analysis, but it is important that the FLMs agreed to a state-specific modification of the natural conditions endpoint, and this substantially changed the perceived rate of progress of the SIP plan toward the altered natural conditions endpoint.

Although the TCEQ did not address other particulate matter components in this same way, a review of air parcel back trajectories previously available from the IMPROVE web site (<u>http://views.cira.colostate.edu/web/</u>) suggests that other components, such as organic matter due to wildfires, could be substantially due to natural causes, so that this component should also be considered as at least partially natural.

The TCEQ discussed the issue of how emissions from Mexico could interfere with progress on the RHR, but they did not appear to adjust the glide path based upon Mexican emissions. On the other hand, in its weight of evidence analysis, North Dakota did evaluate adjustments based upon anthropogenic emissions that could not be controlled from Canadian sources, but did not take into account any specific particulate species that are generally not emitted by major anthropogenic sources of SO<sub>2</sub> and NO<sub>x</sub>.

## **Natural Haze Levels**

The Regional Haze Rule establishes the goal that natural visibility conditions should be attained in Federal Class I areas by the year 2064. Additionally, the states are required to determine the uniform rate of progress (URP) of visibility improvement necessary to attain the natural visibility goal by 2064. Finally, each state must develop a SIP identifying reasonable control measures that will be adopted well before 2018 to reduce source emissions of visibility-impairing particulate matter (PM) and its precursors (SO<sub>2</sub> and NO<sub>x</sub>).

Estimates of natural haze levels have been developed by the EPA for visibility planning purposes and are described in the above-referenced EPA 2003 document. The natural haze estimates were based on ambient data analysis of selected PM species for days with good visibility and are shown in Table A-1.

<sup>&</sup>lt;sup>15</sup> See Appendix 2-2 at <u>http://www.tceq.state.tx.us/implementation/air/sip/bart/haze\_appendices.html</u>.

These estimates were derived from Trijonis<sup>16</sup> and use two different sets of natural concentrations for the eastern and western U.S. Tombach<sup>17</sup> provides a detailed review and discussion of uncertainty in the USEPA natural PM estimates. Natural visibility can be calculated using the IMPROVE equation which calculates the light scattering caused by each

# Table A-1: Average Natural Levels of Aerosol Components from Table 2-1 of Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (EPA, 2003)

|                               | Average Natural Concentration |              |                   | Dry                                |
|-------------------------------|-------------------------------|--------------|-------------------|------------------------------------|
|                               | West (µg/m³)                  | East (µg/m³) | – Error<br>Factor | Extinction<br>Efficiency<br>(m²/g) |
| Ammonium sulfate <sup>b</sup> | 0.12                          | 0.23         | 2                 | 3                                  |
| Ammonium nitrate              | 0.10                          | 0.10         | 2                 | 3                                  |
| Organic carbon mass °         | 0.47                          | 1.40         | 2                 | 4                                  |
| Elemental carbon              | 0.02                          | 0.02         | 2-3               | 10                                 |
| Soil                          | 0.50                          | 0.50         | 1½ - 2            | 1                                  |
| Coarse Mass                   | 3.0                           | 3.0          | 1½ - 2            | 0.6                                |

a: After Trijonis, see footnote 12

b: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.1  $\mu$ g/m<sup>3</sup> and 0.2  $\mu$ g/m<sup>3</sup> of ammonium bisulfate.

c: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.5 µg/m<sup>3</sup> and 1.5 µg/m<sup>3</sup> of organic compounds.

component of PM. After much study, changes in the IMPROVE equation and in the method for calculating natural visibility were developed in 2005 and are described by Pitchford et al.<sup>18</sup>

The EPA guidance also makes provision for refined estimates of site-specific natural haze that differ from the default values using either data analysis or model simulations. However, most states have continued to use the default natural haze levels for calculating the progress toward natural visibility conditions.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>16</sup> Trijonis, J. C. Characterization of Natural Background Aerosol Concentrations. Appendix A in Acidic Deposition: State of Science and Technology. Report 24. Visibility: Existing and Historical Conditions -- Causes and Effects. J. C. Trijonis, lead author. National Acid Precipitation Assessment Program: Washington, DC, 1990.

<sup>&</sup>lt;sup>17</sup> Tombach, I., (2008) *Natural Haze Levels Sensitivity -- Assessment of Refinements to Estimates of Natural Conditions,* Report to the Western Governors Association, January 2008, available at <a href="http://www.wrapair.org/forums/aamrf/projects/NCB/index.html">http://www.wrapair.org/forums/aamrf/projects/NCB/index.html</a>.

<sup>&</sup>lt;sup>18</sup> Pitchford, M., Malm, W., Schichtel, B., Kumar, N., Lowenthal, D., Hand, J., Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data, J. Air & Waste Manage, Assoc. 57: 1326 – 1336, 2007.

Tombach and Brewer<sup>19</sup> reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach<sup>8</sup> also reviewed estimates of natural haze levels and proposed that, instead of using two sets of default natural PM concentrations for the eastern and western US, a large number of sensitivity zones should be developed that reflect regional variability in natural PM sources. Tombach<sup>8</sup> also suggested that modeling studies are a possible approach to further revise estimates of natural PM concentrations.

Previous modeling studies have shown that the estimates of natural visibility described above for "clean" days will differ from the results of model simulations when United States anthropogenic emissions are totally eliminated (Tonnesen et al., 2006<sup>20</sup>; Koo et al., 2010<sup>21</sup>), especially when natural wild fire emissions are included in the model simulation. Because the URP is calculated using model simulations of PM on the 20% of days with the worst visibility, wild fires and other extreme events can result in estimated levels of natural haze (even without any contribution of US anthropogenic sources) that can be significantly greater than the natural levels used in the EPA guidance for URP calculation. This could make it difficult or impossible for states to identify emissions control measures sufficient to demonstrate the URP toward attaining visibility goals because the endpoint is unachievable even if all US anthropogenic emissions are eliminated, as North Dakota has already determined even for the interim goal in 2018.

### Previous Suppression of Wildfire Activity and its Effect upon the EPA Default Natural Conditions

Throughout history, except for the past few decades, fires have been used to clear land, change plant and tree species, sterilize land, maintain certain types of habitat, among other purposes. Native Americans used fires as a technique to maintain certain pieces of land or to improve habitats. Although early settlers often used fires in the same way as the Native Americans, major wildfires on public domain land were largely ignored and were often viewed as an opportunity to open forestland for grazing.

Especially large fires raged in North America during the 1800s and early 1900s. The public was becoming slowly aware of fire's potential for life-threatening danger. Federal involvement in trying to control forest fires began in the late 1890s with the hiring of General Land Office rangers during the fire season. When the management of the forest reserves (now called national forests) was transferred to the newly formed Forest Service in 1905, the agency took on the responsibility of creating professional standards for firefighting, including having more rangers and hiring local people to help put out fires.

Since the beginning of the 20<sup>th</sup> century, fire suppression has resulted in a buildup of vegetative "fuels" and catastrophic wildfires. Recent estimates of background visual range, such as Trijonis<sup>16</sup>, have underestimated the role of managed fire on regional haze. Since about 1990, various government agencies have increased prescribed burning to reduce the threat of dangerous wildfires, and the

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>19</sup> Tombach, I., and Brewer, P. (2005). Natural Background Visibility and Regional Haze Goals in the Southeastern United States. *J. Air & Waste Manage. Assoc. 55*, 1600-1620.

<sup>&</sup>lt;sup>20</sup> Tonnesen, G., Omary, M., Wang, Z., Jung, C.J., Morris, R., Mansell, G., Jia, Y., Wang, B., and Z. Adelman (2006) Report for the Western Regional Air Partnership Regional Modeling Center, University of California Riverside, Riverside, California, November. (<u>http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC 2006 report FINAL.pdf</u>).

<sup>&</sup>lt;sup>21</sup> Koo B., C.J. Chien, G. Tonnesen, R. Morris , J. Johnson, T. Sakulyanontvittaya, P. Piyachaturawat, and G.Yarwood, 2010. Natural emissions for regional modeling of background ozone and particulate matter and impacts on emissions control strategies. <u>Atm. Env.</u>, 44, 2372-2382.

increased haze due to these fires is often more of an impairment to visibility than industrial sources, especially for  $NO_X$  reductions that are only effective in winter, the time of the lowest tourist visitation in most cases.

The National Park Service indicates at <u>http://www.nps.gov/thro/parkmgmt/firemanagement.htm</u> for the Theodore Roosevelt National Park that:

"For most of the 20<sup>th</sup> Century, wildfires were extinguished immediately with the assumption that doing so would protect lives, property, and natural areas. However, following the unusually intense fire season of 1988, agencies including the National Park Service began to rethink their policies." Even this policy is not always successful, as experienced by the USDA Forest Service<sup>22</sup> in their management of wildfires near the Boundary Waters Canoe Area that can contribute significantly to visibility degradation during the peak tourist season. In this case, even small fires, if left unchecked, have been known to evolve into uncontrollable fires and then require substantial resources to extinguish.

EPA's 2003 "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" acknowledges that wildfires are a contributor to natural visibility conditions, but the data used in estimates of natural conditions were taken during a period of artificial fire suppression so that the true impact of natural wildfires is understated. The report notes that "data should be available for EPA and States to develop improved estimates of the contribution of fire emissions to natural visibility conditions in mandatory Federal Class I areas over time." As noted by several studies noted above, the impact due to natural fire levels is underestimated in the EPA natural visibility conditions include the distortion of Reasonable Progress analyses and also to BART modeling results that overestimate the visibility improvement achievable from NO<sub>X</sub> emission reductions due to the use of inaccurate natural visibility conditions.

### **Recommendations for an Improved Estimate of Visibility Natural Conditions**

A reasonable approach would be to combine the effects of the uncontrollable particulate matter components and the emissions from international sources to determine a new glide path endpoint that is achievable by controlling (only) U.S. anthropogenic emissions. To compute this new endpoint, regional photochemical modeling using CMAQ or CAMx could be conducted for the base case (already done) and then for a future endpoint case that has no U.S. anthropogenic emissions, but with natural particulate matter emissions (e.g., dust, fires, organic matter) as well as fine particulate, SO<sub>2</sub> and NO<sub>x</sub> emissions associated with all non-U.S. sources set to the current baseline levels. The simulation should include an higher level of wildfire activity than in the recent past to reflect a truer level of fire activity before manmade suppression in the 20<sup>th</sup> century. Then, states could use a relative reduction factor (RRF) approach to determine the ratio of the haze impacts between the base case and the reasonable future case, and then apply the RRF values to the baseline haze to obtain a much more reasonable "natural conditions" haze endpoint. The more accurate natural background would also result in a reduction in the degree to which CALPUFF modeling overstates visibility improvement from emission reductions.

<sup>&</sup>lt;sup>22</sup> See explanation at <u>http://www.msnbc.msn.com/id/48569985/ns/us\_news-environment/t/forest-service-gets-more-aggressive-small-fires/</u>.

# **APPENDIX B**

# MODEL OVERPREDICTION ISSUES FOR WINTERTIME NITRATE HAZE

This appendix includes a discussion of CALPUFF predictions for nitrate haze, followed by more general issues with CALPUFF predictions.

## **CALPUFF Predictions of Nitrate Haze**

Secondary pollutants such as nitrates and sulfates contribute to light extinction in Class I areas. The CALPUFF model was approved by EPA for use in BART determinations to evaluate the effect of these pollutants on visibility in Class I areas. CALPUFF version 5.8 (the current guideline version) uses the EPA-approved MESOPUFF II chemical reaction mechanism to convert SO<sub>2</sub> and NO<sub>x</sub> emissions to secondary sulfate and nitrate. This section describes how secondary pollutants, specifically nitrate, are formed and the factors affecting their formation, especially as formulated in CALPUFF.

In the CALPUFF model, the oxidation of NO<sub>x</sub> to nitric acid (HNO<sub>3</sub>) depends on the NO<sub>x</sub> concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration. In CALPUFF, total nitrate (TNO<sub>3</sub> = HNO<sub>3</sub> + NO<sub>3</sub>) is partitioned into gaseous HNO<sub>3</sub> and NO<sub>3</sub> particles according to the equilibrium relationship between the two species. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate particles *strongly* depends on availability of NH<sub>3</sub> to form ammonium nitrate, as shown in Figure 6<sup>23</sup>. The figure on the left shows that with 1 ppb of available ammonia and fixed temperature and humidity (for example, 275 K and 80% humidity), only 50% of the total nitrate is in the form of particulate matter. When the available ammonia is increased to 2 ppb, as shown in the figure on the right, as much as 80% of the total nitrate is in the particulate form. Figure B-1 also shows that colder temperatures and higher relative humidity favor particulate nitrate formation. A summary of the conditions affecting nitrate formation are listed below:

- Colder temperature and higher relative humidity create more favorable conditions to form nitrate particulate matter in the form of ammonium nitrate;
- Warmer temperatures and lower relative humidity create less favorable conditions for nitrate particulate matter resulting in a small fraction of total nitrate in the form of ammonium nitrate;
- Ammonium sulfate formation preferentially scavenges available atmospheric ammonia over ammonium nitrate formation. In air parcels where sulfate concentrations are high and ambient ammonia concentrations are low, there is less ammonia available to react with nitrate, and less ammonium nitrate is formed.

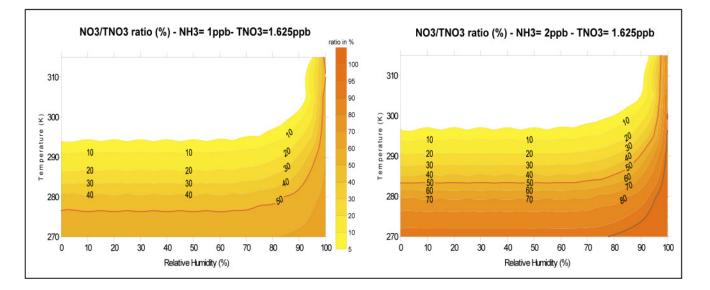
The effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various  $NO_x$  control options. For the reasons discussed above, the seasons with lower temperatures are the most likely to be most important for ammonium nitrate formation when regional haze is more effectively reduced by controlling  $NO_x$ .

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

September 2012

27

<sup>&</sup>lt;sup>23</sup> Scire, Joseph. CALPUFF MODELING SYSTEM. CALPUFF course presented at Chulalongkorn University, Bangkok, Thailand. May 16-20, 2005; slide 40 available at <u>http://aqnis.pcd.go.th/tapce/plan/4CALPUFF%20slides.pdf</u>, accessed March 2011.



## Figure B-1: NO<sub>3</sub>/HNO<sub>3</sub> Equilibrium Dependency on Temperature and Humidity

## Sensitivity of CALPUFF Haze Calculations to Background Ammonia Concentration

In an independent analysis, the Colorado Department of Public Health and Environment (CDPHE) performed a sensitivity modeling analysis to explore the effect of the specified ammonia concentration applied in CALPUFF on the predicted visibility impacts for a source with high NO<sub>x</sub> emissions relative to SO<sub>2</sub> emissions<sup>24</sup>. The results of the sensitivity modeling are shown in Figure B-2. It is noteworthy that the largest sensitivity occurs for specified ammonia input between 1 and 0.1 ppb. In that factor-of-ten range, the difference in the peak visibility impact predicted by CALPUFF is slightly more than a factor of three. This sensitivity analysis shows that the specification of background ammonia is very important in terms of the magnitude of visibility impacts predicted by CALPUFF. The fact that regional, diurnal and seasonal variations of ambient ammonia concentrations are not well-characterized and mechanisms not well-understood effectively limits the effectiveness of CALPUFF in modeling regional haze, especially in terms of the contribution of ammonium nitrate.

It is also noteworthy that CALPUFF version 5.8's demonstrated over-predictions of wintertime nitrate can be mitigated to some extent by using lower winter ammonia background values, although there is not extensive measurement data to determine the ambient ammonia concentrations. This outcome showing the superiority of the monthly-varying background ammonia concentrations was found by Salt River

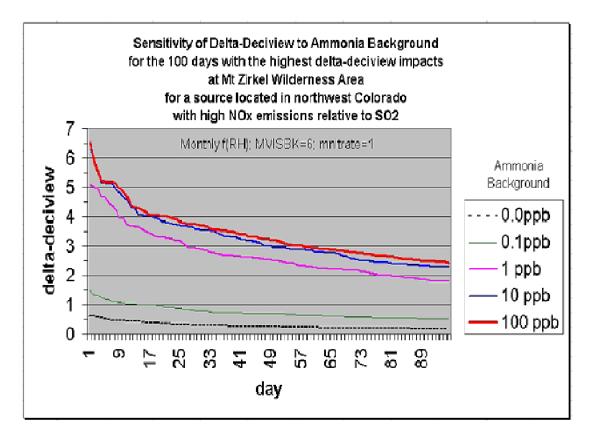
September 2012 Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>24</sup> Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at <u>http://www.colorado.gov/airquality/documents/Draft-</u> ColoradoSupplementalBARTAnalysisCALPUFFProtocol-25June2010.pdf. (2010)

Project in case studies of the Navajo Generating Station impacts on Grand Canyon monitors, as presented<sup>25</sup> to EPA in 2010.

It is important to note that 14 years ago in 1998, when the IWAQM Phase 2 guidance<sup>26</sup> was issued, CALPUFF did not even have the capability of accommodating monthly ammonia background concentrations; only a single value was allowed. Since then, CALPUFF has evolved to be able to receive as input monthly varying ammonia concentrations. EPA's guidance on the recommended input values that are constant all year has not kept pace with the CALPUFF's capability. The weight of evidence clearly indicates that the use of monthly varying ammonia concentrations with lower wintertime values will result in more accurate predictions.

# Figure B-2: CDPHE Plot of Sensitivity of Visibility Impacts Modeled by CALPUFF for Different Ammonia Backgrounds.



<sup>&</sup>lt;sup>25</sup> Salt River Project, 2010. Measurements of Ambient Background Ammonia on the Colorado Plateau and Visibility Modeling Implications. Salt River Project, P.O. Box 52025 PAB352, Phoenix, Arizona 85072.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>26</sup> IWAQM Phase 2 Summary Report and Recommendations (EPA-454/R-98-019), EPA OAQPS, December 1998). <u>http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf</u>.

## Independent Studies of the Effect of Model Chemistry on Nitrate Predictions

The Regional Haze BART Rule acknowledged that CALPUFF tends to overestimate the amount of nitrate that is produced. In particular, the overestimate of ammonium nitrate concentrations on visibility at Class I areas is the greatest in the winter, when temperatures (and visitation) are lowest, the nitrate concentrations are the greatest, and the sulfate concentrations tend to be the least due to reduced oxidation rates of SO<sub>2</sub> to sulfate.

On page 39121, the BART rule<sup>27</sup> stated that: "...the simplified chemistry in the [CALPUFF] model tends to magnify the actual visibility effects of that source."

On page 39123, the BART rule stated that: "We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. In its next review of the Guideline on Air Quality Models, EPA will evaluate these and other newer approaches<sup>28</sup>."

EPA did not conduct such an evaluation, but the discussion below reports on the efforts of other investigators.

A review of independent evaluations of the CALPUFF model is reported here, with a focus on identifying studies that address the nitrate chemistry used in the model. Morris et al.<sup>29</sup> reported that the CALPUFF MESOPUFF II transformation rates were developed using temperatures of 86, 68 and 50 °F. Therefore, the 50 °F minimum temperature used in development of the model could result in overestimating sulfate and nitrate formation in colder conditions. These investigators found that CALPUFF tended to overpredict nitrate concentrations during winter by a factor of about three.

A recent independent study of the CALPUFF performance by Karamchandani et al (referred to here as the KCBB study) is highly relevant to this issue<sup>30</sup>. The KCBB study presented several improvements to the Regional Impacts on Visibility and Acid Deposition (RIVAD) chemistry option in CALPUFF, an alternative treatment that was more amenable to an upgrade than the MESOPUFF II chemistry option. Among other items, the improvements included the replacement of the original CALPUFF secondary particulate matter (PM) modules by newer algorithms that are used in current state-of-the-art regional air quality models such as CMAQ, CMAQ-MADRID, CAMx and REMSAD, and in advanced puff models

<sup>29</sup> Morris, R., Steven Lau and Bonyoung Koo. Evaluation of the CALPUFF Chemistry Algorithms. Presented at A&WMA 98th Annual Conference and Exhibition, June 21-25, 2005 Minneapolis, Minnesota. (2005)

<sup>30</sup> Karamchandani, P., S. Chen, R. Bronson, and D. Blewitt. Development of an Improved Chemistry Version of CALPUFF and Evaluation Using the 1995 SWWYTAF Data Base. Presented at the Air & Waste Management Association Specialty Conference on Guideline on Air Quality Models: Next Generation of Models, October 28-30, 2009, Raleigh, NC. (2009)

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>27</sup> July 6, 2005 Federal Register publication of the Regional Haze BART rule.

<sup>&</sup>lt;sup>28</sup> The next (9<sup>th</sup>) EPA modeling conference was held in 2008, during which the concepts underlying the chemistry upgrades in CALPUFF 6.42 were presented. However, EPA failed to conduct the promised evaluation in its review of techniques at that conference held 4 years ago. As a result of the 10<sup>th</sup> EPA modeling conference held in March 2012, EPA appears to be continuing to rely upon CALPUFF version 5.8, which it admitted in the July 6, 2005 BART rule has serious shortcomings.

such as SCICHEM. In addition, the improvements included the incorporation of an aqueous-phase chemistry module based on the treatment in CMAQ. Excerpts from the study papers describing each of the improvements made to CALPUFF in the KCBB study are repeated below.

#### Gas-Phase Chemistry Improvements

The KCBB study applied a correction to CALPUFF in that the upgraded model was modified to keep track of the puff ozone concentrations between time steps. The authors also updated the oxidation rates of  $SO_2$  and nitrogen dioxide (NO<sub>2</sub>) by the hydroxide ion (OH<sup>-</sup>) to the rates employed in contemporary photochemical and regional PM models.

#### Treatment of Inorganic Particulate Matter

The KCBB study scientists noted that the EPA-approved version of CALPUFF currently uses a simple approach to simulate the partitioning of nitrate and sulfate between the gas and particulate phases. In this approach, sulfate is appropriately assumed to be entirely present in the particulate phase, while nitrate is assumed to be formed by the reaction between nitric acid and ammonia.

The KCBB study implemented an additional treatment for inorganic gas-particle equilibrium, based upon an advanced aerosol thermodynamic model referred to as the ISORROPIA model<sup>31</sup>. This model is currently used in several state-of-the-art regional air quality models. With this new module, the improved CALPUFF model developed in the KCBB study includes a treatment of inorganic PM formation that is consistent with the state of the science in air quality modeling, and is critical for the prediction of regional haze due to secondary nitrate formation from NO<sub>X</sub> emissions.

#### Treatment of Organic Particulate Matter

The KCBB study added a treatment for secondary organic aerosols (SOA) that is coupled with the corrected RIVAD scheme described above. The treatment is based on the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID)<sup>32,33</sup>, which treats SOA formation from both anthropogenic and biogenic volatile organic compound emissions.

#### Aqueous-Phase Chemistry

The current aqueous-phase formation of sulfate in both CALPUFF's RIVAD and MESOPUFF II schemes is currently approximated with a simplistic treatment that uses an arbitrary pseudo-first order rate in the presence of clouds (0.2% per hour), which is added to the gas-phase rate. There is no explicit treatment

<sup>33</sup> Pun, B., C. Seigneur, J. Pankow, R. Griffin, and E. Knipping. An upgraded absorptive secondary organic aerosol partitioning module for three-dimensional air quality applications, 24th Annual American Association for Aerosol Research Conference, Austin, TX, October 17-21, 2005. (2005)

September 2012

<sup>&</sup>lt;sup>31</sup> Nenes A., Pilinis C., and Pandis S.N. Continued Development and Testing of a New Thermodynamic Aerosol Module for Urban and Regional Air Quality Models, *Atmos. Env.* **1998**, 33, 1553-1560.

<sup>&</sup>lt;sup>32</sup>Zhang, Y., B. Pun, K. Vijayaraghavan, S.-Y. Wu, C. Seigneur, S. Pandis, M. Jacobson, A. Nenes and J.H. Seinfeld. Development and Application of the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID), *J. Geophys. Res.* **2004**, 109, D01202, doi:10.1029/2003JD003501.

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

of aqueous-phase SO<sub>2</sub> oxidation chemistry. The KCBB study incorporated into CALPUFF a treatment of sulfate formation in clouds that is based on the treatment that is used in EPA's CMAQ model.

### CALPUFF Model Evaluation and Sensitivity Tests

The EPA-approved version of CALPUFF and the version with the improved chemistry options were evaluated using the 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database<sup>34</sup>, available from the Wyoming Department of Environmental Quality. The database includes MM5 output for 1995, CALMET and CALPUFF codes and control files, emissions for the Southwest Wyoming Regional modeling domain, and selected outputs from the CALPUFF simulations. Several sensitivity studies were also conducted to investigate the effect of background NH<sub>3</sub> concentrations on model predictions of PM nitrate. Twice-weekly background NH<sub>3</sub> concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH<sub>3</sub> concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

- MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH<sub>3</sub> concentration of 1 ppb for arid land. As discussed previously, the MESOPUFF II algorithm is the basis for the currently approved version of CALPUFF that is being used for BART determinations throughout the United States.
- 2. Improved CALPUFF RIVAD/ARM3 chemistry using background values of NH<sub>3</sub> concentrations based on measurements in the Pinedale, Wyoming area, as described above.

PM sulfate and nitrate were predicted by the two models and compared with actual measured values obtained at the Bridger Wilderness Area site from the IMPROVE network and the Pinedale site from the Clean Air Status and Trends Network (CASTNET). For the two model configurations evaluated in this study, the results for PM sulfate were very similar, which was expected since the improvements to the CALPUFF chemistry were anticipated to have the most impact on PM nitrate predictions. Therefore, the remaining discussion focuses on the performance of each model with respect to PM nitrate.

The EPA-approved CALPUFF model was found to significantly overpredict PM nitrate concentrations at the two monitoring locations, by a factor of two to three. The performance of the version of CALPUFF with the improved RIVAD chemistry was much better, with an overprediction of about 4% at the Pinedale CASTNET site and of about 28% at the Bridger IMPROVE site.

In an important sensitivity analysis conducted within the KCBB study, both the EPA-approved version of CALPUFF and the improved version were run with a constant ammonia background of 1 ppb, as recommended by IWAQM Phase II<sup>35</sup>. The results were similar to those noted above: the improved

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>34</sup> Wyoming Department of Environmental Quality. 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database. Background and database description are available at http://deq.state.wy.us/aqd/prop/2003AppF.pdf. (2010)

<sup>&</sup>lt;sup>35</sup> Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Long-Range Transport Modeling, EPA-454/R-98-019. (1998)

CALPUFF predictions were about two to three times lower than those from the EPA-approved version of CALPUFF. This result is similar to the results using the seasonal observed values of ammonia, and indicates that the sensitivity of the improved CALPUFF model to the ammonia input value is potentially less than that of the current EPA-approved model.

Similar sensitivity was noted by Scire et al. in their original work in the SWWYATF study<sup>36</sup>, in which they tested seasonally varying levels of background ammonia in CALPUFF (using 0.23 ppb in winter, for example; see Figure B-3. The sensitivity modeling for predicting levels of nitrate formation shows very similar results to those reported in the KCBB study.

These findings indicate that to compensate for the tendency of the current EPA-approved version of CALPUFF to overpredict nitrates, the background ammonia values that should be used as input in CALPUFF modeling should be representative of isolated areas (e.g., Class I areas).

On November 3, 2010, TRC released a new version (6.42) of CALPUFF to fix certain coding "bugs" in EPA-approved version 5.8 and to improve the chemistry module. Additional enhancements to CALPUFF version 6.42 have been reported at EPA's 10<sup>th</sup> modeling conference in March 2012 by Scire<sup>37</sup>, who also has conducted recent evaluations of this version in comparison to the regulatory version (5.8). Despite the evidence that this CALPUFF version is a generation ahead of the currently approved version for modeling secondary particulate formation, EPA has not acted to adopt it as a guideline model. Even with evidence provided by independent investigators<sup>29,30</sup> that also indicate that wintertime nitrate estimated by CALPUFF version 5.8 is generally overpredicted by a factor between 2 and 4, EPA has not taken steps to adopt the improved CALPUFF model, noting that extensive peer review, evaluations, and rulemaking are still needed for this adoption to occur. In the meantime, EPA, in retaining CALPUFF version 5.8 as the regulatory model for regional haze predictions, is ignoring the gross degree of overestimation of particulate nitrate and is thus ensuring that regional haze modeling conducted for BART is overly conservative. EPA's delay in adopting CALPUFF version 6.42 will thus result in falsely attributing regional haze mitigation to NO<sub>X</sub> emission reductions.

September 2012 Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas 33

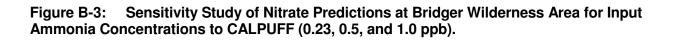
<sup>&</sup>lt;sup>36</sup> Scire, J.S., Z-X Wu, D.G. Strimaitis and G.E. Moore. The Southwest Wyoming Regional CALPUFF Air Quality Modeling Study – Volume I. Prepared for the Wyoming Dept of Environmental Quality. (2001)

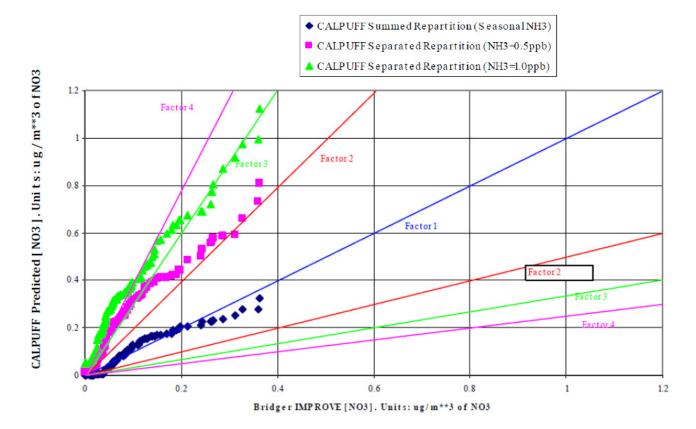
<sup>&</sup>lt;sup>37</sup> Scire, J., 2012. New Developments and Evaluations of the CALPUFF Model. <u>http://www.epa.gov/ttn/scram/10thmodconf/presentations/3-5-CALPUFF Improvements Final.pdf</u>.

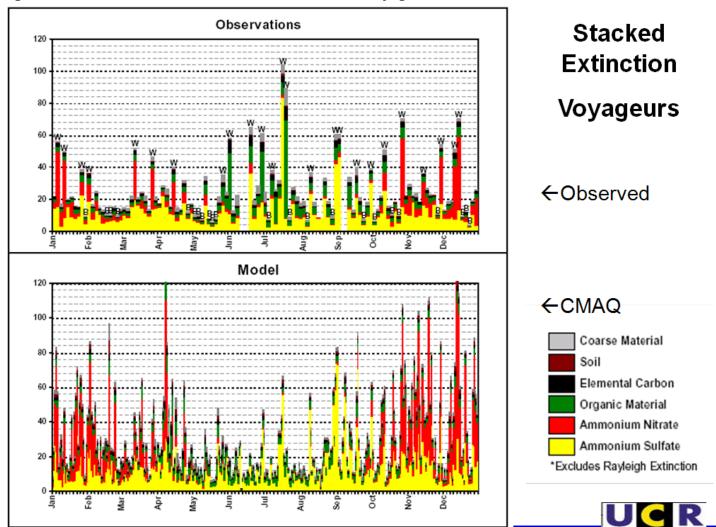
### **OVERPREDICTIONS OF NITRATE HAZE BY REGIONAL PHOTOCHEMICAL MODELS**

The overprediction tendency for modeling of wintertime nitrate haze is not limited to CALPUFF. Even the state-of-the-art regional photochemical models are challenged in getting the right ammonium nitrate concentrations. This is evident in a presentation<sup>38</sup> made by Environ to the CENRAP Regional Planning Organization in 2006. The relevant figures from the Ralph Morris presentation (shown in Figures B-4 and B-5 below) indicate that both CMAQ and CAMx significantly overpredict nitrate haze in winter at Voyageurs National Park, by about a factor of 2. This is shown by the height of the red portion of the composition plot stacked bars between the observed and predicted timelines. It is noteworthy that Minnesota and EPA have relied upon this modeling approach for their BART determinations. Similar to CALPUFF, as discussed above, the agency modeling is prone to significantly overpredicting wintertime nitrate haze, leading to an overestimate of visibility improvement with NO<sub>x</sub> emission reductions.

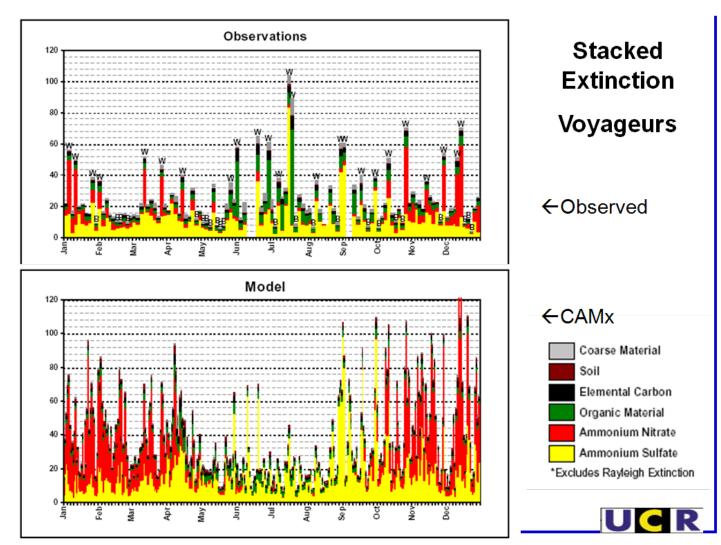
<sup>&</sup>lt;sup>38</sup> <u>http://pah.cert.ucr.edu/aqm/cenrap/meetings.shtml</u>, under "MPE", slides 9 and 10.







## Figure B-4 CMAQ vs. Observed Haze Predictions at Voyageurs National Park



# Figure B-5 CAMx vs. Observed Haze Predictions at Voyageurs National Park

## **APPENDIX C**

Haze Time Series Plots for Voyageurs National Park, Seney Wilderness Area, and Isle Royale National Park

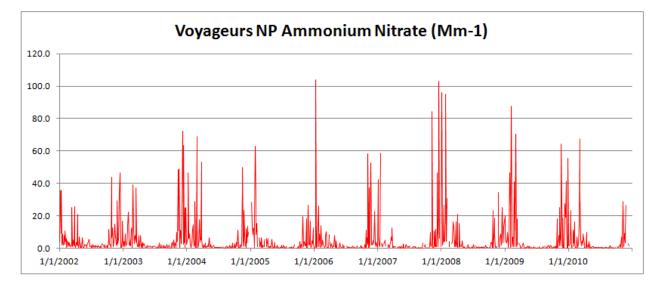
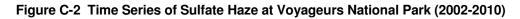
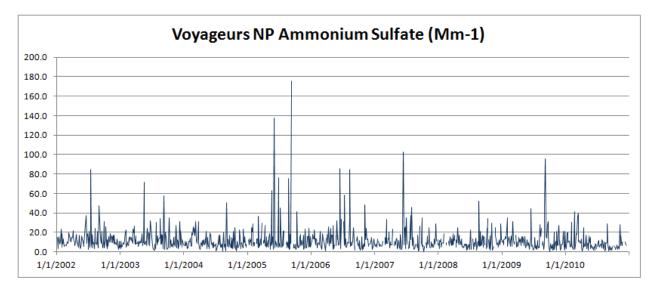
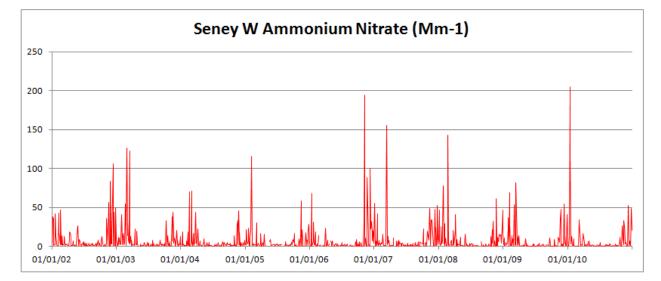


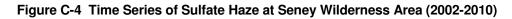
Figure C-1 Time Series of Nitrate Haze at Voyageurs National Park (2002-2010)

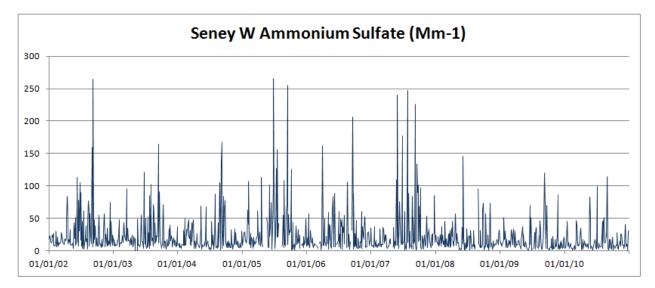


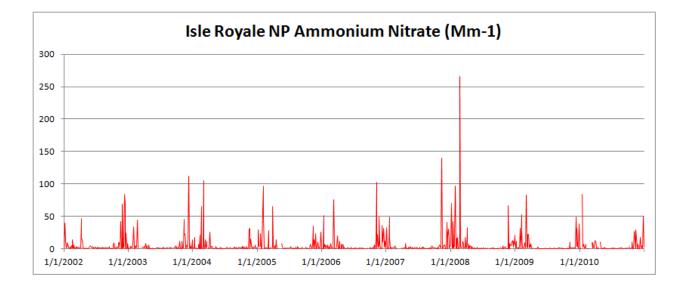




### Figure C-3 Time Series of Nitrate Haze at Seney Wilderness Area (2002-2010)

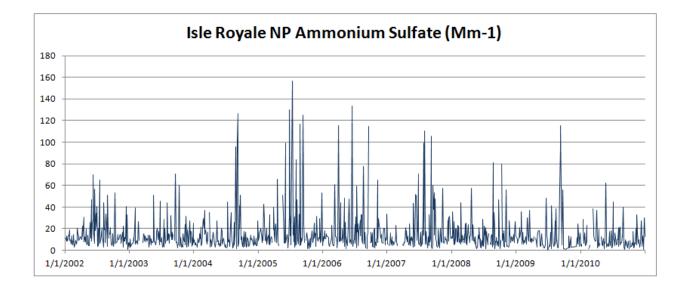






#### Figure C-5 Time Series of Nitrate Haze at Isle Royale National Park (2002-2010)

#### Figure C-6 Time Series of Sulfate Haze at Isle Royale National Park (2002-2010)



### APPENDIX D

### EXAMPLE OF VISIBILITY CHANGES AFTER ACTUAL EMISSION REDUCTIONS: SHUTDOWN OF THE MOHAVE GENERATING STATION

The Mohave Generating Station (MGS) shut down at the end of 2005, which should have had a large, beneficial effect (over 2 dv, according to CALPUFF) upon Grand Canyon visibility on the 98<sup>th</sup> percentile worst days. The MGS was a large (1590 MW) coal-fired plant located near the southern tip of Nevada (Laughlin, NV). MGS was placed in operation in the early 1970s, and was retired at the end of 2005 as a result of a consent agreement with the United States Environmental Protection Agency (EPA). The agreement had provided MGS with the option of continued operation if state-of-the-art emissions controls were installed for SO<sub>2</sub> and NOx emissions, but the owners determined that the cost of controls was too high to justify the investment. As a result, the plant was shut down on December 31, 2005 and has not been in operation since then.

As shown in Figure C-1, the MGS location is about 115 km away from the closest point of the Grand Canyon National Park, for which a southwesterly wind is needed to carry the emissions from MGS to most of the park. A multi-year study<sup>39</sup> completed by the EPA in 1999 (Project MOHAVE) indicated that MGS could be a significant contributor to haze in the Grand Canyon. In fact, typical annual emissions from MGS during the last several years of operation were approximately 40,000 tons per year (TPY) of SO<sub>2</sub> and 20,000 TPY of NOx. EPA noted in their Project MOHAVE conclusions that due to this level of emissions of haze precursors and its proximity to the Grand Canyon, MGS was the single largest emission source that could cause regional haze within the Grand Canyon.

Haze observations at three locations in the Grand Canyon (Meadview, Indian Garden, and Hance Camp monitors are available every third day for periods both before and after the plant shut down at the end of 2005. By comparing haze measurements before and after plant shutdown, it may be possible to determine whether the haze in the Grand Canyon has perceptibly changed since 2005 by reviewing the data from these three monitors. The Meadview monitor is at the western edge of the Park, and is relatively close to MGS. The other two IMPROVE monitors are located near some of the most heavily visited areas of the park (Hance Camp, on the South Rim, and Indian Garden, about 1,100 feet lower near the bottom of the canyon).

A 2010 *Atmospheric Environment* paper by Terhorst and Berkman<sup>40</sup> studied the effects of the opportunistic "experiment" afforded by the abrupt shutdown of the largest source affecting the Grand Canyon (according to EPA). The paper noted that Project MOHAVE's conclusions about the effects of MGS on the Grand Canyon visibility were ambiguous. The project's tracer studies revealed that while the MGS emissions did reach the park, particularly in the summer, there was no evidence linking these elevated concentrations with actual visibility impairment; indeed, "correlation between measured tracer concentration and both particulate sulfur and light extinction were virtually nil."

On the other hand, dispersion models produced results inconsistent with the observations. Noting the disconnect between the measurements and model predictions, EPA noted the disparity between the measurements and modeling results, but still appeared to favor the models when it concluded that MGS was the largest sole contributor to visibility impairment in the Grand Canyon.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>39</sup> Pitchford, M., Green, M., Kuhns, H., Scruggs, M., Tombach, I., Malm, W., Farber, R., Mirabella, V., 1999. Project MOHAVE: Final Report. Tech. Rep., U.S. Environmental Protection Agency (EPA).

<sup>&</sup>lt;sup>40</sup> Jonathan Terhorst and Mark Berkman. "Effect of Coal-Fired Power Generation on Visibility in a Nearby National Park," Atmospheric Environment, 44(2010) 2544-2531. This publication is available by request from Mark Berkman at <u>mark.berkman@berkeleyeconomics.com</u>.

According to the authors, the Project Mohave observations were consistent with observations during temporary outages of MGS, for which there were no reports of substantial changes to visibility in the Grand Canyon.

Best Available Retrofit Technology (BART) studies evaluated a possible conversion of MGS to natural gas firing in 2008. These studies used the CALPUFF dispersion model in a manner prescribed by EPA to determine the change in visibility between the baseline emissions associated with coal firing to the natural gas firing alternative. The BART analyses conducted by the Nevada Department of Environmental Protection indicated that large differences in haze would result: an improvement of about 2.4 deciviews for the 98<sup>th</sup> percentile peak day, and a haze reduction to below 0.5 deciview on 186 days over 3 years modeled. Since natural gas firing would eliminate nearly all of the SO<sub>2</sub> emissions (although not all of the NOx emissions) this modeled result would tend to underestimate the visibility improvement that would be anticipated with a total plant shutdown.

Terhorst and Berkman analyzed several statistics to determine the change in sulfate concentrations and visibility in the Grand Canyon between the period 2003-2005 (pre-shutdown) and the period 2006-2008 (post-shutdown). They also considered other areas to determine how other regional and environmental effects might be reflected in changes at the Grand Canyon. Terhorst and Berkman calculated the average visibility over all IMPROVE monitoring days between 2003-2005 and 2006-2008, and determined that the average visibility was unchanged at Meadview, slightly improved on the South Rim (Hance Camp), and slightly worse at Indian Garden. Consistent with the observations of minimal visibility impact of MGS during Project MOHAVE, they concluded that the closure of MGS had a relatively minor effect on visibility in the Grand Canyon. These authors questioned the veracity of CALPUFF modeling (e.g., for BART) in that it predicts relatively large improvements in the Grand Canyon visibility that are not borne out by observations.

Emissions reductions associated with the shutdown of the Mohave Generating Station at the end of 2005 have provided an opportunistic means to discern the effect of retrofitting emission controls on coal-fired power plants in the western United States. In the case of MGS, although EPA had determined that this facility was the single most important contributor to haze in the Grand Canyon National Park and CALPUFF modeling using EPA's BART procedures provided predictions of significant improvements in haze, actual particulate and haze measurements taken before and after the shutdown do not reflect the large reductions that would be anticipated from these studies. This may be due in part to the fact that there are several aspects to the CALPUFF modeling procedures that greatly inflate the predicted haze (as noted below), and therefore, the predicted improvements due to emission reductions.

# AECOM

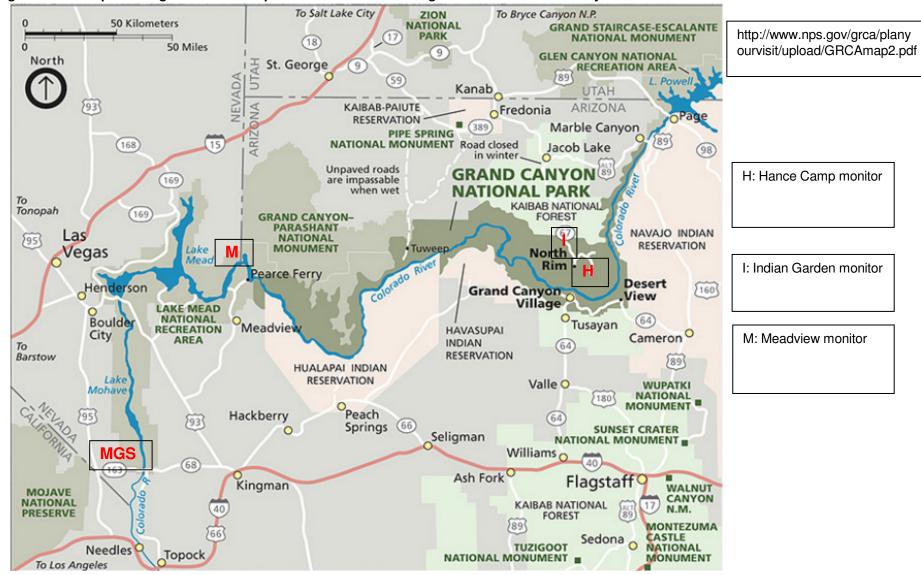


Figure D-1 : Map Showing the Relationship of the Mohave Generating Station to the Grand Canyon National Park

September 2012

Page 45 of 45

www.aecom.com

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas



ELECTRONIC CORRESPONDENCE ONLY

June 1, 2020

Mr. Hassan M. Bouchareb Environmental Analysis and Outcomes Division Minnesota Pollution Control Agency 520 Lafayette Road North St. Paul, Minnesota 55155-4194 Hassan.Bouchareb@state.mn.us

Re: Effectively Controlled Source Determination
 MPCA Request for Information – Regional Haze Rule, Reasonable Progress, Four Factor Analysis
 Minnesota Power's Bowell Energy Center (Title V Operating Permit No. 06100004-008)

Dear Mr. Bouchareb,

On January 29, 2020, the Minnesota Pollution Control Agency (MPCA) issued Minnesota Power (MP) a Regional Haze Rule Request for Information (RFI) for MP's Boswell Energy Center (BEC). The RFI requested that MP submit by July 31, 2020 a "Four Factor Analysis" for the following BEC emission units:

- Unit 1 Wall-fired dry bottom (EQUI 82 / EU 001) that addresses emissions of NOx and SO<sub>2</sub>
- Unit 2 Wall-fired dry bottom (EQUI 83 / EU 002) that addresses emissions of NOx and SO<sub>2</sub>
- Unit 3 Wall-fired dry bottom (EQUI 100 / EU 003) that addresses emissions of NOx and SO<sub>2</sub>
- Unit 4 Wall-fired dry bottom (EQUI 85 / EU 004) that addresses emissions of NOx and SO<sub>2</sub>

This letter is MP's response to the "Four Factor Analysis" request for BEC.

#### BEC Unit 1 (EQUI 82 / EU 001) and Unit 2 (EQUI 83 / EU 002)

BEC Units 1 and 2 were permanently retired and removed from the Acid Rain Permit (ARP) in December 2018. These two units are no longer legally permitted to operate per MP's state/federal Consent Decree and MPCA Title V Permit 06100004-008 (5.18.16 and 5.19.16) which mandated their retirement no later than December 31, 2018. Therefore a "Four Factor Analysis" is not required for BEC Unit 1 and 2.

MPCA was informed of MP's intent to not complete the RFI for the retired BEC units 1 and 2 units via electronic correspondence dated January 29, 2020. During this communication, you concurred that BEC 1 and 2 analysis was not necessary, and requested MP restate the circumstances within this submittal.

Mr. Hassan Bouchareb, MPCA MP Regional Haze RFI Response – Boswell June 1, 2020

#### BEC Unit 3 (EQUI 100 / EU 003)

The MPCA specifies in the RFI that U.S. Environmental Protection Agency (USEPA) guidance<sup>1</sup> should be followed to complete a "Four Factor Analysis". This guidance document includes a discussion that states can reasonably exclude sources already equipped with effective emission controls from the requirement to conduct a "Four Factor Analysis" due to the likely conclusion of such an analysis being that no further controls are necessary<sup>2</sup>. The guidance document provides several examples of the types of emission controls that could be installed for a source to be considered "effectively controlled" while noting the examples are not an exhaustive list.

As noted in the following bullet points, BEC Unit 3 (BEC3) meets at least one of the "effectively controlled" source examples for both  $NO_X$  and  $SO_2$  which excludes the source from the requirement to conduct a "Four Factor Analysis":

- NO<sub>x</sub> One example of an "effectively controlled" emission source included in USEPA's guidance document is a BART-eligible emission unit that "*installed and began operating controls to meet BART emission limits for the first implementation period*."<sup>3</sup> The Technical Support Document (TSD) for BEC's Title V Operating Permit that was issued on March 28, 2007 (No. 06100004-003) specifies that BEC3 would install low-NO<sub>x</sub> burners, over-fire air, and selective catalytic reduction<sup>4</sup> to control NO<sub>x</sub> emissions. One of the justifications for the installation of this control equipment, among others, is the Regional Haze Rule. As noted on page 12 of the Technical Support Document (TSD)<sup>5</sup> for BEC's Title V Operating Permit (No. 06100004-008), BEC3's NO<sub>x</sub> BART limit was later replaced with BEC3's more restrictive Consent Decree limit<sup>6</sup>. As such, BEC Unit 3 meets this example, and is "effectively controlled" for NO<sub>x</sub> as defined in USEPA's guidance document.
- SO<sub>2</sub> Another example of an "effectively controlled" emission source included in USEPA's guidance document is an electric generating unit (EGU) with flue gas desulfurization (FGD) and

<sup>&</sup>lt;sup>1</sup> USEPA, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019.

<sup>&</sup>lt;sup>2</sup> Ibid, Pages 22-25.

<sup>&</sup>lt;sup>3</sup> Ibid, Page 25.

 <sup>&</sup>lt;sup>4</sup> Controls identified as TREA 5 and TREA 8 in the facility's current Title V Operating Permit No. 06100004-008.
 <sup>5</sup> Technical Support Document to Permit No. 06100004-008, Page 12 of 71

<sup>&</sup>lt;sup>6</sup> Case No.: 0:14-cv-02911-ADM-LIB, <u>https://www.epa.gov/sites/production/files/2014-</u>

<sup>07/</sup>documents/minnesotapower-cd.pdf

that meets the applicable alternative SO<sub>2</sub> emission limit of the 2012 Mercury Air Toxics Standards (MATS) Rule. USEPA states that for a source of this type "... *[it] is unlikely [...] that even more stringent control of SO<sub>2</sub> is necessary to make reasonable progress.*"<sup>7</sup> BEC3 is an EGU equipped with wet FGD (TREA 10) and is currently complying with the alternative SO<sub>2</sub> emission limit of the MATS Rule. BEC3 therefore meets the example scenario of USEPA's guidance document and is considered "effectively controlled" for SO<sub>2</sub>.

#### BEC Unit 4 (EQUI 85 / EU 004)

Following the same EPA guidance used for BEC3 above, BEC Unit 4 (BEC4) meets at least one of the "effectively controlled" source examples for both NO<sub>x</sub> and SO<sub>2</sub> which excludes the source from the requirement to conduct a "Four Factor Analysis":

• NO<sub>x</sub> – Another example of an "effectively controlled" emission source included in USEPA's guidance document is a source that has completed a best available control technology (BACT) or lowest achievable emission rate (LAER) review and received a construction permit on or after July 31, 2013. Although not explicitly stated in the USEPA's guidance document, it may then be also reasonably assumed that a source would be considered "effectively controlled" if the current control technologies and their effectiveness are *equivalent or sufficiently similar to the control technologies for similar sources that did undergo a more recent BACT or LAER review*. A source should also be considered as "effectively controlled" if the source's existing permit limits, independent of statutory basis, are *consistent or sufficiently similar to recent best BACT or LAER determinations completed for similar sources*. MP believes these are valid assumptions because it is unlikely that additional controls would be necessary if the source already operates with BACT/LAER equivalent controls and/or emission limits, especially if those limits are stringent and Consent Decree-based as in the case of the MP Boswell units. In many cases, recent Air Quality Consent Decree limits are equivalent to or lower than BACT limits.

A search of the USEPA's RACT/BACT/LAER Clearinghouse<sup>8</sup> (RBLC) in May 2020 revealed there have been no NOx BACT or LAER determinations entered into the database for coal-fired utility

<sup>&</sup>lt;sup>7</sup> USEPA, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, Page 23.

<sup>&</sup>lt;sup>8</sup> <u>https://cfpub.epa.gov/rblc/index.cfm?action=Home.Home&lang=en</u>

boilers with a maximum firing rate of greater than 250 MMBtu/hr since July 31, 2013<sup>9</sup> (the date specified by the USEPA's guidance document). However, extending the start date of the RBLC search back to January 1, 2010 shows several NO<sub>x</sub> BACT evaluations between January 1, 2010 and July 31, 2013<sup>10</sup>. Although, BEC4 has not undergone a BACT or LAER review for NO<sub>x</sub> at any time, the current BEC4 NO<sub>x</sub> limit (0.12 lb NO<sub>x</sub>/MMBtu) is much more stringent than these most recent RBLC-listed NO<sub>x</sub> BACT evaluations (0.24 – 0.25 lb/MMBtu) for tangentially-fired coal boilers<sup>11</sup>.

To achieve this NOx limit, BEC4 is equipped with existing NO<sub>x</sub> control equipment, consisting of low-NO<sub>x</sub> burners with separated over fire air and ROTA-Mix Selective Non-Catalytic Reduction<sup>12</sup>. These controls are consistent with other BACT determinations for all types of coal-fired boilers, not just tangentially-fired units, identified in the RBLC search<sup>13</sup>. As such, BEC Unit 4 should be considered "effectively controlled" for NO<sub>x</sub>, based on the USEPA's guidance document which references "*…effective controls in place … to meet another CAA requirement*"<sup>14</sup>.

• **SO**<sub>2</sub> – Similar to BEC3, BEC4 is an EGU equipped with semi-dry FGD (TREA 21) and utilizes the MATS Rule alternative SO<sub>2</sub> emission limit compliance demonstration option. BEC4 is therefore "effectively controlled" for SO<sub>2</sub> as defined in USEPA's guidance document [an electric generating unit (EGU) with flue gas desulfurization (FGD) and that meets the applicable alternative SO<sub>2</sub> emission limit of the 2012 Mercury Air Toxics Standards (MATS) Rule]. Again, USEPA states that for a source of this type "... [*it*] *is unlikely* [...] *that even more stringent control of SO*<sub>2</sub> *is necessary to make reasonable progress.*"<sup>15</sup>

Power Cooperative (ND-0026) for examples of similar controls accepted as BACT.

<sup>&</sup>lt;sup>9</sup> Search of RBLC conducted for process type "11.110 – Coal (includes bituminous, subbituminous, anthracite, and lignite)", pollutant name "NOx", and date range of 07/31/2013 to 05/14/2020.

<sup>&</sup>lt;sup>10</sup> The same search of the RBLC was conducted, except the date range was changed to 01/01/2010 to 07/31/2013. <sup>11</sup> See BACT evaluations for Navajo Generating Station (AZ-0055), and Limestone Electric Generating Station (TX-0557), which specify limits of 0.24 and 0.25 lb NO<sub>X</sub>/MMBtu, respectively.

 <sup>&</sup>lt;sup>12</sup> Controls identified as TREA 6 and TREA 7 in the facility's current Title V Operating Permit No. 06100004-008.
 <sup>13</sup> See BACT evaluations for Navajo Generating Station (AZ-0055), Wolverine Power (MI-0400), and Minnkota

<sup>&</sup>lt;sup>14</sup> USEPA, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, Page 22.

<sup>&</sup>lt;sup>15</sup> Ibid. Page 23.

#### **Conclusion**

Two of the emission units identified in MPCA's RFI, Unit 1 (EQUI 82 / EU 001) and Unit 2 (EQUI 83 / EU 002), have been retired and therefore a four-factor analysis is not necessary for these sources.

The other two emission units, Unit 3 (EQUI 100 / EU 003) and Unit 4 (EQUI 85 / EU 004), are "effectively controlled" for  $NO_X$  and  $SO_2$  per the USEPA guidance and do not require a four-factor analysis.

Minnesota Power trusts this submittal fulfills the MPCA Regional Haze RFI for the Boswell Energy Center units. Please contact me if you have questions or require additional information.

Sincerely,

Melisso S. Weglarz

Melissa Weglarz Environmental Audit & Policy Manager Minnesota Power Environmental & Land Mgmt. <u>mweglarz@mnpower.com</u> Mobile: 218-343-0927

Enclosure: RBLC Search for NO<sub>X</sub> BACT and LAER Determinations from Coal-Fired Utility Boilers

#### Minnesota Power - Boswell Energy Center Regional Haze RFI Coal-Fired Utility Boiler NOx RBLC Search

#### Pollutant Name: NO<sub>x</sub>

NOTE: Draft determinations are marked with a " \* " beside the RBLC ID.

| RBLCID  | t determinations are marked with a FACILITY NAME | CORPORATE OR COMPANY<br>NAME                          | FACILITY<br>STATE | PERMIT NUM             | NAICS<br>CODE | PERMIT DATE    | FACILITY DESCRIPTION  | Process Name  | Fuel             | Through-<br>put | UNITS           | Pollutant                | Emission Control Description  | Emission<br>Limit 1 | Limits Units 1 | Avg Time                                       | CASE-BY-<br>CASE<br>BASIS | Emission<br>Limit 2 | Limits Units2 | Avg Time2                      |
|---------|--|---|-------------------|------------------------|---------------|----------------|---|---|------------------|-----------------|-----------------|--------------------------|---|---------------------|----------------|--|---------------------------|---------------------|---------------|--------------------------------|
| 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<br>BOILER   | COAL             | 7725            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | LOW NOX BURNER (LNB), SEPARATED<br>OVERFIRE AIR (SOFA) SYSTEM,  | 0.24                | LB/MMBTU       | 30-DAY ROLLING<br>AVG                          | BACT-PSD                  |                     |               |                                |
| AZ-0055 | NAVAJO GENERATING STATION                        | SALT RIVER PROJECT AGRICULTURAL AND<br>POWER DISTRICT | AZ                | AZ 08-01               | 221112        | 02/06/2012 ACT | 2,250 MW COAL FIRED POWER PLANT   | PULVERIZED COAL FIRED<br>BOILER   | COAL             | 7725            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | LOW NOX BURNER (LNB), SEPARATED<br>OVERFIRE AIR (SOFA) SYSTEM,  | 0.24                | LB/MMBTU       | 30-DAY ROLLING<br>AVG                          | BACT-PSD                  |                     |               |                                |
| AZ-0055 | NAVAJO GENERATING STATION                        | SALT RIVER PROJECT AGRICULTURAL AND<br>POWER DISTRICT | AZ                | AZ 08-01               | 221112        | 02/06/2012 ACT | 2,250 MW COAL FIRED POWER PLANT   | PULVERIZED COAL FIRED<br>BOILER   | COAL             | 7725            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | LOW NOX BURNER (LNB), SEPARATED<br>OVERFIRE AIR (SOFA) SYSTEM,  | 0.24                | LB/MMBTU       | 30-DAY ROLLING<br>AVG                          | BACT-PSD                  |                     |               |                                |
| CA-1206 | STOCKTON COGEN COMPANY                           | APMC STOCKTON COGEN                                   | CA                | SJ 85-04               | 221112        | 09/16/2011 ACT | 49.9 MW COGENERATION POWER PLANT OWNED BY AIR<br>PRODUCTS MANUFACTURING CORPORATION (APMC)<br>STOCKTON COGEN AND LOCATED IN STOCKTON, CALIFORNIA  | CIRCULATING FLUIDIZED BED<br>BOILER   | COAL             | 730             | MMBTU/H         | Nitrogen Oxides<br>(NOx) | LOW BED TEMPERATUR STAGED<br>COMBUSTION; SELECTIVE NON-CATALYTIC<br>REDUCTION (SNCR)                        | 50                  | PPM            | @3% O2, 3-HR AVG                               | BACT-PSD                  | 42                  | LB/H          | 3-HR AVG                       |
| MI-0399 | DETROIT EDISONMONROE                             | DETROIT EDISON  | MI                | 93-09A                 | 221112        | 12/21/2010 ACT | UtilityCoal fired power plant   | Boiler Units 1, 2, 3 and 4  | Coal             | 7624            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | Staged combustion, low-NOx burners,<br>overfire air, and SCR.   | 0.08                | lb/MMBTU       | EACH, 12-MONTH<br>ROLLING AVG.                 | BACT-PSD                  | 222.6               | T/MO          | EACH, 12-MONTH<br>ROLLING AVG. |
| MI-0400 | WOLVERINE POWER                                  | WOLVERINE POWER SUPPLY COOPERATIVE,<br>INC.           | МІ                | 317-07                 | 221112        | 06/29/2011 ACT | Coal-fired power plant.   | 2 Circulating Fluidized Bed<br>Boilers (CFB1 & CFB2)                                      | Petcoke/coa<br>I | 3030            | MMBTU/H<br>EACH | Nitrogen Oxides<br>(NOx) | SNCR (Selective Non-Catalytic Reduction)  | 1                   | LB/MW-H        | GROSS OUTPUT;<br>EACH; 30 D ROLL.<br>AVG; NSPS | BACT-PSD                  | 281.1               | LB/H          | EACH; 24H<br>ROLL.AVG.; BACT   |
| MI-0400 | WOLVERINE POWER                                  | WOLVERINE POWER SUPPLY COOPERATIVE,<br>INC.           | MI                | 317-07                 | 221112        | 06/29/2011 ACT | Coal-fired power plant.   | 2 Circulating Fluidized Bed<br>Boilers (CFB1 & CFB2) -<br>EXCLUDING Startup &<br>Shutdown | Petcoke/coa<br>I | 3030            | MMBTU/H<br>each | Nitrogen Oxides<br>(NOx) | SNCR (Selective Non-Catalytic Reduction)  | 0.07                | LB/MMBTU       | EACH, 30 D<br>ROLLING AVG;<br>BACT             | BACT-PSD                  |                     |               |                                |
| 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<br>(NOx) | SNCR plus separated over fire air   | 0.36                | LB/MMBTU       | 30 DAY ROLLING<br>AVERAGE                      | BACT-PSD                  | 2070.2              | LB/H          | 24 HOUR AV<br>DURING STARTUP   |
| 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<br>(NOx) | SNCR plus separated over fire air   | 0.35                | lb/MMBTU       | 30 DAY ROLLING<br>AVERAGE                      | BACT-PSD                  | 3995.6              | LB/H          | 24 HOUR AV<br>DURING STARTUP   |
| OK-0151 | SOONER GENERATING STATION                        | O G AND E   | OK                | 2010-338-C(M-<br>1)PSD | 221112        | 01/17/2013 ACT | The facility is an electricity generation plant (SIC Code 4911)<br>located in an attainment area. The facility is currently<br>operating under Permit No. 2010-338-TVR2 issued November<br>21, 2011.  | COAL-FIRED BOILERS  | COAL             | 550             | MW              | Nitrogen Oxides<br>(NOx) | LOW-NOX BURNERS AND OVERFIRE AIR.   | 0.15                | lb/MMBTU       | 30-DAY AVG                                     | BART                      |                     |               |                                |
| OK-0152 | MUSKOGEE GENERATING STATION                      | O G AND E   | ОК                | 2005-271-C(M-<br>5)PSD | 221112        | 01/30/2013 ACT | The Muskogee Generating Station utilizes sub-bituminous<br>coal, natural gas, and some waste products (used oil-sorb,<br>used antifreeze, used solvents, used oil, chemical cleaning<br>wastes, hazardous waste fuel, activated carbon, demineralizer<br>resin, and waste water treatment sludge) to produce electricit<br>(SIC 4911). The facility includes 3 large boiler units and<br>auxiliary facilities for storage and processing of solid and liquid<br>fuels and for handling ash and other wastes.  | у   | COAL             | 550             | MW              | Nitrogen Oxides<br>(NOx) | LOW-NOX BURNERS AND OVERFIRE AIR  | 0.15                | LB/MMBTU       | 30-DAY AVG                                     | BART                      |                     |               |                                |
| TX-0554 | COLETO CREEK UNIT 2                              | COLETO CREEK  | тх                | PSDTX1118 AND<br>83778 | 221112        | 05/03/2010 ACT | Coal-fired boiler   | Coal-fired Boiler Unit 2  | PRB coal         | 6670            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | low-NOx burners with OFA, Selective Catalytic<br>Reduction  | 0.06                | LB/MMBTU       | ROLLING 30 DAY<br>AVG                          | BACT-PSD                  | 0.05                | LB/MMBTU      | ROLLING 12<br>MONTH AVG        |
| TX-0556 | HARRINGTON STATION UNIT 1 BOILER                 | SOUTHWESTERN PUBLIC SERVICE COMPANY                   | тх                | PSDTX631M1<br>AMD 1388 | 221112        |                | The Southwestern Public Service Company (Xcel), the operator<br>of a 3,630 MMBtu/hr coal fired electrical generating facility, is<br>seeking authorization to install modifications to the Unit 1<br>Boiler at the Harrington Station Roler Unit 1 in conjunction<br>with a federally-mandated NOx reduction project. These<br>modifications to this pollution control project include a<br>separated overfire air windbox system, low-NOx burner tips<br>and additional yaw control to the burners. These modifications<br>will allow control of sufficient control emissions such that<br>actual NOX emissions are expected to be reduced by an<br>estimated 514 tons per year. However, as a result of these<br>modifications, collateral increases in actual CO emissions are<br>projected to be approximately 4,862 tons per year. Since this<br>increase in CO emissions is in excess of 100 tpy, this project<br>triggers the requirements for a PSD major modification. This<br>project is not expected to increase other NAAQS constituents. |   | Coal             | 3630            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | Separated overfire air windbox system; low-<br>NOx burner tips and additional ya control to<br>the burners. | 1452                | LB/H           |  | BACT-PSD                  |                     |               |                                |

#### Minnesota Power - Boswell Energy Center Regional Haze RFI Coal-Fired Utility Boiler NOx RBLC Search

#### Pollutant Name: NO<sub>x</sub>

NOTE: Draft determinations are marked with a " \* " beside the RBLC ID.

| RBLCID   | FACILITY NAME                         | CORPORATE OR COMPANY<br>NAME      | FACILITY<br>STATE | PERMIT NUM                           | NAICS<br>CODE | PERMIT DATE    | FACILITY DESCRIPTION   | Process Name      | Fuel                       | Through-<br>put | UNITS   | Pollutant                | Emission Control Description   | Emission<br>Limit 1 | Limits Units 1 | Avg Time            | CASE-BY-<br>CASE<br>BASIS | Emission<br>Limit 2 | Limits Units2 | Avg Time2      |
|----------|---------------------------------------|-----------------------------------|-------------------|--------------------------------------|---------------|----------------|--|-------------------|----------------------------|-----------------|---------|--------------------------|--|---------------------|----------------|---------------------|---------------------------|---------------------|---------------|----------------|
| TX-0557  | LIMESTONE ELECTRIC GENERATING STATION | NRG TEXAS POWER LLC               | тх                | PSDTX371M4<br>AND 8576               | 221112        | 02/01/2010 ACT | NRG Texas Power LLC (NRG) operates two coal and petroleum<br>coke-fired steam/electric units, otherwise known as Limestone<br>Units 1 and 2, which were originally permitted to operate in<br>September 1981. These units are Combustion Engineering<br>tangentially-fired, controlled circulation radiant reheat,<br>divided furnace boilers. In January 2000 and August 2001,<br>these units were authorized to install and operate low-NOX<br>combustion systems, including secondary air staging<br>technology and low-NOX burner tips with separated over-fire<br>air. The tilting tangential firing system consists of ten<br>elevations of solid fuel firing equipment with two elevations of<br>Close Coupled Overfire Air and one elevation of warm-up gas<br>firing. The modification requested under this amendment is a<br>tuning of the existing low-NOX firing system consitue deeper<br>state combustion for NOX reductions with no new<br>construction. Although, the deeper stage combustion will<br>reduce NOX emissions, it will also result in significant<br>collateral increase in CO emissions above the current actual CC<br>emission rates with no increase in authorized emission rates.   | LMS Units 1 and 2 | Coal                       | 9061            | MMBtu/H | Nitrogen Oxides<br>(NOx) | Tuning of existing low-NOx firing system to<br>induce deeper state combustion. | 0.25                | LB/MMBTU       | 30-DAY              | BACT-PSD                  |                     |               |                |
| *TX-0577 | WHITE STALLION ENERGY CENTER          | WHITE STALLION ENERGY CENTER, LLC | ТХ                | 86088, PAL26,<br>HAP28,<br>PSDTX1160 | 221112        |                | WSEC proposes to construct and operate new steam-electric<br>utility generating facilities using four circulating fluidized bed<br>(CFB) boilers, each with a design maximum heat input of 3,300<br>MW net electric output. The gross electric output of the four<br>steam electric generators is about 1,320 MW; the net electric<br>output of the WSEC is about 1,200 MW. The proposed fuels<br>are Illinois Basin coal and petroleum coke. Low-sulfur distillate<br>fuel oil is proposed as the CFB startup fuel. Steam<br>condensation is supported by four water-cooled cooling<br>towers, each with a cooling water circulation design rate of<br>161,000 gallons per minute. Coal and petroleum coke fuels,<br>and limestone for the CFB beds may be received by barge, rail,<br>or truck, and will be transported via partially enclosed<br>conveyors to large stockpiles for storage. These materials will<br>be conveyed to a crusher building before being stored in silos<br>next to the boilers. Activated carbon for mercury control, lime<br>for sulfur dioxide (SO2) control, and sand for CFB bed<br>stabilization will be delivered via railcar or truck and conveyed<br>pneumatically to storage silos. The fly ash and boiler bottom<br>ash solid wastes will be stored in silos near the boilers, loaded<br>into trucks, and sent to an on-site landfill. | CFB ROILER        | COAL & PET<br>COKE         | 3300            | MMBTU/H | Nitrogen Oxides<br>(NOx) | CFR AND SNCR   | 0.07                | LB NOX/MMBTU   | 30-DAY ROLLING      | BACT-PSD                  | 0.1                 | LB NOX/MMBTU  | 1-HR           |
| TX-0585  | TENASKA TRAILBLAZER ENERGY CENTER     | TENASKA TRAILBLAZER PARTNERS LLC  | ТХ                | PSDTX1123 AND<br>HAP13, 84167        | 221112        | 12/30/2010 ACT | Coal-fired electric generating facility  | Coal-fired Boiler | Sub-<br>bituminous<br>coal | 8307            | MMBTU/H | Nitrogen Oxides<br>(NOx) | Selective Catalytic Reduction  | 0.05                | LB/MMBTU       | 12-MONTH<br>ROLLING | BACT-PSD                  | 0.06                | LB/MMBTU      | 30-DAY ROLLING |



ELECTRONIC CORRESPONDENCE ONLY

July 31, 2020

Mr. Hassan M. Bouchareb Environmental Analysis and Outcomes Division Minnesota Pollution Control Agency 520 Lafayette Road North St. Paul, Minnesota 55155-4194 Hassan.Bouchareb@state.mn.us

Re: MPCA Request for Information – Regional Haze Rule, Reasonable Progress, Four Factor Analysis Minnesota Power's Taconite Harbor Energy Center (Title V Operating Permit No. 06100004-009)

Dear Mr. Bouchareb,

On January 29, 2020, the Minnesota Pollution Control Agency (MPCA) issued Minnesota Power (MP) a Regional Haze Rule Request for Information (RFI) for MP's Taconite Harbor Energy Center (THEC). The RFI requested that MP submit by July 31, 2020 a "Four Factor Analysis" for the following THEC emission units:

- Boiler No. 1 (EQUI 64 / EU 001) for NO<sub>x</sub> and SO<sub>2</sub>
- Boiler No. 2 (EQUI 5 / EU 002) for NO<sub>x</sub> and SO<sub>2</sub>

This letter is and the attached report is MP's response to this request.

MP trusts this submittal fulfills the MPCA RFI and thanks the MPCA for its review. Please contact me at <u>mweglarz@mnpower.com</u> or 218-343-0927 if you have questions or require additional information.

Sincerely,

Melisso S. Weglarz

Melissa Weglarz Environmental Audit & Policy Manager Minnesota Power Environmental & Land Mgmt.

enclosure: Regional Haze Four-Factor Analysis for NO<sub>x</sub> and SO<sub>2</sub> Emissions Control cc: Barr Engineering: Beau Thurman, Erik Boleman



# Regional Haze Four-Factor Analysis for NO<sub>X</sub> and SO<sub>2</sub> Emissions Control

Boiler No. 1 (EQUI 64 / EU 001) Boiler No. 2 (EQUI 5 / EU 002)

Prepared for Minnesota Power Taconite Harbor Energy Center

July 31, 2020

325 South Lake Avenue Duluth, MN 55802 218.529.8200 www.barr.com

## Regional Haze Four-Factor Analysis for NO<sub>X</sub> and SO<sub>2</sub> Emissions Control

July 31, 2020

# Contents

| 1 |     | Executive Summary   | 1  |
|---|-----|---|----|
| 2 |     | Introduction  | 1  |
|   | 2.1 | Four-factor Analysis Regulatory Background                                | 1  |
|   | 2.2 | Facility Description  | 2  |
| 3 |     | Existing Controls and Baseline Emission Rates                             | 3  |
|   | 3.1 | Existing Emission Controls  | 3  |
|   | 3.2 | Baseline Emissions Performance  | 3  |
| 4 |     | Four-factor Analysis Overview   | 7  |
|   | 4.1 | Emission Control Options  | 7  |
|   | 4.1 | 1.1 NO <sub>X</sub> Control Options                                       | 8  |
|   | 4.1 | 1.2 SO2 Control Options   | 9  |
|   | 4.2 | Factor 1 – Cost of Compliance   | 10 |
|   | 4.3 | Factor 2 – Time Necessary for Compliance                                  | 11 |
|   | 4.4 | Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance | 11 |
|   | 4.5 | Factor 4 – Remaining Useful Life of the Source                            | 12 |
| 5 |     | NO <sub>x</sub> Four-factor Analysis                                      | 13 |
|   | 5.1 | NO <sub>x</sub> Control Measures Overview                                 | 13 |
|   | 5.2 | Factor 1 – Cost of Compliance   | 14 |
|   | 5.3 | Factor 2 – Time Necessary for Compliance                                  | 15 |
|   | 5.4 | Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance | 16 |
|   | 5.5 | Factor 4 – Remaining Useful Life of the Source                            | 16 |
|   | 5.6 | Proposed NO <sub>x</sub> Controls and Emissions Rates                     | 16 |
| 6 |     | SO <sub>2</sub> Four-factor Analysis                                      | 17 |
|   | 6.1 | SO <sub>2</sub> Control Measures Overview                                 | 17 |
|   | 6.2 | Factor 1 – Cost of Compliance   | 17 |
|   | 6.3 | Factor 2 – Time Necessary for Compliance                                  | 18 |
|   | 6.4 | Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance | 19 |
|   | 6.5 | Factor 4 – Remaining Useful Life of the Source                            | 19 |
|   | 6.6 | Proposed SO <sub>2</sub> Controls and Emissions Rates                     | 19 |

### List of Tables

| Table 1-1 Summary of NO <sub>X</sub> Four-Factor Analysis1   |
|--|
| Table 1-2 Summary of SO <sub>2</sub> Four-factor Analysis1   |
| Table 2-1 Identified Emission Units1   |
| Table 3-1 THEC Boiler No. 1 (EQUI 64 / EU 001) Historical Fuel Usage   |
| Table 3-2 THEC Boiler No. 2 (EQUI 5 / EU 002) Historical Fuel Usage  |
| Table 3-3 Baseline Emissions for THEC Boiler No. 1 (EQUI 64 / EU 001) and No. 2 (EQUI 5 / EU 002)6                   |
| Table 4-1 Coal-Fired Utility Boilers RBLC Summary – NO <sub>x</sub> 9  |
| Table 4-2 Coal-Fired Utility Boilers RBLC Summary – SO2 10   |
| Table 5-1 Additional NO <sub>X</sub> Control Measures with Potential Application to THEC Boilers No. 1 and 2 14      |
| Table 5-2 Potential NO <sub>X</sub> Emission Reductions for THEC Boiler No. 1 (EQUI 64 / EU 001) and No. 2 (EQUI 5 / |
| EU 002)  |
| Table 5-3 NO <sub>X</sub> Control Cost Summary, per Unit Basis15   |
| Table 6-1 Additional SO <sub>2</sub> Control Measures with Potential Application to THEC Boilers No. 1 and 2         |
| Table 6-2 Potential SO <sub>2</sub> Emission Reductions for THEC Boiler No. 1 (EQUI 64 / EU 001) and No. 2 (EQUI 5 / |
| EU 002)  |
| Table 6-3 SO <sub>2</sub> Control Cost Summary, per Unit Basis   |

### List of Appendices

Appendix A: RACT/BACT/LAER Clearinghouse (RBLC) Review Summary

Appendix A.1:RBLC Search for Coal-Fired Utility Boilers for NOxAppendix A.2:RBLC Search for Coal-Fired Utility Boilers for SO2

### Appendix B: Unit Specific Screening Level Cost Summary for NO<sub>X</sub> Control Measures

Appendix C: Unit Specific Screening Level Cost Summary for SO<sub>2</sub> Control Measures

### Abbreviations

| BART            | best available retrofit technology   |
|-----------------|--|
| BWCA            | Boundary Waters Canoe Area   |
| CEDR            | Consolidated Emissions Data Repository   |
| CFB             | circulating fluidized bed  |
| EPA             | U.S. Environmental Protection Agency   |
| FGR             | flue gas desulfurization   |
| IMPROVE         | Interagency Monitoring of Protected Visual Environments                            |
| Isle Royale     | Isle Royale National Park  |
| LADCO           | Lake Michigan Air Directors Consortium   |
| lb              | pound  |
| LNB             | low-NO <sub>X</sub> Burners  |
| MISO            | Midwest Independent System Operator  |
| MP              | Minnesota Power  |
| MPCA            | Minnesota Pollution Control Agency   |
| MMBtu/hr        | Million British Thermal Units (BTU)/hour   |
| MW              | megawatt   |
| NO              | nitric oxide   |
| NOx             | nitrogen oxides  |
| O&M             | operating and maintenance  |
| OFA             | over-fire air  |
| PUC             | Public Utilities Commission  |
| RBLC            | RACT/BACT/LAER Clearinghouse   |
| RFI             | Request for Information letter from Hassan Bouchareb of MPCA to Melissa Weglarz of |
|                 | Minnesota Power dated January 29, 2020   |
| RHR             | Regional Haze Rule   |
| ROTA-MIX        | rotating over-fire air and SNCR  |
| SCR             | selective catalytic reduction  |
| SNCR            | selective non-catalytic reduction  |
| SIP             | State Implementation Plan  |
| SO <sub>2</sub> | sulfur dioxide   |
| THEC            | Taconite Harbor Energy Center  |
| tpy             | tons per year  |
| Voyageurs       | Voyageurs National Park  |

# **1 Executive Summary**

In accordance with Minnesota Pollution Control Agency's (MPCA's) January 29, 2020 Request for Information (RFI) Letter<sup>1</sup>, Minnesota Power's (MP's) Taconite Harbor Energy Center (THEC) evaluated potential emissions reduction measures for sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>X</sub>) for Boiler No. 1 (EQUI 64 / EU 001) and Boiler No. 2 (EQUI 5 / EU 002) as part of the preparation of the State Implementation Plan (SIP) for the Regional Haze Rule (RHR)<sup>2</sup>. The analysis considers potential emissions reduction measures by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i) and pursuant to the final U.S. Environmental Protection Agency (EPA) RHR SIP guidance<sup>3</sup> (2019 RH SIP Guidance):

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

This report presents the four-factor analysis for  $NO_X$  and  $SO_2$  emissions controls for the boilers at THEC. The four-factor analysis conclusions are summarized in Table 1-1 and Table 1-2 for  $NO_X$  and  $SO_2$ , respectively.

The NO<sub>X</sub> four-factor analysis evaluated the following NO<sub>X</sub> emissions reduction measures:

- Low-NO<sub>X</sub> burners (coal tip replacement)
- Enhancements to existing selective non-catalytic reduction (SNCR) system

In the Factor 1 – Cost of Compliance analysis, no additional controls were identified to be cost effective (refer to Section 5.2 for more information). Therefore, the facility's existing NO<sub>X</sub> emission performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

The SO<sub>2</sub> four-factor analysis evaluated the following SO<sub>2</sub> emissions reduction measures:

• Enhancements to the existing lime injection system

In the Factor 1 – Cost of Compliance analysis, no additional controls were identified to be cost effective (refer to Section 6.2 for more information). Therefore, the facility's existing SO<sub>2</sub> emission performance

<sup>&</sup>lt;sup>1</sup> January 29, 2020 letter from Hassan Bouchareb of MPCA to Melissa Weglarz of Minnesota Power.

<sup>&</sup>lt;sup>2</sup> The U.S. Environmental Protection Agency (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>&</sup>lt;sup>3</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

(refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

### Table 1-1 Summary of NO<sub>x</sub> Four-Factor Analysis

| List of Emission<br>Reduction<br>Technology              | Factor 1 – Cost<br>of Compliance<br>(\$/ton) | Factor 2 – Time<br>Necessary for<br>Compliance | Factor 3 - Energy and<br>Non-Air Quality<br>Environmental Impacts of<br>Compliance                           | Factor 4 –<br>Remaining Useful<br>Life of the Source | Factor 5 –<br>Visibility<br>Improvements | Does this Analysis<br>Support the<br>Installation of this<br>Emission Reduction<br>Technology? |
|--|--|--|--|--|--|--|
| Low NO <sub>X</sub> Burners<br>(Coal Tip<br>Replacement) | \$19,010/ton<br>NO <sub>X</sub> controlled   | 2 to 3 years                                   | None expected  | Conservatively<br>Excluded from<br>Analysis          | Not Evaluated                            | No   |
| ROFA/SNCR<br>System<br>Enhancements                      | \$9,530/ton NO <sub>X</sub><br>controlled    | 2 to 3 years                                   | Minimal concern related to<br>construction activities and<br>additional truck traffic for<br>SNCR deliveries | Conservatively<br>Excluded from<br>Analysis          | Not Evaluated                            | No   |

### Table 1-2 Summary of SO<sub>2</sub> Four-factor Analysis

| List of Emission<br>Reduction<br>Technology | Factor 1 – Cost<br>of Compliance<br>(\$/ton) | Factor 2 – Time<br>Necessary for<br>Compliance | Factor 3 - Energy and<br>Non-Air Quality<br>Environmental Impacts of<br>Compliance                      | Factor 4 –<br>Remaining Useful<br>Life of the Source | Factor 5 –<br>Visibility<br>Improvements | Does this Analysis<br>Support the<br>Installation of this<br>Emission Reduction<br>Technology? |
|---|--|--|---|--|--|--|
| Lime Injection<br>System<br>Enhancements    | \$18,780/ton SO <sub>2</sub><br>controlled   | 2 years  | Minimal concern related to<br>construction activities and<br>potential increases in ash<br>for disposal | Conservatively<br>Excluded from<br>Analysis          | Not Evaluated                            | No   |

# 2 Introduction

This section discusses the pertinent regulatory background information, and a description of THEC's boilers.

### 2.1 Four-factor Analysis Regulatory Background

The RHR published on July 15, 2005 by the 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 SIPs in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. The initial 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 initial 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 SIPs by July 31, 2021.

On January 29, 2020, the MPCA sent an RFI to THEC. The RFI stated that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) 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 SO<sub>2</sub> and NO<sub>x</sub>. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze in Isle Royale, Michigan must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts. As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFI also stated that THEC was identified as a significant source of  $NO_X$  and  $SO_2$  located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that THEC submit a "four-factor analysis" by July 31, 2020 for the emission units identified in Table 2-1 to support development of the SIP.

| Unit         | Unit ID          | Applicable Pollutants             |  |  |
|--------------|------------------|-----------------------------------|--|--|
| Boiler No. 1 | EQUI 64 / EU 001 | NO <sub>X</sub> , SO <sub>2</sub> |  |  |
| Boiler No. 2 | EQUI 5 / EU 002  | NO <sub>X</sub> , SO <sub>2</sub> |  |  |

#### Table 2-1 Identified Emission Units

The analysis considers potential emissions reduction measures by addressing the four statutory factors which are laid out in 40 CFR 51.308(f)(2)(i):

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

The RFI letter to THEC specified that the "... analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to the final 2019 RH SIP Guidance<sup>4</sup>.

This report describes the background and required procedure for conducting a four-factor analysis for  $NO_X$  and  $SO_2$  as applied to the review of potential emissions controls at THEC for the units identified in Table 2-1.

### 2.2 Facility Description

THEC is a coal-fired steam electric utility generating plant consisting of three identical tangentially-fired coal-burning units located at 8124 West Highway 61 in Schroeder, Cook County, Minnesota on the north shore of Lake Superior. Boilers No. 1 and No. 2 are permitted to burn bituminous and subbituminous coal, as well as distillate fuel oil, which is used primarily for startup. Boiler No. 3 was shut down June 1, 2015 and is no longer permitted to operate. Boilers No. 1 and No. 2 have been idled since 2016, but are permitted to operate (see Title V Operating Permit No. 03100001-009) and MP continues to maintain the facility such that it could begin operation at any time. Boilers No. 1 and No. 2 are both rated to a maximum heat input rate of 900 MMBtu/hr, with net generating capacities of 79 MW and 76 MW, respectively.

When in operation, the facility uses western subbituminous coal which is received by boat and stored in an outdoor storage pile. Ash is pneumatically conveyed to and collected in a storage bin, then wetted to reduce fugitive emissions and disposed of at a landfill. Natural gas is not available at the site. Non-contact cooling water used to supply the boiler steam condensers is drawn from Lake Superior. The facility also includes a taconite ore loading dock that is owned and operated by the co-permittee, Cliffs-Erie LLC.

<sup>&</sup>lt;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.

# **3 Existing Controls and Baseline Emission Rates**

This section describes the existing  $NO_X$  and  $SO_2$  emissions controls, and the baseline emissions rates which were used to evaluate the cost effectiveness for the associated emission reduction technologies.

### 3.1 Existing Emission Controls

Boilers No. 1 and No. 2 are each equipped with identical emission controls. For NO<sub>X</sub> control, the boilers are equipped with SNCR with urea injection and over fire air (OFA) (TREA 22, TREA 5). These controls achieve a combined NO<sub>X</sub> control efficiency of about 62% and typical emission rate of approximately 0.125 Ib NO<sub>X</sub>/MMBtu<sup>5</sup>. The permitted limit for both boilers is 0.160 lb NO<sub>X</sub>/MMBtu on a 30-day rolling average basis. For SO<sub>2</sub> control, the boilers are equipped with Hydrated Lime Injection (TREA 23, TREA 6), and Sodium Bicarbonate Injection (TREA 28, TREA 27). These controls achieve a SO<sub>2</sub> control efficiency of about 65% and typical emission rate of 0.28 lb SO<sub>2</sub>/MMBtu<sup>6</sup>. The permitted limit for both boilers is 0.30 lb SO<sub>2</sub>/MMBtu on a 30-day rolling average basis.

### 3.2 Baseline Emissions Performance

The four-factor analysis requires the establishment of a baseline scenario for evaluating a potential emission reduction technology. The 2019 RH SIP Guidance considers the projected 2028 emissions scenario as a "reasonable and convenient choice" for the baseline control scenario<sup>7</sup> (emphasis added):

"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

<sup>&</sup>lt;sup>5</sup> The 62% NO<sub>X</sub> control efficiency for TREA 22 and TREA 5 noted here is the control efficiency specified for the control equipment in form GI-05A included in the Title V Operating Permit renewal application for THEC submitted in 2016. The quoted 0.125 lb NO<sub>X</sub>/MMBtu emission rate is the annual average emission rate observed at Boilers No. 1 and 2 in calendar years 2015 and 2016.

<sup>&</sup>lt;sup>6</sup> The 65% SO<sub>2</sub> control efficiency for TREA 28 and TREA 27 noted here is the control efficiency specified for the control equipment in form GI-05A included in the Title V Operating Permit renewal application for THEC submitted in 2016. The quoted 0.28 lb SO<sub>2</sub>/MMBtu emission rate is the annual average emission rate observed at Boilers No. 1 and 2 in calendar year 2016.

<sup>&</sup>lt;sup>7</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, Page 29.

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."

THEC Boilers No. 1 and No. 2 have been idled since 2016. Despite their current idled status, THEC Boilers No. 1 and No. 2 are still permitted to operate, and as such MP has completed this four-factor analysis using conservative assumptions of future operation and remaining equipment life in the event that the units are restarted. MP has maintained a modest fuel supply onsite to allow the units to be restarted to provide reliability to the electric system or address system emergencies. MP has also offered THEC Boilers No. 1 and No. 2 into the Midwest Independent System Operator's (MISO's) capacity auction each year since the units were idled. THEC has not been selected into MISO's annual capacity auction to-date. MP continues to maintain the facility such that it could begin operation at any time, but there are currently no plans to restart the units.

For both the NO<sub>X</sub> and SO<sub>2</sub> baseline emissions, MP conservatively assumed that the operation of THEC Boilers No. 1 and No. 2 prior to their idling in late 2016 would be representative of their operation in 2028. Table 3-1 and Table 3-2 below shows the annual fuel usage for calendar years 2011 through 2015 for THEC Boilers No. 1 and No. 2, respectively. This represents the five most recent full calendar years of operation for the boilers. The values presented in this table were sourced directly from the Annual Emission Inventory Reports submitted to the MPCA via the Consolidated Emissions Data Repository (CEDR) for the calendar years specified.

| Parameter                          | 2011      | 2012      | 2013      | 2014      | 2015      |
|------------------------------------|-----------|-----------|-----------|-----------|-----------|
| Coal Fired<br>(short ton/year)     | 253,593   | 224,487   | 180,741   | 256,023   | 268,677   |
| Fuel Oil Fired<br>(1,000 gal/year) | 30.9      | 31.5      | 55.2      | 19.5      | 34.6      |
| Total Heat Input<br>(MMBtu/year)   | 4,575,772 | 4,054,231 | 3,276,941 | 4,616,605 | 4,830,987 |

Table 3-1 THEC Boiler No. 1 (EQUI 64 / EU 001) Historical Fuel Usage

### Table 3-2 THEC Boiler No. 2 (EQUI 5 / EU 002) Historical Fuel Usage

| Parameter                          | 2011      | 2012      | 2013      | 2014      | 2015      |
|------------------------------------|-----------|-----------|-----------|-----------|-----------|
| Coal Fired<br>(short ton/year)     | 206,840   | 102,755   | 220,489   | 208,881   | 262,050   |
| Fuel Oil Fired<br>(1,000 gal/year) | 48.7      | 37.2      | 39.1      | 51.1      | 23.6      |
| Total Heat Input<br>(MMBtu/year)   | 3,736,786 | 1,855,899 | 3,989,114 | 3,764,819 | 4,704,992 |

Based on these historic operating rates and emission rates, MP conservatively assumed that the highest total heat input observed for each boiler in this five year period, rounded up to the nearest 50,000 MMBtu would be representative of their 2028 operation. This is 4,850,000 MMBtu/year for Boiler No. 1 and 4,750,000 MMBtu/year for Boiler No. 2. To simplify the evaluations in this document, MP conservatively assumed that both boilers would operate at the higher of these two values, 4,850,000 MMBtu/year.

For the 2028 NO<sub>X</sub> and SO<sub>2</sub> emission rates, the permitted limits for both Boilers No. 1 and 2 are 0.160 lb NO<sub>X</sub>/MMBtu and 0.30 lb SO<sub>2</sub>/MMBtu<sup>8</sup>. These limits only became effective relatively recently<sup>9,10</sup> and as such there is a limited record of operation of the boilers with the limits in place. MP operators and engineers observed a typical emission rate of at 0.125 lb NO<sub>X</sub>/MMBtu<sup>11</sup> and 0.28 lb SO<sub>2</sub>/MMBtu<sup>12</sup> for both Boilers

<sup>&</sup>lt;sup>8</sup> Both the NO<sub>X</sub> and SO<sub>2</sub> limits apply to each boiler individually are on a 30-day rolling average basis and were established by Consent Decree (CASE 0:14-cv-02911-ADM-LIB Document 3-1).

<sup>&</sup>lt;sup>9</sup> The 0.16 lb NO<sub>X</sub>/MMBtu limit became effective on the "Date of Entry of the Consent Decree", which is July 16, 2014, as noted within Consent Decree (CASE 0:14-cv-02911-ADM-LIB Document 3-1) Paragraph 84.

<sup>&</sup>lt;sup>10</sup> The 0.30 lb SO2/MMBtu limit became effective on December 31, 2015 as noted within Consent Decree (CASE 0:14-cv-02911-ADM-LIB Document 3-1) Paragraphs 104 and 105.

<sup>&</sup>lt;sup>11</sup> The quoted 0.125 lb NO<sub>X</sub>/MMBtu emission rate is the annual average emission rate observed at Boilers No. 1 and 2 in calendar years 2015 and 2016, the calendar years of operation after the 0.16 lb NO<sub>X</sub>/MMBtu limit became effective.

<sup>&</sup>lt;sup>12</sup> The quoted 0.28 lb SO<sub>2</sub>/MMBtu emission rate is the annual average emission rate observed at Boilers No. 1 and 2 in calendar year 2016, the calendar year of operation after the 0.30 lb SO<sub>2</sub>/MMBtu limit became effective.

No. 1 and 2 after the limits became effective. These estimates were used for the 2028 projected emission rates.

Combining the 2028 projected total heat input with the expected emission rates from the boilers establishes the conservatively projected baseline emissions to be the values shown in Table 3-3 below.

| Emission Unit   | NO <sub>x</sub> (ton/year) | SO <sub>2</sub> (ton/year) |  |  |  |  |  |
|---|----------------------------|----------------------------|--|--|--|--|--|
| Boiler No. 1<br>(EQUI 64 / EU 001)  | 303 <sup>[1]</sup>         | 679 <sup>[2]</sup>         |  |  |  |  |  |
| Boiler No. 2<br>(EQUI 5 / EU 002)   | 303 <sup>[1]</sup>         | 679 <sup>[2]</sup>         |  |  |  |  |  |
| $[1] 303 \frac{ton NO_X}{year} = 4,850,000 \frac{MMBtu}{yr} \times 0.125 \frac{lb NO_X}{MMBtu} \times \frac{ton}{2,000  lb}$ $[2] 679 \frac{ton NO_X}{year} = 4,850,000 \frac{MMBtu}{yr} \times 0.280 \frac{lb SO_2}{MMBtu} \times \frac{ton}{2,000  lb}$ |                            |                            |  |  |  |  |  |

Table 3-3 Baseline Emissions for THEC Boiler No. 1 (EQUI 64 / EU 001) and No. 2 (EQUI 5 / EU 002)

# **4** Four-factor Analysis Overview

This section summarizes the four-factor analysis approach with respect to the Regional Haze program detailed in the 2019 RH SIP guidance.

### 4.1 Emission Control Options

EPA states that the "first step in characterizing control measures for a source is the identification of technically feasible control measures" but recognized that "there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures."<sup>13</sup> However, a "state must reasonably pick and justify the measures that is will consider."<sup>14</sup> The EPA provides the following examples of the types of emission control measures states may consider<sup>15</sup>:

- Emission reductions through improved work practices
- Retrofits for sources with no existing controls
- Upgrades or replacements for existing, less effective controls
- Year-round operation of existing controls
- Fuel mix with inherently lower SO<sub>2</sub>, NO<sub>x</sub>, and/or PM<sup>16</sup> emissions. States may also determine that it is unreasonable to consider some fuel-use changes because they would be too fundamental to the operation and design of a source.
- Operating restrictions on hours, fuel input, or product output to reduce emissions.
- Energy efficiency and renewable energy measures that could be applied elsewhere in a state to reduce emissions from EGUs.
- Basic smoke management practices and smoke management programs for agricultural or wildland prescribed fires.

Not all of these potential control measures are applicable to THEC. MP focused this evaluation on potential upgrades to or replacement of the existing control equipment. The following methodology was used to select a reasonable set of emission control technologies that were considered in the four-factor analysis:

<sup>&</sup>lt;sup>13</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 28-29.

<sup>&</sup>lt;sup>14</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 29.

<sup>&</sup>lt;sup>15</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 29-30.

<sup>&</sup>lt;sup>16</sup> Please note that PM emissions were not included in the RFI as potentially impacting visibility and thus are not included in this evaluation.

- 1. Search the RBLC<sup>17</sup> for available control technologies with the following search criteria:
  - Similar emission unit type (utility boilers larger than 250 MMBtu/hr)
  - Similar fuel (coal)
  - 10-year look back
- 2. Eliminate technologies that would not would not apply to the specific emission unit under consideration
- 3. Advance the remaining technologies for consideration in the four-factor analysis

MP also considered a fuel-mix change to utilize natural gas instead of or in addition to coal combustion.

### 4.1.1 NO<sub>X</sub> Control Options

The RBLC search for coal-fired utility boilers for NO<sub>X</sub> is presented in Appendix A.1. Most RBLC entries specify that multiple control technologies have been implemented at each facility. To avoid confusion, MP has summarized the individual control technologies noted in the RBLC into Table 4-1 below along with example RBLC IDs where the technology was implemented and the applicability to THEC. MP has also included one potential control option (fuel conversion to natural gas) that was not specified in the RBLC, but is another control measures that can be considered as noted in section 4.1.

<sup>&</sup>lt;sup>17</sup> RACT/BACT/LAER Clearinghouse (RBLC) as maintained by USEPA (link to RBLC website)

| Technology   | Example RBLC IDs   | Applicable to<br>THEC? |  |  |  |  |  |
|--|--------------------|------------------------|--|--|--|--|--|
| Low-NO <sub>X</sub> Burners (LNB)  | AZ-0055            | Yes                    |  |  |  |  |  |
|  | OK-0151            |                        |  |  |  |  |  |
|  | TX-0554            |                        |  |  |  |  |  |
| Over-Fire Air  | AZ-0055            | Yes <sup>[1]</sup>     |  |  |  |  |  |
| Includes Separated Over-Fire Air (SOFA) and Rotating                                       | OK-0151            |                        |  |  |  |  |  |
| Over-Fire Air (ROFA)   | TX-0554            |                        |  |  |  |  |  |
| Selective Non-Catalytic Reduction (SNCR)   | CA-1206            | Yes <sup>[1]</sup>     |  |  |  |  |  |
|  | MI-0400            |                        |  |  |  |  |  |
|  | TX-0577            |                        |  |  |  |  |  |
| Selective Catalytic Reduction (SCR)  | MI-0399            | No <sup>[2]</sup>      |  |  |  |  |  |
|  | TX-0554            |                        |  |  |  |  |  |
|  | TX-0585            |                        |  |  |  |  |  |
| Low Bed Temperatures   | CA-1206            | No <sup>[3]</sup>      |  |  |  |  |  |
| Convert Boilers to Use Natural Gas as Fuel   | N/A <sup>[4]</sup> | No <sup>[5]</sup>      |  |  |  |  |  |
| Table Footnotes  |                    |                        |  |  |  |  |  |
| [1] THEC Boilers No. 1 and No. 2 are both equipped with SNCR and ROFA (TREA 22 and TREA 5, |                    |                        |  |  |  |  |  |

### Table 4-1 Coal-Fired Utility Boilers RBLC Summary – NO<sub>X</sub>

[1] THEC Boilers No. 1 and No. 2 are both equipped with SNCR and ROFA (TREA 22 and TREA 5, respectively). Installation of other types of over-fire air systems would interfere with the existing ROFA systems and require significant alterations to the boiler, and thus are impractical to evaluate.

[2] SCR is considered not applicable primarily due to space limitations at THEC. Additionally, the relatively small size of the boilers and ductwork are likely to make achieving the required flue gas temperatures for SCR to work properly a challenge.

[3] Low bed temperatures are a control technology for circulating fluidized bed (CFB) boilers. THEC Boilers No. 1 and No. 2 are both tangentially-fired boilers.

[4] There are no RBLC entries which specify a fuel switch to natural gas as a control technology. However, it is included as changes to a facility's fuel mix are included in the types of potential control options under consideration for regional haze. See Section 4.1 for details.

[5] There is currently no access to natural gas at THEC. The nearest natural gas pipeline terminates in Silver Bay, MN.

Based on this information, the reasonable set of control technologies considered in this four-factor analysis are:

- Low-NO<sub>X</sub> Burners (LNB, achieved via coal tip replacement)
- Enhancements to the existing ROFA and SNCR systems

### 4.1.2 SO2 Control Options

The RBLC search for coal-fired utility boilers for SO<sub>2</sub> is presented in Appendix A.2. Most RBLC entries specify that multiple control technologies have been implemented at each facility. To avoid confusion, MP has summarized the individual control technologies noted in the RBLC into Table 4-2 below along with example RBLC IDs where the technology was implemented and the technology's applicability to THEC. MP

has also included one potential control option (fuel conversion to natural gas) that was not specified in the RBLC, but is another control measures that can be considered as noted in section 4.1.

| Technology  | Example RBLC IDs   | Applicable to THEC? |
|---|--------------------|---------------------|
| Reagent (Lime, Limestone, Sodium Bicarbonate) Injection | CA-1206            | Yes <sup>[1]</sup>  |
|   | KY-0100            |                     |
| Spray Dryer   | MI-0400            | No <sup>[2]</sup>   |
|   | TX-0554            |                     |
| Wet Lime Scrubbing (Wet Flue-Gas Desulfurization, FGD)  | MI-0399            | No <sup>[3]</sup>   |
|   | TX-0585            |                     |
| Convert Boilers to Use Natural Gas as Fuel              | N/A <sup>[4]</sup> | No <sup>[5]</sup>   |

#### Table 4-2 Coal-Fired Utility Boilers RBLC Summary – SO2

#### **Table Footnotes**

[1] THEC Boilers No. 1 and No. 2 are both equipped with Hydrated Lime Injection (TREA 23 and TREA 6, respectively) and Sodium Bicarbonate Injection (TREA 28 and TREA 27, respectively).

[2] Space limitations at THEC make the installation of a spray dryer, storage of wastes generated by spray dryer, and waste loading materials, infeasible.

[3] The Coal Combustion Residuals (CCR) Rule (40 CFR 257 Subpart D) requires dewatering of wet FGD slurry before disposal, or significant design, operation, and closure requirements for drying ponds. Space limitations at THEC make the installation of a scrubber, and dewatering equipment or drying ponds infeasible.

[4] There are no RBLC entries which specify a fuel switch to natural gas as a control technology. However, it is included for completeness as changes to a facility's fuel mix are included in the types of potential control options under consideration for regional haze. See Section 4.1 for details.

[5] There is currently no access to natural gas at THEC. The nearest natural gas pipeline terminates in Silver Bay, MN.

Based on this information, Reagent Injection is the only applicable control option for THEC. Since the facility already operates Hydrated Lime Injection and Sodium Bicarbonate Injection systems, enhancement of the existing injection systems is the only applicable control technology considered in this four-factor analysis.

### 4.2 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>18</sup> unless more refined site-specific estimate are available. Under this

<sup>&</sup>lt;sup>18</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 <u>https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution</u> as of the date of this report.

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."

Generally, if the average cost effectiveness is greater than a threshold, the cost is considered to not be reasonable, pending an evaluation of other factors. Conversely, if the average cost effectiveness is less than a 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 an intermediate or high degree of effectiveness, as is the case for the THEC Boilers No. 1 and No. 2 due to their existing NO<sub>X</sub> and SO<sub>2</sub> emissions controls.

The cost of an emissions control measure is derived using capital and annual 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 3.2, 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, THEC compared the estimated annual emission reductions for each control measure relative to the baseline emissions as presented in Table 3-3.

### 4.3 Factor 2 – Time Necessary for Compliance

Factor #2 is considered by MPCA in setting reasonable deadlines for the selected control. This includes the planning, installation, and commissioning of the selected control, as well as environmental permitting and associated review.

# 4.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

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.

### 4.5 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" (meaning, the emission unit) 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 for Boilers No. 1 and No. 2 are conservatively assumed to be longer than the useful life of the additional emission controls measures. Therefore, the expected useful life of the *control measure itself, not the emission unit,* is used to calculate the emissions reductions, amortized costs, and the resulting cost per ton removed.

# **5** NO<sub>X</sub> Four-factor Analysis

This section identifies and describes various  $NO_X$  emission reduction technologies, evaluates the four statutory factors for THEC Boilers No. 1 and No. 2, and proposes a  $NO_X$  emission limit for the selected emission reduction technology. Consistent with EPA's guidance and MPCA direction, THEC has completed a four-factor analysis for  $NO_X$  as summarized in Sections 5.1 to 5.5.

### 5.1 NO<sub>X</sub> Control Measures Overview

There are three mechanisms by which  $NO_X$  production occurs in boilers. They are fuel, thermal, and prompt  $NO_X$  formation.

Fuel bound NO<sub>X</sub> is primarily a concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. Bituminous and subbituminous coal, the type combusted in THEC Boilers No. 1 and No. 2, naturally contains 0.5 to 2 weight percent nitrogen and can account for up to 80 percent of the total NO<sub>X</sub> emissions from coal combustion<sup>19</sup>.

 $NO_X$  is also generated in the combustion process through thermal  $NO_X$  formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air to nitric oxide (NO). The thermal oxidation reaction is as follows:

 $N_2 + O_2 \rightarrow 2NO \tag{1}$ 

Downstream of the flame, significant amounts of  $NO_2$  can be formed when NO is mixed with air. The reaction is as follows:

$$2NO + O_2 \rightarrow 2NO_2 \tag{2}$$

Thermal NO<sub>X</sub> formation is a function of the residence time, free oxygen, and peak reaction temperature.

Prompt NO<sub>X</sub> is a form of thermal NO<sub>X</sub> which is generated at the flame boundary. It is the result of reactions between nitrogen and hydrocarbon radicals generated during combustion. Only a small fraction of NO<sub>X</sub> emissions from combustion sources are from prompt NO<sub>X</sub> formation.

Theoretically, several techniques can be used to reduce  $NO_X$  emissions from tangentially-fired coal-fueled utility boilers, as listed in Table 4-1. Table 5-1 lists the control technologies identified as the applicable set of control technologies in Section 4.1.1 and are further evaluated in this section.

<sup>&</sup>lt;sup>19</sup> Section 1.1.3.3 of AP-42, Fifth Edition, Chapter 1.1 - *Bituminous and Subbituminous Coal Combustion*, September 1998.

Table 5-1 Additional NO<sub>x</sub> Control Measures with Potential Application to THEC Boilers No. 1 and 2

| Control Technology   |  |  |  |  |
|--|--|--|--|--|
| Low-NO <sub>X</sub> Burners (LNB, achieved via coal tip replacement) |  |  |  |  |
| Enhancements to the existing ROFA and SNCR systems                   |  |  |  |  |

MP estimates that replacement of the coal tip (LNB) would result in a typical emission rate of 0.12 lb NO<sub>x</sub>/MMBtu, and that the enhancements to the existing SNCR and ROFA systems would result in a typical emission rate of 0.11 to 0.12 lb NO<sub>x</sub>/MMBtu. For the purposes of this evaluation, MP has conservatively assumed that these enhancements would achieve the lower estimate of 0.11 lb NO<sub>x</sub>/MMBtu. Combining these emission rates with the projected 2028 operating rates and baseline emission rates determined in Section 3.2 of this document results in the projected emissions reduction estimates for each boiler shown in Table 5-2.

Table 5-2 Potential NO<sub>x</sub> Emission Reductions for THEC Boiler No. 1 (EQUI 64 / EU 001) and No. 2 (EQUI 5 / EU 002)

| Emission Unit   | Baseline<br>NO <sub>X</sub><br>(ton/year) <sup>[1]</sup> | NO <sub>X</sub><br>Emissions<br>with LNB<br>(ton/year) | Emissions<br>Reduction<br>from LNB<br>(ton/year) | NO <sub>X</sub> Emissions with<br>SNCR/ROFA<br>Enhancements<br>(ton/year) | Emissions Reduction<br>from SNCR/ ROFA<br>Enhancements<br>(ton/year) |  |  |  |  |
|---|--|--|--|---|--|--|--|--|--|
| Boiler No. 1<br>(EQUI 64 / EU 001)  | 303  | 291 <sup>[2]</sup>                                     | 12 <sup>[3]</sup>                                | 267 <sup>[4]</sup>  | 36 <sup>[3]</sup>  |  |  |  |  |
| Boiler No. 2<br>(EQUI 5 / EU 002)   | 303  | 291 <sup>[2]</sup>                                     | 12 <sup>[3]</sup>                                | 267 <sup>[4]</sup>  | 36 <sup>[3]</sup>  |  |  |  |  |
| [1] See Table 3-3<br>[2] 291 $\frac{ton NO_x}{year} = 4,850,000 \frac{MMBtu}{yr} \times 0.120 \frac{lb NO_x}{MMBtu} \times \frac{ton}{2,000  lb}$<br>[3] Difference between baseline emissions and emissions estimate with control equipment added.<br>[4] 267 $\frac{ton NO_x}{year} = 4,850,000 \frac{MMBtu}{yr} \times 0.110 \frac{lb NO_x}{MMBtu} \times \frac{ton}{2,000  lb}$ |  |  |  |   |  |  |  |  |  |

### 5.2 Factor 1 – Cost of Compliance

MP has completed a screening-level cost estimate for the selected NO<sub>X</sub> emission control measures for each boiler. As noted in section 4.2, these control cost estimates were developed in accordance with the EPA Control Cost Manual. The capital cost estimates are considered by MP's engineering staff to be conservatively low, based on their considerable experience with projects at THEC and informal conversations with other companies that have completed similar types of projects at other facilities. A more detailed cost estimate is likely to increase the estimated costs for installing and implementing either of these technologies. Cost summary spreadsheets for the NO<sub>X</sub> emission control measures are provided in Appendix B.

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) is used for the SNCR and ROFA enhancements, and a 10-year life is used for the coal tip replacement (LNB). A 3.25% interest is assumed in annualizing capital costs<sup>20</sup>.

The resulting cost effectiveness calculations are summarized in Table 5-3. Please note that THEC Boilers No. 1 and No. 2 have identical estimated emission reductions and costs estimated for each control technology in Table 5-2. As such, the values presented in Table 5-3 are representative of both boilers.

| Additional<br>Emissions Control<br>Measure                    | Installed<br>Capital Cost<br>(\$) | Annualized<br>Capital Cost<br>(\$/yr) | Annual<br>Operating<br>Costs (\$/yr) | Total<br>Annualized<br>Costs (\$/yr) | Annual<br>Emissions<br>Reduction<br>(tpy) | Pollution<br>Control Cost<br>Effectiveness<br>(\$/ton) |
|---|-----------------------------------|---------------------------------------|--------------------------------------|--------------------------------------|---|--|
| Low-NO <sub>X</sub> Burners<br>(LNB, Coal Tip<br>Replacement) | \$609,375                         | \$72,352                              | \$155,775                            | \$228,127                            | 12  | \$19,010   |
| Enhancements to<br>the existing ROFA<br>and SNCR systems      | \$1,218,750                       | \$83,824                              | \$259,221                            | \$343,045                            | 36  | \$9,530  |

Table 5-3 NO<sub>X</sub> Control Cost Summary, per Unit Basis

MP has determined that neither of these control technologies are cost effective based on a consideration of RHR analyses conducted in other states. Sections 5.3 through 5.5 provide a screening-level summary of the remaining three factors evaluated for the NO<sub>X</sub> emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

### 5.3 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the 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.

The technologies would require significant resources and time of at least two to three years to engineer, permit, and install the equipment. Currently both THEC Boilers No. 1 and No. 2 are idled. It is unknown at this time if these units will be restarted, retrofitted, refueled, or retired. Any substantial investments in THEC Boilers No. 1 and No. 2 would likely require approval from the Public Utilities Commission (PUC) and, if the unit is retrofitted or refueled, would require MPCA permitting.

<sup>&</sup>lt;sup>20</sup> Bank Prime Rate for July 16, 2020 from https://www.federalreserve.gov/releases/h15/.

# 5.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

As stated previously, THEC Boilers No. 1 and No. 2 were idled in 2016 and have not operated since then. MP has maintained a modest fuel supply onsite to allow the units to be restarted to provide reliability to the electric system or address system emergencies. MP has also offered THEC Boilers No. 1 and No. 2 into MISO's capacity auction each year since the units were idled. THEC has not been selected into MISO's annual capacity auction to-date. MP currently plans to continue maintaining the facility such that it could begin operation at any time, but there are currently no plans to restart the units. Any substantial investments in THEC Boilers No. 1 and No. 2 would likely require approval from the Public Utilities Commission (PUC) and, if the unit is retrofitted or refueled, would require MPCA permitting.

Replacing the coal tip (LNB) represents a fairly simple change to the design of the existing burners and does not present any anticipated energy or non-air quality environmental impacts.

Enhancing the existing ROFA and SNCR systems will result in an increase in construction activities that could increase water run-off into Lake Superior. However, this would only be during the construction phase of the project, the construction activities would be permitted, and the appropriate mitigation techniques would be implemented as-needed. The increase in SNCR reagent usage will also require a small increase in truck traffic from deliveries, thus increasing fugitive particulate matter emissions.

### 5.5 Factor 4 – Remaining Useful Life of the Source

MP's August 22, 2019 *Remaining Life Depreciation Petition*<sup>21</sup> states that the THEC Boilers No. 1 and No. 2 end of useful life is December 31, 2026. This date is primarily used for ratemaking purposes and should not be construed as a retirement commitment date for the boilers. For maximum conservatism in this analysis, the useful life of the individual control measures, not the emission units, is used to calculate emission reductions, amortized costs and cost effectiveness on a dollar per ton basis.

### 5.6 Proposed NO<sub>X</sub> Controls and Emissions Rates

This analysis does not support the installation of additional NO<sub>X</sub> emissions measures at THEC Boilers No. 1 and No. 2 beyond those described in Section 3.1. The available and potential technically feasible control strategies for the boilers are considered economically infeasible.

As such, MP proposes to retain the existing NO<sub>X</sub> emission limits and control technologies at THEC.

<sup>&</sup>lt;sup>21</sup> Docket No. E015/D-19-534, Document 20198-155376-01.

## **6** SO<sub>2</sub> Four-factor Analysis

This section identifies and describes various  $SO_2$  emission reduction technologies, evaluates the four statutory factors for THEC Boilers No. 1 and No. 2, and proposes a  $SO_2$  emission limit for the selected emission reduction technology. Consistent with EPA's guidance and MPCA direction, MP has completed a four-factor analysis for  $SO_2$  as summarized in Sections 6.1 to 6.5.

### 6.1 SO<sub>2</sub> Control Measures Overview

SO<sub>2</sub> emissions occur as a result of oxidation of sulfur in the fuels combusted. Theoretically, several techniques can be used to reduce SO<sub>2</sub> emissions from tangentially-fired coal-fueled utility boilers, as listed in Table 4-2. Table 6-1 lists the control technologies identified as the reasonable set of control technologies in Section 4.1.2 and are further evaluated in this section.

#### Table 6-1 Additional SO<sub>2</sub> Control Measures with Potential Application to THEC Boilers No. 1 and 2

|         | Control Technology                           |
|---------|--|
| Enhance | ements to the existing Lime Injection System |

Based on operating experience at THEC and other MP facilities and restrictions caused by the boilers' designs, MP estimates that the enhancements to the existing lime injection systems would result in a marginal improvement in performance, achieving a typical emission rate of 0.25 lb SO<sub>2</sub>/MMBtu. Combining this emission rate with the projected 2028 operating rates and baseline emission rates determined in Section 3.2 of this document results in the projected emissions reduction estimates for each boiler shown in Table 6-2.

# Table 6-2 Potential SO<sub>2</sub> Emission Reductions for THEC Boiler No. 1 (EQUI 64 / EU 001) and No. 2 (EQUI 5 / EU 002)

| Emission Unit                      | Baseline NO <sub>X</sub><br>(ton/year) <sup>[1]</sup>                       | SO <sub>2</sub> Emissions with Lime Injection<br>System Enhancements (ton/year)           |
|------------------------------------|---|---|
| Boiler No. 1<br>(EQUI 64 / EU 001) | 679   | 606 <sup>[2]</sup>  |
| Boiler No. 2<br>(EQUI 5 / EU 002)  | 665   | 606 <sup>[2]</sup>  |
| 5                                  | $50,000 \frac{MMBtu}{yr} \times 0.250 \frac{ll}{M}$ en baseline emissions a | $\frac{DNO_X}{MBtu} \times \frac{ton}{2,000 \ lb}$<br>and emissions estimate with control |

### 6.2 Factor 1 – Cost of Compliance

MP has completed a screening-level cost estimate for the selected SO<sub>2</sub> emission control measure. As noted in section 4.2, these control cost estimates were developed in accordance with the EPA Control Cost

Manual. The capital cost estimates are considered by THEC's plant engineering staff to be conservatively low, based on their considerable experience with projects at THEC and their informal conversations with other companies that have completed similar types of projects at other facilities. A more detailed cost estimate is likely to increase the costs for installing and implementing this technology. Cost summary spreadsheets for the SO<sub>2</sub> emission control measures are provided in Appendix C.

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 3.25% interest is assumed in annualizing capital costs<sup>22</sup>.

The resulting cost effectiveness calculation is summarized in Table 6-3. Please note that THEC Boilers No. 1 and No. 2 are identical, and have identical estimated emission reductions and costs estimated for each control technology in Table 6-2. As such, the values presented in Table 6-3 are representative of both boilers.

Table 6-3 SO<sub>2</sub> Control Cost Summary, per Unit Basis

| Additional<br>Emissions Control<br>Measure               |             | Annualized<br>Capital Cost<br>(\$/yr) | Annual<br>Operating<br>Costs<br>(\$/yr) | Total<br>Annualized<br>Costs<br>(\$/yr) | Annual<br>Emissions<br>Reduction<br>(tpy) | Pollution Control<br>Cost<br>Effectiveness<br>(\$/ton) |
|--|-------------|---------------------------------------|---|---|---|--|
| Enhancements to<br>the existing Lime<br>Injection System | \$3,656,250 | \$251,473                             | \$1,119,705                             | \$1,371,178                             | 73  | \$18,780   |

MP has determined that this control technology is not cost effective based on a consideration of RHR analyses conducted in other states. Sections 6.3 through 6.5 provide a screening-level summary of the remaining three factors evaluated for the SO<sub>2</sub> emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

### 6.3 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the 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.

Based on previous project experience and technical judgement, MP expects the lime injection enhancement project would require significant resources and time of approximately two years to obtain

<sup>&</sup>lt;sup>22</sup> Bank Prime Rate for July 16, 2020 from https://www.federalreserve.gov/releases/h15/.

project regulatory approvals, engineer, and install the equipment. Currently both THEC Boilers No. 1 and No. 2 are idled. It is unknown at this time if these units will be restarted, retrofitted, refueled, or retired. Any substantial investments in THEC Boilers No. 1 and No. 2 would likely require approval from the Public Utilities Commission (PUC) and, if the unit is retrofitted or refueled, would require MPCA permitting.

# 6.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

As stated previously, THEC Boilers No. 1 and No. 2 were idled in 2016 and have not operated since then. MP has maintained a modest fuel supply onsite to allow the units to be restarted to provide reliability to the electric system or address system emergencies. MP has also offered THEC Boilers No. 1 and No. 2 into MISO's capacity auction each year since the units were idled. THEC has not been selected into MISO's annual capacity auction to-date. MP currently plans to continue maintaining the facility such that it could begin operation at any time, but there are currently no plans to restart the units. Any changes to the operating status of THEC Boilers No. 1 and No. 2 would require approval from the Public Utilities Commission (PUC) and, if the unit is retrofitted or refueled, permitted the MPCA.

Enhancing the existing lime injection systems will result in an increase in construction activities that could increase water run-off into Lake Superior. However, this would only be during the construction phase of the project, the construction activities would be permitted, and the appropriate mitigation techniques would be implemented as-needed. The increased lime injection will result in more particulate matter in the flue gas. While the boilers will still be required to use their existing particulate matter control equipment and meet their respective particulate matter emission limits, this will result in an increase in ash collected by the control equipment which will need to be disposed.

### 6.5 Factor 4 – Remaining Useful Life of the Source

MP's August 22, 2019 *Remaining Life Depreciation Petition*<sup>23</sup> states that the THEC Boilers No. 1 and No. 2 end of useful life is December 31, 2026. This date is primarily used for ratemaking purposes and should not be construed as a retirement commitment date for the boilers. For maximum conservatism in this analysis, the useful life of the individual control measure, not the emission units, is used to calculate emission reductions, amortized costs and cost effectiveness on a dollar per ton basis.

### 6.6 Proposed SO<sub>2</sub> Controls and Emissions Rates

This analysis does not support the installation of additional SO<sub>2</sub> emissions measures at the THEC Boilers No. 1 and No. 2 beyond those described in Section 3.1. The available and potential technically feasible control strategies for the boilers are considered economically.

<sup>&</sup>lt;sup>23</sup> Docket No. E015/D-19-534, Document 20198-155376-01.

As such, MP proposes to retain the existing  $SO_2$  emission limits and control technologies at THEC.

# 7 Conclusion

MP's THEC evaluated potential emissions reduction measures for NO<sub>X</sub> and SO<sub>2</sub> for Boiler No. 1 (EQUI 64 / EU 001) and Boiler No. 2 (EQUI 5 / EU 002) in response to an RFI from the MPCA. No additional NO<sub>X</sub> or SO<sub>2</sub> controls were identified to be cost effective (refer to Sections 5.2 and 6.2 for more information). Therefore, the facility's existing NO<sub>X</sub> and SO<sub>2</sub> emission performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

# Appendix A

RACT/BACT/LAER Clearinghouse (RBLC) Review Summaries

# Appendix A.1

**RBLC Search for Coal-Fired Utility Boilers for NO**<sub>X</sub>

#### Minnesota Power - Taconite Harbor Energy Center Regional Haze RFI Appendix A-1: RBLC Search for Coal-Fired Utility Boilers for NO<sub>x</sub>

#### Pollutant Name: NO<sub>X</sub>

NOTE: Draft determinations are marked with a " \* " beside the RBLC ID.

|        |                                      |   |                   |                                      |               |                |  |  |                            |                 |                 |                          |   |                     |                |  | CASE-BY-      |                     |               |                                | Standard          |                         |                            |
|--------|--------------------------------------|---|-------------------|--------------------------------------|---------------|----------------|--|--|----------------------------|-----------------|-----------------|--------------------------|---|---------------------|----------------|--|---------------|---------------------|---------------|--------------------------------|-------------------|-------------------------|----------------------------|
| RBLCID | FACILITY NAME                        | CORPORATE OR COMPANY NAME                             | FACILITY<br>STATE | PERMIT NUM                           | NAICS<br>CODE | PERMIT DATE    | FACILITY DESCRIPTION   | Process<br>Name  | Fuel                       | Through-<br>put | UNITS           | Pollutant                | Emission Control Description  | Emission<br>Limit 1 | Limits Units 1 | Avg Time                                       | CASE<br>BASIS | Emission<br>Limit 2 | Limits Units2 | Avg Time2                      | Emission<br>Limit | Standard Limit<br>Units | Standard Limit<br>Avg Time |
| 2-0055 | NAVAJO GENERATING STATION            | SALT RIVER PROJECT AGRICULTURAL AND<br>POWER DISTRICT | AZ                | AZ 08-01                             | 221112        | 02/06/2012 ACT | 2,250 MW COAL FIRED POWER PLANT  | PULVERIZED<br>COAL FIRED<br>BOILER                           | COAL                       | 7725            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | LOW NOX BURNER (LNB), SEPARATED<br>OVERFIRE AIR (SOFA) SYSTEM,  | 0.24                | LB/MMBTU       | 30-DAY ROLLING<br>AVG                          | BACT-PSD      | 0                   |               |                                | 0                 |                         |                            |
| 2-0055 | NAVAJO GENERATING STATION            | SALT RIVER PROJECT AGRICULTURAL AND<br>POWER DISTRICT | AZ                | AZ 08-01                             | 221112        | 02/06/2012 ACT |  | PULVERIZED<br>COAL FIRED<br>BOILER                           | COAL                       | 7725            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | LOW NOX BURNER (LNB), SEPARATED<br>OVERFIRE AIR (SOFA) SYSTEM,  | 0.24                | LB/MMBTU       | 30-DAY ROLLING<br>AVG                          | BACT-PSD      | 0                   |               |                                | 0                 |                         |                            |
| 2-0055 | NAVAJO GENERATING STATION            | SALT RIVER PROJECT AGRICULTURAL AND<br>POWER DISTRICT | AZ                | AZ 08-01                             | 221112        | 02/06/2012 ACT |  | PULVERIZED<br>COAL FIRED<br>BOILER                           | COAL                       | 7725            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | LOW NOX BURNER (LNB), SEPARATED<br>OVERFIRE AIR (SOFA) SYSTEM,  | 0.24                | LB/MMBTU       | 30-DAY ROLLING<br>AVG                          | BACT-PSD      | 0                   |               |                                | 0                 |                         |                            |
| A-1206 | STOCKTON COGEN COMPANY               | APMC STOCKTON COGEN                                   | CA                | SJ 85-04                             | 221112        | 09/16/2011 ACT | 49.9 MW COGENERATION POWER PLANT OWNED BY AIR<br>PRODUCTS MANUFACTURING CORPORATION (APMC) STOCKTON<br>COGEN AND LOCATED IN STOCKTON, CALIFORNIA   | CIRCULATING<br>FLUIDIZED BED<br>BOILER                       | COAL                       | 730             | MMBTU/H         | Nitrogen Oxides<br>(NOx) | LOW BED TEMPERATUR STAGED<br>COMBUSTION; SELECTIVE NON-CATALYTIC<br>REDUCTION (SNCR)                        | 50                  | РРМ            | @3% O2, 3-HR AVG                               | BACT-PSD      | 42                  | LB/H          | 3-HR AVG                       | 0                 |                         |                            |
| 1-0399 | DETROIT EDISONMONROE                 | DETROIT EDISON  | MI                | 93-09A                               | 221112        | 12/21/2010 ACT | UtilityCoal fired power plant  | Boiler Units 1, 2,<br>3 and 4                                | Coal                       | 7624            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | Staged combustion, low-NOx burners, overfire air, and SCR.  | 0.08                | LB/MMBTU       | EACH, 12-MONTH<br>ROLLING AVG.                 | BACT-PSD      | 222.6               | T/MO          | EACH, 12-MONTH<br>ROLLING AVG. | 0                 |                         |                            |
| 1-0400 | WOLVERINE POWER                      | WOLVERINE POWER SUPPLY COOPERATIVE,<br>INC.           | MI                | 317-07                               | 221112        | 06/29/2011 ACT | Coal-fired power plant.  | 2 Circulating<br>Fluidized Bed<br>Boilers (CFB1 &<br>CFB2)   | Petcoke/coa<br>I           | 3030            | MMBTU/H<br>EACH | Nitrogen Oxides<br>(NOx) | SNCR (Selective Non-Catalytic Reduction)  | 1                   | LB/MW-H        | GROSS OUTPUT;<br>EACH; 30 D ROLL.<br>AVG; NSPS | BACT-PSD      | 281.1               | LB/H          | EACH; 24H<br>ROLL.AVG.; BACT   | 0                 |                         |                            |
| 1-0400 | WOLVERINE POWER                      | WOLVERINE POWER SUPPLY COOPERATIVE,<br>INC.           | MI                | 317-07                               | 221112        | 06/29/2011 ACT | Coal-fired power plant.  | 2 Circulating<br>Fluidized Bed<br>Boilers (CFB1 &<br>CFB2) - | Petcoke/coa<br>I           | 3030            | MMBTU/H<br>each | Nitrogen Oxides<br>(NOx) | SNCR (Selective Non-Catalytic Reduction)  | 0.07                | LB/MMBTU       | EACH, 30 D<br>ROLLING AVG;<br>BACT             | BACT-PSD      | 0                   |               |                                | 0                 |                         |                            |
| D-0026 | M.R. YOUNG STATION                   | MINNKOTA POWER COOPERATIVE                            | ND                | PTC12003                             | 221112        | 03/08/2012 ACT |  | Cyclone Boilers,<br>Unit 1                                   | Lignite                    | 3200            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | SNCR plus separated over fire air   | 0.36                | LB/MMBTU       | 30 DAY ROLLING<br>AVERAGE                      | BACT-PSD      | 2070.2              | LB/H          | 24 HOUR AV<br>DURING STARTUP   | 0                 |                         |                            |
| D-0026 | M.R. YOUNG STATION                   | MINNKOTA POWER COOPERATIVE                            | ND                | PTC12003                             | 221112        | 03/08/2012 ACT | Two lignite fired cyclone boilers.   | Cyclone Boilers,<br>Unit 2                                   | Lignite                    | 6300            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | SNCR plus separated over fire air   | 0.35                | LB/MMBTU       | 30 DAY ROLLING<br>AVERAGE                      | BACT-PSD      | 3995.6              | LB/H          | 24 HOUR AV<br>DURING STARTUP   | 0                 |                         |                            |
| K-0151 | SOONER GENERATING STATION            | O G AND E   | ОК                | 2010-338-C(M-<br>1)PSD               | 221112        |                | The facility is an electricity generation plant (SIC Code 4911) located<br>in an attainment area. The facility is currently operating under<br>Permit No. 2010-338-TVR2 issued November 21, 2011.  | COAL-FIRED<br>BOILERS  | COAL                       | 550             | MW              | Nitrogen Oxides<br>(NOx) | LOW-NOX BURNERS AND OVERFIRE AIR.   | 0.15                | LB/MMBTU       | 30-DAY AVG                                     | BART          | 0                   |               |                                | 0                 |                         |                            |
| K-0152 | MUSKOGEE GENERATING STATION          | O G AND E   | ОК                | 2005-271-C(M-<br>5)PSD               | 221112        | 01/30/2013 ACT | The Muskogee Generating Station utilizes sub-bituminous coal,<br>natural gas, and some waste products (used oil-sorb, used<br>antifreeze, used solvents, used oil, chemical cleaning wastes,<br>hazardous waste fuel, activated carbon, demineralizer resin, and                     | COAL-FIRED<br>BOILER   | COAL                       | 550             | MW              | Nitrogen Oxides<br>(NOx) | LOW-NOX BURNERS AND OVERFIRE AIR  | 0.15                | LB/MMBTU       | 30-DAY AVG                                     | BART          | 0                   |               |                                | 0                 |                         |                            |
| (-0554 | COLETO CREEK UNIT 2                  | COLETO CREEK  | ТХ                | PSDTX1118 AND<br>83778               | 221112        | 05/03/2010 ACT |  | Coal-fired Boiler<br>Unit 2                                  | PRB coal                   | 6670            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | low-NOx burners with OFA, Selective<br>Catalytic Reduction  | 0.06                | LB/MMBTU       | ROLLING 30 DAY<br>AVG                          | BACT-PSD      | 0.05                | LB/MMBTU      | ROLLING 12<br>MONTH AVG        | 0                 |                         |                            |
| (-0556 | HARRINGTON STATION UNIT 1 BOILER     | SOUTHWESTERN PUBLIC SERVICE COMPANY                   | тх                | PSDTX631M1<br>AMD 1388               | 221112        | 01/15/2010 ACT | The Southwestern Public Service Company (Xcel), the operator of a<br>3,630 MMBtu/hr coal fired electrical generating facility, is seeking<br>authorization to install modifications to the Unit 1 Boiler at the<br>Harrington Station Boiler Unit 1 in conjunction with a federally- | Unit 1 Boiler  | Coal                       | 3630            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | Separated overfire air windbox system; low-<br>NOx burner tips and additional ya control to<br>the burners. | 1452                | LB/H           |  | BACT-PSD      | 0                   |               |                                | 0                 |                         |                            |
| -0557  | LIMESTONE ELECTRIC GENERATING STATIC | N NRG TEXAS POWER LLC                                 | ТХ                | PSDTX371M4<br>AND 8576               | 221112        | 02/01/2010 ACT | NRG Texas Power LLC (NRG) operates two coal and petroleum coke-<br>fired steam/electric units, otherwise known as Limestone Units 1<br>and 2, which were originally permitted to operate in September<br>1981. These units are Combustion Engineering tangentially-fired,            | LMS Units 1 and<br>2   | Coal                       | 9061            | MMBtu/H         | Nitrogen Oxides<br>(NOx) | Tuning of existing low-NOx firing system to<br>induce deeper state combustion.                              | 0.25                | LB/MMBTU       | 30-DAY   | BACT-PSD      | 0                   |               |                                | 0                 |                         |                            |
| X-0577 | WHITE STALLION ENERGY CENTER         | WHITE STALLION ENERGY CENTER, LLC                     | ТХ                | 86088, PAL26,<br>HAP28,<br>PSDTX1160 | 221112        | 12/16/2010 ACT | WSEC proposes to construct and operate new steam-electric utility<br>generating facilities using four circulating fluidized bed (CFB)<br>boilers, each with a design maximum heat input of 3,300 million<br>British thermal units per hour (MMBtu/h) and 300 MW net electric         | CFB BOILER   | COAL & PET<br>COKE         | 3300            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | CFB AND SNCR  | 0.07                | LB NOX/MMBTU   | 30-DAY ROLLING                                 | BACT-PSD      | 0.1                 | LB NOX/MMBTU  | 1-HR                           | 0                 |                         |                            |
| (-0585 | TENASKA TRAILBLAZER ENERGY CENTER    | TENASKA TRAILBLAZER PARTNERS LLC                      | тх                | PSDTX1123 AND<br>HAP13, 84167        | 221112        | 12/30/2010 ACT | Coal-fired electric generating facility  | Coal-fired Boiler  | Sub-<br>bituminous<br>coal | 8307            | MMBTU/H         | Nitrogen Oxides<br>(NOx) | Selective Catalytic Reduction   | 0.05                | LB/MMBTU       | 12-MONTH<br>ROLLING                            | BACT-PSD      | 0.06                | LB/MMBTU      | 30-DAY ROLLING                 | 0                 |                         |                            |

# Appendix A.2

RBLC Search for Coal-Fired Utility Boilers for  $\mathsf{SO}_2$ 

#### Minnesota Power - Taconite Harbor Energy Center Regional Haze RFI Appendix A-2: RBLC Search for Coal-Fired Utility Boilers for SO<sub>2</sub>

#### Pollutant Name: SO<sub>2</sub>

NOTE: Draft determinations are marked with a " \* " beside the RBLC ID.

| RBLCID   | FACILITY NAME                        | CORPORATE OR COMPANY NAME                             | FACILITY<br>STATE | PERMIT NUM                           | NAICS<br>CODE | PERMIT DATE    | FACILITY DESCRIPTION   | Process<br>Name  | Fuel                       | Through-<br>put | UNITS           | Pollutant            | Emission Control Description   | Emission<br>Limit 1 | Limits Units 1 | Avg Time                                    | CASE-BY-<br>CASE<br>BASIS | Emission<br>Limit 2 | Limits Units2 | Avg Time2                                   | Standard<br>Emission<br>Limit | Standard Limit<br>Units | Standard Limit<br>Avg Time      |
|----------|--------------------------------------|---|-------------------|--------------------------------------|---------------|----------------|--|--|----------------------------|-----------------|-----------------|----------------------|--|---------------------|----------------|---|---------------------------|---------------------|---------------|---|-------------------------------|-------------------------|---------------------------------|
| MI-0400  | WOLVERINE POWER                      | WOLVERINE POWER SUPPLY COOPERATIVE,<br>INC.           | MI                | 317-07                               | 221112        | 06/29/2011 ACT | Coal-fired power plant.  | 2 Circulating<br>Fluidized Bed<br>Boilers (CFB1 &<br>CFB2)   | Petcoke/coa<br>I           | 3030            | MMBTU/H<br>EACH | Sulfur Dioxide (SO2) | Dry flue gas desulfurization (spray dry<br>absorber or polishing scrubber).  | 303                 | LB/H           | EACH; 24-H<br>ROLL.AVG.; BACT &<br>SIP      | BACT-PSD                  | 1.4                 | LB/MW-H       | GROSS OUTPUT;<br>EACH; 30D<br>ROLL.AVG.     | 0                             |                         |                                 |
| MI-0400  | WOLVERINE POWER                      | WOLVERINE POWER SUPPLY COOPERATIVE,<br>INC.           | МІ                | 317-07                               | 221112        | 06/29/2011 ACT | Coal-fired power plant.  | 2 Circulating<br>Fluidized Bed<br>Boilers (CFB1 &<br>CFB2) - | Petcoke/coa<br>I           | 3030            | MMBTU/H<br>each | Sulfur Dioxide (SO2) | Dry flue gas desulfurization (spray dry<br>absorber or polishing scrubber).  | 0.06                | LB/MMBTU       | EACH; 30D<br>ROLL.AVG.;<br>BACT&SIP EXC. SS | BACT-PSD                  | 0.05                | LB/MMBTU      | EACH;12-MO<br>ROLL.AVG.;<br>BACT&SIP EXC.SS | 0                             |                         |                                 |
| AZ-0055  | NAVAJO GENERATING STATION            | SALT RIVER PROJECT AGRICULTURAL AND<br>POWER DISTRICT | AZ                | AZ 08-01                             | 221112        | 02/06/2012 ACT | 2,250 MW COAL FIRED POWER PLANT  | PULVERIZED<br>COAL FIRED<br>BOILER                           | COAL                       | 7725            | MMBTU/H         | Sulfur Dioxide (SO2) | FLUE GAS DESULFURIZATION (FGD),<br>SCRUBBER  | 0                   |                |   | BART                      | 0                   |               |   | 0                             |                         |                                 |
| AZ-0055  | NAVAJO GENERATING STATION            | SALT RIVER PROJECT AGRICULTURAL AND<br>POWER DISTRICT | AZ                | AZ 08-01                             | 221112        | 02/06/2012 ACT | 2,250 MW COAL FIRED POWER PLANT  | PULVERIZED<br>COAL FIRED<br>BOILER                           | COAL                       | 7725            | MMBTU/H         | Sulfur Dioxide (SO2) | FLUE GAS DESULFURIZATION (FGD),<br>SCRUBBER  | 0                   |                |   | BART                      | 0                   |               |   | 0                             |                         |                                 |
| AZ-0055  | NAVAJO GENERATING STATION            | SALT RIVER PROJECT AGRICULTURAL AND<br>POWER DISTRICT | AZ                | AZ 08-01                             | 221112        | 02/06/2012 ACT | 2,250 MW COAL FIRED POWER PLANT  | PULVERIZED<br>COAL FIRED<br>BOILER                           | COAL                       | 7725            | MMBTU/H         | Sulfur Dioxide (SO2) | FLUE GAS DESULFURIZATION (FGD),<br>SCRUBBER  | 0                   |                |   | BART                      | 0                   |               |   | 0                             |                         |                                 |
| *TX-0577 | WHITE STALLION ENERGY CENTER         | WHITE STALLION ENERGY CENTER, LLC                     | тх                | 86088, PAL26,<br>HAP28,<br>PSDTX1160 | 221112        | 12/16/2010 ACT | WSEC proposes to construct and operate new steam-electric utility<br>generating facilities using four circulating fluidized bed (CFB)<br>bollers, each with a design maximum heat input of 3,300 million<br>British thermal units ger hour (IMBRU/h) and 300 MW net electric | CFB BOILER   | COAL & PET<br>COKE         | 3300            | MMBTU/H         | Sulfur Dioxide (SO2) | LIMESTONE BED CFB AND LIME SPRAY DRYER<br>PERMIT DESIGN SULFUR CONTENT OF ILL<br>BASIN COAL IS 3.9 WT% AND OF PET COKE<br>4.3 AVG/6.0 MAX HI WEIGHTING OF LIMITS | 0.114               | LB SO2/MMBTU   | PET COKE 30-DAY<br>ROLLING                  | BACT-PSD                  | 0.086               | LB SO2/MMBTU  | PET COKE 12-MO<br>ROLLING                   | 0.063                         | LB SO2/MMBTU            | COAL 30-DAY & 12-<br>MO ROLLING |
| кү-0100  | J.K. SMITH GENERATING STATION        | EAST KENTUCKY POWER COOPERATIVE, INC                  | KY                | V-05-070 R3                          | 221112        | 04/09/2010 ACT | NEW CFB EGU BECAUSE OF A LEGAL CHALLENGE OUTSIDE OF THE<br>TITLE V PROCEDURES, PERMITTEE AGREED TO TERMINATE<br>CONSTRUCTION AUTHORITY FOR PROJECT. R4 TO THIS PERMIT<br>REMOVES CONSTRUCTION AURTHORITY, AND THE PERMIT MAY   | CIRCULATING<br>FLUIDIZED BED<br>BOILER CFB1<br>AND CFB2      | COAL                       | 3000            | MMBTU/H         | Sulfur Dioxide (SO2) | LIMESTONE INJECTION (CFB)AND A FLASH<br>DRYER ABSORBER WITH FRESH LIME<br>INJECTION  | 0.075               | LB/MMBTU       | 30 DAY AVERAGE                              | BACT-PSD                  | 225                 | LB/H          | 24 HOUR BLOCK                               | 0                             |                         |                                 |
| CA-1206  | STOCKTON COGEN COMPANY               | APMC STOCKTON COGEN                                   | CA                | SJ 85-04                             | 221112        | 09/16/2011 ACT | 49.9 MW COGENERATION POWER PLANT OWNED BY AIR<br>PRODUCTS MANUFACTURING CORPORATION (APMC) STOCKTON<br>COGEN AND LOCATED IN STOCKTON, CALIFORNIA   | CIRCULATING<br>FLUIDIZED BED<br>BOILER                       | COAL                       | 730             | MMBTU/H         | Sulfur Dioxide (SO2) | LIMESTONE INJECTION W/ A MINIMUM<br>REMOVAL EFFICIENCY OF 70% (3-HR AVG) TO<br>BE MAINTAINED AT ALL TIMES  | 59                  | LB/H           | 8-HR AVG                                    | BACT-PSD                  | 100                 | LB/H          | 3-HR AVG                                    | 0                             |                         |                                 |
| TX-0554  | COLETO CREEK UNIT 2                  | COLETO CREEK  | тх                | PSDTX1118 AND<br>83778               | 221112        | 05/03/2010 ACT | Coal-fired boiler  | Coal-fired Boiler<br>Unit 2                                  | PRB coal                   | 6670            | MMBTU/H         | Sulfur Dioxide (SO2) | Spray Dry Adsorber/Fabric Filter   | 0.06                | LB/MMBTU       | 30-DAY ROLLING                              | BACT-PSD                  | 0.06                | LB/MMBTU      | 12-MONTH<br>ROLLING                         | 0                             |                         |                                 |
| TX-0601  | GIBBONS CREEK STEAM ELECTRIC STATION | TEXAS MUNICIPAL POWER AGENCY                          | тх                | 5699 AND<br>PSDTX18M2                | 221122        | 10/28/2011 ACT | one 5,060 MMBtu/h boiler burning natural gas, lignite, coal, and a<br>blend of lignite or coal with petroleum coke   | Boiler   | Coal                       | 5060            | MMBtu/h         | Sulfur Dioxide (SO2) | Wet Flue Gas Desulfurization   | 1.2                 | LB/MMBTU       |   | BACT-PSD                  | 1771                | LB/H          |   | 6052                          | T/YR                    |                                 |
| MI-0399  | DETROIT EDISONMONROE                 | DETROIT EDISON  | МІ                | 93-09A                               | 221112        | 12/21/2010 ACT | UtilityCoal fired power plant  | Boiler Units 1, 2,<br>3 and 4                                | Coal                       | 7624            | MMBTU/H         | Sulfur Dioxide (SO2) | Wet flue gas desulfurization.  | 0.107               | LB/MMBTU       | EACH, 24-H ROLL.<br>AVG.                    | BACT-PSD                  | 815.8               | LB/H          | EACH, 24-H ROLL.<br>AVG.                    | 0                             |                         |                                 |
| TX-0585  | TENASKA TRAILBLAZER ENERGY CENTER    | TENASKA TRAILBLAZER PARTNERS LLC                      | тх                | PSDTX1123 AND<br>HAP13, 84167        | 221112        | 12/30/2010 ACT | Coal-fired electric generating facility  | Coal-fired Boiler  | Sub-<br>bituminous<br>coal | 8307            | MMBTU/H         | Sulfur Dioxide (SO2) | Wet limestone scrubber   | 0.06                | LB/MMBTU       | 30-DAY ROLLING                              | BACT-PSD                  | 0.06                | LB/MMBTU      | 12-MONTH<br>ROLLING                         | 0                             |                         |                                 |

### Appendix B

Unit-Specific Screening Level Cost Summary for NO<sub>X</sub> Control Measures

| Regional Haze RFI<br>Control Equipment Cost Evalua   | ation  |  | NOTE   | : Costs pres  | ented per unit  | but projects would only be done on both unit  | s toge   | ther           |
|--|--|--|--|---|---|---|--|----------------|
| ······································   |  |  |  |   |   |   | Ŭ  |                |
| QUIPMENT DETAILS   |  |  |  |   |   |   |  |                |
| Emission Unit Number   | Boi  | lers No. 1   | and No. 2  |   |   |   |  |                |
| Control Equipment Type   | Bur  | ner Modif  | ications - I NR  | coal tin renla  | cement only (   | NOx improvement)  |  |                |
|  |  |  |  |   |   |   |  |                |
| Details  | кер  |  | tip with nozzle ti   | p that changes  | s poller lifeball   | snape   |  |                |
| Max Operating Design   |  |  | MMBtu/hr   |   |   |   |  |                |
| Expected Utilization Rate  |  | 100%   |  |   |   |   |  |                |
| Expected Annual Hours of Operation   |  | 8,760  | Hours  |   |   |   |  |                |
| Annual Interest Rate   |  | 3.25%  | Bank Prime Ra  | ate for July 16,  | 2020 from http  | s://www.federalreserve.gov/releases/h15/.   |  |                |
| Expected Equipment Life  |  | 10   | yrs  |   |   |   |  |                |
| APITAL COSTS   |  |  |  |   |   |   |  |                |
| Direct Capital Costs   |  |  |  |   |   |   |  |                |
| Purchased Equipment (A) (1)<br>Purchased Equipment Costs (A)   |  |  |  | Engineering   | iudaomont ho  | and on provinue project by Minnegote Rower  | ¢  | 500,00         |
| Instrumentation  |  |  |  | Engineering   |   | sed on previous project by Minnesota Power<br>of control device cost (A)  | \$<br>\$   | 50,00          |
| Sales Taxes  |  |  |  |   |   | of control device cost (A)  | э<br>\$  | 34,37          |
| Freight  |  |  |  |   |   | of control device cost (A)  | \$   | 25,00          |
| Purchased Equipment Total (B)  |  |  |  |   | 5.078   |   | \$   | 609,37         |
|  |  |  |  |   |   |   |  |                |
| Installation<br>Foundations & supports   |  |  |  |   | 0%  | Conservatively excluded from analysis   | \$   | -              |
| Handling & erection  |  |  |  |   |   | Conservatively excluded from analysis   | \$   | -              |
| Electrical   |  |  |  |   |   | Conservatively excluded from analysis   | \$   | -              |
| Piping   |  |  |  |   | 0%  | Conservatively excluded from analysis   | \$   | -              |
| Insulation   |  |  |  |   |   | Conservatively excluded from analysis   | \$   | -              |
| Painting   |  |  |  |   | 0%  | Conservatively excluded from analysis   | \$   | -              |
| Installation Subtotal Standard Expens  | ses  |  |  |   |   | · · · ·   | \$   |                |
| Site Preparation, as required  |  |  |  |   | 0%  | None required   | \$   | -              |
| Buildings, as required   |  |  |  |   |   | None required   | \$   | -              |
| Site Specific - Other  |  |  |  |   | 0%  | None required   | \$   | -              |
| Total Site Specific Costs  |  |  |  |   |   | ·   | \$   | -              |
| Installation Total   |  |  |  |   |   |   | \$   | -              |
| Total Direct Capital Cost, DC  |  |  |  |   |   |   | \$   | 609,37         |
| Indirect Capital Costs   |  |  |  |   |   |   |  |                |
| Engineering, supervision   |  |  |  |   | 0%  | Conservatively excluded from analysis   | \$   | -              |
| Construction & field expenses  |  |  |  |   | 0%  | Conservatively excluded from analysis   | \$   | -              |
| Contractor fees  |  |  |  |   | 0%  | Conservatively excluded from analysis   | \$   | -              |
| Start-up   |  |  |  |   | 0%  | Conservatively excluded from analysis   | \$   | -              |
| Performance test   |  |  |  |   |   | Conservatively excluded from analysis   | \$   | -              |
| Model Studies  |  |  |  |   |   | Conservatively excluded from analysis   | \$   | -              |
| Contingencies  |  |  |  |   | 0%  | Conservatively excluded from analysis   | \$   | -              |
| Total Indirect Capital Costs, IC   |  |  |  |   |   |   | \$   | -              |
| otal Capital Investment (TCI) = DC + IC  |  |  |  |   |   |   | \$   | 609,37         |
|  |  | Bans et  | c) for Canital R   | ecovery Cost  | ł   |   | \$   | 609,37         |
| liusted TCI for Replacement Parts (Cataly  | st Filter  | Bugo, or   |  |   |   | fic project, not all-in costs (for example, additional  |  |                |
|  |  | TE: These  | t additional read  | gent needed, a  | dditional tons  | of waste generated, etc.)   |  |                |
| djusted TCI for Replacement Parts (Cataly:<br>PERATING COSTS   | NO   |  |  |   |   | si waato gonoratoa, oto.)   |  |                |
|  | NO<br>the  |  | Unit of<br>Measure   | Use Rate  | Unit of<br>Measure  | Comments  |  |                |
| PERATING COSTS<br>Item<br>Direct Annual Operating Costs, DC  | NO<br>the  | equipmen   | Unit of  | Use Rate  | Unit of   |   |  |                |
| PERATING COSTS<br>Item<br>Direct Annual Operating Costs, DC<br>Operating Labor   | NO<br>the<br>Ur  | equipmen<br>nit Cost   | Unit of<br>Measure   |   | Unit of<br>Measure  | Comments  |  |                |
| PERATING COSTS<br>Item<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator   | NO<br>the  | equipmen<br>nit Cost<br>60.00  | Unit of<br>Measure<br>\$/Hr  | <b>Use Rate</b><br>0.00   | Unit of<br>Measure  | Comments No additional labor costs  | \$   |                |
| PERATING COSTS<br>Item<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor   | NO<br>the<br>Ur  | equipmen<br>nit Cost<br>60.00  | Unit of<br>Measure   |   | Unit of<br>Measure  | Comments  | \$   |                |
| Item<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance  | NO<br>the<br>Ui  | equipmen<br>nit Cost<br>60.00<br>15%   | Unit of<br>Measure<br>\$/Hr<br>of Op. Labor  | 0.00  | Unit of<br>Measure<br>hr/8 hr shift   | Comments No additional labor costs 15% of Operator Costs  | \$   | 65.7(          |
| PERATING COSTS<br>Item<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor   | NO<br>the<br>Ur  | equipmen<br>nit Cost<br>60.00  | Unit of<br>Measure<br>\$/Hr<br>of Op. Labor  |   | Unit of<br>Measure<br>hr/8 hr shift   | Comments No additional labor costs  | \$   | 65,70          |
| Item<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance  | NO<br>the<br>Ui  | equipmen<br>nit Cost<br>60.00<br>15%<br>60.00  | Unit of<br>Measure<br>\$/Hr<br>of Op. Labor  | 0.00  | Unit of<br>Measure<br>hr/8 hr shift   | Comments No additional labor costs 15% of Operator Costs \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr, Based on average annual   | \$<br>\$   |                |
| PERATING COSTS<br>Item<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor   | NO<br>the<br>Ur<br>\$  | equipmen<br>nit Cost<br>60.00<br>15%<br>60.00<br>100%  | Unit of<br>Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor   | 0.00  | Unit of<br>Measure<br>hr/8 hr shift   | Comments No additional labor costs 15% of Operator Costs \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr, Based on average annual maintenenance cost for labor and material   | \$   | 65,70<br>65,70 |
| PERATING COSTS<br>Item<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials  | NO<br>the<br>Ur<br>\$  | equipmen<br>nit Cost<br>60.00<br>15%<br>60.00<br>100%<br>nagemen   | Unit of<br>Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor   | 0.00  | Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift  | Comments No additional labor costs 15% of Operator Costs \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr, Based on average annual maintenenance cost for labor and material of maintenance labor costs  | \$<br>\$   |                |
| PERATING COSTS<br>Item<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & W<br>Fuel Penalty   | NO <sup>°</sup><br>the <sup>°</sup><br>\$<br>\$<br>/aste Ma  | equipmen<br>nit Cost<br>60.00<br>15%<br>60.00<br>100%<br>nagemen<br>13.640   | Unit of<br>Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t  | 0.00<br>1.00<br>0   | Unit of<br>Measure<br>hr/8 hr shift   | Comments No additional labor costs 15% of Operator Costs \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr, Based on average annual maintenenance cost for labor and material of maintenance labor costs No impacts expected - engineering judgment   | \$<br>\$<br>\$   |                |
| PERATING COSTS<br>Item<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & W   | NO<br>the<br>\$<br>\$<br>/aste Ma<br>\$<br>\$  | equipmen<br>nit Cost<br>60.00<br>15%<br>60.00<br>100%<br>nagemen<br>13.640<br>0.036  | Unit of<br>Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr   | 0.00<br>1.00<br>0<br>0  | Unit of<br>Measure  | Comments No additional labor costs 15% of Operator Costs \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr, Based on average annual maintenenance cost for labor and material of maintenance labor costs No impacts expected - engineering judgment No impacts expected - engineering judgment  | \$<br>\$<br>\$<br>\$   |                |
| PERATING COSTS<br>Item<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & W<br>Fuel Penalty<br>Electricity  | NO<br>the<br>U<br>\$<br>\$<br>/aste Ma<br>\$<br>\$<br>\$   | equipmen<br><u>nit Cost</u><br>60.00<br>15%<br>60.00<br>100%<br>nagemen<br>13.640<br>0.036<br>0.004                                | Unit of<br>Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal  | 0.00<br>1.00<br>0<br>0<br>0   | Unit of<br>Measure  | Comments No additional labor costs 15% of Operator Costs \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr, Based on average annual maintenenance cost for labor and material of maintenance labor costs No impacts expected - engineering judgment No impacts expected - engineering judgment  | \$<br>\$<br>\$   |                |
| PERATING COSTS<br>Item<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & W<br>Fuel Penalty<br>Electricity<br>Water   | NO<br>the<br>\$<br>\$<br>/aste Ma<br>\$<br>\$  | equipmen<br>nit Cost<br>60.00<br>15%<br>60.00<br>100%<br>nagemen<br>13.640<br>0.036  | Unit of<br>Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mscf                                 | 0.00<br>1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0                               | Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mscf/yr             | Comments No additional labor costs 15% of Operator Costs \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr, Based on average annual maintenenance cost for labor and material of maintenance labor costs No impacts expected - engineering judgment  | \$<br>\$<br>\$<br>\$<br>\$   |                |
| PERATING COSTS Item Direct Annual Operating Costs, DC Operating Labor Operator Supervisor Maintenance Maintenance Labor Maintenance Materials Utilities, Supplies, Replacements & W Fuel Penalty Electricity Water Compressed Air  | NO<br>the<br>\$<br>\$<br>\$<br>/aste Ma<br>\$<br>\$<br>\$<br>\$                                      | equipmen<br>nit Cost<br>60.00<br>15%<br>60.00<br>100%<br>nagemen<br>13.640<br>0.036<br>0.004<br>0.367                              | Unit of<br>Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mscf<br>/mgal                        | 0.00<br>1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0                     | Unit of<br>Measure  | Comments No additional labor costs 15% of Operator Costs \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr, Based on average annual maintenenance cost for labor and material of maintenance labor costs No impacts expected - engineering judgment  | \$<br>\$<br>\$<br>\$<br>\$<br>\$   |                |
| PERATING COSTS Item Direct Annual Operating Costs, DC Operating Labor Operator Supervisor Maintenance Maintenance Labor Maintenance Materials Utilities, Supplies, Replacements & W Fuel Penalty Electricity Water Compressed Air Wastewater Treatment   | NO:<br>the<br>\$<br>\$<br>\$<br>/aste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$                         | equipmen<br>hit Cost<br>60.00<br>15%<br>60.00<br>100%<br>nagemen<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800           | Unit of<br>Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mscf<br>/mgal<br>/ton                | 0.00<br>1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0      | Unit of<br>Measure  | Comments No additional labor costs 15% of Operator Costs \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr, Based on average annual maintenenance cost for labor and material of maintenance labor costs No impacts expected - engineering judgment   | \$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$                         |                |
| PERATING COSTS Item Direct Annual Operating Costs, DC Operating Labor Operator Supervisor Maintenance Maintenance Labor Maintenance Materials Utilities, Supplies, Replacements & W Fuel Penalty Electricity Water Compressed Air Wastewater Treatment Solid Waste Disposal                          | NO:<br>the<br>\$<br>\$<br>\$<br>Vaste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$             | equipmen<br>nit Cost<br>60.00<br>15%<br>60.00<br>100%<br>nagemen<br>13.640<br>0.036<br>0.04<br>0.367<br>1.957<br>48.800<br>488.000 | Unit of<br>Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mscf<br>/mgal<br>/ton                | 0.00<br>1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure  | Comments No additional labor costs 15% of Operator Costs \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr, Based on average annual maintenenance cost for labor and material of maintenance labor costs No impacts expected - engineering judgment  | \$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$   |                |
| PERATING COSTS Item Direct Annual Operating Costs, DC Operating Labor Operator Supervisor Maintenance Maintenance Labor Maintenance Materials Utilities, Supplies, Replacements & W Fuel Penalty Electricity Water Compressed Air Wastewater Treatment Solid Waste Disposal Hazardous Waste Disposal | NO:<br>the<br>\$<br>\$<br>\$<br>/aste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | equipmen<br>nit Cost<br>60.00<br>15%<br>60.00<br>100%<br>nagemen<br>13.640<br>0.036<br>0.04<br>0.367<br>1.957<br>48.800<br>488.000 | Unit of<br>Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/ton coal<br>/mgal<br>/ton<br>/ton-mi | 0.00<br>1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mgal/yr<br>ton/year | Comments No additional labor costs 15% of Operator Costs \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr, Based on average annual maintenenance cost for labor and material of maintenance labor costs No impacts expected - engineering judgment | \$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ |                |

|                                       |          |         |                |   |             | maintenenance cost for labor and material  |
|---------------------------------------|----------|---------|----------------|---|-------------|--|
|                                       |          |         |                |   |             |  |
| Maintenance Materials                 |          | 100%    | of Maint Labor |   |             | of maintenance labor costs                 |
| Utilities, Supplies, Replacements & V | Vaste Ma | nagemen | t              |   |             |  |
| Fuel Penalty                          | \$       | 13.640  | /ton coal      | 0 | ton coal/yr | No impacts expected - engineering judgment |
| Electricity                           | \$       | 0.036   | /kw-hr         | 0 | kw-hr/yr    | No impacts expected - engineering judgment |
| Water                                 | \$       | 0.004   | /mgal          | 0 | mgal/yr     | No impacts expected - engineering judgment |
| Compressed Air                        | \$       | 0.367   | /mscf          | 0 | mscf/yr     | No impacts expected - engineering judgment |
| Wastewater Treatment                  | \$       | 1.957   | /mgal          | 0 | mgal/yr     | No impacts expected - engineering judgment |
| Solid Waste Disposal                  | \$       | 48.800  | /ton           | 0 | ton/year    | No impacts expected - engineering judgment |
| Hazardous Waste Disposal              | \$       | 488.000 | /ton           | 0 | ton/year    | No impacts expected - engineering judgment |
| Waste Transport                       | \$       | 0.652   | /ton-mi        | 0 | ton-mi/yr   | No impacts expected - engineering judgment |
| Lime                                  | \$       | 290.000 | /ton           | 0 | ton/yr      | No impacts expected - engineering judgment |
| Ammonia                               | \$       | 0.293   | /gal           | 0 | gal/yr      | No impacts expected - engineering judgment |
| tal Annual Direct Operating Costs     |          |         |                |   |             |  |

| tal Annual Indirect Operating Costs     |  | \$<br>96,72 |
|---|--|-------------|
| tel Annual Indianat Oncostina Ocota     | life and 3.3% interest rate                            | \$<br>72,35 |
| Capital Recovery                        | 0.1187 capital recovery factor for a 10-year equipment |             |
| Insurance (1% total capital costs)      | 1% of total capital costs (TCI)                        | \$<br>6,0   |
| Property tax (1% total capital costs)   | 1% of total capital costs (TCI)                        | \$<br>6,0   |
| Administration (2% total capital costs) | 2% of total capital costs (TCI)                        | \$<br>12,1  |
| Overhead                                | 0% Conservatively excluded from analysis               | \$<br>-     |

131,400

Ammonia Total Annual Direct Operating Costs

#### Minnesota Power - Taconite Harbor Energy Center Regional Haze RFI Control Equipment Cost Evaluation

|  | on  |   | NOTE  | : Costs prese   | ented per unit  | t but projects would only be done on both uni  | ts tog   | eurer  |
|--|---|---|---|---|---|--|--|--|
| QUIPMENT DETAILS   |   |   |   |   |   |  |  |  |
| Emission Unit Number   | Boil  | ers No. 1   | and No. 2   |   |   |  |  |  |
| Control Equipment Type   |   |   | R/ROFA (NOx   | improvemen  | t)  |  |  |  |
| Details  |   |   | •   | •   |   | ts and locations, add additional ROFA system co  | ntrolo   |  |
|  | Auu   |   |   | change SNC  | K injection por   | is and locations, and additional ROFA system co  | 1111015  |  |
| Max Operating Design   |   |   | MMBtu/hr  |   |   |  |  |  |
| Expected Utilization Rate  |   | 100%  |   |   |   |  |  |  |
| Expected Annual Hours of Operation   |   | ,   | Hours   |   |   |  |  |  |
| Annual Interest Rate   |   |   |   | te for July 16,   | 2020 from http  | os://www.federalreserve.gov/releases/h15/.   |  |  |
| Expected Equipment Life  |   | 20  | yrs   |   |   |  |  |  |
| APITAL COSTS   |   |   |   |   |   |  |  |  |
| Direct Capital Costs   |   |   |   |   |   |  |  |  |
| Purchased Equipment (A) (1)  |   |   |   |   |   |  |  |  |
| Purchased Equipment Costs (A)  |   |   |   | Engineering   | judgement ba  | sed on previous project by Minnesota Power   | \$   | 1,000,000  |
| Instrumentation  |   |   |   |   |   | of control device cost (A)   | \$   | 100,000  |
| Sales Taxes  |   |   |   |   |   | of control device cost (A)   | \$   | 68,750   |
| Freight Purchased Equipment Total (B)  |   |   |   |   | 5.0%  | of control device cost (A)   | \$<br>\$   | 50,000<br>1,218,750  |
| Purchased Equipment Total (B)  |   |   |   |   |   |  | φ  | 1,210,750  |
|  |   |   |   |   | <b></b>   | Concernatively evoluted from the   | ¢  |  |
| Foundations & supports   |   |   |   |   |   | Conservatively excluded from analysis  | \$   | -  |
| Handling & erection  |   |   |   |   |   | Conservatively excluded from analysis  | \$   | -  |
| Electrical   |   |   |   |   |   | Conservatively excluded from analysis<br>Conservatively excluded from analysis   | \$<br>\$   | -  |
| Piping<br>Insulation   |   |   |   |   |   | Conservatively excluded from analysis<br>Conservatively excluded from analysis   | \$<br>\$   | -  |
| Painting   |   |   |   |   |   | Conservatively excluded from analysis  | э<br>\$  | -  |
| Installation Subtotal Standard Expenses  |   |   |   | <u> </u>  | 576   |  | \$   | -  |
| Site Preparation, as required  |   |   |   |   | 00/   | None required  | \$   |  |
| Site Preparation, as required<br>Buildings, as required  |   |   |   |   |   | None required<br>None required   | ծ<br>Տ   | -  |
| Site Specific - Other  |   |   |   |   |   | None required  | э<br>\$  | -  |
| Total Site Specific Costs  |   |   |   |   | 070   | None required  | \$   | -  |
| Installation Total   |   |   |   |   |   |  | \$   | -  |
| Total Direct Capital Cost, DC  |   |   |   |   |   |  | \$   | 1,218,750  |
|  |   |   |   |   |   |  |  |  |
| Indirect Capital Costs   |   |   |   |   | 00/   | Concernatively evaluated from analysis   | \$   |  |
| Engineering, supervision<br>Construction & field expenses  |   |   |   |   |   | Conservatively excluded from analysis<br>Conservatively excluded from analysis   | э<br>\$  | -  |
| Contractor fees  |   |   |   |   |   | Conservatively excluded from analysis  | \$   | -  |
| Start-up   |   |   |   |   |   | Conservatively excluded from analysis  | \$   | -  |
| Performance test   |   |   |   |   |   | Conservatively excluded from analysis  | \$   | -  |
| Model Studies  |   |   |   |   |   | Conservatively excluded from analysis  | \$   | -  |
| Contingencies  |   |   |   |   | 0%  | Conservatively excluded from analysis  | \$   | -  |
| Total Indirect Capital Costs, IC   |   |   |   |   |   |  | \$   | -  |
| otal Capital Investment (TCI) = DC + IC  |   |   |   |   |   |  | \$   | 1,218,750  |
| djusted TCI for Replacement Parts (Catalyst,   | Filtor  | Bage of   | c) for Capital P  | Cocovery Cost   | •   |  | \$   | 1,218,750  |
| ajusted For for Replacement Farts (Gatalyst,   |   |   |   |   |   | ific project, not all-in costs (for example, additiona   | - · ·  |  |
| PERATING COSTS   |   |   |   |   |   | of waste generated, etc.)  |  |  |
|  |   |   | Unit of   |   | Unit of   |  |  |  |
| Item<br>Direct Annual Operating Costs, DC  | Ur  | nit Cost  | Measure   | Use Rate  | Measure   | Comments   |  |  |
| Operating Labor  |   |   |   |   |   |  |  |  |
| Operator   | \$  |   |   |   |   |  |  |  |
|  |   | 60.00   | \$/Hr   | 1.00  | hr/8 hr shift   | \$60/Hr value is from EPA's cost spreadsheet fo  | r \$   | 65,700   |
|  |   | 60.00   | \$/Hr   | 1.00  | hr/8 hr shift   | SCR controls and includes benefits, 1 hr/8 hr  | r \$   | 65,700   |
| Supervisor   |   |   | •   | 1.00  | hr/8 hr shift   | SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr   |  | ,  |
| Supervisor<br>Maintenance  |   |   | \$/Hr<br>of Op. Labor   | 1.00  | hr/8 hr shift   | SCR controls and includes benefits, 1 hr/8 hr  | r \$<br>\$   | ,  |
|  | \$  |   | •   | 1.00  | hr/8 hr shift   | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo  | \$   | ,  |
| Maintenance  | \$  | 15%   | of Op. Labor  |   |   | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr   | \$<br>r  | 9,855  |
| Maintenance<br>Maintenance Labor   | \$  | 15%<br>60.00  | of Op. Labor<br>\$/Hr   | 1.00  |   | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr   | \$<br>r<br>\$  | 9,855  |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials  |   | 15%<br>60.00<br>100%  | of Op. Labor<br>\$/Hr<br>of Maint Labor   | 1.00  |   | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr   | \$<br>r  | 9,855  |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was   | te Ma   | 15%<br>60.00<br>100%<br>nagement  | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t  | 1.00  | hr/8 hr shift   | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs   | \$<br>r<br>\$  | 9,855  |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty   | te Ma   | 15%<br>60.00<br>100%<br>nagement<br>13.640  | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal   | 1.00  | hr/8 hr shift<br>ton coal/yr  | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement   | \$<br>r<br>\$<br>\$<br>\$  | 9,855<br>65,700  |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity  | te Ma<br>\$<br>\$   | 15%<br>60.00<br>100%<br>nagement<br>13.640<br>0.036   | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr   | 1.00<br>0<br>0  | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr  | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement   | s<br>r<br>\$<br>\$<br>\$<br>\$   | 9,855<br>65,700  |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty   | te Ma   | 15%<br>60.00<br>100%<br>nagement<br>13.640<br>0.036<br>0.004  | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal  | 1.00<br>0<br>0<br>0   | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr   | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement   | s<br>r<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$   | 9,855<br>65,700  |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Wase<br>Fuel Penalty<br>Electricity<br>Water  | te Ma<br>\$<br>\$<br>\$   | 15%<br>60.00<br>100%<br>nagement<br>13.640<br>0.036   | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mscf   | 1.00<br>0<br>0<br>0<br>0<br>0   | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr   | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement   | s<br>r<br>\$<br>\$<br>\$<br>\$   | 9,855<br>65,700  |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Wase<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air  | te Ma<br>\$<br>\$<br>\$<br>\$   | 15%<br>60.00<br>100%<br>nagement<br>13.640<br>0.036<br>0.004<br>0.367   | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal   | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0   | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mscf/yr<br>mgal/yr   | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement   | s<br>s<br>s<br>s<br>s<br>s<br>s<br>s<br>s<br>s<br>s<br>s<br>s<br>s<br>s<br>s<br>s<br>s<br>s                    | 9,85   |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Wase<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal  | te Ma<br>\$<br>\$<br>\$<br>\$<br>\$   | 15%<br>60.00<br>100%<br>nagement<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>4.8800<br>488.000                     | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/mgal<br>/mscf<br>/mgal<br>/ton                                  | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0                     | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mscf/yr<br>mgal/yr<br>ton/year<br>ton/year   | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement   | ,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,                    | 9,85   |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Wass<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport   | te Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 15%<br>60.00<br>100%<br>nagement<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652            | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton                 | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0      | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton/year  | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement   | ,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,                    | 9,85   |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime  | te Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 15%<br>60.00<br>100%<br>nagemeni<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton         | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mscf/yr<br>mgal/yr<br>ton/year<br>ton-wi/yr<br>ton/yr                                    | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement   | ,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,                    | 9,855<br>65,700<br>65,700  |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Wast<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia  | te Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 15%<br>60.00<br>100%<br>nagement<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652            | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton         | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0      | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mscf/yr<br>mgal/yr<br>ton/year<br>ton-wi/yr<br>ton/yr                                    | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement   | ,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,                    | 9,855<br>65,700<br>65,700<br>3,516   |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime  | te Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 15%<br>60.00<br>100%<br>nagemeni<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton         | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mscf/yr<br>mgal/yr<br>ton/year<br>ton-wi/yr<br>ton/yr                                    | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement   | ,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,<br>,                    | 9,855<br>65,700<br>65,700<br>3,516   |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs  | te Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 15%<br>60.00<br>100%<br>nagemeni<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton         | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton-wi/yr<br>ton/yr<br>gal/yr                         | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement<br>engineering judgement  | \$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 9,855<br>65,700<br>65,700  |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Wass<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs<br>Overhead   | te Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 15%<br>60.00<br>100%<br>nagemeni<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton         | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton/year<br>ton/year<br>ton/yr<br>gal/yr              | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement<br>engineering judgement<br>compacts expected engineering judgement<br>engineering judgement  | \$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 9,853<br>65,700<br>65,700<br><u>3,510</u><br><b>210,47</b>                                   |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Wass<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Maste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)  | te Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 15%<br>60.00<br>100%<br>nagemeni<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton         | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton/year<br>ton/yr<br>gal/yr                          | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement<br>engineering judgement<br>conservatively excluded from analysis<br>of total capital costs (TCI)   | \$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 9,855<br>65,700<br>65,700<br><u>3,516</u><br>210,471   |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Wast<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)                               | te Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 15%<br>60.00<br>100%<br>nagemeni<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton         | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mscf/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton-wi/yr<br>ton/yr<br>gal/yr              | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement<br>engineering judgement<br>of impacts expected engineering indgement<br>of impacts expected engineering indgement<br>engineering indgement | \$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 9,855<br>65,700<br>65,700<br>  |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Wast<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)<br>Insurance (1% total capital costs)                     | te Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 15%<br>60.00<br>100%<br>nagemeni<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton         | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton-mi/yr<br>ton/yr<br>gal/yr<br>0%<br>2%<br>1%<br>1% | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement<br>engineering judgement<br>of impacts expected engineering idgement<br>of impacts expected engineering idgement<br>of impacts expected engineering idgement<br>of intel capital costs (TCI)<br>of total capital costs (TCI)  | \$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 9,855<br>65,700<br>65,700<br><u>3,516</u><br><b>210,471</b><br>24,375<br>12,186              |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Wast<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)                               | te Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 15%<br>60.00<br>100%<br>nagemeni<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton         | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton-mi/yr<br>ton/yr<br>gal/yr<br>0%<br>2%<br>1%<br>1% | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement<br>engineering judgement<br>conservatively excluded from analysis<br>of total capital costs (TCI)<br>of total capital costs (TCI)<br>of total capital costs (TCI)<br>capital recovery factor for a 20-year equipment  | \$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 65,700<br>9,855<br>65,700<br>65,700<br>  |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Wast<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)<br>Insurance (1% total capital costs)                     | te Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 15%<br>60.00<br>100%<br>nagemeni<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton         | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton-mi/yr<br>ton/yr<br>gal/yr<br>0%<br>2%<br>1%<br>1% | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement<br>engineering judgement<br>of impacts expected engineering idgement<br>of impacts expected engineering idgement<br>of impacts expected engineering idgement<br>of intel capital costs (TCI)<br>of total capital costs (TCI)  | \$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 9,855<br>65,700<br>65,700<br><u>3,516</u><br>210,471<br>24,375<br>12,186<br>12,186<br>83,824 |
| Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Wass<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastevater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)<br>Insurance (1% total capital costs)<br>Capital Recovery | te Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$   | 15%<br>60.00<br>100%<br>nagement<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>0.652<br>290.000<br>0.293   | of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton<br>/gal | 1.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton-mi/yr<br>ton/yr<br>gal/yr<br>0%<br>2%<br>1%<br>1% | SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet fo<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>no impacts expected- engineering judgement<br>no impacts expected- engineering judgement<br>engineering judgement<br>conservatively excluded from analysis<br>of total capital costs (TCI)<br>of total capital costs (TCI)<br>of total capital costs (TCI)<br>capital recovery factor for a 20-year equipment  | \$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 9,855<br>65,700<br>65,700<br>  |

### Appendix C

Unit-Specific Screening Level Cost Summary for SO<sub>2</sub> Control Measures

#### Minnesota Power - Taconite Harbor Energy Center Regional Haze RFI Control Equipment Cost Evaluation

NOTE: Costs presented per unit but projects would only be done on both units together

| Indirect Capital Costs     0% None required     \$       Engineering, supervision     0% None required     \$       Constructor fees     0% None required     \$       Start-up     0% None required     \$       Petromance test     0% None required     \$       Model Studies     0% None required     \$       Constructor fees     0% None required     \$       India Indirect Capital Investment (TCI) = DC + IC     \$     \$       India Indirect Capital Investment (TCI) = DC + IC     \$     \$       India Indirect Capital Investment (TCI) = DC + IC     \$     \$       India Indirect Capital Investment (TCI) = DC + IC     \$     \$       Indirect Anal Investment (TCI) = DC + IC     \$     \$       International Capital Investment (TCI) = DC + IC     \$     \$       International Capital Investment (TCI) = DC + IC     \$     \$       International Capital Investment (TCI) = DC + IC     \$     \$       International Capital Investment (TCI) = DC + IC     \$     \$       International Capital Investment (TCI) = DC + IC     \$     \$       International Capital Investment (TCI) = DC + IC     \$     \$       International Capital Investment (TCI) = DC + IC     \$     \$       International Capital Investment (TCI) = DC + IC     \$     \$       Internatio  | Emission Unix Number         Existen L: Inset Displance Unixed Displance D                                 |  |  |  |   |  |  |   |  |  |
|---|--|--|--|--|---|--|--|---|--|--|
| Emission but Number         Delate Iso 1 and No. 2           Control Equipment Type         CPD moduling to adjust injection processment)         Sold Market Section 2         Sold Section  | Emission Univ Number         Deleter No. 1 and No. 2           Concret Explorem Type         Concret Explorem Type           Data is         CPD moduling to signili spectro por tocations and reacive operational problems.           Main Concret Query         Main Sector S  | UIPMENT DETAILS  |  |  |   |  |  |   |  |  |
| Current Type         Enhance LineadSD Appendix IntegIO part Inculation are readive gradeous proteines         Set   | Cardial Captioner Type         Enhance LandSDC Supportement)           Debits         100 MUBBahr           Expended Structure Rule         100 MUBBahr           Expended Structure Rule         2.00 None           Partal Costs         2.00 None           <  |  | Boi  | lers No. 1   | and No. 2   |  |  |   |  |  |
| Durinis         CPD notable to adjust historio pot locators and nocke operational problems           Max Cpersing Priority         900 MMBuhr           Expected Annual Fund Operation         8.720 Hous           Score Cost         20 ym           Prior Capital Cost         900 MMBuhr           Direct Capital Cost         900 MMBuhr           Direct Capital Cost         900 MMBuhr           Direct Capital Cost         900 MMBuhr           Prior Capital Cost         900 MMBuhr   | Durinis         CPD modaling to adjust injection port locations and resolve operational problems           Max Cpencing Design         500 MMAurit*           Expected Annual Fund and Cpencing         100%           Spected Annual Fund and Cpencing         3.700 Facal           2.20 yrs         3.200 from face //www.indoinalisesene.gov/releasesh15/.200 from face //www.indoinalisesene.gov/releasesh15/.200 yrs           Prior Capital Costs         0.00%           Prior Capital Costs         0.00%           Prior Capital Costs         0.00%           Producting a seguring         0.00% </td <td></td> <td></td> <td></td> <td></td> <td>n (SO2 impro</td> <td>vement)</td> <td></td> <td></td> <td></td>   |  |  |  |   | n (SO2 impro   | vement)  |   |  |  |
| Mar. Covering Design Expensed Units Relation Relatio Relation Relation Relation Rela  | Mar. Covering Design 200 MMB/sum 200 MMB/sum 200 MMB/sum   |  |  |  | •   | • •  |  | operational problems  |  |  |
| Expended Vollation Network Index (2) Particle 2005 100/05 200/05/05 200/  | Expected Viliation Rate         100%           Expected Viliation Rate         3,20% Bank Prime Rate to July 16, 2020 from these diverses ex. gov/teleasesh15/.           Expected Rate To Rate         3,20% Bank Prime Rate to July 16, 2020 from these diverses ex. gov/teleasesh15/.           Decid Capital Cess         Final Prime Rate Statement (State Capital Cess)           Prime Capital Cess         6,87% of critical device case (N)         5           Prime Capital Cess         6,87% of critical device case (N)         5           Prime Capital Cess         0,00% of constraint/vy excluded from analysis         5           Prime Capital Cess         0% Conservatively excluded from analysis         5           Prime Capital Cess         0% Conservatively excluded from analysis         5           Prime Capital Cess         0% Conservatively excluded from analysis         5           Prime Capital Cess         0% Conservatively excluded from analysis         5           Prime Capital Cess         0% Conservatively excluded from analysis         5           Prime Capital Cess         0% Conservatively excluded from analysis         5           Prime Capital Cess         0% Conservatively excluded from analysis         5           Prime Capital Cess         0% Conservatively excluded from analysis         5           Prime Capital Cess         0% Conservatively excluded f   |  | OIL  |  |   | ion port locatio   |  | e operational problems  |  |  |
| Expected Annual Hours of Quence         9,700 Hours         225% (Bach Prior Rate for July 16, 2020 from Higs, Juwe Indextalence are govine incession 15%.           Expected Equipment Line         225% (Bach Prior Rate for July 16, 2020 from Higs, Juwe Indextalence are govine incession 15%.         3,000 Migs           Perchase Equipment (In Proceeding) Indextalence are govine incession (In Control Gachero Set (In Contr   | Experted Annual Hours of Operation         A.700 Hours           Annual Hours of Experiment Life         3.25% (EAR) Prime Rate for July 16, 2020 Houn Haps.//www.federalines.res.gov/releases/h1fs/.           Prich Cortis         State Transmission         3.25% (EAR) Prime Rate for July 16, 2020 Houn Haps.//www.federalines.res.gov/releases/h1fs/.           Prich Cortis         State Transmission         6.000 State Costs         5.000 State Costs           Prich Cortis         State Transmission         5.000 State Costs         5.000 State Costs           Prich Cortis         State Transmission         5.000 State Costs         5.000 State Costs           Prich Cortis         State Transmission         5.000 State Costs         5.000 State Costs           Prich Cortis         State Transmission         State Transmission         5.000 State Costs         5.000 State Costs           Prich Cortis         State Transmission         Discontral division analysis         5         5           Prich Cortis         State Transmission         Discontral division analysis         5         5           Prich Cortis         Discontral division analysis         S         5         5           Pricing         Discontral division analysis         S         5         5           Pricing         Discontral division analysis         S         5  |  |  |  |   |  |  |   |  |  |
| Animal Instrume Rate         3.2% Bark Prime Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 from Meps-lawse Independent Access The Construme Rate for July 18, 2020 fr  | Arrung Arrung Deprote Deprot Deprote Deprote Deprote Deprote Deprote Deprote De                        |  |  |  |   |  |  |   |  |  |
| Excerct Support         20 ys           APT/AL COSTS         Decided Explorement (A) (1)<br>Proceedings (A) (1)<br>Proceeding Explorement (A) (1)<br>Proceeding   | Expected Equipment Life 20 ys  PTRAL COSTS   |  |  | ,  |   | te for July 16   | 2020 from httr   | s://www.federalresen/e.gov/releases/b15/  |  |  |
| APPTAL COSTS Dec. Capacity Casts Dec. Dec. Dec. Dec. Dec. Dec. Dec. Dec.  | THAL COSTS The Characteristic Section 1 (1) The Characteristic Section 1 (2) The Sectio |  |  |  |   | ite for oury ro,   | 2020 110111 110  |   |  |  |
| Direct Capital Costs Purchased Equipment (2016) Purchased Equipment (2016) Purchased Equipment (2016) Purchased Equipment (2016) Equipment (2016) Sales Trans Sale  | Direct Capital Costs         Engineering judgment chand on protokia project by Momental Power (\$ 2000)         3.0000           Purchased Equipment Costs (A)         5.0000         3.0000         3.0000           Sales Taxes         5.076 d'oracted device cost (A)         5.0000         3.0000           Purchased Equipment Total (B)         5.076 d'oracted device cost (A)         5.0000         3.0000           Prednased Equipment Total (B)         0% Conservatively excluded from analysis         5         -           Purchased Equipment Total (B)         0% Conservatively excluded from analysis         5         -           Prednased Equipment Total (B)         0% Conservatively excluded from analysis         5         -           Prednase Equipment Total (B)         0% Conservatively excluded from analysis         5         -           Prednase Equipment Total (B)         0% Conservatively excluded from analysis         5         -           Prednase Equipment Total (B)         0% Konserequired         5         -           Prednase Equipment Total (B)         0% Konserequired         5         -           Total Contex (Caluel A)         0% Konserequired         5         -           Total Contex (Caluel A)         0% Konserequired         5         -           Total Contex (Caluel A)         0% Konserequired </td <td></td> <td></td> <td></td> <td><i>j.</i> -</td> <td></td> <td></td> <td></td> <td></td> <td></td>  |  |  |  | <i>j.</i> -   |  |  |   |  |  |
| Perchasel Equipment (1)         Engineering judgement based on previous project by Minesoba Power (1)         3.000.00           Perchasel Equipment Total (b)         Engineering judgement based on previous project by Minesoba Power (1)         3.000.00           Perchasel Equipment Total (b)         Status (1)         Status (1)         Status (1)           Perchasel Equipment Total (b)         Status (1)         Status (1)         Status (1)           Perchasel Equipment Total (b)         Status (1)         Status (1)         Status (1)           Perchasel Equipment Total (b)         Status (1)         Status (1)         Status (1)           Perchasel Equipment Total (b)         Status (1)         Status (1)         Status (1)         Status (1)           Perchasel Equipment Total (b)         Status (1)         Status (1)         Status (1)         Status (1)           Perchasel Equipment Total (b)         Status (1)         Status (1)         Status (1)         Status (1)           Perchasel Equipment Total (b)         Status (1)         Status (1)         Status (1)         Status (1)           Perchasel Equipment Total (1)         Status (1)         Status (1)         Status (1)         Status (1)           Perchasel Equipment Total (1)         Status (1)         Status (1)         Status (1)         Status (1)         Status (1) </td <td>Purchasel Equipment Cats (r)         Engineering judgement tasks on previous project by Minnetota Power (r)         3.000.00           Purchasel Equipment Total (r)         Engineering judgement tasks on previous project by Minnetota Power (r)         3.000.00           Purchasel Equipment Total (r)         S.000.00         S.000.00         S.000.00           Purchasel Equipment Total (r)         S.000.00         S.000.00         S.000.00           Installation         OVE Conservatively excluded from analysis         S.000.00           Particip Residence Cats (r)         S.000.00         S.000.00         S.000.00         S.000.00           Particip Reside Cats (r)         S.000.00         S.000.00<td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></td>  | Purchasel Equipment Cats (r)         Engineering judgement tasks on previous project by Minnetota Power (r)         3.000.00           Purchasel Equipment Total (r)         Engineering judgement tasks on previous project by Minnetota Power (r)         3.000.00           Purchasel Equipment Total (r)         S.000.00         S.000.00         S.000.00           Purchasel Equipment Total (r)         S.000.00         S.000.00         S.000.00           Installation         OVE Conservatively excluded from analysis         S.000.00           Particip Residence Cats (r)         S.000.00         S.000.00         S.000.00         S.000.00           Particip Reside Cats (r)         S.000.00         S.000.00 <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td>   |  |  |  |   |  |  |   |  |  |
| Purchased Equipment (bits (A))         Engineering isogenet to sate do previous project by Minesola Power \$  | Purchase Equipment Data (n)         Engineering indeprent task on pervisuing angles by Minescia Power (s)         3.000.00           Description         0.00% of control device cost (A)         5.000.00           Description         0.00% of control device cost (A)         5.000.00           Purchase Equipment Total (b)         5.000.00         5.000.00           Purchase Equipment Total (b)         5.000.00         5.000.00           Part (c)         0.000.00         0.000.00         5.000.00           Part (c) <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td>  |  |  |  |   |  |  |   |  |  |
| Internetiation         10.00% of control device cost (A)         \$ 300.00           Sets Trans         2.0% of control device cost (A)         \$ 300.00           Percentation Equipment Total (B)         2.0% of control device cost (A)         \$ 200.20           Installation         70% of control device cost (A)         \$ 200.20           Percentation Equipment Total (B)         0% Contensitivity vocubed from analysis         \$           Foundation & supports         0% Contensitivity vocubed from analysis         \$           Percentation Standard Expanse         0% Contensitivity vocubed from analysis         \$           Installation Standard Expanse         0% Contensitivity vocubed from analysis         \$           Installation Standard Expanse         0% Contensitivity vocubed from analysis         \$           Installation Standard Expanse         0% None required         \$         \$  | Instantaneous         Instantentaneous         Instantaneous         Insta   |  |  |  |   | Engineering  | iudaement ba   | sed on previous project by Minnesota Power  | \$   | 3.000.00   |
| Sele Taxes         6.87% of control device cost (A)         \$ 206.25           Proget         5.9% of control device cost (A)         \$ 3.866.25           Productions & supports         0% Conservatively excluded from analysis         \$ -           Handlag Servation         0% Conservatively excluded from analysis         \$ -           Production         0% None required         \$ -           Baildings, as regarded         0% None required         \$ -           Tead She Specific - Oher         \$ -         \$ -           Tead She Specific - Oher         \$ -         \$ -           Tead She Specific - Oher         \$ -         \$ -           Tead She Specific - Oher         \$ -         \$ -           Tead She Specific - Oher         \$ -         \$ -           Startup         <  | Sile Taxes         0.87% of control device cost (A)         5         202.23           Purchase Equipment Total (B)         0.9% of control device cost (A)         5.356.21           Purchase Equipment Total (B)         0.9% of control device cost (A)         5.356.21           Purchase Equipment Total (B)         0.9% Conservatively excluded from analysis         5           Period         0% Kone required         5           Parallation Selections         0% Kone required         5           Parallation Selections         0% Kone required         5           Teal Bits Selection:         5         5           Period Costs         0% Kone required         5           Ecliptical Costs         0% Kone required         5           Preferences         0% Kone required         5           Preferences         0% Kone required         5           Preferencose         0% K  |  |  |  |   | 2.19.1001.19   |  |   |  |  |
| Perchased Equipment Total (6)         \$ 3.555.25           Installation         0% Conservatively excluded from markpits         \$ -           Honding A supports         0% Conservatively excluded from markpits         \$ -           Plong         0% Conservatively excluded from markpits         \$ -           Plong         0% Conservatively excluded from markpits         \$ -           Installation Subtotal Standard Expenses         0% Conservatively excluded from markpits         \$ -           Installation Subtotal Standard Expenses         0% None required         \$ -           Installation Subtotal Standard Expenses         0% None required         \$ -           Installation Subtotal Standard Expenses         0% None required         \$ -           Installation Subtotal Standard Expenses         0% None required         \$ -           Installation Subtotal Standard Expenses         0% None required         \$ -           Installation Subtotal Standard Expenses         0% None required         \$ -           Installation Subtotal Standard Expenses         0% None required         \$ -           Installation Subtotal Standard Expenses         0% None required         \$ -           Installation Subtotal Standard Expenses         0% None required         \$ -           Installation Standard Expenses         0% None required         \$ -  | Purchase Equipment Total (8)         \$ 3.555.2           Installation         0% Conservatively packade from analysis         \$           Electrical         0% Conservatively packade from analysis         \$           Pring         0% Conservatively packade from analysis         \$           Pring         0% Conservatively packade from analysis         \$           Installation         0% Conservatively packade from analysis         \$           Installation Subtoal Standard Exponses         0% Conservatively packade from analysis         \$           Installation Subtoal Standard Exponses         0% None required         \$         \$           Installation Subtoal Standard Exponses         0% None required         \$         \$           Installation Subtoal Standard Exponses         0% None required         \$         \$           Installation Subtoal Standard Exponses         0% None required         \$         \$           Installation Subtoal Standard Exponses         0% None required         \$         \$           Installation Subtoal Standard Exponses         0% None required         \$         \$           Installation Subtoal Standard Exponses         0% None required         \$         \$           Installation Subtoal Standard Exponse         0% None required         \$         \$   | Sales Taxes  |  |  |   |  |  |   | \$   | 206,25   |
| Installation         Off. Conservatively excluded from analysis         S         -           Printing         0% Conservatively excluded from analysis         S         -           Treal Site Specific Costs         0% None required         S         -           Treal Site Specific Costs         0% None required         S         -           Treal Site Specific Costs         0% None required         S         -           Statistion Studes         0% None required         S         -           Treal Site Specific Costs         0% None required         S         -           Statistion Studes         0% None required         S         -           Treal Site Specific Costs         0% None required         S         -           Statistion Studes         0% None required         S         -   | Installation         Off. Conservatively excluded from analysis         S         -           Beefing         Off. Conservatively excluded from analysis         S         -           Pring         Off. Conservatively excluded from analysis         S         -           Installation         Off. Conservatively excluded from analysis         S         -           Pring         Off. Conservatively excluded from analysis         S         -           Installation         Off. Conservatively excluded from analysis         S         -           Printing         Off. None required         S         -           Building, as required         Off. None required         S         -           Table Site Specific - Other         Off. None required         S         -           Total Site Specific - Other         S         -         -         -           Total Site Specific - Other         S         -         -         -         -           Total Site Specific Costs         -         S         -   |  |  |  |   |  | 5.0%   | of control device cost (A)  |  |  |
| Foundations & supports         ONE Conservatively excluded from analysis         \$         -           Handing & section         ONE Conservatively excluded from analysis         \$         -           Electrical         ONE Conservatively excluded from analysis         \$         -           Installation for during         ONE Conservatively excluded from analysis         \$         -           Trad Direct Spanson         ONE Conservatively excluded from analysis         \$         -           Trad Direct Spanson         ONE Conservatively excluded from analysis         \$         -           Trad Direct Spanson         ONE Conservatively excluded from analysis         \$         -           Trad Direct Spanson         ONE None required         \$         -           Trad Direct Spanson         ONE None required         \$         -           Trad Direct Spanson         ONE None required         \$         -           Contraction & field spanson         ONE None required         \$         -           Trad Direct Spanson         ONE None required         \$         -           Contraction & field spanson         ONE None required         \$         -           Trad Direct Spanson         ONE None required         \$         -           Direct Spanson         ONE N  | Foundations & supports         0%         Conservatively excluded from analysis         5         -           Handing & exclude         0%         Conservatively excluded from analysis         5         -           Bislandino         0%         Conservatively excluded from analysis         5         -           Installation Subtral Standard Exponses         9%         Conservatively excluded from analysis         5         -           Total Site Specific Costs         0%         None required         5         -         -           Total Site Specific Costs         0%         None required         5         -         -           Total Site Specific Costs         0%         None required         5         -  | Purchased Equipment Total (B)  |  |  |   |  |  |   | \$   | 3,656,25   |
| Handing & erection     0% Conservatively excluded from analysis     \$     -       Parting     0% Conservatively excluded from analysis     \$     -       Parting     0% Conservatively excluded from analysis     \$     -       Parting     0% Conservatively excluded from analysis     \$     -       Installation Subtaini Standard Expenses     0% Conservatively excluded from analysis     \$     -       Installation Subtaini Standard Expenses     0% None required     \$     -       Total District Standard Expenses     0% None required     \$     -       Total District Standard Expenses     0% None required     \$     -       Total District Standard Expenses     0% None required     \$     -       Total District Standard Expenses     0% None required     \$     -       Total District Standard Expenses     0% None required     \$     -       Installation Static Standard Expenses     0% None required     \$     -       Contractor frees     0% None required     \$     -       Start-sp     0% None required     \$     -       Optimized Expenses     0% None required     \$     -       Contactor frees     0% None required     \$     -       Start-sp     0% None required     \$     -       Total Diverse Tot   | Handing & erection         0% Conservatively excluded from analysis         \$         -           Plenning         0% None required         \$         -           Building as required         0% None required         \$         -           Total Direct Capital Costs         0% None required         \$         -           Indirect Capital Costs         0% None required         \$         -           Contractor fors         0% None required         \$         -           Start-up         0% None required         \$         -           Start-up         0% None required         \$         -           Contractor fors         0% None required         \$         -           Start-up         0% None required         \$         -           Contractor fors         0% None required  |  |  |  |   |  |  |   |  |  |
| Electrical     0% Conservatively excluded from analysis     \$       Point<br>Installation     0% Conservatively excluded from analysis     \$       Painting     0% Conservatively excluded from analysis     \$       Installation     0% Conservatively excluded from analysis     \$       Installation     0% Conservatively excluded from analysis     \$       Installation     0% None required     \$       Buildings, as required     0% None required     \$       Site Preparation, as required     0% None required     \$       Site Specific Costs     -     \$       Teal Direct Capital Costs     0% None required     \$       Engineering, supervision     0% None required     \$       Construction & field exprese     0% None required     \$       Optimize test     0% None required     \$       Model Studies     0% None required     \$       Contraction A field exprese     0% None required     \$       Contrequired     \$  | Electrical       0% Conservatively excluded from analysis       \$         Pining       0% Conservatively excluded from analysis       \$         Instaltion       0% Conservatively excluded from analysis       \$         Sile Preparation, as required       0% None required       \$         Bile Specific Costs       3       \$         Total Direct Capital Costs       3       \$         Construction field expenses       0% None required       \$         Construction field expenses       0% None required       \$         Construction field expenses       0% None required       \$         Construction field expense       0% None required       \$         Contingenoment exits </td <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td>-</td>  |  |  |  |   |  |  |   |  | -  |
| Piping     0% Conservatively excluded from analysis     \$     -       Installation Subtral Standard Expenses     0% Conservatively excluded from analysis     \$     -       Sub Preparation, as required     0% None required     \$     -       Buildings, as required     0% None required     \$     -       Tetal Biol Statutal Standard Expenses     0% None required     \$     -       Tetal Biol Statutal Standard Expenses     0% None required     \$     -       Tetal Biol Statutal   | Pring<br>Installation<br>Participation         0% Conservatively excluded from analysis<br>s         s         -           Installation<br>Suppresentation, as required         0% Conservatively excluded from analysis<br>s         -         -           Suppresentation, as required         0% None required         s         -           Suppresentation, as required         0% None required         s         -           Total Site Specific Costs         0% None required         s         -           Total Site Specific Costs         0% None required         s         -           Installation Total         s         -         s         -           Total Site Specific Costs         0% None required         s         -           Environment Cost         0% None required         s         -           Contraction & field expreses         0% None required         s         -           Contraction fees         0% None required         s         - <tr< td=""><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>-</td></tr<>  |  |  |  |   |  |  |   |  | -  |
| Instalation         Offic Conservatively excluded from analysis         \$         -           Instalation Suboral Standard Expense         0% Conservatively excluded from analysis         \$         -           Stip Pregrammed Statistics as required         0% None required         \$         -           Buildings, as required         0% None required         \$         -           Buildings, as required         0% None required         \$         -           Tetal Dives Capital Cost b         \$         -         \$         -           Instalation Supervision         0% None required         \$         -         -           Construction field expenses         0% None required         \$         -         -           Construction field         \$         -   | Instaliation         Offic Conservatively excluded from analysis         \$         -           Instalation Subtral Standard Expenses         0% Conservatively excluded from analysis         \$         -           Stip Prestramation As required         0% None required         \$         -           Buildings, as required         0% None required         \$         -           Stip Specific Costs         \$         -         -           Instalation for old         0% None required         \$         -           Total Direct Costal Costs         \$         -         -           Indirect Costal Costs         0% None required         \$         -           Construction Red         0% None required         \$         -           Optimized Castal Costs         0% None required         \$         -           Contractor files         0% None required         \$         -           Model Studies         0% None required         \$         -           Model Studies         0% None required         \$         -           Intel Costal Integratement Parts (Catalyst, Filter Bags, etc) for Costal of the apedic protect red aff or earned, additional feabor hours to red the eard for earned, additional feabor hours to red the eard for earned, additional feabor hours to red the eard for earned, ed. )           Intel To  |  |  |  |   |  |  |   |  | -  |
| Paining         Offic Conservatively excluded from analysis         \$           Stat Programation, as required         0%. None required         \$           Stat Programation, as required         0%. None required         \$           Stat Programation, as required         0%. None required         \$           Stat Programation, as required         \$         -           Stat Programation, as required         \$         -           Total Stat Specific Costs         \$         -           Total Stat Specific Costs         \$         -           Construction & Inde spenses         0%. None required         \$           Construction & Red spenses         0%. None required         \$           Construction & Inde spenses         0%. None required         \$           Construction & Inde spenses         0%. None required         \$           Construction & Inde spenses         0%. None required         \$           Deat Construction & Inde spenses         0%. None required         \$           Deat Construction & Inde spenses         0%. None required         \$           Deat Construction & Inde spenses         0%. None required         \$           Deat Construction & Inde spenses         0%. None required         \$           Total Deat Conste Deat Construction & Inde sp  | Perining         0% Conservatively excluded from analysis         s         -           Site Preparation, as required         0% None required         \$         -           Site Preparation, as required         0% None required         \$         -           Total Site Specific Costs         0% None required         \$         -           Total Site Specific Costs         \$         \$         -           Indirect Capital Costs         0% None required         \$         -           Indirect Capital Costs         0% None required         \$         -           Indirect Capital Costs         0% None required         \$         -           Contraction & Site Specific Costs         0% None required         \$         -           Contraction & Site Specific Costs         0% None required         \$         -           Contraction & Site Specific Costs         0% None required         \$         -           Contraction & Site Specific Costs         0% None required         \$         -           Contraction & Site Specific Costs         0% None required         \$         -           Contraction & Site Specific Costs         0% None required         \$         -           Contraction & Site Specific Costs         0% None required         \$         - <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td>-</td>  |  |  |  |   |  |  |   |  | -  |
| Installation Subtrail Student Expenses         visual of the sequence         s         -           Site Proparation, as required         0% None required         \$         -           Buildings, as required         0% None required         \$         -           Dissipation - Come rests         0% None required         \$         -           Installation Suberout State         0% None required         \$         -           Text Direct Capital Costs         \$         -         \$         3.855.25           Indirect Capital Costs         0% None required         \$         -         -           Statustion State data space science         0% None required         \$         -         -           Statustion A field aconneces         0% None required         \$         -         -         -           Ordingencies         0% None required         \$         -         -         -         -           Total Indirect Capital Costs. IC         5         -  | Installation Subtral Standard Expenses         9         9           Sile Preparation, as required         0% None required         \$           Buildings, as trequired         0% None required         \$           Sile Specific - Other         5         -           Teal Differed Specific - Other         \$         -           Teal Differed Capital Cost, 0C         \$         3.456.22           Indirect Capital Cost, 0C         \$         \$           Contingencies         0% None required         \$           Oritingencies         0% None required         \$           Indirect Capital Cost, 0C         \$         3.456.22           Initiation Of Cost Information         \$         3.456.22<  |  |  |  |   |  |  |   |  | -  |
| Building, as required         0% None required         \$         -           Site Specific Costs         \$         -  | Building: as required         0% None required         \$         -           Site Specific Costs         \$         -         5         -           Intellation Total         \$         -         5         3,856,22           Intellation Total         \$         -         -         5         3,856,22           Intellation State         \$         0% None required         \$         -         -         5         3,556,22         -         -         5         3,556,22         -         5         3,556,22         -         -         5         3,556,22         -         -         5         3,556,22         - <td< td=""><td></td><td>3</td><td></td><td></td><td></td><td>570</td><td></td><td></td><td>-</td></td<>   |  | 3  |  |   |  | 570  |   |  | -  |
| Billinging, as required         0%. None required         \$         -           Total Site Specific Costs         \$         -         -           Total Site Specific Costs         \$         -         -           Total Divert Capital Cost, DC         \$         3,865,265           Indirect Capital Costs         0%. None required         \$         -           Constructions. supervision         0%. None required         \$         -           Constructions. Steps vision         0%. None required         \$         -           Construction Fees         0%. None required         \$         -           Construction Fees         0%. None required         \$         -           Start-up         0%. None required         \$         -           Total Diverse         0%. None required         \$         -           Total Start-up         0%. None required         \$         -           Total Diverse         5         3,656,25         -         -           Start-up         NOTE: These are incremental "add-on" costs of the specific project, not al-in costs (for example, additional labor hours to rur the coupernent, additional totage of waste generated, etc.)         -           Total Diverse         0         0         NOTE: These are incremental "addi-on" costs o   | Building: as required         0% None required         \$         -           Site Specific Costs         \$         -         5         -           Intellation Total         \$         -         5         3,856,22           Intellation Total         \$         -         -         5         3,856,22           Intellation State         \$         0% None required         \$         -         -         5         3,556,22         -         -         5         3,556,22         -         5         3,556,22         -         -         5         3,556,22         -         -         5         3,556,22         - <td< td=""><td>Site Properation on required</td><td></td><td></td><td></td><td></td><td>00/</td><td>None required</td><td>¢</td><td></td></td<>   | Site Properation on required   |  |  |   |  | 00/  | None required   | ¢  |  |
| Site Specific - Other     0% None required     \$       Total Site Specific Costs     \$       Indirect Capital Costs, DC     \$       Contractor fee     0% None required     \$       Contractor fee     0% None required     \$       Contractor fee     0% None required     \$       Star-up     0% None required     \$       Performance test     0% None required     \$       Model Studies     0% None required     \$       Contractor fee     0% None required     \$       Total Intel Capital Costs, DC     0% None required     \$       Contractor fee     0% None required     \$       Contractor fee     0% None required     \$       Total Intel Capital Costs, DC     \$     \$       Contractor fee     0% None required     \$       Total Intel Capital Investment (TCI) = DC + IC     \$     \$       Start Up     Dectation formation induces to non the equipment, additional format on of waste generated, etc.)     \$       International Investment, additional format of waste generated, etc.)     \$     \$       International Costs, DC     Ont of Unit of Unit of Unit of Costs     \$       Operator     \$     \$     \$       Operator     \$     \$     \$       Operator     \$     \$     \$<   | Site Specific C-Other     0% None required     \$       Total Site Specific Costs     \$       Installation Total     \$       Captal Dect Capital Costs     \$       Exploreting, supervision     0% None required     \$       Contractor feas     0% None required     \$       Contractor feas     0% None required     \$       Start-up     0% None required     \$       Performance test     0% None required     \$       Model Studies     0% None required     \$       Contractor feas     0% None required     \$       Total Intercet Capital Costs, IC     \$     \$       Contractor feas     0% None required     \$       Contractor feas     0% None required     \$       Contractor feas     0% None required     \$       Total Intercet Capital Costs, IC     \$     3,656,22       Unit dor     Unit of     \$     3,656,22       Unit dor     Unit of     None required     \$       Contractor, ITC Registerment Parts (Catalyst, Filter Bags, etc) Ior Capital Recovery Cost     \$     3,656,22       Unit dor     Unit of     None required     \$     \$       Performance Lest     Unit of     None required     \$     \$       Divert Annual Operating Costs, DC     Operating Costs, DC  |  |  |  |   |  |  |   |  | -  |
| Total Site Specific Costs       \$         Installation Total       \$         Tetal Direct Capital Costs       \$         Engineering, supervision       0%, None required       \$         Construction & field expenses       0%, None required       \$         Start-tipe       0%, None required       \$         Start-tipe       0%, None required       \$         Construction & field expenses       0%, None required       \$         Start-tipe       0%, None required       \$         Operation       \$       0%, None required       \$         Construction & field expenses       0%, None required       \$       \$         Operation       \$       0%, None required       \$       \$         Constitution & the expenses       0%, None required       \$       \$       \$         Table Addirect Capital Costs, DC       \$       3,656,259       \$       3,656,259         Equation Costs, Contraction & for example, additional babor hours to run the examplenerit, additional reagent medded, additional babor hours to run the examplenerit, additional reagent medded, additional babor hours to run the examplenerit, additional tabor       \$       3,656,259         Operator       \$       60,00       \$Hr       1,00       Invit of the same genereliad, clot, 1,01%       \$   | Total Site Specific Costs         \$           Installation Total         \$           Total Direct Capital Costs, DC         \$           Indirect Capital Cost, DC         \$           Engineering, supervision<br>Construction & field expenses         0%, None required         \$           Start, St  |  |  |  |   |  |  |   |  | -  |
| Installation Total         \$         -           Total Direct Capital Cost, DC         \$         3,855,25           Indirect Capital Cost, DC         0% None required         \$           Constructor fees         0% None required         \$           Start-up         0% None required         \$           Added Studies         0% None required         \$           Contractor fees         0% None required         \$           Total Indirect Capital Costs, IC         0% None required         \$           Total Indirect Capital Costs, IC         \$         \$           More Regulation         \$         \$           Intal Capital Investment (TCD) = DC + IC         \$         \$           NOTE: These are increated Recovery Cost         \$         \$           Direct Annual Operating Costs, DC         Work Segmental additional labor hours to rur           Operator         \$         \$         \$           Supervisor         15% of Op. Labor         Instrumental sequental, \$         \$           Maintenance         \$ <t< td=""><td>Installation Total     s     -       Total Direct Capital Costs     \$ 3,656,22       Indirect Capital Costs     Construction Reduces       Construction Reduces     0% None required     \$ -       Construction Reduces     0% None required     \$ -       Start-up     0% None required     \$ -       Start-up     0% None required     \$ -       Octimation Tees     0% None required     \$ -       Octimation Tees     0% None required     \$ -       Indirect Capital Costs     0% None required     \$ -       Contragencies     0% None required     \$ -       Total Indirect Capital Costs, IC     \$ 3,656,22       Direct Annual Operating Costs, IC     \$ 3,656,22       Unit of     Unit of     \$ 3,656,22       Direct Annual Operating Costs, IC     \$ 3,656,22       Direct Annual Operating Costs, IC     \$ 3,656,22       Operator     \$ 60,00 \$Hr     1,00       Note Required     \$ 0     \$ 3,656,22       Maintenance Labor     \$ 60,00 \$Hr     1,00       Supervisor     15% of Op.Labor     SCR controls and includes benefits, 1 hr/8 hr       <t< td=""><td></td><td></td><td></td><td></td><td></td><td>070</td><td></td><td></td><td>-</td></t<></td></t<>   | Installation Total     s     -       Total Direct Capital Costs     \$ 3,656,22       Indirect Capital Costs     Construction Reduces       Construction Reduces     0% None required     \$ -       Construction Reduces     0% None required     \$ -       Start-up     0% None required     \$ -       Start-up     0% None required     \$ -       Octimation Tees     0% None required     \$ -       Octimation Tees     0% None required     \$ -       Indirect Capital Costs     0% None required     \$ -       Contragencies     0% None required     \$ -       Total Indirect Capital Costs, IC     \$ 3,656,22       Direct Annual Operating Costs, IC     \$ 3,656,22       Unit of     Unit of     \$ 3,656,22       Direct Annual Operating Costs, IC     \$ 3,656,22       Direct Annual Operating Costs, IC     \$ 3,656,22       Operator     \$ 60,00 \$Hr     1,00       Note Required     \$ 0     \$ 3,656,22       Maintenance Labor     \$ 60,00 \$Hr     1,00       Supervisor     15% of Op.Labor     SCR controls and includes benefits, 1 hr/8 hr <t< td=""><td></td><td></td><td></td><td></td><td></td><td>070</td><td></td><td></td><td>-</td></t<>  |  |  |  |   |  | 070  |   |  | -  |
| Indirect Capital Costs         O% None required         \$         -           Constructor fees         0% None required         \$         -           Start-up         0% None required         \$         -           Operation & field expenses         0% None required         \$         -           Operation & field expenses         0% None required         \$         -           Operation & field expenses         0% None required         \$         -           Total Indirect Capital Costs IC         \$         \$         -           Total Indirect Capital Newsment (TCI) = DC + IC         \$         \$         3,855,25           Opticat Information Capital Costs IC         \$         3,855,25         -           PERATING COSTS         Note required intons of waste generated, etc.)         \$         3,855,25           Imm         Unit Cost         Measure         Use Rate         Measure         Comments           Direct Annual Operating Costs, DC         Unit Cost         Measure         Comments         \$         5,67,07           Operation         \$         60,00         \$Hr         1.00         hr/8 tr shift \$50Hr/1 value is from EPA's cost spreadsheet for \$         \$         9,85           Maintenance         \$         0.000  | Indirect Capital Costs         0% None required         \$         -           Constructor fees         0% None required         \$         -           Contractor fees         0% None required         \$         -           Start-up         0% None required         \$         -           Model Buades         0% None required         \$         -           Model Buades         0% None required         \$         -           Total Indirect Capital Costs / C         \$         \$         -           Total Indirect Capital Costs / C         \$         \$         -           Total Indirect Capital Costs / C         \$         3.656.22         \$           Justed Totor Replacement Parts (Catityat, Filter Bags, etc) for Capital Recovery Cost         \$         3.656.22           Direct Annual Operating Costs, DC         0         Unit of         Unit of         Unit of           Terest Annual Operating Costs, DC         0         Unit of         Unit of         None required         \$           Operator         \$         60.00         \$Hr         1.00         hr/8 hr shift, 8.70 Mr/yr         \$           Supervisor         15% of Op. Labor         15% of Operator Costs         \$         9.86           Maintenance         <   |  |  |  |   |  |  |   |  | -  |
| Engineering, supervision         0%         None required         \$         -           Constructor fees         0%         None required         \$         -           Star-up         0%         None required         \$         -           Performance test         0%         None required         \$         -           Total Inferce Capital Costs, IC         \$         -         \$         -           Total Inferce Capital Costs, IC         \$         \$         -         -           Total Inferce Capital Costs, IC         \$         \$         -         -           Total Inferce Capital Costs, IC         \$         \$         3,056,25           Supervisor         NOTE: These are incremental "did-on" costs of the specific project, not all-in costs (for example, additional toos to run the specific project, not all-in costs (for example, additional toos to run the specific project, not all-in costs (for example, additional toos to run the example, additional toos to run the specific project, not all-in costs (for example, additional toos to run the example, additional toos to run the specific project, not all-in costs (for example, additional toos to run the example, additional toos to run the example, additional toos to run the ex   | Engineering, supervision         0% None required         \$         -           Constructor fees         0% None required         \$         -           Start-up         0% None required         \$         -           Performance test         0% None required         \$         -           Model Studies         0% None required         \$         -           Tatal Indirect Capital Costs, IC         \$         -         \$         3.656.22           Justact Tall Indirect Capital Costs, IC         \$         3.656.22         \$         3.656.22           Justact Tall Indirect Capital Costs, IC         \$         3.656.22         \$         3.656.22           Pertarting Costs         NOTE: Tresse are incremental "add-on" costs of the specific project, not all-in costs (for example, additional not on waste generated, etc.)         \$         3.656.22           Pertarting Costs         Work for the specific project, not all-in costs (for example, additional not on waste generated, etc.)         \$         3.656.22           Direct Annual Operating Costs, DC         Operating Labor         Comments         \$         6.7.7           Supervisor         15% of Op. Labor         1.00         hr/B hr shift \$60/Hr value is from EPA's cost spreadsheet for S         \$         9.86           Maintenance Labor         \$   | Total Direct Capital Cost, DC  |  |  |   |  |  |   | \$   | 3,656,25   |
| Engineering, supervision         0%         None required         \$         -           Constructor fees         0%         None required         \$         -           Star-up         0%         None required         \$         -           Performance test         0%         None required         \$         -           Model Studies         0%         None required         \$         -           Cantingencies         0%         None required         \$         -           Total Inferce Capital Costs, IC         \$         \$         -         \$           Start-up         None required         \$         -         \$         \$           Total Inferce Capital Costs, IC         \$         \$         3,656,29         \$         \$           Start Capital Investment (TCI) = DC + IC         \$         3,656,29         \$         \$         3,656,29           PERATING COSTS         NOTE: Tresse are incremental "did-on" costs of the specific project, not all-in costs (for cample, additional not waste generated, ec.)         \$         3,656,29           Direct Annual Operating Costs, DC         Unit of         Unit of         Unit of         Maint of           Supervisor         15% of Op. Labor         100 hr/8 hr shift \$60/Hr value is from EPA's  | Engineering, supervision         0% None required         \$         -           Constructor fees         0% None required         \$         -           Start-up         0% None required         \$         -           Performance test         0% None required         \$         -           Model Studies         0% None required         \$         -           Tatal Indirect Capital Costs, IC         \$         -         \$         3.656.22           Justact Tall Indirect Capital Costs, IC         \$         3.656.22         \$         3.656.22           Justact Tall Indirect Capital Costs, IC         \$         3.656.22         \$         3.656.22           Pertarting Costs         NOTE: Tresse are incremental "add-on" costs of the specific project, not all-in costs (for example, additional not on waste generated, etc.)         \$         3.656.22           Pertarting Costs         Work for the specific project, not all-in costs (for example, additional not on waste generated, etc.)         \$         3.656.22           Direct Annual Operating Costs, DC         Operating Labor         Comments         \$         6.7.7           Supervisor         15% of Op. Labor         1.00         hr/B hr shift \$60/Hr value is from EPA's cost spreadsheet for S         \$         9.86           Maintenance Labor         \$   | Indirect Capital Costs   |  |  |   |  |  |   |  |  |
| Contractor fees       0% None required       \$       -         Start-up       0% None required       \$       -         Model Studies       0% None required       \$       -         Contingencies       0% None required       \$       -         Total Indirect Capital Costs. IC       \$       3.656.25         State Capital Costs. IC       \$       3.656.25         PERATING COSTS       NOTE: These are incremental "add-on" costs of the specific project, not all-in costs (for example, additional labor hours to rur the equipment, additional reagent medded, additional nos of waste generated, etc.)         Item       Unit of       Unit of       Comments         Operating Labor       \$       60.00       %Hr       1.00       hr/8 hr shift, \$700 hr/y       \$       65.70         Supervisor       15% of Op. Labor       15% of Operator Costs       \$       9.85         Maintenance Labor       \$       0.000 %Hr       2.00       hr/8 hr shift \$500 Hr value is from EPA's cost spreadsheet for \$       131.40         Utilities       \$       0.300 % of Maint Labor       of maintenance labor costs       \$       9.85         Maintenance Materials       100% of Maint Labor       of nonally weak sequencing judgement       \$       131.40         Utilities       0.303 % Mr/r<   | Contractor fees     0% None required     \$     -       Star-up     0% None required     \$     -       Model Studies     0% None required     \$     -       Contingencies     0% None required     \$     -       Total Indirect Capital Costs. IC     \$     3.656.22       Interact Capital Costs. IC     \$     3.656.22       Interact Capital Investment (TCI) = DC + IC     \$     3.656.22       Interact Capital Costs. IC     \$     \$     3.656.22       Operating Costs. DC     \$     \$     \$     \$  |  |  |  |   |  | 0%   | None required   |  | -  |
| Start-up<br>Performance test       0% None required       \$       -         Model Studies       0% None required       \$       -         Cantingencies       0% None required       \$       -         Total Indirect Capital Costs, IC       \$       -       -         Total Indirect Capital Costs, IC       \$       3.655,25         Signed Capital Investment (TC) = DC + IC       \$       3.655,25         Total Capital Costs, IC       \$       3.655,25         PERATING COSTS       NOTE: These are incremental "add-on" costs of the specific project, not al-in costs (for example, additional labor hours to rur<br>the equipment, additional reagent needed, additional tons of waste generated, etc. )       Init of         Item       Unit Cost       Measure       Comments         Operating Lobr       0       N/B hr shit \$60/Hr value is from EPA's cost spreadsheet for \$       \$         Operating Labor       10% of Op. Labor       10% hr B hr shit \$60/Hr value is from EPA's cost spreadsheet for \$       \$         Maintenance       \$       0.00 % Hr       1.00 hr/B hr shit \$60/Hr value is from EPA's cost spreadsheet for \$       \$         Maintenance       \$       0.00 % of Main Labor       0 ton coallyr No impacts expected- engineering iudgement \$       \$         Maintenance       \$       0.366 //hr no coal       0 ton coally  | Start-up<br>Performance test       0% None required       \$       -         Model Studies       0% None required       \$       -         Contingencies       0% None required       \$       -         Tatal Indirect Capital Costs, IC       \$       -       -         Ital Capital Costs, IC       \$       3.655.21       \$       -         Ital Capital Costs, IC       \$       3.655.21       \$       3.655.21         Usated TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost       \$       3.655.21         PERATING COSTS       MOTE: These are incremental "add-on" costs of the specific project, not all-in costs (for example, additional labor hours to rule the equipment, additional reagent needed, additional tons of waste generated, etc.)       Init of         Item       Unit Cost       Measure       Comments       Comments         Direct Annual Operating Costs, DC       Operator       \$       60.00 <shr< td="">       1.00       hr/8 hr shit \$60/Hr value is from EPA's cost spreadsheet for \$       \$       65.70         Operator       \$       60.00<shr< td="">       1.00       hr/8 hr shit \$60/Hr value is from EPA's cost spreadsheet for \$       \$       131.40         Site of Operator       \$       60.00<shr< td="">       2.00       hr/8 hr shit \$60/Hr value is from EPA's cost spreadsheet for \$       \$</shr<></shr<></shr<>  |  |  |  |   |  |  |   |  | -  |
| Performance test<br>Model Studies       0% None required       \$       -         Contingencies       0% None required       \$       -         Total Indirect Capital Costs, IC       \$       -         All Capital Investment (TCI) = DC + IC       \$       3,855,25         Jijusted TCI for Replacement Parts (Catabyst, Filter Bags, etc) for Capital Recovery Cost       \$       3,855,25         PERATING COSTS       NOTE: These are incremental "add-on" costs of the specific project, not all-in costs for example, additional labor hours to run<br>the equipment, additional equipment medid, additional tons of waste generated, etc. )       -         Tirect Annual Operating Costs, DC       Unit Cost       Measure       Comments         Operating Labor       0       S 60.00       SHr       1.00       hr/8 tr shift, 8/760 hr/y         Operating Labor       5       60.00       SHr       2.00       hr/8 tr shift, S0/Hr value is from EPA's cost spreadsheet for \$       5         Maintenance Labor       \$       60.00       SHr       2.00       hr/8 tr shift, S0/Hr value is from EPA's cost spreadsheet for \$       9.85         Maintenance Materials       100% of Maint Labor       0 ton coal/yr       No impacts expected- engineering iudgement \$       131.40         SGR controls and includes benefits, 2 hr/8 tr shift, 8/76 hr/yr       No impacts expected- engineering iudgement \$   | Performance test<br>Model Studies     0% None required     \$     -       Contingencies     0% None required     \$     -       Total Indirect Capital Costs. IC     \$     -       Indirect Capital Costs. IC     \$     3,656,22       Jjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost     \$     3,656,22       PerATING COSTS     NOTE: These are incremental "add-on" costs of the specific project, not all-in costs (for example, additional labor hours to ru<br>the equipment, additional reagent needed, additional tons of waste generated, etc.)     Image: Cost of the specific project, not all-in costs (for example, additional labor hours to ru<br>the equipment, additional reagent needed, additional tons of waste generated, etc.)     Image: Cost of the specific project, not all-in costs (for example, additional labor hours to ru<br>the equipment, additional reagent needed, additional tons of waste generated, etc.)     Image: Cost of the specific project, not all-in costs (for example, additional labor hours to ru<br>the equipment additional reagent needed, additional tons of waste generated, etc.)     Image: Cost of the specific project, not all-in costs (for example, additional head reagent needed, additional tons of waste generated, etc.)     Image: Cost of the specific project, not all-in costs (for example, additional reagent needed, additional tons of waste generated, etc.)     Image: Cost of the specific project, not all-in costs (for example, additional reagent needed, additional tons of waste generated, etc.)     Image: Cost of the specific project, not all-in costs (for example, additional reagent needed, additional tons of waste generated, etc.)     Image: Cost of the specific proj   |  |  |  |   |  |  |   |  | -  |
| Model Studies       0% None required       \$       -         Total Indirect Capital Costs. IC       0% None required       \$       -         Indication Capital Costs. IC       \$       3,856,259         chail Capital Investment (TCI) = DC + IC       \$       3,856,259         chail Capital Investment (TCI) = DC + IC       \$       3,856,259         chail Capital Investment (TCI) = DC + IC       \$       3,856,259         percent (TCI) = DC + IC       \$       3,855,259         percent (TCI) = DC + IC       \$       3,855,259         percent (TCI) = DC + IC       \$       3,855,259         percent (TCI) = DC + IC       Unit Cost       Unit Cost       Vaste generated, etc.)         tem       Unit Cost       Unit Cost       Unit Cost       Waste generated, etc.)         Total Indirect (TCI) = DC + IC       Unit Cost       Unit Cost       Comments       SCR controls and includes benefits, 1 hr/8 hr         Signervisor       \$       60.00 S/Hr       1.00       hr/8 hr shift S00/Hr valu  | Model Studies       0% None required       \$       -         Contingencies       0% None required       \$       -         Total Indirect Capital Costs, IC       \$       3,656,25         Justed TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost       \$       3,656,25         PERATING COSTS       NOTE: These are incremental "add-on" costs of the specific project, not ali-in costs (for example, additional leader headed, additional ors of waste generated, etc.)       *         Item       Unit Cost       Weasure       Use Rate       Measure       Comments         Operator       \$       60.00 S/Hr       1.00       hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift \$60 Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift \$670 Hr/yr       \$       9,85         Maintenance       5       60.00 S/Hr       2.00       hr/8 hr shift \$670 Hr/yr       \$       9,85         Maintenance Materials       100% of Maint Labor       15% of Op. Labor       15% of Operator       \$       9,85         Viater       \$       0.036 Arwhr       2.00       hr/8 hr shift \$670 Hr/yr       \$       131,40         Site Add0 Anon coal       0 ton coal/yr       No impacts expected - engineering indgement \$       \$       131,40  |  |  |  |   |  |  |   |  | -  |
| Contingencies         0% None required         \$         .           Total Indirect Capital Costs.IC         \$         3.656,257           Lical Capital Investment (TCI) = DC + IC         \$         3.656,257           Justed Tot Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost         \$         3.656,257           PERATING COSTS         NOTE: These are incremental 'add-on' costs of the specific project, not all-in costs (for example, additional labor hours to rur the equipment, additional reagent medded, additional cons of waste generated, etc.)         Total Additional reagent medded, additional cons of waste generated, etc.)           Item         Unit Cost         Measure         Use Rate         Measure         Comments           Direct Annual Operating Costs, DC         Operating Labor         SCR controls and includes benefits, 1 hr/8 hr shift, 8/0Hr/ value is from EPA's cost spreadsheet for \$         65,70           Supervisor         15% of Op. Labor         15% of Operator Costs         \$         9,85           Maintenance         100% of Main Labor         of maintenance labor costs         \$         131,40           Utilities, Supplies, Replacements & Waste Management         Fuel Penalty         \$         134,00           Fuel Penalty         \$         0.004 /mgal         of maintenance labor costs         \$         131,40           Wastereanalt         \$  | Contingencies         0% None required         \$         -           Total Indirect Capital Costs, IC         \$         -  |  |  |  |   |  |  |   |  |  |
| Label Capital Investment (TCI) = DC + IC       \$ 3,656,259         cipused TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost       \$ 3,656,259         VDTE: These are incremental "add-on" costs of the specific project, not all-in costs (for example, additional labor hours to run the equipment, additional reagent needed, additional tons of waste generated, etc.)       Inte of         Item       Unit Cost       Measure       Use Rate       Measure       Comments         Operating Labor       Operator       \$ 60.00 \$/Hr       1.00 hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for \$ 65,700       \$ 9,565         Supervisor       15% of Op. Labor       15% of Operator Costs       \$ 9,856         Maintenance       100% of Maint Labor       of maintenance labor       \$ 100% of Maint Labor       10% hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for \$ 131,400         Vultities, Supplies, Replacements & Waste Management       Fuel Penalty       \$ 136,400 /non coal       0 ton coall/yr       No impacts expected- engineering judgement \$ 131,400         Vultities, Supplies, Replacements & Unit S       0.367 /msc1       0 mail/yr       No impacts expected- engineering judgement \$ 131,400         Vaster Transport       \$ 1.957 /mga1       0 mail/yr       No impacts expected- engineering judgement \$ 20,300 /msc1       0 mail/yr       No impacts expected- engineering judgement \$ 20,300 /msc1       \$ 0.552,000   | Late Capital Investment (TCI) = DC + IC       \$ 3,656,22         Late Capital Investment (TCI) = DC + IC       \$ 3,656,22         Vertain Construction       NOTE: These are incremental "add-on" costs of the specific project, not all-in costs (for example, additional labor hours to runthe equipment, additional reagent needed, additional loss of waste generated, etc.)         Item       Unit of         Item       Unit of         Operating Labor       Operator         Operator       \$ 60.00 \$/Hr         Supervisor       15% of Op. Labor         Maintenance       15% of Op. Labor         Maintenance       15% of Op. Labor         Maintenance       10% of Maint Labor         Unit ite analytic supervisor       \$ 134,40         Maintenance Materials       100% of Maint Labor         Unitite Supplies, Replacements & Waste Management       0 tor coall 0         Fuel Penalty       \$ 13,460 /thr coall       0 tor coall/V         Vastewater Treatment       \$ 0,367 /mscf       0 maintenance labor costs       \$ 131,40         Compressed Air       \$ 0,367 /mscf       0 maintenance labor costs       \$ 131,40         Vastes Disposal       \$ 48,800 /non       0 majl/Vr       No impacts expected - engineering judgement       \$ 0.367 /mscf         Sold Waste Disposal       \$ 0,283 /mscf       0   |  |  |  |   |  |  |   |  | -  |
| djusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost         \$ 3,656,251           PERATING COSTS         NOTE: These are incremental "add-on" costs of the specific project, not ali-in costs (for example, additional labor hours to run the equipament, additional reagent needed, additional cost of waste generated, etc.)           Item         Unit Cost         Measure         Use Rate         Measure         Comments           Direct Annual Operating Costs, DC         Operating Labor         Operating Labor         S 60.00 \$/Hr         1.00         hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for \$ 65,700         \$ 65,700           Supervisor         15% of Op. Labor         15% of Op. Labor         SCR controls and includes benefits, 1 hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for \$ 131,400         \$ 131,400           Maintenance         100% of Maint Labor         of maintenance labor costs         \$ 131,400           Vuiltities, Supplies, Replacements & Waste Management         Fuel Penalty         \$ 136,40 /ton coal         0 ton coal/yr         No impacts expected- engineering judgement         \$ 131,400           Vuater         \$ 0.367 /msdf         0 mag/yr         No impacts expected- engineering judgement         \$ 131,400           Vaster Disposal         \$ 488,000 /ton         0 ton/vear         No impacts expected- engineering judgement         \$ 131,400           Vaster Disposal         <  | Supervisor         Source         Source <thsource< th=""> <thsource< th="">         Sourc</thsource<></thsource<>  | Total Indirect Capital Costs, IC   |  |  |   |  |  |   | \$   |  |
| djusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost         \$ 3,656,251           PERATING COSTS         NOTE: These are incremental "add-on" costs of the specific project, not ali-in costs (for example, additional labor hours to run the equipament, additional reagent needed, additional cost of waste generated, etc.)           Item         Unit Cost         Measure         Use Rate         Measure         Comments           Direct Annual Operating Costs, DC         Operating Labor         Operating Labor         S 60.00 \$/Hr         1.00         hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for \$ 65,700         \$ 65,700           Supervisor         15% of Op. Labor         15% of Op. Labor         SCR controls and includes benefits, 1 hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for \$ 131,400         \$ 131,400           Maintenance         100% of Maint Labor         of maintenance labor costs         \$ 131,400           Vuiltities, Supplies, Replacements & Waste Management         Fuel Penalty         \$ 136,40 /ton coal         0 ton coal/yr         No impacts expected- engineering judgement         \$ 131,400           Vuater         \$ 0.367 /msdf         0 mag/yr         No impacts expected- engineering judgement         \$ 131,400           Vaster Disposal         \$ 488,000 /ton         0 ton/vear         No impacts expected- engineering judgement         \$ 131,400           Vaster Disposal         <  | Supervisor         Source         Source <thsource< th=""> <thsource< th="">         Sourc</thsource<></thsource<>  | otal Capital Investment (TCI) = DC + IC  |  |  |   |  |  |   | \$   | 3.656.250  |
| NOTE:       These are incremental 'add-on' costs of the specific project, not all-in costs (for example, additional loss of waste generated, etc.)         Item       Unit O       Unit of       Unit of         Direct Annual Operating Costs, DC       Operating Labor       Comments         Operator       \$ 60.00 \$/Hr       1.00       hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr       \$ 95,700         Supervisor       15% of Op. Labor       15% of Op. Labor       SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr       \$ 93,600         Maintenance       100% of Maint Labor       SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr       \$ 131,400         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 131,400         Vuillites, Supplies, Replacements & Waste Management       \$ 13,640 /ton coal       0 ton coal/yr       No impacts expected-engineering judgement       \$ 131,400         Vuaste Disposal       \$ 48,800 /ton coal       0 ton coal/yr       No impacts expected-engineering judgement       \$ 0.057 /mscf       0 msc//yr       No impacts expected-engineering judgement       \$ 0.052 /msc//mscf       \$ 0.052 /msc//mscf       \$ 0.052 /msc//msc//msc//msc//msc//msc//msc//msc  | NOTE:         These are incremental 'add-on' costs of the specific project, not all-in costs (for example, additional labor hours to ru<br>the equipment, additional reagent needed, additional cost waste generated, etc.)           Item         Unit O         Unit of         Unit of           Direct Annual Operating Costs, DC<br>Operator         S         60.00         \$/Hr         1.00         hr/8 hr shift         \$60.70           Supervisor         15% of Op. Labor         1.00         hr/8 hr shift         \$60.00         \$/Hr         \$2.00         hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for<br>\$60.00         \$9.85           Maintenance         100% of Maint Labor         0         hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for<br>\$5.00 k//r         \$13.46           Utilities, Supplies, Replacements & Waste Management         \$0.003 k/w-hr         0.00 k/w-hr/W         No impacts expected- engineering judgement         \$           Fuel Penalty         \$13.460 /ton coal         0 ton coal/Y         No impacts expected- engineering judgement         \$           Vasterewater Treatment         \$1.957 /msql  |  |  |  |   |  |  |   |  |  |
| PERATING COSTS       the equipment, additional reagent needed, additional or so waste generated, etc.)         Item       Unit Cot       Waster       Use Rate       Measure       Comments         Direct Annual Operating Costs, DC       Operator       \$ 60.00       \$/Hr       1.00       hr/8 hr shift       \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8760 hr/yr       \$ 65,700         Supervisor       15%       0 Op. Labor       15% of Op. Labor       \$ 8,600       \$ 9,853         Maintenance       15%       of Op. Labor       \$ 8,600       \$ 131,400         Maintenance Labor       \$ 60.00       \$/Hr       2.00       hr/8 hr shift       \$60/Hr value is from EPA's cost spreadsheet for \$ 131,400       \$ 131,400         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 131,400         Water       \$ 0.036       /kv-hr       0 ton coal/yr       No impacts expected- engineering judgement       \$ 134,00         Fuel Penalty       \$ 13.640       36.00       0 ton coal/yr       No impacts expected- engineering judgement       \$ 0.036         Kwater       \$ 0.036       /kv-hr       0 kw-hr/yr       No impacts expected- engineering judgement       \$ 0.040         Water       \$ 0.036       /kv-hr <td< td=""><td>PERATING COSTS       the equipment, additional reagent needed, additional tons of waste generated, etc.)         Item       Unit Cost       Measure       Use Rate       Measure       Comments         Direct Annual Operating Costs, DC       Operator       \$ 60.00       \$/Hr       1.00       hr/8 hr shift       \$60/Hr value is from EPA's cost spreadsheet for shift, 8/760 hr/yr       \$ 65,76         Supervisor       15%       0 Op. Labor       15% of Op. Labor       \$ 9,86         Maintenance       15%       0 Op. Labor       \$ 131,40         Maintenance Materials       100% of Maint Labor       of maintenance labor oscillations (br/yr)       \$ 131,40         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 131,40         Fuel Penalty       \$ 10,80 / fun coal       0 ton coal/yr       No impacts expected- engineering judgement       \$         Fuel Penalty       \$ 0.036 //w-hr       0 weight/maintenance labor costs       \$ 131,40       \$       \$         Waster       \$ 0.040 //maagement       \$ 0.057 //macd       0 ton coal/yr       No impacts expected- engineering judgement       \$         Fuel Penalty       \$ 10,800 //macd       0 maga/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48,800 //man</td><td>djusted TCI for Replacement Parts (Catalyst,</td><td></td><td></td><td></td><td></td><td></td><td></td><td>-</td><td></td></td<>  | PERATING COSTS       the equipment, additional reagent needed, additional tons of waste generated, etc.)         Item       Unit Cost       Measure       Use Rate       Measure       Comments         Direct Annual Operating Costs, DC       Operator       \$ 60.00       \$/Hr       1.00       hr/8 hr shift       \$60/Hr value is from EPA's cost spreadsheet for shift, 8/760 hr/yr       \$ 65,76         Supervisor       15%       0 Op. Labor       15% of Op. Labor       \$ 9,86         Maintenance       15%       0 Op. Labor       \$ 131,40         Maintenance Materials       100% of Maint Labor       of maintenance labor oscillations (br/yr)       \$ 131,40         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 131,40         Fuel Penalty       \$ 10,80 / fun coal       0 ton coal/yr       No impacts expected- engineering judgement       \$         Fuel Penalty       \$ 0.036 //w-hr       0 weight/maintenance labor costs       \$ 131,40       \$       \$         Waster       \$ 0.040 //maagement       \$ 0.057 //macd       0 ton coal/yr       No impacts expected- engineering judgement       \$         Fuel Penalty       \$ 10,800 //macd       0 maga/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48,800 //man   | djusted TCI for Replacement Parts (Catalyst,   |  |  |   |  |  |   | -  |  |
| ItemUnit CostMeasureUse RateUnit of<br>MeasureCommentsDirect Annual Operating Costs, DC<br>OperatorOperating LaborOperating Labor60.00\$//r1.00hr//8 hr shift\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr\$65,700Supervisor15% of Op. Labor15% of Operator Costs\$9,853Maintenance60.00\$//Hr2.00hr/8 hr shift\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr\$13,400Maintenance Materials100% of Maint Laborof maintenance labor costs\$131,400Utilities, Supplies, Replacements & Waste Management0 ton coallyr<br>s 0.004 /mgalof maintenance labor costs\$131,400Vater\$0.004 /mgal0 mgal/yrNo impacts expected- engineering judgement<br>s 0.036 /kw-hr\$0 mgal/yrWater\$0.057 /mscf0 msgal/yrNo impacts expected- engineering judgement<br>s 0.062 /non-mi\$\$Waste Transport\$0.652 /non-mi0 ton-wil/yrNo impacts expected- engineering judgement<br>s 0.000 /non\$\$Hazardous Waste Disposal\$488.000 /non0 ton-wil/yrNo impacts expected- engineering judgement<br>s 0.000 /non\$\$Ammonia\$0.293 /gal0 gal/yrNo impacts expected- engineering judgement<br>s 0.000 /non\$\$Ammonia\$0.293 /gal0 gal/yrNo impacts expected- engineering judgement<br>s 0.000 /no\$\$Ammonia\$0.293 /g   | Item         Unit Costs         Weasure         Use Rate         Unit of<br>Measure         Comments           Direct Annual Operating Costs, DC<br>Operating Labor         Direct Annual Operating Costs, DC         Comments         5         60.00         \$/Hr         1.00         hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8760 hr/yr         \$         65.70           Supervisor         15% of Op. Labor         15% of Operator Costs         \$         9.85           Maintenance         15% of Op. Labor         15% of Operator Costs         \$         9.85           Maintenance Materials         100% of Maint Labor         of maintenance labor costs         \$         131.40           Vultities, Supplies, Replacements & Waste Management         relif hrmad         of maintenance labor costs         \$         131.40           Fuel Penalty         \$         0.36 / kw-hr         0 kw-hr/w         No impacts expected- engineering judgement         \$           Vaster Vaste Maragement         \$         0.36 / kw-hr         0 kw-hr/w         No impacts expected- engineering judgement         \$           Vaster Vaste Maragement         \$         0.367 / msc/         0 msc/l/w         No impacts expected- engineering judgement         \$           Vaster Sobidi         \$         0.367 / msc/ <th>PERATING COSTS</th> <th></th> <th></th> <th></th> <th></th> <th>sts of the speci</th> <th></th> <th></th> <th></th>   | PERATING COSTS   |  |  |   |  | sts of the speci   |   |  |  |
| Direct Annual Operating Costs, DC<br>Operator       Operating Labor       Operating Labor       Softward       1.00       hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr       \$65,700         Supervisor       15% of Op. Labor       15% of Operator Costs       \$9,851         Maintenance       \$60.00 \$/Hr       2.00       hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr       \$131,400         Maintenance Labor       \$60.00 \$/Hr       2.00       hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr       \$131,400         Utilities, Supplies, Replacements & Waste Management       \$100% of Maint Labor       of maintenance labor costs       \$131,400         Viarer       \$0.004 /mgal       0 ton coal/yr       No impacts expected - engineering judgement       \$<br>Vater       \$0,367 /mscf       0 msc/yr       No impacts expected - engineering judgement       \$<br>Solid Waste Disposal       \$ 48,800 /ron       0 ton/year       No impacts expected - engineering judgement       \$<br>Maintenance       \$<br>Solid Waste Disposal       \$ 48,800 /ron       0 ton/year       No impacts expected - engineering judgement       \$<br>Amoints and includes benefits, 1 hr/8 hr       \$<br>Solid Waste Disposal       \$ 48,800 /ron       0 ton/year       No impacts expected - engineering judgement       \$<br>A  | Direct Annual Operating Costs, DC       Operating Labor       Operating Labor         Operating Labor       \$ 60.00 \$/Hr       1.00 hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8760 hr/yr       \$ 65.70         Supervisor       15% of Op. Labor       15% of Operator Costs       \$ 9.85         Maintenance       15% of Op. Labor       15% of Operator Costs       \$ 131.40         Maintenance Labor       \$ 60.00 \$/Hr       2.00 hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 2 hr/8 hr shift, 8760 hr/yr       \$ 131.40         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 131.40         Vultities, Supplies, Replacements & Waste Management       \$ 0.367 /mscf       0 mcal/yr       No impacts expected - engineering judgement       \$ 0.407 /mscf         Vastewater Treatment       \$ 1.957 /mgal       0 mgal/yr       No impacts expected - engineering judgement       \$ 0.52 /mscf         Solid Waste Disposal       \$ 48.800 /ton       0 ton/vear       No impacts expected - engineering judgement       \$ 0.52 /mscf         Total Annual Direct Operating Costs       \$ 0.252 /mscf       0 mgal/yr       No impacts expected - engineering judgement       \$ 0.51 /mscf         Total Annual Direct Operating Costs       \$ 0.293 /gal       0 qal/yr       No impacts expected   |  |  | oquipinon  |   | ant needed a   | additional tons  |   | labor  | hours to run   |
| Operator         \$         60.00         \$/Hr         1.00         hr/8 hr shift         \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8.760 hr/yr         \$         65,700           Supervisor         15% of Op. Labor         15% of Operator Costs         \$         9,851           Maintenance         15% of Op. Labor         15% of Operator Costs         \$         9,851           Maintenance Labor         \$         60.00         \$/Hr         2.00         hr/8 hr shift         \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr         \$         131,400           Maintenance Materials         100% of Maint Labor         of maintenance labor costs         \$         131,400           Vilitities, Supplies, Replacements & Waste Management         \$         13,640 /ron coal         0 ton coal/yr         No impacts expected-engineering judgement         \$           Fuel Penalty         \$         13,640 /ron coal         0 ton coal/yr         No impacts expected-engineering judgement         \$           Vaster         \$         0.367 /rmsc1         0 msc1/yr         No impacts expected-engineering judgement         \$           Solid Waste Disposal         \$         4.88.00 /ron         0 ton/year         No impacts expected-engineering judgement         \$  | Operating Labor         Operator         \$         60.00         \$/Hr         1.00         hr/8 hr shift         \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr         \$         65,70           Supervisor         15% of Op. Labor         15% of Operator Costs         \$         9,85           Maintenance          15% of Operator Costs         \$         9,85           Maintenance         100% of Maint Labor         hr/8 hr shift         \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr         \$         131,40           Maintenance Materials         100% of Maint Labor         of maintenance labor costs         \$         131,40           Vater         \$         0.366 /kw-hr         0 kw-hr/yr         No impacts expected engineering judgement         \$           Vater         \$         0.367 /mscf         0 mscf/yr         No impacts expected engineering judgement         \$           Solid Waste Disposal         \$         488.000 /ton         0 ton/year         No impacts expected engineering judgement         \$           Hazardous Waste Disposal         \$         488.000 /ton         0 ton/year         No impacts expected engineering judgement         \$           Uret tananuol Treet Operating Costs         \$ <th></th> <th>U</th> <th></th> <th>Unit of</th> <th>gent needed, a</th> <th></th> <th></th> <th>labor</th> <th>hours to run</th>  |  | U  |  | Unit of   | gent needed, a   |  |   | labor  | hours to run   |
| Operator       \$       60.00       \$/Hr       1.00       hr/8 hr shift       \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8/60 hr/yr       \$67,00         Supervisor       15% of Op. Labor       15% of Operator Costs       \$       9,851         Maintenance       15% of Op. Labor       15% of Operator Costs       \$       9,851         Maintenance       100% of Maint Labor       0       hr/8 hr shift, 8/00 hr/yr       \$       131,400         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$       131,400         Utilities, Supplies, Replacements & Waste Management       r       0 ton coal/yr       No impacts expected- engineering judgement       \$         Fuel Penalty       \$       13.640 /no cocal       0 ton coal/yr       No impacts expected- engineering judgement       \$         Compressed Air       \$       0.367 /mscf       0 msc/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$       48.800 /ton       0 ton/war       No impacts expected- engineering judgement       \$         Hazardous Waste Transport       \$       0.522 /ton-mi       0 ton-mi/yr       No impacts expected- engineering judgement       \$         Total Annual Direct Operating Costs       <   | Operator       \$       60.00       \$/Hr       1.00       hr/8 hr shift       \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 3700 hr/yr       \$       65,70         Supervisor       15% of Op. Labor       15% of Operator Costs       \$       9,85         Maintenance       10% of Maint Labor       15% of Operator Costs       \$       9,85         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$       131,40         Utilities, Supplies, Replacements & Waste Management       rocal Anoral Costs       \$       131,40       \$         Fuel Penalty       \$       13,640 /nor cocal       0       tor coal/yr       No impacts expected-engineering iudgement       \$         Compressed Air       \$       0.367 /mscf       0       mas/try       No impacts expected-engineering iudgement       \$         Solid Waste Disposal       \$       48.800 /non       0       tor/year       No impacts expected-engineering iudgement       \$         Umater Transport       \$       0.552 /non-mi       0       tor/year       No impacts expected-engineering iudgement       \$         Maintenance (2% total capital costs)       1.957 /mgal       0       mas/try       No impacts expected-engineering iudgement       \$      <   |  |  | nit Cost   |   |  | Unit of  |   | labor  | hours to run   |
| Supervisor       15% of Op. Labor       SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr       9,851         Maintenance       15% of Op. Labor       15% of Op. Labor       15% of Operator Costs       \$ 9,851         Maintenance       \$ 60.00 \$/Hr       2.00 hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr       \$ 131,400         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 131,400         Utilities, Supplies, Replacements & Waste Management       of monocal       0 ton coal/yr       No impacts expected- engineering judgement       \$         Fuel Penalty       \$ 13.640 /ton coal       0 ton coal/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.004 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.036 /kw-hr       0 km/r/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48.800 /ton       0 magal/yr       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652 /ton-mi       0 ton-mi/yr       No impacts expected- engineering judgement       \$         Ummonia       \$ 209.000 /ton       2.190 /ton /yr       Engineering judgement       \$       \$   | Supervisor       15% of Op. Labor       SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr       String 3,760 hr/yr         Maintenance       \$ 60.00 \$/Hr       2.00 hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr       \$ 131,40         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 131,40         Utilities, Supplies, Replacements & Waste Management       rule Penalty       \$ 136,40 /ton coal       0 ton coal/yr       No impacts expected- engineering judgement       \$ 131,40         Puel Penalty       \$ 13.640 /ton coal       0 ton coal/yr       No impacts expected- engineering judgement       \$ 131,40         Water       \$ 0.003 /kr/mal       0 mgal/yr       No impacts expected- engineering judgement       \$ 131,40         Water       \$ 0.004 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$ 0.004 /mgal         Solid Waste Disposal       \$ 48,800 /ton       0 ton/year       No impacts expected- engineering judgement       \$ 0.652 /mon-mi         Waste Transport       \$ 0.652 /mon-mi       0 ton/year       No impacts expected- engineering judgement       \$ 0.53,100         Maintenance (2000 /mon       2,190 /mon       0 mol/yr       No impacts expected- engineering judgement       \$ 0.53,100         Maintenance       \$ 2  |  |  | nit Cost   |   |  | Unit of  |   | labor  | hours to run   |
| Supervisor       15% of Op. Labor       15% of Operator Costs       \$       9,853         Maintenance       Maintenance       \$       60.00 \$/Hr       2.00       hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr       \$       131,400         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$       131,400         Utilities, Supplies, Replacements & Waste Management       13.640 /non coal       0 ton coal/yr       No impacts expected- engineering judgement       \$         Fuel Penalty       \$       0.036 /kw-hr       0 kw-hr/yr       No impacts expected- engineering judgement       \$         Water       \$       0.036 /kw-hr       0 mgal/yr       No impacts expected- engineering judgement       \$         Vastewater Treatment       \$       1.957 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Vaste Disposal       \$       488.000 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$       0.652 /ton-mi       0 ton/year       No impacts expected- engineering judgement       \$         Maintenance (2% total capital costs)       0.623 /ton-mi       0 ton-n/yer       No impacts expected- engineering judgement       \$ <td>Supervisor       15% of Op. Labor       15% of Operator Costs       \$ 9,85         Maintenance       Maintenance       \$ 60.00 \$/Hr       2.00       hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr       \$ 131,40         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 131,40         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 131,40         Fuel Penalty       \$ 0.036 /kw-hr       0 ton coal/yr       No impacts expected- engineering judgement       \$ 13,40         Water       \$ 0.036 /kw-hr       0 mai/yr       No impacts expected- engineering judgement       \$ 13,40         Water       \$ 0.036 /kw-hr       0 mai/yr       No impacts expected- engineering judgement       \$ 140         Waste Disposal       \$ 48,800 /ton       0 mai/yr       No impacts expected- engineering judgement       \$ 0.52 /ton-mi         Waste Transport       \$ 0.652 /ton-mi       0 ton/year       No impacts expected- engineering judgement       \$ 0.537 /magi         Maintenance Operating Costs       \$ 0.652 /ton-mi       0 ton/year       No impacts expected- engineering judgement       \$ 0.537 /magi         Maintenance       \$ 0.652 /ton-mi       0 ton/year       No impacts expected- engineering judgement       \$ 0.537 /to</td> <td></td> <td>¢</td> <td></td> <td>Measure</td> <td>Use Rate</td> <td>Unit of<br/>Measure</td> <td>Comments</td> <td></td> <td></td>   | Supervisor       15% of Op. Labor       15% of Operator Costs       \$ 9,85         Maintenance       Maintenance       \$ 60.00 \$/Hr       2.00       hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr       \$ 131,40         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 131,40         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 131,40         Fuel Penalty       \$ 0.036 /kw-hr       0 ton coal/yr       No impacts expected- engineering judgement       \$ 13,40         Water       \$ 0.036 /kw-hr       0 mai/yr       No impacts expected- engineering judgement       \$ 13,40         Water       \$ 0.036 /kw-hr       0 mai/yr       No impacts expected- engineering judgement       \$ 140         Waste Disposal       \$ 48,800 /ton       0 mai/yr       No impacts expected- engineering judgement       \$ 0.52 /ton-mi         Waste Transport       \$ 0.652 /ton-mi       0 ton/year       No impacts expected- engineering judgement       \$ 0.537 /magi         Maintenance Operating Costs       \$ 0.652 /ton-mi       0 ton/year       No impacts expected- engineering judgement       \$ 0.537 /magi         Maintenance       \$ 0.652 /ton-mi       0 ton/year       No impacts expected- engineering judgement       \$ 0.537 /to   |  | ¢  |  | Measure   | Use Rate   | Unit of<br>Measure   | Comments  |  |  |
| Maintenance       Maintenance Labor       \$       60.00       \$\fmodel{V}\frac{1}{2}\$       2.00       hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for \$SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr       \$       131,40         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$       131,40         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$       131,40         Utilities, Supplies, Replacements & Waste Management       of maintenance labor costs       \$       131,40         Fuel Penalty       \$       13,640 /ton coal       0 ton coal/yr       No impacts expected-engineering judgement       \$         Water       \$       0.036 /kw-hr       0       ton coal/yr       No impacts expected-engineering judgement       \$         Compressed Air       \$       0.367 /mscf       0       mscf/yr       No impacts expected-engineering judgement       \$         Vastewater Treatment       \$       1.957 /mgal       0       mscl/yr       No impacts expected-engineering judgement       \$         Hazardous Waste Disposal       \$       488.000 /ton       0       ton/year       No impacts expected-engineering judgement       \$         Lime       \$       290,000 /ton       2,190 ton/yr       Engineering   | Maintenance       Maintenance Labor       \$       60.00       \$/Hr       2.00       hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for \$       \$       131,40         Maintenance Labor       \$       60.00       \$/Hr       2.00       hr/8 hr shift \$60/Hr value is from EPA's cost spreadsheet for \$       \$       131,40         Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$       131,40         Utilities, Supplies, Replacements & Waste Management       of maintenance labor costs       \$       131,40         Fuel Penalty       \$       13.640 /ton coal       0       to coal/yr       No impacts expected- engineering judgement       \$         Water       \$       0.036 /kw-hr       0       to coal/yr       No impacts expected- engineering judgement       \$         Compressed Air       \$       0.367 /mscf       0       mscf/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$       48.800 /ton       0       ton/year       No impacts expected- engineering judgement       \$         Hazardous Waste Disposal       \$       488.000 /ton       2,190       ton/year       No impacts expected- engineering judgement       \$         Lime       \$       0.290,000       /ton       2,190<   |  | \$   |  | Measure   | Use Rate   | Unit of<br>Measure   | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for  |  |  |
| Maintenance Materials       100% of Maint Labor       SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr         Utilities, Supplies, Replacements & Waste Management       of maintenance labor costs       \$ 131,400         Fuel Penalty       \$ 13.640 / ton coal       0 ton coal/yr       No impacts expected- engineering judgement       \$         Electricity       \$ 0.036 / kw-hr       0 kw-hr/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.367 / mscf       0 mgal/yr       No impacts expected- engineering judgement       \$         Compressed Air       \$ 0.367 / mscf       0 mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48.800 / ton       0 ton/vear       No impacts expected- engineering judgement       \$         Hazardous Waste Disposal       \$ 488.000 / ton       0 ton/vear       No impacts expected- engineering judgement       \$         Lime       \$ 290.000 / ton       2,190 ton/yr       Engineering judgement       \$       635,100         Ammonia       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$       973,455         Dverhead       0% Conservatively excluded from analysis       \$       -       973,455         Indirect Operating Costs       2% of total capital costs (TCl)   | Maintenance Materials       100% of Maint Labor       SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr         Utilities, Supplies, Replacements & Waste Management       of maintenance labor costs       \$ 131,40         Fuel Penalty       \$ 13.640 /ton coal       0 ton coal/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.036 /kw-hr       0 kw-hr/yr       No impacts expected- engineering judgement       \$         Compressed Air       \$ 0.367 /mscf       0 mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48.800 /ton       0 ton-mi/yr       No impacts expected- engineering judgement       \$         Hazardous Waste Disposal       \$ 488.000 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Uime       \$ 290,000 /ton       2,190 ton/yr       Engineering judgement       \$       635,10         Total Annual Direct Operating Costs       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$         Property tax (1% total capital costs)       2% of total capital costs (TCI)       \$ 36,56       \$       \$         Overhead       0% conservatively excluded from analysis       \$ -1,37,12       \$       36,56         Insurance (1% total capital costs)       1% of total capital co  | Operator   | \$   | 60.00  | Measure<br>\$/Hr  | Use Rate   | Unit of<br>Measure   | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr   | \$   | 65,700   |
| Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 131,40         Utilities, Supplies, Replacements & Waste Management         Fuel Penalty       \$ 13,640       /ton coal       0       ton coal/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.036       /kw-hr       0       kw-hr/yr       No impacts expected- engineering judgement       \$         Compressed Air       \$ 0.367       /mscf       0       mscf/yr       No impacts expected- engineering judgement       \$         Vastewater Treatment       \$ 1.957       /mgal       0       mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48.000       /ton       0       ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652       /ton-mi       0       ton/year       No impacts expected- engineering judgement       \$         Lime       \$ 290,000       /ton       2,190       ton/yr       No impacts expected- engineering judgement       \$         Total Annual Direct Operating Costs       \$ 0.293       /gal       0       ton/yr       Ingineering judgement       \$       973,453         Overhead       0% Conservatively excluded from analysi   | Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 131,40         Utilities, Supplies, Replacements & Waste Management       of maintenance labor costs       \$ 131,40         Fuel Penalty       \$ 13,640       /ton coal       0       ton coal/yr       No impacts expected- engineering judgement       \$         Electricity       \$ 0.036       /kw-hr       0       kw-hr/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.036       /kw-hr       0       mgal/yr       No impacts expected- engineering judgement       \$         Compressed Air       \$ 0.367       /mscf       0       mscf/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48.800       /ton       0       ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652       /ton-mi       0       ton/year       No impacts expected- engineering judgement       \$         Lime       \$ 290,000       /ton       2,190       ton/yr       Engineering judgement       \$       635,10         Administration (2% total capital costs)       < 0,293  | Operator<br>Supervisor   | \$   | 60.00  | Measure<br>\$/Hr  | Use Rate   | Unit of<br>Measure   | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr   | \$   | 65,70  |
| Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$       131,40         Utilities, Supplies, Replacements & Waste Management       \$       13.640 /ton coal       0       ton coal/yr       No impacts expected- engineering judgement       \$         Fuel Penalty       \$       0.366 /kw-hr       0       ton coal/yr       No impacts expected- engineering judgement       \$         Water       \$       0.004 /mgal       0       mgal/yr       No impacts expected- engineering judgement       \$         Water       \$       0.004 /mgal       0       mgal/yr       No impacts expected- engineering judgement       \$         Wastewater Treatment       \$       1.957 /mgal       0       mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$       48.800 /ton       0       ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$       0.652 /ton-mi       0       ton/year       No impacts expected- engineering judgement       \$         Lime       \$       290.000 /ton       2.190       ton/yr       Engineering judgement       \$       \$         Administration (2% total capital costs)       \$       0       gal/yr       No impacts expected- engineer   | Maintenance Materials       100% of Maint Labor       of maintenance labor costs       \$ 13,40         Utilities, Supplies, Replacements & Waste Management       13.64 /nto coal       0 ton coal/yr       No impacts expected- engineering judgement       \$         Fuel Penalty       \$ 0.366 /kw-hr       0 kw-hr/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.004 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.367 /mscf       0 mgal/yr       No impacts expected- engineering judgement       \$         Wastewater Treatment       \$ 1.957 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652 /ton-mi       0 ton/wer       No impacts expected- engineering judgement       \$         Lime       \$ 290.000 /ton       2.190 ton/yr       Engineering judgement       \$       635.10         Administration (2% total capital costs)       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$         Property tax (1% total capital costs)       \$ 0.793.42       \$       973.42       \$         Indirect Operating Costs       0%   | Operator<br>Supervisor<br>Maintenance  |  | 60.00<br>15%   | Measure<br>\$/Hr<br>of Op. Labor  | Use Rate<br>1.00   | Unit of<br>Measure<br>hr/8 hr shift  | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for  | \$   | 65,70<br>9,85  |
| Utilities, Supplies, Replacements & Waste Management         Fuel Penalty       \$ 13.640       /ton coal       0       ton coal/yr       No impacts expected- engineering judgement       \$         Electricity       \$ 0.036       /kw-hr       0       ton coal/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.036       /kw-hr       0       mgal/yr       No impacts expected- engineering judgement       \$         Compressed Air       \$ 0.367       /mscf       mscf/yr       No impacts expected- engineering judgement       \$         Wastewater Treatment       \$ 1.957       /mgal       mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48.800       /ton       0       ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652       /ton-mi       0       ton/year       No impacts expected- engineering judgement       \$         Lime       \$ 290.000       /ton       2,190       ton/year       No impacts expected- engineering judgement       \$         Administration (2% total capital costs)  | Utilities, Supplies, Replacements & Waste Management         Fuel Penalty       \$ 13.640       /ton coal       0       ton coal/yr       No impacts expected- engineering judgement       \$         Electricity       \$ 0.036       /kw-hr       0       kw-hr/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.004       /mgal       0       mgal/yr       No impacts expected- engineering judgement       \$         Compressed Air       \$ 0.367       /mscf       0       mscf/yr       No impacts expected- engineering judgement       \$         Vastewater Treatment       \$ 1.957       /mgal       0       mgal/yr       No impacts expected- engineering judgement       \$         Vastewater Treatment       \$ 1.957       /mgal       0       mgal/yr       No impacts expected- engineering judgement       \$         Waste Disposal       \$ 48.800       /ton       0       ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652       /ton-mi       0       ton/year       No impacts expected- engineering judgement       \$         Lime       \$ 290.000       /ton       2.190       ton/yr       Engineering judgement       \$       635,10         Ammonia       \$ 0.293  | Operator<br>Supervisor<br>Maintenance  |  | 60.00<br>15%   | Measure<br>\$/Hr<br>of Op. Labor  | Use Rate<br>1.00   | Unit of<br>Measure<br>hr/8 hr shift  | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr   | \$   | 65,700<br>9,85   |
| Fuel Penalty       \$ 13.640 /ton coal       0 ton coal/yr       No impacts expected- engineering judgement       \$         Electricity       \$ 0.036 /kw-hr       0 kw-hr/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.040 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Compressed Air       \$ 0.367 /mscf       0 msc/rv       No impacts expected- engineering judgement       \$         Wastewater Treatment       \$ 1.957 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48.800 /ton       0 ton/vear       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652 /ton-mi       0 ton/vear       No impacts expected- engineering judgement       \$         Lime       \$ 290.000 /ton       2,190 ton/yr       No impacts expected- engineering judgement       \$         Ammonia       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$         Mainistration (2% total capital costs)       2% of total capital costs (TCl)       \$ 37,12         Property tax (1% total capital costs)       2% of total capital costs (TCl)       \$ 36,56         Compressed Air       0.0688 capital recovery factor for a 20-year equipment       \$ 251,47 <t< td=""><td>Fuel Penalty       \$ 13.640 /ton coal       0 ton coal/yr       No impacts expected- engineering judgement       \$         Electricity       \$ 0.036 /kw-hr       0 kw-hr/vr       No impacts expected- engineering judgement       \$         Water       \$ 0.040 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.067 /mscf       0 msc/rv       No impacts expected- engineering judgement       \$         Wastewater Treatment       \$ 1.957 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 488.000 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Hazardous Waste Disposal       \$ 488.000 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652 /ton-mi       0 ton/year       No impacts expected- engineering judgement       \$         Lime       \$ 290.000 /ton       2,190 ton/yr       Engineering judgement       \$       635,10         Adminoita       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$         Indirect Operating Costs       \$       2% of total capital costs (TCI)       \$       73,42         Indirect Operating Costs       \$       2% of total</td><td>Operator<br/>Supervisor<br/><b>Maintenance</b><br/>Maintenance Labor</td><td></td><td>60.00<br/>15%<br/>60.00</td><td>Measure<br/>\$/Hr<br/>of Op. Labor<br/>\$/Hr</td><td>Use Rate<br/>1.00</td><td>Unit of<br/>Measure<br/>hr/8 hr shift</td><td>Comments<br/>\$60/Hr value is from EPA's cost spreadsheet for<br/>SCR controls and includes benefits, 1 hr/8 hr<br/>shift, 8,760 hr/yr<br/>15% of Operator Costs<br/>\$60/Hr value is from EPA's cost spreadsheet for<br/>SCR controls and includes benefits, 2 hr/8 hr<br/>shift, 8,760 hr/yr</td><td>\$<br/>\$</td><td>65,70<br/>9,85<br/>131,40</td></t<>   | Fuel Penalty       \$ 13.640 /ton coal       0 ton coal/yr       No impacts expected- engineering judgement       \$         Electricity       \$ 0.036 /kw-hr       0 kw-hr/vr       No impacts expected- engineering judgement       \$         Water       \$ 0.040 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.067 /mscf       0 msc/rv       No impacts expected- engineering judgement       \$         Wastewater Treatment       \$ 1.957 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 488.000 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Hazardous Waste Disposal       \$ 488.000 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652 /ton-mi       0 ton/year       No impacts expected- engineering judgement       \$         Lime       \$ 290.000 /ton       2,190 ton/yr       Engineering judgement       \$       635,10         Adminoita       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$         Indirect Operating Costs       \$       2% of total capital costs (TCI)       \$       73,42         Indirect Operating Costs       \$       2% of total   | Operator<br>Supervisor<br><b>Maintenance</b><br>Maintenance Labor  |  | 60.00<br>15%<br>60.00  | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr   | Use Rate<br>1.00   | Unit of<br>Measure<br>hr/8 hr shift  | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr   | \$<br>\$   | 65,70<br>9,85<br>131,40  |
| Electricity       \$       0.036       /kw-hr       0       kw-hr/yr       No impacts expected- engineering judgement       \$         Water       \$       0.004       /mgal       0       mgal/yr       No impacts expected- engineering judgement       \$         Compressed Air       \$       0.367       /mscf       0       mscf/yr       No impacts expected- engineering judgement       \$         Wastewater Treatment       \$       1.957       /mgal       0       mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$       48.800       /ton       0       ton/year       No impacts expected- engineering judgement       \$         Wastewater Trasport       \$       0.652       /ton-mi       0       ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$       0.293       /gal       0       ton/year       No impacts expected- engineering judgement       \$         Lime       \$       0.293       /gal       0       gal/yr       No impacts expected- engineering judgement       \$       635,10         Ammonia       \$       0.293       /gal       0       gal/yr       No impacts expected- engineering judgement       \$       7       <   | Electricity       \$ 0.036 /kw-hr       0 kw-hr/yr       No impacts expected- engineering judgement       \$         Water       \$ 0.004 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Compressed Air       \$ 0.367 /mscf       0 mscf/yr       No impacts expected- engineering judgement       \$         Wastewater Treatment       \$ 1.957 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Wastewater Treatment       \$ 0.652 /ton-mi       0 ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652 /ton-mi       0 ton/year       No impacts expected- engineering judgement       \$         Lime       \$ 290.000 /ton       2,190 ton/yr       Engineering judgement       \$       973,45         Indirect Operating Costs       0% Conservatively excluded from analysis       \$       -       7       -         Overhead       0% Conservatively excluded from analysis       \$       -       7       -       -       -       -       -       -       -       -       -       -       -       -       -       -       -       -  | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials  | \$   | 60.00<br>15%<br>60.00<br>100%  | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor   | Use Rate<br>1.00   | Unit of<br>Measure<br>hr/8 hr shift  | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr   | \$<br>\$   | 65,70<br>9,85<br>131,40  |
| Compressed Air       \$ 0.367 /mscf       0 mscf/yr       No impacts expected- engineering judgement       \$         Wastewater Treatment       \$ 1.957 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Hazardous Waste Disposal       \$ 48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652 /ton-mi       0 ton-mi/yr       No impacts expected- engineering judgement       \$         Lime       \$ 290.000 /ton       2,190 ton/yr       Engineering judgement       \$       635,10         Ammonia       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$       637,45         Indirect Operating Costs       0% Conservatively excluded from analysis       \$       -       73,12         Property tax (1% total capital costs)       2% of total capital costs (TCI)       \$       36,56         Distribut (1% total capital costs)       1% of total capital costs (TCI)       \$       36,56         Coapital Recovery       0.0688 capital recovery factor for a 20-year equipment       \$       251,47         Total Annual Indirect Operating Costs       \$       397,72 <t< td=""><td>Compressed Air       \$ 0.367 /mscf       0 mscf/yr       No impacts expected- engineering judgement       \$         Wastewater Treatment       \$ 1.957 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Hazardous Waste Disposal       \$ 48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652 /ton-mi       0 ton-mi/yr       No impacts expected- engineering judgement       \$         Lime       \$ 290.000 /ton       2,190 ton/yr       Engineering judgement       \$       635,10         Ammonia       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$       973,45         Indirect Operating Costs       0% Conservatively excluded from analysis       \$       -         Overhead       0% Conservatively excluded from analysis       \$       -         Administration (2% total capital costs)       2% of total capital costs (TCI)       \$       73,12         Property tax (1% total capital costs)       2% of total capital costs (TCI)       \$       36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment       \$       251,47</td><td>Operator<br/>Supervisor<br/>Maintenance<br/>Maintenance Labor<br/>Maintenance Materials<br/>Utilities, Supplies, Replacements &amp; Was</td><td>\$<br/>ste Ma</td><td>60.00<br/>15%<br/>60.00<br/>100%<br/>anagemen</td><td>Measure<br/>\$/Hr<br/>of Op. Labor<br/>\$/Hr<br/>of Maint Labor</td><td>Use Rate<br/>1.00<br/>2.00</td><td>Unit of<br/>Measure<br/>hr/8 hr shift<br/>hr/8 hr shift</td><td>Comments<br/>\$60/Hr value is from EPA's cost spreadsheet for<br/>SCR controls and includes benefits, 1 hr/8 hr<br/>shift, 8,760 hr/yr<br/>15% of Operator Costs<br/>\$60/Hr value is from EPA's cost spreadsheet for<br/>SCR controls and includes benefits, 2 hr/8 hr<br/>shift, 8,760 hr/yr<br/>of maintenance labor costs<br/>No impacts expected- engineering judgement</td><td>\$ \$ \$</td><td>65,70<br/>9,85<br/>131,40</td></t<> | Compressed Air       \$ 0.367 /mscf       0 mscf/yr       No impacts expected- engineering judgement       \$         Wastewater Treatment       \$ 1.957 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         Solid Waste Disposal       \$ 48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Hazardous Waste Disposal       \$ 48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652 /ton-mi       0 ton-mi/yr       No impacts expected- engineering judgement       \$         Lime       \$ 290.000 /ton       2,190 ton/yr       Engineering judgement       \$       635,10         Ammonia       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$       973,45         Indirect Operating Costs       0% Conservatively excluded from analysis       \$       -         Overhead       0% Conservatively excluded from analysis       \$       -         Administration (2% total capital costs)       2% of total capital costs (TCI)       \$       73,12         Property tax (1% total capital costs)       2% of total capital costs (TCI)       \$       36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment       \$       251,47   | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was   | \$<br>ste Ma   | 60.00<br>15%<br>60.00<br>100%<br>anagemen  | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor   | Use Rate<br>1.00<br>2.00   | Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift   | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>No impacts expected- engineering judgement   | \$ \$ \$   | 65,70<br>9,85<br>131,40  |
| Wastewater Treatment       \$         1.957 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         S         Solid Waste Disposal       \$         48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$          Hazardous Waste Disposal       \$         48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$          Waste Transport       \$         0.652 /ton-mi       0 ton/year       No impacts expected- engineering judgement       \$          Lime       \$         290.000 /ton       2,190 ton/yr       Engineering judgement       \$         635,10          Ammonia       \$         0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$         973,45          Indirect Operating Costs       0 con/year       No impacts expected- engineering judgement       \$         973,45          Overhead       0 year/year       No impacts expected- engineering judgement       \$         973,45          Property tax (1% total capital costs)       2% of total capital costs (TCl)       \$         73,12          Insurance (1% total capital costs)       1% of total capital costs (TCl)       \$         36,56          Capital Recovery       0.0688 capital recovery factor for a 20-year equipment  | Wastewater Treatment       \$         1.957 /mgal       0 mgal/yr       No impacts expected- engineering judgement       \$         48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$         48.800 /ton         Hazardous Waste Disposal       \$         48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$          Waste Transport       \$         0.652 /ton-mi       0 ton/war       No impacts expected- engineering judgement       \$          Lime       \$         290.000 /ton       2,190 ton/yr       Engineering judgement       \$        635,10          Ammonia       \$         0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$        973,45          Indirect Operating Costs       Verhead       0% Conservatively excluded from analysis       \$        -         73,42          Overhead       0% total capital costs (TCl)       \$         73,12        \$         73,65        -         73,65        -         73,65          Property tax (1% total capital costs)       1% of total capital costs (TCl)       \$         36,56        -         36,56        -         36,56          Capital Recovery       0.0688       capital recovery factor for a 20-year equipment        -         36,56        -  | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fluel Penalty<br>Electricity   | \$<br>ste Ma<br>\$<br>\$   | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036   | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr   | Use Rate<br>1.00<br>2.00<br>0<br>0   | Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr  | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>No impacts expected- engineering judgement<br>No impacts expected- engineering judgement   | \$ \$ \$   | 65,70<br>9,85<br>131,40  |
| Solid Waste Disposal       \$ 48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Hazardous Waste Disposal       \$ 488.000 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652 /ton-min       0 ton-mi/yr       No impacts expected- engineering judgement       \$         Lime       \$ 290.000 /ton       2,190 ton/yr       Engineering judgement       \$       635,10         Ammonia       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$       973,45         Total Annual Direct Operating Costs       \$ 973,45       \$       973,45         Overhead       0% Conservatively excluded from analysis       \$       -         Administration (2% total capital costs)       2% of total capital costs (TCI)       \$ 36,56         Property tax (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment       \$         Ife and 3.3% interest rate       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,72   | Solid Waste Disposal       \$ 48.800 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Hazardous Waste Disposal       \$ 488.000 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652 /ton-mi       0 ton-mi/yr       No impacts expected- engineering judgement       \$         Lime       \$ 20000 /ton       2,190 ton/yr       Engineering judgement       \$       635,100         Ammonia       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$       973,450         Indirect Operating Costs       0% Conservatively excluded from analysis       \$       -       -       7       -   | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water   | \$<br>ste Ma<br>\$<br>\$<br>\$   | 60.00<br>15%<br>60.00<br>100%<br>13.640<br>0.036<br>0.004  | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal  | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0   | Unit of<br>Measure   | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>No impacts expected- engineering judgement<br>No impacts expected- engineering judgement<br>No impacts expected- engineering judgement   | \$ \$ \$ \$  | 65,70<br>9,85<br>131,40  |
| Hazardous Waste Disposal       \$ 488.000 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652 /ton-mi       0 ton-mi/yr       No impacts expected- engineering judgement       \$         Lime       \$ 290.000 /ton       2,190 ton/yr       Engineering judgement       \$       635,10         Ammonia       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$         Total Annual Direct Operating Costs       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$         Overhead       0% Conservatively excluded from analysis       \$ -       -       73,12         Administration (2% total capital costs)       2% of total capital costs (TCl)       \$ 36,56         Insurance (1% total capital costs)       1% of total capital costs (TCl)       \$ 36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment life and 3.3% interest rate       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,72       \$ 397,72  | Hazardous Waste Disposal       \$ 488.000 /ton       0 ton/year       No impacts expected- engineering judgement       \$         Waste Transport       \$ 0.652 /ton-mi       0 ton-mi/yr       No impacts expected- engineering judgement       \$         Lime       \$ 290.000 /ton       2,190 ton/yr       Engineering judgement       \$       635,10         Ammonia       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$         Total Annual Direct Operating Costs       \$       973,45       \$       973,45         Overhead       0% Conservatively excluded from analysis       \$       -         Administration (2% total capital costs)       2% of total capital costs (TCl)       \$       73,12         Property tax (1% total capital costs)       1% of total capital costs (TCl)       \$       36,56         Linsurance (1% total capital costs)       1% of total capital costs (TCl)       \$       36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment       if e and 3.3% interest rate       \$       251,47         Total Annual Indirect Operating Costs       \$       \$       \$       397,77  | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air   | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$   | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036<br>0.004<br>0.367   | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mscf                                 | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>mscf/yr  | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>No impacts expected- engineering judgement<br>No impacts expected- engineering judgement   | \$ \$ \$ \$ \$   | 65,70<br>9,85<br>131,40  |
| Waste Transport       \$ 0.652 /ton-mi       0 ton-mi/yr       No impacts expected- engineering judgement       \$ 635,10         Lime       \$ 290,000 /ton       2,190 ton/yr       Engineering judgement       \$ 635,10         Ammonia       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$ 635,10         Total Annual Direct Operating Costs       \$ 973,45       \$ 973,45         Indirect Operating Costs       \$ 0% Conservatively excluded from analysis       \$ -         Overhead       0% Conservatively excluded from analysis       \$ -         Administration (2% total capital costs)       2% of total capital costs (TCI)       \$ 73,12         Property tax (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment life and 3.3% interest rate       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,72       \$ 397,72  | Waste Transport       \$ 0.652 /ton-mi       0 ton-mi/yr       No impacts expected- engineering judgement       \$ 635,10         Ammonia       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$ 635,10         Total Annual Direct Operating Costs       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$ 973,45         Indirect Operating Costs       \$ 0.293 /gal       0 % Conservatively excluded from analysis       \$ -         Overhead       0% Conservatively excluded from analysis       \$ -         Administration (2% total capital costs)       2% of total capital costs (TCI)       \$ 73,12         Property tax (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,77       \$ 397,77   | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment   | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$   | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957  | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal                                 | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure   | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>No impacts expected- engineering judgement<br>No impacts expected- engineering judgement   | \$ \$ \$ \$\$  | 65,70<br>9,85<br>131,40  |
| Lime       \$ 290.000 /ton       2,190 ton/yr       Engineering judgement       \$ 635,10         Ammonia       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$ 973,45         Indirect Operating Costs       \$ 0% Conservatively excluded from analysis       \$ -         Overhead       0% Conservatively excluded from analysis       \$ -         Administration (2% total capital costs)       2% of total capital costs (TCl)       \$ 73,12         Property tax (1% total capital costs)       1% of total capital costs (TCl)       \$ 36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,72  | Lime       \$ 290.000 /ton       2,190 ton/yr       Engineering judgement       \$ 635,10         Ammonia       \$ 0.293 /gal       0 gal/yr       No impacts expected- engineering judgement       \$ 973,45         Total Annual Direct Operating Costs       \$ 0.293 /gal       0 % Conservatively excluded from analysis       \$ -         Indirect Operating Costs       0% Conservatively excluded from analysis       \$ -         Overhead       0% Conservatively excluded from analysis       \$ -         Administration (2% total capital costs)       2% of total capital costs (TCl)       \$ 36,56         Property tax (1% total capital costs)       1% of total capital costs (TCl)       \$ 36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,72       \$ 397,72   | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal   | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$   | 60.00<br>15%<br>60.00<br>100%<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800  | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton                         | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure   | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>No impacts expected- engineering judgement<br>No impacts expected- engineering judgement   | \$ \$ \$ \$ \$ \$ \$                                     | 65,70<br>9,85<br>131,40  |
| Total Annual Direct Operating Costs       \$ 973,45         Indirect Operating Costs       0% Conservatively excluded from analysis       \$ -         Overhead       0% Conservatively excluded from analysis       \$ 73,12         Administration (2% total capital costs)       2% of total capital costs (TCI)       \$ 73,12         Property tax (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Insurance (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment life and 3.3% interest rate       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,72       \$ 397,72   | Total Annual Direct Operating Costs       \$ 973,45         Indirect Operating Costs       0% Conservatively excluded from analysis       \$ -         Overhead       0% Conservatively excluded from analysis       \$ 73,12         Administration (2% total capital costs)       2% of total capital costs (TCI)       \$ 73,12         Property tax (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Insurance (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment life and 3.3% interest rate       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,72       397,72   | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal   | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$                   | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000                     | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mscf<br>/mgal<br>/ton                | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure   | Comments<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>No impacts expected- engineering judgement<br>No impacts expected- engineering judgement   | \$ \$ \$ \$ \$\$   | 65,70<br>9,85<br>131,40  |
| Indirect Operating Costs       0% Conservatively excluded from analysis       \$         Administration (2% total capital costs)       2% of total capital costs (TCI)       \$       73,12         Property tax (1% total capital costs)       1% of total capital costs (TCI)       \$       36,56         Insurance (1% total capital costs)       1% of total capital costs (TCI)       \$       36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment       ife and 3.3% interest rate       \$       251,47         Total Annual Indirect Operating Costs       \$       397,72       \$       397,72   | Indirect Operating Costs       0% Conservatively excluded from analysis       -         Overhead       0% Conservatively excluded from analysis       -         Administration (2% total capital costs)       2% of total capital costs (TCI)       \$ 73,12         Property tax (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Insurance (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment       -         If e and 3.3% interest rate       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,72  | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime  | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure   | Comments           \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr           15% of Operator Costs           \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr           of maintenance labor costs           No impacts expected- engineering judgement<br>No impacts expected- engineering judgement  | * * * * *****  | 65,70<br>9,85<br>131,40<br>131,40  |
| Overhead       0% Conservatively excluded from analysis       \$       -         Administration (2% total capital costs)       2% of total capital costs (TCI)       \$       73,12         Property tax (1% total capital costs)       1% of total capital costs (TCI)       \$       36,56         Insurance (1% total capital costs)       1% of total capital costs (TCI)       \$       36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment       1         Ife and 3.3% interest rate       \$       251,47         Total Annual Indirect Operating Costs       \$       397,72   | Overhead       0% Conservatively excluded from analysis       \$         Administration (2% total capital costs)       2% of total capital costs (TCI)       \$       73,12         Property tax (1% total capital costs)       1% of total capital costs (TCI)       \$       36,56         Insurance (1% total capital costs)       1% of total capital costs (TCI)       \$       36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment       1         Ife and 3.3% interest rate       \$       251,47         Total Annual Indirect Operating Costs       \$       397,72  | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia   | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure   | Comments           \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr           15% of Operator Costs           \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr           of maintenance labor costs           No impacts expected- engineering judgement<br>No impacts expected- engineering judgement  | \$ \$ \$ \$ \$\$   | 65,70<br>9,85<br>131,40<br>131,40<br>635,10  |
| Administration (2% total capital costs)       2% of total capital costs (TCI)       \$ 73,12         Property tax (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Insurance (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,72   | Administration (2% total capital costs)       2% of total capital costs (TCI)       \$ 73,12         Property tax (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Insurance (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,72  | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia   | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure   | Comments           \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr           15% of Operator Costs           \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr           of maintenance labor costs           No impacts expected- engineering judgement<br>No impacts expected- engineering judgement  | \$ \$ \$ \$ \$\$   | 65,70<br>9,85<br>131,40<br>131,40<br>635,10  |
| Property tax (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Insurance (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment life and 3.3% interest rate       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,72  | Property tax (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Insurance (1% total capital costs)       1% of total capital costs (TCI)       \$ 36,56         Capital Recovery       0.0688 capital recovery factor for a 20-year equipment<br>life and 3.3% interest rate       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,72  | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs  | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure   | \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>No impacts expected- engineering judgement<br>No impacts expected- engineering judgement | \$ \$ \$ \$ \$\$\$\$\$\$\$\$\$                           | 65,70<br>9,85<br>131,40<br>131,40<br>635,10  |
| Insurance (1% total capital costs)     1% of total capital costs (TCI)     \$ 36,56       Capital Recovery     0.0688 capital recovery factor for a 20-year equipment<br>life and 3.3% interest rate     \$ 251,47       Total Annual Indirect Operating Costs     \$ 397,72  | Insurance (1% total capital costs)     1% of total capital costs (TCI)     \$ 36,56       Capital Recovery     0.0688 capital recovery factor for a 20-year equipment<br>life and 3.3% interest rate     \$ 251,47       Total Annual Indirect Operating Costs     \$ 397,72   | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Maste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs<br>Overhead  | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton/year<br>ton/year<br>ton/year<br>ton/year         | \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr         15% of Operator Costs         \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr         of Operator Costs         \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr         of maintenance labor costs         No impacts expected- engineering judgement Engineering judgement Engineering iudgement No impacts expected- engineering judgement No impacts expected- engineering iudgement No impacts expected- engineering iudgement Engineering iudgement Engineering iudgement No impacts expected engineering iu  | \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ | 65,70<br>9,85<br>131,40<br>131,40<br>635,10<br><b>973,45</b>   |
| Capital Recovery       0.0688 capital recovery factor for a 20-year equipment<br>life and 3.3% interest rate       \$ 251,47         Total Annual Indirect Operating Costs       \$ 397,72  | Capital Recovery 0.0688 capital recovery factor for a 20-year equipment life and 3.3% interest rate \$ 251,47 Total Annual Indirect Operating Costs \$ 397,72  | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Maste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)   | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton/year<br>ton/yr<br>gal/yr                         | S60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>No impacts expected- engineering judgement<br>No impacts expected engineering judgement   | \$ \$ \$ \$ \$\$\$\$\$\$\$\$\$                           | 65,70<br>9,85<br>131,40<br>131,40<br>635,10<br><b>973,45</b>   |
| Ife and 3.3% interest rate     \$ 251,47       Total Annual Indirect Operating Costs     \$ 397,72  | Iife and 3.3% interest rate     \$ 251,47       Total Annual Indirect Operating Costs     \$ 397,72  | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)  | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>ton/year<br>ton-mi/yr<br>ton/year<br>ton-mi/yr<br>ton/yr<br>gal/yr           | S60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>No impacts expected- engineering judgement<br>No impacts expected- engineering judgement<br>Engineering judgement<br>No impacts expected- engineering judgement<br>Engineering judgement<br>No impacts expected engineering ing provide engineering ing engineering e                    | \$ \$ \$ \$ \$\$\$\$\$\$\$\$\$                           | 65,700<br>9,853<br>131,400<br>131,400<br>635,100<br><b>973,45</b><br>-<br>73,122<br>36,566               |
| Total Annual Indirect Operating Costs     \$ 397,72   | Total Annual Indirect Operating Costs     \$ 397,72  | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)<br>Insurance (1% total capital costs)  | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton/year<br>ton/year<br>ton/year<br>ton/yr<br>gal/yr | \$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 1 hr/8 hr<br>shift, 8,760 hr/yr<br>15% of Operator Costs<br>\$60/Hr value is from EPA's cost spreadsheet for<br>SCR controls and includes benefits, 2 hr/8 hr<br>shift, 8,760 hr/yr<br>of maintenance labor costs<br>No impacts expected- engineering judgement<br>No impacts expected- engineering judgement<br>Conservatively excluded from analysis<br>of total capital costs (TCI)<br>of total capital costs (TCI)  | \$ \$ \$ \$ \$\$\$\$\$\$\$\$\$                           | 65,700<br>9,853<br>131,400<br>131,400<br>635,100<br><b>973,45</b><br>-<br>73,122<br>36,566               |
|   | tal Annual Cost (Direct Operating Cost + Indirect Operating Cost) \$ 1,371,17  | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Was<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Waste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)<br>Insurance (1% total capital costs)  | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton/year<br>ton/year<br>ton/year<br>ton/yr<br>gal/yr | \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr         15% of Operator Costs         \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr         of Operator Costs         \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr         of maintenance labor costs         No impacts expected- engineering judgement So impacts expected- engineering judgement So impacts expected- engineering judgement Engineering judgement Engineering judgement So impacts expected- engineering judgement So impacts expected engineering ing prove So (SO (SO (SO (SO (SO (SO (SO (SO (SO  | \$ \$ \$ \$ \$\$\$\$\$\$\$\$\$                           | 65,700<br>9,853<br>131,400<br>131,400<br>635,100<br><b>973,45</b> 5<br>73,122<br>36,563<br>36,563        |
|   | tal Annual Cost (Direct Operating Cost + Indirect Operating Cost) \$ 1,371,17  | Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Wass<br>Fuel Penalty<br>Electricity<br>Water<br>Compressed Air<br>Wastewater Treatment<br>Solid Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Hazardous Waste Disposal<br>Maste Transport<br>Lime<br>Ammonia<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)<br>Insurance (1% total capital costs)<br>Capital Recovery | \$<br>ste Ma<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$<br>\$ | 60.00<br>15%<br>60.00<br>100%<br>anagemen<br>13.640<br>0.036<br>0.004<br>0.367<br>1.957<br>48.800<br>488.000<br>0.652<br>290.000 | Measure<br>\$/Hr<br>of Op. Labor<br>\$/Hr<br>of Maint Labor<br>t<br>/ton coal<br>/kw-hr<br>/mgal<br>/mgal<br>/ton<br>/ton<br>/ton<br>/ton | Use Rate<br>1.00<br>2.00<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0<br>0 | Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>ton coal/yr<br>kw-hr/yr<br>mgal/yr<br>ton/year<br>ton/year<br>ton/year<br>ton/year<br>ton/year<br>ton/yr<br>gal/yr | \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr         15% of Operator Costs         \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr         of Operator Costs         \$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr         of maintenance labor costs         No impacts expected- engineering judgement So impacts expected- engineering judgement So impacts expected- engineering judgement Engineering judgement Engineering judgement So impacts expected- engineering judgement So impacts expected engineering ing prove So (SO (SO (SO (SO (SO (SO (SO (SO (SO  | \$ \$ \$ \$ \$\$\$\$\$\$\$\$\$\$\$                       | 65,700<br>9,855<br>131,400<br>131,400<br>635,100<br>973,455<br>-<br>73,125<br>36,565<br>36,565<br>36,565 |

# Regional Haze Four-Factor Analysis for NO<sub>X</sub> and SO<sub>2</sub> Emissions Control

Power Boiler 1 EQUI 14/EU 001

### Power Boiler 2 EQUI 15/EU 002

Prepared for Northshore Mining Company

July 31, 2020



# Regional Haze Four-Factor Analysis for NO<sub>x</sub> and SO<sub>2</sub> Emissions Control

Power Boiler 1 EQUI 14/EU 001

Power Boiler 2 EQUI 15/EU 002

Prepared for Northshore Mining Company

July 31, 2020

325 South Lake Avenue Duluth, MN 55802 218.529.8200 www.barr.com

### Regional Haze Four-Factor Analysis for NO $_X$ and SO $_2$ Emissions Control

### Power Boiler 1 and Power Boiler 2

### July 31, 2020

### Contents

| 1 | E>    | ecutive Summary  | 1  |
|---|-------|--|----|
| 2 | In    | troduction   | 1  |
| 2 | 2.1   | Four-Factor Analysis Regulatory Background                                 | 1  |
| 2 | 2.2   | Source Description   | 2  |
| 3 | E>    | xisting Controls and Baseline Emission Performance                         | 4  |
| Э | 3.1   | Existing Emission Controls   | 4  |
| З | 3.2   | Baseline Emissions Performance   | 4  |
| 4 | Fc    | our-Factor Analysis Overview   | 8  |
| Z | 4.1   | Emission Control Options   | 8  |
| Z | 4.2   | Factor #1 – Cost of Compliance   | 8  |
| Z | 1.3   | Factor #2 – Time Necessary for Compliance                                  | 9  |
| Z | 1.4   | Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance | 10 |
| Z | 4.5   | Factor #4 – Remaining Useful Life of the Source                            |    |
| 5 | Ν     | Ox Four-Factor Analysis for Power Boilers                                  | 11 |
| 5 | 5.1   | NO <sub>x</sub> Control Measures Overview                                  |    |
|   | 5.1.1 | Low NOx Burners (LNB)  | 11 |
|   | 5.1.2 |  |    |
|   | 5.1.3 |  |    |
|   | 5.1.4 |  |    |
|   | 5.2   | Factor #1 – Cost of Compliance   |    |
|   | 5.3   | Factor #2 – Time Necessary for Compliance                                  |    |
| 5 | 5.4   | Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance |    |
|   | 5.4.1 | LNB with OFA   |    |
|   | 5.4.2 |  |    |
|   | 5.4.3 |  |    |
| 5 | 5.5   | Factor #4 – Remaining Useful Life of the Source                            | 18 |

P:\Mpls\23 MN\38\23381133 NSM RHR 4-Factor Analysis\WorkFiles\Four Factor Analysis\NSM - RH Four Factor Analysis v3.doc

|   | 5.6 |    | NO <sub>x</sub> Four-Factor Analysis Conclusion                            |    |
|---|-----|----|--|----|
| 6 |     | SC | $D_2$ Four-Factor Analysis for Power Boilers                               | 19 |
|   | 6.1 |    | SO2 Control Measures Overview  | 19 |
|   | 6.1 | .1 | Dry Sorbent Injection (DSI) with New Baghouse                              |    |
|   | 6.1 | .2 | Spray Dryer Absorber (SDA) with New Baghouse                               | 19 |
|   | 6.2 |    | Factor #1 – Cost of Compliance   | 20 |
|   | 6.3 |    | Factor #2 – Time Necessary for Compliance                                  | 21 |
|   | 6.4 |    | Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance | 21 |
|   | 6.4 | .1 | Energy Impacts   | 21 |
|   | 6.4 | .2 | Environmental Impacts  | 21 |
|   | 6.5 |    | Factor #4 – Remaining Useful Life of the Source                            | 21 |
|   | 6.6 |    | SO <sub>2</sub> Four-Factor Analysis Conclusion                            |    |

#### List of Tables

| Table 1-1 Summary of NO <sub>x</sub> Four-Factor Analysis  | 1   |
|--|-----|
| Table 1-2 Summary of SO <sub>2</sub> Four-Factor Analysis  | 4   |
| Table 2-1 Identified Emission Units  | 1   |
| Table 3-1 Silver Bay Power Emissions   | 6   |
| Table 5-1: Additional NO <sub>x</sub> Control Measures with Potential Application at the Power Boilers | .14 |
| Table 5-2: NO <sub>X</sub> Control Cost Summary, per Unit Basis  | .14 |
| Table 6-1 Additional SO <sub>2</sub> Control Measures with Potential Application at Power Boilers      | .20 |
| Table 6-2: SO <sub>2</sub> Control Cost Summary for Power Boilers 1 and 2, per Unit Basis              | .20 |

#### List of Appendices

Appendix A: Unit Specific Screening Level Cost Summary for Power Boiler 1 Appendix B: Unit Specific Screening Level Cost Summary for Power Boiler 2 Appendix C: Submittals to MPCA Regarding Indurating Furnaces 11 and 12

#### Abbreviations

| BART            | Best Available Retrofit Technology                      |
|-----------------|---|
| BWCA            | Boundary Waters Canoe Area                              |
| CAIR            | Clean Air Interstate Rule                               |
| CEPCI           | Chemical Engineering Plant Cost Index                   |
| CPI             | Consumer Price Index                                    |
| CSAPR           | Cross-State Air Pollution Rule                          |
| D.C.            | District of Colombia                                    |
| DSI             | Dry Sorbent Injection                                   |
| EGU             | Electric Generating Units                               |
| EPA             | U.S. Environmental Protection Agency                    |
| IMPROVE         | Interagency Monitoring of Protected Visual Environments |
| Isle Royale     | Isle Royale National Park                               |
| LADCO           | Lake Michigan Air Directors Consortium                  |
| Lb              | Pound   |
| LNB             | Low-NO <sub>x</sub> Burners                             |
| MPCA            | Minnesota Pollution Control Agency                      |
| NO              | Nitric Oxide  |
| NOx             | Nitrogen Oxides   |
| Northshore      | Northshore Mining Company                               |
| OFA             | Overfire Air  |
| O&M             | Operating and Maintenance                               |
| PSD             | Prevention of Significant Deterioration                 |
| RFI             | Request for Information                                 |
| RH              | Regional Haze   |
| RHR             | Regional Haze Rule                                      |
| SCR             | Selective Catalytic Reduction                           |
| SDA             | Spray Dryer Absorber                                    |
| SIP             | State Implementation Plan                               |
| SNCR            | Selective Non-Catalytic Reduction                       |
| SO <sub>2</sub> | Sulfur Dioxide  |
| tpy             | Tons Per Year   |
| TVOP            | Title V Operating Permit                                |
| Voyageurs       | Voyageurs National Park                                 |
| U.S.            | United States   |
| WWESP           | Wet Walled Electrostatic Precipitator                   |
|                 |   |

### **1 Executive Summary**

In accordance with Minnesota Pollution Control Agency's (MPCA's) February 24, 2020 Request for Information (RFI) Letter<sup>1</sup>, Northshore Mining Company (Northshore) evaluated potential emissions control measures for sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>) for Power Boilers 1 (EQUI 14/ EU001) and 2 (EQUI 15/EU002) as part of the state's Regional Haze Rule (RHR)<sup>2</sup> reasonable progress. The analysis considers potential emissions control measures by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i) and pursuant to the final U.S. Environmental Protection Agency (EPA) RHR State Implementation Plan (SIP) guidance<sup>3</sup> on August 20, 2019 (2019 RH SIP Guidance):

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

This report describes the background and analysis for responding to the RFI and conducting the Four-Factor Analysis for NO<sub>X</sub> and SO<sub>2</sub> as applied to the review of emissions controls for the Power Boilers at Northshore. The Four-Factor Analysis conclusions are summarized in Table 1-1 and Table 1-2 for NO<sub>X</sub> and SO<sub>2</sub>, respectively.

The NO<sub>x</sub> Four-Factor Analysis evaluated the following NO<sub>x</sub> emissions control measures for the Power Boilers:

- Low NOx burners with overfire air (LNB-OFA); for Power Boiler 2 only
- Selective non-catalytic reduction (SNCR)
- Selective catalytic reduction (SCR)

In the Factor #1 – Cost of Compliance analysis, the associated cost effectiveness (\$ for each ton of emissions reduction) for each of the evaluated measures is indeterminate because the projected NOx emissions for 2028 are zero, and accordingly there are no expected additional reductions from any of the potential control technologies (refer to Sections 4.2 and 5.2 and Appendices A and B for more control cost information). Therefore, Northshore's existing NO<sub>X</sub> emission performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

<sup>&</sup>lt;sup>1</sup> February 24, 2020 letter from Hassan Bouchareb of MPCA to Andrea Hayden of Northshore Mining Company.

<sup>&</sup>lt;sup>2</sup> The U.S. Environmental Protection Agency (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>&</sup>lt;sup>3</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

The SO<sub>2</sub> Four-Factor Analysis evaluated the following SO<sub>2</sub> emissions control measures for the Power Boilers:

- Dry sorbent injection (DSI) with new baghouses
- Spray dryer absorption (SDA) with new baghouses

In the Factor #1 – Cost of Compliance analysis, the associated cost effectiveness (\$ for each ton of emissions reduction) for each of the evaluated measures is indeterminate because the projected SO<sub>2</sub> emissions for 2028 are zero, and accordingly there are no expected additional reductions from any of the potential control technologies (refer to Sections 4.2 and 6.2 and Appendices A and B for more control cost information). The Power Boilers SO<sub>2</sub> emissions are minimized by coal pre-processing. Therefore, Northshore's existing SO<sub>2</sub> emission performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

In addition to the four statutory factors, states have the discretion to consider any potential visibility improvements if Northshore were to implement the emission control measures, which is referred to as the "fifth factor." Northshore continues to evaluate visibility benefits associated with possible NOx and SO<sub>2</sub> control measures internally and reserves the right to supplement this analysis with information related to visibility benefits. Northshore plans to conduct CAMx modeling after modeling information from the Lake Michigan Air Directors Consortium (LADCO) is available.

Table 1-1 Summary of NO<sub>X</sub> Four-Factor Analysis

|   | Factor #1 – Cost of Compliance   |  |  |  |  |   |   |
|---|--|--|--|--|--|---|---|
| List of<br>Emission<br>Control<br>Measure | Installed<br>Capital Cost<br>(\$)                                      | Annualized<br>Operating Cost<br>(\$/year)                            | Pollution<br>Control<br>Cost<br>(\$/ton) | Factor #2 –<br>Time<br>Necessary<br>for<br>Compliance        | Factor #3 – Energy and Non-Air<br>Quality Environmental Impacts of<br>Compliance   | Factor #4 –<br>Remaining Useful<br>Life of the Source | Does this Analysis<br>Support the<br>Installation of this<br>Emission Control<br>Measure? |
| LNB-OFA<br>(Power<br>Boiler 2<br>only)    | \$11,609,362   | \$1,725,870  | NA – See<br>Section 3.2                  | 5 years after<br>SIP<br>promulgation.<br>See Section<br>5.3. | Environmental<br>Increased carbon monoxide emissions,<br>loss of efficiency, and likely Prevention<br>of Significant Deterioration (PSD)<br>permitting implications.   | 20 years control<br>equipment life                    | No  |
|   |  |  |  |  | Potential for increased steam tube<br>damage and maintenance due to<br>flame impingement on tubes.   |   |   |
|   |  |  |  |  | Increased maintenance due to scale build-up and corrosion.   |   |   |
| SNCR                                      | \$7,239,275 for<br>Power Boiler 1<br>\$8,917,925 for<br>Power Boiler 2 | \$992,019 for<br>Power Boiler 1<br>\$1,435,176 for<br>Power Boiler 2 | NA – See<br>Section 3.2                  | 5 years after<br>SIP<br>promulgation.<br>See Section<br>5.3. | EnergyIncreased energy use to overcome the<br>increased differential pressure.Increased water use for reagent<br>dilution.Increased fuel usage for vaporization<br>of the water in the reagent solution.Environmental<br>Increased ammonia emissions from<br>ammonia slip, which contributes to<br>regional haze.Additional ammonia reacts with<br>sulfates causing increased visibility<br>impairment pollutants. | 20 years control<br>equipment life                    | No  |

|   | Factor #1 – Cost of Compliance   |  |  |  |   |   |   |
|---|--|--|--|--|---|---|---|
| List of<br>Emission<br>Control<br>Measure | Installed<br>Capital Cost<br>(\$)  | Annualized<br>Operating Cost<br>(\$/year)                              | Pollution<br>Control<br>Cost<br>(\$/ton) | Factor #2 –<br>Time<br>Necessary<br>for<br>Compliance        | Factor #3 – Energy and Non-Air<br>Quality Environmental Impacts of<br>Compliance  | Factor #4 –<br>Remaining Useful<br>Life of the Source | Does this Analysis<br>Support the<br>Installation of this<br>Emission Control<br>Measure? |
|   |  |  |  |  | Ammonia emissions will increase<br>condensable PM emissions that will<br>have possible PSD permitting<br>implications.<br>Loss of fly ash re-use.<br>Nitrogen deposition onto nearby lakes<br>and waters of the state will contribute<br>nutrients and to undesirable biological<br>growth.<br>Additional safety and regulatory<br>concerns associated with ammonia or<br>urea storage on site. |   |   |
| SCR                                       | \$40,647,490 for<br>Power Boiler 1<br>\$55,724,684 for<br>Power Boiler 2 | \$4,159,366 for<br>Power Boiler 1<br>\$5,985,367 for<br>Power Boiler 2 | NA – See<br>Section 3.2                  | 5 years after<br>SIP<br>promulgation.<br>See Section<br>5.3. | Energy<br>Increased energy use to overcome the<br>increased differential pressure.<br>Electricity is required for the SCR<br>equipment, to vaporize the aqueous<br>ammonia reagent.<br>Environmental<br>Increased ammonia emissions from<br>ammonia slip.   | 20 years control<br>equipment life                    | No  |

|   | Factor #1 – Cost of Compliance    |   |  |   |  |   |   |
|---|-----------------------------------|---|--|---|--|---|---|
| List of<br>Emission<br>Control<br>Measure | Installed<br>Capital Cost<br>(\$) | Annualized<br>Operating Cost<br>(\$/year) | Pollution<br>Control<br>Cost<br>(\$/ton) | Factor #2 –<br>Time<br>Necessary<br>for<br>Compliance | Factor #3 – Energy and Non-Air<br>Quality Environmental Impacts of<br>Compliance   | Factor #4 –<br>Remaining Useful<br>Life of the Source | Does this Analysis<br>Support the<br>Installation of this<br>Emission Control<br>Measure? |
|   |                                   |   |  |   | Ammonium would combine with NOx and SO <sub>2</sub> to form ammonia salts, which would be emitted to the atmosphere as $PM_{10}$ .           |   |   |
|   |                                   |   |  |   | Emissions of ammonia, ammonium<br>sulfates, and sulfuric acid mist increase<br>plume visibility and contribute to<br>regional haze.          |   |   |
|   |                                   |   |  |   | Sulfuric acid mist emissions will increase due to the oxidation of $SO_2$ to $SO_3$ by the SCR catalyst.                                     |   |   |
|   |                                   |   |  |   | Loss of fly ash re-use.<br>Increased oxidized mercury emissions.   |   |   |
|   |                                   |   |  |   | Nitrogen deposition onto nearby lakes<br>and waters of the state will contribute<br>nutrients and to undesirable biological<br>growth.       |   |   |
|   |                                   |   |  |   | There are safety risks associated with the transportation, handling, and storage of aqueous ammonia or urea.                                 |   |   |
|   |                                   |   |  |   | Spent catalyst from the SCR is typically<br>disposed of in a landfill; however,<br>catalyst recycling or reconditioning<br>may be available. |   |   |

#### Table 1-2 Summary of SO<sub>2</sub> Four-Factor Analysis

|  | Factor #1 – Cost of Compliance   |  |  | Factor #2 –  |   |  | Does this Analysis  |
|--|--|--|--|--|---|--|---|
| List of<br>Emission<br>Control<br>Technology | Installed<br>Capital Cost<br>(\$)  | Annualized<br>Operating<br>Cost<br>(\$/year)                                   | Pollution<br>Control<br>Cost<br>(\$/ton) | Time<br>Necessary<br>for<br>Compliance                       | Factor #3 – Energy and Non-Air<br>Quality Environmental Impacts of<br>Compliance  | Factor #4 –<br>Remaining<br>Useful Life of<br>the Source | Support the<br>Installation of this<br>Emission Control<br>Measure? |
| DSI/Baghouse                                 | \$34,463,571<br>for Power<br>Boiler 1<br>\$37,737,598<br>for Power<br>Boiler 2 | \$6,144,640<br>for Power<br>Boiler 1<br>\$6,943,044<br>for Power<br>Boiler 2   | NA – See<br>Section 3.2                  | 5 years after<br>SIP<br>promulgation.<br>See Section<br>6.3. | Energy<br>Increased energy use to accommodate<br>new baghouse and additional equipment<br>for material preparation and handling.<br>Environmental<br>Additional solid waste generated and<br>disposed.<br>Loss of fly ash re-use.<br>Increase in wastewater generation. | 20 years control<br>equipment life                       | No  |
| SDA/Baghouse                                 | \$58,737,702<br>for Power<br>Boiler 1<br>\$61,962,015<br>for Power<br>Boiler 2 | \$12,796,563<br>for Power<br>Boiler 1<br>\$13,572,909<br>for Power<br>Boiler 2 | NA – See<br>Section 3.2                  | 5 years after<br>SIP<br>promulgation.<br>See Section<br>6.3. | Energy<br>Increased energy use to accommodate<br>new baghouse and additional equipment<br>for material preparation and handling.<br>Environmental<br>Additional solid waste generated and<br>disposed.<br>Loss of fly ash re-use.<br>Increase in wastewater generation. | 20 years control<br>equipment life                       | No  |

# 2 Introduction

This section discusses the pertinent regulatory background information, and a description of Northshore's Power Boilers.

### 2.1 Four-Factor Analysis Regulatory Background

The RHR published on July 15, 2005 by the 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 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 February 24, 2020, the MPCA sent an RFI to Northshore. The RFI stated that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) 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 SO<sub>2</sub> and NO<sub>x</sub>. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze in Isle Royale, Michigan must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts. As part of the planning process for the SIP development, MPCA is working with the LADCO to evaluate regional emission reductions.

The RFIs also stated that Northshore was identified as a significant source of NO<sub>X</sub> and SO<sub>2</sub> that is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that Northshore submit a "Four-Factors Analysis" (herein termed as a Four-Factor Analysis) by July 31, 2020 for the emission units identified in Table 2-1 as part of the State's regional haze reasonable progress.

| Unit                  | Unit ID                       | Applicable Pollutants               |  |  |
|-----------------------|-------------------------------|-------------------------------------|--|--|
| Indurating Furnace 11 | EQUI 126 & 127 (EU 100 & 104) | $NO_x$ and $SO_2$                   |  |  |
| Indurating Furnace 12 | EQUI 128 & 129 (EU 110 & 114) | NO <sub>x</sub> and SO <sub>2</sub> |  |  |
| Power Boiler 1        | EQUI 14 (EU 001)              | $NO_x$ and $SO_2$                   |  |  |
| Power Boiler 2        | EQUI 15 (EU 002)              | NO <sub>x</sub> and SO <sub>2</sub> |  |  |

#### Table 2-1 Identified Emission Units

The analysis considers potential emissions control measures by addressing the four statutory factors which are laid out in 40 CFR 51.308(f)(2)(i) and explained in the 2019 RH SIP Guidance:

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

The RFI letter to the Northshore specified that the "... analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to the final 2019 RH SIP Guidance.<sup>3</sup>

This report describes the background and analysis for conducting a Four-Factor Analysis for NO<sub>X</sub> and SO<sub>2</sub> as applied to the review of emissions controls at Northshore for the Power Boilers identified in Table 2-1. Northshore has requested that the MPCA exclude the Indurating Furnaces identified in Table 2-1 from the sources required to conduct a Four-Factor Analysis because the furnaces are already effectively controlled with BART emission limits for NO<sub>X</sub> and SO<sub>2</sub>. The request was submitted separately from this report on July 6, 2020. MPCA requested additional supplementary information on July 28, 2020 and Northshore responded on July 30, 2020. Copies of the two submittals are provided in Appendix C.

### 2.2 Source Description

Northshore mines iron ore (magnetite) and produces taconite pellets that are shipped to steel producers for processing in blast furnaces. The iron ore is crushed and routed through several concentration stages including grinding, magnetic separation, and thickening. The concentrated iron ore slurry is then dewatered, followed by mixing the filter cake with bentonite and/or other binding agents. The mixed filter cake is then formed into greenballs, which are fed through the indurating furnace(s) to create a final product.

Silver Bay Power Company, located at Northshore, has two industrial boilers listed in the RFI, identified as Power Boiler 1 and Power Boiler 2. The boilers provide process steam and electricity to the taconite operations. Each industrial boiler has an electric generator set. The electricity generated is used primarily by the Silver Bay taconite processing facility. However, a portion may be sold to the electric grid. Process steam can be produced at the power plant using evaporators that extract heat from the Power Boilers or from a recently constructed steam plant. The process steam is used in taconite processing operations.

Power Boiler 1 is a natural gas, distillate fuel oil, or coal-fired boiler, which has a dry bottom, front-wallfired configuration and a rating of 517 MMBtu/hr, or an output of 45 megawatts. Power Boiler 2 is a natural gas or coal-fired boiler, which has a dry bottom, front-walled-fired configuration and a rating of 765 MMBtu/hr, or an output of 70 megawatts.

As of October 2019, Power Boilers 1 and 2 have been economically idled. In 2016, Northshore entered into a binding Power Service Agreement (PSA) with Minnesota Power to provide electricity to Northshore

Mining through 2031. Silver Bay Power Company is maintaining the boilers in a manner that allows startup if and when called upon by Minnesota Power to provide emergency stability to the regional electrical grid in the event of catastrophic failure. The idled boilers may resume operation in the future after termination of the PSA, but a typical operating scenario has not yet been determined. Northshore may reevaluate the control costs in the future if an operating scenario beyond the PSA is established.

# 3 Existing Controls and Baseline Emission Performance

This section describes the existing  $NO_X$  and  $SO_2$  emissions controls on Northshore's Power Boilers and the baseline emissions to evaluate the costs for the associated emission control measures.

### 3.1 Existing Emission Controls

The existing pollution control equipment includes a fabric filter baghouse to control particulate matter on each boiler and low NO<sub>x</sub> burners in conjunction with overfire air on Power Boiler 1 for NO<sub>x</sub> control. SO<sub>2</sub> emissions from the boilers are reduced by coal processing prior to combustion. There are no post-combustion SO<sub>2</sub> controls. SO<sub>2</sub> emissions are limited by Northshore's Title V Operating Permit (TVOP) (Permit No. 07500003-010) to 1.5 lb/MMBtu on an annual basis when burning coal.

In the MPCA's 2012 SIP supplement, the MPCA revised the BART strategy for electric generating units to use the Cross-State Air Pollution Rule (CSAPR) instead of site-specific determinations. This strategy was subsequently approved by the USEPA and serves as BART for both Power Boiler 1 and 2. Subsequently, on August 21, 2012 the United States Court of Appeals for the D.C. Circuit issued its ruling to vacate CSAPR. On April 29, 2014, the U.S. Supreme Court reversed the D.C. Circuit opinion vacating CSAPR. However, the rule remained stayed at that point in time. On June 26, 2014 the U.S. government filed a motion with the U.S. Court of Appeals for the D.C. circuit to lift the stay of the CSAPR which was subsequently granted on October 23, 2014. The motion also included extending the original compliance deadlines by three years, so that Phase 1 emissions budgets apply in 2015 and 2016 (instead of 2012 and 2013), and the Phase 2 emissions budgets apply in 2017 and beyond (instead of 2014 and beyond). As noted, MPCA determined that BART-eligible sources complying with CSAPR is considered meeting BART control requirements. Both Power Boilers 1 and 2 are subject to CSAPR.

### 3.2 Baseline Emissions Performance

The Four-Factor Analysis requires the establishment of a baseline scenario for evaluating a potential emission control measure. EPA's August 20, 2019 memo, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" (2019 RH SIP Guidance)<sup>4</sup>, provides recommended practices for states to consider when developing an approvable regional haze SIP for the second implementation period, which covers 2018-2028.

The 2019 RH SIP Guidance specifically addresses in Section II.B.3.b recommendations for states to consider when selecting sources for the purpose of evaluating air quality model-based visibility impacts based on a facility's level of estimated emissions in 2028. EPA also describes in Section II.B.4.b

<sup>&</sup>lt;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. <u>https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period</u>

recommendations for states to consider when estimating 2028 emissions <u>for the purpose of evaluating</u> <u>potential emission control measures</u> by referring to the same information as described in Section II.B.3.b. EPA states in Section II.B.4.b, "This information on emission reductions feeds into the estimation of visibility benefits and into calculations of cost effectiveness." The following excerpt from Section II.B.3.b describes how to estimate future emissions for evaluating both visibility impacts and potential control cost (emphasis added).

#### <u>Selection of emissions information when estimating visibility impacts (or surrogates) for source</u> <u>selection purposes</u>

... Generally, we recommend that states use estimates of 2028 emissions (resolved by day and hour, as appropriate) to estimate visibility impacts (or related surrogates) when selecting sources, rather than values of recent year emissions. By doing so, sources that are projected on a reasonable basis to cease or greatly reduce their operations or to install much more effective emissions controls by 2028 may be removed from further consideration early in the SIP development process, which can reduce analytical costs. Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions in 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.

If a state uses a value for emissions in an earlier year, we recommend the state consider whether emissions have appreciably changed (or will change) between the earlier year, the current period, and the projected future year (2028). It is especially important to consider whether source emissions have increased or are likely to increase in the future compared to earlier emissions values.

#### Use of actual emissions versus allowable emissions

Generally, we recommend that a reasonably projected actual level of source operation in 2028 be used to estimate 2028 actual emissions for purposes of selecting sources for control measure analysis. Source operation during a historical period can inform this projection, but temporary factors that suppressed or bolstered the level of operation in the historical period should be considered, along with factors that indicate a likely increase or decrease in operation. See the SIP Emissions Inventory Guidance for more details. Questions about projecting 2028 emissions may be directed to EPA Regional offices. As reported in a news release from Cleveland-Cliffs on May 24, 2016,<sup>5</sup> Cleveland-Cliffs entered into a binding, multi-year Power Service Agreement (PSA) with Minnesota Power to provide electricity to Northshore through 2031. Minnesota Power's SEC 10-K filing 2016<sup>6</sup> also described the PSA as partially supplying electricity for Northshore from 2016-2019 while it was transitioning away from self-generation, and on December 31, 2019, Minnesota Power would supply the entire energy requirements of the facility.

Silver Bay Power Boiler 1 has not operated since June 2019 and Silver Bay Power Boiler 2 has not operated since September 2019. The following chart illustrates the reduced level of emissions through third quarter 2019 and no emissions since then. While Silver Bay Power remains fully permitted and maintained in a state of operational readiness, Silver Bay Power is not expected to operate until at least the expiration of the PSA in 2031. Accordingly, Northshore is projecting no emissions through the Regional Haze Second Planning Period (2028).

#### Table 3-1 Silver Bay Power Emissions

| Silver Bay Power Emissions |                                     |                               |        |        |  |  |
|----------------------------|-------------------------------------|-------------------------------|--------|--------|--|--|
|                            | Power                               | Power Boiler 1 Power Boiler 2 |        |        |  |  |
|                            | SO <sub>2</sub> NOx SO <sub>2</sub> |                               |        | NOx    |  |  |
|                            | (tons)                              | (tons)                        | (tons) | (tons) |  |  |
| January <b>2019</b>        | 91                                  | 55.4                          | 0      | 0      |  |  |
| February                   | 91.7                                | 55.9                          | 0      | 0      |  |  |
| March                      | 91.7                                | 55.6                          | 0      | 0      |  |  |
| April                      | 79.2                                | 49.9                          | 0      | 0      |  |  |
| May                        | 88.3                                | 50.7                          | 0      | 0      |  |  |
| June                       | 14.8                                | 9.5                           | 50.3   | 75.1   |  |  |
| July                       | 0                                   | 0                             | 80.4   | 134.5  |  |  |
| August                     | 0                                   | 0                             | 77     | 135.5  |  |  |
| September                  | 0                                   | 0                             | 32.8   | 59.1   |  |  |
| October                    | 0                                   | 0                             | 0      | 0      |  |  |
| November                   | 0                                   | 0                             | 0      | 0      |  |  |
| December                   | 0                                   | 0                             | 0      | 0      |  |  |
|                            |                                     |                               |        |        |  |  |
| January <b>2020</b>        | 0                                   | 0                             | 0      | 0      |  |  |
| February                   | 0                                   | 0                             | 0      | 0      |  |  |

<sup>&</sup>lt;sup>5</sup> Cliffs Natural Resources, Inc. (2016, May 24) *Cliffs Announces Agreements with Minnesota Power* [Press Release]. Retrieved from <u>http://www.clevelandcliffs.com/English/news-center/news-releases/news-releases-details/2016/Cliffs-Announces-Agreements-with-Minnesota-Power/default.aspx</u>

<sup>6</sup> Allete, Inc. (2016) *Form 10-K*. Retrieved from

https://www.allete.com/Content/Documents/Investors/AnnualReports/FINALREPORTALLETE2016.pdf

| Silver Bay Power Emissions |                 |                            |                 |        |  |  |
|----------------------------|-----------------|----------------------------|-----------------|--------|--|--|
|                            | Power           | Power Boiler 1 Power Boile |                 |        |  |  |
|                            | SO <sub>2</sub> | NOx                        | SO <sub>2</sub> | NOx    |  |  |
|                            | (tons)          | (tons)                     | (tons)          | (tons) |  |  |
| March                      | 0               | 0                          | 0               | 0      |  |  |
| April                      | 0               | 0                          | 0               | 0      |  |  |
| May                        | 0               | 0                          | 0               | 0      |  |  |
| June                       | 0               | 0                          | 0               | 0      |  |  |
| July                       | 0               | 0                          | 0               | 0      |  |  |

Northshore is complying with MPCA's request to conduct a Four-Factor Analysis on potential control technologies for Power Boilers 1 and 2. While Northshore has made an earnest effort to complete all other sections of the analysis, including estimating expected capital costs and annual operating costs for candidate technologies, it cannot reasonably provide a cost-effectiveness estimate in terms of dollars per ton of pollutant removed because expectations are no emissions through 2028, and therefore, no pollutants removed by installation of any control technology.

Also, for the purposes of estimating actual 2028 emissions to evaluate Class I visibility impacts, MPCA should allocate zero tons per year of NOx and SO<sub>2</sub> emissions to Silver Bay Power in its visibility model.

## 4 Four-Factor Analysis Overview

This section summarizes the Four-Factor Analysis approach with respect to the Regional Haze program detailed in the 2019 RH SIP guidance.

### 4.1 Emission Control Options

Prior to completing a Four-Factor Analysis of each emissions control measure, all technically feasible emission control options for Power Boilers must first be identified. Potentially available emission control measures include both physical and operational changes. Once all technically feasible emission control measures are identified, the facility justifies which emission control measures are reasonable to consider against the four factors, recognizing there is no statutory or regulatory requirement to consider all technically feasible measures.

In order to be considered 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, industrial operations are not considered as part of this analysis. Instead, this evaluation focuses on commercially demonstrated control options.

The control efficiencies of currently available emission control measures under consideration ranges from 25 percent to 80 percent for NO<sub>x</sub> and 50 percent to 90 percent for SO<sub>2</sub>. For purposes of this analysis, Northshore evaluated only those control measures that have the potential to achieve an overall pollutant reduction greater than the performance of the existing systems, including optimizations.

An evaluation of the technically feasible control measures for  $NO_X$  and  $SO_2$  is discussed in Sections 5.1 and 6.1, respectively.

### 4.2 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>7</sup> unless more refined site-specific estimate are available. Under this step, the annualized cost of installation and operation on a dollar per ton of pollutant removed (\$/ton) of

<sup>&</sup>lt;sup>7</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 <u>https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution</u> as of the date of this report.

the control measure, referred to as "average cost effectiveness," is compared to a cost effectiveness threshold that is estimated by EPA (see discussion below for the associated  $NO_x$  and  $SO_2$  thresholds).

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 an intermediate or high degree of effectiveness.

The cost of an emissions control measure is derived using capital and annual 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 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.

Space limitations are also a concern for installation of new equipment. The Power Boilers are bounded by the switchyard on the north, the pelletizing plant on the west, traveling screens for the non-contact cooling water, and the lake on the south, and a steep embankment and roadway that provides access to the lower levels on the east. Additional buildings for new control equipment would require significant structural building modifications. Due to space considerations, a 60 percent markup of the total capital investment (i.e. 1.6 retrofit factor) was included in the costs to account for the retrofit installation to provide for additional site-work and construction costs to accommodate the new equipment within the facility. The site-specific estimate was based on Barr's experience with similar projects.

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 (2028 baseline emissions) in tons per year (tpy), and 2) expected annual emissions performance through installation of the additional control measure (controlled emissions), also in tpy. As described in Section 3.2, the cost-effectiveness calculations are not applicable because the projected emissions for 2028 are zero, and accordingly there are no expected additional reductions from any of the potential control technologies.

# 4.3 Factor #2 - Time Necessary for Compliance

Factor #2 considers the time needed for Northshore to comply with potential emission control measures. This includes the planning, permitting, installation, and commissioning of the selected control based on experiences with similar sources and source-specific factors.

For purposes of this analysis, and if a given NO<sub>x</sub> or SO<sub>2</sub> control measure requires a unit outage as part of its installation, Northshore considers the forecasted outage schedule for the associated units in conjunction with the expected timeframe for engineering and equipment procurement following MPCA and EPA approval of the given control measure.

# 4.4 Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance

Factor #3 considers the energy and non-air environmental impacts of each control measure. Energy impacts to be considered are the direct energy consumed at the source, in terms of kilowatt-hours or mass of fuels used. Non-air quality impacts may include solid or hazardous waste generation, wastewater discharges from a control device, increased water consumption, and land use. The analysis is conducted based on consideration of site-specific circumstances.

# 4.5 Factor #4 – Remaining Useful Life of the Source

Factor #4 considers 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 Northshore 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 the source is under an enforceable requirement to cease operation. 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 for the units are 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 removed.

# 5 NO<sub>X</sub> Four-Factor Analysis for Power Boilers

This section identifies and describes various NO<sub>X</sub> emission control measures, evaluates the four statutory factors for the Power Boilers, considers other factors, and determines if an emission control measure or measures are necessary to make reasonable progress. Consistent with EPA's guidance and MPCA direction, Northshore has completed a Four-Factor Analysis for NO<sub>X</sub> as described in Sections 5.1 to 5.6.

# 5.1 NO<sub>x</sub> Control Measures Overview

Three mechanisms by which NO<sub>X</sub> production typically forms are thermal, fuel and prompt NO<sub>X</sub> formation. In the case of natural gas combustion, the primary mechanism of NO<sub>X</sub> production is through thermal NO<sub>X</sub> formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air to nitric oxide (NO). The thermal oxidation reaction is as follows:

$$N_2 + O_2 \rightarrow 2NO \tag{1}$$

Downstream of the flame, significant amounts of  $NO_2$  can be formed when NO is mixed with air. The reaction is as follows:

$$2NO + O_2 \rightarrow 2NO_2 \qquad (2)$$

Thermal oxidation is a function of the residence time, free oxygen, and peak reaction temperature.

Prompt NO<sub>X</sub> is a form of thermal NO<sub>X</sub>, which is generated at the flame boundary. It is the result of reactions between nitrogen and hydrocarbon radicals generated during combustion. Only minor amounts of NO<sub>X</sub> are emitted as prompt NO<sub>X</sub>.

Fuel-bound NO<sub>x</sub> is primarily a concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. Natural gas has minimal fuel bound nitrogen, which eliminates fuel bound NO<sub>x</sub> as a major concern.

The following describes pertinent technical information regarding the technologies and whether the technologies are technically feasible as applied to the Power Boilers.

### 5.1.1 Low NOx Burners (LNB)

The LNB technology utilizes advanced-burner design to reduce NOx formation through the restriction of oxygen, flame temperature, and/or residence time. The LNB technology 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.

The LNB control technology were installed on Power Boiler 1 in 2015. Northshore has not installed LNB control technology on Power Boiler 2.

Alone or in combination with additional controls, the LNB technology is a technically feasible option to further reduce emissions from Power Boiler 2. Based on the currently achieved emission rates a reduction in the range of 15 to 30 percent would be expected depending on operational conditions. The value of 15 percent is chosen until real data is available after installation and true performance can be assessed.

# 5.1.2 Overfire Air (OFA)

The OFA diverts a portion of the total combustion air from the burners and injects it through separate airports above the top level of burners. The OFA technology is the typical control technology used in coal-fired boilers and is primarily geared to reduce thermal NOx. 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. The OFA technology would not gain NOx control with the existing burners because the existing burners lack sufficient fuel and airflow control. However, the OFA technology is considered a technically feasible option when utilized in conjunction with new burners that would be LNB.

The OFA with LNB technologies were installed on Power Boiler 1 in 2015. Northshore has not installed OFA with LNB technologies on Power Boiler 2. Therefore, OFA with LNB technologies will be considered as a technically feasible option for Power Boiler 2. OFA used in conjunction with LNB could have a control efficiency of 30 to 50 percent. The value of 40 percent is chosen for Power Boiler 2. This value is consistent with the control efficiency achieved on Power Boiler 1. Because Northshore has previously evaluated the installation of OFA with LNB, and OFA with LNB achieves a higher control efficiency than LNB alone, Northshore has only included OFA with LNB, not LNB alone, as part of the reasonable set of controls for Power Boiler 2.

# 5.1.3 Selective Non-Catalytic Reduction (SNCR)

In the SNCR process, urea or ammonia-based chemicals are injected into the flue gas stream to convert nitrous oxide (NO) to molecular nitrogen, N<sub>2</sub>, and water. The SNCR control efficiency is typically 25 percent to 50 percent. Without a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:

NO + NH<sub>3</sub> +  $\frac{1}{4}O_2 \rightarrow N_2 + \frac{3}{2}H_2O$  (1)

 $NH_3 + \frac{1}{4}O_2 \rightarrow NO + \frac{3}{2}H_2O(2)$ 

At temperature ranges of 1470°F to 1830°F, reaction (1) dominates. At temperatures above 2000°F, reaction (2) will dominate. The temperature of flue gas at the point of reagent injection and the available residence time within the optimum reaction temperature window along with mixing efficiency are the key ingredients in achieving maximum NOx reductions with the SNCR process. The SNCR process can be retrofitted to most if not all utility boilers; however, the NOx reductions achieved are very site specific

since they are highly dependent on the temperature and residence time profiles of the individual boiler. If consideration of this technology were to advance, it may be appropriate to further study and establish the residence times of the flue gases in the reaction temperature window, the location of the temperature window, ease of access for installation of the reagent injection ports at that temperature window, and the ability to achieve rapid and complete mixing of the reagent within that temperature window.

The boiler geometry and operating conditions may not provide sufficient residence time within the required operating temperature range for effective implementation of SNCR. While there is uncertainty that the residence time would be adequate, the assumption is this control option will be considered technically feasible. The control efficiency for SNCR is assumed to be 25 percent in this analysis.

## 5.1.4 SCR

The SCR technology is also a common technology used to control NOx emissions. The SCR control technology is a process that involves post-combustion removal of NOx from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the combustion unit exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reaction takes place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy required for the NOx decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging, ammonia slip emissions, and design of the NH<sub>3</sub> injection system.

Reduction catalysts are composed of active metals or ceramics with a highly porous structure. For the majority of commercial catalysts (metal oxides), the operating temperatures for the SCR process range from 480°F to 800°F. Proper reactor temperature is important in order to achieve high reductions in NOx emissions. According to the EPA Air Pollution Control Cost Manual (EPA Control Cost Manual) for SCR (updated June 2019), the NOx removal efficiency is optimized when the temperature is approximately 700°F to 750°F. Based on an engineering assessment and current NOx emissions, SCR is technically feasible for Power Boilers 1 and 2 and could provide a NOx reduction of up to 80 percent.

Based on the information presented above, Northshore has identified LNB with OFA for Power Boiler 2 only, along with SNCR, and SCR for Power Boiler 1 and 2 and to be considered whether their installation is necessary to make reasonable progress based on the factors presented below. Table 5-1 lists technically feasible NO<sub>X</sub> control measures for the Power Boilers.

Table 5-1: Additional NO<sub>X</sub> Control Measures with Potential Application at the Power Boilers

| Control Measures   |
|--|
| Low NOx Burners with Overfired Air (LNB-OFA) for Power Boiler 2 only |
| Selective Non-Catalytic Reduction (SNCR)                             |
| Selective Catalytic Reduction (SCR)                                  |

# 5.2 Factor #1 – Cost of Compliance

Northshore has completed cost estimates for the selected NO<sub>x</sub> emission control measures. Due to the limited time available in responding to MPCA's request, assumptions were made in the cost estimates resulting in conservatively low equipment costs. Cost estimates for LNB-OFA are based on vendor engineering estimates, scaled for inflation using the CEPCI. The EPA Control Cost Manual was used to estimate the equipment costs for SCR and SNCR. The capital cost estimates are considered by Northshore's plant and Barr's engineering staff, based on their considerable experience with projects at Northshore and their informal conversations with other companies that have completed similar types of projects at other facilities, to be conservatively low. Cost summary spreadsheets for the NO<sub>x</sub> emission control measures are provided in Appendix A for Power Boiler 1 and Appendix B for Power Boiler 2.

As discussed in Section 4.2, cost effectiveness in terms of dollars per ton of pollutant removed cannot reasonably be estimated because expectations are no emissions in 2028, and therefore no pollutants removed by installation of any control technology.

The resulting control cost calculations are summarized in Table 5-2.

| Emission Unit  | Additional Emissions<br>Control Measure | Installed Capital Cost<br>(\$MM) | Total Annualized<br>Costs (\$/yr) |
|----------------|---|----------------------------------|-----------------------------------|
| Power Boiler 1 | SNCR                                    | \$7,239,275                      | \$992,019                         |
| Power Boiler 1 | SCR                                     | \$40,647,490                     | \$4,159,366                       |
| Power Boiler 2 | LNB-OFA                                 | \$11,609,362                     | \$1,725,870                       |
| Power Boiler 2 | SNCR                                    | \$8,917,925                      | \$1,435,176                       |
| Power Boiler 2 | SCR                                     | \$55,724,684                     | \$5,985,367                       |

### Table 5-2: NO<sub>x</sub> Control Cost Summary, per Unit Basis

Sections 5.3 through 5.5 provide a summary of the remaining three factors evaluated for the NO<sub>X</sub> emission control measures, understanding that these projects represent substantial capital investments that are not justified on an absolute cost basis.

# 5.3 Factor #2 – Time Necessary for Compliance

The amount of time needed for full implementation of the emission control measure or measures varies. Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the SIP by state and federal action, time for MPCA to modify Northshore's Title V operating permit to allow construction to commence, then to implement the project necessary to meet the SIP limit for the emissions control measure, including capital funding, construction, tie-in to the process, commissioning, and performance testing.

A state SIP revision is needed to approve a new statistically derived emissions limit methodology, e.g. 99 percent UPL. Barr assumes that the revisions would occur within 12 to 18 months after the MPCA submits its regional haze SIP for the second implementation period (approximately 2022 to 2023).

The technologies would require significant resources and time of at least three to five years to engineer, permit, and install the equipment following the SIP revision. Although Northshore obtained a permit authorizing construction of LNB-OFA for Power Boiler 2, the permit authorization has expired according to the permit condition on page A-7 of Title V Operating Permit No. 07500003-009:

"The Permittee is authorized to construct the following equipment: Low Nitrogen Oxide Burners with Overfire Air Systems for EU 001 and EU 002. The construction authorization expires if construction does not commence within 18 months after receipt of such approval by Air Emissions Permit No. 07500003-009, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time."

Power Boiler 2 is currently economically idled and construction of the LNB-OFA system has not been completed. Northshore would need to apply for a major permit amendment to install any of the control technologies in this analysis.

# 5.4 Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above-identified NO<sub>x</sub> control measures are summarized herein. Northshore has considered air quality impacts for regional haze pollutants because they are directly applicable to the goals of this analysis. Overall, there are secondary air quality impacts associated with SNCR or SCR operation, which diminish some of the benefits of the NOx reductions.

### 5.4.1 LNB with OFA

Negative non-air environmental impacts from the installation of LNB with OFA are summarized below:

LNB have the potential for increased steam tube damage and maintenance due to flame impingement on tubes. Flame impingement can result in premature coking of tubes, shortened run lengths, and tube failures. Increased maintenance will be required due to scale build-up and corrosion.

LNB-OFA will increase carbon monoxide emissions and will likely have PSD permitting implications.

## 5.4.2 SNCR

The operation of an SNCR system has significant negative environmental impacts. The impacts from the use of an SNCR system are summarized below.

As with all add-on controls, operation of an SNCR system results in an increase in energy demand to operate the system, requiring increased electrical usage by the plant. The SNCR system also requires increased water usage for dilution of the reagent and increased fuel usage for vaporization of the water in the reagent solution. The cost of energy required to operate the control devices has been included in the cost analyses found in Appendices A and B.

Urea, which is decomposed in an external reactor to form ammonia, would be used in SNCR. The SNCR system consists of an injection system for an ammonia-based reagent into the boiler at a location where the temperature is in the appropriate range for the reaction of ammonia radicals with NOx. Unreacted ammonia may escape through to the exhaust gas. This is commonly called "ammonia slip." Ammonia slip from SNCR is highly variable, 5 to 50 ppm or more according to one vendor's estimates. The ammonia that is released may also react with other pollutants in the exhaust stream to create fine PM<sub>10</sub> in the form of ammonium salts. Ammonia slip will also contribute to nitrogen deposition onto nearby lakes and waters of the state, which causes undesirable biological growth.

SNCR will cause the facility to begin handling a new toxic and hazardous chemical, ammonia or urea. Working with these chemicals could potentially increase the risk of injury and death to the workers and contractors on the site. The presence of this chemical would also potentially increase the risk of hazard to neighboring industrial and rural areas. Additional regulatory burdens would be imposed on the site due to these hazards.

Fly ash is currently sold as a raw material to the concrete industry. SNCR will contaminate the fly ash, will prohibit its beneficial reuse, and will consequently eliminate the income stream this material currently provides.

# 5.4.3 SCR

The operation of an SCR system has significant energy requirements and negative environmental impacts. The impacts from the use of an SCR system are summarized below.

As with all add-on controls, operation of an SCR system results in an increase in energy demand due to the pressure drop across the SCR catalyst. At a minimum, this would require increased electrical usage by the plant. The cost of energy required to operate the control devices has been included in the cost analyses found in Appendices A and B.

Urea, which is decomposed in an external reactor to form ammonia, would be used in the SCR. The SCR system consists of an ammonia injection system and a catalytic reactor. Unreacted ammonia may escape through to the exhaust gas. This is commonly called "ammonia slip." Ammonia slip was estimated using 2 ppm to minimize collateral emissions of pollutants that impact visibility. The ammonia that is released may also react with other pollutants in the exhaust stream to create fine PM<sub>10</sub> in the form of ammonium salts. Ammonia slip will also contribute to nitrogen deposition onto nearby lakes and waters of the state, which causes undesirable biological growth.

The SCR catalysts must also be replaced on a routine basis. In some cases, these catalysts may be classified as hazardous waste. This typically requires either returning the material to the manufacturer for recycle and reuse or disposal in permitted landfills.

Some of the issues confronted by utility boilers with SCR systems on units firing sulfur-bearing fuels involve secondary impacts from the SCR system. The impacts include the formation of SO<sub>3</sub> in the reactor, the emissions of unreacted ammonia from the reactor, and formation of byproducts from the reaction. These effects are often interconnected because SO<sub>3</sub> and unreacted ammonia can react within and downstream of the SCR reactor. The same catalyst that promotes the reactions between ammonia and NOx also promotes the oxidation of SO<sub>2</sub> to SO<sub>3</sub>. It is important to understand that SO<sub>2</sub> oxidation is dependent on other SCR design parameters. When high levels of catalyst activity are needed to target high NOx reduction efficiencies and low levels of ammonia slip or to counteract significant catalyst deactivation rates, SO<sub>2</sub> oxidation rates would be expected to increase. If lower levels of SO<sub>2</sub> oxidation are targeted, NOx reduction, ammonia slip, or both must be compromised.

There are several reasons why industries are concerned about the level of SO<sub>2</sub> oxidation in an SCR reactor. In the absence of other interactions, downstream equipment (e.g., the baghouses) that operate below the sulfuric acid dew point can experience severe corrosion. In addition, sulfuric acid mist formed in such equipment can promote the formation of a visible plume. Sulfuric acid can lead to reduced control efficiency, equipment corrosion, and visible emissions. Concentrations of SO<sub>3</sub> and H<sub>2</sub>SO<sub>4</sub> of 6 to 10 ppm can cause a visible plume, or a blue plume. To meet visible emission limitations, a wet scrubber is essential to control corrosion and to minimize the possibility of a visible plume due to formation of sulfuric acid mist. In addition, elemental mercury will oxidize forming oxidized mercury. As will be discussed under mercury oxidation section below, a wet scrubber would be required to control the oxidized mercury formed in the SCR.

In the case of mercury, the SCR oxidizes mercury from its elemental form. Given the propensity for oxidized mercury to deposit near an emission point, the increase in mass of oxidized mercury emissions is expected to result in more local deposition (i.e., increased loading of mercury) near an emission source and most certainly within northeast Minnesota. An increase in mercury loading to northeast Minnesota is inconsistent with the Statewide Mercury Total Maximum Daily Load (TMDL) study that requires a reduction in loading in order to reduce fish tissue mercury concentrations.

Installation of an SCR system will cause the facility to begin handling a new toxic and hazardous chemical, ammonia or urea. Working with these chemicals could potentially increase the risk of injury and death to

the workers and contractors on the site. The presence of this chemical would also potentially increase the risk of hazard to neighboring industrial and rural areas. Additional regulatory burdens would be imposed on the site due to these hazards.

Fly ash is currently sold as a raw material to the concrete industry. SCR will contaminate the fly ash, will prohibit its beneficial reuse, and will consequently eliminate the income stream this material currently provides.

# 5.5 Factor #4 - Remaining Useful Life of the Source

Because Northshore is assumed to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life, per Section 4.5) is used to calculate emission reductions and amortized costs.

# 5.6 NO<sub>x</sub> Four-Factor Analysis Conclusion

Based on the analysis conducted in Sections 5.1 through 5.5, Northshore has determined that installation of additional NO<sub>X</sub> emissions measures at the Power Boilers 1 and 2 beyond those described in Section 3.1 are not required to make reasonable progress in reducing NO<sub>X</sub> emissions. As such, Northshore intends to continue complying with CSAPR, which EPA has been determined to be better than BART.

# 6 SO<sub>2</sub> Four-Factor Analysis for Power Boilers

This section identifies and describes various SO<sub>2</sub> emission control measures, evaluates the four statutory factors for Power Boilers 1 and 2, considers other factors, and determines if an emission control measure or measures are necessary to make reasonable progress. Consistent with EPA's guidance and MPCA direction, Northshore has completed a Four-Factor Analysis for SO<sub>2</sub> as described in Sections 6.1 to 6.6.

# 6.1 SO<sub>2</sub> Control Measures Overview

SO<sub>2</sub> emissions from the Power Boilers occur as a result of oxidation of sulfur in the fuels combusted. The following describes pertinent technical information regarding the control measure and whether the control measure is technically feasible as applied to Power Boilers 1 and 2.

# 6.1.1 Dry Sorbent Injection (DSI) with New Baghouse

DSI involves the injection of a lime, limestone powder, or trona into the exhaust gas stream. The stream is then passed through a baghouse or electrostatic precipitator to remove the sorbent and entrained SO<sub>2</sub>. The process was developed as a lower cost flue gas desulfurization 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 percent and 70 percent. For Power Boiler 1 and 2, the existing baghouse could not handle the additional particulate loading without a corresponding increase in particulate emissions. Therefore, it is technically feasible, but is not viable as a retrofit with the existing baghouse due to an increase in PM loading. If the DSI is accompanied with a new baghouse, removal is expected to be 70 percent when using trona. DSI is technically feasible for Power Boilers 1 and 2.

# 6.1.2 Spray Dryer Absorber (SDA) with New Baghouse

SDA systems spray lime slurry into an absorption tower where SO<sub>2</sub> is absorbed by the slurry, forming CaSO<sub>3</sub>/CaSO<sub>4</sub>. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are carried out with the gas and collected with a fabric filter. The normal SO<sub>2</sub> control efficiency range for SDA is up to 90 percent, and 90 percent was used in this analysis.

Based on the information contained with this report, SDA is considered an available technology for SO<sub>2</sub> reduction for this Four-Factor Analysis. For Power Boiler 1 and 2, the existing baghouse could not handle the additional particulate loading without a corresponding increase in particulate emissions. Therefore, it is technically feasible, but is not viable as a retrofit with the existing baghouse due to an increase in PM loading. If the SDA system is accompanied with a new baghouse, it is technically feasible for Power Boilers 1 and 2.

Based on the information presented above, Northshore has identified DSI and SDA technologies, each accompanied by new baghouses, to be considered whether their installation is necessary to make reasonable progress reducing SO<sub>2</sub> emissions based on the factors presented below. Table 6-1 lists technically feasible SO<sub>2</sub> control measures for Power Boilers 1 and 2.

Table 6-1 Additional SO<sub>2</sub> Control Measures with Potential Application at Power Boilers

| Control Measures                               |
|--|
| Dry Sorbent Injection (DSI) with New Baghouse  |
| Spray Dryer Absorption (SDA) with New Baghouse |

# 6.2 Factor #1 – Cost of Compliance

Northshore has completed costs estimate for the selected SO<sub>2</sub> emission control measures. Due to the limited time available in responding to MPCA's request, assumptions were made in the cost estimates resulting in conservatively low equipment costs. Cost estimates are based on vendor engineering estimates for installation of equipment at similar projects, scaled for Northshore's design flow and adjusted for inflation using the CEPCI.

The capital cost estimates are considered by Northshore's plant and Barr's engineering staff, based on their considerable experience with projects at Northshore and their informal conversations with other companies that have completed similar types of projects at other facilities, to be conservatively low. Cost summary spreadsheets for the SO<sub>2</sub> emission control measures are provided in Appendix A for Power Boiler 1 and Appendix B for Power Boiler 2.

As discussed in Section 4.2, cost effectiveness in terms of dollars per ton of pollutant removed cannot reasonably be estimated because there are expected to be no emissions in 2028, and therefore no pollutants removed by installation of any control technology.

The resulting control cost calculations are summarized in Table 6-2.

| Emission Unit  | Additional Emissions<br>Control Measure | Installed Capital Cost<br>(\$MM) | Total Annualized<br>Costs<br>(\$/yr) |
|----------------|---|----------------------------------|--------------------------------------|
| Power Boiler 1 | DSI/Baghouse                            | \$34,463,571                     | \$6,144,640                          |
| Power Boiler 1 | SDA/Baghouse                            | \$58,737,702                     | \$12,796,563                         |
| Power Boiler 2 | DSI/Baghouse                            | \$37,737,598                     | \$6,943,044                          |
| Power Boiler 2 | SDA/Baghouse                            | \$61,962,015                     | \$13,572,909                         |

#### Table 6-2: SO<sub>2</sub> Control Cost Summary for Power Boilers 1 and 2, per Unit Basis

Sections 6.3 through 6.5 provide a summary of the remaining three factors evaluated for the SO<sub>2</sub> emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

# 6.3 Factor #2 – Time Necessary for Compliance

Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the SIP by state and federal action, time for MPCA to modify Northshore's Title V operating permit to allow construction to commence, then to implement the project necessary to meet the SIP limit for the emissions control measure, including capital funding, construction, tie-in to the process, commissioning, and performance testing.

A SIP revision is needed to approve a new statistically derived emissions limit methodology, e.g. 99 percent UPL. Barr assumes that the revisions would occur in within 12 to 18 months after the MPCA submits its regional haze SIP for the second implementation period (approximately 2022 to 2023). After the SIP is promulgated, the control measures would require significant resources and time of at least three to five years to engineer, permit, and install the equipment.

# 6.4 Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified SO<sub>2</sub> control measures are summarized herein.

# 6.4.1 Energy Impacts

For DSI or SDA, the electricity requirements are expected to increase with the new baghouse. Similar to the NOx add-on controls, operation of add-on SO<sub>2</sub> control systems such as SDA with baghouses results in increased energy use due to the pressure drop across the reactor and fabric filter, material preparation such as grinding limestone, additional material-handling equipment such as pumps and blowers, and steam requirements. Power consumption is also affected by the reagent utilization of the control technology, which also affects the control efficiency of the control technology. The cost of energy required to operate the control devices has been included in the cost analyses found in Appendices A and B.

# 6.4.2 Environmental Impacts

The SO<sub>2</sub> control technology would generate a significant amount of solid waste that would require disposal in permitted landfills. The collected solids would not be suitable for recycling back into the process or for beneficial reuse resale as currently occurs, resulting in increased solids to the landfill. In addition, the SO<sub>2</sub> control technology processes would generate additional wastewater that would require modifications to their existing wastewater permits for inclusion of this additional wastewater.

# 6.5 Factor #4 - Remaining Useful Life of the Source

Because Northshore is assumed to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life, per Section 4.5) is used to calculate emission reductions and amortized costs.

# 6.6 SO<sub>2</sub> Four-Factor Analysis Conclusion

Based on the analysis conducted in Sections 6.1 through 6.5, Northshore has determined that installation of additional SO<sub>2</sub> emissions measures at Power Boilers 1 and 2 beyond those described in Section 3.1 are not required to make reasonable progress in reducing SO<sub>2</sub> emissions. As such, Northshore proposes to maintain compliance with its SO<sub>2</sub> emission limits of 1.5 lb/MMBtu in its Title V Operating Permit and to continue complying with CSAPR, which EPA has determined to be better than BART.

# Appendix A

Unit-specific Screening Level Cost Summary for Power Boiler 1

# Cleveland Cliffs - Northshore Mining Power Boiler #1 Appendix A - Four-Factor Control Cost Analysis Table A-1: Cost Summary

## NO<sub>x</sub> Control Cost Summary

| Control Technology                          | Control Eff % | Installed Capital<br>Cost \$ | Annualized<br>Operating Cost<br>\$/yr |
|---|---------------|------------------------------|---------------------------------------|
| Selective Non-Catalytic<br>Reduction (SNCR) | 25%           | \$7,239,275                  | \$992,019                             |
| Selective Catalytic Reduction<br>(SCR)      | 80%           | \$40,647,490                 | \$4,159,366                           |

# SO<sub>2</sub> Control Cost Summary

| Control Technology                           | Control Eff % | Installed Capital<br>Cost \$ | Annualized<br>Operating Cost<br>\$/yr |
|--|---------------|------------------------------|---------------------------------------|
| Dry Sorbent Injection (DSI)<br>with Baghouse | 70%           | \$34,463,571                 | \$6,144,640                           |
| Spray Dry Absorber (SDA)<br>with Baghouse    | 90%           | \$58,737,702                 | \$12,796,563                          |

#### Cleveland Cliffs - Northshore Mining Power Boiler #1 Appendix A - Four-Factor Control Cost Analysis Table A-2: Summary of Utility, Chemical and Supply Costs

| Emission busic Number         EQUIT 14 (F41 UC)<br>2000           Name         Description         Description         Description         Name           School Number of Labor         400 Str.         Construction         School Number of Labor         Name           Marrier of Labor         400 Str.         Construction         School Number of Labor         Name           Marrier of Labor         400 Str.         Name         School Number of Labor         Name           Marrier of Labor         400 Str.         Name         School Number of Labor         Name           View of Labor         400 Str.         Name         School Number of Labor         Name           Config Water         0.42 Str.         Name         School Number of Labor         Adapted for 3% relation           Config Water         0.42 Str.         0.43 Str.         0.43 Str.         School Number of Labor         Adapted for 3% relation           Config Water         0.42 Str.         0.44 Str.         School Number of Labor         Adapted for 3% relation         Adapted for 3% relation           Config Water         0.42 Str.         0.43 Str.         School Number of Labor         Adapted for 3% relation           Config Water         0.42 Str.         0.43 Str.         School Number of Labor Number of Labor Number of Labor Num   | Item<br>Derating Labor<br>Maintenance Labor<br>Electricity  | SV 001<br>2020<br>Unit Cost<br>60<br>60 | Units                       | Cost    |              |  |   |
|--|---|---|-----------------------------|---------|--------------|--|---|
| DescriptionData SourceNotesOperating dataCostYearData SourceNotesOperating data0.017Edu200Suspection dataService0.017Service100EduEduNatural Gas4.48SacdNo590Suspection dataNatural Gas4.48SacdNo590Suspection cost Marcal Ref 201Suspection dataValee0.02SyndSuspection dataEduSuspection cost Marcal Ref 201Suspection cost Marcal Ref 201Coding Valee0.02Singla0.22Section 3 CognetEduSuspection 3 CognetCoding Valee0.02Singla0.22Section 3 CognetEduAdaes for 3% inflationCompression Air0.04Synd100201Suspection 3 CognetAdaes for 3% inflationCompression Air1.04Synd100201Suspection 3 CognetAdaes for 3% inflationCompression Air1.04Synd100201Suspection 3 Cognet 7.76Adaes for 3% inflationCompression Air1.04Synd100201Suspection 3 Cognet 7.76Adaes fo  | Item<br>Operating Labor<br>Maintenance Labor<br>Electricity | 2020<br>Unit Cost<br>60<br>60           |                             | Cost    |              |  |   |
| Item         Unit Cost         Units         Cost         Year         Data Source         Notes           Contrag Lator         60 Str         200 Str specific data  | Operating Labor<br>Maintenance Labor<br>Electricity         | Unit Cost<br>60<br>60                   |                             | Cost    |              |  |   |
| Operating Labor         60 Shr         60 200 Shr-specific data         method (sc in Mar)           Author desc         0.00 Shr         200 Shr-specific data         method (sc in Mar)           Sectionsy         0.01 Shr         200 Shr-specific data         method (sc in Mar)           Nature Ges         4.89 Short         NA         press orenge based on 014-2016 gas           Water Cons         0.34 Singul         0.20         2000 Shr-specific data         Method (Sc in Mar)           Conference on 014-2016 gas         0.34 Singul         0.20         2000 She specific data         Method (Sc in Mar)           Conference on 04-20 Singul         0.42 Singul         0.20         2000 She specific data         Method (Sc in Mar)           Conference data         0.43 Singul         0.20         2000 She specific data         Method (Sc in Mar)         Method (Sc in Mar)           Conference data         0.43 Singul         0.33         Singul         2000 She specific data         Method (Sc in Mar)         Method (Sc in Mar)           Conference data         0.43 Singul         0.33         Singul         2000 She specific data         Method (Sc in Mar)         Method (Sc in Mar)           Conference data         1.81 Singul         Singul         2000 She specific data         Method (Sc in Mar)         Method (Sc in Mar  | Operating Labor<br>Maintenance Labor<br>Electricity         | 60<br>60                                |                             | Cost    |              |  |   |
| Generating Labor         60 Shr.         2000 Sim-specific data         method in the status of the status   | Maintenance Labor<br>Electricity                            | 60<br>60                                | A.1                         |         | Year         | Data Source                                      | Notes   |
| Materian productAnd by the stand of a standAnd by the stand and a stand of a stand   | Maintenance Labor<br>Electricity                            | 60                                      | s/nr                        |         | 2020         | Site-specific data                               |   |
| Exercisely         Outpoint         Eth 2007 Augree housened   | Electricity   |   |                             |         | 2020         | Site-specific data                               |   |
| Natural Gas         4.48         Stact         Spear average base in 2014-2016 gas         Performance in 2014-2016 gas           Water         0.34         Singal         0.20         2022         2021         2021         2021         2021         2021         2021         2021         20210         2021         2021         2   |   | 0.076                                   | \$/kwh                      |         | 2020         | FIA 2020 Avg Price Industrial Nat Gas in MN      |   |
| Natural Gas         4.98         Skect         NA         press or paga or<br>page or page or<br>page or page or page or<br>page or page or page or page or<br>page or page or page or page or<br>page or page or page or page or page or<br>page or page or page or page or page or page or<br>page or page or page or page or page or page or page or<br>page or page or<br>page or page or<br>page or page or<br>page or page or<br>page or page or<br>page or page or<br>page or page or<br>page or page or<br>page or page or<br>page or page or  | Natural Gas   | 0.070                                   | ç, itini                    |         |              |  |   |
| Water         0.34         Singal         0.20         2002 Section 3 Charger 1         4deated for 3% inflation           Cooling Water         0.42         Singal         0.23         1988 2002 Section 3 Charger 1         Chareser 1         Chareser  | Natural Cas   | 4 98                                    | \$/kecf                     |         | ΝΔ           |  |   |
| Water         0.34 Singal         0.20         2002         2002         2002         Result of Singler 2         Adjusted (m Singler 2)           Cooling Water         0.42         Single         0.42         Single         0.42         Singler 2)   |   | 4.50                                    | anaci                       |         | 10/3         |  |   |
| Cooling Water         0.02<br>(any Water         EPA A Priodian Costed Cost Manual Dist<br>(b)         Control Manua   | Water   | 0.34                                    | \$/maal                     | 0.20    | 2002         |  | Adjusted for 3% inflation   |
| Cooley Warr         0.62 (smgal         0.23         1998 2002. Second 3.1 Chapter 1         Ch 1 Gaton Absorbers. 1999 30.1 58.03 Augu 22.5 and 7 yrs and 3% inflation           Compressed Air<br>Conserves and Air<br>Cons | Trator  | 0.04                                    | \$/mgai                     | 0.20    | 2002         |  | Adjusted for 576 million  |
| Compressed Ar         0.4         Sket         0.8         202         2002, Section C Cost Manual On Edit         Adjunted for 3%, inflation           Chemical & Supplies         107         200.0         Section C Cost Manual On Edit         Adjunted for 3%, inflation           Une 30%: Stakion         1.86         207.0         Section C Cost Manual On Edit         Adjunted for 3%, inflation           Une 30%: Stakion         1.86         207.0         Section C Cost Manual On Edit         Adjunted for 3%, inflation           Une 30%: Stakion         1.86         207.7         Section C Cost Manual On Edit         Adjunted for 3%, inflation           Exercise Cost Manual Chapter 7, 7h         Edition default         EPA Control Cost Manual Chapter 7, 7h         Adjunted for 3%, inflation           Sect Catabylis cost (CC munus)         244         Scake for includes nem         227         200.7         Scate Manual Chapter 7, 7h           Solid per Log         240.20         Stag         160         2000         NorthForce         Adjunted for 3%, inflation           Solid per Log         240.27         Stag         100         2000         Mark Manual Chapter 7, 7h           Solid per Log         240.27         Stag         200.00         Current MN sales tax rate         Adjunted for 3%, inflation           Solid per Log<  | Cooling Water   | 0.42                                    | ¢/maal                      | 0.00    | 1000         |  | Ch 1 Carbon Absorbers 1000 \$0 15-\$0 30 Avg of 22 5 and 7 vrs and 3% inflation |
| Compressed Air<br>Chemicals 5 2016         0.48         Shard         0.38         0.212         2012 2012 Science Chapter 1         Adjusted for 3% inflation           Line         167.17         Shon         140.00         2014         Sin Specific         Adjusted for 3% inflation           Line Soft% Schulon         181         Spalon         166         2017         Editorial Schward Chapter 7, Ph<br>Editorial Chapter 7, Ph<br>Editorian Chapter 7, Ph<br>Editorial Chapter 7, Ph<br>Editorial Chapter 7, Ph   | Cooling Water   | 0.42                                    | ə/mgai                      | 0.23    | 1999         |  | on roadon Absorbers, 1555 \$0.15 \$0.56 Avg of 22.5 and 7 yrs and 5% imitation  |
| Chemical & Supplies         Image of the state of t   | 0   | 0.40                                    | C 11-1-1                    | 0.00    | 0040         |  | A Friday of Face 201/ Inflations  |
| Line         167.17 \$\nn         140.00         201 \$\stressel         Adjusted for 3% inflation           Toma         285.00 \$\nn         End         <   |   | 0.48                                    | \$/KSCI                     | 0.38    | 2012         | 2002, Section 6 Chapter 1                        | Adjusted for 3% inflation   |
| Tona         285.00         Shon         Vendod   |   |   |                             |         |              | 01. 0. 10  |   |
| Use 50% Solution         1.81         Spalon         1.66         2071         Editor (Correl Cost Manal Orspite 7, 7h<br>Editor (Aduated for 3%, inflation         Adjusted for 3%, inflation           Eminated operating life of the catalyst (Puene)         2.4.00         hours         EPA Correl Cost Manal Orspite 7, 7h<br>Editor (Aduated         Adjusted for 3%, inflation           SCR Catalyst Cost, (CC, registed)         2.4.02         \$body         EPA Correl Cost Manal Orspite 7, 7h<br>Editor (Aduated         Adjusted for 3%, inflation           Cost per lang         2.4.07         School foot (includes ren         2.27         Zolo         More Particle   |   | 167.17                                  | \$/ton                      | 140.00  | 2014         |  | Adjusted for 3% inflation   |
| Use Solution     1.81 Signalon     1.66     2017     Adjusted for 3% inflation       Estimated operating life of the catalyst (H <sub>unterl</sub> )     20,000     PAC.Control Cost Manual Chapter 7, 7h     Adjusted for 3% inflation       SCR Catalyst cost (CC <sub>reginen</sub> )     248     Scolub foot (includes rem     227     2077     Reference of the catalyst (H <sub>unterl</sub> )     Adjusted for 3% inflation       Cost per lag     249.27     Shag     160     2005     MPCA.     Adjusted for 3% inflation       States Tax     6.870%     2002     PAC.Control Cost Manual Chapter 7, 7h     Adjusted for 3% inflation       States Tax     6.870%     2020     PAC.Anton Cost Manual Chapter 7, 7h     Adjusted for 3% inflation       Sold Wasto Disposal     42,66     \$hon     25     2002     Cost per lag     Adjusted for 3% inflation       Configencies     10% of parchased exaits cost (B)     PAC.Anton Cost Manual Chapter 7, 7h     Adjusted for 3% inflation       Configencies     10% of parchased exaits cost (B)     PAC.Anton Cost Manual Chapter 7, 7h     Adjusted for 3% inflation       Configencies     10% of parchased exaits cost (B)     PAC.Anton Cost Manual Chapter 7, 7h     Adjusted for 3% inflation       Markup on capital investment (vetroff factor)     60%     PAC.Anton Cost Manual Chapter 7, 7h     Adjusted for 3% inflation       Markup on capital investment (vetroff factor)     60   | Irona   | 285.00                                  | \$/ton                      |         |              |  |   |
| Entrolited operating life of the catalyst (H <sub>unspen</sub> )         24,000         hours         EPA Control Cost Manual Chapter 7, 7h.           SCR Catalyst cost (CC <sub>caption</sub> )         248         Sicubic foot (includes rem         227         2017         Edition diffault         Adjusted for 3%: inflation           Cost per bag         249.27         Sinag         160         Northshore Mining March 2009 submitsto         Adjusted for 3%: inflation           Other           2007         Edition diffault         Adjusted for 3%: inflation           State Tax         6.875%         2020         Correct NN aships tax rate         Adjusted for 3%: inflation           Sold Waste Disposal         42.56         Sinon         25         2022         2002, Section Core Manual Chapter 7, 7h.           Edition diffault          Edition diffault         Adjusted for 3%: inflation         Adjusted for 3%: inflation           Sold Waste Disposal         42.56         Sinon         25         2022         2002, Section Core Manual Chapter 7, 7h.         Edition diffault         Edition diffau   |   |   |                             |         |              |  |   |
| Estimated operating life of the catalyst (Husson)         24.000         hours         Edition default         Market Construction           SCR Catalyst Cost (CC mapping)         24.8         Scholic foot (includes rem         227         20.7         Edition default         Adjusted for 3% inflation           Cost per bag         24.8.27         Stand         0         2005         MPCA         Adjusted for 3% inflation           Other         0         0         0         0         Adjusted for 3% inflation           Start Start         6.875%         0         2000         Current NN sales tax rate         Adjusted for 3% inflation           Sold Waste Disposal         42.55         Shon         25         2002         2002         2002         2002         2002         Adjusted for 3% inflation           Confingencies         10%         of parchased explo osi (E)         Edition default         Adjusted for 3% inflation         Adjusted for 3% inflation           Markup on capital investment (retroft factor)         60%         25         2002         2002         2002         2002         2002         Adjusted for 3% inflation         Adjusted for 3% inflation           Markup on capital investment (retroft factor)         60%         Current No sales tax rate         Adjusted for 3% inflation         Adjusted   | Urea 50% Solution   | 1.81                                    | \$/gallon                   | 1.66    | 2017         |  | Adjusted for 3% inflation   |
| Cost per tang     2 Hold Cost and Cost Markaul Crapter 7, 7m     Adjusted for 3%, inflation       Cost per tang     248     Scholar tool (includes rem     227       Cost per tang     248 227     Staag     160       Cost per tang     249.27     Staag     160       Sales Tax     6.875%     2000     Current NN sales tax rate       Sales Tax     6.875%     2000     Current NN sales tax rate       Sold Waste Disposal     42.65     Ston     25       Sold Waste Disposal     42.65     Ston     25       Contingencies     10%, of purchased explor cost (B)     Control Cost Markaul Chapter 7, 7m       Markup on capital investment (tetroff factor)     60%     EAPA Auton Correl Cost Manual Chapter 7, 7m       Markup on capital investment (tetroff factor)     60%     EAPA Auton Correl Cost Manual Chapter 7, 7m       Markup on capital investment (tetroff factor)     60%     EAPA Auton Correl Cost Manual Chapter 7, 7m       Markup on capital investment (tetroff factor)     60%     EAPA Auton Correl Cost Manual Chapter 7, 7m       Markup on capital investment (tetroff factor)     60%     EAPA Auton Correl Cost Manual Chapter 7, 7m       Markup on capital investment (tetroff factor)     60%     EAPA Auton Cost Markup on 5, 15%       Utization Rate     73%     EAPA Auton Cost Cost Manual Chapter 7, 7m       Markup on capital   |   |   |                             |         | 1            | EPA Control Cost Manual Chapter 7, 7th           |   |
| Cost per tang     2 Hold Cost and Cost Markaul Crapter 7, 7m     Adjusted for 3%, inflation       Cost per tang     248     Scholar tool (includes rem     227       Cost per tang     248 227     Staag     160       Cost per tang     249.27     Staag     160       Sales Tax     6.875%     2000     Current NN sales tax rate       Sales Tax     6.875%     2000     Current NN sales tax rate       Sold Waste Disposal     42.65     Ston     25       Sold Waste Disposal     42.65     Ston     25       Contingencies     10%, of purchased explor cost (B)     Control Cost Markaul Chapter 7, 7m       Markup on capital investment (tetroff factor)     60%     EAPA Auton Correl Cost Manual Chapter 7, 7m       Markup on capital investment (tetroff factor)     60%     EAPA Auton Correl Cost Manual Chapter 7, 7m       Markup on capital investment (tetroff factor)     60%     EAPA Auton Correl Cost Manual Chapter 7, 7m       Markup on capital investment (tetroff factor)     60%     EAPA Auton Correl Cost Manual Chapter 7, 7m       Markup on capital investment (tetroff factor)     60%     EAPA Auton Correl Cost Manual Chapter 7, 7m       Markup on capital investment (tetroff factor)     60%     EAPA Auton Cost Markup on 5, 15%       Utization Rate     73%     EAPA Auton Cost Cost Manual Chapter 7, 7m       Markup on capital   | Estimated operating life of the catalyst (H_restated)       | 24.000                                  | hours                       |         | 1            | Edition default                                  |   |
| SCR Catalyst cost (CC upuse)         248         Scudu foot (includes rem         227         2017         Edition default         Adjusted for 3% inflation           Cost per bag         249.27         \$bag         160         2005         MPCA         Adjusted for 3% inflation           Other         6.87%         2002         Cerrert MN sales tx rate         Adjusted for 3% inflation           Interest Rate         5.50%         2020         Cerrert MN sales tx rate         Adjusted for 3% inflation           Sold Waste Disposal         42.56         \$100         2020         Cerrert MN sales tx rate         Adjusted for 3% inflation           Sold Waste Disposal         42.56         \$100         25         2020         2020         Zerrert MN sales tx rate         Adjusted for 3% inflation           Contrigencies         10%         of purchased equip cost (B         2020         2020         Zerrert MN sales tx rate         Adjusted for 3% inflation           Markup on capital investment (retroff factor)         6 purchased equip cost (B         2020         Zerrert MN sales tx rate         Adjusted for 3% inflation           Markup on capital investment (retroff factor)         60%         Per Control Cost Manual Chapter 2, 7th<br>Edition cating facilities         Adjusted for 3% inflation           Markup on capital investment (retroff factor)   | , or ( - calayst)   | ,000                                    |                             |         |              |  |   |
| Cost per bag         249.27         Shag         160         2005         MPCA         Adjusted for 3% inflation           Other            Adjusted for 3% inflation           Sales Tax         6.875%           Adjusted for 3% inflation           Sales Tax         6.875%           Adjusted for 3% inflation           Sales Tax         6.875%           Adjusted for 3% inflation           Sold Waste Disposal         42.56         Shon           Adjusted for 3% inflation           Contingencies         10% of purchased equip cost (B)          ERform Schron Cost Manual Chapter 2, 7h         Adjusted for 3% inflation           Contingencies         10% of purchased equip cost (B)               Opcument Page 2 alons up to a 60% retrofit<br>factor for instalations in existing facilities.               Opcument Page 2 alons up to a 60% retrofit<br>factor for instalations in existing facilities.              Opcument Page 2 alons up to a 60% retrofit<br>factor for instalations in existing facilities.               Opcume   | SCR Catalyst cost (CC)                                      | 2/18                                    | \$/cubic foot (includes rem | 227     | 2017         |  | Adjusted for 3% inflation   |
| Cost per bag     249.27     Steag     160     2005     MPCA     Adjusted for 3% inflation       Other     Image: Cost per bag     Adjusted for 3% inflation     Adjusted for 3% inflation       Other     Image: Cost per bag     PPA Control Cost Manual Chapter 7, 7th     Image: Cost per bag       Interest Rate     5.00%     Image: Cost per bag     PPA Control Cost Manual Chapter 7, 7th       Sold Waste Disposal     42.56     Ston     25     2002 Course Cost Manual Chapter 2, 7th       Contingencies     10% of purchased equip cost (B)     EPA Control Cost Manual Chapter 2, 7th     Edition estimates configencies for 51%, Assumed the mid range       Markup on capital investment (retrofit factor)     60%, of purchased equip cost (B)     Assumed the mid range     PPA Control Cost Manual Chapter 2, 7th       Markup on capital investment (retrofit factor)     60%, of purchased equip cost (B)     Assumed the mid range     PPA Control Cost Manual Chapter 2, 7th       Markup on capital investment (retrofit factor)     60%, of purchased equip cost (B)     Assumed the mid range     PPA Control Cost Manual Chapter 2, 7th       Markup on capital investment (retrofit factor)     60%, of purchased equip cost (B)     Assumed the mid range       Operating Information     Edition estimate     2017 Site-specific operating factors       Operating Information     2017 Site-specific operating factors     2017 Site-specific operating factors   | con outlingst cost (oo replace/                             | 240                                     | would foot (includes feffi  | 221     | 2017         |  |   |
| Other         Other         Other           Sales Tax         6.87%         2020           Current MN sales tax rate         Edition default           Interest Rate         5.50%         Edition default           Sole Stax         2200         Current MN sales tax rate           Sole Waste Disposal         42.56         \$thom         25         2002         2002. Section 6 Chapter 1         Adjusted for 3%, inflation           Contingencies         10% of purchased equip cost (B)         Assumed the mid range         Adjusted for 3%, inflation           Contingencies         10% of purchased equip cost (B)         Assumed the mid range         CUECost Workbook Version 1.0, USEPA           Markup on capital investment (tetrolif factor)         60%         CUECost Workbook Version 1.0, USEPA           Markup on capital investment (tetrolif factor)         60%         2017 Site-specific operating hours           Utization Rate         73%         2017 Site-specific operating hours           Utization Rate         73%         Site-specific estimate         Estimate           Design Capacity         517.0         MMBTUhr         Site-specific estimate         Estimate           Disture Content         8.8%         Site-specific estimate         Estimate         Estimate           Disture Content   | o   | a.c                                     |                             |         |              |  |   |
| Sales Tax     6.87%     2020 Current MN sales tax rate       Interest Rate     5.50%     EPA Control Cost Manual Chapter 7, 7h       Sold Waste Disposal     42.56 \$ton     25       Sold Waste Disposal     42.56 \$ton     25       Contingencies     10% of purchased equip cost (B)     EPA Cint Policon Control Cost Manual Chapter 2, 7h       Contingencies     0 purchased equip cost (B)     Adjusted Disposal       Markup on capital investment (retrofit factor)     60%     CUECost Workbook Version 1.0, USEPA       Operating Information     Cuel Cost Manual Chapter 2, 7h     Edition estimates contingencies from 5-15%, Assumed the mid range       Annual Op. Hrs     5.650 Hours     CUECost Workbook Version 1.0, USEPA       Operating Information     Cuel Cost Manual Chapter 2, 7h     Edition estimates contingencies from 5-15%, Assumed the mid range       Utilization Rate     73%     Cuel Cost Workbook Version 1.0, USEPA       Utilization Rate     73%     Sale specific estimate, 2017 emission investing facilities.       Utilization Rate     73%     Sale specific estimate     Edition estimate       Utilization Rate     73%     Sale specific estimate     Edition estimate       Utilization Rate     73%     Sale specific estimate     Edition estimate       Utilization Rate     72%     Sale specific estimate     Edition estimate       Utilization   | Cost per bag  | 249.27                                  | \$/bag                      | 160     | 2005         | MPCA   | Adjusted for 3% inflation   |
| Sales Tax     6.87%     2020 Current MN sales tax rate       Interest Rate     5.50%     EPA Control Cost Manual Chapter 7, 7h       Sold Waste Disposal     42.56 \$ton     25       Sold Waste Disposal     42.56 \$ton     25       Contingencies     10% of purchased equip cost (B)     EPA Cint Policon Control Cost Manual Chapter 2, 7h       Contingencies     0 purchased equip cost (B)     Adjusted Disposal       Markup on capital investment (retrofit factor)     60%     CUECost Workbook Version 1.0, USEPA       Operating Information     Cuel Cost Manual Chapter 2, 7h     Edition estimates contingencies from 5-15%, Assumed the mid range       Annual Op. Hrs     5.650 Hours     CUECost Workbook Version 1.0, USEPA       Operating Information     Cuel Cost Manual Chapter 2, 7h     Edition estimates contingencies from 5-15%, Assumed the mid range       Utilization Rate     73%     Cuel Cost Workbook Version 1.0, USEPA       Utilization Rate     73%     Sale specific estimate, 2017 emission investing facilities.       Utilization Rate     73%     Sale specific estimate     Edition estimate       Utilization Rate     73%     Sale specific estimate     Edition estimate       Utilization Rate     73%     Sale specific estimate     Edition estimate       Utilization Rate     72%     Sale specific estimate     Edition estimate       Utilization   |   |   |                             |         |              |  |   |
| Interest Rate         5.50%         EPA Control Cost Manual Chapter 7, 7h           Sold Waste Disposal         42.56         \$ion         25         2002, Section 6 Chapter 1         Adjusted for 3% inflation           Sold Waste Disposal         42.56         \$ion         25         2002, Section 6 Chapter 1         Adjusted for 3% inflation           Contingencies         10% of purchased equip cost (B)         EPA Control Cost Manual Chapter 2, 7h         Edition efficiences from 5-15%.           Annual On capital investment (retroft factor)         60%         CUECost Workbook Version 10, USEPA           Deparating Information         0         CUECost Workbook Version 10, USEPA           Diparating Information         20         2005, Section existing facilities.         Intervestment (retroft factor)           Utilization Rate         73%         2017 Site-specific estimate         Intervestment (2017 emission           Utilization Rate         73%         Site-specific estimate         Intervestment           Utilization Rate         230 Deg F         Assured         Site-specific estimate           Information         280 Deg F         Site-specific estimate         Intervestment           Site Specific estimate         2000 Site Control Cost Marual Chapter 7, 7h         Site-specific estimate           Site Specific estimate         200 Site Cont   |   |   |                             |         |              |  |   |
| Interest Rate         5,0%         Edition default           Solid Waste Disposal         42.56         Stron         25         2002         2002. Section 6 Chapter 1         Adusted for 3% inflation           Contingencies         10% of purchased equip cost (B)         EPA Air Opulicon Control Cost Manual Chapter 2, 7h         Adusted for 3% inflation           Markup on capital investment (retrofit factor)         60%         EPA Control Cost Manual Chapter 2, 7h         Adusted for 3% inflation           Operating Information         EPA Control Cost Manual Chapter 2, 7h         EPA Control Cost Manual Chapter 2, 7h         Adusted for 3% inflation           Ulization Rate         10% of purchased equip cost (B)         Assumed the mid range         Adusted for 3% inflation           Markup on capital investment (retrofit factor)         60%         CUECost Workbook Version 10, USEPA         Document Page 2 allows up to a 60% retrofit           Markup on capital investment (retrofit factor)         60%         EPA Air Or instalations in existing facilities.   | Sales Tax   | 6.875%                                  |                             |         | 2020         | Current MN sales tax rate                        |   |
| Sold Waste Disposal         42.6         \$ton         25         2002 2002, Section 6 Chapter 1         Adjusted for 3% inflation           Contingencies         10% of purchased equip cost (8)         EPA Control Cost Manual Chapter 2, 7th<br>Edition estimates considerations from 5-15%.<br>Assumed the mid range         Assumed the mid range         CUE Cost Workbook Version 10, USEPA           Deparating Information         60%         CUE Cost Workbook Version 10, USEPA         Document Page 2 allows up to a 60% retrofit<br>factor for installations in existing facilities.           Operating Information         2017 Sile specific operating hours         2017 Sile specific operating hours         2017 Sile specific operating hours           Utilization Rate         73%         2017 Sile specific estimate         2017 Sile specific estimate         2017 Sile specific estimate           Utilization Rate         73%         Sile specific estimate         2017 Sile specific estimate         2017 Sile specific estimate           Utilization Rate         73%         Sile specific estimate         2017 Sile specific estimate         2017 Sile specific estimate           Utilization Rate         73%         Sile specific estimate         2017 Sile specific estimate         2017 Sile specific estimate           Temperature         280 Deg F         Sile specific estimate         2017 Sile specific estimate         2017 Sile specific estimate           Dry Stort Forte   |   |   |                             |         |              | EPA Control Cost Manual Chapter 7, 7th           |   |
| Sold Waste Disposal     42.56     Ston     25     2002 <th< td=""><td>Interest Rate</td><td>5.50%</td><td></td><td></td><td></td><td>Edition default</td><td></td></th<>  | Interest Rate   | 5.50%                                   |                             |         |              | Edition default                                  |   |
| Sold Waste Disposal         42.56         Shon         25         2002         2002, Section 6 Chapter 1         Adjusted for 3% inflation           Contingencies         10% of purchased equip cost (B)         Faction estimates contingencies from 5-15%,<br>Assumed the mid range         Assumed the mid range         Assumed the mid range           Markup on capital investment (retrofit factor)         60%         CUECost Workbook Version 1.0, USEPA<br>(Bactor for instalations in existing facilities.         Document Page 2 allows up to a 60% retrofit<br>factor for instalations in existing facilities.           Operating Information         1         2017 Site-specific operating hours         Internation           Annual Op. Hrs         5.650         Hours         Site-specific estimate, 2017 emission         Internation           Utization Rate         73%         Site-specific estimate         Internation         Internation           Cutization Rate         20 yrs         Assumed         Assumed         Internation         Internation           Catage Chement Life         20 yrs         Assumed         Site-specific estimate         Internation           Solard Sub Four Chement Age         200 gr m         Site-specific estimate         Internation           Solard Sub Four Chement Age         200 gr m         Site-specific estimate         Internation           Fundar Chement Life         <   |   |   |                             |         |              | EPA Air Pollution Control Cost Manual 6th Ed     |   |
| Contingencies     10% of purchased equip cost (B)     EPA Control Cost Manual Chapter 2, 7h<br>Edition estimates contingencies from 5-15%.<br>Assumed the mid range       Markup on capital investment (retrofit factor)     60%     CUECost Workbook Version 10, USEPA<br>Document Page 2 allows up to a 60% retrofit<br>factor for instalations in existing facilities.       Operating Information     0     0       Annual Op. Hrs     5,650 Hours     2017 Site-specific operating hours       Utilization Rate     73%     2017 Site-specific operating hours       Utilization Rate     73%     Site-specific estimate       Equipment Life     201 yrs     Assumed       Temperature     280 Deg F     Site-specific estimate       Motine Content     8.8%     Site-specific estimate       State-specific estimate     200.00 ac/m     Site-specific estimate       Status Content     8.8%     Site-specific estimate       Actual Fbw Rate     140.800 sc/m @ 68° F     133.505 sc/m @ 32° F       Disc-specific estimate     200.00 ac/m     Site-specific estimate       Part Elevation     764 Feet above sea level     Site specific estimate       Fuel Nafter Asatily value (HHV)     8.826 BTU/b     Effation estimate Cost Manual Chapter 7, 7th       Fuel Suffic Content (%)     0.41 %     Effation estimate       Fuel Suffic Content (%)     0.41 %     Site Especific Data   | Solid Waste Disposal  | 42.56                                   | \$/ton                      | 25      | 2002         |  | Adjusted for 3% inflation   |
| Contingencies       10%       of purchased equip cost (B)       Edition estimates contingencies from 5-15%.<br>Assumed the mid range         Markup on capital investment (retrofit factor)       60%       CUECost Workbook Version 1.0, USEPA<br>Document Page 2 allows up to a 60% retrofit<br>factor for installations in existing facilities.         Operating Information       Image: Control of the state of the  | i i i i i i i i i i i i i i i i i i i                       |   |                             |         |              |  |   |
| Contingencies       10%       of purchased equip cost (B)       Assumed the mid range <sup>-</sup> Markup on capital investment (retrofit factor)       60%       CUECost Workbook Version 1.0. USEPA         Markup on capital investment (retrofit factor)       60%       Itactor for installations in existing facilities.         Operating Information       1       1       1         Annual Op. Hrs       5,550       Hours       2017 Site-specific operating hours         Uitization Rate       73%       Site-specific estimate, 2017 emission         Design Capacity       517.0       MMBTU/hr       Site-specific estimate         Equipment Life       20       yrs       Assumed         Immediate Content       8.%       Site-specific estimate         Actual Flow Rate       200.00 acfm       Site-specific estimate         Standardzed Flow Rate       140.800 scfm @ 68° F       133.505 scfm @ 32° F         Fuel holder heating value (HHV)       8.86 BTU/b       EPA Control Cost Manual Chapter 7, 7th         Fuel Suffur Content (%)       0.41 %       EPA Control Cost Manual Chapter 7, 7th         Fuel Suffur Content (%)       0.41 %       EPA Control Cost Manual Chapter 7, 7th         Fuel holder heating value (HHV)       8.86 BTU/b       EPA Control Cost Manual Chapter 7, 7th         Fuel holder heating valu   |   |   |                             |         |              |  |   |
| Markup on capital investment (retrofit factor)         60%         CLECcost Workbook Version 1.0. USEPA<br>Document Page 2 allows up to a 60% retrofit<br>factor for installations in existing facilities.           Operating Information         Comment Page 2 allows up to a 60% retrofit<br>factor for installations in existing facilities.           Annual Op. Hrs         5,650         Hours         2017 Site-specific operating hours           Utilization Rate         73%         Site-specific estimate, 2017 emission<br>inventory         Inventory           Design Capacity         517.0         MBTU/hr         Site-specific estimate         Emission           Equipment Life         200 pog F         Site-specific estimate         Emission           Moisture Content         8.8%         Site-specific estimate         Emission           Standardized Flow Rate         200.800 acfm         Site-specific estimate         Emission           Visue Flow Rate         140,800 dscm@ 68° F         133.505 scfm@ 32° F         Site-specific estimate           Fuel higher heating value (HHV)         8,828 BTU/lb         EPA Control Cost Manual Chapter 7, 7th           Fuel Suffur Content (%)         0.41 %         EPA Control Cost Manual Chapter 7, 7th           Fuel Suffur Content (%)         0.41 %         EPA Control Cost Manual Chapter 7, 7th           Fuel Suffur Content (%)         0.41 %         EPA Control Cost Ma   | Contingencies   | 10%                                     | of purchased equip cost (B  | )       |              |  |   |
| Markup on capital investment (retrofit factor)         60%         Document Page 2 alows up to a 60% retrofit factor for installations in existing facilities.           Operating Information         Common Page 2 alows up to a 60% retrofit factor for installations in existing facilities.           Operating Information         Common Page 2 alows up to a 60% retrofit factor for installations in existing facilities.           Operating Information         Common Page 2 alows up to a 60% retrofit factor for installations in existing facilities.           Operating Information         Common Page 2 alows up to a 60% retrofit factor for installations in existing facilities.           Operating Information         Common Page 2 alows up to a 60% retrofit factor for installations in existing facilities.           Utilization Rate         Common Page 2 alows up to a 60% retrofit factor for installations in existing facilities.           Utilization Rate         Common Page 2 alows up to a 60% retrofit factor for installations in existing facilities.           Utilization Rate         Common Page 2 alows up to a 60% retrofit factor for installations in existing facilities.           Euglignent Life         200 tyrs         Assumed         Site-specific estimate           Could Page F         Site-specific estimate         Site-specific estimate           Actual Fow Rate         140.000 actm @ 68° F         133.505 scfm @ 32° F         Site-specific estimate           Dry Sul Flow Rate         140.800 dscfm @ 68° F  |   | 1070                                    |                             | ,       |              |  |   |
| Markup on capital investment (retrofit factor)     60%     factor for installations in existing facilities.       Operating Information     intervention     intervention       Annual Op. Hrs     5,650     Hours     2017 Site-specific operating hours       Utilization Rate     73%     Site-specific estimate. 2017 mission       Utilization Rate     73%     inventory.       Design Capacity     517.0     MMBTU/hr     Site-specific estimate       Equipment Life     20 yrs     Assumed     Este-specific estimate       Matkuz Content     8.%     Site-specific estimate       Standardized Flow Rate     200.00 ac/m     Site-specific estimate       Dry Suf Flow Rate     140.800 scfm @ 68° F     133.505 scfm @ 32° F       Fuel higher heating value (HHV)     8.228     BTU/b     EPA Control Cost Manual Chapter 7, 7th       Fuel Suffur Content (%)     0.41 %.     EPA Control Cost Manual Chapter 7, 7th       Fuel Suffur Content (%)     0.41 %.     Site Specific Data  |   |   |                             |         |              |  |   |
| Operating Information         Image: Content of the second se   | Markup on capital investment (retrofit factor)              | 60%                                     |                             |         |              |  |   |
| Annual Op. Hrs     5,650 Hours     2017 Site-specific operating hours       Utilization Rate     73%     Site-specific estimate, 2017 emission       Design Capacity     517.0 IMBTU/hr     Site-specific estimate       Equipment Life     20) vrs     Assumed       Temperature     280 Deg F     Site-specific estimate       Moisture Content     8.8%     Site-specific estimate       Actual Flow Rate     200,800 acfm     Site-specific estimate       Dry Std Flow Rate     140,800 scfm @ 68° F     133,505 scfm @ 32° F       Dry Std Flow Rate     128,300 dscfm @ 68° F     Site-specific estimate       Fuel higher heating value (HHV)     8,826 BTU/hb     EPA Control Cost Manual Chapter 7, 7th       Fuel higher heating value (HHV)     0.41 %     EPA Control Cost Manual Chapter 7, 7th       Fuel Sulfur Content (%)     0.41 %     EPA Control Cost Manual Chapter 7, 7th       Fuel Sulfur Content (%)     0.41 %     Site Specific Data  | warkup on capital investment (reaont factor)                | 0078                                    |                             |         |              | ractor for installations in existing facilities. |   |
| Annual Op. Hrs     5,650     Hours     2017 Site-specific operating hours       Utilization Rate     73%     Site-specific estimate, 2017 emission       Design Capacity     517.0     MMBTU/hr     Site-specific estimate       Equipment Life     20) tys     Assumed       Temperature     2800     Deg F     Site-specific estimate       Moisture Content     8.8%     Site-specific estimate       Actual Flow Rate     200,800 acfm     Site-specific estimate       Dry Ster Flow Rate     140,800 scfm @ 68° F     133,505 scfm @ 32° F       Dry Ster Flow Rate     128,300 dscfm @ 68° F     Site-specific estimate       Fuel higher heating value (HHv)     8.826 BTU/hb     EPA Control Cost Manual Chapter 7, 7th       Fuel higher heating value (HHv)     764 Feet above sea level     Site Evention       Fuel Sulfur Content (%)     0.41 %     EPA Control Cost Manual Chapter 7, 7th       Fuel Sulfur Content (%)     0.41 %     EIdition default for sub-hituminous   | Operating Information                                       |   |                             |         |              |  |   |
| Utilization Rate         Site-specific estimate         Site-specific estimate           Design Capacity         517.0         MMBTU/hr         Site-specific estimate           Equipment Life         20 yrs         Assumed           Temperature         280 Deg F         Site-specific estimate           Moisture Content         8.8%         Site-specific estimate           Actual Flow Rate         200.00 actm @ 68° F         133.505 scfm @ 32° F         Site-specific estimate           Dry.Std Flow Rate         140.800 scfm @ 68° F         133.505 scfm @ 32° F         Site-specific estimate           Dry.Std Flow Rate         128.300 dscfm @ 68° F         Site-specific estimate         Ether specific estimate           Dry.Std Flow Rate         128.300 dscfm @ 68° F         Site-specific estimate         Ether specific estimate           Dry.Std Flow Rate         128.300 dscfm @ 68° F         Site-specific estimate         Ether specific estimate           Dry.Std Flow Rate         128.300 dscfm @ 68° F         Site-specific estimate         Ether specific estimate           Dry.Std Flow Rate         128.300 dscfm @ 68° F         Site-specific estimate         Ether specific estimate           Dry.Std Flow Rate         128.300 dscfm @ 68° F         Ether specific estimate         Ether specific estimate           Dry.Std Flow Rate         1  |   | 5.650                                   | Houro                       |         |              | 2017 Eite epocific operating hours               |   |
| Utilization Rate     73%     inventory       Design Capacity     517.0 MMBTU/hr     Site-specific estimate       Equipment Life     20 yrs     Assumed       Temperature     280 Deg F     Site-specific estimate       Moisture Content     8.8%     Site-specific estimate       Actual Flow Rate     200.800 actm     Site-specific estimate       Standardized Flow Rate     200.800 actm     Site-specific estimate       Dry Suf Flow Rate     140.800 scfm @ 68° F     133.505 scfm @ 32° F       Fuel higher heating value (HHV)     8.226 BTU/lb     EPA Control Cost Manual Chapter 7, 7th       Fuel higher heating value (HHV)     8.226 BTU/lb     Site specific estimate       Fuel Sulfur Content (%)     0.41 %     EPA Control Cost Manual Chapter 7, 7th       Fuel Sulfur Content (%)     0.41 %     Ethich default for sub-biturninous   | Annual Op. Hrs  | 5,650                                   | Hours                       |         |              |  |   |
| Design Capacity         517.0         MMBTU/hr         Site-specific estimate           Equipment Life         200 tyrs         Assumed         Image: Site-specific estimate           Temperature         280 Deg F         Site-specific estimate         Image: Site-specific estimate           Moisture Content         8.%         Site-specific estimate         Image: Site-specific estimate           Actual Flow Rate         200.000 ac/m @ 68° F         133.505 sc/m @ 32° F         Site-specific estimate           Dry Std Flow Rate         140.800 sc/m @ 68° F         133.505 sc/m @ 32° F         Site-specific estimate           Dry Std Flow Rate         128.300 dsc/m @ 68° F         Site-specific estimate         Image: Site-specific estimate           Fuel higher heating value (HHV)         8.826 BTU/b         EPA Control Cost Manual Chapter 7, 7th           Fuel higher heating value (HHV)         8.826 BTU/b         EPA Control Cost Manual Chapter 7, 7th           Fuel Sulfur Content (%)         0.41 %         EPA Control Cost Manual Chapter 7, 7th           Fuel Sulfur Content (%)         0.41 %         EPA Control Cost Manual Chapter 7, 7th           Fuel Sulfur Content (%)         0.41 %         Site Specific Data   | Ulfradian Data  |   |                             |         | 1            |  |   |
| Equipment Life         20 /yrs         Assumed           Temperature         280 Deg F         Site-specific estimate           Moisture Content         8.8%         Site-specific estimate           Actual Flow Rate         200.800 actm         Site-specific estimate           Standardized Flow Rate         140.800 schm @ 68° F         133.505 schm @ 32° F           Dry Std Flow Rate         128.300 dschm @ 68° F         Site-specific estimate           Dry Std Flow Rate         128.300 dschm @ 68° F         Site-specific estimate           Fuel higher heating value (HHV)         8.826 BTU/lb         EPA Control Cost Manual Chapter 7, 7th           Fuel higher content         764 Feet above sea level         Site Evention           Fuel Sulfur Content (%)         0.41 %         EPA Control Cost Manual Chapter 7, 7th           Fuel Sulfur Content (%)         0.41 %         Site Specific Data  |   |   |                             |         |              |  |   |
| Temperature         280 Deg F         Site-specific estimate           Moisture Content         8.8%         Site-specific estimate           Actual Flow Rate         200,000 acfm         Site-specific estimate           Standardzed Flow Rate         140,800 sc/m @ 68° F         133,505 sc/m @ 32° F           Dry Std Flow Rate         128,300 dsc/m @ 68° F         Site-specific estimate           Fuel higher heating value (HHV)         8,826 BTU/b         EPA Control Cost Manual Chapter 7, 7th           Fuel higher heating value (HHV)         8,826 BTU/b         EPA Control Cost Manual Chapter 7, 7th           Fuel higher heating value (HHV)         0.41 %         EPA Control Cost Manual Chapter 7, 7th           Fuel Sulfur Content (%)         0.41 %         EPA Control Cost Manual Chapter 7, 7th           Fuel Sulfur Content (%)         0.41 %         Etidion default for sub-biturinous  |   |   |                             |         |              |  |   |
| Moisture Content         8.8%         Site-specific estimate           Actual Flow Rate         200.800 acfm         Site-specific estimate           Standardzed Flow Rate         140,000 scfm @ 68° F         133.505 scfm @ 32° F         Site-specific estimate           Dry Staf Bow Rate         128.300 dscfm @ 68° F         Site-specific estimate            Evel higher heating value (HHV)         8.826 BTU/b         EPA Control Cost Manual Chapter 7, 7th           Fuel higher heating value (HHV)         8.826 BTU/b         Edition default for sub-bituminous           Plant Elevation         764 Feet above sea level         Site Elevation           Fuel Sulfur Content (%)         0.41 %         Edition default for sub-bituminous           f days boiler operates         235 days         Site Specific Data  |   |   |                             |         |              |  |   |
| Actual Flow Rate         200.800         actm         Site-specific estimate           Standardzed Flow Rate         140,800         s68° F         133,505         scfm @ 32° F         Site-specific estimate         Difference   |   | 280                                     | Deg F                       |         |              |  |   |
| Standardzad Flow Rate         140.800         sc/m @ 68° F         133.505         Stle-specific estimate           Dry Std Flow Rate         128.300         ds/m @ 68° F         Stle-specific estimate         Image: Stle-specific estimate           Dry Std Flow Rate         128.300         ds/m @ 68° F         Stle-specific estimate         Image: Stle-specific estimate           Lei higher heating value (HHV)         8.826         BTU/b         EPA Control Cost Manual Chapter 7, 7th           Fuel higher heating value (HHV)         8.826         BTU/b         Stle-specific estimate           Fuel sufture content (%)         0.41         Ket Elevation         EPA Control Cost Manual Chapter 7, 7th           Fuel sufture content (%)         0.41         Ket Elevation         EPA control Cost Manual Chapter 7, 7th           # days boller operates         235         days         Site Specific Data  |   |   |                             |         |              |  |   |
| Dry Std Flow Rate         128,300 dsc/m @ 68° F         Site-specific estimate           Fuel higher heating value (HHV)         8,826 BTU/lb         EPA Control Cost Manual Chapter 7, 7th<br>Edition default for sub-biturninous           Plant Elevation         764 Feet above sea level         Site Elevation           Fuel Sulfur Content (%)         0.41 %         EPA Control Cost Manual Chapter 7, 7th<br>Edition default for sub-biturninous           fuel Sulfur Content (%)         0.41 %         Edition default for sub-biturninous           if days boiler operates         236 davs         Site Specific Data  |   |   |                             |         |              |  |   |
| Fuel higher heating value (HHV)         8,826         BTU/b         EPA Control Cost Manual Chapter 7, 7th<br>Edition default for sub-bituminous           Plant Elevation         764         Feet above sea level         Site Elevation           Fuel Sulfur Content (%)         0.41         %         EPA Control Cost Manual Chapter 7, 7th<br>EPA Control Cost Manual Chapter 7, 7th<br>EPA Control Cost Manual Chapter 7, 7th<br>EPA Control Cost Manual Chapter 7, 7th<br>Edition default for sub-bituminous           # days boiler operates         235         days         Site Specific Data  |   |   |                             | 133,505 | scfm @ 32º F |  |   |
| Fuel higher heating value (HHV)         8,826         BTU/b         Edition default for sub-bituminous           Plant Elevation         764         Feet above sea level         Site Elevation           Fuel Suffur Content (%)         0.41         %         Edition default for sub-bituminous           Fuel Suffur Content (%)         0.41         %         Edition default for sub-bituminous           # days boiler operates         23         days         Site Specific Data   | Dry Std Flow Rate   | 128,300                                 | dscfm @ 68º F               |         |              |  |   |
| Fuel higher heating value (HHV)         8,826         BTU/b         Edition default for sub-bituminous           Plant Elevation         764         Feet above sea level         Site Elevation           Fuel Suffur Content (%)         0.41         %         Edition default for sub-bituminous           Fuel Suffur Content (%)         0.41         %         Edition default for sub-bituminous           # days boiler operates         23         days         Site Specific Data   |   |   |                             |         |              | EPA Control Cost Manual Chapter 7, 7th           |   |
| Plant Elevation         764         Feet above sea level         Site Elevation           Fuel Sulfur Content (%)         0.41 %         EPA Control Cost Manual Chapter 7, 7th<br>Edition default for sub-biturninous           # days bolier operates         235         days         Site Specific Data  | Fuel higher heating value (HHV)                             | 8,826                                   | BTU/b                       |         |              | Edition default for sub-bituminous               |   |
| Fuel Sulfur Content (%)     0.41     %     EPA Control Cost Manual Chapter 7, 7th<br>Edition default for sub-biturninous       # days boiler operates     235     days     Site Specific Data  |   | 764                                     |                             |         |              |  |   |
| Fuel Sulfur Content (%)         0.41 %         Edition default for sub-bituminous           # days boiler operates         235 days         Site Specific Data   |   |   |                             |         |              |  |   |
| # days boiler operates 235 days Site Specific Data   | Fuel Sulfur Content (%)                                     | 0.41                                    | %                           |         | 1            |  |   |
|  |   |   |                             |         | İ.           |  |   |
|  |   | 200                                     | 1                           |         |              |  |   |
| I echnology Control Efficiency   | Technology Control Efficiency                               |   |                             |         |              | •  |   |
| EPA tact sheet for flue gas desulturization  |   | 1                                       | 1                           |         | 1            | EPA fact sheet for flue gas desulfurization      |   |
| (new installations)  |   |   |                             |         | 1            |  |   |
| SDA - SO <sub>2</sub> Control Efficiency 90% https://www3.epa.gov/thcatc1/dir1/f/dg.pdf  | SDA - SO <sub>2</sub> Control Efficiency                    | 0.0%                                    |                             |         | 1            |  |   |
| SUN-SO2 CONTROL Enclency Source on Transport   | Soft So <sub>2</sub> Sofitor Enlocitoy                      | 90%                                     |                             |         | <u> </u>     |  |   |
|  | DOL DO Octobel Efficiency                                   |   |                             |         | 1            |  |   |
| DSI - SO <sub>2</sub> Control Efficiency 70% Trona Control Efficiency injected reagent.  |   | 70%                                     | I rona Control Efficiency   |         |              | -  |   |
| SCR - NO, Control Efficiency 80% Based on engineering assessment.  | SCR - NO <sub>x</sub> Control Efficiency                    | 80%                                     |                             |         | 1            |  |   |
| EPA Control Cost Manual Chapter 7, 7th   | · · ·   | 1                                       |                             |         | İ.           | EPA Control Cost Manual Chapter 7, 7th           |   |
| Edition, SCR Figure 1.1  |   |   |                             |         | 1            |  |   |
| (efficiency vs inlet NOx concentration   |   | 1                                       |                             |         | 1            |  |   |
|  | SNCR - NO <sub>x</sub> Performance                          | 0.26                                    | Ib/MMBtu                    |         | 1            | approximation (25%) reduction)                   |   |
|  | Short NO <sub>X</sub> r chomande                            | 0.26                                    | IUNIVIDIU                   |         |              |  |   |

#### Air Pollution Control Cost Estimation Spreadsheet For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency Air Economics Group Health and Environmental Impacts Division Office of Air Quality Planning and Standards

(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

#### Instructions

Step 1: Please select on the Data Inputs tab and click on the Reset Form button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the SNCR Design Parameters tab to see the calculated design parameters and the Cost Estimate tab to view the calculated cost data for the installation and operation of the SNCR.

|   | D  | ata Inputs  |
|---|--|---|
| Enter the following data for your combustion unit:  |  |   |
|   | ndustrial  | What type of fuel does the unit burn?   |
| Is the SNCR for a new boiler or retrofit of an existing boiler?   | •  |   |
| Please enter a retrofit factor equal to or greater than 0.84 based on the Enter 1 for projects of average retrofit difficulty.      | e level of difficulty. 1.6   | * NOTE: You must document why a retrofit factor of 1.6 is appropriate for the proposed project.   |
| Complete all of the highlighted data fields:  |  |   |
| What is the maximum heat input rate (QB)?   | 517 MMBtu/hour   | Provide the following information for coal-fired boilers: Type of coal burned: Sub-Bituminous   |
| What is the higher heating value (HHV) of the fuel?<br>*HHV value of 8826 Btu/lb is a default value. See below for data source. Ent | 8,826 Btu/lb<br>ter actual HHV for fuel burned, if known.                      | Enter the sulfur content (%S) = 0.41 percent by weight or   |
| What is the estimated actual annual fuel consumption?   | 241,600,555 lbs/year   | Select the appropriate SO <sub>2</sub> emission rate:<br>*The sulfur content of 0.41% is a default value. See below for data source. Enter actual value, if<br>known.   |
| Is the boiler a fluid-bed boiler?   | No   | Ash content (%Ash): 5.84 percent by weight *The ash content of 5.84% is a default value. See below for data source. Enter actual value, if known.   |
| Enter the net plant heat input rate (NPHR)  | 10 MMBtu/MW  | For units burning coal blends:<br>Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter<br>the actual values for these parameters in the table below. If the actual value for any parameter is<br>not known, you may use the default values provided.   |
| If the NPHR is not known, use the default NPHR value:   | Fuel TypeDefault NPHRCoal10 MMBtu/MWFuel Oil11 MMBtu/MWNatural Gas8.2 MMBtu/MW | Inaction in       Second Blend       Second Blend       Provide Cost         Bituminous       0 |

#### Enter the following design parameters for the proposed SNCR:

| Number of days the SNCR operates $(t_{\text{SNCR}})$      | 235 days              | Plant Elevation  | 764                 | Feet above sea level     |                           |
|---|-----------------------|--|---------------------|--------------------------|---------------------------|
| Inlet $NO_x$ Emissions ( $NOx_{in}$ ) to SNCR             | 0.35 lb/MMBtu         |  |                     |                          |                           |
| Oulet $NO_x$ Emissions ( $NOx_{out}$ ) from SNCR          | 0.26 lb/MMBtu         | ]  |                     |                          |                           |
| Estimated Normalized Stoichiometric Ratio (NSR)           | 1.00                  | *The NSR for a urea system may be calculate<br>Control Cost Manual (as updated March 201 |                     | 1.17 in Section 4, Chapt | er 1 of the Air Pollution |
|   |                       | -  |                     |                          |                           |
| Concentration of reagent as stored (C <sub>stored</sub> ) | 50 Percent            |  |                     |                          |                           |
| Density of reagent as stored (p <sub>stored</sub> )       | 71 lb/ft <sup>3</sup> |  |                     |                          |                           |
| Concentration of reagent injected (C <sub>inj</sub> )     | 10 percent            | Densities of typical SI  | NCR reagents:       |                          |                           |
| Number of days reagent is stored $(t_{storage})$          | 14 days               | 50% urea so  | olution             | 71 lbs/ft <sup>3</sup>   |                           |
| Estimated equipment life                                  | 20 Years              | 29.4% aqueo  | ous NH <sub>3</sub> | 56 lbs/ft <sup>3</sup>   |                           |
|   |                       |  |                     |                          |                           |
| Select the reagent used                                   | Urea 🔻                |  |                     |                          | -                         |

#### Enter the cost data for the proposed SNCR:

| Desired dollar-year   | 2020   |   |
|---|--|---|
| CEPCI for 2020  | 607.5 2019 Final CEPCI Value 541.7 2016 CEPCI    | CEPCI = Chemical Engineering Plant Cost Index   |
|   |  | * 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at |
| Annual Interest Rate (i)  | 5.50 Percent*                                    | https://www.federalreserve.gov/releases/h15/.)  |
| Fuel (Cost <sub>fuel</sub> )                                      | 2.13 \$/MMBtu                                    |   |
| Reagent (Cost <sub>reag</sub> )                                   | 1.81 \$/gallon for a 50 percent solution of urea |   |
| Water (Cost <sub>water</sub> )                                    | 0.0051 \$/gallon                                 |   |
| Electricity (Cost <sub>elect</sub> )                              | 0.0760 \$/kWh                                    |   |
| Ash Disposal (for coal-fired boilers only) (Cost <sub>ash</sub> ) | 42.56 \$/ton                                     |   |

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) = Administrative Charges Factor (ACF) =

| 0.015 |
|-------|
| 0.03  |

#### Data Sources for Default Values Used in Calculations:

|  |               |   | If you used your own site-specific values, please enter the value used |
|--|---------------|---|--|
| Data Element                               | Default Value | Sources for Default Value   | and the reference source   |
| Reagent Cost (\$/gallon)                   |               | U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector<br>Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and<br>Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5,<br>Attachment 5-4, January 2017. Available at:<br>https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-<br>4_sncr_cost_development_methodology.pdf. |  |
| Water Cost (\$/gallon)                     | 0.00417       | Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see<br>2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at<br>http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-<br>brochure-water-wastewater-rate-survey.pdf.   |  |
| Electricity Cost (\$/kWh)                  | 0.0676        | U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published<br>December 2017. Available at:<br>https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.   |  |
| Fuel Cost (\$/MMBtu)                       | 1.89          | U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4.<br>Published December 2017. Available at:<br>https://www.eia.gov/electricity/annual/pdf/epa.pdf.   |  |
| Ash Disposal Cost (\$/ton)                 | 48.8          | Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft<br>Demand. July 11, 2017. Available at:<br>http://www.wastebusinessjournal.com/news/wbj20170711A.htm.   |  |
| Percent sulfur content for Coal (% weight) | 0.41          | Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy<br>Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant<br>Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.   |  |
| Percent ash content for Coal (% weight)    | 5.84          | Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy<br>Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant<br>Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.  |  |
| Higher Heating Value (HHV) (Btu/lb)        | 8,826         | 2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy<br>Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant<br>Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.  |  |
| -ligher Heating Value (HHV) (Btu/lb)       | 8,826         | Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant  |  |

#### **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 <sub>B</sub> ) =        | HHV x Max. Fuel Rate =   | 517              | MMBtu/hour |
| Maximum Annual fuel consumption (mfuel) =                 | (QB x 1.0E6 Btu/MMBtu x 8760)/HHV =  | 513,133,923      | lbs/year   |
| Actual Annual fuel consumption (Mactual) =                |  | 241,600,555      | lbs/year   |
| Heat Rate Factor (HRF) =                                  | NPHR/10 =  | 1.00             |            |
| Total System Capacity Factor (CF <sub>total</sub> ) =     | (Mactual/Mfuel) x (tSNCR/365) =  | 0.30             | fraction   |
| Total operating time for the SNCR (t <sub>op</sub> ) =    | CF <sub>total</sub> x 8760 =   | 5650             | hours      |
| NOx Removal Efficiency (EF) =                             | (NOx <sub>in</sub> - NOx <sub>out</sub> )/NOx <sub>in</sub> =  | 25               | percent    |
| 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) | 1.05             |            |
| $SO_2$ Emission rate =                                    | (%S/100)x(64/32)*(1x10 <sup>6</sup> )/HHV =  | < 3              | lbs/MMBtu  |
| Elevation Factor (ELEVF) =                                | 14.7 psia/P =  | 1.03             |            |
| Atmospheric pressure at 764 feet above sea level<br>(P) = | 2116x[(59-(0.00356xh)+459.7)/518.6] <sup>5.256</sup> x (1/144)*<br>=                                   | 14.3             | psia       |
| Retrofit Factor (RF) =                                    | Retrofit to existing boiler  | 1.60             |            |

\* 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 <sub>reagent</sub> ) = | $(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR) =$     | 118              | lb/hour   |
|  | (whre SR = 1 for $NH_3$ ; 2 for Urea)                                     |                  |   |
| Reagent Usage Rate (m <sub>sol</sub> ) =           | m <sub>reagent</sub> /C <sub>sol</sub> =                                  | 236              | lb/hour   |
|  | (m <sub>sol</sub> x 7.4805)/Reagent Density =                             | 24.9             | gal/hour  |
| Estimated tank volume for reagent storage =        | (m <sub>sol</sub> x 7.4805 x t <sub>storage</sub> x 24 hours/day)/Reagent | 8.400            | gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons) |
|  | Density =   | 8,400            | rounded up to the nearest 100 gallons)  |

#### **Capital Recovery Factor:**

| Parameter                       | Equation                                      | Calculated Value |
|---------------------------------|---|------------------|
| Capital Recovery Factor (CRF) = | $i (1+i)^n / (1+i)^n - 1 =$                   | 0.0837           |
|                                 | Where n = Equipment Life and i= Interest Rate |                  |

| Parameter   | Equation  | Calculated Value | Units        |
|---|---|------------------|--------------|
| Electricity Usage:  |   |                  |              |
| Electricity Consumption (P) =   | (0.47 x NOx <sub>in</sub> x NSR x Q <sub>B</sub> )/NPHR =             | 8.5              | kW/hour      |
| Water Usage:  |   |                  |              |
| Water consumption $(q_w) =$   | ( $m_{sol}$ /Density of water) x (( $C_{stored}$ / $C_{inj}$ ) - 1) = | 113              | gallons/hour |
| Fuel Data:<br>Additional Fuel required to evaporate water in                |   |                  |              |
| injected reagent (ΔFuel) =  | $Hv \times m_{reagent} \times ((1/C_{inj})-1) =$                      | 0.96             | MMBtu/hour   |
| Ash Disposal:   |   |                  |              |
| Additional ash produced due to increased fuel consumption ( $\Delta$ ash) = | (Δfuel x %Ash x 1x10 <sup>6</sup> )/HHV =                             | 6.3              | lb/hour      |

Balance of Plant Costs (BOP<sub>cost</sub>) =

# **Cost Estimate**

#### Total Capital Investment (TCI)

\$3,335,563 in 2020 dollars

| 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 <sub>cost</sub> ) = | \$2,233,111 in 2020 dollars                                |
| Air Pre-Heater Costs (APH <sub>cost</sub> )* =       | \$0 in 2020 dollars  |

 Total Capital Investment (TCI) =
 \$7,239,275 in 2020 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 <sub>cost</sub> )   |  |
|---|--|--|
| For Coal-Fired Utility Boilers:   |  |  |
| SNCR <sub>cost</sub>  | $_{\rm t}$ = 220,000 x (B <sub>MW</sub> x HRF) <sup>0.42</sup> x CoalF x BTF x ELEVF x RF                |  |
| For Fuel Oil and Natural Gas-Fired Utility Boil   | ers:   |  |
| S   | $NCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$                          |  |
| For Coal-Fired Industrial Boilers:  |  |  |
| SNCR <sub>cost</sub> =  | : 220,000 x (0.1 x Q <sub>B</sub> x HRF) <sup>0.42</sup> x CoalF x BTF x ELEVF x RF                      |  |
| For Fuel Oil and Natural Gas-Fired Industrial   | Boilers:   |  |
| SNC   | R <sub>cost</sub> = 147,000 x ((Q <sub>B</sub> /NPHR)x HRF) <sup>0.42</sup> x ELEVF x RF                 |  |
|   |  |  |
| SNCR Capital Costs (SNCR <sub>cost</sub> ) =  | \$2,233,111 in 2020 dollars  |  |
|   |  |  |
|   |  |  |
|   | Air Pre-Heater Costs (APH <sub>cost</sub> )*   |  |
| For Coal-Fired Utility Boilers:   |  |  |
| AP  | H <sub>cost</sub> = 69,000 x (B <sub>MW</sub> x HRF x CoalF) <sup>0.78</sup> x AHF x RF                  |  |
| For Coal-Fired Industrial Boilers:  |  |  |
| APH   | <sub>cost</sub> = 69,000 x (0.1 x Q <sub>B</sub> x HRF x CoalF) <sup>0.78</sup> x AHF x RF               |  |
|   |  |  |
| Air Pre-Heater Costs (APH <sub>cost</sub> ) =   | \$0 in 2020 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 <sub>cost</sub> )  |  |
| For Coal-Fired Utility Boilers:   | Datance of Flam costs (Dol cost)   |  |
|   | = 320,000 x (B <sub>MW</sub> ) <sup>0.33</sup> x (NO <sub>x</sub> Removed/hr) <sup>0.12</sup> x BTF x RF |  |
| For Fuel Oil and Natural Gas-Fired Utility Boilers:   |  |  |
| $BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$   |  |  |
| For Coal-Fired Industrial Boilers:  |  |  |
| For Coal-Fired industrial Bollers:<br>BOP <sub>cost</sub> = 320,000 x $(0.1 \times Q_B)^{0.33}$ x $(NO_x Removed/hr)^{0.12}$ x BTF x RF |  |  |
|   |  |  |
| For Fuel Oil and Natural Gas-Fired Industrial Boilers:  |  |  |
| BOP <sub>cost</sub>   | = 213,000 x (Q <sub>B</sub> /NPHR) <sup>0.33</sup> x (NO <sub>x</sub> Removed/hr) <sup>0.12</sup> x RF   |  |
|   |  |  |
| Balance of Plant Costs (BOP <sub>cost</sub> ) =   | \$3,335,563 in 2020 dollars  |  |

#### **Annual Costs**

#### **Total Annual Cost (TAC)**

#### TAC = Direct Annual Costs + Indirect Annual Costs

| Direct Annual Costs (DAC) =           | \$382,834 in 2020 dollars |
|---------------------------------------|---------------------------|
| Indirect Annual Costs (IDAC) =        | \$609,185 in 2020 dollars |
| Total annual costs (TAC) = DAC + IDAC | \$992,019 in 2020 dollars |

#### **Direct Annual Costs (DAC)**

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

| Annual Maintenance Cost = | 0.015 x TCI =  | \$108,589 in 2020 dollars |
|---------------------------|--|---------------------------|
| Annual Reagent Cost =     | $q_{sol} \times Cost_{reag} \times t_{op} =$             | \$255,054 in 2020 dollars |
| Annual Electricity Cost = | P x Cost <sub>elect</sub> x t <sub>op</sub> =            | \$3,652 in 2020 dollars   |
| Annual Water Cost =       | $q_{water} x Cost_{water} x t_{op} =$                    | \$3,281 in 2020 dollars   |
| Additional Fuel Cost =    | $\Delta$ Fuel x Cost <sub>fuel</sub> x t <sub>op</sub> = | \$11,498 in 2020 dollars  |
| Additional Ash Cost =     | $\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$          | \$761 in 2020 dollars     |
| Direct Annual Cost =      |  | \$382,834 in 2020 dollars |

#### Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

| Administrative Charges (AC) = | 0.03 x Annual Maintenance Cost = | \$3,258 in 2020 dollars   |
|-------------------------------|----------------------------------|---------------------------|
| Capital Recovery Costs (CR)=  | CRF x TCI =                      | \$605,927 in 2020 dollars |
| Indirect Annual Cost (IDAC) = | AC + CR =                        | \$609,185 in 2020 dollars |

#### **Cost Effectiveness**

#### Cost Effectiveness = Total Annual Cost/ NOx Removed/year

| Total Annual Cost (TAC) = | \$992,019 per year in 2020 dollars         |
|---------------------------|--|
| NOx Removed =             | N/A tons/year                              |
| Cost Effectiveness =      | N/A per ton of NOx removed in 2020 dollars |
|                           |  |

Note: Cost Effectiveness is not determined because emissions in 2028 are projected to be zero.

#### Cleveland Cliffs - Northshore Mining Power Boiler #1 Appendix A - Four-Factor Control Cost Analysis Table A-3: NO<sub>x</sub> Control - Selective Catalytic Reduction

| Operating Unit: | Power Boiler 1 |
|-----------------|----------------|
|                 |                |

| Emission Unit Number               | EQUI 14 / EU | 001      | Stack/Vent Number      | SV 001  |               |
|------------------------------------|--------------|----------|------------------------|---------|---------------|
| Design Capacity                    | 517          | mmbtu/hr | Standardized Flow Rate | 133,505 | scfm @ 32º F  |
| Expected Utilization Rate          | 73%          |          | Temperature            | 280     | Deg F         |
| Expected Annual Hours of Operation | 5,650        | Hours    | Moisture Content       | 8.8%    |               |
| Annual Interest Rate               | 5.5%         |          | Actual Flow Rate       | 200,800 | acfm          |
| Expected Equipment Life            | 20           | yrs      | Standardized Flow Rate | 140,800 | scfm @ 68º F  |
|                                    |              |          | Dry Std Flow Rate      | 128,300 | dscfm @ 68º F |

#### CONTROL EQUIPMENT COSTS

| Capital Costs                                |                |   |                   |             |         |            |
|--|----------------|---|-------------------|-------------|---------|------------|
| Direct Capital Costs                         | EPRI Correla   | tion  |                   |             |         |            |
|  |                |   |                   |             |         |            |
|  |                |   |                   |             |         |            |
|  |                |   |                   |             |         |            |
|  |                |   |                   |             |         |            |
|  |                |   |                   |             |         |            |
|  |                |   |                   |             |         |            |
|  |                |   |                   |             |         |            |
| Total Capital Investment (TCI) with Retrofit |                |   |                   |             |         | 40,647,490 |
|  |                |   |                   |             |         | 40,647,490 |
| Operating Costs                              |                |   |                   |             |         |            |
| Total Annual Direct Operating Costs          |                | Labor, supervision, materials, replacement parts, utilities, etc. |                   |             | 753,037 |            |
| Total Annual Indirect Operating Costs        |                | Sum indirect oper of  | osts + capital re | covery cost |         | 3,406,329  |
| Total Annual Cost (Annualized Capital Co     | st + Operating | g Cost)   |                   |             |         | 4,159,366  |

#### Notes & Assumptions

Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 7th Ed SCR Control Cost Spreadsheet
 Costs scaled to current dollars from the Chemical Engineering Plant Cost Index (CEPCI)

#### Cleveland Cliffs - Northshore Mining Power Boiler #1 Appendix A - Four-Factor Control Cost Analysis Table A-3: NOx Control - Selective Catalytic Reduction

| CAPITAL COSTS<br>SCR Capital Costs (SCRcost)<br>Reagent Preparation Costs (RPC)<br>Air Pre-Heater Costs (APHC)<br>Balance of Plant Costs (BPC)<br>Retrofit factor<br>Total Capital Investment (TCI) | 60%     | Refer to the SCR Cost Estimate tab<br>Refer to the SCR Cost Estimate tab<br>Refer to the SCR Cost Estimate tab<br>Refer to the SCR Cost Estimate tab<br>of TCI, see SCR Cost Estimate tab | 22,537,169<br>3,510,336<br>-<br>5,219,795<br><b>40,647,490</b> |
|---|---------|---|--|
| OPERATING COSTS<br>Direct Annual Operating Costs, DC  |         |   |  |
|   |         |   |  |
| Maintenance<br>Annual Maintenance Cost =  |         | Refer to the SCR Cost Estimate tab  | 203,237  |
|   |         |   | 200,201  |
| Utilities, Supplies, Replacements & Waste Manag   | gement  |   |  |
| Annual Electricity Cost =   |         | Refer to the SCR Cost Estimate tab  | 126,956  |
| Annual Catalyst Replacement Cost =  |         | Refer to the SCR Cost Estimate tab  | 208,599  |
| Annual Reagent Cost =   |         | Refer to the SCR Cost Estimate tab  | 214,245  |
| Total Annual Direct Operating Costs   |         |   | 753,037  |
| Indirect Operating Costs  |         |   |  |
| Administrative Charges (AC) =   |         | Refer to the SCR Cost Estimate tab  | 4,134  |
| Capital Recovery Costs (CR)=  | 0.0837  | Refer to the SCR Cost Estimate tab  | 3,402,195  |
|   |         |   |  |
| Total Annual Indirect Operating Costs   |         | Sum indirect oper costs + capital recovery cost   | 3,406,329  |
| Total Annual Cost (Annualized Capital Cost + Operating  | g Cost) |   | 4,159,366  |

Cleveland Cliffs - Northshore Mining Power Boiler #1 Appendix A - Four-Factor Control Cost Analysis Table A-3: NOx Control - Selective Catalytic Reduction

Capital Recovery Factors Primary Installation Interest Rate Equipment Life CRF

5.50% 20 years 0.0837

Replacement Catayst - Refer to the SCR Cost Estimate Tab

Reagent Use Refer to the SCR Cost Estimate tab

Operating Cost Calculations Refer to the SCR Cost Estimate tab Annual hours of operation: Utilization Rate: 5,650 73%

#### Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency Air Economics Group Health and Environmental Impacts Division Office of Air Quality Planning and Standards (June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO<sub>x</sub> emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO<sub>x</sub> within a specific temperature range to produce N<sub>2</sub> and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

#### Instructions

Step 1: Please select on the Data Inputs tab and click on the Reset Form button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume (Vol<sub>catalyst</sub>) or flue gas flow rate (Q<sub>flue gas</sub>), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the SCR Design Parameters tab to see the calculated design parameters and the Cost Estimate tab to view the calculated cost data for the installation and operation of the SCR.

| Data Inputs   |   |  |   |                          |
|---|---|--|---|--------------------------|
| Enter the following data for your combustion unit:  |   |  |   |                          |
| Is the combustion unit a utility or industrial boiler?  | <ul> <li>▼</li> </ul>   | What type of fuel does the unit burn?                                      | ? Coal 🗨  |                          |
| Please enter a retrofit factor between 0.8 and 1.5 based on the level of diffic projects of average retrofit difficulty.                    | 1.6   | NOTE: You must document why a retrofit factor of 1.<br>e proposed project. | .6 is appropriate for   |                          |
| Complete all of the highlighted data fields:  |   |  |   |                          |
| What is the maximum heat input rate (QB)?   | 517 MMBtu/hour  | Provide the following information for co<br>Type of coal burned: Sub-Bitur |   |                          |
| What is the higher heating value (HHV) of the fuel?<br>*HHV value of 8826 Btu/lb is a default value. See below for data source. Enter actua | 8,826 Btu/lb<br>I HHV for fuel burned, if known.  | Enter the sulfur content (%S) =     *The sulfur content of 0.41% is a def  | 0.41 percent by weight<br>fault value. See below for data source. Enter actual value, if known.   |                          |
| What is the estimated actual annual fuel consumption?   | 241,600,555 lbs/year  | For units burning coal blends:   |   |                          |
| Operating Hours<br>Enter the net plant heat input rate (NPHR)   | 5,650 323,950,000.00  | Note: The table below is pre-po  | oopulated with default values for HHV and %S. Please ente<br>below. If the actual value for any parameter is not known,   |                          |
| 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 | Coal Type<br>Bituminous<br>Sub-Bituminous<br>Lignite                       | Fraction in         %5         HHV (Btu/lb)           0         1.84         11,841           0         0.41         8,826           0         0.82         6,685 |                          |
| Plant Elevation   | 764 Feet above sea level  | values based on the data in the  | either Method 1 or Method 2 to calculate the  | OMethod 1                |
|   |   |  | uations for both methods are shown on rows<br>ıb. Please select your preferred method:  | Method 2  Not applicable |

#### Enter the following design parameters for the proposed SCR:

| Number of days the SCR operates $(t_{\scriptscriptstyle SCR})$                        | 235 days          | Number of SCR reactor chambers (n <sub>scr</sub> )  | 1                             |                        |
|---|-------------------|---|-------------------------------|------------------------|
| Number of days the boiler operates $\left(t_{\text{plant}}\right)$                    | 235 days          | Number of catalyst layers ( $R_{layer}$ )   | :                             |                        |
| Inlet NO <sub>x</sub> Emissions (NOx <sub>in</sub> ) to SCR                           | 0.35 lb/MMBtu     | Number of empty catalyst layers ( $R_{empty}$ )   | 1                             |                        |
| Outlet $NO_x$ Emissions ( $NOx_{out}$ ) from SCR                                      | 0.07 lb/MMBtu     | Ammonia Slip (Slip) provided by vendor  | 2                             | ppm                    |
| Stoichiometric Ratio Factor (SRF)   | 0.525             | Volume of the catalyst layers (Vol <sub>catalyst</sub> )<br>(Enter "UNK" if value is not known)                         | UNI                           | Cubic feet             |
| *The SRF value of 0.525 is a default value. User should enter actual value, if known. |                   | Flue gas flow rate (Q <sub>fluegas</sub> )<br>(Enter "UNK" if value is not known)                                       | 301,336                       | i acfm                 |
|   |                   |   |                               |                        |
| Estimated operating life of the catalyst ( $H_{catalyst}$ )                           | 24,000 hours      |   |                               |                        |
| Estimated SCR equipment life  | 20 Years*         | Gas temperature at the SCR inlet (T)  | 650                           | °F                     |
| * For industrial boilers, the typical equipment life is between 20 and 25 years.      |                   | Base case fuel gas volumetric flow rate facto   | cor (Q <sub>fuel</sub> ) 516  | ft³/min-MMBtu/hour     |
| Concentration of reagent as stored ( $C_{\text{stored}}$ )                            | 50 percent*       | *The reagent concentration of 50% and density of 71 lbs/cft are default   |                               |                        |
| Density of reagent as stored ( $\rho_{\text{stored}})$                                | 71 lb/cubic feet* | values for urea reagent. User should enter actual values for reagent, if<br>different from the default values provided. |                               |                        |
| Number of days reagent is stored $(t_{storage})$                                      | 14 days           | Densit  | ties of typical SCR reagents: |                        |
|   |                   | 50% u   | urea solution                 | 71 lbs/ft <sup>3</sup> |
|   |                   | 29.4%   | 6 aqueous NH₃                 | 56 lbs/ft <sup>3</sup> |
| Select the reagent used Urea  | •                 |   |                               |                        |

#### Enter the cost data for the proposed SCR:

|  |   | -  |
|--|---|--|
| Desired dollar-year                    | 2019  |  |
| CEPCI for 2019                         | 607.5 2019 CEPCI Final Value 541.7 2016 CEPCI   | CEPCI = Chemical Engineering Plant Cost Index  |
| Annual Interest Rate (i)               | 5.50 Percent*   | * 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.) |
|  |   |  |
| Reagent (Cost <sub>reag</sub> )        | 1.814 \$/gallon for 50% urea  |  |
| Electricity (Cost <sub>elect</sub> )   | 0.0760 \$/kWh   |  |
| Catalyst cost (CC <sub>replace</sub> ) | \$/cubic foot (includes removal and disposal/regeneration of existing<br>248.05 catalyst and installation of new catalyst |  |
| 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) = Administrative Charges Factor (ACF) =



#### 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)                   |               | U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector<br>Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and<br>Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5,<br>Attachment 5-3, January 2017. Available at:<br>https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3<br>3 scr. cost. development_methodology.pdf |   |
| Electricity Cost (\$/kWh)                  | 0.0676        | U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published<br>December 2017. Available at:<br>https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.   |   |
| Percent sulfur content for Coal (% weight) | 0.41          | Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy<br>Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant<br>Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.   |   |
| Higher Heating Value (HHV) (Btu/lb)        | 8,826         | 2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy<br>Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant<br>Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.  |   |
| Catalyst Cost (\$/cubic foot)              | 227           | U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector<br>Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation.<br>May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-<br>sector-modeling-platform-v6.  |   |
| Operator Labor Rate (\$/hour)              | \$60.00       | U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector<br>Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation.<br>May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-<br>sector-modeling-platform-v6.  |   |
| Interest Rate (Percent)                    | 5.5           | Default bank prime rate   |   |

#### 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 <sub>B</sub> ) =       | HHV x Max. Fuel Rate =   | 517              | MMBtu/hour |
| Maximum Annual fuel consumption (mfuel) =                | (QB x 1.0E6 x 8760)/HHV =  | 513,133,923      | lbs/year   |
| Actual Annual fuel consumption (Mactual) =               |  | 241,600,555      | lbs/year   |
| Heat Rate Factor (HRF) =                                 | NPHR/10 =  | 1.00             |            |
| Total System Capacity Factor (CF <sub>total</sub> ) =    | (Mactual/Mfuel) x (tscr/tplant) =  | 0.471            | fraction   |
| Total operating time for the SCR $(t_{op})$ =            | CF <sub>total</sub> x 8760 =   | 5,650            | hours      |
| NOx Removal Efficiency (EF) =                            | (NOx <sub>in</sub> - NOx <sub>out</sub> )/NOx <sub>in</sub> =  | 80.0             | percent    |
| NO <sub>x</sub> removal factor (NRF) =                   | EF/80 =  | 1.00             |            |
| Volumetric flue gas flow rate (q <sub>flue gas</sub> ) = | Q <sub>fuel</sub> x QB x (460 + T)/(460 + 700)n <sub>scr</sub> =   | 301,336          | acfm       |
| Space velocity (V <sub>space</sub> ) =                   | q <sub>flue gas</sub> /Vol <sub>catalyst</sub> =   | 144.04           | /hour      |
| Residence Time   | 1/V <sub>space</sub>   | 0.01             | hour       |
| Coal Factor (CoalF) =                                    | 1 for oil and natural gas; 1 for bituminous; 1.05 for sub-<br>bituminous; 1.07 for lignite (weighted average is used for<br>coal blends) | 1.05             |            |
| 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 =  | 1.03             |            |
| Atmospheric pressure at sea level (P) =                  | 2116 x [(59-(0.00356xh)+459.7)/518.6] <sup>5.256</sup> x (1/144)* =  | 14.3             | psia       |
| Retrofit Factor (RF)                                     | Retrofit to existing boiler  | 1.60             |            |

\* 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) <sup>Y</sup> -1), where $Y = H_{catalyts}/(t_{SCR} \times 24$ hours) rounded to the nearest integer | 0.2303           | Fraction        |
| Catalyst volume (Vol <sub>catalyst</sub> ) =                    | 2.81 x $Q_B$ x EF <sub>adj</sub> x Slipadj x NOx <sub>adj</sub> x S <sub>adj</sub> x (T <sub>adj</sub> /N <sub>scr</sub> )                | 2,091.98         | Cubic feet      |
| Cross sectional area of the catalyst (A <sub>catalyst</sub> ) = | q <sub>flue gas</sub> /(16ft/sec x 60 sec/min)  | 314              | ft <sup>2</sup> |
| Height of each catalyst layer (H <sub>layer</sub> ) =           | (Vol <sub>catalyst</sub> /(R <sub>layer</sub> x A <sub>catalyst</sub> )) + 1 (rounded to next highest integer)                            | 3                | feet            |

#### SCR Reactor Data:

| Parameter   | Equation   | Calculated Value | Units           |
|---|--|------------------|-----------------|
| Cross sectional area of the reactor (A <sub>SCR</sub> ) = | 1.15 x A <sub>catalyst</sub>                             | 361              | ft <sup>2</sup> |
| Reactor length and width dimensions for a square          | (A <sub>SCR</sub> ) <sup>0.5</sup>                       | 10.0             | feet            |
| reactor =   | (A <sub>SCR</sub> )                                      | 19.0             | leet            |
| Reactor height =  | $(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$ | 50               | feet            |

#### Reagent Data:

Type of reagent used

Molecular Weight of Reagent (MW) = 60.06 g/mole Density = 71 lb/ft<sup>3</sup>

| Parameter  | Equation   | Calculated Value | Units   |
|--|--|------------------|---|
| Reagent consumption rate (m <sub>reagent</sub> ) = | (NOx <sub>in</sub> x Q <sub>B</sub> x EF x SRF x MW <sub>R</sub> )/MW <sub>NOx</sub> = | 99               | lb/hour   |
| Reagent Usage Rate (m <sub>sol</sub> ) =           | m <sub>reagent</sub> /Csol =   | 198              | lb/hour   |
|  | (m <sub>sol</sub> x 7.4805)/Reagent Density  | 21               | gal/hour  |
| Estimated tank volume for reagent storage =        | (m <sub>sol</sub> x 7.4805 x t <sub>storage</sub> x 24)/Reagent Density =              | 7,100            | gallons (storage needed to store a 14 day reagent supply rounded to t |

#### Capital Recovery Factor:

| Parameter                       | Equation                                      | Calculated Value |
|---------------------------------|---|------------------|
| Capital Recovery Factor (CRF) = | $i (1+i)^n / (1+i)^n - 1 =$                   | 0.0837           |
|                                 | Where n = Equipment Life and i= Interest Rate |                  |

Urea

| Other parameters              | Equation   | Calculated Value | Units |
|-------------------------------|--|------------------|-------|
| Electricity Usage:            |  |                  |       |
| Electricity Consumption (P) = | A x 1,000 x 0.0056 x (CoalF x HRF) <sup>0.43</sup> = | 295.66           | kW    |
|                               | where A = (0.1 x QB) for industrial boilers.         |                  |       |

### **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 <sub>cost</sub> ) = | \$22,537,169                                       | in 2019 dollars |  |  |  |
| Reagent Preparation Cost (RPC) =                   | \$3,510,336  | in 2019 dollars |  |  |  |
| Air Pre-Heater Costs (APHC)* =                     | \$0  | in 2019 dollars |  |  |  |
| Balance of Plant Costs (BPC) =                     | \$5,219,795  | in 2019 dollars |  |  |  |
| Total Capital Investment (TCI) =                   | \$40,647,490                                       | in 2019 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<sub>cost</sub>)

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

For Coal-Fired Utility Boilers >25 MW:

 $SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$ 

 $SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$ 

SCR Capital Costs (SCR<sub>cost</sub>) =

\$22,537,169 in 2019 dollars

| Reagent Preparation Costs (RPC)                    |  |  |  |  |  |
|--|--|--|--|--|--|
| For Coal-Fired Utility Boilers >25 MW:             |  |  |  |  |  |
|  | RPC = 564,000 x (NO $x_{in}$ x B <sub>MW</sub> x NPHR x EF) <sup>0.25</sup> x RF |  |  |  |  |
| For Coal-Fired Industrial Boilers >250 MMBtu/hour: |  |  |  |  |  |
|  | RPC = 564,000 x (NOx <sub>in</sub> x Q <sub>B</sub> x EF) <sup>0.25</sup> x RF   |  |  |  |  |
|  |  |  |  |  |  |

Reagent Preparation Costs (RPC) =

\$3,510,336 in 2019 dollars

|   | Air Pre-Heater Costs (APHC)*   |                     |
|---|--|---------------------|
| For Coal-Fired Utility Boilers >25MW:                                       |  |                     |
|   | APHC = 69,000 x ( $B_{MW}$ x HRF x CoalF) <sup>0.78</sup> x AHF x RF             |                     |
| For Coal-Fired Industrial Boilers >250 MMBtu/hour:                          |  |                     |
|   | APHC = 69,000 x (0.1 x Q <sub>8</sub> x CoalF) <sup>0.78</sup> x AHF x RF        |                     |
|   |  |                     |
| Air Pre-Heater Costs (APH <sub>cost</sub> ) =                               |  | \$0 in 2019 dollars |
| * Not applicable - This factor applies only to coal-fired boilers that burn | n 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 x $(B_{MW} x HRFx CoalF)^{0.42} x ELEVF x RF$       |                             |  |  |  |
| For Coal-Fired Industrial Boilers >250 MMBtu/hour: |   |                             |  |  |  |
|  | BPC = 529,000 x $(0.1 \times Q_8 \times CoalF)^{0.42}$ ELEVF x RF |                             |  |  |  |
|  |   |                             |  |  |  |
| Balance of Plant Costs (BOP <sub>cost</sub> ) =    |   | \$5,219,795 in 2019 dollars |  |  |  |

SCR Costs

### **Annual Costs**

### Total Annual Cost (TAC) TAC = Direct Annual Costs + Indirect Annual Costs

| Direct Annual Costs (DAC) =           | \$753,037 in 2019 dollars   |
|---------------------------------------|-----------------------------|
| Indirect Annual Costs (IDAC) =        | \$3,406,329 in 2019 dollars |
| Total annual costs (TAC) = DAC + IDAC | \$4,159,366 in 2019 dollars |

| Direct Annual Costs (DAC)  |  |                                  |  |  |  |
|--|--|----------------------------------|--|--|--|
| DAC = (A   | nnual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Co                           | st) + (Annual Catalyst Cost)     |  |  |  |
|  |  |                                  |  |  |  |
| Annual Maintenance Cost =  | 0.005 x TCI =  | \$203,237 in 2019 dollars        |  |  |  |
| Annual Reagent Cost =  | m <sub>sol</sub> x Cost <sub>reag</sub> x t <sub>op</sub> =  | \$214,245 in 2019 dollars        |  |  |  |
| Annual Electricity Cost =  | P x Cost <sub>elect</sub> x t <sub>op</sub> =  | \$126,956 in 2019 dollars        |  |  |  |
| Annual Catalyst Replacement Cost =   |  | \$208,599 in 2019 dollars        |  |  |  |
| For coal-fired boilers, the following methods  | may be used to calcuate the catalyst replacement cost.   |                                  |  |  |  |
| Method 1 (for all fuel types): $n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{laver}) \times FWF$ |  | * Calculation Method 2 selected. |  |  |  |
| Method 2 (for coal-fired industrial boilers):  | $(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$ |                                  |  |  |  |
| Direct Annual Cost =   |  | \$753,037 in 2019 dollars        |  |  |  |

### Indirect Annual Cost (IDAC)

### IDAC = Administrative Charges + Capital Recovery Costs

| Administrative Charges (AC) = | 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) = | \$4,134 in 2019 dollars     |
|-------------------------------|--|-----------------------------|
| Capital Recovery Costs (CR)=  | CRF x TCI =  | \$3,402,195 in 2019 dollars |
| Indirect Annual Cost (IDAC) = | AC + CR =  | \$3,406,329 in 2019 dollars |

### Cost Effectiveness

### Cost Effectiveness = Total Annual Cost/ NOx Removed/year

| Total Annual Cost (TAC) = | \$4,159,366 per year in 2019 dollars       |
|---------------------------|--|
| NOx Removed =             | N/A tons/year                              |
| Cost Effectiveness =      | N/A per ton of NOx removed in 2019 dollars |

Note: Cost Effectiveness is not determined because emissions in 2028 are projected to be zero.

### Cleveland Cliffs - Northshore Mining Power Boiler #1 Appendix A - Four-Factor Control Cost Analysis Table A-4: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

| Operating Unit:        | Power Boiler 1 | l        |                          |         |               |
|------------------------|----------------|----------|--------------------------|---------|---------------|
| Emission Unit Number   |                |          | Stack/Vent Number        |         |               |
| Design Capacity        | 517            | MMBtu/hr | Standardized Flow Rate   | 133,505 | scfm @ 32º F  |
| Utilization Rate       | 73%            |          | Exhaust Temperature      | 280     | Deg F         |
| Annual Operating Hours | 5,650          | hr/yr    | Exhaust Moisture Content | 8.8%    |               |
| Annual Interest Rate   | 5.50%          |          | Actual Flow Rate         | 200,800 | acfm          |
| Control Equipment Life | 20             | yrs      | Standardized Flow Rate   | 140,800 | scfm @ 68º F  |
| Plant Elevation        | 764            | ft       | Dry Std Flow Rate        | 128,300 | dscfm @ 68º F |

### CONTROL EQUIPMENT COSTS

| Capital Costs                                   |                      |                      |                      |                       |        |            |
|---|----------------------|----------------------|----------------------|-----------------------|--------|------------|
| Direct Capital Costs                            |                      |                      |                      |                       |        |            |
| Purchased Equipment (A)                         |                      |                      |                      |                       |        | 8,140,624  |
| Purchased Equipment Total (B)                   | 22%                  | of control device co | ost (A)              |                       |        | 9,921,386  |
| Installation - Standard Costs                   | 74%                  | of purchased equip   | p cost (B)           |                       |        | 7,341,825  |
| Installation - Site Specific Costs              |                      |                      |                      |                       |        | N/A        |
| Installation Total                              |                      |                      |                      |                       |        | 7,341,825  |
| Total Direct Capital Cost, DC                   |                      |                      |                      |                       |        | 17,263,211 |
| Total Indirect Capital Costs, IC                | 52%                  | of purchased equip   | o cost (B)           |                       |        | 5,159,121  |
| Total Capital Investment (TCI) = DC + IC        |                      |                      |                      |                       |        | 21,539,732 |
| Adjusted TCI for Replacement Parts              |                      |                      |                      |                       |        | 21,539,732 |
| Total Capital Investment (TCI) with Retrofit Fa | ictor                |                      |                      |                       |        | 34,463,571 |
| Operating Costs                                 |                      |                      |                      |                       |        |            |
| Total Annual Direct Operating Costs             |                      | Labor, supervision   | , materials, replace | ment parts, utilities | , etc. | 1,566,197  |
| Total Annual Indirect Operating Costs           |                      | Sum indirect oper    | costs + capital reco | overy cost            |        | 4,578,443  |
| Total Annual Cost (Annualized Capital Cost +    | <b>Operating Cos</b> | st)                  |                      |                       |        | 6,144,640  |

#### Notes & Assumptions

- 1 Baghouse cost estimate from 2008 vendor data for 165,000 acfm baghouse, (Northshore Mining March 2009 submittal to MPCA)
- 2 Purchased equipment costs include anciliary equipment
- 3 Costs scaled up to design airflow using the 6/10 power law
- 4 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
- 5 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
- 6 Cost Effectiveness in \$/ton removed is not determined because emissions in 2028 are projected to be zero.

# Cleveland Cliffs - Northshore Mining Power Boiler #1 Appendix A - Four-Factor Control Cost Analysis Table A-4: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

### CAPITAL COSTS

| Direct Costs   |               |  |                   |
|--|---------------|--|-------------------|
| Direct Capital Costs<br>Purchased Equipment (A) <sup>(1)</sup> |               |  | 8,140,624         |
| Purchased Equipment Costs (A) - Injection Syste                | -m + auviliar | v equipment EC   | 0,140,024         |
| Instrumentation  |               | Included in vendor estimate                                | 814,062           |
| State Sales Taxes  |               | of control device cost (A)                                 | 559,668           |
| Freight  |               | of control device cost (A)                                 | 407,031           |
| Purchased Equipment Total (B)                                  | 22%           |  | 9,921,386         |
|  |               |  |                   |
| Installation   |               |  |                   |
| Foundations & supports   |               | of purchased equip cost (B)                                | 396,855           |
| Handling & erection  |               | of purchased equip cost (B)                                | 4,960,693         |
| Electrical<br>Piping   |               | of purchased equip cost (B)<br>of purchased equip cost (B) | 793,711<br>99,214 |
| Insulation   |               | of purchased equip cost (B)                                | 694,497           |
| Painting   |               | Included in vendor estimate                                | 396,855           |
| Installation Subtotal Standard Expenses                        | 74%           |  | 7,341,825         |
|  |               |  |                   |
| Other Specific Costs (see summary)                             |               |  |                   |
| Site Preparation, as required                                  |               | Site Specific  |                   |
| Buildings, as required   |               | Site Specific  |                   |
| Lost Production for Tie-In                                     | N/A           | Site Specific  |                   |
| Total Site Specific Costs                                      |               |  | N/A               |
| Installation Total   |               |  | 7,341,825         |
| Total Direct Capital Cost, DC                                  |               |  | 17,263,211        |
| Indiract Canital Casta   |               |  |                   |
| Indirect Capital Costs<br>Engineering, supervision             | 10%           | of purchased equip cost (B)                                | 992,139           |
| Construction & field expenses                                  |               | of purchased equip cost (B)                                | 1,984,277         |
| Contractor fees  |               | of purchased equip cost (B)                                | 992,139           |
| Start-up   |               | of purchased equip cost (B)                                | 99,214            |
| Performance test   |               | of purchased equip cost (B)                                | 99,214            |
| Model Studies  |               | of purchased equip cost (B)                                | -                 |
| Contingencies  |               | of purchased equip cost (B)                                | 992,139           |
| Total Indirect Capital Costs, IC                               | 52%           | of purchased equip cost (B)                                | 5,159,121         |
| Total Capital Investment (TCI) = DC + IC                       |               |  | 22,422,332        |
| Adjusted TCI for Replacement Parts (Catalyst, Filter B         | ags, etc) fo  | r Capital Recovery Cost                                    | 21,539,732        |
| Total Capital Investment (TCI) with Retrofit Factor            | 60%           |  | 34,463,571        |
| OPERATING COSTS  |               |  |                   |
|  |               |  |                   |
| Direct Annual Operating Costs, DC<br>Operating Labor           |               |  |                   |
| Operator   | 60.00         | ¢/Hr   | 84,750            |
| Supervisor   |               | of Op Labor  | 12,713            |
| Maintenance  | 0.10          |  | 12,710            |
| Maintenance Labor  | 60.00         | \$/Hr  | 42,375            |
| Maintenance Materials  |               | % of Maintenance Labor                                     | 42,375            |
| Utilities, Supplies, Replacements & Waste Mana                 |               |  | ,                 |
| Electricity  | 0.08          | \$/kwh, 218.1 kW-hr, 5650 hr/yr, 73% utilization           | 93,639            |
| N/A<br>Comprosed Air   | 0.40          | \$/keef 2.0 setm/keefm 5650 br/sr 720/ utilization         | -                 |
| Compressed Air<br>N/A  | 0.48          | \$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization       | 47,841            |
| Solid Waste Disposal   | 42.56         | \$/ton, 0.5 ton/hr, 5650 hr/yr, 73% utilization            | 84,175            |
| Trona  |               | \$/ton, 1,193.8 lb/hr, 5650 hr/yr, 73% utilization         | 701,646           |
| Filter Bags  | 249.27        | \$/bag, 2,952 bags, 5650 hr/yr, 73% utilization            | 206,684           |
| Lost Revenue - Fly Ash   |               |  | 250,000           |
| N/A  |               |  | -                 |
| N/A  |               |  | -                 |
| N/A<br>Total Annual Direct Operating Costs                     |               |  | -<br>1,566,197    |
|  |               |  | .,000,107         |
| Indirect Operating Costs                                       |               |  |                   |
| Overhead   |               | of total labor and material costs                          | 109,328           |
| Administration (2% total capital costs)                        |               | of total capital costs (TCI)                               | 689,271           |
| Property tax (1% total capital costs)                          |               | of total capital costs (TCI)                               | 344,636           |
| Insurance (1% total capital costs)                             |               | of total capital costs (TCI)                               | 344,636           |
| Capital Recovery   | 0.0837        | for a 20-year equipment life and a 5.5% interest rate      | 2,883,889         |
| Total Annual Indirect Operating Costs                          |               | Sum indirect oper costs + capital recovery costs           | 4,578,443         |
| Total Annual Cost (Annualized Capital Cost + Operatin          | na Cost)      |  | 6 144 640         |
| i otal Annual Oost (Annualized Capital Oost + Operatili        | -g 003ij      |  | 6,144,640         |

### Cleveland Cliffs - Northshore Mining Power Boiler #1 Appendix A - Four-Factor Control Cost Analysis Table A-4: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

| Capital Recovery Factors       |               |  |           |                              |
|--------------------------------|---------------|--|-----------|------------------------------|
| Primary Installation           |               |  |           |                              |
| Interest Rate                  | 5.50%         |  |           |                              |
| Equipment Life                 | 20 years      |  |           |                              |
| CRF                            | 0.0837        |  |           |                              |
| Replacement Parts & Equipment: | Filter Bags   |  |           |                              |
| Equipment Life                 | 5 years       |  |           |                              |
| CRF                            | 0.2342        |  |           |                              |
| Rep part cost per unit         | 249.27 \$/bag |  |           |                              |
| Amount Required                | 2952 # of Bag | is for new baghouse                            |           |                              |
| Total Rep Parts Cost           |               | usted for freight, sales tax, and bag disposal |           |                              |
| Installation Labor             | 59,035 20 min | per bag  |           |                              |
| Total Installed Cost           | 882,600       |  |           |                              |
| Annualized Cost                | 206,684       |  |           |                              |
|                                |               |  |           |                              |
| Electrical Use                 |               |  |           |                              |
| Flow acfm                      | D P in F      | 120  | kWhr/yr   |                              |
| Blower 200,800                 | 6.00          | )  | 1,232,089 | Electricity for new baghouse |
|                                |               |  |           |                              |
|                                |               |  |           |                              |
|                                |               |  |           |                              |
|                                |               |  |           |                              |
|                                |               |  |           |                              |
|                                |               |  |           |                              |
| Total                          |               |  | 1,232,089 |                              |

### Reagent Use & Other Operating Costs

Trona use - 1.5 NSR Solid Waste Disposal 
 214.87
 lb/hr SO2
 1193.80
 lb/hr Trona

 2,709
 ton/yr DSI unreacted sorbent and reaction byproducts

### Operating Cost Calculations

| Utilization Rate               | 73%         | Annual Oper    | ating Hours | 5,650         |           |               |  |
|--------------------------------|-------------|----------------|-------------|---------------|-----------|---------------|--|
|                                | Unit        | Unit of        | Use         | Unit of       | Annual    | Annual        | Comments   |
| Item                           | Cost \$     | Measure        | Rate        | Measure       | Use*      | Cost          |  |
| Operating Labor                |             |                |             |               |           |               |  |
| Op Labor                       | 60.00       | \$/Hr          | 2.0         | hr/8 hr shift | 1,413     | \$<br>84,750  | \$/Hr, 2.0 hr/8 hr shift, 1,413 hr/yr                |
| Supervisor                     | 15%         | of Op Labor    |             |               | NA        | \$<br>12,713  | % of Operator Costs                                  |
| Maintenance                    |             |                |             |               |           |               |  |
| Maint Labor                    | 60.00       | \$/Hr          | 1.0         | hr/8 hr shift | 706       | \$<br>42,375  | \$/Hr, 1.0 hr/8 hr shift, 706 hr/yr                  |
| Maint Mtls                     | 100%        | of Maintenance | Labor       |               | NA        | \$<br>42,375  | 100% of Maintenance Labor                            |
| Utilities, Supplies, Replaceme | nts & Waste | e Management   |             |               |           |               |  |
| Electricity                    | 0.076       | \$/kwh         | 218.1       | kW-hr         | 1,232,089 | \$<br>93,639  | \$/kwh, 218.1 kW-hr, 5650 hr/yr, 73% utilization     |
| Water                          |             |                | N/A         | gpm           |           |               |  |
| Compressed Air                 | 0.481       | \$/kscf        | 2.0 :       | scfm/kacfm    | 99,384    | \$<br>47,841  | \$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization |
| Cooling Water                  |             |                | N/A         | gpm           |           |               |  |
| Solid Waste Disposal           | 42.56       | \$/ton         | 0.5         | ton/hr        | 1,978     | \$<br>84,175  | \$/ton, 0.5 ton/hr, 5650 hr/yr, 73% utilization      |
| Trona                          | 285.00      | \$/ton         | 1,193.8     | b/hr          | 2,462     | \$<br>701,646 | \$/ton, 1,193.8 lb/hr, 5650 hr/yr, 73% utilization   |
| Filter Bags                    | 249.27      | \$/bag         | 2,952       | bags          | N/A       | \$<br>206,684 | \$/bag, 2,952 bags, 5650 hr/yr, 73% utilization      |
|                                |             |                |             |               |           |               |  |
|                                |             |                |             |               |           |               |  |

### **Cleveland Cliffs - Northshore Mining Power Boiler #1** Appendix A - Four-Factor Control Cost Analysis Table A-5: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

**Operating Unit:** Power Boiler 1

| Emission Unit Number   | EQUI 14 / EU 00 | 1        | Stack/Vent Number      | SV 001  |               |
|------------------------|-----------------|----------|------------------------|---------|---------------|
| Design Capacity        | 517             | MMBtu/hr | Standardized Flow Rate | 133,505 | scfm @ 32º F  |
| Utilization Rate       | 73%             |          | Temperature            | 280     | Deg F         |
| Annual Operating Hours | 5,650           | Hours    | Moisture Content       | 8.8%    |               |
| Annual Interest Rate   | 5.5%            |          | Actual Flow Rate       | 200,800 | acfm          |
| Equipment Life         | 20              | yrs      | Standardized Flow Rate | 140,800 | scfm @ 68º F  |
|                        |                 |          | Drv Std Flow Rate      | 128,300 | dscfm @ 68º F |

#### CONTROL EQUIPMENT COSTS

| Capital Costs                              |     |                   |                    |                |                  |  |            |
|--|-----|-------------------|--------------------|----------------|------------------|--|------------|
| Direct Capital Costs                       |     |                   |                    |                |                  |  |            |
| Purchased Equipment (A)                    |     |                   |                    |                |                  |  | 21,325,238 |
| Purchased Equipment Total (B)              | 22% | of control device | e cost (A)         |                |                  |  | 25,990,134 |
|  |     |                   |                    |                |                  |  |            |
| Installation - Standard Costs              | 74% | of purchased ed   | quip cost (B)      |                |                  |  | 19,232,699 |
| Installation - Site Specific Costs         |     |                   |                    |                |                  |  | NA         |
| Installation Total                         |     |                   |                    |                |                  |  | 19,232,699 |
| Total Direct Capital Cost, DC              |     |                   |                    |                |                  |  | 45,222,832 |
| Total Indirect Capital Costs, IC           | 52% | of purchased ed   | quip cost (B)      |                |                  |  | 13,514,869 |
| Total Capital Investment (TCI) = DC + IC   |     |                   |                    |                |                  |  | 58,737,702 |
| Adjusted TCI for Replacment Parts          |     |                   |                    |                |                  |  | 57,855,102 |
| TCI with Retrofit Factor                   |     |                   |                    |                |                  |  | 92,568,163 |
| Operating Costs                            |     |                   |                    |                |                  |  |            |
| Total Annual Direct Operating Costs        |     | Labor supervis    | ion, materials, re | placement part | ts utilities etc |  | 1,031,783  |
| Total Annual Indirect Operating Costs      |     |                   | er costs + capita  |                |                  |  | 11,764,780 |
| Total Annual Cost (Annualized Capital Cost |     |                   |                    | 10000019 0030  |                  |  | 12,796,563 |

#### Notes & Assumptions

1 Capital cost estimate based on flow rate of 300,000 scfm from Northshore Mining Powerhouse #2 March 2009 submittal including anciliary equipment

Costs scaled up to design airflow using the 6/10 power law
 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

5 Cost Effectiveness in \$/ton removed is not determined because emissions in 2028 are projected to be zero.

### Cleveland Cliffs - Northshore Mining Power Boiler #1 Appendix A - Four-Factor Control Cost Analysis

### Table A-5: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

| Direct Capital Costs  |  |  |
|---|--|--|
| Purchased Equipment (A) (1)   |  | 21,325,2   |
| Purchased Equipment Costs (A) - Absorber<br>Instrumentation   | + packing + auxiliary equipment, EC<br>10% of control device cost (A)  | 2,132,5  |
| State Sales Taxes   | 6.9% of control device cost (A)  | 1,466,1  |
| Freight   | 5% of control device cost (A)  | 1,066,2  |
| Purchased Equipment Total (B)   | 22%  | 25,990,1   |
| Installation  |  | 4 000 0  |
| Foundations & supports<br>Handling & erection   | 4% of purchased equip cost (B)<br>50% of purchased equip cost (B)  | 1,039,6<br>12,995,0  |
| Electrical  | 8% of purchased equip cost (B)   | 2,079,2  |
| Piping  | 1% of purchased equip cost (B)   | 259,9  |
| Insulation  | 7% of purchased equip cost (B)   | 1,819,3  |
| Painting<br>Installation Subtotal Standard Expenses   | 4% of purchased equip cost (B)<br>74%  | 1,039,6<br><b>19,232,6</b>   |
| instanation Subiotal Standard Expenses  | 1770   | 13,232,0   |
| Other Specific Costs (see summary)<br>Site Preparation, as required   | N/A Site Specific  |  |
| Buildings, as required  | N/A Site Specific  | -  |
| Site Specific - Other   | N/A Site Specific  | -  |
| Total Site Specific Costs   |  |  |
| Installation Total  |  | 19,232,6   |
| Total Direct Capital Cost, DC   |  | 45,222,8   |
| Indirect Capital Costs  |  | -  |
| Engineering, supervision  | 10% of purchased equip cost (B)  | 2,599,0  |
| Construction & field expenses   | 20% of purchased equip cost (B)<br>10% of purchased equip cost (B)   | 5,198,0<br>2,599,0   |
| Start-up  | 1% of purchased equip cost (B)   | 2,399,0  |
| Performance test  | 1% of purchased equip cost (B)   | 259,9  |
| Model Studies   | N/A of purchased equip cost (B)  |  |
| Contingencies   | 10% of purchased equip cost (B)  | 2,599,0  |
|   | E20/ /   |  |
| Total Indirect Capital Costs, IC  | 52% of purchased equip cost (B)  | 13,514,8   |
| Total Indirect Capital Costs, IC<br>al Capital Investment (TCI) = DC + IC   | 52% of purchased equip cost (B)  | <u> </u>   |
|   |  | 58,737,7   |
| al Capital Investment (TCI) = DC + IC   | ter Bags, etc) for Capital Recovery Cost   | 58,737,7<br>57,855,1   |
| al Capital Investment (TCI) = DC + IC<br>Isted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor   | ter Bags, etc) for Capital Recovery Cost   | 58,737,7<br>57,855,1   |
| al Capital Investment (TCI) = DC + IC<br>.sted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS  | ter Bags, etc) for Capital Recovery Cost   | 58,737,7<br>57,855,1   |
| al Capital Investment (TCI) = DC + IC<br>Isted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor   | ter Bags, etc) for Capital Recovery Cost   | 58,737,7<br>57,855,1   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator  | ter Bags, etc) for Capital Recovery Cost<br>r 60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr  | 58,737,7<br>57,855,1<br>92,568,1<br>84,7   |
| al Capital Investment (TCI) = DC + IC<br>Isted TCI for Replacement Parts (Catalyst, Fil-<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor   | ter Bags, etc) for Capital Recovery Cost<br>r 60%  | 58,737,7<br>57,855,1<br>92,568,1<br>84,7   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil-<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance  | ter Bags, etc) for Capital Recovery Cost<br>r 60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs   | 58,737,7<br>57,855,1<br>92,568,1<br>84,7<br>12,7   |
| al Capital Investment (TCI) = DC + IC<br>Isted TCI for Replacement Parts (Catalyst, Fil-<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor   | ter Bags, etc) for Capital Recovery Cost<br>r 60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr   | <b>58,737,7</b><br><b>57,855,1</b><br><b>92,568,1</b><br>84,7<br>12,7  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor  | ter Bags, etc) for Capital Recovery Cost<br>r 60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs  | <b>58,737,7</b><br><b>57,855,1</b><br><b>92,568,1</b><br>84,7<br>12,7  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil-<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity  | ter Bags, etc) for Capital Recovery Cost<br>r 60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs<br>Management<br>0.08 \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization   | <b>58,737,</b><br><b>57,855,</b><br><b>92,568,</b><br>84,,<br>12,<br>12,<br>42,<br>42,<br>156,   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air  | ter Bags, etc) for Capital Recovery Cost<br>r 60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs<br>Management  | <b>58,737,</b><br><b>57,855,</b><br><b>92,568,</b><br>84,,<br>12,<br>12,<br>42,<br>42,<br>156,   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A   | ter Bags, etc) for Capital Recovery Cost<br>r 60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs<br>Management<br>0.08 \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization  | <b>58,737,7</b><br><b>57,855,</b><br><b>92,568,</b><br>84,1<br>12,1<br>42,<br>42,<br>42,<br>42,<br>42,<br>56,<br>47,8  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal   | ter Bags, etc) for Capital Recovery Cost<br>r 60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs<br>Management<br>0.08 \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization<br>42.56 \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization   | <b>58,737,7</b><br><b>57,855,1</b><br><b>92,568,1</b><br><b>92,568,1</b><br>84,7<br>12,7<br>42,2<br>42,2<br>156,6<br>47,8                                    |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil-<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime  | ter Bags, etc) for Capital Recovery Cost           r         60%           60.00         \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs           60.00         \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs           Management         0.08           0.08         \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization<br>0.48           42.56         \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization<br>167.17   | <b>58,737,7</b><br><b>57,855,</b><br><b>92,568,</b><br>84,7<br>12,7<br>42,5<br>42,5<br>42,5<br>156,<br>47,5<br>51,6<br>137,5                                 |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal   | ter Bags, etc) for Capital Recovery Cost<br>r 60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs<br>Management<br>0.08 \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization<br>42.56 \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization   | <b>58,737,7</b><br><b>57,855,1</b><br><b>92,568,1</b><br><b>92,568,1</b><br>12,7<br>42,3<br>42,3<br>156,0<br>47,8<br>51,0<br>137,3<br>206,6                  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil-<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A  | ter Bags, etc) for Capital Recovery Cost           r         60%           60.00         \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs           60.00         \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs           Management         0.08           0.08         \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization<br>0.48           42.56         \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization<br>167.17   | <b>58,737,7</b><br><b>57,855,</b><br><b>92,568,</b><br><b>92,568,</b><br>12,1<br>12,1<br>42,5<br>42,5<br>156,0<br>47,5<br>51,0<br>137,7<br>206,6             |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil-<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A                                   | ter Bags, etc) for Capital Recovery Cost           r         60%           60.00         \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs           60.00         \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs           Management         0.08           0.08         \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization<br>0.48           42.56         \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization<br>167.17   | <b>58,737,7</b><br><b>57,855,1</b><br><b>92,568,1</b><br><b>92,568,1</b><br>12,7<br>42,3<br>42,3<br>156,0<br>47,8<br>51,0<br>137,3<br>206,6                  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A   | ter Bags, etc) for Capital Recovery Cost           r         60%           60.00         \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs           60.00         \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs           Management         0.08           0.08         \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization<br>0.48           42.56         \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization<br>167.17   | <b>58,737,7</b><br><b>57,855,1</b><br><b>92,568,1</b><br><b>92,568,1</b><br>12,7<br>12,7<br>42,5<br>42,5<br>156,0<br>47,8<br>51,0<br>137,5<br>206,6          |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A  | ter Bags, etc) for Capital Recovery Cost           r         60%           60.00         \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs           60.00         \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs           Management         0.08           0.08         \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization<br>0.48           42.56         \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization<br>167.17   | <b>58,737,7</b><br><b>57,855,1</b><br><b>92,568,1</b><br><b>92,568,1</b><br>12,7<br>12,7<br>42,5<br>42,5<br>156,0<br>47,8<br>51,0<br>137,5<br>206,6          |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A   | ter Bags, etc) for Capital Recovery Cost           r         60%           60.00         \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs           60.00         \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs           Management         0.08           0.08         \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization<br>0.48           42.56         \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization<br>167.17   | <b>58,737,7</b><br><b>57,855,1</b><br><b>92,568,1</b><br><b>92,568,1</b><br>12,7<br>12,7<br>42,5<br>42,5<br>156,0<br>47,8<br>51,0<br>137,5<br>206,6          |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Operator<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A                        | ter Bags, etc) for Capital Recovery Cost           r         60%           60.00         \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs           60.00         \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs           Management         0.08           0.08         \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization<br>0.48           42.56         \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization<br>167.17   | <b>58,737,7</b><br><b>57,855,1</b><br><b>92,568,1</b><br><b>92,568,1</b><br>12,7<br>12,7<br>42,5<br>42,5<br>156,0<br>47,8<br>51,0<br>137,5<br>206,6          |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil-<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Atterials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A       | ter Bags, etc) for Capital Recovery Cost           r         60%           60.00         \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs           60.00         \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs           Management         0.08           0.08         \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization<br>0.48           42.56         \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization<br>167.17   | <b>58,737,7</b><br><b>57,855,1</b><br><b>92,568,1</b><br><b>92,568,1</b><br>12,7<br>42,2<br>42,2<br>156,0<br>47, <u>8</u><br>51,6<br>137,3<br>206,6<br>250,0 |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil-<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Aterials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A        | ter Bags, etc) for Capital Recovery Cost           r         60%           60.00 \$//Hr, 2.0 hr/8 hr shift, 5650 hr/yr<br>15% 15% of Operator Costs           60.00 \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr<br>100% of maintenance labor costs           Management           0.08 \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization<br>142.56 \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization<br>145.717 \$/ton, 290.7 lb/hr, 5650 hr/yr, 73% utilization<br>249.27 \$/bag, 2,952 bags, 5650 hr/yr, 73% utilization  | 58,737,7<br>57,855,<br>92,568,<br>84,1<br>12,1<br>42,0<br>42,0<br>42,0<br>42,0<br>42,0<br>42,0<br>42,0<br>42,0   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A        | ter Bags, etc) for Capital Recovery Cost         r       60%         0.000 \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr         15% 15% of Operator Costs         0.000 \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr         100% of maintenance labor costs         Mangement         0.08 \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization         0.48 \$/ksct, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization         0.42 \$/kon, 0.2 ton/hr, 5650 hr/yr, 73% utilization         24.256 \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization         24.27 \$/bag, 2,952 bags, 5650 hr/yr, 73% utilization         24.27 \$/bag, 2,952 bags, 5650 hr/yr, 73% utilization   | 58,737,7<br>57,855,1<br>92,568,1<br>12,7<br>42,3<br>42,3<br>156,0<br>47,8<br>51,6<br>137,3<br>206,6<br>250,0<br>1,031,7                                      |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil-<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A | ter Bags, etc) for Capital Recovery Cost         r       60%         60.00 \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr         15% 15% of Operator Costs         60.00 \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr         100% of maintenance labor costs         Management         0.08 \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization         42.56 \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization         167.17 \$/ton, 290.7 lb/hr, 5650 hr/yr, 73% utilization         249.27 \$/bag, 2,952 bags, 5650 hr/yr, 73% utilization         60% of total labor and material costs         60% of total labor and material costs   | 58,737,7<br>57,855,1<br>92,568,1<br>84,7<br>12,7<br>42,3<br>42,3<br>156,6<br>47,8<br>51,6<br>137,3<br>206,6<br>250,0<br>1,031,7<br>109,3<br>1,851,3          |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil-<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A | ter Bags, etc) for Capital Recovery Cost         r       60%         60.00       \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr         15%       15% of Operator Costs         60.00       \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr         100%       of maintenance labor costs         Management       0.08         0.08       \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization         0.48       \$/kscf, 2.0 sc/m/kac/m, 5650 hr/yr, 73% utilization         167.17       \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization         167.17       \$/ton, 290.7 lb/hr, 5650 hr/yr, 73% utilization         249.27       \$/bag, 2,952 bags, 5650 hr/yr, 73% utilization         249.27       \$/bag, 2,952 bags, 5650 hr/yr, 73% utilization         60%       of total labor and material costs         2%       of total labor and material costs         2%       of total capital costs (TCI)         1%       of total capital costs (TCI) | 58,737,7<br>57,855,1<br>92,568,1<br>84,7<br>12,7<br>42,3<br>42,3<br>156,0<br>47,8<br>51,6<br>137,3<br>206,6<br>250,0<br>1,031,7<br>109,3<br>1,851,3<br>925,6 |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil-<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A | ter Bags, etc) for Capital Recovery Cost         r       60%         60.00 \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr         15% 15% of Operator Costs         60.00 \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr         100% of maintenance labor costs         Management         0.08 \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization         42.56 \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization         167.17 \$/ton, 290.7 lb/hr, 5650 hr/yr, 73% utilization         249.27 \$/bag, 2,952 bags, 5650 hr/yr, 73% utilization         60% of total labor and material costs         60% of total labor and material costs   |  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fil-<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste I<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A       | ter Bags, etc) for Capital Recovery Cost         r       60%         60.00 \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr         15% 15% of Operator Costs         60.00 \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr         100% of maintenance labor costs         Management         0.08 \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization         0.48 \$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization         167.17 \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization         167.17 \$/ton, 290.7 lb/hr, 5650 hr/yr, 73% utilization         249.27 \$/bag, 2,952 bags, 5650 hr/yr, 73% utilization         249.27 \$/bag, 2,952 bags, 5650 hr/yr, 73% utilization         60% of total labor and material costs         2% of total capital costs (TCI)         1% of total capital costs (TCI)         1% of total capital costs (TCI)         1% of total capital costs (TCI)   | 58,737,7<br>57,855,1<br>92,568,1<br>84,7<br>12,7<br>42,3<br>42,3<br>156,0<br>47,8<br>51,6<br>137,3<br>206,6<br>250,0<br>1,031,7<br>1,031,7                   |

### Cleveland Cliffs - Northshore Mining Power Boiler #1 Appendix A - Four-Factor Control Cost Analysis Table A-5: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

| Primary Installation           |               |               |                    |            |               |   |
|--------------------------------|---------------|---------------|--------------------|------------|---------------|---|
| Interest Rate                  | 5.50%         |               |                    |            |               |   |
| Equipment Life                 | 20            | years         |                    |            |               |   |
| CRF                            | 0.0837        |               |                    |            |               |   |
| Replacement Parts & Equipment: | Filter Bags   |               |                    |            |               |   |
| Equipment Life                 | 5             | years         |                    |            |               |   |
| CRF                            | 0.2342        |               |                    |            |               |   |
| Rep part cost per unit         | 249.27        | \$/bag        |                    |            |               |   |
| Amount Required                | 2952          | # of Bags for | new baghouse       |            |               |   |
| Total Rep Parts Cost           |               |               | d for freight & sa |            |               |   |
| Installation Labor             | 59,035        | 10 min per b  | ag, Labor + Ove    | rhead (68% | = \$29.65/hr) | EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4 |
| Total Installed Cost           |               |               | o replacement      | parts need | ed            | lists replacement times from 5 - 20 min per bag.      |
| Annualized Cost                | 206,684       |               |                    |            |               |   |
|                                |               |               |                    |            |               |   |
| Electrical Use                 |               |               |                    |            |               |   |
|                                | Elever a star | D P in H2O    | Efficiency         | Hp         | kW            |   |
| Blower, Baghouse               | Flow acfm     |               |                    |            | 2.053.481     | Electricity demand for new baghouse                   |

| Total                       |                                       | 2,053,481          |
|-----------------------------|---------------------------------------|--------------------|
| Reagents and Other Operatin | g Costs                               |                    |
| Lime Use Rate               | 1.30 lb-mole CaO/lb-mole SO2          | 290.74 lb/hr Lime  |
| Solid Waste Disposal        | 1,214 ton/yr unreacted sorbent and re | eaction byproducts |

#### **Operating Cost Calculations**

| Utilization Rate                | 73%          | Annual Ope    | rating Hours | 5,650         |           |               |  |
|---------------------------------|--------------|---------------|--------------|---------------|-----------|---------------|--|
|                                 | Unit         | Unit of       | Use          | Unit of       | Annual    | Annual        | Comments   |
| Item                            | Cost \$      | Measure       | Rate         | Measure       | Use*      | Cost          |  |
| Operating Labor                 |              |               |              |               |           |               |  |
| Op Labor                        | 60.00        | \$/Hr         | 2.0          | hr/8 hr shift | 1,413     | \$<br>84,750  | \$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr                 |
| Supervisor                      | 15%          | of Op.        |              |               | NA        | \$<br>12,713  | 15% of Operator Costs                                |
| Maintenance                     |              |               |              |               |           |               |  |
| Maint Labor                     | 60.00        | \$/Hr         | 1.0          | hr/8 hr shift | 706       | \$<br>42,375  | \$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr                 |
| Maint Mtls                      | 100          | % of Maintena | nce Labor    |               | NA        | \$<br>42,375  | 100% of Maintenance Labor                            |
| Utilities, Supplies, Replacemen | ts & Waste N | lanagement    |              |               |           |               |  |
| Electricity                     | 0.076        | \$/kwh        | 363.4        | kW-hr         | 2,053,481 | \$<br>156,065 | \$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization     |
| Compressed Air                  | 0.481        | \$/kscf       | 2            | scfm/kacfm    | 99,384    | \$<br>47,841  | \$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization |
| Water                           | 0.340        | \$/mgal       |              | gpm           |           |               | \$/mgal, 0 gpm, 5650 hr/yr, 73% utilization          |
| SW Disposal                     | 42.56        | \$/ton        | 0.21         | ton/hr        | 1,214     | \$<br>51,679  | \$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization      |
| Lime                            | 167.17       | \$/ton        | 290.7        | lb/hr         | 821       | \$<br>137,302 | \$/ton, 290.7 lb/hr, 5650 hr/yr, 73% utilization     |
| Filter Bags                     | 249.27       | \$/bag        | 2,952        | bags          | N/A       | \$<br>206,684 | \$/bag, 2,952 bags, 5650 hr/yr, 73% utilization      |
|                                 |              |               |              |               |           |               |  |

## Appendix B

Unit-specific Screening Level Cost Summary for Power Boiler 2

### Cleveland Cliffs - Northshore Mining Power Boiler #2 Appendix B - Four-Factor Control Cost Analysis Table B-1: Cost Summary

### NO<sub>x</sub> Control Cost Summary

| Control Technology  | Control Eff % | Installed Capital<br>Cost \$ | Annualized<br>Operating Cost<br>\$/yr |
|---|---------------|------------------------------|---------------------------------------|
| Low NOx Burners + Over<br>Fire Air (LNB+OFA) Coal-<br>Fired | 40%           | \$11,609,362                 | \$1,725,870                           |
| Selective Non-Catalytic<br>Reduction (SNCR)                 | 25%           | \$8,917,925                  | \$1,435,176                           |
| Selective Catalytic<br>Reduction (SCR)                      | 80%           | \$55,724,684                 | \$5,985,367                           |

### SO<sub>2</sub> Control Cost Summary

| Control Technology                           | Control Eff % | Installed Capital<br>Cost \$ | Annualized<br>Operating Cost<br>\$/yr |
|--|---------------|------------------------------|---------------------------------------|
| Dry Sorbent Injection (DSI)<br>with Baghouse | 70%           | \$37,737,598                 | \$6,943,044                           |
| Spray Dry Absorber (SDA)<br>with Baghouse    | 90%           | \$61,962,015                 | \$13,572,909                          |

#### Cleveland Cliffs - Northshore Mining Power Boiler #2 Appendix B - Four-Factor Control Cost Analysis Table B-2: Summary of Utility, Chemical and Supply Costs

| Operating Unit:   | Power Boiler 2           |                            | Study Year | 2020         |   |  |
|---|--------------------------|----------------------------|------------|--------------|---|--|
| Emission Unit Number<br>Stack/Vent Number                         | EQUI 15 / EU (<br>SV 002 | J02                        |            |              |   |  |
|   | 2020                     |                            |            |              |   |  |
| Item  | Unit Cost                | Units                      | Cost       | Year         | Data Source   | Notes  |
| Operating Labor   |                          | \$/hr                      |            | 2020         |   |  |
| Maintenance Labor   | 60                       | \$/hr                      |            | 2020         | Site-specific data  |  |
| Electricity   | 0.076                    | \$/kwh                     |            |              | EIA 2020 Avg Price Industrial Nat Gas in MN               |  |
|   |                          |                            |            |              | 5-year average based on 2014-2018 gas                     |  |
| Natural Gas   | 4.98                     | \$/kscf                    |            | NA           | prices on epia.gov  |  |
| Water   | 0.34                     | \$/mgal                    | 0.20       | 2002         | 2002, Section 6 Chapter 2                                 | Adjusted for 3% inflation  |
| Cooling Water   | 0.42                     | \$/mgal                    | 0.23       | 1999         | 2002, Section 3.1 Chapter 1                               | Ch 1 Carbon Absorbers, 1999 \$0.15-\$0.30 Avg of 22.5 and 7 yrs and 3% inflation |
|   |                          |                            |            |              | EPA Air Pollution Control Cost Manual 6th Ed              |  |
| Compressed Air  | 0.48                     | \$/kscf                    | 0.38       | 2012         | 2002, Section 6 Chapter 1                                 | Adjusted for 3% inflation  |
| Chemicals & Supplies  |                          |                            |            |              |   |  |
| Lime  | 167.17                   | \$/ton                     | 140.00     | 2014         | Site Specific   | Adjusted for 3% inflation  |
| Trona   | 285.00                   |                            |            |              | Vendor estimated delivered cost                           |  |
|   |                          |                            |            |              | EPA Control Cost Manual Chapter 7, 7th                    |  |
| Urea 50% Solution   | 1.81                     | \$/gallon                  | 1.66       | 2017         |   | Adjusted for 3% inflation  |
|   |                          |                            |            |              | Edition default<br>EPA Control Cost Manual Chapter 7, 7th |  |
| Estimated operating life of the catalyst (H <sub>catalyst</sub> ) | 24,000                   | hours                      |            |              | Edition default   |  |
| (i reatalyst)   | 2-7,000                  |                            |            |              | EPA Control Cost Manual Chapter 7, 7th                    | 1  |
| SCR Catalyst cost (CC replace)                                    | 0.40                     | \$/cubic foot              | 227        | 2017         |   | Adjusted for 3% inflation  |
| Con Catalyst COst (CC replace)                                    | 248                      | arcabic 1001               | 221        | 2017         |   | · · · · · · · · · · · · · · · · · · ·  |
|   |                          |                            |            |              | Northshore Mining March 2009 submittal to                 |  |
| Fabric Filter Bags  | 249.27                   | \$/bag                     | 160        | 2005         | MPCA  | Adjusted for 3% inflation  |
|   |                          |                            |            |              |   |  |
| Other   |                          |                            |            |              |   |  |
| Sales Tax   | 6.875%                   |                            |            | 2020         | Current MN sales tax rate                                 |  |
|   |                          |                            |            |              | EPA Control Cost Manual Chapter 7, 7th                    |  |
| Interest Rate   | 5.50%                    |                            |            | 2016         | Edition default   |  |
|   |                          |                            |            |              | EPA Air Pollution Control Cost Manual 6th Ed              |  |
| Solid Waste Disposal  | 42.56                    | \$/ton                     | 25         | 2002         |   | Adjusted for 3% inflation  |
|   |                          |                            |            |              | EPA Control Cost Manual Chapter 2, 7th                    |  |
|   |                          |                            |            |              | Edition estimates contingencies from 5-15%.               |  |
| Contingencies   | 10%                      | of purchased equip cost (B | )          |              | Assumed the mid range                                     |  |
|   |                          |                            |            |              | CUECost Workbook Version 1.0, USEPA                       |  |
|   |                          |                            |            |              | Document Page 2 allows up to a 60% retrofit               |  |
| Markup on capital investment (retrofit factor)                    | 60%                      |                            |            |              | factor for installations in existing facilities.          |  |
|   |                          |                            |            |              |   |  |
| Operating Information   |                          |                            |            |              |   |  |
| Annual Op. Hrs  | 5,774                    | Hours                      |            |              | 2017 Site-specific operating hours                        |  |
|   |                          |                            |            |              |   |  |
| Utilization Rate  | 78%                      |                            |            |              | Site-specific estimate, 2017 emission inventory           |  |
| Design Capacity   | 765.0                    | MMBTU/hr                   |            |              | Site-specific estimate                                    |  |
| Equipment Life  | 20                       | vrs                        |            |              | Assumed   |  |
| Temperature   | 265                      | Deg F                      |            |              | Site-specific estimate                                    |  |
| Moisture Content  | 11.0%                    |                            |            |              | Site-specific estimate                                    |  |
| Actual Flow Rate  | 232,100                  | acfm                       |            |              | Site-specific estimate                                    |  |
| Standardized Flow Rate  | 163,800                  | scfm @ 68º F               | 157,508    | scfm @ 32º F | Site-specific estimate                                    |  |
| Dry Std Flow Rate   | 145,700                  |                            |            |              | Site-specific estimate                                    |  |
|   |                          |                            |            |              | EPA Control Cost Manual Chapter 7, 7th                    |  |
| Fuel higher heating value (HHV)                                   | 8,826                    | BTU/b                      |            |              | Edition default for sub-bituminous                        |  |
| Plant Elevation   |                          | Feet above sea level       |            |              | Site Elevation  |  |
|   |                          |                            |            |              | EPA Control Cost Manual Chapter 7, 7th                    |  |
| Fuel Sulfur Content (%)   | 0.41                     | %                          |            | 1            | Edition default for sub-bituminous                        |  |
| # days boiler operates  |                          | days                       |            |              | Site Specific Data  |  |
|   |                          |                            |            |              |   |  |
| Technology Control Efficiency                                     |                          |                            |            |              | ·   | •  |
|   |                          |                            |            |              | EPA fact sheet for flue gas desulfurization (new          |  |
|   | 1                        |                            |            | 1            | installations)  |  |
| SDA - SO <sub>2</sub> Control Efficiency                          | 90%                      |                            |            |              | https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf               |  |
|   | 0070                     |                            |            |              | Control efficiency is based on trona as injected          |  |
| DSI - SO <sub>2</sub> Control Efficiency                          | 70%                      | Trona Control Efficiency   |            |              | reagent.  |  |
|   |                          | TIONA CONTOLETICIENCY      |            |              | Based on engineering assessment.                          |  |
| SCR - NO <sub>x</sub> Control Efficiency                          | 80%                      |                            |            |              |   |  |
|   |                          |                            |            |              | Northshore Mining September 2006 submittal                |  |
| LNB+OFA- NO <sub>x</sub> Control Efficiency                       | 40%                      |                            |            |              | to MPCA   | <u> </u>   |
|   |                          |                            |            |              | EPA Control Cost Manual Chapter 7, 7th                    |  |
|   |                          |                            |            |              | Edition, SCR Figure 1.1                                   |  |
|   |                          |                            |            |              | (efficiency vs inlet NOx concentration                    |  |
| SNCR - NO <sub>x</sub> Performance                                | 0.44                     | lb/MMBtu                   |            | 1            | approximation (25%) reduction)                            |  |
|   | -                        |                            |            | 1            |   |  |
| <u>k</u>  |                          |                            |            |              |   | 1  |

### Cleveland Cliffs - Northshore Mining Power Boiler #2 Appendix B - Four-Factor Control Cost Analysis Table B-3: NO<sub>x</sub> Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

Operating Unit: Power Boiler 2

| Emission Unit Number               | EQUI 15 / EU | 002      | Stack/Vent Number      | SV 002  |               |
|------------------------------------|--------------|----------|------------------------|---------|---------------|
| Desgin Capacity                    | 765          | MMBtu/hr | Standardized Flow Rate | 157,508 | scfm @ 32º F  |
| Expected Utiliztion Rate           | 78%          |          | Temperature            | 265     | Deg F         |
| Expected Annual Hours of Operation | 5,774        | Hours    | Moisture Content       | 11.0%   |               |
| Annual Interest Rate               | 5.5%         |          | Actual Flow Rate       | 232,100 | acfm          |
| Expected Equipment Life            | 20           | yrs      | Standardized Flow Rate | 163,800 | scfm @ 68º F  |
|                                    |              |          | Dry Std Flow Rate      | 145,700 | dscfm @ 68º F |

### CONTROL EQUIPMENT COSTS

| Capital Costs                                |           |                      |                   |               |                 |  |            |
|--|-----------|----------------------|-------------------|---------------|-----------------|--|------------|
| Direct Capital Costs                         |           |                      |                   |               |                 |  |            |
| Purchased Equipment (A)                      |           |                      |                   |               |                 |  | 2,948,468  |
| Purchased Equipment Total (B)                | 14%       | of control device co | st (A)            |               |                 |  | 3,357,568  |
| Installation - Standard Costs                | 95%       | of purchased equip   | cost (B)          |               |                 |  | 3,189,689  |
| Installation - Site Specific Costs           |           |                      |                   |               |                 |  | 1,218,983  |
| Installation Total                           |           |                      |                   |               |                 |  | 3,189,689  |
| Total Direct Capital Cost, DC                |           |                      |                   |               |                 |  | 6,547,257  |
| Total Indirect Capital Costs, IC             | 68%       | of purchased equip   | cost (B)          |               |                 |  | 5,062,104  |
| Total Capital Investment (TCI) = DC + IC     |           |                      |                   |               |                 |  | 11,609,362 |
| Operating Costs                              |           |                      |                   |               |                 |  |            |
| Total Annual Direct Operating Costs          |           | Labor, supervision,  | materials, repla  | cement parts, | utilities, etc. |  | 277,985    |
| Total Annual Indirect Operating Costs        |           | Sum indirect oper o  | osts + capital re | ecovery cost  |                 |  | 1,447,885  |
| Total Annual Cost (Annualized Capital Cost + | Operating | g Cost)              |                   |               |                 |  | 1,725,870  |

#### Notes & Assumptions

1 Cost estimate from vendor engineering estimate scaled for inflation using the Chemical Engineering Plant Cost Index (CEPCI)

2 Installation cost assumptions and calculation methodology based on vendor engineering estimates

3 Maintenance and replacement power costs based on vendor engineering estimate

4 Cost Effectiveness in \$/ton removed is not determined because emissions in 2028 are projected to be zero.

### Cleveland Cliffs - Northshore Mining Power Boiler #2 Appendix B - Four-Factor Control Cost Analysis Table B-3: NOx Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

| PITAL COSTS  |   |   |                                   |
|--|---|---|-----------------------------------|
| Direct Capital Costs<br>Purchased Equipment (A) (1)  |   |   | 2,948,468                         |
| Purchased Equipment Costs (A)  |   |   | 2,940,400                         |
| Instrumentation  | 2%  | of control device cost (A)  | 58,969                            |
| MN Sales Taxes   | 6.9%  | of control device cost (A)  | 202,707                           |
| Freight  | 5%  | of control device cost (A)  | 147,423                           |
| Purchased Equipment Total (B)  | 14%   |   | 3,357,568                         |
| Installation [1]   |   |   |                                   |
| Foundations & supports   |   | of purchased equip cost (B)   | 1,007,270                         |
| Handling & erection<br>Electrical  |   | of purchased equip cost (B)<br>of purchased equip cost (B)  | 671,514<br>671,514                |
| Piping   |   | of purchased equip cost (B)   | 335,757                           |
| Insulation   |   | of purchased equip cost (B)   | 335,75                            |
| Painting   |   | of purchased equip cost (B)   | 83,939                            |
| Demolition   | 2.5%  | of purchased equip cost (B)   | 83,939                            |
| Installation Subtotal Standard Expenses  | 95%   |   | 3,189,689                         |
| Installation Total   |   |   | 3,189,689                         |
| Total Direct Capital Cost, DC  |   |   | 6,547,257                         |
| Indirect Capital Costs   |   |   |                                   |
| Engineering, supervision<br>Owner's cost   |   | of direct costs (DC)  | 982,089                           |
| Construction & field expenses  |   | of direct costs (DC)<br>of direct costs (DC)  | 654,72                            |
| Contractor fees  |   | of direct costs (DC)<br>of direct costs (DC)  | 327,36<br>982,08                  |
| Start-up and spare parts   |   | of direct costs (DC)  | 130,94                            |
| Performance test   |   | Engineering estimate  | 50,00                             |
| Model Studies  |   | of direct costs (DC)  | N//                               |
| Contingencies  | 20%   | of direct costs (DC) and indirect costs (IC) above  | 1,934,89                          |
| Total Indirect Capital Costs, IC   | 68%   | of direct costs (DC)  | 5,062,104                         |
| al Capital Investment (TCI) = DC + IC  |   |   | 11,609,36                         |
| Site Preparation, as required  |   | Site Specific   | NA                                |
| Buildings, as required   |   | Site Specific   | NA                                |
| Allowance for funds used during construciton<br>Total Site Specific Costs  | 10.5%   | of DC + IC  | 1,218,98<br><b>1,218,98</b>       |
| with site specifics for capital recovery cost  |   |   | 12,828,344                        |
| al Capital Investment (TCI) with Retrofit Factor   | 0%  | No retrofit factor needed based on site-specific analysis   | 12,828,344                        |
| PERATING COSTS<br>Direct Annual Operating Costs, DC  |   |   |                                   |
| Maintenance labor and materials  | 3%  | of direct capital (DC) costs  | 196,418                           |
|  |   |   |                                   |
| Utilities, Supplies, Replacements & Waste Man<br>Replacement power from efficiency loss                              |   | 0.2% OFA efficiency drop per engineering estimates  | 81,563                            |
| Replacement power from efficiency loss NA  | NA<br>NA  | 0.2% OFA efficiency drop per engineering estimates  | 81,56                             |
| Replacement power from efficiency loss<br>NA<br>NA   | NA<br>NA<br>NA  |   | 81,56                             |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA   | NA<br>NA<br>NA  |   | 81,56                             |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA   | NA<br>NA<br>NA<br>NA  |   | 81,56                             |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA   | NA<br>NA<br>NA  |   | 81,56                             |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA   | NA<br>NA<br>NA<br>NA<br>NA  |   | 81,56                             |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | NA<br>NA<br>NA<br>NA<br>NA<br>NA  |   | 81,56                             |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA                               | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA                                    |   | 81,56                             |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA                         | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA                                    |   | 81,56                             |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA                   | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA                              |   | 81,56                             |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA       | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA                  |   | 81,56                             |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA            |   | 81,56                             |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA            |   | 81,56                             |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA            |   |                                   |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA            |   |                                   |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA                  |   | 277,98                            |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA            |   | 277,98                            |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>N | of total labor and material costs   | 277,98<br>117,85                  |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA                  | of total labor and material costs<br>of total capital costs (TCI)                                 | <b>277,98</b><br>117,85<br>256,56 |
| Replacement power from efficiency loss<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>N/A     | of total labor and material costs<br>of total capital costs (TCI)<br>of total capital costs (TCI) | 81,567<br>                        |

Total Annual Cost (Annualized Capital Cost + Operating Cost)

1,725,870

### Cleveland Cliffs - Northshore Mining Power Boiler #2 Appendix B - Four-Factor Control Cost Analysis Table B-3: NOx Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

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

Replacement Parts & Equipment: N/A

Replacement Parts & Equipment: N/A

Electrical Use

Reagent Use & Other Operating Costs

| Operating Cost | Calculations from E | ngineering Ven     | ıdor        | Operating Ho<br>Utilization Ra |                | 5,774<br>78%   |          |  |
|----------------|---------------------|--------------------|-------------|--------------------------------|----------------|----------------|----------|--|
| ltem           | Unit<br>Cost \$     | Unit of<br>Measure | Use<br>Rate | Unit of<br>Measure             | Annual<br>Use* | Annual<br>Cost | Comments |  |
|                |                     |                    |             |                                |                |                |          |  |
|                |                     |                    |             |                                |                |                |          |  |
|                |                     |                    |             |                                |                |                |          |  |
|                |                     |                    |             |                                |                |                |          |  |
|                |                     |                    |             |                                |                |                |          |  |
|                |                     |                    |             |                                |                |                |          |  |
|                |                     |                    |             |                                |                |                |          |  |
|                |                     |                    |             |                                |                |                |          |  |
|                |                     |                    |             |                                |                |                |          |  |
|                |                     |                    |             |                                |                |                |          |  |

### Air Pollution Control Cost Estimation Spreadsheet For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency Air Economics Group Health and Environmental Impacts Division Office of Air Quality Planning and Standards

(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

#### Instructions

Step 1: Please select on the Data Inputs tab and click on the Reset Form button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the SNCR Design Parameters tab to see the calculated design parameters and the Cost Estimate tab to view the calculated cost data for the installation and operation of the SNCR.

| Data Inputs  |   |  |  |  |
|--|---|--|--|--|
| Enter the following data for your combustion unit:   |   |  |  |  |
| Is the combustion unit a utility or industrial boiler?   | What type of fuel does the unit burn?   |  |  |  |
| Is the SNCR for a new boiler or retrofit of an existing boiler?  |   |  |  |  |
| difficulty. Enter 1 for projects of average retroit difficulty.  | DTE: You must document why a retrofit factor of 1.6 is appropriate he proposed project.   |  |  |  |
| Complete all of the highlighted data fields:   |   |  |  |  |
|  | Provide the following information for coal-fired boilers:   |  |  |  |
| What is the maximum heat input rate (QB)? 765 MMBtu/hour   | Type of coal burned:  |  |  |  |
| What is the higher heating value (HHV) of the fuel? *HHV value of 8826 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known. | Enter the sulfur content (%S) = 0.41 percent by weight  |  |  |  |
|  | or<br>Select the appropriate SO <sub>2</sub> emission rate: Not Applicable  |  |  |  |
| What is the estimated actual annual fuel consumption? 390,363,222 lbs/year   | *The sulfur content of 0.41% is a default value. See below for data source. Enter actual value, if known.   |  |  |  |
|  | Ash content (%Ash): 5.84 percent by weight  |  |  |  |
| Is the boiler a fluid-bed boiler?  | *The ash content of 5.84% is a default value. See below for data source. Enter actual value, if known.  |  |  |  |
|  | For units burning coal blends:  |  |  |  |
| Enter the net plant heat input rate (NPHR) 10 MMBtu/MW   | 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 Fuel Cost<br>Coal Blend %S %Ash HHV (Btu/lb) (\$/MMBtu)   |  |  |  |
| If the NPHR is not known, use the default NPHR value: Fuel Type Default NPHR   | Bituminous 0 1.84 9.23 11,841 2.4   |  |  |  |
| Coal 10 MMBtu/MW<br>Fuel Oil 11 MMBtu/MW   | Sub-Bituminous         0         0.41         5.84         8,826         1.89           Lignite         0         0.83         13.6         6,620         1.74  |  |  |  |
| Natural Gas 8.2 MMBtu/MW   |   |  |  |  |
|  | 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 $(t_{\mbox{\tiny SNCR}})$      | 241 days              | Plant Elevation   | 764 Feet               | above sea level         |                           |
|---|-----------------------|---|------------------------|-------------------------|---------------------------|
| Inlet $NO_x$ Emissions ( $NOx_{in}$ ) to SNCR                   | 0.58 lb/MMBtu         |   |                        |                         |                           |
| Oulet NO <sub>x</sub> Emissions (NOx <sub>out</sub> ) from SNCR | 0.44 lb/MMBtu         |   |                        |                         |                           |
| Estimated Normalized Stoichiometric Ratio (NSR)                 | 0.80                  | *The NSR for a urea system may be cal<br>Control Cost Manual (as updated Marc | · ·                    | 17 in Section 4, Chapte | er 1 of the Air Pollution |
| Concentration of reagent as stored $(C_{stored})$               | 50 Percent            | ]   |                        |                         |                           |
| Density of reagent as stored ( $\rho_{stored}$ )                | 71 lb/ft <sup>3</sup> | 1   |                        |                         |                           |
| Concentration of reagent injected (C <sub>inj</sub> )           | 10 percent            | Densities of typi   | cal SNCR reagents:     |                         |                           |
| Number of days reagent is stored (t <sub>storage</sub> )        | 14 days               | 50% ur  | ea solution            | 71 lbs/ft <sup>3</sup>  |                           |
| Estimated equipment life  | 20 Years              | 29.4% a   | queous NH <sub>3</sub> | 56 lbs/ft <sup>3</sup>  |                           |
| Select the reagent used   | Urea 🔻                |   |                        |                         |                           |

### Enter the cost data for the proposed SNCR:

| Desired dollar-year   | 2020   |   |
|---|--|---|
| CEPCI for 2020  | 607.5 2019 Final CEPCI Value 541.7 2016 CEPCI    | CEPCI = Chemical Engineering Plant Cost Index   |
|   |  | * 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at |
| Annual Interest Rate (i)  | 5.50 Percent*                                    | https://www.federalreserve.gov/releases/h15/.)  |
| Fuel (Cost <sub>fuel</sub> )                                      | 2.13 \$/MMBtu                                    |   |
| Reagent (Cost <sub>reag</sub> )                                   | 1.81 \$/gallon for a 50 percent solution of urea |   |
| Water (Cost <sub>water</sub> )                                    | 0.0051 \$/gallon                                 |   |
| Electricity (Cost <sub>elect</sub> )                              | 0.0760 \$/kWh                                    |   |
| Ash Disposal (for coal-fired boilers only) (Cost <sub>ash</sub> ) | 42.56 \$/ton                                     |   |

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) = Administrative Charges Factor (ACF) =



### Data Sources for Default Values Used in Calculations:

|  |  |  | If you used your own site-specific values, please enter the value used |
|--|--|--|--|
| Data Element<br>Reagent Cost (\$/gallon)   | Default Value           \$1.66/gallon of           50% urea           solution | Sources for Default Value<br>U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector<br>Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and<br>Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5,<br>Attachment 5-4, January 2017. Available at:<br>https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-<br>4_sncr_cost_development_methodology.pdf. | and the reference source   |
| 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 http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.  |  |
| Electricity Cost (\$/kWh)                  | 0.0676   | U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published<br>December 2017. Available at:<br>https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.  |  |
| Fuel Cost (\$/MMBtu)                       | 1.89   | U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4.<br>Published December 2017. Available at:<br>https://www.eia.gov/electricity/annual/pdf/epa.pdf.  |  |
| Ash Disposal Cost (\$/ton)                 | 48.8   | Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft<br>Demand. July 11, 2017. Available at:<br>http://www.wastebusinessjournal.com/news/wbj20170711A.htm.  |  |
| Percent sulfur content for Coal (% weight) | 0.41   | Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy<br>Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant<br>Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.  |  |
| Percent ash content for Coal (% weight)    | 5.84   | Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy<br>Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant<br>Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.   |  |
| Higher Heating Value (HHV) (Btu/lb)        | 8,826  | 2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy<br>Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant<br>Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.   |  |

### **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 <sub>B</sub> ) =        | HHV x Max. Fuel Rate =   | 765              | MMBtu/hour |
| Maximum Annual fuel consumption (mfuel) =                 | (QB x 1.0E6 Btu/MMBtu x 8760)/HHV =  | 759,279,402      | lbs/year   |
| Actual Annual fuel consumption (Mactual) =                |  | 390,363,222      | lbs/year   |
| Heat Rate Factor (HRF) =                                  | NPHR/10 =  | 1.00             |            |
| Total System Capacity Factor (CF <sub>total</sub> ) =     | (Mactual/Mfuel) x (tSNCR/365) =  | 0.34             | fraction   |
| Total operating time for the SNCR (t <sub>op</sub> ) =    | CF <sub>total</sub> x 8760 =   | 5774             | hours      |
| NOx Removal Efficiency (EF) =                             | (NOx <sub>in</sub> - NOx <sub>out</sub> )/NOx <sub>in</sub> =  | 25               | percent    |
| 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) | 1.05             |            |
| 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 =  | 1.03             |            |
| Atmospheric pressure at 764 feet above sea level<br>(P) = | 2116x[(59-(0.00356xh)+459.7)/518.6] <sup>5.256</sup> x (1/144)*<br>=                                   | 14.3             | psia       |
| Retrofit Factor (RF) =                                    | Retrofit to existing boiler  | 1.60             |            |

\* 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 M | Aolecular Weight of Reagent (MW) = | 60.06 g/mole |
|-----------------------------|------------------------------------|--------------|
|-----------------------------|------------------------------------|--------------|

Density = 71 lb/gallon

| Parameter  | Equation  | Calculated Value | Units   |
|--|---|------------------|---|
| Reagent consumption rate (m <sub>reagent</sub> ) = | $(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR) =$     | 232              | lb/hour   |
|  | (whre SR = 1 for $NH_3$ ; 2 for Urea)                                     |                  |   |
| Reagent Usage Rate (m <sub>sol</sub> ) =           | m <sub>reagent</sub> /C <sub>sol</sub> =                                  | 464              | lb/hour   |
|  | (m <sub>sol</sub> x 7.4805)/Reagent Density =                             | 48.9             | gal/hour  |
| Estimated tank volume for reagent storage =        | (m <sub>sol</sub> x 7.4805 x t <sub>storage</sub> x 24 hours/day)/Reagent | 16 500           | gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons) |
|  | Density =   | 16,500           | rounded up to the nearest 100 gallons)  |

### **Capital Recovery Factor:**

| Parameter                       | Equation                                      | Calculated Value |
|---------------------------------|---|------------------|
| Capital Recovery Factor (CRF) = | $i (1+i)^n / (1+i)^n - 1 =$                   | 0.0837           |
|                                 | Where n = Equipment Life and i= Interest Rate |                  |

| Parameter  | Equation   | Calculated Value | Units        |
|--|--|------------------|--------------|
| Electricity Usage:   |  |                  |              |
| Electricity Consumption (P) =  | (0.47 x NOx <sub>in</sub> x NSR x Q <sub>B</sub> )/NPHR =        | 16.7             | kW/hour      |
| Water Usage:   |  |                  |              |
| Water consumption $(q_w) =$  | $(m_{sol}/Density of water) \times ((C_{stored}/C_{inj}) - 1) =$ | 223              | gallons/hour |
| Fuel Data:   |  |                  |              |
| Additional Fuel required to evaporate water in injected reagent ( $\Delta$ Fuel) = | Hv x $m_{reagent}$ x ((1/ $C_{inj}$ )-1) =                       | 1.88             | MMBtu/hour   |
| Ash Disposal:  |  |                  |              |
| Additional ash produced due to increased fuel consumption ( $\Delta$ ash) =        | (Δfuel x %Ash x 1x10 <sup>6</sup> )/HHV =                        | 12.4             | 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:          |  |  |
|  | $TCI = 1.3 x (SNCR_{cost} + BOP_{cost})$                   |  |
|  |  |  |
| Capital costs for the SNCR (SNCR <sub>cost</sub> ) = | \$2,632,583 in 2020 dollars                                |  |
| Air Pre-Heater Costs (APH <sub>cost</sub> )* =       | \$0 in 2020 dollars  |  |

 Balance of Plant Costs (BOP<sub>cost</sub>) =
 \$4,227,360 in 2020 dollars

 Total Capital Investment (TCI) =
 \$8,917,925 in 2020 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 <sub>cost</sub> )   |  |  |  |  |
|--|--|--|--|--|--|
| For Coal-Fired Utility Boilers:  |  |  |  |  |  |
|  | = 220,000 x $(B_{MW} \times HRF)^{0.42}$ x CoalF x BTF x ELEVF x RF                                      |  |  |  |  |
| For Fuel Oil and Natural Gas-Fired Utility Boil  |  |  |  |  |  |
| ,  | $NCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$                          |  |  |  |  |
| For Coal-Fired Industrial Boilers:   |  |  |  |  |  |
|  | 220,000 x (0.1 x Q <sub>B</sub> x HRF) <sup>0.42</sup> x CoalF x BTF x ELEVF x RF                        |  |  |  |  |
| For Fuel Oil and Natural Gas-Fired Industrial  |  |  |  |  |  |
|  | $R_{cost} = 147,000 \times ((Q_{B}/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$                      |  |  |  |  |
| 0110   |  |  |  |  |  |
| SNCR Capital Costs (SNCR <sub>cost</sub> ) =   | \$2,632,583 in 2020 dollars  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  | Air Pre-Heater Costs (APH <sub>cost</sub> )*   |  |  |  |  |
| For Coal-Fired Utility Boilers:  |  |  |  |  |  |
| AP   | $H_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$                  |  |  |  |  |
| 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 <sub>cost</sub> ) =  | \$0 in 2020 dollars  |  |  |  |  |
|  | d boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu                          |  |  |  |  |
| of sulfur dioxide.   |  |  |  |  |  |
|  | Balance of Plant Costs (BOP <sub>cost</sub> )  |  |  |  |  |
| For Coal-Fired Utility Boilers:  |  |  |  |  |  |
|  | = 320,000 x (B <sub>MW</sub> ) <sup>0.33</sup> x (NO <sub>x</sub> Removed/hr) <sup>0.12</sup> x BTF x RF |  |  |  |  |
| For Fuel Oil and Natural Gas-Fired Utility Boilers:  |  |  |  |  |  |
| $BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$  |  |  |  |  |  |
| For Coal-Fired Industrial Boilers:   |  |  |  |  |  |
| BOP <sub>cost</sub> = 320,000 x $(0.1 \times Q_B)^{0.33}$ x $(NO_x Removed/hr)^{0.12}$ x BTF x RF  |  |  |  |  |  |
|  |  |  |  |  |  |
| For Fuel Oil and Natural Gas-Fired Industrial Boilers:<br>BOP <sub>cost</sub> = 213,000 x $(Q_B/NPHR)^{0.33}$ x $(NO_xRemoved/hr)^{0.12}$ x RF |  |  |  |  |  |
| BOP <sub>cost</sub>  | $-213,000 \times (Q_B/METHY) \times (MO_X REHIOVED/HI) \times RE$  |  |  |  |  |
| Balance of Plant Costs (BOP <sub>cost</sub> ) = \$4,227,360 in 2020 dollars  |  |  |  |  |  |
|  | \$4,227,300 m 2020 donais  |  |  |  |  |

### **Annual Costs**

### **Total Annual Cost (TAC)**

### TAC = Direct Annual Costs + Indirect Annual Costs

| Direct Annual Costs (DAC) =           | \$684,733 in 2020 dollars   |
|---------------------------------------|-----------------------------|
| Indirect Annual Costs (IDAC) =        | \$750,443 in 2020 dollars   |
| Total annual costs (TAC) = DAC + IDAC | \$1,435,176 in 2020 dollars |

### **Direct Annual Costs (DAC)**

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

| Annual Maintenance Cost = | 0.015 x TCI =  | \$133,769 in 2020 dollars |
|---------------------------|--|---------------------------|
| Annual Reagent Cost =     | $q_{sol} \times Cost_{reag} \times t_{op} =$             | \$512,408 in 2020 dollars |
| Annual Electricity Cost = | P x Cost <sub>elect</sub> x t <sub>op</sub> =            | \$7,337 in 2020 dollars   |
| Annual Water Cost =       | $q_{water} x Cost_{water} x t_{op} =$                    | \$6,591 in 2020 dollars   |
| Additional Fuel Cost =    | $\Delta$ Fuel x Cost <sub>fuel</sub> x t <sub>op</sub> = | \$23,099 in 2020 dollars  |
| Additional Ash Cost =     | $\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$          | \$1,529 in 2020 dollars   |
| Direct Annual Cost =      |  | \$684,733 in 2020 dollars |

### Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

| Administrative Charges (AC) = | 0.03 x Annual Maintenance Cost = | \$4,013 in 2020 dollars   |
|-------------------------------|----------------------------------|---------------------------|
| Capital Recovery Costs (CR)=  | CRF x TCI =                      | \$746,430 in 2020 dollars |
| Indirect Annual Cost (IDAC) = | AC + CR =                        | \$750,443 in 2020 dollars |

### **Cost Effectiveness**

### Cost Effectiveness = Total Annual Cost/ NOx Removed/year

| Total Annual Cost (TAC) = | \$1,435,176 per year in 2020 dollars       |
|---------------------------|--|
| NOx Removed =             | N/A tons/year                              |
| Cost Effectiveness =      | N/A per ton of NOx removed in 2020 dollars |
|                           |  |

Note: Cost Effectiveness is not determined because emissions in 2028 are projected to be zero.

### **Cleveland Cliffs - Northshore Mining Power Boiler #2** Appendix B - Four-Factor Control Cost Analysis Table B-4: NO<sub>x</sub> Control - Selective Catalytic Reduction

| Emission Unit Number               | EQUI 15 / EU | 002      | Stack/Vent Number      | SV 002  |               |
|------------------------------------|--------------|----------|------------------------|---------|---------------|
| Design Capacity                    | 765          | mmbtu/hr | Standardized Flow Rate | 157,508 | scfm @ 32º F  |
| Expected Utilization Rate          | 78%          |          | Temperature            | 265     | Deg F         |
| Expected Annual Hours of Operation | 5,774        | Hours    | Moisture Content       | 11.0%   |               |
| Annual Interest Rate               | 5.5%         |          | Actual Flow Rate       | 232,100 | acfm          |
| Expected Equipment Life            | 20           | yrs      | Standardized Flow Rate | 163,800 | scfm @ 68º F  |
|                                    |              |          | Dry Std Flow Rate      | 145,700 | dscfm @ 68º F |

#### CONTROL EQUIPMENT COSTS

| Capital Costs                                |                |   |                   |                 |  |           |            |
|--|----------------|---|-------------------|-----------------|--|-----------|------------|
| Direct Capital Costs                         | EPRI Correla   | tion  |                   |                 |  |           |            |
|  |                |   |                   |                 |  |           |            |
|  |                |   |                   |                 |  |           |            |
|  |                |   |                   |                 |  |           |            |
|  |                |   |                   |                 |  |           |            |
|  |                |   |                   |                 |  |           |            |
|  |                |   |                   |                 |  |           |            |
|  |                |   |                   |                 |  |           |            |
| Total Capital Investment (TCI) with Retrofit | ofit           |   |                   |                 |  |           | 55,724,684 |
|  |                |   |                   |                 |  |           | 55,724,684 |
|  |                |   |                   |                 |  |           |            |
| Operating Costs                              |                |   |                   |                 |  |           |            |
| Total Annual Direct Operating Costs          |                | Labor, supervision, materials, replacement parts, u |                   | utilities, etc. |  | 1,316,135 |            |
| Total Annual Indirect Operating Costs        |                | Sum indirect oper o                                 | osts + capital re | covery cost     |  |           | 4,669,232  |
| Total Annual Cost (Annualized Capital Co     | st + Operating | g Cost)   |                   |                 |  |           | 5,985,367  |

#### Notes & Assumptions

- Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 7th Ed SCR Control Cost Spreadsheet
   Costs scaled to current dollars from the Chemical Engineering Plant Cost Index (CEPCI)
- 3 Cost Effectiveness in \$/ton removed is not determined because emissions in 2028 are projected to be zero.

### Cleveland Cliffs - Northshore Mining Power Boiler #2 Appendix B - Four-Factor Control Cost Analysis Table B-4: NOx Control - Selective Catalytic Reduction

| CAPITAL COSTS<br>SCR Capital Costs (SCRcost)<br>Reagent Preparation Costs (RPC)<br>Air Pre-Heater Costs (APHC)<br>Balance of Plant Costs (BPC)<br>Retrofit factor<br>Total Capital Investment (TCI) | 60%     | Refer to the SCR Cost Estimate tab<br>Refer to the SCR Cost Estimate tab<br>Refer to the SCR Cost Estimate tab<br>Refer to the SCR Cost Estimate tab<br>of TCI, see SCR Cost Estimate tab | 32,318,901<br>4,392,698<br>-<br>6,153,542<br><b>55,724,684</b> |
|---|---------|---|--|
| OPERATING COSTS<br>Direct Annual Operating Costs, DC  |         |   |  |
| Maintenance   |         |   |  |
| Annual Maintenance Cost =   |         | Refer to the SCR Cost Estimate tab  | 278,623  |
| Utilities, Supplies, Replacements & Waste Manag<br>Annual Electricity Cost =<br>Annual Catalyst Replacement Cost =<br>Annual Reagent Cost =<br>Total Annual Direct Operating Costs                  | gement  | Refer to the SCR Cost Estimate tab<br>Refer to the SCR Cost Estimate tab<br>Refer to the SCR Cost Estimate tab  | 191,978<br>308,662<br>536,872<br><b>1,316,135</b>              |
| Indirect Operating Costs  |         |   |  |
| Administrative Charges (AC) =<br>Capital Recovery Costs (CR)=   | 0.0837  | Refer to the SCR Cost Estimate tab<br>Refer to the SCR Cost Estimate tab  | 5,076<br>4,664,156   |
| Total Annual Indirect Operating Costs   |         | Sum indirect oper costs + capital recovery cost   | 4,669,232  |
| Total Annual Cost (Annualized Capital Cost + Operating  | g Cost) |   | 5,985,367  |

### Cleveland Cliffs - Northshore Mining Power Boiler #2 Appendix B - Four-Factor Control Cost Analysis Table B-4: NOx Control - Selective Catalytic Reduction

| Capital Recovery Factors           |                         |           |  |
|------------------------------------|-------------------------|-----------|--|
| Primary Installation               |                         |           |  |
| Interest Rate                      | 5.50%                   |           |  |
| Equipment Life                     | 20 years                |           |  |
| CRF                                | 0.0837                  |           |  |
| Dealessment Cotonet Defende th     | - COD Cost Folimete Tab |           |  |
| Replacement Catayst - Refer to the | e SCR Cost Estimate Tab |           |  |
|                                    |                         |           |  |
|                                    |                         |           |  |
|                                    |                         |           |  |
|                                    |                         |           |  |
|                                    |                         |           |  |
|                                    |                         |           |  |
|                                    |                         |           |  |
| Reagent Use                        |                         |           |  |
| Refer to the SCR Cost Estimate tab |                         |           |  |
|                                    |                         |           |  |
|                                    |                         |           |  |
|                                    |                         |           |  |
| Operating Cost Calculations        | Annual hours of operati | on: 5,774 |  |
| Refer to the SCR Cost Estimate tab | Utilization Rate:       | 78%       |  |

### Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency Air Economics Group Health and Environmental Impacts Division Office of Air Quality Planning and Standards (June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO<sub>x</sub> emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO<sub>x</sub> within a specific temperature range to produce N<sub>2</sub> and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

#### Instructions

Step 1: Please select on the Data Inputs tab and click on the Reset Form button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume (Vol<sub>catalyst</sub>) or flue gas flow rate (Q<sub>flue gas</sub>), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the SCR Design Parameters tab to see the calculated design parameters and the Cost Estimate tab to view the calculated cost data for the installation and operation of the SCR.

| Data Inputs  |  |  |  |  |  |  |
|--|--|--|--|--|--|--|
| Enter the following data for your combustion unit:   |  |  |  |  |  |  |
| Is the combustion unit a utility or industrial boiler? Industrial<br>Is the SCR for a new boiler or retrofit of an existing boiler?          | <ul> <li>▼</li> </ul>  | What type of fuel does the unit burn?  |  |  |  |  |
| Please enter a retrofit factor between 0.8 and 1.5 based on the level of diffic projects of average retrofit difficulty.                     | 1.6  | NOTE: You must document why a retrofit factor of 1.6 is appropriate for<br>e proposed project.   |  |  |  |  |
| Complete all of the highlighted data fields:   |  |  |  |  |  |  |
| What is the maximum heat input rate (QB)?  | 765 MMBtu/hour   | Provide the following information for coal-fired boilers: Type of coal burned: Sub-Bituminous  |  |  |  |  |
| What is the higher heating value (HHV) of the fuel?<br>*HHV value of 8826 Btu/Ib is a default value. See below for data source. Enter actual | 8,826 Btu/lb<br>HHV for fuel burned, if known.                                 | Enter the sulfur content (%S) = 0.41 percent by weight<br>*The sulfur content of 0.41% is a default value. See below for data source. Enter actual value, if known.  |  |  |  |  |
| What is the estimated actual annual fuel consumption?  | 390,363,222 lbs/year   |  |  |  |  |  |
| Operating Hours  | 5,774 323,950,000.00   | For units burning coal blends:<br>Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for<br>these parameters in the table below. If the actual value for any parameter is not known, you may use the<br>default values provided.  |  |  |  |  |
| Enter the net plant heat input rate (NPHR)   | 10 MMBtu/MW  | Fraction in  |  |  |  |  |
| If the NPHR is not known, use the default NPHR value:  | Fuel TypeDefault NPHRCoal10 MMBtu/MWFuel Oil11 MMBtu/MWNatural Gas8.2 MMBtu/MW | Coal TypeCoal Blend%SHHV (Btu/lb)Bituminous01.8411,841Sub-Bituminous00.418,826Lignite00.826,685  |  |  |  |  |
| Plant Elevation  | 764 Feet above sea level   | 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:       OMethod 1         • Method 2       • Method 2         • ONot applicable       • Not applicable |  |  |  |  |

### Enter the following design parameters for the proposed SCR:

| Number of days the SCR operates ( $t_{\rm SCR}$ )                                     | 241 days          | Number of SCR reactor chambers (n <sub>scr</sub> )  |                                   | 1  |
|---|-------------------|---|-----------------------------------|--|
| Number of days the boiler operates $(\boldsymbol{t}_{\text{plant}})$                  | 241 days          | Number of catalyst layers (R <sub>layer</sub> )   |                                   | 3  |
| Inlet NO <sub>x</sub> Emissions (NOx <sub>in</sub> ) to SCR                           | 0.58 lb/MMBtu     | Number of empty catalyst layers (R <sub>empty</sub> )   |                                   | 1  |
| Outlet $NO_x$ Emissions ( $NOx_{out}$ ) from SCR                                      | 0.12 lb/MMBtu     | Ammonia Slip (Slip) provided by vendor  |                                   | 2 ppm  |
| Stoichiometric Ratio Factor (SRF)   | 0.525             | Volume of the catalyst layers (Vol <sub>catalyst</sub> )<br>(Enter "UNK" if value is not known)                         | UN                                | K Cubic feet                                     |
| *The SRF value of 0.525 is a default value. User should enter actual value, if known. |                   | Flue gas flow rate (Q <sub>fluegas</sub> )<br>(Enter "UNK" if value is not known)                                       | 355,52                            | 3 acfm   |
|   |                   | 7   |                                   |  |
| Estimated operating life of the catalyst ( $H_{\text{catalyst}}$ )                    | 24,000 hours      | -   |                                   |  |
| Estimated SCR equipment life  | 20 Years*         | Gas temperature at the SCR inlet (T)  | 65                                | 0 °F   |
| * For industrial boilers, the typical equipment life is between 20 and 25 years.      |                   | Base case fuel gas volumetric flow rate factor  | Q <sub>fuel</sub> ) 51            | 6 ft <sup>3</sup> /min-MMBtu/hour                |
| Concentration of reagent as stored (C <sub>stored</sub> )                             | 50 percent*       | *The reagent concentration of 50% and density of 71 lbs/cft are default   |                                   |  |
| Density of reagent as stored ( $\rho_{\text{stored}})$                                | 71 lb/cubic feet* | values for urea reagent. User should enter actual values for reagent, if<br>different from the default values provided. |                                   |  |
| Number of days reagent is stored ( $t_{\text{storage}}$ )                             | 14 days           |   | of typical SCR reagents:          |  |
|   |                   | 50% urea<br>29.4% ac  | solution<br>leous NH <sub>3</sub> | 71 lbs/ft <sup>3</sup><br>56 lbs/ft <sup>3</sup> |
| Select the reagent used Urea  | •                 |   |                                   |  |

### Enter the cost data for the proposed SCR:

| Desired dollar-year                    | 2019  | ]   |
|--|---|---|
| CEPCI for 2019                         | 607.5 2019 CEPCI Final Value 541.7 2016 CEPCI   | CEPCI = Chemical Engineering Plant Cost Index   |
| Annual Interest Rate (i)               | 5.50 Percent*   | * 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at<br>https://www.federalreserve.gov/releases/h15/.) |
| Reagent (Cost <sub>reag</sub> )        | 1.814 \$/gallon for 50% urea  |   |
| Electricity (Cost <sub>elect</sub> )   | 0.0760 \$/kWh   |   |
| Catalyst cost (CC <sub>replace</sub> ) | \$/cubic foot (includes removal and disposal/regeneration of existing<br>248.05 catalyst and installation of new catalyst |   |
| 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) = Administrative Charges Factor (ACF) =



### 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)                   | · · · · ·     | U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector<br>Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and<br>Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5,<br>Attachment 5-3, January 2017. Available at:<br>https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-<br>3, scr. cost. development.methodology.pdf |   |
| Electricity Cost (\$/kWh)                  | 0.0676        | U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published<br>December 2017. Available at:<br>https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.   |   |
| Percent sulfur content for Coal (% weight) | 0.41          | Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy<br>Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant<br>Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.   |   |
| Higher Heating Value (HHV) (Btu/lb)        | 8,826         | 2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy<br>Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant<br>Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.  |   |
| Catalyst Cost (\$/cubic foot)              | 227           | U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector<br>Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation.<br>May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-<br>sector-modeling-platform-v6.  |   |
| Operator Labor Rate (\$/hour)              | \$60.00       | U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector<br>Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation.<br>May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-<br>sector-modeling-platform-v6.  |   |
| Interest Rate (Percent)                    | 5.5           | Default bank prime rate   |   |

### 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 $(Q_B)$ =                 | HHV x Max. Fuel Rate =   | 765              | MMBtu/hour |
| Maximum Annual fuel consumption (mfuel) =                | (QB x 1.0E6 x 8760)/HHV =  | 759,279,402      | lbs/year   |
| Actual Annual fuel consumption (Mactual) =               |  | 390,363,222      | lbs/year   |
| Heat Rate Factor (HRF) =                                 | NPHR/10 =  | 1.00             |            |
| Total System Capacity Factor (CF <sub>total</sub> ) =    | (Mactual/Mfuel) x (tscr/tplant) =  | 0.514            | fraction   |
| Total operating time for the SCR $(t_{op})$ =            | CF <sub>total</sub> x 8760 =   | 5,774            | hours      |
| NOx Removal Efficiency (EF) =                            | (NOx <sub>in</sub> - NOx <sub>out</sub> )/NOx <sub>in</sub> =  | 80.0             | percent    |
| NO <sub>x</sub> removal factor (NRF) =                   | EF/80 =  | 1.00             |            |
| Volumetric flue gas flow rate (q <sub>flue gas</sub> ) = | Q <sub>fuel</sub> x QB x (460 + T)/(460 + 700)n <sub>scr</sub> =   | 355,523          | acfm       |
| Space velocity (V <sub>space</sub> ) =                   | q <sub>flue gas</sub> /VoI <sub>catalyst</sub> =   | 106.69           | /hour      |
| Residence Time   | 1/V <sub>space</sub>   | 0.01             | hour       |
| Coal Factor (CoalF) =                                    | 1 for oil and natural gas; 1 for bituminous; 1.05 for sub-<br>bituminous; 1.07 for lignite (weighted average is used for<br>coal blends) | 1.05             |            |
| 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 =  | 1.03             |            |
| Atmospheric pressure at sea level (P) =                  | 2116 x [(59-(0.00356xh)+459.7)/518.6] <sup>5.256</sup> x (1/144)* =  | 14.3             | psia       |
| Retrofit Factor (RF)                                     | Retrofit to existing boiler  | 1.60             |            |

\* 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) <sup>Y</sup> -1), where $Y = H_{catalyts}/(t_{SCR} \times 24$ hours) rounded to the nearest integer | 0 2202           | Fraction        |
|   |   | 0.2303           | Fraction        |
| Catalyst volume (Vol <sub>catalyst</sub> ) =                    | 2.81 x $Q_8$ x EF $_{adj}$ x Slipadj x NOx $_{adj}$ x $S_{adj}$ x ( $T_{adj}/N_{scr}$ )   | 3,332.24         | Cubic feet      |
| Cross sectional area of the catalyst (A <sub>catalyst</sub> ) = | q <sub>flue gas</sub> /(16ft/sec x 60 sec/min)  | 370              | ft <sup>2</sup> |
| Height of each catalyst layer (H <sub>layer</sub> ) =           | (Vol <sub>catalyst</sub> /(R <sub>layer</sub> x A <sub>catalyst</sub> )) + 1 (rounded to next highest integer)                            | 4                | feet            |

### SCR Reactor Data:

| Parameter   | Equation   | Calculated Value | Units           |
|---|--|------------------|-----------------|
| Cross sectional area of the reactor (A <sub>SCR</sub> ) = | 1.15 x A <sub>catalyst</sub>                             | 426              | ft <sup>2</sup> |
| Reactor length and width dimensions for a square          | (A <sub>SCR</sub> ) <sup>0.5</sup>                       | 20.6             | faat            |
| reactor =   | (A <sub>SCR</sub> )                                      | 20.0             | leet            |
| Reactor height =  | $(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$ | 53               | feet            |

### Reagent Data:

Type of reagent used

Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole Density = 71 lb/ft<sup>3</sup>

| Parameter  | Equation   | Calculated Value | Units   |
|--|--|------------------|---|
| Reagent consumption rate (m <sub>reagent</sub> ) = | (NOx <sub>in</sub> x Q <sub>B</sub> x EF x SRF x MW <sub>R</sub> )/MW <sub>NOx</sub> = | 243              | lb/hour   |
| Reagent Usage Rate (m <sub>sol</sub> ) =           | m <sub>reagent</sub> /Csol =   | 487              | lb/hour   |
|  | (m <sub>sol</sub> x 7.4805)/Reagent Density  | 51               | gal/hour  |
| Estimated tank volume for reagent storage =        | (m <sub>sol</sub> x 7.4805 x t <sub>storage</sub> x 24)/Reagent Density =              | 17,300           | gallons (storage needed to store a 14 day reagent supply rounded to t |

### Capital Recovery Factor:

| Parameter                       | Equation   | Calculated Value |
|---------------------------------|--|------------------|
| Capital Recovery Factor (CRF) = | $i (1+i)^n / (1+i)^n - 1 =$                          | 0.0837           |
|                                 | Where n = Equipment Life and i= Interest Rate        |                  |
|                                 |  |                  |
| Other parameters                | Equation   | Calculated Value |
| Electricity Usage:              |  |                  |
|                                 |  |                  |
| Electricity Consumption (P) =   | A x 1,000 x 0.0056 x (CoalF x HRF) <sup>0.43</sup> = | 437.48           |

For Coal-Fired Boilers:

### **Cost Estimate**

### Total Capital Investment (TCI)

### TCI for Coal-Fired Boilers

### TCI = $1.3 \times (SCR_{cost} + RPC + APHC + BPC)$

| Capital costs for the SCR (SCR <sub>cost</sub> ) = | \$32,318,901 | in 2019 dollars |
|--|--------------|-----------------|
| Reagent Preparation Cost (RPC) =                   | \$4,392,698  | in 2019 dollars |
| Air Pre-Heater Costs (APHC)* =                     | \$0          | in 2019 dollars |
| Balance of Plant Costs (BPC) =                     | \$6,153,542  | in 2019 dollars |
| Total Capital Investment (TCI) =                   | \$55,724,684 | in 2019 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 <sub>cost</sub> )   |                                |
|--|--------------------------------|
| For Coal-Fired Utility Boilers >25 MW:   |                                |
| $SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF$   | 1 <sup>0.92</sup> x FLEVE x RE |
| For Coal-Fired Industrial Boilers >250 MMBtu/hour:   |                                |
| $SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_{R} \times CoalF)^{0}$   | <sup>.92</sup> x FLFVF x RF    |
|  |                                |
| SCR Capital Costs (SCR <sub>cost</sub> ) =   | \$32,318,901 in 2019 dollars   |
|  | ¢02,010,001 m 2010 donard      |
| Reagent Preparation Costs (RPC   |                                |
| For Coal-Fired Utility Boilers >25 MW:   | ,                              |
| RPC = 564,000 x (NOx <sub>in</sub> x B <sub>MW</sub> x NPHR x E  | F) <sup>0.25</sup> x RF        |
| For Coal-Fired Industrial Boilers >250 MMBtu/hour:   |                                |
| RPC = 564,000 x (NOx <sub>in</sub> x Q <sub>8</sub> x EF) <sup>0.25</sup>  | x RF                           |
|  |                                |
| Reagent Preparation Costs (RPC) =  | \$4,392,698 in 2019 dollars    |
|  |                                |
| Air Pre-Heater Costs (APHC)*   |                                |
| For Coal-Fired Utility Boilers >25MW:  |                                |
| APHC = 69,000 x (B <sub>MW</sub> x HRF x CoalF) <sup>0.78</sup> x  | AHF x RF                       |
| For Coal-Fired Industrial Boilers >250 MMBtu/hour:   |                                |
| APHC = 69,000 x $(0.1 \times Q_8 \times CoalF)^{0.78} \times M_{\odot}$  | AHF x RF                       |
|  |                                |
| Air Pre-Heater Costs (APH <sub>cost</sub> ) =  | \$0 in 2019 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.      |
|  |                                |
| Delever of Direct (DDC)  |                                |
| For Coal-Fired Utility Boilers >25MW: Balance of Plant Costs (BPC)   |                                |
| For Coal-Fired Utility Bollers >25000 :<br>BPC = 529,000 x $(B_{MW}$ x HRFx CoalF) <sup>0.42</sup> x E                             |                                |
| For Coal-Fired Industrial Boilers >250 MMBtu/hour:   |                                |
| For Coal-Fired industrial Bollers >250 MiNBtu/nour:<br>BPC = $529,000 \times (0.1 \times Q_n \times CoalF)^{0.42}$ ELf             |                                |
| $BPC = 529,000 \times (0.1 \times Q_B \times COBF)^2$ ELL  | EVF X KF                       |
| Balance of Plant Costs (BOP <sub>cost</sub> ) =  | ČC 450 540 to 2040 dollars     |
| balance of Fiant Costs (BOP <sub>cost</sub> ) -  | \$6,153,542 in 2019 dollars    |

### Annual Costs

### Total Annual Cost (TAC)

### TAC = Direct Annual Costs + Indirect Annual Costs

| Direct Annual Costs (DAC) =           | \$1,316,135 in 2019 dollars |
|---------------------------------------|-----------------------------|
| Indirect Annual Costs (IDAC) =        | \$4,669,232 in 2019 dollars |
| Total annual costs (TAC) = DAC + IDAC | \$5,985,367 in 2019 dollars |
|                                       |                             |

### Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

| Annual Reagent Cost =                           | m <sub>sol</sub> x Cost <sub>reag</sub> x t <sub>op</sub> =   | \$536,872 in 2019 dollars        |
|---|---|----------------------------------|
| Annual Electricity Cost =                       | P x Cost <sub>elect</sub> x t <sub>op</sub> =   | \$191,978 in 2019 dollars        |
| Annual Catalyst Replacement Cost =              |   | \$308,662 in 2019 dollars        |
| For coal-fired boilers, the following methods i | may be used to calcuate the catalyst replacement cost.  |                                  |
| Method 1 (for all fuel types):                  | n <sub>scr</sub> x Vol <sub>cat</sub> x (CC <sub>replace</sub> /R <sub>layer</sub> ) x FWF                      | * Calculation Method 2 selected. |
| Method 2 (for coal-fired industrial boilers):   | (Q <sub>B</sub> /NPHR) x 0.4 x (CoalF) <sup>2.9</sup> x (NRF) <sup>0.71</sup> x (CC <sub>replace</sub> ) x 35.3 |                                  |
| Direct Annual Cost =                            |   | \$1,316,135 in 2019 dollars      |

### Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

| Administrative Charges (AC) = | 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) = | \$5,076 in 2019 dollars     |
|-------------------------------|--|-----------------------------|
| Capital Recovery Costs (CR)=  | CRF x TCI =  | \$4,664,156 in 2019 dollars |
| Indirect Annual Cost (IDAC) = | AC + CR =  | \$4,669,232 in 2019 dollars |

### **Cost Effectiveness**

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

| Total Annual Cost (TAC) = | \$5,985,367 per year in 2019 dollars       |
|---------------------------|--|
| NOx Removed =             | N/A tons/year                              |
| Cost Effectiveness =      | N/A per ton of NOx removed in 2019 dollars |

Note: Cost Effectiveness is not determined because emissions in 2028 are projected to be zero.

#### Cleveland Cliffs - Northshore Mining Power Boiler #2 Appendix B - Four-Factor Control Cost Analysis Table B-5: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

| Operating Unit:        | Power Boiler 2 |          |                          |         |               |
|------------------------|----------------|----------|--------------------------|---------|---------------|
| Emission Unit Number   |                |          | Stack/Vent Number        |         |               |
| Design Capacity        | 765            | MMBtu/hr | Standardized Flow Rate   | 157,508 | scfm @ 32º F  |
| Utilization Rate       | 78%            |          | Exhaust Temperature      | 265     | Deg F         |
| Annual Operating Hours | 5,774          | hr/yr    | Exhaust Moisture Content | 11.0%   |               |
| Annual Interest Rate   | 5.50%          |          | Actual Flow Rate         | 232,100 | acfm          |
| Control Equipment Life | 20             | yrs      | Standardized Flow Rate   | 163,800 | scfm @ 68º F  |
| Plant Elevation        | 764            | ft       | Dry Std Flow Rate        | 145,700 | dscfm @ 68º F |

#### CONTROL EQUIPMENT COSTS

| Capital Costs                                   |               |                      |                      |                       |        |            |
|---|---------------|----------------------|----------------------|-----------------------|--------|------------|
| Direct Capital Costs                            |               |                      |                      |                       |        |            |
| Purchased Equipment (A)                         |               |                      |                      |                       |        | 8,933,488  |
| Purchased Equipment Total (B)                   | 22%           | of control device co | ost (A)              |                       |        | 10,887,688 |
| Installation - Standard Costs                   | 74%           | of purchased equip   | cost (B)             |                       |        | 8,056,889  |
| Installation - Site Specific Costs              |               |                      |                      |                       |        | N/A        |
| Installation Total                              |               |                      |                      |                       |        | 8,056,889  |
| Total Direct Capital Cost, DC                   |               |                      |                      |                       |        | 18,944,577 |
| Total Indirect Capital Costs, IC                | 52%           | of purchased equip   | o cost (B)           |                       |        | 5,661,598  |
| Total Capital Investment (TCI) = DC + IC        |               |                      |                      |                       |        | 23,585,999 |
| Adjusted TCI for Replacement Parts              |               |                      |                      |                       |        | 23,585,999 |
| Total Capital Investment (TCI) with Retrofit Fa | actor         |                      |                      |                       |        | 37,737,598 |
| Operating Costs                                 |               |                      |                      |                       |        |            |
| Total Annual Direct Operating Costs             |               | Labor, supervision   | , materials, replace | ment parts, utilities | , etc. | 1,925,055  |
| Total Annual Indirect Operating Costs           |               | Sum indirect oper    | costs + capital reco | overy cost            |        | 5,017,989  |
| Total Annual Cost (Annualized Capital Cost +    | Operating Cos | st)                  |                      |                       |        | 6,943,044  |

#### Notes & Assumptions

- 1 Baghouse cost estimate from 2008 vendor data for 165,000 acfm baghouse, (Northshore Mining March 2009 submittal to MPCA)
- 2 Purchased equipment costs include anciliary equipment
- 3 Costs scaled up to design airflow using the 6/10 power law
- 4 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
- 5 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
- 6 Cost Effectiveness in \$/ton removed is not determined because emissions in 2028 are projected to be zero.

# Cleveland Cliffs - Northshore Mining Power Boiler #2 Appendix B - Four-Factor Control Cost Analysis Table B-5: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

### CAPITAL COSTS

| Direct Capital Costs   |              |  |                               |
|--|--------------|--|-------------------------------|
| Purchased Equipment (A) <sup>(1)</sup>   |              |  | 8,933,488                     |
| Purchased Equipment Costs (A) - Injection Syste<br>Instrumentation                             |              | Included in vendor estimate                                | 893.349                       |
| State Sales Taxes  |              | of control device cost (A)                                 | 614,177                       |
| Freight  |              | of control device cost (A)                                 | 446,674                       |
| Purchased Equipment Total (B)  | 22%          |  | 10,887,688                    |
| Installation   |              |  |                               |
| Foundations & supports   | 4%           | of purchased equip cost (B)                                | 435,508                       |
| Handling & erection  |              | of purchased equip cost (B)                                | 5,443,844                     |
| Electrical   | 8%           | of purchased equip cost (B)                                | 871,015                       |
| Piping   | 1%           | of purchased equip cost (B)                                | 108,877                       |
| Insulation   | 7%           | of purchased equip cost (B)                                | 762,138                       |
| Painting   | 4%           | Included in vendor estimate                                | 435,508                       |
| Installation Subtotal Standard Expenses  | 74%          |  | 8,056,889                     |
| Other Specific Costs (see summary)   |              |  |                               |
| Site Preparation, as required  | N/A          | Site Specific  |                               |
| Buildings, as required   | N/A          | Site Specific  |                               |
| Lost Production for Tie-In   | N/A          | Site Specific  |                               |
| Total Site Specific Costs  |              |  | N/A                           |
| Installation Total<br>Total Direct Capital Cost, DC  |              |  | 8,056,889                     |
| , eta, Direct Gapitar Gost, DO   |              |  | 18,944,577                    |
| Indirect Capital Costs   | 400/         | of purchased equip cost (P)                                | 1 000 700                     |
| Engineering, supervision   |              | of purchased equip cost (B)<br>of purchased equip cost (B) | 1,088,769                     |
| Construction & field expenses  |              |  | 2,177,538                     |
| Contractor fees  |              | of purchased equip cost (B)                                | 1,088,769                     |
| Start-up   |              | of purchased equip cost (B)                                | 108,877                       |
| Performance test   |              | of purchased equip cost (B)<br>of purchased equip cost (B) | 108,877                       |
| Model Studies<br>Contingencies   |              | of purchased equip cost (B)                                | -<br>1,088,769                |
| Total Indirect Capital Costs, IC   |              | of purchased equip cost (B)                                | 5,661,598                     |
| Total Capital Investment (TCI) = DC + IC   |              |  | 24,606,175                    |
| Adjusted TCI for Replacement Parts (Catalyst, Filter B   | ags, etc) fo | r Capital Recovery Cost                                    | 23,585,999                    |
| Total Capital Investment (TCI) with Retrofit Factor  | 60%          |  | 37,737,598                    |
| OPERATING COSTS  |              |  |                               |
| Direct Annual Operating Costs, DC  |              |  |                               |
| Operating Labor  |              |  |                               |
| Operator   | 60.00        | \$/Hr  | 86,610                        |
| Supervisor   | 0.15         | of Op Labor  | 12,992                        |
| Maintenance  |              |  |                               |
| Maintenance Labor  | 60.00        | \$/Hr  | 43,305                        |
| Maintenance Materials  | 100          | % of Maintenance Labor                                     | 43,305                        |
| Utilities, Supplies, Replacements & Waste Mana   | igement      |  |                               |
| Electricity  | 0.08         | \$/kwh, 252.1 kW-hr, 5774 hr/yr, 78% utilization           | 110,610                       |
| N/A<br>Compressed Air  | 0.48         | \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization       | -<br>60,382                   |
| N/A  |              | •• •• •  | -                             |
| Solid Waste Disposal   |              | \$/ton, 0.6 ton/hr, 5774 hr/yr, 78% utilization            | 115,574                       |
| Trona  |              | \$/ton, 1,501.1 lb/hr, 5774 hr/yr, 78% utilization         | 963,375                       |
| Filter Bags  | 249.27       | \$/bag, 3,412 bags, 5774 hr/yr, 78% utilization            | 238,901                       |
| Lost Revenue - Fly Ash<br>N/A  |              |  | 250,000                       |
| N/A  |              |  | -                             |
| N/A  |              |  |                               |
| Total Annual Direct Operating Costs  |              |  | 1,925,055                     |
| Indirect Operating Costs   |              |  |                               |
| Overhead   | 60%          | of total labor and material costs                          | 111,727                       |
| Administration (2% total capital costs)  |              | of total capital costs (TCI)                               | 754,752                       |
| Property tax (1% total capital costs)  |              | of total capital costs (TCI)                               | 377,376                       |
| Insurance (1% total capital costs)   |              | of total capital costs (TCI)                               | 377,376                       |
| Capital Recovery   |              | for a 20-year equipment life and a 5.5% interest rate      |                               |
|  | 0.0037       | ior a zo-yoar equipment ne and a 3.3% interest idle        | 3,157,857                     |
| Total Annual Indirect Operating Costs  |              | Sum indirect oper costs + canital recovery costs           | 5 017 090                     |
| Total Annual Indirect Operating Costs  |              | Sum indirect oper costs + capital recovery costs           | 5,017,989                     |
| Total Annual Indirect Operating Costs<br>Total Annual Cost (Annualized Capital Cost + Operatir | ng Cost)     | Sum indirect oper costs + capital recovery costs           | <u>5,017,989</u><br>6,943,044 |

# Cleveland Cliffs - Northshore Mining Power Boiler #2 Appendix B - Four-Factor Control Cost Analysis Table B-5: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

| Capital Recovery Factors      |         |            |               | -                    |                        |           |                              |  |
|-------------------------------|---------|------------|---------------|----------------------|------------------------|-----------|------------------------------|--|
| Primary Installation          |         |            |               |                      |                        |           |                              |  |
| Interest Rate                 |         | 5.50%      |               |                      |                        |           |                              |  |
| Equipment Life                |         | 20         | years         |                      |                        |           |                              |  |
| CRF                           |         | 0.0837     |               |                      |                        |           |                              |  |
| Replacement Parts & Equipment | t: Fi   | ilter Bags |               |                      |                        |           |                              |  |
| Equipment Life                |         | 5          | years         |                      |                        |           |                              |  |
| CRF                           |         | 0.2342     |               |                      |                        |           |                              |  |
| Rep part cost per unit        |         | 249.27     | \$/bag        |                      |                        |           |                              |  |
| Amount Required               |         | 3412       | # of Bags for | new baghouse         |                        |           |                              |  |
| Total Rep Parts Cost          |         | 951,939    | Cost adjuste  | d for freight, sales | s tax, and bag dispose | al        |                              |  |
| Installation Labor            |         | 68,237     | 20 min per b  | ag                   |                        |           |                              |  |
| Total Installed Cost          |         | 1,020,177  |               |                      |                        |           |                              |  |
| Annualized Cost               |         | 238,901    |               |                      |                        |           |                              |  |
|                               |         |            |               |                      |                        |           |                              |  |
| Electrical Use                |         |            |               |                      |                        |           |                              |  |
| Flo                           | ow acfm |            | D P in H2O    |                      |                        | kWhr/yr   |                              |  |
| Blower 2                      | 32,100  |            | 6.00          |                      |                        | 1,455,398 | Electricity for new baghouse |  |
|                               |         |            |               |                      |                        |           |                              |  |
|                               |         |            |               |                      |                        |           |                              |  |
|                               |         |            |               |                      |                        |           |                              |  |
|                               |         |            |               |                      |                        |           |                              |  |
|                               |         |            |               |                      |                        |           |                              |  |
| Total                         |         |            |               |                      |                        | 1,455,398 |                              |  |
| TUTAI                         |         |            |               |                      |                        | 1,433,396 |                              |  |

#### Reagent Use & Other Operating Costs

Trona use - 1.5 NSR Solid Waste Disposal

 270.18
 lb/hr SO2
 1501.10
 lb/hr Trona

 3,481
 ton/yr DSI unreacted sorbent and reaction byproducts

| <b>Operating Cost Calculations</b> |     |       |
|------------------------------------|-----|-------|
| Utilization Rate                   | 78% | Annua |
|                                    |     |       |

| Utilization Rate             | 78%           | Annual Ope     | rating Hours | 5,774         |           |               |  |
|------------------------------|---------------|----------------|--------------|---------------|-----------|---------------|--|
|                              | Unit          | Unit of        | Use          | Unit of       | Annual    | Annual        | Comments   |
| tem                          | Cost \$       | Measure        | Rate         | Measure       | Use*      | Cost          |  |
| Operating Labor              |               |                |              |               |           |               |  |
| Op Labor                     | 60.00         | \$/Hr          | 2.0 ł        | nr/8 hr shift | 1,444     | \$<br>86,610  | \$/Hr, 2.0 hr/8 hr shift, 1,444 hr/yr                |
| Supervisor                   | 15%           | of Op Labor    |              |               | NA        | \$<br>12,992  | % of Operator Costs                                  |
| Maintenance                  |               |                |              |               |           |               |  |
| Vaint Labor                  | 60.00         | \$/Hr          | 1.0 ł        | nr/8 hr shift | 722       | \$<br>43,305  | \$/Hr, 1.0 hr/8 hr shift, 722 hr/yr                  |
| Vaint Mtls                   | 100%          | of Maintenance | Labor        |               | NA        | \$<br>43,305  | 100% of Maintenance Labor                            |
| Utilities, Supplies, Replace | nents & Waste | Management     |              |               |           |               |  |
| Electricity                  | 0.076         | \$/kwh         | 252.1 k      | W-hr          | 1,455,398 | \$<br>110,610 | \$/kwh, 252.1 kW-hr, 5774 hr/yr, 78% utilization     |
| Water                        |               |                | N/A g        | jpm           |           |               |  |
| Compressed Air               | 0.481         | \$/kscf        | 2.0 s        | cfm/kacfm     | 125,438   | \$<br>60,382  | \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization |
| Cooling Water                |               |                | N/A g        | jpm           |           |               |  |
| Solid Waste Disposal         | 42.56         | \$/ton         | 0.6 t        | on/hr         | 2,716     | \$<br>115,574 | \$/ton, 0.6 ton/hr, 5774 hr/yr, 78% utilization      |
| Trona                        | 285.00        | \$/ton         | 1,501.1 I    | b/hr          | 3,380     | \$<br>963,375 | \$/ton, 1,501.1 lb/hr, 5774 hr/yr, 78% utilization   |
| Filter Bags                  | 249.27        | \$/bag         | 3,412 k      | bags          | N/A       | \$<br>238,901 | \$/bag, 3,412 bags, 5774 hr/yr, 78% utilization      |

#### Cleveland Cliffs - Northshore Mining Power Boiler #2 Appendix B - Four-Factor Control Cost Analysis Table B-6: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

**Operating Unit:** Power Boiler 2

| Emission Unit Number   | EQUI 15 / EU 00 | )2       | Stack/Vent Number      | SV 002  |               |
|------------------------|-----------------|----------|------------------------|---------|---------------|
| Design Capacity        | 765             | MMBtu/hr | Standardized Flow Rate | 157,508 | scfm @ 32º F  |
| Utilization Rate       | 78%             |          | Temperature            | 265     | Deg F         |
| Annual Operating Hours | 5,774           | Hours    | Moisture Content       | 11.0%   |               |
| Annual Interest Rate   | 5.5%            |          | Actual Flow Rate       | 232,100 | acfm          |
| Equipment Life         | 20              | yrs      | Standardized Flow Rate | 163,800 | scfm @ 68º F  |
|                        |                 |          | Drv Std Flow Rate      | 145,700 | dscfm @ 68º F |

#### CONTROL EQUIPMENT COSTS

|  |     |                   |                    |                 |                   |    | <br>       |
|--|-----|-------------------|--------------------|-----------------|-------------------|----|------------|
| Capital Costs                                |     |                   |                    |                 |                   |    |            |
| Direct Capital Costs                         |     |                   |                    |                 |                   |    |            |
| Purchased Equipment (A)                      |     |                   |                    |                 |                   |    | 22,495,853 |
| Purchased Equipment Total (B)                | 22% | of control device | e cost (A)         |                 |                   |    | 27,416,821 |
|  |     |                   |                    |                 |                   |    |            |
| Installation - Standard Costs                | 74% | of purchased ed   | quip cost (B)      |                 |                   |    | 20,288,447 |
| Installation - Site Specific Costs           |     |                   |                    |                 |                   |    | NA         |
| Installation Total                           |     |                   |                    |                 |                   |    | 20,288,447 |
| Total Direct Capital Cost, DC                |     |                   |                    |                 |                   |    | 47,705,268 |
| Total Indirect Capital Costs, IC             | 52% | of purchased ed   | quip cost (B)      |                 |                   |    | 14,256,747 |
| Total Capital Investment (TCI) = DC + IC     |     |                   |                    |                 |                   |    | 61,962,015 |
| Adjusted TCI for Replacment Parts            |     |                   |                    |                 |                   |    | 60,941,838 |
| TCI with Retrofit Factor                     |     |                   |                    |                 |                   |    | 97,506,941 |
| Operating Costs                              |     |                   |                    |                 |                   |    |            |
| Total Annual Direct Operating Costs          |     | Labor, supervis   | ion, materials, re | placement part  | s, utilities, etc | 1. | 1,162,688  |
| Total Annual Indirect Operating Costs        |     | Sum indirect op   | er costs + capita  | I recovery cost |                   |    | 12,410,221 |
| Total Annual Cost (Annualized Capital Cost + |     |                   |                    |                 |                   |    | 13,572,909 |

#### Notes & Assumptions

1 Capital cost estimate based on flow rate of 300,000 scfm from Northshore Mining Powerhouse #2 March 2009 submittal including anciliary equipment

Costs scaled up to design airflow using the 6/10 power law
 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

5 Cost Effectiveness in \$/ton removed is not determined because emissions in 2028 are projected to be zero.

### Cleveland Cliffs - Northshore Mining Power Boiler #2 Appendix B - Four-Factor Control Cost Analysis

### Table B-6: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

| Direct Capital Costs   |   |   |
|--|---|---|
| Purchased Equipment (A) (1)  |   | 22,495,8  |
| Purchased Equipment Costs (A) - Absorber +<br>Instrumentation  | packing + auxiliary equipment, EC<br>10% of control device cost (A)   | 2 240 5   |
| State Sales Taxes  | 6.9% of control device cost (A)   | 2,249,5<br>1,546,5  |
| Freight  | 5% of control device cost (A)   | 1,124,7   |
| Purchased Equipment Total (B)  | 22%   | 27,416,8  |
|  |   |   |
| Installation<br>Foundations & supports   | 4% of purchased equip cost (B)  | 1,096,6   |
| Handling & erection  | 50% of purchased equip cost (B)   | 13.708.4  |
| Electrical   | 8% of purchased equip cost (B)  | 2,193,3   |
| Piping   | 1% of purchased equip cost (B)  | 274,1   |
| Insulation   | 7% of purchased equip cost (B)  | 1,919,1   |
| Painting   | 4% of purchased equip cost (B)  | 1,096,6   |
| Installation Subtotal Standard Expenses  | 74%   | 20,288,4  |
| Other Specific Costs (see summary)   |   |   |
| Site Preparation, as required  | N/A Site Specific   | -   |
| Buildings, as required   | N/A Site Specific   | -   |
| Site Specific - Other  | N/A Site Specific   | -   |
|  |   |   |
| Total Site Specific Costs<br>Installation Total  |   | 20,288,4  |
| Total Direct Capital Cost, DC  |   | 47,705,2  |
| Indirect Capital Costs   |   | ,   |
| Engineering, supervision   | 10% of purchased equip cost (B)   | 2,741,6   |
| Construction & field expenses  | 20% of purchased equip cost (B)   | 5,483,3   |
| Contractor tees  | 10% of purchased equip cost (B)   | 2,741,6   |
| Start-up   | 1% of purchased equip cost (B)  | 274,1   |
| Performance test   | 1% of purchased equip cost (B)  | 274,1   |
| Model Studies  | N/A of purchased equip cost (B)   |   |
| Contingencies  | 10% of purchased equip cost (B)<br>52% of purchased equip cost (B)  | 2,741,6<br>14,256,7   |
|  |   | 14.230.7  |
| Total Indirect Capital Costs, IC<br>al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte  |   | 61,962,0<br>60,941,8  |
| al Capital Investment (TCI) = DC + IC  |   | 61,962,0  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS   | r Bags, etc) for Capital Recovery Cost  | 61,962,0<br>60,941,8  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC  | r Bags, etc) for Capital Recovery Cost  | 61,962,0<br>60,941,8  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor   | r Bags, etc) for Capital Recovery Cost<br>60%   | 61,962,0<br>60,941,8<br>97,506,9  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator   | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr   | 61,962,0<br>60,941,8<br>97,506,9<br>86,6  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor   | r Bags, etc) for Capital Recovery Cost<br>60%   | 61,962,0<br>60,941,8<br>97,506,9  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator   | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr   | 61,962,0<br>60,941,8<br>97,506,9<br>86,6  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Supervisor<br>Maintenance   | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs  | 61,962,0<br>60,941,8<br>97,506,9<br>86,6<br>12,9<br>43,3  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor   | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs   | 61,962,0<br>60,941,8<br>97,506,9<br>86,6<br>12,9  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Ma<br>Electricity  | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization   | 61,962,0<br>60,941,8<br>97,506,9<br>866,6<br>12,9<br>43,3<br>43,3<br>184,3  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Ma<br>Electricity<br>Compressed Air   | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement  | 61,962,0<br>60,941,8<br>97,506,9<br>86,6<br>12,9<br>43,3<br>43,3<br>184,3   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Ma<br>Electricity<br>Compressed Air<br>N/A  | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$//Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$//Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization  | 61,962,0<br>60,941,8<br>97,506,9<br>86,6<br>12,5<br>43,3<br>43,3<br>184,3<br>60,3   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>With Retrofit Factor  | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$//Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% of Operator Costs<br>60.00 \$//Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization   | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>86,6<br>12,9<br>43,3<br>43,3<br>184,3<br>60,3<br>66,4   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Materials<br>Materials<br>Utilities, Supplies, Replacements & Waste Materials<br>Utilities, Supplies, Replacements & Waster Materials<br>Utilities, Supplies, Replacements & Waster Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Materials<br>Mater | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization<br>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization  | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>86,6<br>12,5<br>43,3<br>43,3<br>43,3<br>43,3<br>43,3<br>60,3<br>66,4<br>176,4   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Operator<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Ma<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags  | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$//Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% of Operator Costs<br>60.00 \$//Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization   | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>86,6<br>12,9<br>43,3<br>43,3<br>184,3<br>60,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilites, Supplies, Replacements & Waste Maintenance Maintenance Materials<br>Utilites, Supplies, Replacements & Waste Maintenance Materials<br>Utilites, Supplies, Replacements & Waste Maintenance Ma   | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization<br>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization  | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>86,6<br>12,9<br>43,3<br>43,3<br>184,3<br>60,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Atterials<br>Utilities, Supplies, Replacements & Waste Maintenance Atterials<br>Difference Atterials<br>N/A  | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization<br>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization  | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>86,6<br>12,9<br>43,3<br>43,3<br>184,3<br>60,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Ma<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A   | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization<br>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization  | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>86,6<br>12,9<br>43,3<br>43,3<br>184,3<br>60,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Atterials<br>Utilities, Supplies, Replacements & Waste Maintenance Atterials<br>Difference Atterials<br>N/A  | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization<br>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization  | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>86,6<br>12,9<br>43,3<br>43,3<br>184,3<br>60,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Operator<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A   | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization<br>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization  | 61,962,0<br>60,941,8<br>97,506,9<br>86,6<br>12,9<br>43,3<br>43,3  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilites, Supplies, Replacements & Waste Maintenance Maintenance Maintenance Materials<br>Utilites, Supplies, Replacements & Waste Maintenance Materials<br>Utilites, Supplies, Replacements & Waste Maintenance Ma  | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization<br>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization  | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>86,6<br>12,9<br>43,3<br>43,3<br>184,3<br>60,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Alternation<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A  | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization<br>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization  | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>86,6<br>12,9<br>43,3<br>43,3<br>184,3<br>60,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Operator<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A  | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization<br>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization  | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>86,6<br>12,9<br>43,3<br>43,3<br>184,3<br>60,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Operator<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A   | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization<br>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization  | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>43,3<br>43,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9<br>250,0  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Alabor<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A  | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization<br>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization  | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>43,3<br>43,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9<br>250,0  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M:<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>Total Annual Direct Operating Costs  | r Bags, etc) for Capital Recovery Cost<br>60%<br>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br>15% 15% of Operator Costs<br>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br>100% of maintenance labor costs<br>anagement<br>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization<br>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization<br>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization<br>249.27 \$/bag, 3,412 bags, 5774 hr/yr, 78% utilization  | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>43,3<br>43,3<br>43,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9<br>250,0<br>1,162,6   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A  | <ul> <li>r Bags, etc) for Capital Recovery Cost</li> <li>60%</li> <li>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr</li> <li>15% of Operator Costs</li> <li>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr</li> <li>100% of maintenance labor costs</li> <li>anagement</li> <li>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization</li> <li>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization</li> <li>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization</li> <li>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization</li> <li>249.27 \$/bag, 3,412 bags, 5774 hr/yr, 78% utilization</li> </ul>  | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>43,3<br>43,3<br>184,3<br>60,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9<br>250,0<br>1,162,6<br>1,162,6                                       |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Auterials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Auterials<br>Utilities, Supplies, Replacements & Waste Maintenance Auterials<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>Total Annual Direct Operating Costs<br>Overhead<br>Administration (2% total capital costs)   | <ul> <li>r Bags, etc) for Capital Recovery Cost</li> <li>60%</li> <li>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr</li> <li>15% of Operator Costs</li> <li>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr</li> <li>100% of maintenance labor costs</li> <li>anagement</li> <li>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization</li> <li>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization</li> <li>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization</li> <li>167.17 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization</li> <li>167.17 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization</li> <li>249.27 \$/bag, 3,412 bags, 5774 hr/yr, 78% utilization</li> <li>249.27 \$/bag, 3,412 bags, 5774 hr/yr, 78% utilization</li> <li>167.17 \$/total capital costs (TCI)</li> <li>1% of total capital costs (TCI)</li> <li>1% of total capital costs (TCI)</li> <li>1% of total capital costs (TCI)</li> </ul> | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>43,3<br>43,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9<br>250,0<br>1,162,6<br>1,162,6  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance (Tapital Costs)<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>Total Annual Direct Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)<br>Insurance (1% total capital costs)<br>Insurance (1% total capital costs)<br>Capital Recovery   | <ul> <li>r Bags, etc) for Capital Recovery Cost</li> <li>60%</li> <li>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr<br/>15% of Operator Costs</li> <li>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr<br/>100% of maintenance labor costs</li> <li>anagement</li> <li>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization</li> <li>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization</li> <li>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization</li> <li>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization</li> <li>167.17 \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization</li> <li>249.27 \$/bag, 3,412 bags, 5774 hr/yr, 78% utilization</li> </ul>   | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>43,3<br>43,3<br>184,3<br>60,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9<br>250,0<br>1,162,6<br>111,7<br>1,950,1<br>975,0<br>975,0<br>8,398,2 |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filte<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Maintenance<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>Lost Revenue - Fly Ash<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A  | <ul> <li>r Bags, etc) for Capital Recovery Cost</li> <li>60%</li> <li>60.00 \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr</li> <li>15% of Operator Costs</li> <li>60.00 \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr</li> <li>100% of maintenance labor costs</li> <li>anagement</li> <li>0.08 \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization</li> <li>0.48 \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization</li> <li>42.56 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization</li> <li>167.17 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization</li> <li>167.17 \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization</li> <li>249.27 \$/bag, 3,412 bags, 5774 hr/yr, 78% utilization</li> <li>249.27 \$/bag, 3,412 bags, 5774 hr/yr, 78% utilization</li> <li>167.17 \$/total capital costs (TCI)</li> <li>1% of total capital costs (TCI)</li> <li>1% of total capital costs (TCI)</li> <li>1% of total capital costs (TCI)</li> </ul> | 61,962,0<br>60,941,8<br>97,506,9<br>97,506,9<br>97,506,9<br>43,3<br>43,3<br>43,3<br>184,3<br>60,3<br>66,4<br>176,4<br>238,9<br>250,0<br>1,162,6<br>1111,7<br>1,950,1<br>975,0<br>975,0                    |

### Cleveland Cliffs - Northshore Mining Power Boiler #2 Appendix B - Four-Factor Control Cost Analysis Table B-6: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

| Capital Recovery Factors        |           |             |               | _                   |             |                 |   |
|---------------------------------|-----------|-------------|---------------|---------------------|-------------|-----------------|---|
| Primary Installation            |           |             |               | 1                   |             |                 |   |
| Interest Rate                   |           | 5.50%       |               |                     |             |                 |   |
| Equipment Life                  |           | 20          | years         |                     |             |                 |   |
| CRF                             |           | 0.0837      |               | ļ                   |             |                 |   |
| Replacement Parts & Equipment:  |           | Filter Bags |               |                     |             |                 |   |
| Equipment Life                  |           | 5           | years         |                     |             |                 |   |
| CRF                             |           | 0.2342      |               |                     |             |                 |   |
| Rep part cost per unit          |           | 249.27      | \$/bag        |                     |             |                 |   |
| Amount Required                 |           |             |               | r new baghouse      |             |                 |   |
| Total Rep Parts Cost            |           |             |               | ed for freight & sa |             |                 |   |
| Installation Labor              |           | 68,237      | 10 min per b  | oag, Labor + Ove    | erhead (68% | 6 = \$29.65/hr) | EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4 |
| Total Installed Cost            |           |             | Zero out if I | no replacement      | parts nee   | ded             | lists replacement times from 5 - 20 min per bag.      |
| Annualized Cost                 |           | 238,901     |               |                     |             |                 |   |
|                                 |           |             |               |                     |             |                 |   |
| Electrical Use                  |           |             |               |                     |             |                 |   |
|                                 | Flow acfm |             | D P in H2O    | Efficiency          | Hp          | kW              |   |
| Blower, Baghouse                | 232,100   |             | 10.00         |                     |             | 2,425,663       | Electricity demand for new baghouse                   |
|                                 |           |             |               |                     |             |                 |   |
|                                 |           |             |               |                     |             |                 |   |
|                                 |           |             |               |                     |             |                 |   |
|                                 |           |             |               |                     |             |                 |   |
|                                 |           |             |               |                     |             |                 |   |
| Total                           |           |             |               |                     |             | 2,425,663       |   |
| Total                           |           |             |               |                     |             | 2,425,663       |   |
| Boagonts and Other Operating Co | ete       |             |               |                     |             |                 |   |

| Lime Use Rate        | 1.30 lb-mole CaO/lb-mole SO2 365.58 lb/hr Lime        |
|----------------------|---|
| Solid Waste Disposal | ,560 ton/yr unreacted sorbent and reaction byproducts |

#### **Operating Cost Calculations**

| Utilization Rate                  | 78%         | Annual Oper    | rating Hours | 5,774         |           |               |  |
|-----------------------------------|-------------|----------------|--------------|---------------|-----------|---------------|--|
|                                   | Unit        | Unit of        | Use          | Unit of       | Annual    | Annual        | Comments   |
| Item                              | Cost \$     | Measure        | Rate         | Measure       | Use*      | Cost          |  |
| Operating Labor                   |             |                |              |               |           |               |  |
| Op Labor                          | 60.00       | \$/Hr          | 2.0          | hr/8 hr shift | 1,444     | \$<br>86,610  | \$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr                 |
| Supervisor                        | 15%         | of Op.         |              |               | NA        | \$<br>12,992  | 15% of Operator Costs                                |
| Maintenance                       |             |                |              |               |           |               |  |
| Maint Labor                       | 60.00       | \$/Hr          | 1.0          | hr/8 hr shift | 722       | \$<br>43,305  | \$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr                 |
| Maint Mtls                        | 100         | % of Maintenar | nce Labor    |               | NA        | \$<br>43,305  | 100% of Maintenance Labor                            |
| Utilities, Supplies, Replacements | s & Waste N | lanagement     |              |               |           |               |  |
| Electricity                       | 0.076       | \$/kwh         | 420.1        | kW-hr         | 2,425,663 | \$<br>184,350 | \$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization     |
| Compressed Air                    | 0.481       | \$/kscf        | 2            | scfm/kacfm    | 125,438   | \$<br>60,382  | \$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization |
| Water                             | 0.340       | \$/mgal        |              | gpm           |           |               | \$/mgal, 0 gpm, 5774 hr/yr, 78% utilization          |
| SW Disposal                       | 42.56       | \$/ton         | 0.27         | ton/hr        | 1,560     | \$<br>66,408  | \$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization      |
| Lime                              | 167.17      | \$/ton         | 365.6        | lb/hr         | 1,055     | \$<br>176,434 | \$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization     |
| Filter Bags                       | 249.27      | \$/bag         | 3,412        | bags          | N/A       | \$<br>238,901 | \$/bag, 3,412 bags, 5774 hr/yr, 78% utilization      |
|                                   |             |                |              |               |           |               |  |

# Appendix C

Submittals to MPCA Regarding Indurating Furnaces 11 and 12



CLEVELAND-CLIFFS INC. Northshore Mining Company 10 Outer Drive, Silver Bay, MN 56614 P 218.226.4125 F 218.226.6037 clevelandcliffs.com

July 6, 2020

Mr. Hassan M. Bouchareb Minnesota Pollution Control Agency 520 Lafayette Road North St. Paul, MN 55155-4194

### Re: Response to Request for Information – Regional Haze Rule, Reasonable Progress, Four Factor Analysis for Indurating Furnaces 11 and 12 at Northshore Mining Company

Dear Mr. Bouchareb:

This letter is in response to the Minnesota Pollution Control Agency's (MPCA's) February 24, 2020 request for information (RFI) letter sent to Cleveland-Cliffs Inc. Northshore Mining Company (Northshore). The February 24, 2020 RFI stated that Northshore emission units were identified as a significant source of NO<sub>X</sub> and SO<sub>2</sub> and are located close enough to Voyageurs National Park and Boundary Waters Canoe Area Wilderness to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requested Northshore to submit a "four-factor analysis" by July 31, 2020 for the emission units identified in Table 1 for NOx and SO<sub>2</sub>.

| Unit                  | Unit ID                              |  |  |
|-----------------------|--------------------------------------|--|--|
| Indurating Furnace 11 | EQUI 126 & EQUI 127/ EU100 & EU104   |  |  |
| Indurating Furnace 12 | EQUI 128 & EQUI 129 / EU110 & EU1114 |  |  |
| Power Boiler 1        | EQUI 14 / EU001                      |  |  |
| Power Boiler 2        | EQUI 15 / EU002                      |  |  |

**Table 1: Identified Emission Units** 

The "four-factor analysis" is a control equipment evaluation, similar to the Best Available Control Technology (BACT) and Best Available Retrofit Technology (BART) evaluations, that must address the four statutory factors laid out in 40 CFR 51.308(f)(2)(i):

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

The MPCA intends to use the four-factor analyses to evaluate additional control measures as part of the development of the State Implementation Plan (SIP), which is due to be submitted to United States Environmental Protection Agency (USEPA) by July 31, 2021. The SIP will be prepared to address the second regional haze implementation period, which ends in 2028.

This letter considers whether a four-factor analysis is warranted for Northshore's indurating furnaces because the furnaces can be classified as an "effectively controlled" source for NO<sub>x</sub> and SO<sub>2</sub>. The MPCA can exclude such sources for evaluation per the regulatory requirements of the Regional Haze Rule and the United States Environmental Protection Agency (USEPA) August 20, 2019 Regional Haze Guidance Memorandum (2019 RH SIP Guidance).<sup>1</sup>.

In Section II.B.3.f of the 2019 RH SIP Guidance<sup>2</sup>, the USEPA acknowledges that states may forgo requiring facilities to complete the detailed four-factor analysis:

"It may be reasonable for a state not to select an effectively controlled source. A source may already have effective controls in place as a result of a previous regional haze SIP or to meet another CAA requirement.".<sup>3</sup>

The associated rationale is that:

"...it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary".<sup>4</sup> to make reasonable progress towards reducing visibility impairments at Class I areas.

Section II.B.4.h. of the 2019 RH SIP Guidance.<sup>5</sup> states,

"It may be appropriate for a state to rely on a previous BART analysis or reasonable progress analysis for the characterization of a factor, for example information developed in the first implementation period on the availability, cost, and effectiveness of controls for a particular source, if the previous analysis was sound and no significant new information is available."

The 2019 RH SIP Guidance identified example scenarios and described the associated rationale for why the sources are "effectively controlled" and that states can exclude similar sources from needing to complete a four-factor analysis. The USEPA stated "BART-eligible units that installed and began operating controls to meet BART emission limits for the first implementation period" may be "effectively controlled"

<sup>5</sup> Ibid, page 28.

<sup>&</sup>lt;sup>1</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019

<sup>&</sup>lt;sup>2</sup> Ibid, page 11.

<sup>&</sup>lt;sup>3</sup> Ibid, page 22.

<sup>&</sup>lt;sup>4</sup> Ibid, page 23.

for the associated pollutants.<sup>6</sup> The USEPA notes, "*it may be unlikely that there will be further available reasonable controls for such sources*."<sup>7</sup> However, the USEPA adds that, "*states may not categorically exclude all BART-eligible sources, or all sources that installed BART control, as candidates for selection for analysis of control measures*."<sup>8</sup> The USEPA further notes that, "*a state might, however, have a different, reasonable basis for not selecting such sources* [sources for which existing controls were determined to be BART] *for control measure analysis*."

As described below, Indurating Furnaces 11 and 12 meet the "effectively controlled" source example scenario for units with BART NOx and SO<sub>2</sub> emission limits which the USEPA concluded that states could exclude from completing a four-factor analysis.

### **Process Description**

Indurating Furnaces 11 and 12 are straight grate furnaces in which pellets move through the entire furnace on a traveling grate. The pellet hardening and oxidation section of the indurating furnace is designed to operate at 2,400 °F. This temperature is required to meet taconite pellet product specifications. Fuel combustion in the induration furnace is carried out at 300 percent to 400 percent excess air to provide sufficient oxygen for pellet oxidation.

Air is used for combustion, pellet cooling, and as a source of oxygen for pellet oxidation. Due to the highenergy demands of the induration process, indurating furnaces have been designed to recover as much heat as possible using hot exhaust gases to heat up incoming pellets. Pellet drying and preheat zones are heated with the hot gases generated in the pellet hardening/oxidation section and the pellet cooler sections. Each of these sections is designed to maximize heat recovery within process constraints. The pellet coolers are also used to preheat combustion air so more of the fuel's energy is directed to the process instead of heating ambient air to combustion temperatures.

Indurating Furnaces 11 and 12 are permitted to burn natural gas and fuel oil. SO<sub>2</sub> emissions are controlled by wet walled electrostatic precipitators (WWESP) using caustic reagent to offset acid conditions.

### **BART-required Control Equipment Installation Scenario**

Indurating Furnaces 11 and 12 were BART-eligible units and BART limits were established during the first implementation phase. The 30 day-rolling average BART limits of 1.2-1.5lb NOx/MMBtu for each furnace (fuel dependent) and 39.0 lb SO<sub>2</sub>/hr for both furnaces combined were established in the final Federal Implementation Plan (FIP) dated February 6, 2013.<sup>9</sup>. The BART limits from the FIP are shown in Table 2.

<sup>&</sup>lt;sup>6</sup> Ibid, page 25.

<sup>7</sup> Ibid.

<sup>&</sup>lt;sup>8</sup> Ibid.

<sup>&</sup>lt;sup>9</sup> Federal Register/ Vol. 78. No. 25, February 6, 2013, EPA-R05-OAR-2010-0037 beginning on page 8706.

| Unit                  | Unit ID                                 | NOx Limit<br>(lb/MMBtu) | SO <sub>2</sub> Limit<br>(lb/hr) |  |  |
|-----------------------|---|-------------------------|----------------------------------|--|--|
| Indurating Furnace 11 | EQUI 126 & EQUI 127/<br>EU100 & EU104   | 1.2-1.5                 | 39                               |  |  |
| Indurating Furnace 12 | EQUI 128 & EQUI 129 /<br>EU110 & EU1114 | 1.2-1.3                 |                                  |  |  |

| Table 2 BART NOx and SO <sub>2</sub> Emission Li | mits |
|--|------|
|--|------|

Indurating Furnaces 11 and 12 did not require installation of additional control equipment to meet the FIP NOx limits because the furnaces design inherently results in low NOx development. The Northshore furnaces emit the lowest tons of NOx per long ton product of any taconite producer making similar pellets. Northshore's furnaces are of an early vintage, which utilizes numerous burners critically located to supply heat to the various furnace sections. The burner layout limits production capability for the size of the furnace. This furnace design is not used by any other taconite producer. An inherent design that prevents formation of the pollutants far exceeds add-on controls that could result in environmental impacts such as higher collateral carbon monoxide formation. In accordance with the FIP, Northshore has continued to operate the indurating furnaces in compliance with the FIP NOx emission limits. Thus, the indurating furnaces are considered "effectively controlled" sources in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for NOx.

Northshore's furnaces are only capable of burning natural gas and fuel oil; with natural gas as the primary fuel. Since natural gas is low in sulfur, the primary source of SO<sub>2</sub> emissions is from trace amounts of sulfur in the iron concentrate and binding agents. Sulfur is also present in fuel oil, if used. Both lines are controlled by WWESPs using caustic reagent. Stack testing using natural gas fuel has demonstrated the WWESP effectively removes SO<sub>2</sub> to one to two parts per million in the exhaust. The USEPA concluded in the 2013 FIP.<sup>10</sup> that because Northshore is burning natural gas and fuel oil, additional SO<sub>2</sub> controls are not economically reasonable and are therefore, not necessary for BART. In accordance with the FIP, Northshore has continued to operate the BART SO<sub>2</sub> control measures and is complying with the FIP SO<sub>2</sub> emission limits. Thus, the indurating furnaces are considered "effectively controlled" sources in accordance with the 2019 RH SIP Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for SO<sub>2</sub>.

The indurating furnaces meet the USEPA's scenario for effectively controlled units because:

T\Environmental\AQ - Air Quality\SVB\Regional Haze (BART)\2020 Four Factor Analysis\7-6-2020 NSM - RH Effectively Controlled Furnaces Letter.docx

<sup>&</sup>lt;sup>10</sup> Approval and Promulgation of Air Quality Implementation Plans; States of Minnesota and Michigan; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Final Rule. 78 Fed. Reg. 8706 (February 6, 2013)

- The indurating furnaces are BART-eligible units, as determined by Minnesota's December 2009 Regional Haze Plan, and are regulated under 40 CFR 52.1235 (Approval and Promulgation of Implementation Plans – Subpart Y Minnesota – Regional Haze)
- The indurating furnaces have controls and must "meet BART emission limits for the first implementation period" for NOx and SO<sub>2</sub>
- In 2013, EPA promulgated a FIP that included, among other things, BART requirements to effectively control NOx and SO<sub>2</sub> for the Northshore indurating furnaces.
- No significant new control technology is available for indurating furnaces since the previous BART analysis.

Northshore is requesting that Indurating Furnaces 11 and 12 be excluded from the request to prepare a four-factor analysis. We are confident a full four-factor analysis would result in the conclusion that no further controls are necessary for the furnaces. Northshore will complete a Four Factor Analysis for Power Boilers 1 and 2 by July 31, 2020. Because of MPCA's request for completion of the Four Factor Analysis by July 31, 2020, Northshore is requesting a response from MPCA as soon as possible regarding this request. Thank you for your consideration.

Sincerely,

Aul Allay lo

Andrea Hayden Environmental Manager, Northshore Mining Company

cc: Paul Carlson – Northshore Jennifer Ramsdell – Northshore Jason Aagenes – Cleveland-Cliffs Teresa Kinder – Barr Engineering Julie Miller – Barr Engineering



CLEVELAND-CLIFFS INC. Northshore Mining Company 10 Outer Drive, Silver Bay, MN 56614 P 218.226.4125 F 218.226.6037 clevelandcliffs.com

July 30, 2020

Mr. Hassan M. Bouchareb Minnesota Pollution Control Agency 520 Lafayette Road North St. Paul, MN 55155-4194

### Re: Follow Up to Response to Request for Information – Regional Haze Rule, Reasonable Progress, Four Factor Analysis for Indurating Furnaces 11 and 12 at Northshore Mining Company

Dear Mr. Bouchareb:

This letter is in response to the Minnesota Pollution Control Agency's (MPCA) email to Northshore Mining Company (Northshore) dated July 28, 2020 regarding the determination on whether Indurating Furnaces 11 and 12 can be considered effectively controlled. MPCA's email reads as follows:

*Please provide a short overview of the different emission reduction opportunities evaluated at part of the Taconite FIP for Northshore. I'm specifically looking for:* 

- Each reduction measure that was evaluated for NOX/SO2 control within the FIP;
- Whether the measure was eliminated from consideration based on technical feasibility;
- Whether the measure was eliminated from consideration based on cost-effectiveness; and
- Whether or not these determinations have materially changed since they were completed.

### Background

On August 15, 2012, the Environmental Protection Agency (EPA) proposed the Regional Haze Federal Implementation Plan (FIP) to address best available retrofit technology (BART) for taconite plants in Minnesota and Michigan.<sup>1</sup> The proposed FIP contained a BART analysis for Northshore's Indurating Furnaces 11 and 12. EPA's FIP was informed by Northshore's submittal to the MPCA on September 6, 2006, "Northshore Mining Company Analysis of Best Available Retrofit Technology (BART)" [2006 BART Analysis]<sup>2</sup>. The information used for the Taconite FIP is summarized in the following paragraphs.

### **NOx BART Analysis**

The following NOx retrofit control technologies were identified for indurating furnaces in the FIP:

- External Flue Gas Recirculation,
- Low-NOx Burners,
- Induced Flue Gas Recirculation Burners,

<sup>&</sup>lt;sup>1</sup> Approval and Promulgation of Implementation Plans; States of Minnesota and Michigan; Regional Haze Federal Implementation Plan. 77 Fed. Reg. 49308. (proposed August 15, 2012).

<sup>&</sup>lt;sup>2</sup> https://www.pca.state.mn.us/sites/default/files/bart-facility-northshore.pdf

Mr. Hassan M. Bouchareb July 30, 2020 Page 2

- Energy Efficiency Projects,
- Ported Kilns,
- Alternate Fuels, and
- Selective Catalytic Reduction (SCR).

Table 1 summarizes the technologies that were eliminated from consideration based on technical feasibility.

Table 1 Potential NOx Emission Control Measures Technical Feasibility Conclusions<sup>3</sup>

| NO <sub>x</sub> Control Measure Technically Feasible for Stra<br>Grate Furnace? |                                 |  |  |  |
|---|---------------------------------|--|--|--|
| Pre-Combustion, Combustion, or Operational Controls                             |                                 |  |  |  |
| LNB   | No – Already required under FIP |  |  |  |
| EFGR  | No                              |  |  |  |
| IFGR  | No                              |  |  |  |
| Ported Kilns  | No                              |  |  |  |
| Energy Efficiency Projects  | No                              |  |  |  |
| Alternate Fuels   | No                              |  |  |  |
| Post-Combustion Controls  |                                 |  |  |  |
| SCR – Pre-WWESP   | No                              |  |  |  |
| SCR – Post-WWESP with<br>Conventional Duct Burner Reheat                        | Potentially                     |  |  |  |

In the proposed FIP, EPA states that U.S. Steel documented the infeasibility of SCR controls. In its 2006 BART Analysis, Northshore identified SCR with conventional reheat as potentially technically feasible. SCR with conventional reheat was eliminated from consideration based on cost-effectiveness in the 2006 BART Analysis. The annualized control cost was expected to be over \$200,000 per ton for each furnace.

In the final FIP dated February 6, 2013, EPA established a NOx limit of 1.2 lbs/MMBtu on a 30-day rolling average for the furnaces when natural gas is used as fuel.<sup>4</sup> The BART limit is based on the expected control achieved using low NOx burners. However, as described in the letter to MPCA dated July 6, 2020, Indurating Furnaces 11 and 12 did not require actual installation of low NOx burners to meet BART NOx limits because the furnaces design inherently results in low NOx development.

NOx control technologies for indurating furnaces have not materially changed since the previous BART analysis. The furnaces are effectively controlled to the same level as low NOx burners. The furnaces' designs would not allow for changes in burner technology that would further reduce NOx emissions. The cost of SCR with conventional reheat has not significantly changed since the previous BART analysis; therefore, the cost effectiveness is expected to be far too high to implement SCR technology. The

<sup>&</sup>lt;sup>3</sup> Ibid., 49315.

<sup>&</sup>lt;sup>4</sup> Approval and Promulgation of Air Quality Implementation Plans; States of Minnesota and Michigan; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze. 78 Fed. Reg. 8706. (February 6, 2013).

Mr. Hassan M. Bouchareb July 30, 2020 Page 3

technical feasibility determinations of the other technologies listed above has not changed. No new NOx retrofit control technologies have been successfully installed on taconite indurating furnaces since the previous BART analysis.

### SO<sub>2</sub> BART Analysis

Both furnaces are controlled by wet-walled electrostatic precipitators (WWESP) using caustic reagent. The following SO<sub>2</sub> retrofit control technologies were identified for indurating furnaces in the FIP:

- Wet-Walled Electrostatic Precipitator,
- Wet Scrubbing,
- Dry Sorbent Injection (DSI),
- Spray Dryer Absorption (SDA),
- Energy Efficiency Projects,
- Alternate Fuels, and
- Coal Drying.

Table 2 summarizes the technologies that were eliminated from consideration based on technical feasibility.

### Table 2 Potential SO<sub>2</sub> Emission Control Measures Technical Feasibility Conclusions.<sup>5</sup>

| SO <sub>2</sub> Control Measure                     | Technically Feasible for Straight-<br>Grate Furnace? |  |  |  |
|---|--|--|--|--|
| Pre-Combustion, Combustion, or Operational Controls |  |  |  |  |
| Energy Efficiency Projects                          | No   |  |  |  |
| Alternate Fuels                                     | No   |  |  |  |
| Coal Drying   | No   |  |  |  |
| Post-Combustion Controls                            |  |  |  |  |
| WWESP - Secondary                                   | Yes  |  |  |  |
| Wet Scrubbing – Secondary                           | Yes  |  |  |  |
| DSI – Post-WWESP                                    | No   |  |  |  |
| SDA– Post-WWESP                                     | No   |  |  |  |

A secondary WWESP or a secondary wet scrubber were eliminated from consideration because of costeffectiveness. "Northshore estimated the annualized pollution control cost of installing and operating secondary WWESPs ranged from roughly \$180,000 to \$540,000 per ton of SO<sub>2</sub> removed. The cost of installing and operating a secondary wet scrubber was estimated to be between \$140,000 and \$420,000 per ton of SO<sub>2</sub> removed.".<sup>6</sup> The cost-effectiveness assumed the control efficiency of a secondary WWESP to be 80 percent and the control efficiency of a secondary wet scrubber to be 60 percent.

 <sup>&</sup>lt;sup>5</sup> Approval and Promulgation of Implementation Plans; States of Minnesota and Michigan; Regional Haze Federal Implementation Plan. 77 Fed. Reg. 49308. (proposed August 15, 2012), p. 49316.
 <sup>6</sup> Ibid.

Mr. Hassan M. Bouchareb July 30, 2020 Page 4

In the final Taconite FIP, EPA established an aggregate SO<sub>2</sub> limit of 39.0 lbs/hr on a 30-day rolling average for the furnaces when natural gas is used as fuel.<sup>7</sup>. The BART limit is based on the WWESPs already installed on the furnaces.

SO<sub>2</sub> control technologies for indurating furnaces have not materially changed since the previous BART analysis. The furnaces are effectively controlled with the existing WWESPs. The cost of installing either a secondary WWESP or a secondary wet scrubber has not significantly changed since the previous BART analysis; therefore, the cost effectiveness is expected to be far too high to implement. The technical feasibility determinations of the other technologies listed above has not changed. No new SO<sub>2</sub> retrofit control technologies have been successfully installed on taconite indurating furnaces since the previous BART analysis.

Please contact me if you have any questions or need further information.

Sincerely,

Aul Allay lo

Andrea Hayden Environmental Manager, Northshore Mining Company

cc: Paul Carlson – Northshore Jennifer Ramsdell – Northshore Jason Aagenes – Cleveland-Cliffs Teresa Kinder – Barr Engineering Julie Miller – Barr Engineering

<sup>&</sup>lt;sup>7</sup> Approval and Promulgation of Air Quality Implementation Plans; States of Minnesota and Michigan; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze. 78 Fed. Reg. 8706. (February 6, 2013).

# sappi

Mr Hassan Bouchareb Environmental and Outcomes Division Minnesota Pollution Control Agency 520 Lafayette Road North St. Paul, MN 55155-4194 UNITED STATES OF AMERICA

22 July 2020

Dear Mr. Bouchareb

# Request for Information – Regional Haze Rule Four-Factor Analysis for NOx and SO<sub>2</sub> Emissions Control

Sappi Cloquet LLC submits the attached Four-Factor Analysis for NOx and SO<sub>2</sub> Emissions Control for Power Boiler #9 (EQUI 4) and Recovery Boiler #10 (EQUI 53) to satisfy the request for information sent on January 29, 2020. Barr Engineering prepared the four-factor analysis for Sappi Cloquet LLC. The report concludes existing permit controls and limits effectively control NOx and SO<sub>2</sub> emissions from Power Boiler #9 and NOx emissions from Recovery Boiler #10. In addition, the report concludes MPCA should use the current trend of emissions reductions to demonstrate reasonable progress toward reducing visibility impairment.

The Recovery Boiler #10 underwent a BACT review for NOx, among other pollutants, and the associated construction permit was issued in 2017 (Air Permit 01700002-101) which is after the USEPA's July 31, 2013 scenario threshold date and qualifies it as being "effectively controlled."

Power Boiler #9 underwent a four-factor analysis. The result of which is that the installation of additional control equipment for NO2 and SO2 is not justified based on the cost of compliance as seen in the table below.

| Additional<br>Emissions Control<br>Measure | Factor 1 – Cost of<br>Compliance |
|--|----------------------------------|
| SCR  | \$9,493/ton                      |
| SNCR                                       | \$7,191/ton                      |

As for the fifth factor, a visibility impacts review was conducted that shows visibility improvements are unlikely with the addition of either of these emissions control measures.

This Four-Factor Analysis is being submitted to Hassan Bouchareb by certified mail and electronically at <u>Hassan.Bouchareb@state.mn.us</u>.

Please contact Alycia McWilliams at 218-879-0637 if you have any questions or comments concerning this report.

### **Sappi North America**

#### **Cloquet Mill**

2201 Avenue B PO Box 511 MN 55720 Cloquet UNITED STATES OF AMERICA Tel +1 218 879 2300

www.sappi.com

Alycia McWilliams Environmental Engineer Tel +1 218 879-0637 Mobile +1 678 209 5453 Alycia.McWilliams@sappi.com

# sappi

Page 2 of 2

Yours sincerely

an tran Tom Radovich

Managing Director Cloquet Operations

sappi/999



# Regional Haze Four-Factor Analysis for NO<sub>x</sub> and SO<sub>2</sub> Emissions Control

Power Boiler #9 (EQUI 4 / EU 004) Recovery Boiler #10 (EQUI 53 / EU 005)

Prepared for Sappi Cloquet LLC

July 17, 2020



# Regional Haze Four-Factor Analysis for NO<sub>x</sub> and SO<sub>2</sub> Emissions Control

Power Boiler #9 (EQUI 4 / EU 004) Recovery Boiler #10 (EQUI 53 / EU 005)

Prepared for Sappi Cloquet LLC

July 17, 2020

325 South Lake Avenue Duluth, MN 55802 218.529.8200 www.barr.com

# Regional Haze Four-Factor Analysis for $NO_X$ and $SO_2$ Emissions Control

July 17, 2020

# Contents

| 1 | E     | xecutive Summary  | 1   |
|---|-------|---|-----|
| 2 | Ir    | ntroduction   | 1   |
|   | 2.1   | Four-factor Analysis Regulatory Background                                | 1   |
|   | 2.2   | Description of Affected Emission Units                                    | 2   |
|   | 2.3   | Existing Emission Controls and Limits                                     | 2   |
| 3 | Ρ     | ower Boiler #9: Four-factor Analysis                                      | 4   |
|   | 3.1   | NO <sub>X</sub> Four-factor Analysis – Power Boiler #9                    | 4   |
|   | 3.1.1 | Emission Control Options  | 4   |
|   | 3.1.2 | Baseline Emission Rates   | 5   |
|   | 3.1.3 | Factor 1 – Cost of Compliance   | 6   |
|   | 3.1.4 | Factor 2 – Time Necessary for Compliance                                  | 7   |
|   | 3.1.5 | Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance | 7   |
|   | 3.1.6 | 5 Factor 4 – Remaining Useful Life of the Source                          | 8   |
|   | 3.1.7 | Proposed NO <sub>x</sub> Controls and Emissions Rates                     | 8   |
|   | 3.2   | SO <sub>2</sub> Four-factor Analysis – Power Boiler #9                    | 8   |
|   | 3.2.1 | Emission Control Options  | 8   |
|   | 3.2.2 | Baseline Emission Rates   | 9   |
|   | 3.2.3 | Factor 1 – Cost of Compliance   | 9   |
|   | 3.2.4 | Factor 2 – Time Necessary for Compliance                                  | .10 |
|   | 3.2.5 | Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance | .10 |
|   | 3.2.6 | Factor 4 – Remaining Useful Life of the Source                            | .11 |
|   | 3.2.7 | Proposed SO <sub>2</sub> Controls and Emissions Rates                     | .11 |
| 4 | R     | ecovery Boiler #10: Effective Controls Analysis                           | .12 |
| 5 | V     | isibility Impacts Review  | .13 |
|   | 5.1   | IMPROVE Data Analysis   | .13 |
|   | 5.2   | Trajectory Analysis   | .17 |

## List of Tables

| Table 1-1: | Projected 2028 NO <sub>X</sub> Emissions (tons per year)             | .2 |
|------------|--|----|
| Table 1-2: | Summary of NO <sub>x</sub> Four-factor Analysis                      | .1 |
| Table 1-3: | Summary of SO <sub>2</sub> Four-factor Analysis                      | .2 |
| Table 2-1: | Identified Emission Units  | .1 |
| Table 2-2: | Power Boiler #9 – NO <sub>X</sub> and SO <sub>2</sub> Permit Limits  | .3 |
| Table 2-3: | Recovery Boiler #10 – NO <sub>X</sub> Permit Limits                  | .3 |
| Table 3-1: | Biomass Power Boiler RBLC Summary – NO <sub>X</sub>                  | .5 |
| Table 3-2: | Projected 2028 NO <sub>X</sub> Emissions (tons per year)             | .6 |
| Table 3-3: | Power Boiler #9 NO <sub>X</sub> Control Cost Summary, per Unit Basis | .6 |
| Table 3-4: | Biomass Power Boiler RBLC Summary – SO <sub>2</sub>                  | .8 |
| Table 3-5: | Projected 2028 SO <sub>2</sub> Emissions (tons per year)             | .9 |
| Table 3-6: | Power Boiler #9 SO <sub>2</sub> Control Cost Summary, per Unit Basis | 10 |

# List of Figures

| Figure 5.1: | Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)                      |
|-------------|---|
| Figure 5.2: | Visibility Trend versus URP – Voyageurs National Park (VOYA1)                         |
| Figure 5.3: | Visibility Trend versus URP – Isle Royale National Park (ISLE1)                       |
| Figure 5.4: | Visibility Components Trend for each Class 1 Monitor from 2004-2018                   |
| Figure 5.5: | Total Number of Most Impaired Trajectories and Number that Cross Near Sappi for 2014- |
|             | 2016  |
| Figure 5.6: | Most Impaired Trajectories from MPCA Analysis that Cross Near Sappi in 2015-2016 (no  |
|             | trajectories cross near Sappi in 2014)  |

# List of Appendices

| Appendix A: | RBLC Search for Biomass Power Boilers for $NO_X$       |
|-------------|--|
| Appendix B: | Power Boiler #9 – Control Cost Calculations for $NO_X$ |
| Appendix C: | RBLC Search for Biomass Power Boilers for $SO_2$       |
| Appendix D: | Power Boiler #9 – Control Cost Calculations for $SO_2$ |

# **1 Executive Summary**

This report presents Sappi Cloquet LLC (Sappi's) response to the Minnesota Pollution Control Agency's (MPCA's) January 29, 2020 Request for Information (RFI) Letter<sup>1</sup> regarding the Regional Haze Rule (RHR)<sup>2</sup> and the state's requirement to make reasonable progress on visibility improvement at nearby Class I areas.<sup>3</sup> As required by the RFI, the report presents the emissions reduction evaluation for nitrogen oxides (NO<sub>X</sub>) and sulfur dioxide (SO<sub>2</sub>) from Power Boiler #9 (EQUI 4 / EU 004) and for NO<sub>X</sub> from Recovery Boiler #10 (EQUI 53 / EU 005). The report was prepared following the requirements of the RHR (40 CFR 51.308) and is consistent with the final U.S. Environmental Protection Agency (EPA) RHR State Implementation Plan (SIP) guidance<sup>4</sup> (2019 SIP Guidance).

**Evaluation for Power Boiler #9:** The analysis for Power Boiler #9 considers potential emissions reduction measures for  $NO_X$  (Section 3.1) and  $SO_2$  (Section 3.2) by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i):

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

The analyses are summarized in Table 1-2 and Table 1-3 for NO<sub>X</sub> and SO<sub>2</sub>, respectively. These analyses demonstrate that the installation of additional control equipment NO<sub>X</sub> and SO<sub>2</sub> is not justified based on the four statutory factors.

In addition, Section 5.1 provides visibility monitoring data that demonstrates that the current visibility impairment in the nearby Class I areas is already below the 2028 Uniform Rate of Progress (URP), suggesting that the MPCA should use the current trend of emission reductions to demonstrate reasonable progress. Furthermore, Section 5.2 provides results from a particle trajectory analyses for the most

<sup>&</sup>lt;sup>1</sup> January 29, 2020 letter from Hassan Bouchareb of MPCA to Sappi

<sup>&</sup>lt;sup>2</sup> 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>&</sup>lt;sup>3</sup> MPCA's letter identified the Boundary Waters Canoe Area Wilderness (Boundary Waters), Voyageurs National Park (Voyageurs) and Isle Royale National Park (Isle Royale) as the nearby Class I areas

<sup>&</sup>lt;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.

impaired days at the Boundary Waters visibility monitor and concludes that additional control measures implemented at Sappi are unlikely to provide a substantial improvement in visibility in the Class I areas.

This analysis does not support the installation of additional  $NO_X$  or  $SO_2$  emission control measures at Power Boiler #9 beyond those described in Section 2.3. As such, Sappi proposes to maintain the existing  $NO_X$  or  $SO_2$  permit limits presented in Table 2-2.

**Evaluation for Recovery Boiler #10:** The 2019 SIP Guidance states that it "may be reasonable for a state not to select an effectively controlled source"<sup>5</sup> for the four-factor analysis with the rationale that "it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls necessary."<sup>6</sup> Section 4 demonstrates that Recovery Boiler #10 is "effectively controlled" and, therefore, a four-factor analysis was not completed for this source.

This analysis does not support the installation of additional  $NO_X$  emissions measures at Recovery Boiler #10 beyond those described in Section 2.3. As such, Sappi proposes to maintain the existing  $NO_X$ permit limits presented in Table 2-3.

**Update to Baseline Emission Rates:** The 2019 SIP Guidance states that 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."<sup>7</sup> Sappi anticipates flat growth in the paper industry and projects that emissions in 2028 will be equivalent to 2019 actual emissions.

The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions. Sappi proposed to revise the projected emissions for LADCO's evaluation as shown in Table 3-2.

| Table 4 4  | Destante LOOOD NO. Fastation             | /1    |       |       |
|------------|--|-------|-------|-------|
| Table 1-1: | Projected 2028 NO <sub>x</sub> Emissions | (tons | per y | year) |

| Year                     | Source              | Pollutant       | Annual Emissions |
|--------------------------|---------------------|-----------------|------------------|
| 2019 Actual Emissions    | Power Boiler #9     | NO <sub>X</sub> | 347 tons/year    |
| And                      | Power Boiler #9     | SO <sub>2</sub> | 22 tons/year     |
| 2028 Projected Emissions | Recovery Boiler #10 | NO <sub>X</sub> | 680 tons/year    |

<sup>7</sup> Ibid, page 29.

<sup>&</sup>lt;sup>5</sup> Ibid, Page 22.

<sup>&</sup>lt;sup>6</sup> Ibid, Page 23.

| Emission<br>Reduction<br>Technology | Factor 1 –<br>Cost of<br>Compliance | Factor 2 –<br>Time<br>Necessary for<br>Compliance | Factor 3 –<br>Energy and Non-Air Quality<br>Environmental Impacts of<br>Compliance   | Factor 4 –<br>Remaining Useful<br>Life of the Source              | Factor 5 –<br>Visibility<br>Improvements | Does this Analysis<br>Support the Installation<br>of this Emission<br>Reduction Technology? |
|-------------------------------------|-------------------------------------|---|--|---|--|---|
| SCR                                 | \$9,493/ton                         | 3 years after<br>SIP approval                     | <ul> <li>Catalyst plugging could lead to<br/>decreased control efficiency,<br/>decreased catalyst life, and<br/>additional boiler downtime</li> <li>Increased truck and/or train traffic<br/>(reagent and catalyst deliveries)</li> <li>Possible ammonia slip (unreacted<br/>reagent that is emitted to the<br/>atmosphere)</li> <li>Increased natural gas burning to<br/>reheat flue gas to achieve SCR<br/>inlet temperatures</li> <li>Catalyst regeneration</li> <li>Catalyst disposal</li> <li>Electricity consumption (fans and<br/>pumps)</li> </ul> | No shutdown or<br>rebuild of Power<br>Boiler #9 is<br>anticipated | Unlikely                                 | No  |
| SNCR                                | \$7,191/ton                         | 3 years after<br>SIP approval                     | <ul> <li>Increased truck and/or train traffic<br/>(reagent deliveries)</li> <li>Possible ammonia slip (unreacted<br/>reagent that is emitted to the<br/>atmosphere)</li> <li>Nitrous oxide (N2O) generation (a<br/>greenhouse gas)</li> <li>Electricity consumption (fans and<br/>pumps)</li> </ul>  | No shutdown or<br>rebuild of Power<br>Boiler #9 is<br>anticipated | Unlikely                                 | No  |

### Table 1-2: Summary of NOx Four-factor Analysis

| List of<br>Emission<br>Reduction<br>Technology | Factor 1 –<br>Cost of<br>Compliance | Factor 2 –<br>Time<br>Necessary for<br>Compliance | Factor 3 –<br>Energy and Non-Air Quality<br>Environmental Impacts of<br>Compliance  | Factor 4 –<br>Remaining Useful<br>Life of the Source              | Factor 5 –<br>Visibility<br>Improvements | Does this Analysis<br>Support the Installation<br>of this Emission<br>Reduction Technology? |
|--|-------------------------------------|---|---|---|--|---|
| Spray dryer                                    | \$1,589,900                         | 3 years after SIP<br>approval                     | <ul> <li>Increased waste generation<br/>and disposal due to additional<br/>material collected in the<br/>particulate emissions control<br/>system</li> <li>Increased truck and/or train<br/>traffic (reagent deliveries and<br/>waste hauling)</li> <li>Water consumption for slurry</li> <li>Electricity consumption (fans<br/>and pumps)</li> <li>Wastewater generation and<br/>disposal</li> </ul> | No shutdown or<br>rebuild of Power<br>Boiler #9 is<br>anticipated | Unlikely                                 | No  |
| Dry sorbent<br>injection                       | \$5,672,396                         | 3 years after SIP<br>approval                     | <ul> <li>Increased waste generation<br/>and disposal due to additional<br/>material collected in the<br/>particulate emissions control<br/>system</li> <li>Increased truck and/or train<br/>traffic (reagent deliveries and<br/>waste hauling)</li> <li>Electricity consumption (fans<br/>and pumps)</li> </ul>   | No shutdown or<br>rebuild of Power<br>Boiler #9 is<br>anticipated | Unlikely                                 | No  |

# 2 Introduction

This section discussed the pertinent regulatory background information, and a description of Sappi's boilers.

# 2.1 Four-factor Analysis Regulatory Background

The RHR 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 SIPs in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Class I areas. The original RHR SIPs were due in 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 SIP for the first RHR planning period 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 SIPs by July 31, 2021.

On January 29, 2020, the MPCA sent an RFI to Sappi. The RFI stated that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites at Boundary Waters Canoe Area Wilderness (Boundary Waters) and Voyageurs National Park (Voyageurs) 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 SO<sub>2</sub> and NO<sub>X</sub>. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze in Isle Royale, Michigan must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts. As part of the planning process for the SIP development, MPCA is working with the LADCO to evaluate regional emission reductions.

In addition, the RFI stated that the facility was identified as a significant source of NO<sub>X</sub> and SO<sub>2</sub> that is located close enough to the Boundary Waters and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, as part of the State's development of the updated SIP, the MPCA requested that Sappi submit a "four factors analysis" (herein termed as a four-factor analysis) by July 31, 2020 for the emission units identified in Table 2-1.

| Unit                | Unit ID          | Applicable Pollutants             |  |
|---------------------|------------------|-----------------------------------|--|
| Recovery Boiler #10 | EQUI 53 / EU 005 | NOx                               |  |
| Power Boiler #9     | EQUI 4 / EU 004  | NO <sub>X</sub> , SO <sub>2</sub> |  |

The analysis must consider potential emissions reduction measures by addressing the four statutory factors which are laid out in 40 CFR 51.308(f)(2)(i):

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

The RFI letter to Sappi specified that the "... analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to the final 2019 SIP Guidance.

This report describes the background and analysis for conducting a four-factor analysis for  $NO_X$  and  $SO_2$  as applied to the review of emissions controls at Sappi for the units identified in Table 2-1.

# 2.2 Description of Affected Emission Units

Sappi is an existing pulp and paper mill which manufactures kraft paper pulp, dissolving wood pulp, and fine coated paper. The two emissions units included in MPCA's RFI are:

- **Power Boiler #9:** This emission unit is a stoker grate design boiler which produce steam to generate electricity and provide heat for other processes at the plant. The boiler burns primarily hog fuel (biomass which is primarily bark from the facility de-barking process), utilizes natural gas as a startup/supplemental fuel and is permitted to burn distillate oil which is maintained as a backup fuel source. The boiler is also a backup combustion source for non-condensable gases (NCG) which are the exhaust gases from the digestion and BLS evaporation processes. Particulate matter emissions from the power boiler are controlled by multiclones and a high-efficiency electrostatic precipitator (ESP).
- **Recovery Boiler #10:** This emission unit burns strong black liquor solids (BLS) that are generated in the kraft pulp mill chemical recovery process. Weak BLS, which is generated as part of the pulping and washing processes, are concentrated in evaporators to make strong BLS. The strong BLS is then charged to the recovery boiler where the organic portion of the BLS is burned to produce steam to generate electricity and provide heat for other processes at the plant. The cooking chemicals collect as molten smelt at the bottom of the boiler. The recovery boiler is a primary source of all criteria pollutant emissions, as well as sulfuric acid (H<sub>2</sub>SO<sub>4</sub>), total reduced sulfur (TRS), and Hazardous Air Pollutants (HAP). Particulate matter emissions from the recovery boiler are controlled by a high-efficiency ESP.

# 2.3 Existing Emission Controls and Limits

The NO<sub>X</sub> and SO<sub>2</sub> limits for Power Boiler #9 from Air Permit 01700002-103 are presented in Table 2-2. Power Boiler #9 does not have add-on NO<sub>X</sub> controls, but does use staged and overfire air to manage the generation of  $NO_X$ . The boiler does not have add-on  $SO_2$  controls but burns low sulfur fuels and the wood ash provides some dry scrubbing of  $SO_2$  when NCGs are burned concurrently.

| Pollutant       | Condition | Limit  | Basis of Limit  |
|-----------------|-----------|--|---|
| NO <sub>X</sub> | 5.9.8     | Nitrogen Dioxide <= 151.10 pounds per hour 30-day rolling average.   | Prevention of<br>Significant<br>Deterioration (PSD)<br>modeling |
| NOx             | 5.9.9     | Nitrogen Dioxide <= 0.20 to 0.70 pounds per million Btu heat<br>input 3-hour rolling average. [Based on fuel mix]  | New Source<br>Performance<br>Standards (NSPS)<br>Subpart D      |
| NO <sub>X</sub> | 5.9.10    | Nitrogen Oxides <= 200.0 pounds per hour.  | PSD modeling  |
| SO <sub>2</sub> | 5.9.11    | Sulfur Dioxide <= 24.60 pounds per hour. This limit does not apply when boiler is used as back-up incineration for NCG.  | PSD modeling  |
| SO <sub>2</sub> | 5.9.12    | Sulfur Dioxide <= 0.80 pounds per million Btu heat input 3-hour<br>rolling average while burning fuel oil or fuel oil and wood. While<br>burning coal, wood, or coal and wood, SO <sub>2</sub> must be less than or<br>equal to 1.2 lb/mmBtu. These limits also apply if natural gas is<br>being burned in combination with these fuels. [Formula for other<br>fuel mixes]<br>All emission limits shall be determined on a 3-hour rolling<br>average basis. NCG is not considered a fuel, and the contribution<br>from burning NCGs is to be disregarded when determining<br>compliance with this limit. | NSPS Subpart D  |

Table 2-2:Power Boiler #9 – NOx and SO2 Permit Limits

The NO<sub>x</sub> limits for Recovery Boiler #10 from Air Permit 01700002-103 are presented in Table 2-3. Recovery Boiler #10 does not have add-on NO<sub>x</sub> controls but does use quaternary air injection to manage the generation of NO<sub>x</sub>.

| Table 2-3: | Recovery Boiler #10 – NO <sub>X</sub> Permit Limits |
|------------|---|
|------------|---|

| Pollutant       | Condition | Limit  | Basis of<br>Limit  |
|-----------------|-----------|--|--------------------|
| NO <sub>X</sub> | 5.17.11   | Nitrogen Dioxide <= 100 parts per million 30-day rolling average by volume (dry) corrected to 8% oxygen.   | BACT limit         |
| NOx             | 5.17.12   | Nitrogen Dioxide <= 226.5 pounds per hour 30-day rolling average.  | MPCA limit         |
| NO <sub>X</sub> | 5.17.13   | Nitrogen Dioxide <= 241.0 pounds per hour 30-day rolling average.  | PSD<br>modeling    |
| NOx             | 5.17.14   | Nitrogen Oxides <= 241.0 pounds per hour 1-hour average.   | BACT limit         |
| NO <sub>x</sub> | 5.17.15   | Nitrogen Dioxide <= 0.20 pounds per million Btu heat input 30-day rolling average while burning natural gas only or fuel oil combined with black liquor. | NSPS<br>Subpart Db |

# 3 Power Boiler #9: Four-factor Analysis

## 3.1 NO<sub>X</sub> Four-factor Analysis – Power Boiler #9

This section identifies baseline emission rates and evaluates the four statutory factors for  $NO_X$  emissions from Power Boiler #9.

## 3.1.1 Emission Control Options

The 2019 SIP Guidance states that the "first step in characterizing control measures for a source is the identification of technically feasible control measures for those pollutants that contribute to visibility impairment."<sup>8</sup> However, USEPA recognized that a "state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures."<sup>9</sup> This section addresses the selection of emission control options for NO<sub>X</sub> from Power Boiler #9.

The following methodology was used to determine which emission control technologies should be considered in the four factor analysis:

- 1. Search the RACT/BACT/LAER Clearinghouse (RBLC)<sup>10</sup> for available control technologies with the following search criteria:
  - Similar emission unit type (process name)
  - o Similar fuel
  - o 10-year look back
- 2. Eliminate technologies that would not would not apply to the specific emission unit under consideration (example: eliminate controls for natural gas combustion when biomass is the primary fuel)
- 3. Advance the remaining technologies for consideration in the four factor analysis

The RBLC search for biomass power boilers for  $NO_X$  is presented in Appendix A and a summary is provided in Table 3-1.

<sup>&</sup>lt;sup>8</sup> Ibid, page 28.

<sup>&</sup>lt;sup>9</sup> Ibid, Page 29.

<sup>&</sup>lt;sup>10</sup> RACT/BACT/LAER Clearinghouse (RBLC) as maintained by USEPA (link to RBLC website)

### Table 3-1:Biomass Power Boiler RBLC Summary – NOx

| RBLC ID | Technology                               |  |  |
|---------|--|--|--|
| CT-0156 | Regenerative SCR (RSCR)                  |  |  |
| AR-0161 | Selective Catalytic Reduction (SCR)      |  |  |
| KS-0034 | Selective Catalytic Reduction (SCR)      |  |  |
| CA-1203 |  |  |  |
| CA-1225 | Solactive Non Catalytic Reduction (SNCR) |  |  |
| GA-0141 | Selective Non-Catalytic Reduction (SNCR) |  |  |
| ME-0037 |  |  |  |
| AL-0250 | Low NO <sub>x</sub> burners              |  |  |

RSCR has a higher capital cost but greater energy efficiency than SCR. The control efficiencies of the two technologies are similar. RSCR is typically targeted for installation on sources with relatively low flue gas temperatures. Because flue gas temperature in Power Boiler #9 (413°F) is higher than the flue gas temperature in typical RSCR installations, the technology was not considered in the four-factor analysis.

Power Boiler #9 burns primarily hog fuel (biomass), utilizes natural gas as a startup/supplemental fuel, is a backup combustion source for NCG, and is permitted to burn distillate oil. Power Boiler #9 is a stoker grate design. Based on the primary fuel use and the design of Power Boiler #9, low NO<sub>X</sub> burners were not considered in the four factor analysis because:

- Low NO<sub>X</sub> burners for solid fuels (like the ones at coal fired power plants) typically utilize dry solid fuel which is pulverized to a fine powder in a mill and fed pneumatically into the burners. This allows staging of air and fuel in the combustion process in order to reduce NO<sub>X</sub> emissions. This technology is not feasible for the stoker grate hog fuel boiler at Sappi.
- Low NO<sub>X</sub> burners for natural gas and/or distillate oil are technically feasible options, but the hog fuel boiler at Sappi burns primarily hog fuel (biomass). Thus, installing low NO<sub>X</sub> burners for natural gas and/or distillate oil would have a minor impact on NO<sub>X</sub> emissions and therefore was not further considered in the four-factor analysis.

Based on this information, the technologies that were considered in the four-factor analysis are:

- SCR
- SNCR

### 3.1.2 Baseline Emission Rates

The 2019 SIP Guidance states that 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."<sup>11</sup> Thus, Sappi anticipates flat growth in the paper industry and projects that emissions in 2028 will be equivalent to 2019 actual emissions. LADCO estimated 473.87 tpy for NO<sub>X</sub> 2028 emissions, but Sappi proposes to revise the projected emissions as shown in Table 3-2.

| Table 3-2: Projected 2028 NO <sub>x</sub> Emissions (tons per ye |
|--|
|--|

| Year                     | Power Boiler #9 |
|--------------------------|-----------------|
| 2019 Actual Emissions    |                 |
| And                      | 347 tons/year   |
| 2028 Projected Emissions |                 |

### 3.1.3 Factor 1 – Cost of Compliance

Sappi has completed compliance cost estimates for the selected NO<sub>X</sub> emission control measures following EPA's Control Cost Manual as recommended in the 2019 SIP Guidance.<sup>12</sup> The capital cost estimates were confirmed by Sappi's plant engineering staff as reasonable, based on their considerable experience with projects at Sappi and their informal conversations with other companies that have completed similar types of projects at other facilities. A more detailed cost estimate is likely to increase the costs for installing and implementing either of the projects. Cost calculation spreadsheets for the NO<sub>X</sub> emission control measures are provided in Appendix B.

The cost effectiveness analysis compares the annualized cost of the technology per ton of pollutant removed and is evaluated on a 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.

The resulting cost effectiveness calculations are summarized in Table 3-3.

| Additional<br>Emissions Control<br>Measure | Total Capital<br>Investment<br>(\$) | Total Annualized<br>Costs<br>(\$/year) | Control Efficiency<br>(%) | Annual Emissions<br>Reduction<br>(tpy) | Pollution Control<br>Cost Effectiveness<br>(\$/ton) |
|--|-------------------------------------|--|---------------------------|--|---|
| SCR  | \$29,195,285                        | \$2,640,036                            | 80%                       | 278.1 tpy                              | \$9,493/ton   |
| SNCR                                       | \$5,021,391                         | \$623,834                              | 25%                       | 96.8 tpy                               | \$7,191/ton   |

 Table 3-3:
 Power Boiler #9 NOx Control Cost Summary, per Unit Basis

<sup>12</sup> Ibid, Page 21.

<sup>&</sup>lt;sup>11</sup> Ibid, page 29.

Based on the information provided in Table 3-3 and in consideration of RHR analyses conducted in other states, the emission control measures were not considered cost effective.

Sections 3.1.4 through 3.1.6 provide a screening-level summary of the remaining three factors evaluated for the NO<sub>X</sub> emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

## 3.1.4 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, the time for compliance considers the time needed to develop and approve the new emissions limit into the 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.

The technologies would require significant resources and time of at least two to three years design, engineer, procure, and install the equipment. The facility would attempt to complete the construction during a regularly scheduled outage but recognizes that the outage may need to be extended to install all required equipment.

The SIP is scheduled to be submitted in 2021 with the anticipated approval in 2022 (approximately one year after submittal). Once the SIP is approved, the design, engineer, procurement and installation schedule would begin. This would put the anticipated date of installation in 2024 or 2025.

# 3.1.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified NO<sub>X</sub> control measures are summarized below.

- SCR
  - Catalyst plugging could lead to decreased control efficiency, decreased catalyst life, and additional boiler downtime
  - o Increased truck and/or train traffic (reagent and catalyst deliveries)
  - o Possible ammonia slip (unreacted reagent that is emitted to the atmosphere)
  - o Increased natural gas burning to reheat flue gas to achieve SCR inlet temperatures
  - o Catalyst regeneration
  - o Catalyst disposal
  - Electricity consumption (fans and pumps)
- SNCR
  - o Increased truck and/or train traffic (reagent deliveries)
  - o Possible ammonia slip (unreacted reagent that is emitted to the atmosphere)
  - Nitrous oxide (N<sub>2</sub>O) generation (a greenhouse gas)
  - Electricity consumption (pumps)

### 3.1.6 Factor 4 – Remaining Useful Life of the Source

Because Power Boiler #9 is expected to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life) was used to calculate emission reductions, amortized costs, and cost effectiveness on a dollar per ton basis.

## 3.1.7 Proposed NO<sub>X</sub> Controls and Emissions Rates

This analysis does not support the installation of additional NO<sub>x</sub> emission control measures at Power Boiler #9 beyond those described in Section 2.3. As such, Sappi proposes to maintain the existing  $NO_x$ permit limits presented in Table 2-3

# 3.2 SO<sub>2</sub> Four-factor Analysis – Power Boiler #9

This section identifies baseline emission rates and evaluates the four statutory factors for SO<sub>2</sub> emissions from Power Boiler #9.

## 3.2.1 Emission Control Options

The selection of SO<sub>2</sub> emission control options followed the same methodology as described in Section 3.1.1.

The RBLC search for biomass power boilers for SO<sub>2</sub> is presented in Appendix C and a summary is provided in Table 3-4.

|            | Technology      |                                      |
|------------|-----------------|--------------------------------------|
| Table 3-4: | Biomass Power B | oiler RBLC Summary – SO <sub>2</sub> |

| <b>RBLC ID</b> | Technology            |  |  |
|----------------|-----------------------|--|--|
| CT-0162        | Spray Dryer           |  |  |
| AR-0161        |                       |  |  |
| GA-0141        | Dry Sorbent Injection |  |  |
| KS-0034        |                       |  |  |
| CT-0156        |                       |  |  |
| LA-0249        | Low Sulfur Fuels      |  |  |
| ME-0037        |                       |  |  |

Low sulfur fuels were not considered in the four-factor analysis because:

- The primary fuel in Power Boiler #9 is hog fuel (biomass which is primarily bark from the facility de-barking process) which is inherently low in sulfur
- Natural gas is a supplemental fuel and is also a low sulfur fuel
- Distillate oil is an available fuel for Power Boiler #9 and the permit already includes a sulfur limit • (0.050% by weight) and 12-month usage limit; distillate oil is an emergency backup fuel and is not a primary fuel for this boiler

 NCG is the primary source of SO<sub>2</sub> in Power Boiler #9, but the sulfur content of NCG is determined by the pulping process and it would be unreasonable to consider a change as the NCG is fundamental to the operation and design of the pulp mill; furthermore, the boiler is not the primary source for NCG combustion and the ability to combust NCG in the boiler must be maintained as part of the overall strategy for limiting emissions of HAP as required by 40 CFR Part 63 Subpart S (National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry)

Based on this information, the technologies that were considered in the four-factor analysis are:

- Spray dryer absorption
- Dry sorbent injection

### 3.2.2 Baseline Emission Rates

As described in Section 3.1.2, Sappi used projected 2028 emissions as the baseline scenario.

Sappi anticipates flat growth in the paper industry and projects SO<sub>2</sub> emissions in 2028 will equal 2019 actual emissions. LADCO estimated 54.18 tpy for 2028 SO<sub>2</sub> emissions, but Sappi proposes to revise the projected emissions as shown in Table 3-5.

### Table 3-5:Projected 2028 SO2 Emissions (tons per year)

| Year                     | Power Boiler #9 |  |
|--------------------------|-----------------|--|
| 2019 Actual Emissions    | 22 tons/year    |  |
| And                      |                 |  |
| 2028 Projected Emissions |                 |  |

### 3.2.3 Factor 1 – Cost of Compliance

Sappi has completed compliance cost estimates for the selected SO<sub>2</sub> emission control measures following EPA's Control Cost Manual as recommended in the 2019 SIP Guidance.<sup>13</sup> The capital cost estimates were confirmed by Sappi's plant engineering staff as reasonable, based on their considerable experience with projects at Sappi and their informal conversations with other companies that have completed similar types of projects at other facilities. A more detailed cost estimate is likely to increase the costs for installing and implementing either of the projects. Cost calculation spreadsheets for the SO<sub>2</sub> emission control measures are provided in Appendix C.

<sup>&</sup>lt;sup>13</sup> Ibid, Page 21.

The cost effectiveness analysis compares the annualized cost of the technology per ton of pollutant removed and is evaluated on a 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.

The resulting cost effectiveness calculations are summarized in Table 3-6.

| Additional<br>Emissions Control<br>Measure | Total Capital<br>Investment<br>(\$) | Total Annualized<br>Costs<br>(\$/year) | Control Efficiency<br>(%) | Annual Emissions<br>Reduction<br>(tpy) | Pollution Control<br>Cost Effectiveness<br>(\$/ton) |
|--|-------------------------------------|--|---------------------------|--|---|
| Spray dryer<br>absorption                  | \$144,535,337                       | \$24,484,747                           | 70%                       | 15.4                                   | \$1,589,900   |
| Dry sorbent<br>injection                   | \$41,178,526                        | \$5,672,396                            | 50%                       | 11.0                                   | \$5,672,396   |

 Table 3-6:
 Power Boiler #9 SO2 Control Cost Summary, per Unit Basis

Based on the information provided in Table 3-6 and in consideration of RHR analyses conducted in other states, the emission control measures were not considered cost effective.

Sections 3.2.4 through 3.2.6 provide a screening-level summary of the remaining three factors evaluated for the SO<sub>2</sub> emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

## 3.2.4 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, the time for compliance considers the time needed to develop and approve the new emissions limit into the 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.

The technologies would require significant resources and time of at least two to three years to engineer, permit, and install the equipment. The facility would attempt to complete the construction during a regularly scheduled outage but recognizes that the outage may need to be extended to install all required equipment.

The SIP is scheduled to be submitted in 2021 with the anticipated approval in 2022 (approximately one year after submittal). Once the SIP is approved, the design, engineer, procurement and installation schedule would begin. This would put the anticipated date of installation in 2024 or 2025.

# 3.2.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified SO<sub>2</sub> control measures are summarized below:

- Spray Dryer
  - Increased waste generation and disposal due to additional material collected in the particulate emissions control system
  - o Increased truck and/or train traffic (reagent deliveries and waste hauling)
  - Water consumption for slurry
  - o Electricity consumption (fans and pumps)
- Dry Sorbent injection
  - Increased waste generation and disposal due to additional material collected in the particulate emissions control system
  - o Increased truck and/or train traffic (reagent deliveries and waste hauling)
  - o Electricity consumption (fans and pumps)

# 3.2.6 Factor 4 – Remaining Useful Life of the Source

Because Power Boiler #9 is expected to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life) was used to calculate emission reductions, amortized costs and cost effectiveness on a dollar per ton basis.

# 3.2.7 Proposed SO<sub>2</sub> Controls and Emissions Rates

This analysis does not support the installation of additional SO<sub>2</sub> emission control measures at Power Boiler #9 beyond those described in Section 2.3. As such, Sappi proposes to maintain the existing SO<sub>2</sub> permit limits presented in Table 2-2.

# 4 Recovery Boiler #10: Effective Controls Analysis

The 2019 SIP Guidance states that it "may be reasonable for a state not to select an effectively controlled source"<sup>14</sup> for the four-factor analysis with the rationale that "it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls necessary."<sup>15</sup> EPA identified potential scenarios that "EPA believes it may be reasonable for a state not to select a particular source for further analysis." However, EPA clarified that the associated scenarios are not a comprehensive list but are merely to illustrate examples for the state to consider.

One of the "effectively controlled" scenarios is for sources that went through a best available control technology (BACT) review with a construction permit issued on or after July 31, 2013.<sup>16</sup> EPA notes that the BACT control equipment review methodologies are "similar to, if not more stringent than, the four statutory factors for reasonable progress."<sup>17</sup>

Recovery Boiler #10 underwent a BACT review for NO<sub>x</sub>, among other pollutants, and the associated construction permit was issued in 2017 (Air Permit 01700002-101), which is after the USEPA's July 31, 2013 scenario threshold date. Thus, this unit meets this scenario and is considered "effectively controlled" and, therefore, a four-factor analysis was not conducted. As such, Sappi proposes to maintain the existing NO<sub>x</sub> permit limits presented in Table 2-3.

- <sup>15</sup> Ibid, Page 23.
- <sup>16</sup> Ibid, Page 23.
- <sup>17</sup> Ibid, Page 23.

<sup>&</sup>lt;sup>14</sup> Ibid, Page 22.

# 5 Visibility Impacts Review

The Regional Haze Rule (RHR) requires that the SIP include an analysis of "baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."<sup>18</sup> This is used to establish progress goals to be achieved by the end of the implementation period in 2028.<sup>19</sup> Section 5.1 provides an analysis of current visibility conditions at the three Class I areas near Sappi's facility: Boundary Waters, Voyageurs, and Isle Royale. Since 2009, the regional haze impairment at all three Class I areas has been declining (i.e., visibility has been improving). Additionally, regional haze impairment fell below the expected 2028 Universal Rate of Progress (URP) goal in 2016 for Boundary Waters and Isle Royale, and 2018 for Voyageurs. Because the existing visibility data demonstrates sustained progress towards visibility goals and the 5-year average visibility impairment on the most impaired days is already below the URP, the MPCA should use the current trend of emission reductions to demonstrate reasonable progress.

Additionally, the 2019 SIP Guidance provides criteria to evaluate when selecting sources that must complete an analysis of emission controls. One of the options for estimating baseline visibility impacts is a particle trajectory analysis.<sup>20</sup> In addition, the 2019 SIP Guidance says that a state can consider visibility impacts in Class I areas when evaluating possible emission control measures.<sup>21</sup> Section 5.2 provides results from two different particle trajectory analyses for the most impaired days at the Boundary Waters visibility monitor. The Boundary Waters area was selected because it is the closest Class I area to the Sappi facility. The results of the analysis conclude that Sappi provides a marginal contribution to visibility impairment at the nearby Class I areas. Thus, additional control measures implemented at Sappi are unlikely to provide a substantial improvement in visibility in the Class I areas.

# 5.1 IMPROVE Data Analysis

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at Boundary Waters (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).<sup>22</sup> The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). The EPA issued guidance for tracking visibility progress, including the methods for selecting the "most impaired days," on December 20, 2018.<sup>23</sup> Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms)

<sup>18 40</sup> CFR 51.308(f)(1)

<sup>19 40</sup> CFR 51.308(f)(3)

<sup>&</sup>lt;sup>20</sup> Ibid, Page 13.

<sup>&</sup>lt;sup>21</sup> Ibid, Page 34.

<sup>&</sup>lt;sup>22</sup> <u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze\_visibility\_metrics\_public/Visibilityprogress</u>

<sup>&</sup>lt;sup>23</sup> <u>https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional</u>

could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."<sup>24</sup>

Figure 5.1 through Figure 5.3 show the rolling 5-year average visibility impairment compared with the URP glidepath<sup>25</sup> at Boundary Waters (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1), respectively. Regional haze impairment has been declining since 2009 for all three Class I areas that are tracked by MPCA. Impacts to the most impaired days at Boundary Waters and Isle Royale fell below the expected 2028 URP goal in 2016 and have continued trending downward since. Voyageurs impaired days fell below the 2028 URP in 2018, and is also on a downward trend.

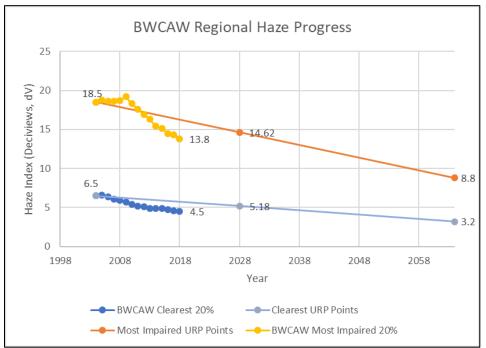


Figure 5.1: Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

<sup>&</sup>lt;sup>24</sup> USEPA, Federal Register, 05/04/2016, Page 26948

<sup>&</sup>lt;sup>25</sup><u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze visibility metrics public/Visibilitypro</u> gress

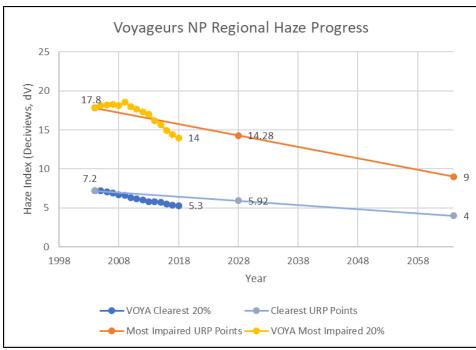


Figure 5.2: Visibility Trend versus URP – Voyageurs National Park (VOYA1)

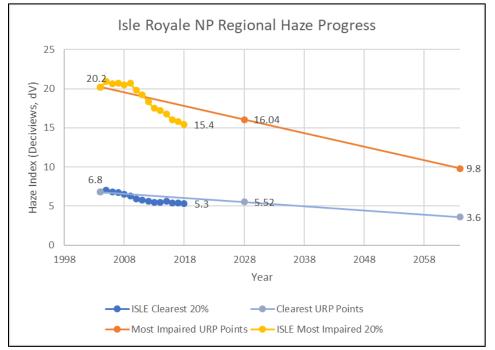
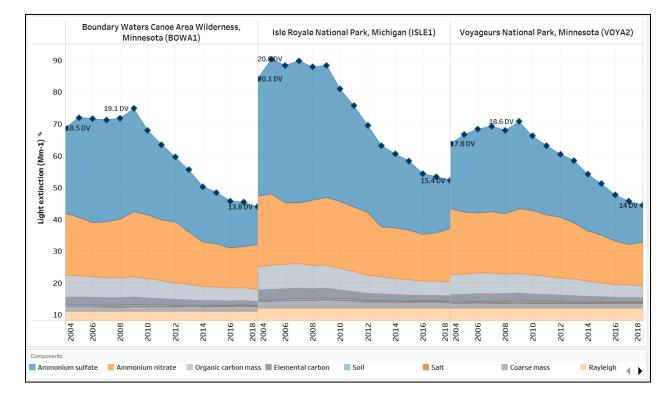


Figure 5.3: Visibility Trend versus URP - Isle Royale National Park (ISLE1)

The downward visibility trend for each of the Class I monitors described above can be mostly attributed to the reductions in ammonium sulfate and, to a lesser extent, ammonium nitrate as show in Figure 5.4. These reductions are a result of a number of different actions taken to reduce emissions from several sources, including:

- Installation of BART during the first RHR implementation period
- Emission reductions from a variety of industries, including pulp and paper mill sources, due to updated rules and regulations
- Transition of power generation systems from coal to natural gas and renewables (wind and solar)



# Figure 5.4: Visibility Components Trend for each Class 1 Monitor from 2004-2018<sup>26</sup>

Additionally, since the end of 2018, many facilities have implemented emission reduction actions that are not represented in the data in Figure 5.1 through Figure 5.4 including:

• Retiring two coal-fired boilers at the Minnesota Power Boswell Energy Center in Cohasset at the end of 2018

<sup>&</sup>lt;sup>26</sup> MPCA – Regional Haze Tableau Public.

https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze visibility metrics public/Visibilityprogress

- The compliance schedules for the NO<sub>X</sub> emission reductions required by the Taconite Federal Implementation Plan (FIP) Establishing BART for Taconite Plants (40 CFR 52.1235)
- Other planned emission reduction projects that are scheduled to occur in Minnesota prior to 2028, such as the Xcel Energy boiler retirements as detailed in their Upper Midwest Integrated Resource Plan, 2020-2034

These emission reductions will further improve the visibility in the Class I areas, thus helping to ensure the trend remains below the URP to reach the 2028 visibility goal.

The 2019 Guidance says that the state will determine which emission control measures are necessary to make reasonable progress in the affected Class I areas.<sup>27</sup> Because the IMPROVE monitoring network data demonstrates sustained progress towards visibility goals and the 5-year average visibility impairment on the most impaired days is already below the URP, the MPCA should use the current trend of emission reductions to demonstrate reasonable progress.

# 5.2 Trajectory Analysis

The 2019 Guidance says that a state should estimate baseline visibility impacts in Class I areas when selecting which sources must conduct a four-factor analysis.<sup>28</sup> In addition, the 2019 Guidance says that a state can consider visibility impacts in Class I areas when evaluating possible emission control measures.<sup>29</sup> Barr conducted a trajectory analysis to provide insight as to the possible visibility impacts in the Boundary Waters due to emissions from Sappi. The Boundary Waters were selected as the closest Class I area.

A trajectory analysis considers the transport path of a particular air mass and the associated particles within the air mass to see if the air mass traveled over certain locations from specific source locations. The MPCA developed a tool<sup>30</sup> which calculates reverse trajectories from Class I areas in Minnesota for the "clearest" and "most impaired" days for 2007-2016 to help illustrate the influence of regional emissions on visibility. The reverse trajectories included in the MPCA tool were developed using the NOAA Hysplit model.<sup>31</sup> The trajectories consist of a single back trajectory for each "most impaired" day beginning at 18:00 and running back 48 hours with a starting height of 10 m.

Barr completed an analysis to determine which of MPCA's reverse trajectories from the Boundary Waters (BOWA1) monitor potentially crossed near Sappi to determine if the emissions from Sappi may have

<sup>29</sup> Ibid, Page 34.

30

<sup>&</sup>lt;sup>27</sup> Ibid, Page 9.

<sup>&</sup>lt;sup>28</sup> Ibid, Page 12.

https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze visibility metrics public/Regionalinflu ence

<sup>&</sup>lt;sup>31</sup> <u>https://www.arl.noaa.gov/hysplit/hysplit/</u>

influenced the visibility on the "most impaired" days at the monitor. Figure 5.5 summarizes the number of "most impaired" trajectories for each year and season from 2014-2016 (the most recent year with data available on the MPCA website) and the corresponding number of "most impaired" trajectories that crossed near Sappi. The trajectories which crossed near Sappi are presented in Figure 5.6.

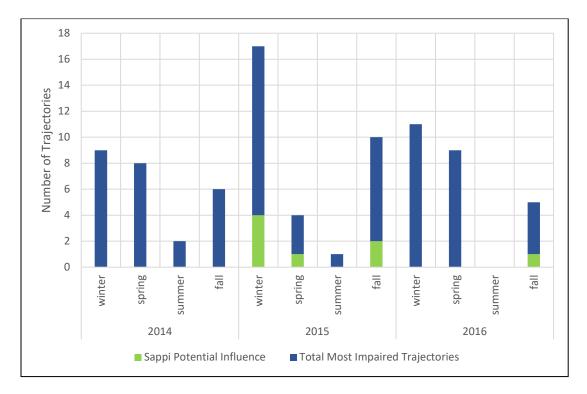


Figure 5.5: Total Number of Most Impaired Trajectories and Number that Cross Near Sappi for 2014-2016



Figure 5.6: Most Impaired Trajectories from MPCA Analysis that Cross Near Sappi in 2015-2016 (no trajectories cross near Sappi in 2014).

Based on the information provided in Figure 5.5, the number of trajectories originating from the Boundary Waters that cross near Sappi indicates that 84% of the time the trajectories did not cross near Sappi for the years analyzed (2014-2016). As expected, this percentage suggests that many sources and source regions other than Sappi are contributing to the visibility of the "most impaired" days at the monitor.

Furthermore, the characterization of potential impacts is a conservative representation as the trajectory only had to cross within 20-30 miles of Cloquet to be included. Also, the majority of the origins of the reverse trajectories are well beyond the Sappi facility location and thus could have influences, depending on the trajectory, from a variety of other sources and from nearby cities such as Duluth, St. Cloud, Rochester, and the Twin Cities (Figure 5.6).

Based on the information provided above, we can conclude that emissions from Sappi are not a primary contributor to visibility impairment on the most impaired days at the Boundary Waters. Thus, additional control measures implemented at Sappi are unlikely to provide a substantial improvement in visibility in the Class I areas.

Appendices

# Appendix A

**RBLC Search for Biomass Power Boilers for NO**<sub>x</sub>

# Sappi Cloquet LLC Appendix A : RBLC Search for Biomass Power Boilers for NOX

Pollutant Name: NOx NOTE: Draft determinations are marked with a " \* " beside the RBLC ID.

| RBLCID   | FACILITY NAME                                  | CORPORATE OR COMPANY<br>NAME                  | FACILITY<br>STATE | PERMIT NUM               | NAICS<br>CODE | PERMIT DATE    | FACILITY DESCRIPTION   | Process<br>Name  | Fuel                             | Through-<br>put | UNITS    | Pollutant                | Emission Control Description  | Emission<br>Limit 1 | Limits Units 1 | Avg Time                           | CASE-BY-<br>CASE<br>BASIS | Emission<br>Limit 2 | Limits Units2 | Avg Time2                                     | Standard<br>Emission<br>Limit | t Standard Limit<br>Avg Time |
|----------|--|---|-------------------|--------------------------|---------------|----------------|--|--|----------------------------------|-----------------|----------|--------------------------|---|---------------------|----------------|------------------------------------|---------------------------|---------------------|---------------|---|-------------------------------|------------------------------|
| AL-0250  | BOISE WHITE PAPER                              | BOISE WHITE PAPER, LLC                        | AL                | 102-0001                 | 322121        | 03/23/2010 ACT |  | COMBINATION<br>BOILER  | WOOD                             | 435             | MMBTU/H  | Nitrogen Oxides<br>(NOx) | LOW NOX BURNERS   | 0.3                 | LB/MMBTU       | 3 H                                | BACT-PSD                  | 130.5               | LB/H          | 3 H   | 0                             |                              |
| *AR-0161 | SUN BIO MATERIAL COMPANY                       | SUN BIO MATERIAL COMPANY                      | AR                | 2384-AOP-R0              | 322110        | 09/23/2019 ACT | A kraft paper mill designed with one high yield Kraft softwood<br>Fiberine and two linerboard machiens. The plant is initially sized<br>to support an approximate, nominal linerboard production<br>capacity of 4,400 machine dry tons per day at varying base             | Power Boiler   | Biomass                          | 1200            | MMBtu/hr | Nitrogen Oxides<br>(NOx) | Selective Catalytic Reduction   | 0.06                | LB/MMBTU       | 3-HOUR                             | BACT-PSD                  | 0                   |               |   | 0                             |                              |
| CA-1203  | SIERRA PACIFIC INDUSTRIES-LOYALTON             | SIERRA PACIFIC INDUSTRIES                     | CA                | SAC 87-01-A              | 221119        | 08/30/2010 ACT | 20 MW COGENERATION POWER PLANT   | RILEY SPREADER<br>STOKER BOILER -<br>Transient Period<br>(see notes) | WOOD                             | 335.7           | MMBTU/H  | Nitrogen Oxides<br>(NOx) | SELECTIVE NON-CATALYTIC REDUCTION<br>(SNCR)                                 | 102                 | PPM            | @12% CO2, 8-HR<br>ROLLING AVG      | BACT-PSD                  | 65                  | LB/H          | 8-HR ROLLING AVG                              | 0                             |                              |
| CA-1203  | SIERRA PACIFIC INDUSTRIES-LOYALTON             | SIERRA PACIFIC INDUSTRIES                     | CA                | SAC 87-01-A              | 221119        | 08/30/2010 ACT | 20 MW COGENERATION POWER PLANT   | RILEY SPREADER<br>STOKER BOILER                                      | WOOD                             | 335.7           | MMBTU/H  | Nitrogen Oxides<br>(NOx) | SELECTIVE NON-CATALYTIC REDUCTION<br>(SNCR)                                 | 80                  | PPM            | @12% CO2, 8-HR<br>ROLLING AVG      | BACT-PSD                  | 50.75               | LB/H          | 8-HR ROLLING AVG                              | 0                             |                              |
| CA-1225  | SIERRA PACIFIC INDUSTRIES-ANDERSON<br>DIVISION | SIERRA PACIFIC INDUSTRIES                     | CA                | SAC 12-01                | 321113        | 04/25/2014 ACT | 31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY   | STOKER BOILER<br>(NORMAL<br>OPERATION)                               | BIOMASS                          | 468             | MMBTU/H  | Nitrogen Oxides<br>(NOx) | SNCR  | 0.13                | LB/MMBTU       | 12-MONTH<br>ROLLING BASIS          | BACT-PSD                  | 0.15                | lb/mmbtu      | 3-HOUR BLOCK<br>AVERAGE                       | 0                             |                              |
| CA-1225  | SIERRA PACIFIC INDUSTRIES-ANDERSON<br>DIVISION | SIERRA PACIFIC INDUSTRIES                     | CA                | SAC 12-01                | 321113        | 04/25/2014 ACT | 31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY   | STOKER BOILER<br>(STARTUP &<br>SHUTDOWN<br>PERIODS)                  | BIOMASS                          | 468             | MMBTU/H  | Nitrogen Oxides<br>(NOx) | SNCR  | 70.2                | LB/H           | 8-HR AVG<br>(STARTUP<br>PERIODS)   | BACT-PSD                  | 70.2                | LB/H          | 8-HR AVG<br>(SHUTDOWN<br>PERIODS)             | 0                             |                              |
| CT-0156  | MONTVILLE POWER LLC                            | NRG ENERGY                                    | СТ                | 107-0056                 | 221119        | 04/06/2010 ACT | 43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED<br>NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL<br>CAPACITY FACTOR)   | 42 MW Biomass<br>utility boiler                                      | Clean wood                       | 600             | MMBTU/H  | Nitrogen Oxides<br>(NOx) | Regenerative SCR  | 0.06                | LB/MMBTU       | 24 HR BLOCK                        | LAER                      | 0                   |               |   | 0                             |                              |
| CT-0162  | PLAINFIELD RENEWABLE ENERGY, LLC               | PLAINFIELD RENEWABLE ENERGY, LLC              | СТ                | 145-0049                 | 221119        | 12/29/2010 ACT | 37.5 MW Biomass Power Plant  | Fluidized Bed<br>Gasification  | Wood                             | 523.1           | MMBtu/hr | Nitrogen Oxides<br>(NOx) | SNCR  | 0.075               | LB/MMBTU       |                                    | LAER                      | 45.3                | PPMVD @7% O2  | 24 HR BLOCK                                   | 0                             |                              |
| GA-0141  | WARREN COUNTY BIOMASS ENERGY<br>FACILITY       | OGETHORPE POWER CORPERATION                   | GA                | 4911-301-0016-P-<br>01-0 | 221119        | 12/17/2010 ACT | The proposed project will include: a bubbling fluidized bed boiler<br>with a maximum total heat input capacity of 1,399 MMBTU/H, 2<br>fire water pump emergency engines; a raw material handling &<br>storage area; a sorbent storage silo; a boiler bed sand silo, a sand | Boiler, Biomass<br>Wood  | Biomass<br>wood                  | 100             | MW       | Nitrogen Oxides<br>(NOx) | Selective non-catalytic reduction system (SNCR)                             | 0.1                 | LB/MMBTU       | 30 D ROLLING AV /<br>CONDITION 2.9 | BACT-PSD                  | 648                 | TONS          | 12 MONTH<br>ROLLING TOTAL /<br>CONDITION 2.18 | 0                             |                              |
| *KS-0034 | ABENGOA BIOENERGY BIOMASS OF KANSAS<br>(ABBK)  | ABENGOA BIOENERGY BIOMASS OF KANSAS<br>(ABBK) | KS                | C-11396                  | 325193        | 05/27/2014 ACT | Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install<br>and operate a biomass-to-ethanol and biomass-to-energy<br>production facility near Hugoton, Kansas.   | biomass to<br>energy<br>cogeneration<br>bioler                       | different<br>types of<br>biomass | 500             | MMBtu/hr | Nitrogen Oxides<br>(NOx) | Selective Catalytic Reduction System (SCR)<br>and an over-fire system (OFA) | 0.3                 | LB/MMBTU       | 30-DAY ROLLING,<br>INCLUDES SSM    | BACT-PSD                  | 157.5               | LB/HR         | 1-HR AVE,<br>INCLUDES SSM                     | 0                             |                              |
| ME-0037  | VERSO BUCKSPORT LLC                            | VERSO BUCKSPORT LLC                           | ME                | A-22-77-4-A              | 322121        | 11/29/2010 ACT | Existing pulp (groundwood and thermomechanical) and paper<br>making facility.  | Biomass Boiler 8   | Biomass                          | 814             | MMBTU/H  | Nitrogen Oxides<br>(NOx) | SNCR  | 0.15                | LB/MMBTU       | 30 DAY ROLLING                     | BACT-PSD                  | 244.2               | LB/H          |   | 0                             |                              |

# Appendix B

Power Boiler #9 – Control Cost Calculations for NO<sub>X</sub>

# Sappi Cloquet LLC Boiler #9 Appendix B - NO<sub>x</sub> SNCR Calculations

|  |           | Boiler 9                               | Comment  |  |  |
|--|-----------|--|--|--|--|
| Max<br>Firing Rate   | 430       | MMBtu/hr                               | PTE Calculations for Boiler 9  |  |  |
| NO <sub>x</sub> Emission Rate<br>(Uncontrolled)                        | 0.292     | lb/MMBtu                               | 2019 Emission Inventory  |  |  |
| System Capacity Factor<br>(Actual rate vs. max<br>firing rate at 8760) | 63.1%     |  | 2019 actual fuel per year / Maximum fuel per<br>year (See "SCR Design Parameters") |  |  |
| Uncontrolled<br>Emissions  | 347.0     | ton/year                               | Calculated from Above  |  |  |
| Control<br>Efficiency  |           | 25.0%                                  | From "Data Inputs"   |  |  |
| NO <sub>x</sub> Controls<br>Emission Rate                              | 0.219     | lb/MMBtu                               | Calculated from Above  |  |  |
| Controlled<br>Emissions  | 260.3     | ton/year                               | Calculated from Above  |  |  |
| Total Capital Investment \$5,021,391<br>(TCI)                          |           | \$5,021,391                            | From "Cost Estimate"   |  |  |
| Total Annual Cost (TAC)<br>=   | \$623,834 | per year in 2020 dollars               |  |  |  |
| NOx Removed =  | 86.8      | tons/year                              | Calculated from above  |  |  |
| Current Retrofit Factor = 1.33   |           | From "Data Inputs"                     |  |  |  |
| Cost Effectiveness =   | \$7,191   | per ton of NOx removed in 2020 dollars | From "Cost Estimate"   |  |  |

| Data Inputs   |  |   |  |  |
|---|--|---|--|--|
| Enter the following data for your combustion unit:  |  |   |  |  |
| Is the combustion unit a utility or industrial boiler?  | ustrial 🗸  | What type of fuel does the unit burn?   |  |  |
| Is the SNCR for a new boiler or retrofit of an existing boiler?   | ▼  |   |  |  |
| Please enter a retrofit factor equal to or greater than 0.84 based on the lev<br>difficulty. Enter 1 for projects of average retrofit difficulty. | vel of 1.33  |   |  |  |
| Complete all of the highlighted data fields:  |  | Provide the following information for coal-fired boilers:   |  |  |
| What is the maximum heat input rate (QB)?   | 430.0 MMBtu/hour   | Type of coal burned:  |  |  |
| What is the higher heating value (HHV) of the fuel?   | 4,597 Btu/lb   | Enter the sulfur content (%S) = 0.05 percent by weight  |  |  |
|   |  | or<br>Select the appropriate SO <sub>2</sub> emission rate: < 3lb/MMBtu •   |  |  |
| What is the estimated actual annual fuel consumption?   | 536,062,322 lbs/Year   |   |  |  |
| Is the boiler a fluid-bed boiler?   | No 🔻   | Ash content (%Ash): 2.8 percent by weight   |  |  |
|   |  | For units burning coal blends:  |  |  |
| Enter the net plant heat input rate (NPHR)  | 10 MMBtu/MW  | 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. |  |  |
| Co<br>Fu  | el Type Default NPHR<br>bal 10 MMBtu/MW<br>el Oil 11 MMBtu/MW<br>atural Gas 8.2 MMBtu/MW | Fraction in<br>Coal Blend%5%AshHHV (Btu/lb)Fuel Cost<br>(\$/MIMBtu)Bituminous01.849.2311,8412.4Sub-Bituminous00.415.848,8261.89Lignite00.8213.66,6261.74  |  |  |

## Enter the following design parameters for the proposed SNCR:

| Number of days the SNCR operates ( $t_{\text{SNCR}}$ )           | 352 days              | Plant Elevation          | 1083 Feet above sea level                  |  |  |
|--|-----------------------|--------------------------|--|--|--|
| Inlet NO <sub>x</sub> Emissions (NOx <sub>in</sub> ) to SNCR     | 0.292 lb/MMBtu        | 25.0% Control Efficiency |  |  |  |
| Outlet NO <sub>x</sub> Emissions (NOx <sub>out</sub> ) from SNCR | 0.219 lb/MMBtu        | ,                        |  |  |  |
| Estimated Normalized Stoichiometric Ratio (NSR)                  | 3.02                  |                          |  |  |  |
|  |                       | _                        |  |  |  |
| Concentration of reagent as stored (C <sub>stored</sub> )        | 29 Percent            |                          |  |  |  |
| Density of reagent as stored ( $\rho_{stored}$ )                 | 56 lb/ft <sup>3</sup> |                          |  |  |  |
| Concentration of reagent injected (C <sub>inj</sub> )            | 10 percent            | Densities of typical SI  | NCR reagents:                              |  |  |
| Number of days reagent is stored (t <sub>storage</sub> )         | 14 days               | 50% urea sc              | lution 71 lbs/ft <sup>3</sup>              |  |  |
| Estimated equipment life   | 20 Years              | 29.4% aqueo              | ous NH <sub>3</sub> 56 lbs/ft <sup>3</sup> |  |  |
|  |                       | _                        |  |  |  |
| Select the reagent used  | Ammonia 🔻             |                          |  |  |  |

## Enter the cost data for the proposed SNCR:

| Desired dollar-year   | 2020  | ]   |
|---|---|---|
| CEPCI for 2020  | 607.5 2019 Final CEPCI value 541.7 2016 CEPCI   | CEPCI = Chemical Engineering Plant Cost Index |
|   |   |   |
| Annual Interest Rate (i)  | 5.5 Percent*  |   |
| Fuel (Cost <sub>fuel</sub> )                                      | 1.74 \$/MMBtu*  |   |
| Reagent (Cost <sub>reag</sub> )                                   | 0.29 \$/gallon for a 29 percent solution of ammonia   |   |
| Water (Cost <sub>water</sub> )                                    | 0.0042 \$/gallon*   |   |
| Electricity (Cost <sub>elect</sub> )                              | 0.0676 \$/kWh*  |   |
| Ash Disposal (for coal-fired boilers only) (Cost <sub>ash</sub> ) | 48.80 \$/ton*   |   |
|   | * The values marked are default values. See the table below for the default values used and |   |

\* 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) = Administrative Charges Factor (ACF) =



## Data Sources for Default Values Used in Calculations:

|   |               |  | If you used your own site-specific values, please enter the value used |
|---|---------------|--|--|
| Data Element                                | Default Value | Sources for Default Value  | and the reference source   |
| Reagent Cost (\$/gallon)                    |               | U.S. Geological Survey, Minerals Commodity Summaries, January 2017                                 |  |
|   |               | (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf                     |  |
|   |               |  |  |
|   |               |  |  |
|   |               |  |  |
| Water Cost (\$/gallon)                      | 0.00417       | Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see             |  |
| water cost (\$/galloll)                     | 0.00417       | 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at                           |  |
|   |               | http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-                          |  |
|   |               | brochure-water-wastewater-rate-survey.pdf.   |  |
|   |               |  |  |
|   |               |  |  |
|   |               |  |  |
| Electricity Cost (\$/kWh)                   | 0.0676        | U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published               |  |
|   |               | December 2017. Available at:   |  |
|   |               | https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.                        |  |
|   |               |  |  |
| Fuel Cost (\$/MMBtu)                        | 1.74          | U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published           |  |
|   |               | December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.                   |  |
|   |               |  |  |
| Ask Disessed Cast (Élber)                   | 48.8          | Wests Dusing a lower little Cost to Londfill MCM Costinues to Disc Despite Coff                    |  |
| 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:<br>http://www.wastebusinessjournal.com/news/wbj20170711A.htm. |  |
|   |               |  |  |
|   |               |  |  |
| Dercent sulfur content for Coal (0/ weight) | 0.82          | Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy                |  |
| Percent sulfur content for Coal (% weight)  | 0.82          | Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant               |  |
|   |               | Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.                       |  |
|   |               |  |  |
|   |               |  |  |
| 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 http://www.eia.gov/electricity/data/eia923/.                       |  |
|   |               |  |  |
| Higher Heating Value (HHV) (Btu/lb)         | 6,685         | Select type of coal  |  |
|   |               |  |  |
|   |               |  |  |
|   |               |  |  |
| Interest Rate (%)                           | 5.5           | Default bank prime rate  |  |
|   |               |  |  |

# **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 <sub>B</sub> ) =         | HHV x Max. Fuel Rate =   | 430              | MMBtu/hour |
| Maximum Annual fuel consumption (mfuel) =                  | (QB x 1.0E6 Btu/MMBtu x 8760)/HHV =  | 819,334,091      | lbs/Year   |
| Actual Annual fuel consumption (Mactual) =                 |  | 536,062,322      | lbs/Year   |
| Heat Rate Factor (HRF) =                                   | NPHR/10 =  | 1.00             |            |
| Total System Capacity Factor (CF <sub>total</sub> ) =      | (Mactual/Mfuel) x (tSNCR/365) =  | 0.631            | fraction   |
| Total operating time for the SNCR (t <sub>op</sub> ) =     | CF <sub>total</sub> x 8760 =   | 5527             | hours      |
| NOx Removal Efficiency (EF) =                              | (NOx <sub>in</sub> - NOx <sub>out</sub> )/NOx <sub>in</sub> =  | 25               | percent    |
| NOx removed per hour =                                     | $NOx_{in} \times EF \times Q_B =$  | 31.39            | lb/hour    |
| Total NO <sub>x</sub> removed per year =                   | (NOx <sub>in</sub> x EF x Q <sub>B</sub> x t <sub>op</sub> )/2000 =                                    | 86.75            | 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             |            |
| $SO_2$ Emission rate =                                     | (%S/100)x(64/32)*(1x10 <sup>6</sup> )/HHV =  | < 3              | lbs/MMBtu  |
| Elevation Factor (ELEVF) =                                 | 14.7 psia/P =  | 1.04             |            |
| Atmospheric pressure at 1083 feet above sea level<br>(P) = | 2116x[(59-(0.00356xh)+459.7)/518.6] <sup>5.256</sup> x (1/144)*<br>=                                   | 14.1             | psia       |
| Retrofit Factor (RF) =                                     | Retrofit to existing boiler  | 1.33             |            |

\* 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 | Ammonia | Molecular Weight of Reagent (MW) = | 17.03 g/mole |

Density = 56 lb/gallon

| Parameter  | Equation  | Calculated Value | Units   |
|--|---|------------------|---|
| Reagent consumption rate (m <sub>reagent</sub> ) = | $(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR) =$     | 141              | lb/hour   |
|  | (whre SR = 1 for $NH_3$ ; 2 for Urea)                                     |                  |   |
| Reagent Usage Rate (m <sub>sol</sub> ) =           | m <sub>reagent</sub> /C <sub>sol</sub> =                                  | 485              | lb/hour   |
|  | (m <sub>sol</sub> x 7.4805)/Reagent Density =                             | 64.8             | gal/hour  |
| Estimated tank volume for reagent storage =        | (m <sub>sol</sub> x 7.4805 x t <sub>storage</sub> x 24 hours/day)/Reagent | 21.800           | gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons) |
|  | Density =   | 21,800           | rounded up to the nearest 100 gallons)  |

## **Capital Recovery Factor:**

| Parameter                       | Equation                                      | Calculated Value |
|---------------------------------|---|------------------|
| Capital Recovery Factor (CRF) = | $i(1+i)^{n}/(1+i)^{n}-1=$                     | 0.0837           |
|                                 | Where n = Equipment Life and i= Interest Rate |                  |

| Parameter  | Equation  | Calculated Value | Units        |
|--|---|------------------|--------------|
| Electricity Usage:<br>Electricity Consumption (P) =  | (0.47 x NOx <sub>in</sub> x NSR x Q <sub>B</sub> )/NPHR =                               | 17.9             | kW/hour      |
| Water Usage:<br>Water consumption (q <sub>w</sub> ) =                                      | (m <sub>sol</sub> /Density of water) x ((C <sub>stored</sub> /C <sub>inj</sub> ) - 1) = | 110              | gallons/hour |
| Fuel Data:<br>Additional Fuel required to evaporate water in<br>injected reagent (ΔFuel) = | Hv x m <sub>reagent</sub> x ((1/C <sub>inj</sub> )-1) =                                 | 1.14             | MMBtu/hour   |
| Ash Disposal:<br>Additional ash produced due to increased fuel<br>consumption (∆ash) =     | ( $\Delta$ fuel x %Ash x 1x10 <sup>6</sup> )/HHV =                                      | 6.9              | lb/hour      |

## **Cost Estimate**

## Total Capital Investment (TCI)

### For Coal-Fired Boilers:

 $TCI = 1.3 x (SNCR_{cost} + APH_{cost} + BOP_{cost})$ 

For Fuel Oil and Natural Gas-Fired Boilers:

TCI =  $1.3 \times (SNCR_{cost} + BOP_{cost})$ 

| Capital costs for the SNCR (SNCR <sub>cost</sub> ) = | \$3,862,609 in 2020 dollars    |
|--|--------------------------------|
| Air Pre-Heater Costs (APH <sub>cost</sub> )* =       | \$0 in 2020 dollars            |
| Balance of Plant Costs (BOP <sub>cost</sub> ) =      | \$0 in 2020 dollars            |
| Total Capital Investment (TCI) =                     | \$5,021,391.50 in 2020 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 <sub>cost</sub> )   |             |   |  |  |  |  |  |
|--|-------------|---|--|--|--|--|--|
|  |             | in 2020 dollars (Jansen report 2012 equipment |  |  |  |  |  |
| SNCR Capital Costs (SNCR <sub>cost</sub> ) = | \$3,862,609 | scaled to 2020 \$)                            |  |  |  |  |  |

|   | Air Pre-Heater Costs (APH <sub>cost</sub> )*   |  |  |  |  |  |
|---|--|--|--|--|--|--|
| For Coal-Fired Utility Boilers:   |  |  |  |  |  |  |
|   | APH <sub>cost</sub> = 69,000 x (B <sub>MW</sub> x HRF x CoalF) <sup>0.78</sup> x AHF x RF                                |  |  |  |  |  |
| For Coal-Fired Industrial Boilers:  |  |  |  |  |  |  |
| A   | $PH_{cost} = 69,000 x (0.1 x Q_B x HRF x CoalF)^{0.78} x AHF x RF$   |  |  |  |  |  |
|   |  |  |  |  |  |  |
| Air Pre-Heater Costs (APH <sub>cost</sub> ) =   | \$0 in 2020 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<br>sulfur dioxide. |  |  |  |  |  |  |
|   | Balance of Plant Costs (BOP <sub>cost</sub> )  |  |  |  |  |  |
| For Coal-Fired Utility Boilers:   |  |  |  |  |  |  |
| BOP <sub>cc</sub>   | $_{\text{ost}}$ = 320,000 x (B <sub>MW</sub> ) <sup>0.33</sup> x (NO <sub>x</sub> Removed/hr) <sup>0.12</sup> x BTF x RF |  |  |  |  |  |
| For Fuel Oil and Natural Gas-Fired Utility B  | oilers:  |  |  |  |  |  |
| BC  | $P_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$                                    |  |  |  |  |  |
| For Coal-Fired Industrial Boilers:  |  |  |  |  |  |  |
| BOP <sub>cost</sub>   | = 320,000 x (0.1 x Q <sub>B</sub> ) <sup>0.33</sup> x (NO <sub>x</sub> Removed/hr) <sup>0.12</sup> x BTF x RF            |  |  |  |  |  |
| For Fuel Oil and Natural Gas-Fired Industrial Boilers:  |  |  |  |  |  |  |
| BOPc  | $_{ost}$ = 213,000 x (Q <sub>B</sub> /NPHR) <sup>0.33</sup> x (NO <sub>x</sub> Removed/hr) <sup>0.12</sup> x RF          |  |  |  |  |  |
|   |  |  |  |  |  |  |
| Balance of Plant Costs (BOP <sub>cost</sub> ) =   | \$0 in 2020 dollars  |  |  |  |  |  |

## **Annual Costs**

### Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

| Direct Annual Costs (DAC) =           | \$201,284 in 2020 dollars |
|---------------------------------------|---------------------------|
| Indirect Annual Costs (IDAC) =        | \$422,550 in 2020 dollars |
| Total annual costs (TAC) = DAC + IDAC | \$623,834 in 2020 dollars |

### **Direct Annual Costs (DAC)**

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

| Annual Maintenance Cost = | 0.015 x TCI =  | \$75,321 in 2020 dollars  |
|---------------------------|--|---------------------------|
| Annual Reagent Cost =     | $q_{sol} \times Cost_{reag} \times t_{op} =$             | \$104,863 in 2020 dollars |
| Annual Electricity Cost = | P x Cost <sub>elect</sub> x t <sub>op</sub> =            | \$6,670 in 2020 dollars   |
| Annual Water Cost =       | $q_{water} x Cost_{water} x t_{op} =$                    | \$2,544 in 2020 dollars   |
| Additional Fuel Cost =    | $\Delta$ Fuel x Cost <sub>fuel</sub> x t <sub>op</sub> = | \$10,951 in 2020 dollars  |
| Additional Ash Cost =     | $\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$          | \$935 in 2020 dollars     |
| Direct Annual Cost =      |  | \$201,284 in 2020 dollars |

### Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

| Administrative Charges (AC) = | 0.03 x Annual Maintenance Cost = | \$2,260 in 2020 dollars   |
|-------------------------------|----------------------------------|---------------------------|
| Capital Recovery Costs (CR)=  | CRF x TCI =                      | \$420,290 in 2020 dollars |
| Indirect Annual Cost (IDAC) = | AC + CR =                        | \$422,550 in 2020 dollars |

## Cost Effectiveness

## Cost Effectiveness = Total Annual Cost/ NOx Removed/year

| Total Annual Cost (TAC) = | \$623,834 per year in 2020 dollars             |  |  |  |  |
|---------------------------|--|--|--|--|--|
| NOx Removed =             | 87 tons/year                                   |  |  |  |  |
| Cost Effectiveness =      | \$7,191 per ton of NOx removed in 2020 dollars |  |  |  |  |

Appendix C

RBLC Search for Biomass Power Boilers for SO<sub>2</sub>

# Sappi Cloquet LLC Appendix C: RBLC Search for Biomass Power Boilers for SO2

Pollutant Name: SO2 NOTE: Draft determinations are marked with a " \* " beside the RBLC ID.

| RBLCID   | FACILITY NAME                                 | CORPORATE OR COMPANY<br>NAME                  | FACILITY<br>STATE | PERMIT NUM               | NAICS<br>CODE | PERMIT DATE    | FACILITY DESCRIPTION   | Process<br>Name                                | Fuel                             | Through-<br>put | UNITS    | Pollutant            | Emission Control Description  | Emission<br>Limit 1 | Limits Units 1 | Avg Time                            | CASE-BY-<br>CASE<br>BASIS | Emission<br>Limit 2 | Limits Units2 | Avg Time2   | Standard<br>Emission<br>Limit | Standard Limit<br>Units Avg Time |
|----------|---|---|-------------------|--------------------------|---------------|----------------|--|--|----------------------------------|-----------------|----------|----------------------|---|---------------------|----------------|-------------------------------------|---------------------------|---------------------|---------------|---|-------------------------------|----------------------------------|
| *AR-0161 | SUN BIO MATERIAL COMPANY                      | SUN BIO MATERIAL COMPANY                      | AR                | 2384-AOP-R0              | 322110        |                | A kraft paper mill designed with one high yield Kraft softwood<br>Fiberline and two linerboard machiens. The plant is initially sized<br>to support an approximate, nominal linerboard production<br>capacity of 4,400 machine dry tons per day at varying base            | Power Boiler                                   | Biomass                          | 1200            | MMBtu/hr | Sulfur Dioxide (SO2) | FGD/Dry Sorbent Injection   | 0.025               | lb/MMBTU       | 3 1-HOUR TESTS                      | BACT-PSD                  | 0                   |               |   | 0                             |                                  |
| CT-0156  | MONTVILLE POWER LLC                           | NRG ENERGY                                    | СТ                | 107-0056                 | 221119        |                | 43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED<br>NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL<br>CAPACITY FACTOR)   | 42 MW Biomass<br>utility boiler                | Clean wood                       | 600             | MMBTU/H  | Sulfur Oxides (SOx)  | Low sulfur fuels  | 0.025               | lb/MMBTU       | 3 HR BLOCK                          | BACT-PSD                  | 0                   |               |   | 0                             |                                  |
| CT-0162  | PLAINFIELD RENEWABLE ENERGY, LLC              | PLAINFIELD RENEWABLE ENERGY, LLC              | СТ                | 145-0049                 | 221119        | 12/29/2010 ACT | 37.5 MW Biomass Power Plant  | Fluidized Bed<br>Gasification                  | Wood                             | 523.1           | MMBtu/hr | Sulfur Dioxide (SO2) | Spray Dryer, Bed Injection  | 0.035               | lb/MMBTU       |                                     | OTHER CASE-<br>BY-CASE    | 15.4                | PPMVD @7% O2  | 3 HR BLOCK  | 0                             |                                  |
| GA-0141  | WARREN COUNTY BIOMASS ENERGY<br>FACILITY      | OGETHORPE POWER CORPERATION                   | GA                | 4911-301-0016-P-<br>01-0 | 221119        | , ,            | The proposed project will include: a bubbling fluidized bed boiler<br>with a maximum total heat input capacity of 1,399 MMBTU/H, 2<br>fire water pump emergency engines; a raw material handling &<br>storage area; a sorbent storage silo; a boiler bed sand silo, a sand | Boiler, Biomass<br>Wood                        | Biomass<br>wood                  | 100             | MW       | Sulfur Oxides (SOx)  | Dust sorbent injection system   | 0.01                | LB/MMBTU       | 30 D ROLLING AV /<br>CONDITION 2.12 | BACT-PSD                  | 56                  | TONS          | 12 MONTH<br>ROLLING TOTAL /<br>CONDITION 2.20     | 0                             |                                  |
| *KS-0034 | ABENGOA BIOENERGY BIOMASS OF KANSAS<br>(ABBK) | ABENGOA BIOENERGY BIOMASS OF KANSAS<br>(ABBK) | KS                | C-11396                  | 325193        |                | Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install<br>and operate a biomass-to-ethanol and biomass-to-energy<br>production facility near Hugoton, Kansas.   | biomass to<br>energy<br>cogeneration<br>bioler | different<br>types of<br>biomass | 500             | MMBtu/hr |                      | Injection of sorbent (lime) in combination<br>with a dry flue gas desulfurization (FGD)<br>system | 0.21                | lb/MMBTU       | 30-DAY ROLLING,<br>INCLUDES SSM     | BACT-PSD                  | 110.25              | LB/HR         | MAX 1-HR,<br>INCLUDES SS,<br>EXCLUDES<br>MALFUNCT | 0                             |                                  |
| LA-0249  | RED RIVER MILL                                | INTERNATIONAL PAPER CO                        | LA                | PSD-LA-562(M-4)          | 322130        | 05/09/2011 ACT | KRAFT PULP MILL WHICH PRODUCES UNBLEACHED LINERBOARD   | NO. 2 HOGGED<br>FUEL BOILER                    | HOGGED<br>FUEL/BARK              | 992.43          | MMBTU/H  | Sulfur Dioxide (SO2) | USE OF LOW SULFUR FUELS   | 60                  | LB/H           | HOURLY<br>MAXIMUM                   | BACT-PSD                  | 262.8               | T/YR          | ANNUAL<br>MAXIMUM                                 | 0.06                          | LB/MMBTU                         |
| ME-0037  | VERSO BUCKSPORT LLC                           | VERSO BUCKSPORT LLC                           | ME                | A-22-77-4-A              | 322121        |                | Existing pulp (groundwood and thermomechanical) and paper<br>making facility.  | Biomass Boiler 8                               | Biomass                          | 814             | MMBTU/H  | Sulfur Dioxide (SO2) | 0.7% sulfur when firing oil   | 0.8                 | lb/MMBTU       | 3-HR AVERAGE                        | BACT-PSD                  | 651.2               | LB/H          |   | 0                             |                                  |

# Appendix D

Power Boiler #9 – Control Cost Calculations for SO<sub>2</sub>

Appendix D, Table 1 - Unit Summary

| Unit  | В       | oiler 9  |
|---|---------|----------|
| Maximum Hourly Heat Input Rate              | 430     | MMBtu/hr |
| Exhaust Flow Rate                           | 271,905 | acfm     |
| Exhaust Temperature                         | 413     | °F       |
| Exhaust Moisture Content                    | 15%     |          |
| Atmospheric Pressure at Elevation           | 14.1    | psia     |
| Capacity Factor (CF) / Utilization          | 70%     |          |
| Expected Annual Hours of Operation          | 8760    | hours    |
| Baseline Emission Rate                      | 0.02    | lb/MMBtu |
| Hourly Emissions (average annual rate)      | 7.2     | lb/hr    |
| Annual Emissions (estimated 2028 emissions) | 22.0    | tons/yr  |
| Annual Interest Rate                        | 5.25%   |          |

## **Control Equipment Costs**

| Control Technology Name                  | Spray Dry<br>Absorption | Dry Sorbent<br>Injection |              |  |  |  |  |
|--|-------------------------|--------------------------|--------------|--|--|--|--|
| Expected Equipment Life (years)          | 20                      | 20                       |              |  |  |  |  |
| SO <sub>2</sub> Control Efficiency       |                         |                          |              |  |  |  |  |
| Controlled Emissions (tons/yr)           | 6.6                     | 11.0                     |              |  |  |  |  |
| Reduction (tons/yr)                      | 15.4                    | 11.0                     |              |  |  |  |  |
| Notes on Technology                      |                         |                          |              |  |  |  |  |
| Capital Costs                            |                         |                          |              |  |  |  |  |
| Direct Capital Costs (DC)                | [1]                     |                          |              |  |  |  |  |
| Indirect Capital Costs (IC)              | [1]                     |                          |              |  |  |  |  |
| Total Capital Investment (TCI = DC + IC) | [1]                     | \$144,535,337            | \$41,178,526 |  |  |  |  |
| Operating Costs                          |                         |                          |              |  |  |  |  |
| Direct Operating Costs (\$/year)         | [2]                     | -                        | \$408,630    |  |  |  |  |
| Indirect Operating Costs (\$/year)       | -                       | \$5,263,766              |              |  |  |  |  |
| Total Annual Cost (\$/year)              | \$24,484,747            | \$5,672,396              |              |  |  |  |  |
| Control Cost Effectiveness (\$/ton)      |                         | \$1,589,900              | \$515,700    |  |  |  |  |

## 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

Appendix D, Table 2 - Spray Dry Absorption

| Unit   | Boiler 9 |            |
|--|----------|------------|
| Maximum Hourly Heat Input Rate                 | 430      | MMBtu/hr   |
| Exhaust Flow Rate                              | 271,905  | acfm       |
| Standardized Flow Rate                         | 164,451  | scfm @ 68F |
| Dry Std Flow Rate                              | 139,783  | scfm @ 68F |
| Exhaust Temperature                            | 413      | ٥F         |
| Exhaust Moisture Content                       | 15%      |            |
| Atmospheric Pressure at Elevation              | 14.1     | psia       |
| Capacity Factor (CF) / Utilization             | 70%      |            |
| Expected Annual Hours of Operation             | 8760     | hours      |
| Baseline Emission Rate                         | 0.02     | lb/MMBtu   |
| Hourly Emissions (*permitted limit)            | 7.2      | lb/hr      |
| Annual Emissions                               | 22.0     | tons/yr    |
| Volumetric Flow Rate SO2 (VFR <sub>SO2</sub> ) | 0.7      | scfm SO2   |
| Concentration SO2 (C <sub>SO2</sub> )          | 4.3      | ppmvd      |
| Annual Interest Rate                           | 5.25%    |            |
| Control Equipment Life                         | 20       | yrs        |

## CONTROL EQUIPMENT COSTS: Equation Type 19 for SO2 - ICI Boilers; SDA

| Capital Cost            |                  |
|-------------------------|------------------|
| Capital Cost            | \$144,535,336.50 |
| CRF                     | 0.08             |
| Annualized Capital Cost | \$11,845,000.82  |
| Operating Costs         |                  |
| Fixed O&M               |                  |
| Variable O&M            |                  |
| Total Annualized Cost   | \$24,484,746.56  |

**Emission Control Cost Calculation** 

| Pollutant            | Max Emis | Annual | Cont Eff | Cont Emis | Reduction | Cont Cost   |
|----------------------|----------|--------|----------|-----------|-----------|-------------|
|                      | Lb/Hr    | Ton/Yr | %        | Ton/Yr    | Ton/Yr    | \$/Ton Rem  |
| Sulfur Dioxide (SO2) | 9.40     | 22.00  | 0.70     | 6.60      | 15.40     | \$1,589,919 |

## Notes & Assumptions

1 Total Capital Investment

$$TCI = [143.76(Fd)] + \left[0.61\left(\frac{\sqrt{Fd}}{\#Ducts}\right)^2\right] + \left[17412.26e^{0.017\left(\frac{\sqrt{Fa}}{\#Ducts}\right)}\right] + [53.973e^{0.014\left(\frac{\sqrt{Fa}}{\#Ducts}\right)}] + 931911.04$$
  
where #Ducts = : 1 if Fd ≤ 154,042  
Fd/154,042 Fd > 154,042

### 2 Total Annualized Cost

 $TAC = (\mathsf{Op}_{\mathsf{hrs}}) \{ [(1.62 \times 10^{-3})(\mathsf{F}_d)] + [(6.84 \times 10^{-7})(\mathsf{C}_{\mathsf{SO2}})(\mathsf{F}_d)] + [(3.72 \times 10^{-5})(\mathsf{F}_d)] + 21.157) \} + \{ [7.2 \times 10^{-2} + \mathsf{CRF}] \times \mathsf{TCI} \}$ 

| 3 | B Chemical Engineerig Magazine Plant Cost Index |      |       |  |  |  |  |
|---|---|------|-------|--|--|--|--|
|   | Historical Date/Cost Index                      | 2008 | 575.4 |  |  |  |  |
|   | Current Date/Cost Index                         | 2019 | 591.1 |  |  |  |  |
|   | Inflation Adjustment                            |      | 1.03  |  |  |  |  |

Appendix D, Table 3 - Dry Sorbent Injection

| Operating Unit:                   | Boiler 9 |          |                          |         |               |                |                |
|-----------------------------------|----------|----------|--------------------------|---------|---------------|----------------|----------------|
| Emission Unit Number              |          |          | Stack/Vent Number        |         |               | Alt Op Para #1 | Alt Op Para #2 |
| Design Capacity                   | 430      | MMBtu/hr | Standardized Flow Rate   |         | scfm @ 32º F  |                |                |
| Utilization Rate                  | 70%      |          | Exhaust Temperature      | 413     | Deg F         |                |                |
| Annual Operating Hours            | 8,760    | hr/yr    | Exhaust Moisture Content | 15%     |               |                |                |
| Annual Interest Rate              | 5.25%    |          | Actual Flow Rate         | 271,905 | acfm          |                |                |
| Control Equipment Life            | 20       | yrs      | Standardized Flow Rate   | 164,451 | scfm @ 68º F  |                |                |
| Plant Elevation                   | -        | ft       | Dry Std Flow Rate        | 139,783 | dscfm @ 68º F |                |                |
| Atmospheric Pressure at Elevation | 14.10    | psia     |                          |         |               |                |                |
|                                   |          |          |                          |         |               |                |                |
|                                   |          |          |                          |         |               |                |                |
|                                   |          |          |                          |         |               |                |                |
|                                   |          |          |                          |         |               |                |                |
|                                   |          |          |                          |         |               |                |                |
|                                   |          |          |                          |         |               |                |                |
|                                   |          |          |                          |         |               |                |                |
|                                   |          |          |                          |         |               |                |                |
|                                   |          |          |                          |         |               |                |                |
|                                   |          |          |                          |         |               |                |                |
|                                   |          |          |                          |         |               |                |                |
|                                   |          |          |                          |         |               |                |                |

| Chemical Engine            | erig Magazine Plant | Cost Index |
|----------------------------|---------------------|------------|
| Historical Date/Cost Index | 1997                | 386.5      |
| Current Date/Cost Index    | 2019                | 591.1      |
| Inflation Adjustment       |                     | 1.53       |

### CONTROL EQUIPMENT COSTS

| Capital Costs                             |               |               |                     |                  |                       |              |                  |                 |                 |
|---|---------------|---------------|---------------------|------------------|-----------------------|--------------|------------------|-----------------|-----------------|
| Direct Capital Costs                      |               |               |                     |                  |                       |              |                  | Equipment       |                 |
| Purchased Equipment (A)                   |               |               |                     |                  | Scaled from DC        | from IAPCS p | orogram estimate | \$10,690,976.67 | \$16,350,417.36 |
| Purchased Equipment Total (B)             | 15%           | of control de | evice cost (A)      |                  |                       |              |                  |                 | \$18,802,979.97 |
| Installation - Standard Costs             | 74%           | of purchase   | d equip cost (B)    |                  |                       |              |                  |                 | \$13,914,205.17 |
| Installation - Site Specific Costs        |               |               |                     |                  |                       |              |                  |                 | N/A             |
| Installation Total                        |               |               |                     |                  |                       |              |                  |                 | \$13,914,205.17 |
| Total Direct Capital Cost, DC             |               |               |                     |                  |                       |              |                  |                 | \$32,717,185.14 |
| Total Indirect Capital Costs, IC          | 45%           | of purchase   | d equip cost (B)    |                  |                       |              |                  |                 | \$8,461,340.98  |
| Total Capital Investment (TCI) = DC + IC  |               |               |                     |                  |                       |              |                  |                 | \$41,178,526.13 |
| Operating Costs                           |               |               |                     |                  |                       |              |                  |                 |                 |
| Total Annual Direct Operating Costs       |               | Labor, supe   | rvision, materials, | replacement p    | arts, utilities, etc. |              |                  |                 | \$408,629.74    |
| Total Annual Indirect Operating Costs     |               | Sum indirect  | t oper costs + cap  | ital recovery co | ost                   |              |                  |                 | \$5,263,766.17  |
| Total Annual Cost (Annualized Capital Cos | t + Operating | g Cost)       |                     |                  |                       |              |                  |                 | \$5,672,395.91  |

### **Emission Control Cost Calculation**

| Pollutant            | Max Emis | Annual | Calculation | Cont Eff | Performance | Conc. | Cont Emis | Reduction | Cont Cost  |
|----------------------|----------|--------|-------------|----------|-------------|-------|-----------|-----------|------------|
|                      | Lb/Hr    | Ton/Yr | Method      | %        | Basis       | Units | Ton/Yr    | Ton/Yr    | \$/Ton Rem |
| Sulfur Dioxide (SO2) | 7.18     | 22.00  | % Removal   | 0.50     |             |       | 11.00     | 11.00     | \$515,700  |

### Notes & Assumptions

Total Direct Capital Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a and adjusted for inflation based on Chemical Engineering Plant Cost Index
 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

2 Calculations per EPA Air Pollution Control Cost Manual of Ed 2002, Section 6 Chapter 1
3 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
4 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.
5 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
6 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

7 Solid waste disposal cost is only for spent lime.8 Used 0.6 power law factor to adjust prices based on acfm from bid basis

| appi Cloquet LLC  |  |                                    |
|---|--|------------------------------------|
| opendix D, Table 3 - Dry Sorbent Injection<br>APITAL COSTS                            |  |                                    |
| Direct Capital Costs  |  |                                    |
| Purchased Equipment (A) <sup>(1)</sup><br>Purchased Equipment Costs (A) - Injection S | vstem + auviliary equipment EC   | \$16,350,417.30                    |
| Instrumentation   | 10% of control device cost (A)   | \$1,635,041.74                     |
| State Sales Taxes   | 0.0% of control device cost (A)  |                                    |
| Freight   | 5% of control device cost (A)  | \$817,520.8                        |
| Purchased Equipment Total (B)   | 15%  | \$18,802,979.97                    |
| Installation  |  |                                    |
| Foundations & supports  | 4% of purchased equip cost (B)   | \$752,119.20                       |
| Handling & erection   | 50% of purchased equip cost (B)  | \$9,401,489.98                     |
| Electrical  | 8% of purchased equip cost (B)   | \$1,504,238.40                     |
| Piping  | 1% of purchased equip cost (B)   | \$188,029.80                       |
| Insulation<br>Painting  | 7% of purchased equip cost (B)   | \$1,316,208.60                     |
| Panning<br>Installation Subtotal Standard Expenses                                    | 4% of purchased equip cost (B)<br>74%                                    | \$752,119.20<br>\$13,914,205.1     |
| Site Preparation, as required   | N/A Site Specific  |                                    |
| Buildings, as required  | N/A Site Specific  | -                                  |
| Site Specific - Other   | N/A Site Specific  | -                                  |
| Total Site Specific Costs   |  | N/4                                |
| Installation Total  |  | \$13,914,205.17                    |
| Total Direct Capital Cost, DC   |  | \$32,717,185.14                    |
| Indirect Capital Costs  |  |                                    |
| Engineering, supervision  | 10% of purchased equip cost (B)  | \$1,880,298.00                     |
| Construction & field expenses   | 20% of purchased equip cost (B)  | \$3,760,595.99                     |
| Contractor fees   | 10% of purchased equip cost (B)  | \$1,880,298.00                     |
| Start-up  | 1% of purchased equip cost (B)   | \$188,029.80                       |
| Performance test  | 1% of purchased equip cost (B)   | \$188,029.80                       |
| Model Studies   | N/A of purchased equip cost (B)  | ¢100,020100                        |
| Contingencies   | 3% of purchased equip cost (B)   | \$564,089.40                       |
| Total Indirect Capital Costs, IC  | 45% of purchased equip cost (B)  | \$8,461,340.98                     |
| otal Capital Investment (TCI) = DC + IC   |  | \$41,178,526.13                    |
| djusted TCI for Replacement Parts (Catalyst, Filt                                     | er Bags, etc) for Capital Recovery Cost                                  | \$41,178,526.13                    |
| PERATING COSTS  |  |                                    |
| Direct Annual Operating Costs, DC   |  |                                    |
| Operating Labor   |  |                                    |
| Operator  | 34.36 \$/Hr  | \$188,125.38                       |
| Supervisor  | 0.15 of Op Labor   | \$28,218.8                         |
| Maintenance   |  |                                    |
| Maintenance Labor   | 28.45 \$/Hr  | \$93,453.65                        |
| Maintenance Materials   | 100 % of Maintenance Labor   | \$93,453.65                        |
| Utilities, Supplies, Replacements & Waste M   |  | <b></b>                            |
| Electricity   | 492.15 kW-hr   | \$2,407.63                         |
| Compressed Air  | 2.00 scfm/kacfm  | \$958.43                           |
| Solid Waste Disposal  | 0.00 ton/hr  | \$4.02                             |
| Lime  | 6.91 lb/hr   | \$20.12                            |
| Filter Bags Total Annual Direct Operating Costs                                       | 198.00 bags  | \$1,988.06<br><b>\$408,629.7</b> 4 |
|   |  |                                    |
| Indirect Operating Costs<br>Overhead  | 60% of total labor and motorial assta                                    | \$0.44 OFO 0                       |
| Administration (2% total capital costs)   | 60% of total labor and material costs<br>2% of total capital costs (TCI) | \$241,950.89<br>\$823,570.52       |
| Property tax (1% total capital costs)   | 1% of total capital costs (TCI)  | \$823,570.52<br>\$411,785.26       |
| Insurance (1% total capital costs)  | 1% of total capital costs (TCI)  | \$411,785.26                       |
| Capital Recovery  | 0.0820 for a 20-year equipment life and a 5.25% interest rate            | \$3,374,674.23                     |
| Total Annual Indirect Operating Costs   |  | \$5,263,766.17                     |
|   | Sum indirect oper costs + capital recovery cost                          |                                    |

See summary page for notes and assumptions

Sappi Cloquet LLC Appendix D, Table 3 - Dry Sorbent Injection Capital Recovery Factors

| Capital Recovery Factors   |  |  |   | -  |   |   |   |
|--|--|--|---|--|---|---|---|
| Primary Installation   |  |  |   |  |   |   |   |
| Interest Rate  |  | 5.25%  |   |  |   |   |   |
| Equipment Life   |  | 20 y   | /ears   |  |   |   |   |
| CRF  |  | 0.0820   |   |  |   |   |   |
| Replacement Parts & Equipment:   |  | Filter bags & c  | ages  | -  |   |   |   |
| Equipment Life   |  |  | /ears   |  |   |   |   |
| CRF  |  | 0.2326   |   |  |   |   |   |
| Rep part cost per unit   |  | 33.71 \$   | k/hag   |  |   |   |   |
| Amount Required  |  | 198 c  |   |  |   |   |   |
| Total Rep Parts Cost   |  |  |   | d for freight &  | cales tay   |   |   |
| Installation Labor   |  |  |   |  | Overhead (64%)  |   | EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4   |
| Total Installed Cost   |  |  |   |  | ent parts needed  |   | lists replacement times from 5 - 20 min per bag.  |
| Annualized Cost  |  | 1,988  |   | io replaceme   | in parts needed   |   | nata replacement times nom 5 - 20 min per bag.  |
|  |  | .,   |   |  |   |   |   |
| Summary of "Other" site specific C   |  | <b>D</b>   |   |  | 1   |   |   |
| Item   | Cost   | Description  |   |  |   |   |   |
| 1  |  | e.g. New Fan,  | new stack, (  | etc.   |   |   |   |
| 2  |  |  |   |  |   |   |   |
| 3  |  |  |   |  |   |   |   |
| 4  |  |  |   |  |   |   |   |
| 5  |  |  |   |  |   |   |   |
| 6  |  |  |   |  |   |   |   |
| Total  | \$0  |  |   |  |   |   |   |
| Electrical Use   |  |  |   |  |   |   |   |
|  | Flow acfm  |  | D P in H2O  | Efficiency   | Hp  | kW  |   |
| Blower, Baghouse   | 271,905  |  | 10  | -  |   | 492.1   |   |
| Baghouse Shaker  | 0  | Gross fabric ar  | ea ft <sup>2</sup>  |  |   | 0.0   | EPA Cont Cost Manual 6th ed Section 6 Chapter 1 Eq 1.14   |
| 3  |  |  |   |  |   |   |   |
|  |  |  |   |  |   |   |   |
|  |  |  |   |  |   |   |   |
|  |  |  |   |  |   |   |   |
|  |  |  |   |  |   |   |   |
| Total  |  |  |   |  |   | 492.1   |   |
| Total  |  |  |   |  |   |   |   |
| Reagent Use & Other Operating Co   |  | lb/br SO2  | 0.06  | In Line / In 200   |   |   | lh/hr Limo  |
| Reagent Use & Other Operating Co<br>Lime Use<br>Water Makeup Rate/WW Disch =   |  | lb/hr SO2  | 0.96<br>gpm   | lb Lime/lb SO2   |   |   | lb/hr Lime  |
| Lime Use<br>Water Makeup Rate/WW Disch =   |  |  |   | lb Lime/lb SO2   |   |   |   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost   |  | ç  |   | lb Lime/lb SO2   |   |   | lb/hr Lime<br>See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs  |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area   | 2,655  | <u>π</u>   | Jpm   |  | 109 Conce   | 6.91  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs  |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages  | 7.18<br>2,655<br>10 ft long  | ς<br>π<br>5 in dia   | Jpm   | Ib Lime/Ib SO2   | 198 Cages   | 6.91  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags  | 7.18<br>2,655<br>10 ft long  | <u>π</u>   | Jpm   |  | 198 Cages   | 6.91<br>11.04<br>22.65  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs  |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages  | 7.18<br>2,655<br>10 ft long  | ς<br>π<br>5 in dia   | Jpm   |  | 198 Cages   | 6.91  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags  | 7.18<br>2,655<br>10 ft long  | ς<br>π<br>5 in dia   | Jpm   |  | 198 Cages   | 6.91<br>11.04<br>22.65  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations  | 7.18<br>2,655<br>10 ft long<br>1.69  | τ<br>T<br>5 in dia<br>\$/ft2 of fabric   | Jpm<br>13.42  | area/cage ft <sup>*</sup>  | i 198 Cages   | 6.91<br>11.04<br>22.65  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total   | 7.18<br>2,655<br>10 ft long<br>1.69  | π<br>5 in dia<br>\$/ft2 of fabric  | 13.42   | area/cage ft <sup>*</sup><br>8,760   |   | 6.91<br>11.04<br>22.66<br>33.71   | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate  | 7.18<br>2,655<br>10 ft long<br>1.69<br>1.69<br>Unit  | τ<br>5 in dia<br>\$/ft2 of fabric<br>Annual Opera<br>Unit of   | 13.42<br>ating Hours<br>Use   | area/cage ft <sup>2</sup><br>8,760<br>Unit of  | Annual  | 6.91<br>11.04<br>22.66<br>33.71<br>Annual   | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item  | 7.18<br>2,655<br>10 ft long<br>1.69  | π<br>5 in dia<br>\$/ft2 of fabric  | 13.42   | area/cage ft <sup>*</sup><br>8,760   |   | 6.91<br>11.04<br>22.66<br>33.71   | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor   | 7.18<br>2,655<br>10 ft long<br>1.69<br>1%<br>Unit<br>Cost \$   | π<br>5 in dia<br>\$/ft2 of fabric<br>Annual Opera<br>Unit of<br>Measure  | 13.42<br>ating Hours<br>Use<br>Rate   | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure   | Annual<br>Use*  | 6.91<br>11.04<br>22.66<br>33.71<br>Annual<br>Cost   | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor   | 7.18<br>2,655<br>10 ft long<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>3.1.69<br>3.1.69  | tt<br>5 in dia<br>\$/ft2 of fabric<br>Unit of<br>Measure<br>\$/Hr  | 13.42<br>ating Hours<br>Use<br>Rate   | area/cage ft <sup>2</sup><br>8,760<br>Unit of  | Annual<br>Use*<br>5,475   | 6.91<br>11.04<br>22.68<br>33.71<br>Annual<br>Cost<br>\$ 188,125   | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr  |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor   | 7.18<br>2,655<br>10 ft long<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>3.1.69<br>3.1.69  | π<br>5 in dia<br>\$/ft2 of fabric<br>Annual Opera<br>Unit of<br>Measure  | 13.42<br>ating Hours<br>Use<br>Rate   | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure   | Annual<br>Use*  | 6.91<br>11.04<br>22.68<br>33.71<br>Annual<br>Cost<br>\$ 188,125   | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maintenance  | 7.18<br>2,655<br>10 ft long<br>1.69<br>Unit<br>Cost \$<br>34.36<br>15%   | π<br>5 in dia<br>\$/ft2 of fabric<br>Annual Opera<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor  | ating Hours<br>Use<br>Rate<br>5.0   | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift  | Annual<br>Use*<br>5,475<br>NA   | 6.91<br>11.04<br>22.66<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maintenance<br>Maint Labor   | 7.18<br>2,655<br>10 ft long<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>2.845<br>34.36<br>15%<br>28.45  | rt<br>5 in dia<br>\$/ft2 of fabric<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr  | ating Hours<br>Use<br>Rate<br>5.0<br>3.0  | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure   | Annual<br>Use*<br>5,475<br>NA<br>3,285  | 6.91<br>11.04<br>22.66<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219<br>\$ 93,454   | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr  |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maintenance<br>Maint Labor<br>Maint Mis  | 7.18<br>2,655<br>10 ft long<br>1.69<br>1%<br>Unit<br>Cost \$<br>34.36<br>15%<br>28.45<br>10%   | π<br>5 in dia<br>\$/ft2 of fabric<br><b>Annual Opera</b><br><b>Unit of</b><br><b>Measure</b><br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance  | ating Hours<br>Use<br>Rate<br>5.0<br>3.0  | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift  | Annual<br>Use*<br>5,475<br>NA   | 6.91<br>11.04<br>22.66<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219<br>\$ 93,454   | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maintenance<br>Maint Labor<br>Maint Mtls<br>Utilities, Supplies, Replacements &  | 7.18<br>2,655<br>10 ft long<br>1.69<br>Unit<br>Cost \$<br>34.36<br>15%<br>28.45<br>100%<br>& Waste Mana  | TT 5 in dia \$/ft2 of fabric<br>Annual Opera Unit of Measure<br>\$/ftr of Op Labor<br>\$/Hr of Op Labor<br>\$/Hr of Maintenance<br>gement  | ating Hours<br>Use<br>Rate<br>5.0<br>9 Labor  | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift   | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA  | 6.91<br>11.04<br>22.66<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 93,454  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maintenance<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Mtls<br>Utilities, Supplies, Replacements &  | 7.18<br>2,655<br>10 ft long<br>1.69<br>Unit<br>Cost \$<br>34.36<br>15%<br>28.45<br>100%<br>& Waste Manag<br>0.080  | rt<br>5 in dia<br>\$/ft2 of fabric<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kW-h   | ating Hours<br>Use<br>Rate<br>5.0<br>3.0<br>⊎ Labor<br>492.1  | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift  | Annual<br>Use*<br>5,475<br>NA<br>3,285  | 6.91<br>11.04<br>22.66<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 93,454  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr  |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Mts<br>Utilites, Supples, Replacements &<br>Electricity<br>Natural Gas  | 7.18<br>2,655<br>10 ft long<br>1.69<br>1.69<br>1.69<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.055<br>1.005<br>2.055<br>1.005<br>2.055<br>1.005<br>1.005<br>2.055<br>1.005<br>1.005<br>2.055<br>1.005<br>2.055<br>1.005<br>2.055<br>1.005<br>2.055<br>2.005<br>2.055<br>2.005<br>2.055<br>2.005<br>2.055<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005                                     | IT<br>5 in dia<br>\$/ft2 of fabric<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kw-h<br>\$/kscf  | 13.42<br>13.42<br>ting Hours<br>Use<br>Rate<br>5.0<br>5.0<br>0 Labor<br>492.1<br>N/A  | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr  | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA<br>30,178                              | 6.91<br>11.04<br>22.62<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 93,454<br>\$ 93,454<br>\$ 93,454<br>\$ 93,454   | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br><b>Comments</b><br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor<br>\$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization  |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maintenance<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Mtls<br>Utilities, Supplies, Replacements &  | 7.18<br>2,655<br>10 ft long<br>1.69<br>1.69<br>1.69<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.055<br>1.005<br>2.055<br>1.005<br>2.055<br>1.005<br>1.005<br>2.055<br>1.005<br>1.005<br>2.055<br>1.005<br>2.055<br>1.005<br>2.055<br>1.005<br>2.055<br>2.005<br>2.055<br>2.005<br>2.055<br>2.005<br>2.055<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005<br>2.005                                     | rt<br>5 in dia<br>\$/ft2 of fabric<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kW-h   | 13.42<br>13.42<br>ting Hours<br>Use<br>Rate<br>5.0<br>5.0<br>0 Labor<br>492.1<br>N/A  | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift   | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA  | 6.91<br>11.04<br>22.62<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 93,454<br>\$ 93,454<br>\$ 93,454<br>\$ 93,454   | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Mts<br>Utilites, Supples, Replacements &<br>Electricity<br>Natural Gas  | 7.18<br>2,655<br>10 ft long<br>1.69<br>1.69<br>Unit<br>Cost \$<br>34.36<br>15%<br>28.45<br>100%<br>& Waste Manay<br>0.080<br>3.770<br>0.340  | IT<br>5 in dia<br>\$/ft2 of fabric<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kw-h<br>\$/kscf  | 13.42<br>13.42<br>ting Hours<br>Use<br>Rate<br>5.0<br>5.0<br>0 Labor<br>492.1<br>N/A  | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr  | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA<br>30,178                              | 6.91<br>11.04<br>22.62<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 93,454<br>\$ 93,454<br>\$ 93,454<br>\$ 93,454   | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br><b>Comments</b><br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor<br>\$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization  |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maintenance<br>Maint Labor<br>Maint Mts<br>Utilities, Supplies, Replacements &<br>Electricity<br>Natural Gas<br>Water  | 7.18<br>2,655<br>10 ft long<br>1.69<br>Unit<br>Cost \$<br>34.36<br>15%<br>28.45<br>100%<br>2 Waste Mana;<br>0.080<br>3.770<br>0.340<br>0.340<br>0.340  | T<br>5 in dia<br>\$/ft2 of fabric<br>Annual Opera<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kw-h<br>\$/kscf<br>\$/kgal  | ating Hours<br>Use<br>Rate<br>5.0<br>9 Labor<br>492.1<br>N/A<br>0<br>N/A  | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr  | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA<br>30,178                              | 6.91<br>11.04<br>22.66<br>33.71<br><b>Annual</b><br><b>Cost</b><br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 93,454 \$ 93,454<br>\$ 93,454<br>\$ 93,454 \$ 93,454<br>\$ 93,454<br>\$ 93,454 \$ 93,454<br>\$ 93,454 \$ 93,454<br>\$ 93,454 \$ 93,454<br>\$ 93,454 \$ 93,454 \$ 93,454 \$ 93,656<br>\$ 94,656 \$ 94,656<br>\$ 94,656 \$ 94,656 \$ 94,656<br>\$ 94,656 \$ 94,656<br>\$ 94,656 \$ 94,6566 \$ 94,6566<br>\$ 94,6566666666666666666666666666666666666  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br><b>Comments</b><br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor<br>\$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization  |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maintenance<br>Maint Labor<br>Maint  7.18<br>2,655<br>10 ft long<br>1.69<br>1.69<br>1.69<br>1.69<br>2.655<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>20%<br>28.45<br>20%<br>20%<br>20%<br>20%<br>20%<br>20%<br>20%<br>20%<br>20%<br>20%   | rt<br>5 in dia<br>\$/ft2 of fabric<br>Annual Opera<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kscf<br>\$/kscf<br>\$/kscf   | ating Hours<br>Use<br>Rate<br>5.0<br>9 Labor<br>492.1<br>N/A<br>0<br>N/A<br>2   | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr<br>gpm<br>scfm/kacfm                           | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA<br>30,178<br>0                         | 6.91<br>11.04<br>22.66<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 93,454<br>\$ 93,454<br>\$ 93,454<br>\$ 2,408<br>\$ 2,408<br>\$ 2,408  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor<br>\$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization<br>\$/kscf, 2 scfm/kacfm, 8760 hr/yr, 0.7% utilization  |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Labor<br>Maint Utis<br>Utilities, Supplies, Replacements &<br>Electricity<br>Natural Gas<br>Water<br>Compressed Air<br>Wastewater Disposal Neutralization   | 7.18<br>2,655<br>10 ft long<br>1.69<br>1%<br>Unit<br>Cost \$<br>34.36<br>15%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>28.45<br>10%<br>0.880<br>3.770<br>0.340<br>0.479<br>0.479<br>2.554   | T<br>5 in dia<br>\$/ft2 of fabric<br>Annual Opera<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kW-h<br>\$/kVr-h<br>\$/kygal<br>\$/kgal<br>\$/kgal  | ating Hours<br>13.42<br>Use<br>Rate<br>5.0<br>3.0<br>↓ Labor<br>492.1<br>N/A<br>0<br>N/A<br>2<br>0  | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr<br>gpm   | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA<br>30,178<br>0<br>2,001                | 6.91<br>11.04<br>22.66<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 93,454<br>\$ 93,454<br>\$ 93,454<br>\$ 2,408<br>\$ 2,408<br>\$ 2,408  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor<br>\$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maintenance<br>Maint Labor<br>Maint Mts<br>Utilities, Supplies, Replacements &<br>Electricity<br>Matural Gas<br>Water<br>Cooling Water<br>Cooling Water<br>Compressed Air<br>Wastewater Disposal Neutralization  | 7.18<br>2,655<br>10 ft long<br>1.69<br>Unit<br>Cost \$<br>34.36<br>15%<br>28.45<br>100%<br>34.36<br>15%<br>28.45<br>100%<br>3.770<br>0.340<br>0.479<br>2.554<br>6.469  | TT<br>5 in dia<br>\$/ft2 of fabric<br>Annual Opera<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kW-h<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal   | ating Hours<br>13.42<br>Use<br>Rate<br>5.0<br>2 Labor<br>3.0<br>492.1<br>N/A<br>0<br>N/A<br>2<br>0<br>0<br>N/A  | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr<br>gpm<br>scfm/kacfm<br>gpm                    | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA<br>30,178<br>0<br>2,001<br>0           | 6.91<br>11.04<br>22.66<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 94,688<br>\$ 95,888<br>\$ 95,8888<br>\$ 95,8888<br>\$ 95,8888<br>\$ 95,88888<br>\$ 95,888888888888888888888888888888888888  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor<br>\$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization   |
| Lime Use Water Makeup Rate/WW Disch = Baghouse Filter Cost Gross BH Filter Area Cages Bags Total Operating Cost Calculations Utilization Rate Item Operating Labor Op Labor Supervisor Maint Labor Maint Labor Maint Abor Maint Mtls Utilites, Supplies, Replacements & Electricity Natural Gas Water Compressed Air Wastewater Disposal Neutralization Wastewater Disposal Biotreatment Solid Waste Disposal Biotreatment Solid Waste Disposal Biotreatment Solid Waste Disposal Biotreatment Solid Waste Disposal Biotreatment Solid Waste Disposal Biotreatment   | 7.18<br>2,655<br>10 ft long<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69  | rt<br>5 in dia<br>\$/ft2 of fabric<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kw-h<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal  | ating Hours<br>13.42<br>Use<br>Rate<br>5.0<br>9 Labor<br>492.1<br>N/A<br>0<br>N/A<br>2<br>0<br>N/A<br>2<br>0<br>0<br>N/A<br>2<br>0<br>0<br>N/A<br>2<br>0<br>0<br>0<br>N/A | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr<br>gpm<br>scfm/kacfm                           | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA<br>30,178<br>0<br>2,001                | 6.91<br>11.04<br>22.66<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 94,688<br>\$ 95,888<br>\$ 95,8888<br>\$ 95,8888<br>\$ 95,8888<br>\$ 95,88888<br>\$ 95,888888888888888888888888888888888888  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor<br>\$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization<br>\$/kscf, 2 scfm/kacfm, 8760 hr/yr, 0.7% utilization  |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maintenance<br>Maint Labor<br>Maint Mts<br>Utilities, Supplies, Replacements &<br>Electricity<br>Matural Gas<br>Water<br>Cooling Water<br>Cooling Water<br>Compressed Air<br>Wastewater Disposal Neutralization  | 7.18<br>2,655<br>10 ft long<br>1.69<br>Unit<br>Cost \$<br>34.36<br>15%<br>28.45<br>100%<br>34.36<br>15%<br>28.45<br>100%<br>3.770<br>0.340<br>0.479<br>2.554<br>6.469  | rt<br>5 in dia<br>\$/ft2 of fabric<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kw-h<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal  | ating Hours<br>13.42<br>Use<br>Rate<br>5.0<br>2 Labor<br>3.0<br>492.1<br>N/A<br>0<br>N/A<br>2<br>0<br>0<br>N/A  | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr<br>gpm<br>scfm/kacfm<br>gpm                    | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA<br>30,178<br>0<br>2,001<br>0           | 6.91<br>11.04<br>22.66<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 94,688<br>\$ 95,888<br>\$ 95,8888<br>\$ 95,8888<br>\$ 95,8888<br>\$ 95,88888<br>\$ 95,888888888888888888888888888888888888  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor<br>\$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization   |
| Lime Use Water Makeup Rate/WW Disch = Baghouse Filter Cost Gross BH Filter Area Cages Bags Total Operating Cost Calculations Utilization Rate Item Operating Labor Op Labor Supervisor Maint Labor Maint Labor Maint Abor Maint Mtls Utilites, Supplies, Replacements & Electricity Natural Gas Water Compressed Air Wastewater Disposal Neutralization Wastewater Disposal Biotreatment Solid Waste Disposal Biotreatment Solid Waste Disposal Biotreatment Solid Waste Disposal Biotreatment Solid Waste Disposal Biotreatment Solid Waste Disposal Biotreatment   | 7.18<br>2,655<br>10 ft long<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69  | rt<br>5 in dia<br>\$/ft2 of fabric<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kw-h<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal  | ating Hours<br>13.42<br>Use<br>Rate<br>5.0<br>9 Labor<br>492.1<br>N/A<br>0<br>N/A<br>2<br>0<br>N/A<br>2<br>0<br>0<br>N/A<br>2<br>0<br>0<br>N/A<br>2<br>0<br>0<br>0<br>N/A | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr<br>gpm<br>scfm/kacfm<br>gpm                    | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA<br>30,178<br>0<br>2,001<br>0           | 6.91<br>11.04<br>22.66<br>33.71<br>Annual<br>Cost<br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 94,688<br>\$ 95,888<br>\$ 95,8888<br>\$ 95,8888<br>\$ 95,8888<br>\$ 95,88888<br>\$ 95,888888888888888888888888888888888888  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor<br>\$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization   |
| Lime Use Water Makeup Rate/WW Disch = Baghouse Filter Cost Gross BH Filter Area Cages Bags Total Operating Cost Calculations Utilization Rate Item Operating Labor Op Labor Supervisor Maint Labor Maint Labor Maint Abor Maint Mtls Utilites, Supplies, Replacements & Electricity Natural Gas Water Compressed Air Wastewater Disposal Neutralization Wastewater Disposal Biotreatment Solid Waste Disposal Biotreatment Solid Waste Disposal Biotreatment Solid Waste Disposal Biotreatment Solid Waste Disposal Biotreatment Solid Waste Disposal Biotreatment   | 7.18<br>2,655<br>10 ft long<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69<br>1.69  | rt<br>5 in dia<br>\$/ft2 of fabric<br>Annual Opera<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kW-h<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/ton<br>\$/ton  | ating Hours<br>13.42<br>Use<br>Rate<br>5.0<br>3.0<br>9 Labor<br>492.1<br>N/A<br>0<br>N/A<br>2<br>0<br>N/A<br>0,0<br>N/A   | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr<br>gpm<br>scfm/kacfm<br>gpm                    | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA<br>30,178<br>0<br>2,001<br>0           | 6.91<br>11.04<br>22.66<br>33.71<br><b>Annual</b><br><b>Cost</b><br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 94<br>\$ 958<br>\$ 958 | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor<br>\$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization   |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maintenance<br>Maint Labor<br>Maint  7.18<br>2,655<br>10 ft long<br>1.69<br>Unit<br>Cost \$<br>34.36<br>15%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>28.45<br>20.05%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>2.55%<br>28.45<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55% | rt<br>5 in dia<br>\$/ft2 of fabric<br>Annual Opera<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kW-h<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/ton<br>\$/ton  | ating Hours<br>13.42<br>Use<br>Rate<br>5.0<br>3.0<br>9 Labor<br>492.1<br>N/A<br>0<br>N/A<br>2<br>0<br>N/A<br>0,0<br>N/A   | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr<br>gpm<br>scfm/kacfm<br>gpm<br>ton/hr          | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA<br>30,178<br>0<br>2,001<br>0<br>0      | 6.91<br>11.04<br>22.66<br>33.71<br><b>Annual</b><br><b>Cost</b><br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 94<br>\$ 958<br>\$ 958 | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor<br>\$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization<br>\$/kon, 0 ton/hr, 8760 hr/yr, 0.7% utilization |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maintenance<br>Maint Labor<br>Maint  7.18<br>2,655<br>10 ft long<br>1.69<br>Unit<br>Cost \$<br>34.36<br>15%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>28.45<br>20.05%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>2.55%<br>28.45<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55%<br>2.55% | rt<br>5 in dia<br>\$/ft2 of fabric<br>Annual Opera<br>Unit of<br>Measure<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Op Labor<br>\$/Hr<br>of Maintenance<br>gement<br>\$/kW-h<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/ton<br>\$/ton  | ating Hours<br>13.42<br>Use<br>Rate<br>5.0<br>3.0<br>9 Labor<br>492.1<br>N/A<br>0<br>N/A<br>2<br>0<br>N/A<br>0,0<br>N/A   | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr<br>gpm<br>scfm/kacfm<br>gpm<br>ton/hr          | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA<br>30,178<br>0<br>2,001<br>0<br>0      | 6.91<br>11.04<br>22.66<br>33.71<br><b>Annual</b><br><b>Cost</b><br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 94<br>\$ 958<br>\$ 958 | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor<br>\$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization<br>\$/kon, 0 ton/hr, 8760 hr/yr, 0.7% utilization |
| Lime Use<br>Water Makeup Rate/WW Disch =<br>Baghouse Filter Cost<br>Gross BH Filter Area<br>Cages<br>Bags<br>Total<br>Operating Cost Calculations<br>Utilization Rate<br>Item<br>Operating Labor<br>Op Labor<br>Supervisor<br>Maintenance<br>Maint Labor<br>Maint  7.18<br>2,655<br>10 ft long<br>1.69<br>Unit<br>Cost \$<br>34.36<br>15%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>100%<br>28.45<br>2.55<br>2.55<br>2.55<br>2.55<br>2.55<br>2.55<br>2.55<br>2   | T<br>5 in dia<br>\$/ft2 of fabric<br>Annual Oper:<br>Unit of<br>Measure<br>\$//Hr<br>of Op Labor<br>\$//Hr<br>of Maintenance<br>\$//Hr<br>of Maintenance<br>\$//Hr<br>of Maintenance<br>\$//Kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kgal<br>\$/kor<br>\$/ton<br>\$/ton | ating Hours<br>13.42<br>Use<br>Rate<br>5.0<br>3.0<br>9 Labor<br>492.1<br>N/A<br>0<br>N/A<br>2<br>0<br>N/A<br>0,0<br>N/A   | area/cage ft <sup>2</sup><br>8,760<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr<br>gpm<br>scfm/kacfm<br>gpm<br>ton/hr<br>lb/hr | Annual<br>Use*<br>5,475<br>NA<br>3,285<br>NA<br>30,178<br>0<br>2,001<br>0<br>0<br>0 | 6.91<br>11.04<br>22.62<br>33.71<br><b>Annual</b><br><b>Cost</b><br>\$ 188,125<br>\$ 28,219<br>\$ 93,454<br>\$ 94,857<br>\$ 94,857  | See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs<br>\$/cage<br>\$/bag<br>Comments<br>\$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr<br>% of Operator Costs<br>\$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr<br>100% of Maintenance Labor<br>\$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization<br>\$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization<br>\$/kon, 0 ton/hr, 8760 hr/yr, 0.7% utilization |

See Summary page for notes and assumptions



# Regional Haze Four-Factor Analysis for NOx and SO2 Emissions Control

# Boiler No. 1 (EQUI17)

Prepared for Southern Minnesota Beet Sugar Cooperative

July 31, 2020

325 South Lake Avenue Duluth, MN 55802 218.529.8200 www.barr.com

# Regional Haze Four-Factor Analysis for NO<sub>x</sub> and SO<sub>2</sub> Emissions Control

July 31, 2020

# Contents

| 1 |     | Еx  | ecutive Summary   | 1  |
|---|-----|-----|---|----|
| 2 |     | In  | troduction  | 1  |
|   | 2.1 |     | Four-factor Analysis Regulatory Background                                | 1  |
|   | 2.2 |     | Facility Description  | 2  |
| 3 |     | Ex  | isting Controls and Baseline Emission Performance                         | 4  |
|   | 3.1 |     | Existing Emission Controls  | 4  |
|   | 3.2 |     | Baseline Emissions Performance  | 4  |
| 4 |     | Fc  | our-factor Analysis Overview  | 6  |
|   | 4.1 |     | Emission Control Options  | 6  |
|   | 4.2 |     | Factor 1 – Cost of Compliance   | 6  |
|   | 4.3 |     | Factor 2 – Time Necessary for Compliance                                  | 8  |
|   | 4.4 |     | Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance | 8  |
|   | 4.5 |     | Factor 4 – Remaining Useful Life of the Source                            | 8  |
| 5 |     | N   | O <sub>x</sub> Four-factor Analysis                                       | 9  |
|   | 5.1 |     | NO <sub>x</sub> Control Measures Overview                                 | 9  |
|   | 5.1 | 1.1 | Low- NO <sub>x</sub> Burners (LNB)  | 10 |
|   | 5.1 | 1.2 | Low NO <sub>x</sub> Burners with Overfire Air (LNB+OFA)                   | 10 |
|   | 5.1 | 1.3 | Selective Catalytic Reduction (SCR)                                       | 10 |
|   | 5.1 | 1.4 | Selective Non-Catalytic Reduction (SNCR)                                  | 11 |
|   | 5.2 |     | Factor 1 – Cost of Compliance   | 12 |
|   | 5.3 |     | Factor 2 – Time Necessary for Compliance                                  | 13 |
|   | 5.4 |     | Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance | 14 |
|   | 5.5 |     | Factor 4 – Remaining Useful Life of the Source                            | 14 |
| 6 |     | SC  | $D_2$ Four-factor Analysis  | 15 |
|   | 6.1 |     | SO <sub>2</sub> Control Measures Overview                                 | 15 |
|   | 6.1 | 1.1 | Spray Dry Absorber with Baghouse  | 15 |
|   | 6.1 | 1.2 | Dry Sorbent Injection   | 15 |
|   | 6.2 |     | Factor 1 – Cost of Compliance   |    |
|   | 6.3 |     | Factor 2 – Time Necessary for Compliance                                  | 17 |

\\barr.com\projects\Mpls\23 MN\65\2365011\WorkFiles\Air Permitting\Regional Haze\SMBSC - RH Four Factor Analysis FINAL.docx

|   | 6.4  | Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance | 17 |
|---|------|---|----|
|   | 6.5  | Factor 4 – Remaining Useful Life of the Source                            | 17 |
| 7 | ,    | Visibility Impacts Review   | 18 |
|   | 7.1  | Emission Inventory and Photochemical Modeling Inputs Review               | 18 |
|   | 7.2  | Visibility Impacts Review   | 19 |
|   | 7.2. | .1 IMPROVE Monitoring Data Analysis                                       | 19 |
|   | 7.2. | 2.2 Transport Frequency and Trajectory Analysis                           | 23 |
|   | 7.3  | Visibility Review Summary   | 25 |

# List of Tables

| Table 1-1: Summary of NO <sub>x</sub> Four-Factor Analysis   | 2  |
|--|----|
| Table 1-2: Summary of SO <sub>2</sub> Four-factor Analysis   | 3  |
| Table 2-1: Identified Emission Units   | 1  |
| Table 5-1: Additional NO <sub>x</sub> Emission Control Measures with Potential Application at Coal-Fired Boilers | 10 |
| Table 5-2: NO <sub>x</sub> Control Cost Summary  | 13 |
| Table 6-1: Additional SO <sub>2</sub> Control Measures with Potential Application at Coal-Fired Boilers          | 15 |
| Table 6-2: SO <sub>2</sub> Control Cost Summary, per Unit Basis  | 16 |
| Table 6-3: SO <sub>2</sub> Control Measure Environmental Impacts   | 17 |
| Table 7-1: 2016 and 2028 EPA Modeling Emissions Inventory for SMBSC Sources (TPY)                                | 19 |

# List of Figures

| Figure 2-1: Boiler 1 Schematic  | 3  |
|---|----|
| Figure 5-1: NO <sub>X</sub> Removal using SCR vs. Flue Gas Temperature          | 11 |
| Figure 7-1: Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)    | 20 |
| Figure 7-2: Visibility Trend versus URP – Voyageurs National Park (VOYA1)       | 20 |
| Figure 7-3: Visibility Trend versus URP – Isle Royale National Park (ISLE1)     | 21 |
| Figure 7-4: Visibility Components Trend for each Class 1 Monitor from 2004-2018 |    |
| Figure 7-5: Olivia Wind Rose  |    |
| Figure 7-6: Voyageurs Trajectories for Most Impaired Days 2014-2016             | 25 |
| Figure 7-7: 2017 Most Imparied Days Forward Trajectories                        |    |
| Figure 7-8: 2018 Most Impaired Days Forward Trajectories                        |    |

# List of Appendices

Appendix A: Control Cost Analysis for NOx and  $SO_2$ 

# Abbreviations

| ACF             | Annual Capacity Factor                                  |
|-----------------|---|
| BART            | Best Available Retrofit Technology                      |
| BWCA            | Boundary Waters Canoe Area                              |
| CEMs            | Continuous Emission Monitoring System                   |
| CEPCI           | Chemical Engineering Plant Cost Index                   |
| CPI             | Consumer Price Index                                    |
| DSI             | Dry Sorbent Injection                                   |
| GCVTV           | Grand Canyon Visibility Transport Commission            |
| IMPROVE         | Interagency Monitoring of Protected Visual Environments |
| LADCO           | Lake Michigan Air Directors Consortium                  |
| LNB             | Low-NOX Burners   |
| MPCA            | Minnesota Pollution Control Agency                      |
| nonEGU          | Non-Electric Generating Unit                            |
| NOx             | Nitrogen Oxides   |
| 0&M             | Operations and Maintenance                              |
| OFA             | Overfire Air  |
| RFI             | Request for Information                                 |
| RHR             | Regional Haze Rule                                      |
| SCC             | Source Classification Code                              |
| SCR             | Selective Catalytic Reduction                           |
| SNCR            | Selective Non-Catalytic Reduction                       |
| SDA             | Spray Dryer Absorber                                    |
| SIP             | State Implementation Plan                               |
| SMBSC           | Southern Minnesota Beet Sugar Cooperative               |
| SO <sub>2</sub> | Sulfur Dioxide  |
| TPY             | Ton per Year  |
| URP             | Universal Rate of Progress                              |
| USEPA           | U.S. Environmental Protection Agency                    |

# **1 Executive Summary**

In accordance with Minnesota Pollution Control Agency's (MPCA's) January 29, 2020, Request for Information (RFI) Letter<sup>1</sup>, Southern Minnesota Beet Sugar Cooperative (SMBSC) evaluated potential emission control measures for sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>X</sub>) for Boiler No. 1 as part of the State's Regional Haze Rule (RHR)<sup>2</sup> reasonable progress. The analysis considers potential emissions control measures by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i) and pursuant to the final EPA RHR State Implementation Plan (SIP) guidance<sup>3</sup> on August 20, 2019 (2019 RH SIP Guidance):

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

This report describes the background and analysis for conducting the four-factor analysis for NO<sub>x</sub> and SO<sub>2</sub> as applied to the review of emissions controls for the coal-fired boiler at SMBSC. The four-factor analysis conclusions are summarized in Table 1-1 and Table 1-2 for NO<sub>x</sub> and SO<sub>2</sub>, respectively.

The NO<sub>x</sub> four-factor analysis evaluated the following NO<sub>x</sub> emissions control measures:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Low NO<sub>x</sub> Burners (LNB)
- Low NO<sub>x</sub> Burners with Over Fire Air (LNB+OFA)

In the Factor 1 – Cost of Compliance analysis, the associated cost effectiveness (\$ for each ton of emissions reduction) for each of the evaluated technologies exceeded the range of cost effectiveness that was stated in the EPA's Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS for NOx emission controls (refer to Sections 4.2 and 5.2 for more information). Therefore, none of the potential NO<sub>x</sub> emission control measures are reasonable for installing on SMBSC's Boiler 1.

The SO<sub>2</sub> four-factor analysis evaluated the following SO<sub>2</sub> emissions reduction technologies:

<sup>&</sup>lt;sup>1</sup> February 14, 2020 letter from Hassan Bouchareb of MPCA to Derwood Brady of Southern Minnesota Beet Sugar Cooperative

<sup>&</sup>lt;sup>2</sup> The U.S. Environmental Protection Agency (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>&</sup>lt;sup>3</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

- Spray Dryer Absorption (SDA)
- Dry Sorbent Injection (DSI)

In the Factor 1 – Cost of Compliance analysis, the associated cost effectiveness (\$ for each ton of emissions reduction) for each of the evaluated technologies far exceeded the range of cost effectiveness in the MPCA's original BART SO<sub>2</sub> cost thresholds (refer to Sections 4.2 and 6.1.1 for more information). Therefore, none of the potential SO<sub>2</sub> emission control measures are reasonable for installing on SMBSC's Boiler 1.

In addition to the four statutory factors, this analysis evaluates the resulting visibility improvements from the emission control measures, which is referred to as the "fifth factor" (refer to Section 7.0 for more information). The results of the analysis conclude that SMBSC provides virtually no contribution to visibility impairment at the Upper Midwest Class I areas. Thus, additional control measures implemented at SMBSC are unlikely to provide improvement in visibility in those areas.

| Table 1-1: Summary of NO <sub>x</sub> | Four-Factor Analysis |
|---------------------------------------|----------------------|
|---------------------------------------|----------------------|

| List of Emission<br>Control<br>Measures              | Factor 1 – Cost<br>of Compliance | Factor 2 – Time<br>Necessary for<br>Compliance | Factor 3 - Energy and Non-<br>Air Quality Environmental<br>Impacts of Compliance  | Factor 4 –<br>Remaining Useful<br>Life of the Source |
|--|----------------------------------|--|---|--|
| Selective<br>Catalytic<br>Reduction with<br>Reheat   | \$7,000/ton                      | 2-3 years                                      | Additional electricity and natural gas consumption for reheat   | 20 years   |
| Low NO <sub>x</sub> Burners                          | \$5,100/ton                      | 2-3 years                                      | Reduced Thermal Efficiency  | 20 years   |
| Low NO <sub>x</sub> Burners<br>with Over Fire<br>Air | \$3,600/ton                      | 2-3 years                                      | Reduced Thermal Efficiency  | 20 years   |
| Selective Non-<br>Catalytic<br>Reduction             | \$3,800/ton                      | 2-3 years                                      | Additional electricity to<br>operate equipment<br>Additional fuel to evaporate<br>water in the injected reagent<br>Additional waste generated<br>due to increased fuel<br>consumption | 20 years   |

Table 1-2: Summary of SO<sub>2</sub> Four-factor Analysis

| List of Emission<br>Control<br>Measures | Factor 1 –<br>Cost of<br>Compliance | Factor 2 – Time<br>Necessary for<br>Compliance | Factor 3 - Energy and Non-<br>Air Quality Environmental<br>Impacts of Compliance                                  | Factor 4 –<br>Remaining Useful<br>Life of the Source |
|---|-------------------------------------|--|---|--|
| Spray Dry<br>Absorber with<br>baghouse  | \$16,600/ton                        | 2-3 years                                      | Additional electricity use to<br>operate equipment<br>Solid waste disposal for spent<br>sorbent and baghouse bags | 20 years   |
| Dry Sorbent<br>Injection                | \$12,700/ton                        | 2-3 years                                      | Additional electricity use to<br>operate equipment<br>Solid waste disposal for spent<br>sorbent and baghouse bags | 20 years   |

# 2 Introduction

This section discussed the pertinent regulatory background information and a description of SMBSC's coal-fired boiler.

# 2.1 Four-factor Analysis Regulatory Background

The RHR 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 February 14, 2020, the MPCA sent an RFI to SMBSC. The RFI stated that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) 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 SO<sub>2</sub> and NO<sub>x</sub>. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze in Isle Royale, they must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts. As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFIs also stated that the facility was identified as a significant source of  $NO_x$  and  $SO_2$  that is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that SMBSC submit a "four factors analysis" (herein termed as a fourfactor analysis) by July 31, 2020 for the emission units identified in Table 1 as part of the State's regional haze reasonable progress.

| Unit         | Unit ID | Applicable Pollutants             |
|--------------|---------|-----------------------------------|
| Boiler No. 1 | EQUI17  | NO <sub>x</sub> & SO <sub>2</sub> |

The analysis considers potential emissions reduction measures by addressing the four statutory factors which are laid out in 40 CFR 51.308(f)(2)(i):

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

The RFI letter to the SMBSC specified that the "... analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to the final 2019 RH SIP Guidance.<sup>3</sup>

This report describes the background and analysis for conducting a four-factor analysis for  $NO_x$  and  $SO_2$  as applied to the review of emissions controls at SMBSC for the unit identified in Table 2-1.

# 2.2 Facility Description

SMBSC processes harvested sugar beets into beet sugar used in consumer food products. The harvested beets are processed through a series of steps including washing, beet slice, diffusion, carbonation, evaporation, and crystallization. To extract and purify the sugar, many of these processes rely upon steam. SMBSC's Boiler 1 generates steam needed for beet processing. The boiler also generates steam for SMBSC's turbine for electricity generation.

Boiler 1 (EQUI 17) is a Babcock and Wilcox (B&W) Stirling boiler installed in 1975. The boiler fires subbituminous coal as the primary fuel source and is controlled by a high-efficiency electrostatic precipitator (TREA 14) for particulate emissions. The flue gas from the electrostatic precipitator is routed to a single stack (STRU 25). The boiler is monitored by a continuous opacity monitor (COM) and continuous emissions monitors (CEMs) for NO<sub>x</sub>, SO<sub>2</sub>, and O2.

Figure 2-1 shows a schematic representation of Boiler 1.

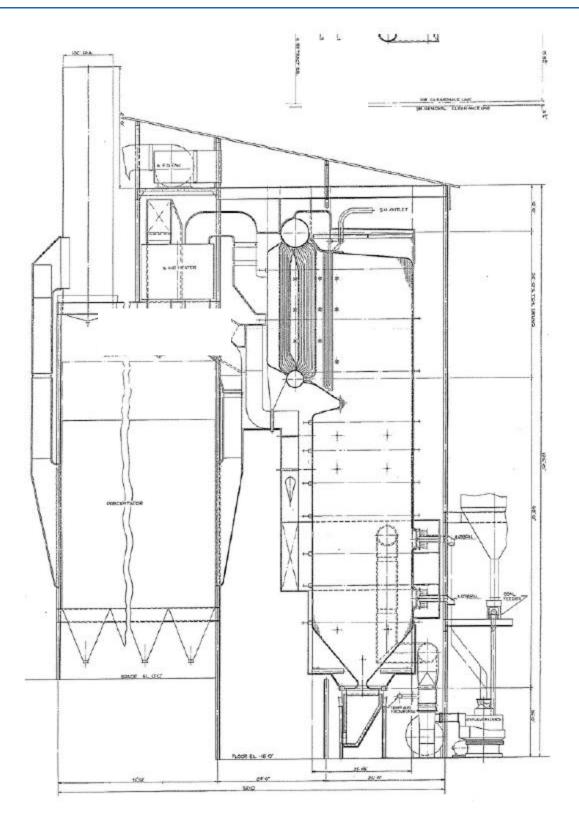


Figure 2-1: Boiler 1 Schematic

# 3 Existing Controls and Baseline Emission Performance

This section describes the existing  $NO_x$  and  $SO_2$  emissions controls, and the baseline emissions to evaluate the cost effectiveness for the associated emission reduction technologies.

# 3.1 Existing Emission Controls

SMBSC's Boiler 1 is equipped with an electrostatic precipitator that controls particulate matter. There is no control equipment currently installed on the boiler for  $SO_2$  or  $NO_x$  control.

### 3.2 Baseline Emissions Performance

The four-factor analysis requires the establishment of a baseline scenario for evaluating a potential emission control measure. 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."

The 2016 and 2028 non-electric generating unit (nonEGU) inventory from EPA was used to determine baseline emissions from Boiler 1 to be used in the four factor analysis. This was acquired from the EPA and confirmed to be accurate by the MPCA. The 2016 modeled emissions align with SMBSC's CEMs data reported to the MPCA. Boiler 1 has a projection factor from 2016 to 2028 of 0.9756 based on coal-fired, non-utility boilers in Minnesota (i.e., not just SMBSC Boiler 1). This represents a 2.5% decrease in emissions from 2016 when projecting forward to 2028 (roughly 0.2% per year). Source classification codes (SCC) beginning with "102002" were projected using this factor. Specifically, this projection factor was

used for SMBSC and other beet sugar processing plant boilers. Table 3-2 provides the 2016 and 2028 baseline emissions. The four-factor analysis uses the 2028 emissions.

| Units    | 2016 SO <sub>2</sub> | 2028 SO <sub>2</sub> | 2016 NO <sub>x</sub> | 2028 NO <sub>x</sub> |
|----------|----------------------|----------------------|----------------------|----------------------|
| Boiler 1 | 805                  | 786                  | 930                  | 907                  |

Table 3-2: 2016 and 2028 EPA Modeling Emissions Inventory for SMBSC Sources (TPY)

# **4** Four-factor Analysis Overview

This section summarizes the four-factor analysis approach with respect to the Regional Haze program detailed in the 2019 RH SIP guidance.

# 4.1 Emission Control Options

Prior to completing a four-factor analysis of each emission control measure, all commercially available and technically feasible emission control options for the coal-fired boiler 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 emission control measure 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, industrial operations are not considered as part of this analysis. Instead, this evaluation focuses on commercially demonstrated control options.

An evaluation of the commercially available and technically feasible control measures for  $NO_x$  and  $SO_2$  are discussed in Sections 5.1 and 6.1, respectively.

# 4.2 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>4</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 MPCA.

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.

<sup>&</sup>lt;sup>4</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 <u>https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution</u> as of the date of this report.

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 3.2, 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, SMBSC uses the updated baseline emissions value of 235 lb  $NO_x$  /hr and 196 lb  $SO_2$ /hr, as described in Section 3.2, in conjunction with projected hours of operation of the unit to determine an annual tpy value. SMBSC assumes 7,536 operating hours per year based on the past five years of operation. SMBSC considers this value representative of projected operations for purposes of determining annualized emissions. The product of the 235 and 196 lb/hr values and projected operating hours converted to a tpy basis is 886 tpy  $NO_x$  and 738 tpy  $SO_2$  and 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.

The calculated cost effectiveness value for each control measure is compared to a cost effectiveness threshold established by the MPCA or the EPA. The MPCA's original BART SO<sub>2</sub> 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>5</sup> This 1999 value is scaled to today's dollars using the Chemical Engineering Plant Cost Index (CEPCI).<sup>6</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 \$5,600 per ton for SO<sub>2</sub>. The average cost effectiveness threshold for NO<sub>x</sub> is based on the EPA's Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS<sup>7</sup> which provides a cost effectiveness

<sup>&</sup>lt;sup>5</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>&</sup>lt;sup>6</sup> More information on CEPCI may be found at this link: <u>https://www.chemengonline.com/pci-home</u>. The CEPCI is accessible by subscription through "Chemical Engineering" magazine. The CEPCI scaling factors for this analysis compare 1999 values to January 2020 values.

<sup>&</sup>lt;sup>7</sup> The EPA's Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS<sup>7</sup> may be found online at this link: <u>https://www.epa.gov/sites/production/files/2017-</u>05/documents/final assessment of nonegu nox emission controls cost of controls and time for compliance final tsd.pdf

value of \$2,400 per ton for NO<sub>x</sub> control on a coal-fired boiler. This 2011 value scaled to today's dollars using CEPCI, is \$3,100 per ton of NO<sub>x</sub>.

### 4.3 Factor 2 – Time Necessary for Compliance

Factor #2 is considered by MPCA 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  $NO_x$  or  $SO_2$  control measure requires a unit outage as part of its installation, SMBSC considers the forecasted outage schedule for the associated units in conjunction with the expected timeframe for engineering and equipment procurement following MPCA and EPA approval of the given control measure.

# 4.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

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 measure results in any significant or unusual energy penalties or benefits. Energy use may be evaluated on energy used per unit of production basis; energy used per ton of pollutant controlled or total annual energy use.

# 4.5 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 for the unit 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).

# **5** NO<sub>x</sub> Four-factor Analysis

This section identifies and describes various  $NO_x$  emission control measures, evaluates the four statutory factors for Boiler 1. Consistent with EPA's guidance and MPCA direction, SMBSC has completed a four-factor analysis for  $NO_x$  as summarized in Sections 5.1 to 5.5.

### 5.1 NO<sub>x</sub> Control Measures Overview

There are three mechanisms by which  $NO_x$  production occurs. They are thermal, fuel, and prompt  $NO_x$  formation.

In the case of natural gas combustion, the primary mechanism of NO<sub>x</sub> production is through thermal NO<sub>x</sub> formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air to nitric oxide (NO). The thermal oxidation reaction is as follows:

 $N_2 + O_2 \rightarrow 2NO \tag{1}$ 

Downstream of the flame, significant amounts of  $NO_2$  can be formed when NO is mixed with air. The reaction is as follows:

 $2NO + O_2 \rightarrow 2NO_2 \tag{2}$ 

Thermal oxidation is a function of the residence time, free oxygen, and peak reaction temperature.

Prompt NO<sub>x</sub> is a form of thermal NO<sub>x</sub> which is generated at the flame boundary. It is the result of reactions between nitrogen and hydrocarbon radicals generated during combustion. Only minor amounts of NO<sub>x</sub> are emitted as prompt NO<sub>x</sub>.

Fuel bound  $NO_x$  is primarily a concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process.

Several techniques can be used to reduce NO<sub>x</sub> emissions from coal-fired boilers, as listed in Table 5-1.

#### Table 5-1: Additional NO<sub>x</sub> Emission Control Measures with Potential Application at Coal-Fired Boilers

| Emission Control Measures                                  |  |  |  |  |  |  |
|--|--|--|--|--|--|--|
| Low- NO <sub>x</sub> Burners (LNB)                         |  |  |  |  |  |  |
| Low- NO <sub>x</sub> Burners with Over Fired Air (LNB+OFA) |  |  |  |  |  |  |
| Post-Combustion Controls                                   |  |  |  |  |  |  |
| Non-Selective Catalytic Reduction (NSCR)                   |  |  |  |  |  |  |
| Selective Catalytic Reduction (SCR)                        |  |  |  |  |  |  |

The following Sections 5.1.1 through 5.1.4 describes aspects of each emission control measure determined to be feasible for coal-fired boilers.

### 5.1.1 Low- NO<sub>x</sub> Burners (LNB)

LNB technology utilizes advanced burner design to reduce NO<sub>x</sub> formation through the restriction of oxygen, flame temperature, and/or residence time. LNB technology is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO<sub>x</sub> formation is limited by either one of two conditions; rich or lean fuel. Under a rich (high fuel) condition, oxygen levels and flame temperatures are low resulting in less NO<sub>x</sub> 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.

LNB technology reduces the formation of NO<sub>x</sub> during fuel combustion, rather than remove it after formation as do other control devices. LNB are more reliable than other control devices because there are no added pieces of equipment to operate, maintain, or malfunction. LNB do not use additional electricity, nor do they generate any wastewater or solid waste streams. They do have the disadvantage that they are not as thermally efficient as standard burners when considering only the thermal requirements and not considering the overall energy (thermal and electrical) as compared to a standard burner technology and the electricity used by a control device and the treatment of wastewater and solid waste disposal.

### 5.1.2 Low NO<sub>x</sub> Burners with Overfire Air (LNB+OFA)

Low NO<sub>x</sub> burners with overfire air utilize the same LNB technology described in Section 5.1.1 with the addition of overfire air. The addition of OFA diverts combustion air away from the primary combustion zone to a location above the highest burner. The overfire air maintains a lower temperature to prevent the formation of thermal NO<sub>x</sub> as well as providing oxygen to complete the combustion reaction.

A Low NO<sub>x</sub> burner with overfire air is a reliable emission control option with no added piece of equipment to operate, maintain, or malfunction. The addition of over-fire air also does not create any additional electricity or waste costs.

### 5.1.3 Selective Catalytic Reduction (SCR)

SCR is a post combustion NO<sub>x</sub> control measure in which ammonia (NH<sub>3</sub>) or urea (CH<sub>4</sub>N<sub>2</sub>O) is injected into the flue gas stream in the presence of a catalyst. SMBSC evaluated urea injection, which converts to

ammonia after injection into the flue gas. SCR control efficiency is typically 70 to 90 percent. SCR requires an optimum temperature range of 570°F to 850°F. Figure 2-1 is a diagram of SCR catalyst activity vs. temperature from Section 4, Chapter 4 from the <u>EPA Air Pollution Control Cost Manual - Sixth Edition</u> (EPA 452/B-02-001)

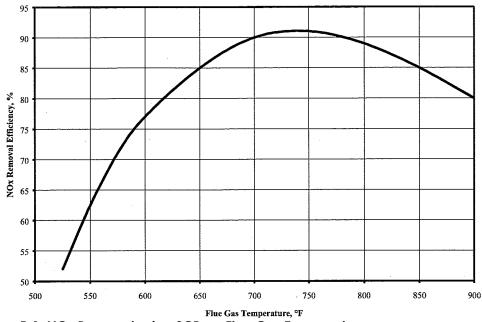


Figure 5-1: NO<sub>X</sub> Removal using SCR vs. Flue Gas Temperature

SMBSC's Boiler 1 flue gas temperature is approximately  $370^{\circ}$ F under current operating conditions. For the SCR to effectively control NO<sub>x</sub> emissions, flue gas reheat would need to be included with this control measure for it to be technically feasible.

### 5.1.4 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 molecular nitrogen,  $N_2$ , and water. SNCR control efficiency is typically 25 to 50 percent. Without the participation of a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:

$$2NO + 2NH_3 + 1/2 O_2 \rightarrow 2 N_2 + 3H_2O \quad (1)$$
  
$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \quad (2)$$

At temperature ranges of 1,470°F to 1,830°F, reaction (1) dominates and NO<sub>x</sub> emissions are controlled. At temperatures above 2,000°F, reaction (2) will dominate and the ammonia will decompose and increase NO<sub>x</sub> emissions. Therefore, it is critical to inject the ammonia or urea reagent into a furnace or boiler at the 1,470°F to 1,830°F temperature range to ensure that NO<sub>x</sub> emissions will be controlled.

### 5.2 Factor 1 – Cost of Compliance

SMBSC has completed a high-level screening-level cost estimate for the selected NO<sub>x</sub> emission control measures. Due to the very limited space around existing equipment, a 50 percent markup of the total capital investment (i.e., a 1.5 retrofit factor) was included in the costs. Retrofit installations have increased handling and erection difficulty for many reasons. Access for transportation, laydown space, etc. for new equipment is significantly impeded or restricted. This is because the spaces surrounding the boiler are congested, or the areas surrounding the building support frequent vehicle traffic. The use of a retrofit factor has been justified by previous projects with the MPCA and other states.<sup>8</sup> Finally, the EPA Air Pollution Control Cost Manual notes that retrofit installations are subjective because the plant designers may not have had the foresight to include additional floor space and room between components for new equipment.<sup>9</sup> Retrofits can impose additional costs to "shoehorn" equipment in existing plant space, which is true for SMBSC. Importantly, this initial set of cost estimates do not include additional outage time that may be necessary. Cost summary spreadsheets for the NO<sub>x</sub> emission control measures 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 a 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.

The resulting cost effectiveness calculations are summarized in Table 5-2.

<sup>&</sup>lt;sup>8</sup> Barr Engineering Co. United Taconite Analysis of Best Available Retrofit Technology. 2006 and U. S. Environmental Protection Agency. Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze (final rule, to be codified at 40 CFR Part 52). Federal Register. January 30, 2014. Vol. 79, 20, p. 5154. EPA–R08–OAR–2012–0026.

<sup>&</sup>lt;sup>9</sup> U.S. Environmental Protection Agency. EPA Air Pollution Control Cost Manual, Sixth Edition, Section 1, Chapter 2.6.4.2 Retrofit Cost Considerations. 2017. <u>https://www.epa.gov/sites/production/files/2017-</u>12/documents/epaccmcostestimationmethodchapter 7thedition 2017.pdf

Table 5-2: NOx Control Cost Summary

| Additional<br>Emissions<br>Control<br>Measure       | Installed Capital<br>Cost with Retrofit<br>Factor<br>(\$) | Indirect<br>Costs<br>(\$/yr) | Direct<br>Operating<br>Costs (\$/yr) | Total<br>Annualized<br>Costs (\$/yr) | Annual<br>Emissions<br>Reduction<br>(tpy) | Pollution<br>Control Cost<br>Effectiveness<br>(\$/ton) |
|---|---|------------------------------|--------------------------------------|--------------------------------------|---|--|
| Low NO <sub>x</sub><br>Burners                      | \$3,090,000   | \$442,000                    | \$100,000                            | \$542,000                            | 106                                       | \$5,100  |
| Low NO <sub>x</sub><br>Burners with<br>Overfire Air | \$5,340,000   | \$721,000                    | \$100,000                            | \$821,000                            | 231                                       | \$3,600  |
| Selective<br>Catalytic<br>Reduction                 | \$39,000,000  | \$3,400,000                  | \$2,280,000                          | \$5,690,000                          | 813                                       | \$7,000  |
| Selective Non-<br>Catalytic<br>Reduction            | \$6,910,000   | \$581,000                    | \$699,000                            | \$1,280,000                          | 340                                       | \$3,800  |

The cost effectiveness values for all the potential  $NO_x$  emission control measures are greater than the cost effectiveness threshold of \$3,100 derived in Section 4.2. Therefore, none of the potential  $NO_x$  emission control measures are reasonable for installing on SMBSC's Boiler 1.

Section 5.3 through 5.5 provide a screening-level summary of the remaining three factors evaluated for the NO<sub>x</sub> emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis, and therefore further supports the determination that none of the potential NO<sub>x</sub> emission control measures are reasonable for installing on SMBSC's Boiler 1.

# 5.3 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the 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.

Each NO<sub>x</sub> control option would require significant resources and time of at least two to three years to engineer, permit, and install the equipment. Assuming that a SIP limit to approve a new emissions limit would occur in 2022, approximately one year after the MPCA submits its regional haze SIP for the second implementation period, the earliest that the project could be completed is during the 2023 and 2024 inter-campaign periods.

# 5.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified  $NO_x$  control measures are summarized herein.

As described in section 5.1.1, there are no additional electricity or waste costs associated with low  $NO_x$  burners or low  $NO_x$  burners with overfire air. However, low  $NO_x$  burners have a reduced thermal efficiency.

The addition of an SCR system to SMBSC's Boiler 1 will increase electricity and natural gas consumption. As described in section 5.1.3, the SCR system would require reheat. This would require an additional 5.8 million KW-hr of electricity and 195,000 scf natural gas each year. The SCR system would also require 2 million KW-hr of additional electricity consumption each year.

A SNCR system increases electricity, fuel, and water consumption along with generating additional waste. Water is injected with the reagent, increasing water consumption by 1.4 million gallons per year. An additional 12,000 MMBTU of fuel per year is required to evaporate the injected water and 38 tons of additional ash would be produced due to the increased fuel consumption.

# 5.5 Factor 4 – Remaining Useful Life of the Source

Because SMBSC is assumed to continue operations for the foreseeable future, the useful life of the individual control measures is used to calculate emission reductions, amortized costs, and cost effectiveness on a dollar per ton basis.

# **6** SO<sub>2</sub> Four-factor Analysis

This section identifies and describes various SO<sub>2</sub> emission reduction technologies, evaluates the four statutory factors for Boiler 1. Consistent with EPA's guidance and MPCA direction, SMBSC has completed a four-factor analysis for SO<sub>2</sub> as summarized in Sections 6.1 to 6.5.

### 6.1 SO<sub>2</sub> Control Measures Overview

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>. Technically feasible SO<sub>2</sub> control options for SMBSC's Boiler 1 are summarized in Table 6-1.



| Control Measure       |  |  |  |  |
|-----------------------|--|--|--|--|
| Spray Dry Absorber    |  |  |  |  |
| Dry Sorbent Injection |  |  |  |  |

### 6.1.1 Spray Dry Absorber with Baghouse

The spray dry absorber (SDA) uses slaked lime  $(Ca(OH)_2)$  as an absorbent to control SO<sub>2</sub> emissions. The lime neutralizes the absorbed SO<sub>2</sub> to form a solid powder.

A SDA requires the installation of a baghouse and lime slaking system. The baghouse is necessary to collect particulate emissions from the spray dry absorber. The lime slaker mixes the dried lime with water in preparation for the lime to be added to the spray dry absorber.

### 6.1.2 Dry Sorbent Injection

Dry sorbent injection uses a calcium or sodium based reagent. For SMBSC's Boiler 1, trona (sodium sesquicarbonate), a sodium reagent is the selected reagent. In this application, the trona is injected into the flue gas stream to react with SO<sub>2</sub>.

The dry sorbent injection system requires the installation of a baghouse to accommodate the additional particulate matter from the injected sorbent and reaction byproducts.

# 6.2 Factor 1 – Cost of Compliance

SMBSC has completed a high-level screening-level cost estimate for the selected SO<sub>2</sub> emission control measures. Due to the very limited space around existing equipment, a 50 percent markup of the total capital investment (i.e., a 1.5 retrofit factor) was included in the costs. Retrofit installations have increased handling and erection difficulty for many reasons. Access for transportation, laydown space, etc. for new equipment is significantly impeded or restricted. This is because the spaces surrounding the boiler are

congested, or the areas surrounding the building support frequent vehicle traffic. The use of a retrofit factor has been justified by previous projects with the MPCA and other states.<sup>10</sup> Finally, the EPA Air Pollution Control Cost Manual notes that retrofit installations are subjective because the plant designers may not have had the foresight to include additional floor space and room between components for new equipment.<sup>11</sup> Retrofits can impose additional costs to "shoehorn" equipment in existing plant space, which is true for SMBSC. Importantly, this initial set of cost estimates do not include additional outage time that may be necessary. Cost summary spreadsheets for the SO<sub>2</sub> emission control measures are provided in Appendix A.

The resulting cost effectiveness calculations are summarized in Table 6-2.

| Additional<br>Emissions<br>Control<br>Measure | Installed<br>Capital Cost<br>with Retrofit<br>Factor<br>(\$) | Indirect Costs<br>(\$/yr) | Direct<br>Operating Costs<br>(\$/yr) | Total<br>Annualized<br>Costs<br>(\$/yr) | Annual<br>Emissions<br>Reduction<br>(tpy) | Pollution<br>Control Cost<br>Effectiveness<br>(\$/ton) |
|---|--|---------------------------|--------------------------------------|---|---|--|
| Spray Dry<br>Absorber                         | \$82,900,000   | \$10,600,000              | \$1,090,000                          | \$11,700,000                            | 707                                       | \$16,600   |
| Dry Sorbent<br>Injection                      | \$36,000,000   | \$4,820,000               | \$2,170,000                          | \$6,990,000                             | 550                                       | \$12,700   |

#### Table 6-2: SO<sub>2</sub> Control Cost Summary, per Unit Basis

The cost effectiveness values for all the SO<sub>2</sub> emission control measures are substantially greater than the cost effectiveness threshold of \$5,600 derived in Section 4.2. Therefore, none of the potential SO<sub>2</sub> emission control measures are reasonable for installing on SMBSC's Boiler 1.

Sections 6.3 through 6.5 provide a screening-level summary of the remaining three factors evaluated for the SO<sub>2</sub> control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis, and therefore further supports the determination that none of the potential SO<sub>2</sub> emission control measures are reasonable for installing on SMBSC's Boiler 1.

<sup>&</sup>lt;sup>10</sup> Barr Engineering Co. United Taconite Analysis of Best Available Retrofit Technology. 2006 and U. S. Environmental Protection Agency. Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze (final rule, to be codified at 40 CFR Part 52). Federal Register. January 30, 2014. Vol. 79, 20, p. 5154. EPA–R08–OAR–2012–0026.

<sup>&</sup>lt;sup>11</sup> U.S. Environmental Protection Agency. EPA Air Pollution Control Cost Manual, Sixth Edition, Section 1, Chapter 2.6.4.2 Retrofit Cost Considerations. 2017. <u>https://www.epa.gov/sites/production/files/2017-</u> 12/documents/epaccmcostestimationmethodchapter 7thedition 2017.pdf

# 6.3 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the 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 project control option would require significant resources and time of at least two to three years to engineer, permit, and install the equipment. Assuming that a SIP limit to approve a new emissions limit would occur in 2022, approximately one year after the MPCA submits its regional haze SIP for the second implementation period, the earliest that the project could be completed is during the 2023 and 2024 inter-campaign periods.

# 6.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified SO<sub>2</sub> control measures are summarized herein.

The SDA and DSI systems both result in an increase in electricity consumption as well as an increase in solid waste generation. Electricity is required to operate the additional system components for each control measure Additional waste streams will be generated from the spent sorbent and unreacted sorbent waste generation. Table 6-3 lists estimated quantities of each material below:

#### Table 6-3: SO<sub>2</sub> Control Measure Environmental Impacts

| Parameter                                    | SDA                        | DSI                        |  |
|--|----------------------------|----------------------------|--|
| Additional Electricity Consumption           | 2.9 million KW-hr per year | 1.7 million KW-hr per year |  |
| Spent and Unreacted Sorbent Waste Generation | 1,600 tons per year        | 3,500 tons per year        |  |

### 6.5 Factor 4 – Remaining Useful Life of the Source

Because SMBSC is assumed to continue operations for the foreseeable future, the useful life of the individual control measures is used to calculate emission reductions, amortized costs, and cost effectiveness on a dollar per ton basis.

# 7 Visibility Impacts Review

The Regional Haze Rule (RHR) requires that the SIP include an analysis of "baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."<sup>12</sup> This is used to establish progress goals to be achieved by the end of the implementation period in 2028.<sup>13</sup> Section 7.1 provides an analysis of current visibility conditions at the three Class I areas being evaluated by MPCA: Boundary Waters, Voyageurs, and Isle Royale. Since 2009, the regional haze impairment at all three Class I areas has been declining (i.e., visibility has been improving). Additionally, regional haze impairment fell below the expected 2028 Universal Rate of Progress (URP) goal in 2016 for Boundary Waters and Isle Royale, and 2018 for Voyageurs. Because the existing visibility data demonstrates sustained progress towards visibility goals and the 5-year average visibility impairment on the most impaired days is already below the URP, the MPCA should use the current trend of emission reductions to demonstrate reasonable progress.

Additionally, the 2019 SIP Guidance provides criteria to evaluate when selecting sources that must complete an analysis of emission controls. One of the options for estimating baseline visibility impacts is a particle trajectory analysis.<sup>14</sup> In addition, the 2019 SIP Guidance says that a state can consider visibility impacts in Class I areas when evaluating possible emission control measures.<sup>15</sup> Section 7.2.2 provides results from two different particle trajectory analyses for the most impaired days at the Voyageurs and Boundary Waters visibility monitors. The results of the analysis conclude that SMBSC provides virtually no contribution to visibility impairment at the nearby Class I areas. Thus, additional control measures implemented at SMBSC are unlikely to provide a substantial improvement in visibility in the Class I areas.

# 7.1 Emission Inventory and Photochemical Modeling Inputs Review

As described in Section 3-2, to understand the emissions from Boiler 1 used in the regional haze modeling analysis completed by US EPA, Barr acquired the 2016 and 2028 non-electric generating unit (nonEGU) inventory from the US EPA and was advised by MPCA that no changes have been made to those inventories for SMBSC.

Table 7-1 includes the SO<sub>2</sub> and NO<sub>x</sub> inventory summary information for Boiler 1.

<sup>15</sup> Ibid, Page 34.

<sup>&</sup>lt;sup>12</sup> 40 CFR 51.308(f)(1)

<sup>&</sup>lt;sup>13</sup> 40 CFR 51.308(f)(3)

<sup>&</sup>lt;sup>14</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003. Page 13.

| Table 7-1 | 2014 and 2028 EPA Modeling | Emissions Inventory for SMBSC Sources (TPY) |
|-----------|----------------------------|---|
|           | ZUTO UNU ZUZO EFA MOUEIING |   |

| Units    | 2016 SO <sub>2</sub> | <b>2028 SO</b> 2 | 2016 NO <sub>x</sub> | 2028 NO <sub>x</sub> |
|----------|----------------------|------------------|----------------------|----------------------|
| Boiler 1 | 806                  | 786              | 930                  | 907                  |

As expected, the 2016 modeled emissions match the CEMs data reported to MPCA. Boiler 1 has a projection factor from 2016 to 2028 of 0.9756 for coal-fired, non-utility boilers in Minnesota (i.e., not just SMBSC Boiler 1). This represents a 2.5% decrease in emissions from 2016 when projecting forward to 2028 (roughly 0.2% per year). Source classification codes (SCC) beginning with "102002" were projected using this factor. Specifically, this projection factor was used for SMBSC and the other beet sugar processing plant boilers as well. The analysis conducted for the four-factor analysis includes the 2028 emissions.

### 7.2 Visibility Impacts Review

#### 7.2.1 IMPROVE Monitoring Data Analysis

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at Boundary Waters (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).<sup>16</sup> The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). The EPA issued guidance for tracking visibility progress, including the methods for selecting the "most impaired days," on December 20, 2018.<sup>17</sup> Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms) could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."<sup>18</sup>

Figure 7-1 through Figure 7-3 show the rolling 5-year average visibility impairment compared with the URP glidepath<sup>19</sup> at Boundary Waters (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1), respectively. Regional haze impairment has been declining since 2009 for all three Class I areas that are tracked by MPCA. Impacts to the most impaired days at Boundary Waters and Isle Royale fell below the expected 2028 URP goal in 2016 and have continued trending downward since. Voyageurs' impaired days fell below the 2028 URP in 2018 and is also on a downward trend.

<sup>&</sup>lt;sup>16</sup> <u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze\_visibility\_metrics\_public/Visibilityprogress</u>

<sup>&</sup>lt;sup>17</sup> <u>https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional</u>

<sup>&</sup>lt;sup>18</sup> USEPA, Federal Register, 05/04/2016, Page 26948

<sup>&</sup>lt;sup>19</sup><u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze\_visibility\_metrics\_public/Visibilitypro</u> gress

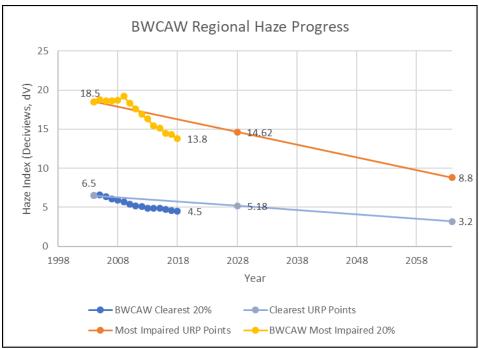


Figure 7-1: Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

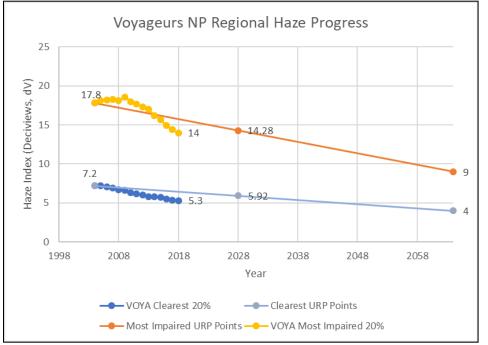


Figure 7-2: Visibility Trend versus URP – Voyageurs National Park (VOYA1)

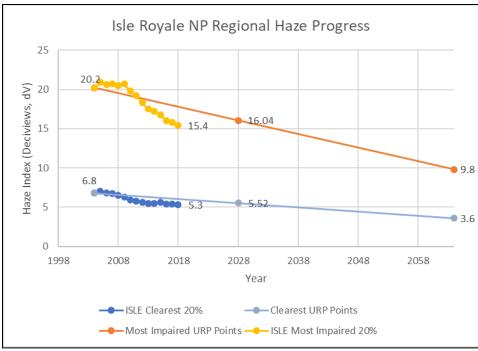
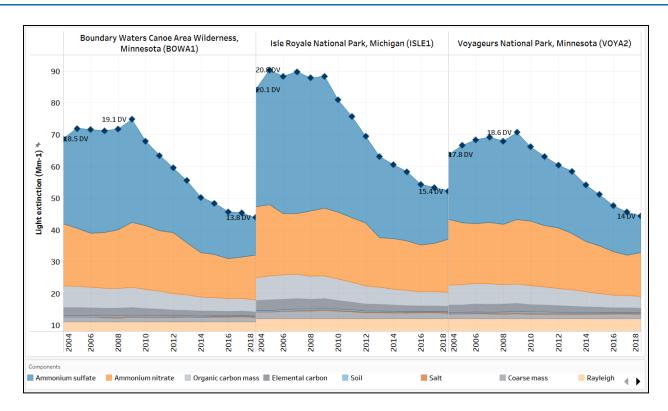


Figure 7-3: Visibility Trend versus URP – Isle Royale National Park (ISLE1)

The downward visibility trend for each of the Class I monitors described above can be mostly attributed to the reductions in ammonium sulfate and, to a lesser extent, ammonium nitrate as shown in Figure 7-4. These reductions are a result of a number of different actions taken to reduce emissions from several sources, including:

- Installation of BART during the first RHR implementation period
- Emission reductions from a variety of industries, including pulp and paper mill sources, due to updated rules and regulations
- Transition of power generation systems from coal to natural gas and renewables (wind and solar)



#### Figure 7-4: Visibility Components Trend for each Class 1 Monitor from 2004-2018<sup>20</sup>

Additionally, since the end of 2018, many facilities have implemented emission reduction actions that are not represented in the data in Figure 7-1 through Figure 7-4 including:

- Retiring two coal-fired boilers at the Minnesota Power Boswell Energy Center in Cohasset at the end of 2018
- The compliance schedules for the NO<sub>x</sub> emission reductions required by the Taconite Federal Implementation Plan (FIP) Establishing BART for Taconite Plants (40 CFR 52.1235)
- Other planned emission reduction projects that are scheduled to occur in Minnesota prior to 2028, such as the Xcel Energy boiler retirements as detailed in their Upper Midwest Integrated Resource Plan, 2020-2034

These emission reductions will further improve the visibility in the Class I areas, thus helping to ensure the trend remains below the URP to reach the 2028 visibility goal.

The 2019 Guidance says that the state will determine which emission control measures are necessary to make reasonable progress in the affected Class I areas.<sup>21</sup> Because the IMPROVE monitoring network data demonstrates sustained progress towards visibility goals and the 5-year average visibility impairment on

<sup>&</sup>lt;sup>20</sup> MPCA – Regional Haze Tableau Public.

https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze visibility metrics public/Visibilityprogress

<sup>&</sup>lt;sup>21</sup> Ibid, Page 9.

the most impaired days is already below the URP, the MPCA should use the current trend of emission reductions to demonstrate reasonable progress.

### 7.2.2 Transport Frequency and Trajectory Analysis

The 2019 Guidance says that a state should estimate baseline visibility impacts in Class I areas when selecting which sources must conduct a four-factor analysis.<sup>22</sup> In addition, the 2019 Guidance says that a state can consider visibility impacts in Class I areas when evaluating possible emission control measures.<sup>23</sup>

As part of this evaluation, Barr considered the distance from SMBSC to the nearest Class I areas. The distance is 400-450 km to both Boundary Waters and Voyageurs and over 550 km to Isle Royale. The distances alone are enough to eliminate SMBSC for consideration as part of any contribution analysis at the Class I areas. As part of Class I area PSD permitting exercises, Federal Land Managers rarely evaluate permits at distances over 300 km and then only when sources are considerably larger than Boiler 1. The rationale for exclusion of sources at these great distances is logical as the pollution has a long time to disperse, react, and/or deposit thereby reducing the downwind impact on the Class I areas.

Further, using the 2028 emissions, the emissions in tons per year divided by the distance in kilometers (Q/d) is less than 4. Traditionally, a Q/d of 10 has been used to screen out sources from inclusion of visibility analysis on Class I areas.

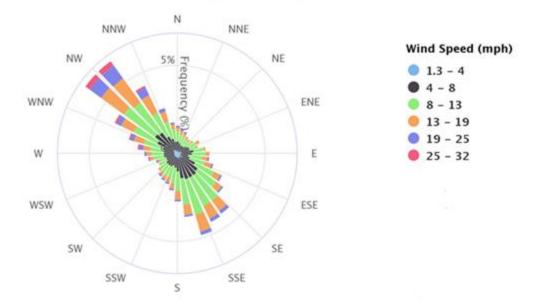
Even if the distance and emissions are not used to screen out the boiler from this evaluation, Barr completed a wind rose for Olivia, MN Regional airport using 2006 -2020 data (Figure 7-5). This rose illustrates the predominant wind directions in this part of Minnesota are from the northwest and southeast/south-southeast. The frequency from the southwest that would be necessary to transport SMBSC emissions to any of the Class I areas is very small (less than 1% of the time). Again, this lack of frequency is sufficient to conclude that the impact of Boiler 1 would not contribute to visibility impairment at the upper Midwest Class I areas.

<sup>&</sup>lt;sup>22</sup> Ibid, Page 12.

<sup>&</sup>lt;sup>23</sup> Ibid, Page 34.

#### OLIVIA RGNL AP (MN) Wind Rose

Jan. 1, 2006 - Mar. 16, 2020 Sub-Interval: Jan. 1 - Dec. 31, 0 - 23



#### Figure 7-5: Olivia Wind Rose

Barr reviewed the trajectory analyses completed by MPCA from 2014-2016 with a focus on Voyageurs, highlighted in Figure 7-6. The trajectory analyses for the most impaired days indicates very few days (<5%) with trajectories passing over SMBSC. Alternatively, many more days showed impacts from the Minneapolis / St. Paul and other areas. In addition, Barr conducted a forward-trajectory analysis from SMBSC's location to the Class I areas on days that exhibit 20% most impaired conditions for 2017 and 2018 (Figures 7-7 and 7-8, respectively). This analysis also indicates that there are only two days per year<sup>24</sup> with potential impact on the upper Midwest Class I areas. It is also important to remember the distance between the source and the Class I areas.

Furthermore, SMBSC Boiler 1 emissions represent less than 0.6% of statewide anthropogenic  $NO_X + SO_2$  emissions (1,735 tons SMBSC / 281,221 tons 2017 statewide<sup>25</sup>). For such long trajectories covering nearly the length of the state, it is unlikely the SMBSC emissions would make up a significant portion of impacts even for trajectories passing over the facility.

<sup>&</sup>lt;sup>24</sup> Forward trajectories were modeled using staggered start times throughout the days of monitored impairment. Trajectories crossing the Class I areas in 2017 are attributable to two modeled days of multiple trajectories, rather than several days of impairment.

<sup>&</sup>lt;sup>25</sup> MPCA 2017 statewide air emissions inventory. <u>https://www.pca.state.mn.us/air/statewide-and-county-air-emissions</u>

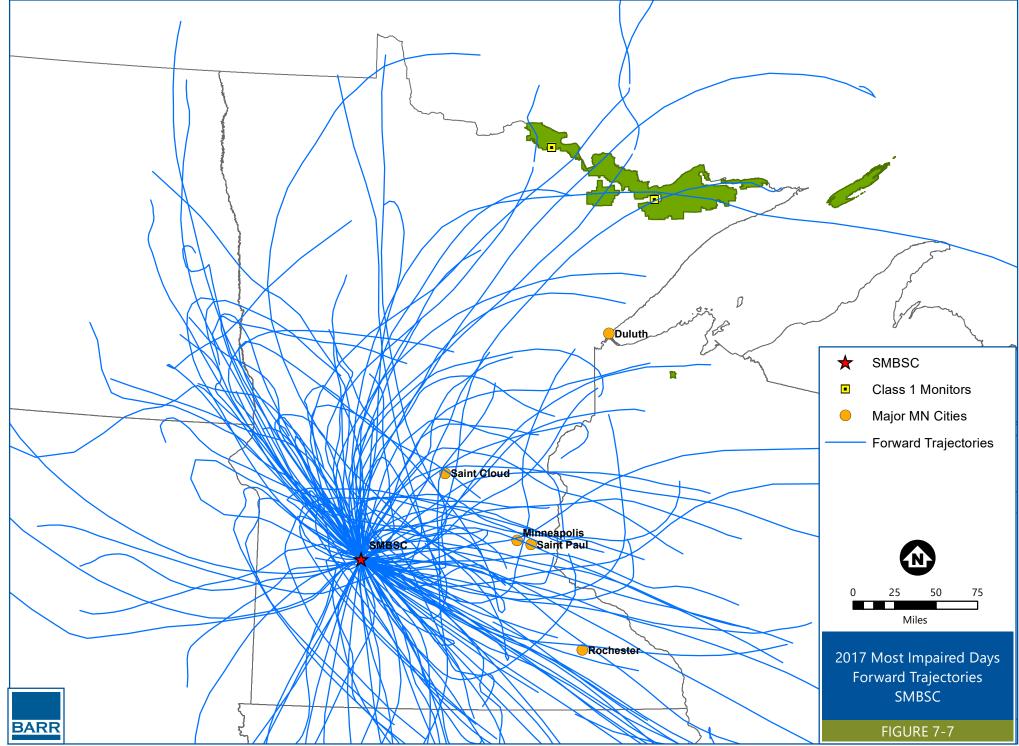


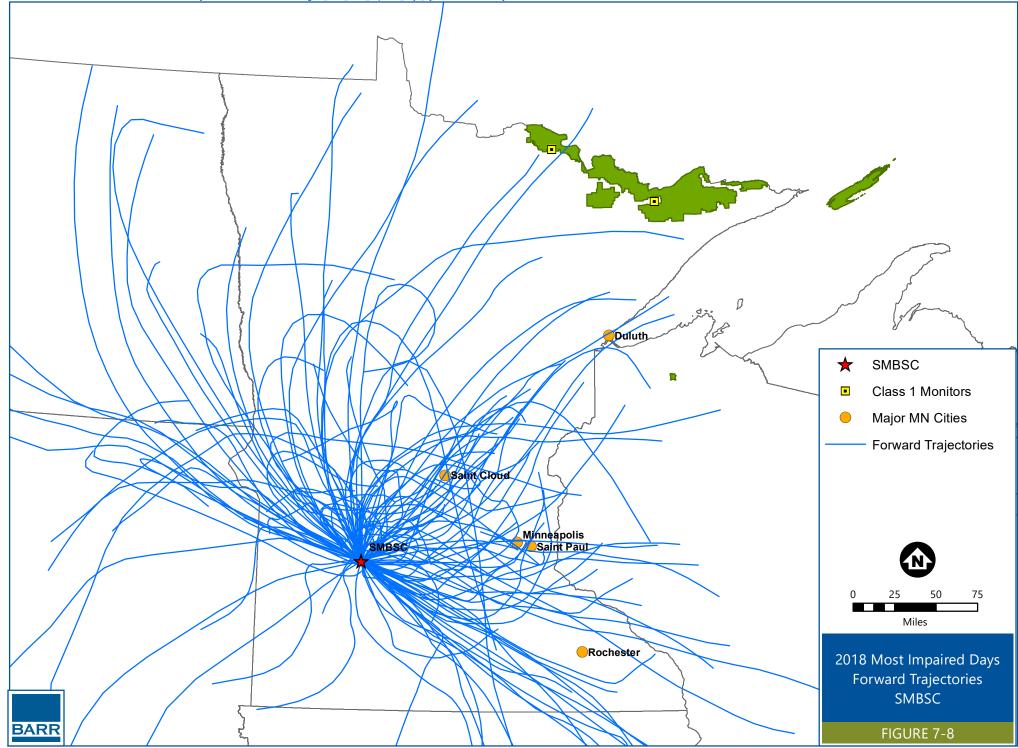
Figure 7-6: Voyageurs Trajectories for Most Impaired Days 2014-2016

### 7.3 Visibility Review Summary

The level of emissions along with the distance to the upper Midwest Class I areas indicate that SMBSC is unlikely to be a significant contributor to visibility impairment. Review of wind direction trends and trajectories associated with impacted days further reinforces the minimal potential for contribution by SMBSC. The results of the analysis conclude that SMBSC provides virtually no contribution to visibility impairment at the nearby Class I areas. Thus, additional control measures implemented at SMBSC are unlikely to provide a substantial improvement in visibility in the Class I areas.







# Appendix A

Control Cost Analysis for NO $_{X}$  and SO $_{2}$ 

#### Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 1: Cost Summary

#### NO<sub>x</sub> Control Cost Summary

| Control Technology   | Control<br>Eff % | Controlled<br>Emissions T/yr | Emission<br>Reduction T/yr | Installed Capital Cost<br>\$ <sup>2</sup> | Annualized Operating<br>Cost \$/yr <sup>2</sup> | Pollution Control<br>Cost \$/ton <sup>2</sup> |
|--|------------------|------------------------------|----------------------------|---|---|---|
| Selective Catalytic Reduction with<br>Reheat (SCR)                   | 90%              | 94.5                         | 812.5                      | \$38,983,220                              | \$5,686,381                                     | \$6,999                                       |
| Low NOx Burners (LNB) Coal-Fired <sup>1</sup>                        | 12%              | 801.0                        | 105.9                      | \$2,057,668                               | \$542,043                                       | \$5,117                                       |
| Low NOx Burners + Over Fire Air<br>(LNB+OFA) Coal-Fired <sup>1</sup> | 25%              | 676.4                        | 230.5                      | \$3,560,926                               | \$820,926                                       | \$3,561                                       |
| Selective Non-Catalytic Reduction<br>(SNCR)                          | 38%              | 566.8                        | 340.1                      | \$6,908,987                               | \$1,280,578                                     | \$3,765                                       |

1) Control efficiency based on vendor estimated performance compared to baseline emission rates

2) Equipment costs scaled to 2019 dollars using the most current Chemical Engineering Plant Cost Index (CEPCI). All other costs scaled to 2020 dollars

#### SO<sub>2</sub> Control Cost Summary

| Control Technology   | Control<br>Eff % | Controlled<br>Emissions T/yr | Emission<br>Reduction T/yr | Installed Capital Cost<br>\$ | Annualized Operating<br>Cost \$/yr | Pollution Control<br>Cost \$/ton |
|--|------------------|------------------------------|----------------------------|------------------------------|------------------------------------|----------------------------------|
| Spray Dry Absorber (SDA) with<br>Baghouse (including lime slaking<br>system)       | 90%              | 78.6                         | 707.2                      | \$56,147,603                 | \$11,708,110                       | \$16,556                         |
| Dry Sorbent Injection (DSI) with<br>Baghouse (including trona injection<br>system) | 70%              | 235.7                        | 550.0                      | \$36,015,563                 | \$6,985,015                        | \$12,700                         |

# Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 2: Summary of Utility, Chemical and Supply Costs

| Operating Unit:   | Boiler 1      |                               | Study Year | 2020         |  |  |
|---|---------------|-------------------------------|------------|--------------|--|--|
| Emission Unit Number  | EQUI17        |                               | -          |              |  |  |
| Stack/Vent Number   | STRU25        |                               |            |              |  |  |
|   | 2020          |                               |            |              |  |  |
| ltem  | Unit Cost     | Units                         | Cost       | Year         | Data Source  | Notes  |
| Operating Labor   |               | \$\$/hr                       | 60         | 2016         | EPA SCR Control Cost Manual Spreadsheet  |  |
| Maintenance Labor   |               | \$ \$/hr                      |            |              |  | Assumed to be equivalent to operating labor  |
| Installation Labor  | 68            | \$ \$/hr                      |            |              |  | Assumed to be equivalent to operating labor  |
| The state it .  | 0.00          | C //                          |            |              | 2015-2019 EIA Average prices for the   |  |
| Electricity   | 0.08          | \$/kwh                        |            |              | commerical sector<br>2015-2019 EIA Average prices for the                        |  |
| Natural Gas   | 3.90          | \$/kscf                       |            |              | commerical sector  |  |
|   | 0.00          | , endo                        |            |              | Average water rates for industrial facilities in                                 |  |
|   |               |                               |            |              | 2013 compiled by Black & Veatch. (see  |  |
|   |               |                               |            |              | 2012/2013 "50 Largest Cities   |  |
|   |               |                               |            |              | Water/Wastewater Rate Survey." Available at                                      |  |
|   |               |                               |            |              | http://www.saws.org/who_we_are/community/R                                       |  |
|   |               |                               |            |              | AC/docs/2014/50-largest-cities-brochure-water-                                   |  |
| Vater   | 5.13          | \$\$/mgal                     | 4.17       | 2013         | wastewater-rate-survey.pdf.  |  |
| Compressed Air  | 0.48          | \$/kscf                       | 0.38       | 2012         | 2 Taconite FIP Docket  |  |
| Chemicals & Supplies  | 183.68        | \$/top                        | 145.00     | 2012         | 2 Taconite FIP Docket  |  |
| lille   | 103.00        | \$/1011                       | 145.00     | 2012         | Reagent cost for trona from another Barr   |  |
| Trona   | 285.00        | \$/ton                        |            | 2020         | Engineering Co. Project.   |  |
| Urea 50% Solution   |               | \$/gallon                     | 1.66       | 2017         | EPA SCR Control Cost Manual Spreadsheet  |  |
|   |               | - ×                           |            | 2011         |  |  |
| Fuel Cost   | 2.13          | 3                             | 1.89       | 2016         | EPA SNCR Control Cost Manual Spreadsheet   |  |
|   |               |                               |            |              | EPA Control Cost Manual for SCR suggests   |  |
| Estimated operating life of the catalyst (H catalyst)           | 20,000        | hours                         |            |              | 16,000 - 24,000 hours  |  |
| SCR Catalyst cost (CC replace)                                  | 255           | \$/cubic foot                 | 227        | 2016         | EPA SCR Control Cost Manual Spreadsheet  | Cost includes removal and disposal/regeneration of existing catalyst and installation of new catalyst              |
| Fabric Filter Bags  | 228.02        | \$/bag                        | 180        | 2012         | 2 Taconite FIP Docket  |  |
| ×   |               | Č.                            |            |              |  |  |
| Other   |               |                               |            |              |  |  |
| Sales Tax   | 6.875%        |                               |            |              | Minnesota sales tax rate   |  |
| nterest Rate  | 5.50%         |                               |            |              | EPA SCR Control Cost Manual Spreadsheet  |  |
| Solid Waste Disposal  |               | \$/ton                        | 50         | 2012         | 2 Taconite FIP Docket  |  |
| Contingencies<br>Markup on capital investment (retrofit factor) | 50%           | of purchased equip cost (B)   |            |              | EPA Cost Control Cost Manual Chapter 2<br>EPA Cost Control Cost Manual Chapter 2 | Suggested contingency range of 5% to 15% of total capital investment   |
| Markup on capital investment (retront factor)                   | 50%           | 5                             |            |              | EPA Cost Control Cost Manual Chapter 2   |  |
| Operating Information   |               |                               |            |              |  |  |
| Annual Op. Hrs  | 7.536         | Hours                         |            |              | Average of 2015-2019 Operating Data  |  |
| Utilization Rate  | 100%          |                               |            |              | Assumed  |  |
| Design Capacity   | 472.4         | MMBTU/hr                      |            |              | Boiler Design Capacity   |  |
| Equipment Life  | 20            | ) yrs                         |            |              | Assumed  |  |
| Temperature   | 370           | ) Deg F                       |            |              | SMBSC CEMS Stack Temperature Data  | 2018-2020 Average, excluding periods of boiler shutdown/startup  |
| Moisture Content  | 11.8%         |                               |            |              | 2014 Boiler 1 Hg Stack Test Data   |  |
| Actual Flow Rate  | 209,000       |                               | 100.000    | ( 0.000 F    | 2014 Boiler 1 Hg Stack Test Data   |  |
| Standardized Flow Rate<br>Dry Std Flow Rate                     | 132,954       | scfm @ 68° F<br>dscfm @ 68° F | 123,889    | scfm @ 32º F | Calculated Value<br>Calculated Value   |  |
| Fuel higher heating value (HHV)                                 |               | BTU/lb                        |            |              | SMBSC Site Specific Data   | Average of 2015-2019 Operating Data  |
| Plant Elevation   |               | Feet above sea level          |            |              | omboo olle opeoliic bala   | Renville, MN elevation   |
| Sulfur Content (%)  | 0.28          |                               |            |              | SMBSC Site Specific Data   | Average of 2015-2019 Operating Data  |
| # days boiler operates  |               | days                          |            |              | SMBSC Site Specific Data   | Average of 2015-2019 Operating Data  |
|   |               |                               |            |              |  |  |
|   | Baseline Emis |                               | lb/hr      | ton/year     |  |  |
| Pollutant   | Lb/Hr         | Ton/Year                      | ppmv       | ppmv         | lb/mmbtu   |  |
| Nitrous Oxides (NOx)  | 240.7         | 906.9                         | 286        | 286.1        | 0.40   | Baseline ton/year is based on 2028 NOx modeling emission inventory. Lb/MMBtu is based on 2015-2019<br>CEMS average |
| Nitrous Oxides (NOx)<br>Sulfur Dioxides (SO2)                   | 240.7         |                               | 286        | 286.1        | 0.48   | Baseline ton/year is based on 2028 SO2 modeling emission inventory.  |
| Juliu Dioxides (302)  | 200.3         | / 00.0                        | 170        | 170.0        | EPA fact sheet for flue gas desulfurization (new                                 | Dascine on year is based on 2020 302 modeling emission inventory.  |
|   | 1             |                               |            |              | installations)   |  |
| SDA - SO <sub>2</sub> Control Efficiency                        | 90%           |                               |            |              | https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf                                      |  |
| •   | 1             | 1                             |            |              | Control efficiency is based on trona as injected                                 |  |
| DSI - SO <sub>2</sub> Control Efficiency                        | 70%           | Trona Ore Control Efficiency  |            |              | reagent.   |  |
|   | 1             | Í                             |            |              | Common design basis for SCR units per EPA  |  |
| SCR - NO <sub>x</sub> Control Efficiency                        | 90%           |                               |            |              | Control Cost Manual  |  |
| NB - NO <sub>x</sub> Performance                                | 0.45          | ib/MMBtu                      |            |              | Vendor estimated burner performance  |  |
| NB+OFA- NO <sub>x</sub> Performance                             |               | b/MMBtu                       |            |              | Vendor estimated burner performance  |  |
|   | 2.00          | 1                             |            |              | EPA Control Cost Manual SCR spreadshet   |  |
|   |               |                               |            |              |  |  |
| SNCR - NO <sub>x</sub> Performance                              | 0.30          | lb/MMBtu                      |            |              | default outlet NOx emission rate   |  |

#### Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 3: NO<sub>x</sub> Control - Selective Catalytic Reduction with Reheat

Boiler 1

#### Operating Unit:

Stack/Vent Number

| Emission Unit Number               | EQUI17 |          | Stack/Vent Number      | STRU25  |               |
|------------------------------------|--------|----------|------------------------|---------|---------------|
| Design Capacity                    | 472    | mmbtu/hr | Standardized Flow Rate | 123,889 | scfm @ 32º F  |
| Expected Utilization Rate          | 100%   |          | Temperature            | 370     | Deg F         |
| Expected Annual Hours of Operation | 7,536  | Hours    | Moisture Content       | 11.8%   |               |
| Annual Interest Rate               | 5.5%   |          | Actual Flow Rate       | 209,000 | acfm          |
| Expected Equipment Life            | 20     | yrs      | Standardized Flow Rate | 132,954 | scfm @ 68° F  |
|                                    |        |          | Dry Std Flow Rate      | 117,332 | dscfm @ 68° F |

#### CONTROL EQUIPMENT COSTS

| Capital Costs                            |                |                      |                   |              |                 |              |            |
|--|----------------|----------------------|-------------------|--------------|-----------------|--------------|------------|
|  |                |                      |                   |              |                 |              |            |
|  |                |                      |                   |              |                 |              |            |
|  |                |                      |                   |              |                 |              |            |
|  |                |                      |                   |              |                 |              |            |
|  |                |                      |                   |              |                 |              |            |
|  |                |                      |                   |              |                 |              |            |
|  |                |                      |                   |              |                 |              |            |
|  |                |                      |                   |              |                 |              |            |
| Total Capital Investment (TCI)           |                |                      |                   |              |                 | SCR Only     |            |
|  |                |                      |                   |              |                 | SCR + Reheat | 38,983,220 |
| Operating Costs                          |                |                      |                   |              |                 |              |            |
| Total Annual Direct Operating Costs      |                | Labor, supervision,  |                   |              | utilities, etc. | SCR + Reheat |            |
| Total Annual Indirect Operating Costs    |                | Sum indirect oper of | osts + capital re | ecovery cost |                 | SCR + Reheat | 3,398,577  |
| Total Annual Cost (Annualized Capital Co | ost + Operatin | ig Cost              |                   |              |                 | SCR + Reheat | 5,686,381  |

#### Emission Control Cost Calculation

| Pollutant            | Max Emis | Annual | Cont Eff | Cont Emis | Reduction | Cont Cost  |
|----------------------|----------|--------|----------|-----------|-----------|------------|
|                      | Lb/Hr    | T/Yr   | %        | T/yr      | T/yr      | \$/Ton Rem |
| Nitrous Oxides (NOx) | 240.7    | 906.9  | 90%      | 94.5      | 812.5     | 6,999      |

 Notes & Assumptions

 1
 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 7th Ed SCR Control Cost Spreadsheet

 2
 Costs scaled to current dollars from the Chemical Engineering Plant Cost Index (CEPCI)

#### Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 3: NOx Control - Selective Catalytic Reduction with Reheat

#### CAPITAL COSTS

| Refer to the SCR Summary tab    | 20,134,912   |
|---------------------------------|--|
| Refer to the SCR Summary tab    | 3,581,809  |
| Refer to the SCR Summary tab    | -  |
| Refer to the SCR Summary tab    | 4,769,432  |
| 50% of TCI, see SCR Summary tab |  |
|                                 | 37,031,999   |
|                                 | Refer to the SCR Summary tab<br>Refer to the SCR Summary tab<br>Refer to the SCR Summary tab |

#### OPERATING COSTS

#### Direct Annual Operating Costs, DC

| Maintenance                                       |            |   |           |
|---|------------|---|-----------|
| Annual Maintenance Cost =                         |            | Refer to the SCR Summary tab                    | 185,160   |
| Utilities, Supplies, Replacements & Waste Ma      | anagement  |   |           |
| Annual Electricity Cost =                         | •          | Refer to the SCR Summary tab                    | 162,055   |
| Annual Catalyst Replacement Cost =                |            | Refer to the SCR Summary tab                    | 212,743   |
| Annual Reagent Cost =                             |            | Refer to the SCR Summary tab                    | 400,990   |
| Total Annual Direct Operating Costs               |            |   | 960,949   |
| Indirect Operating Costs                          |            |   |           |
| Administrative Charges (AC) =                     |            | Refer to the SCR Summary tab                    | 4,766     |
| Capital Recovery Costs (CR)=                      | 0.0837     | Refer to the SCR Summary tab                    | 3,099,578 |
| Total Annual Indirect Operating Costs             |            | Sum indirect oper costs + capital recovery cost | 3,104,345 |
| Total Annual Cost (Annualized Capital Cost + Oper | ating Cost |   | 4,065,293 |

#### Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 3: NOx Control - Selective Catalytic Reduction with Reheat

| Capital Recovery Factors                    |                           |           |  |
|---|---------------------------|-----------|--|
| Primary Installation                        |                           |           |  |
| Interest Rate<br>Equipment Life             | 5.50%<br>20 years         |           |  |
| CRF   | 0.0837                    |           |  |
| Replacement Catayst - Refer to the          | e SCR Summary Tab         |           |  |
|   |                           |           |  |
| Reagent Use<br>Refer to the SCR Summary tab |                           |           |  |
|   |                           |           |  |
| Operating Cost Calculations                 | Annual hours of operation | on: 7,536 |  |
| Refer to the SCR Summary tab                | Utilization Rate:         | 100%      |  |

#### Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 4: NO<sub>x</sub> Control - Flue Gas Reheat for SCR (Thermal Oxidizer)

#### Operating Unit:

Boiler 1

| Emission Unit Number               | EQUI17 |          | Stack/Vent Number      | STRU25  |               | Chemical En    | gineering  |
|------------------------------------|--------|----------|------------------------|---------|---------------|----------------|------------|
| Desgin Capacity                    | 472    | MMBTU/hr | Standardized Flow Rate | 123,889 | scfm @ 32º F  | Chemical Plant | Cost Index |
| Expected Utilization Rate          | 100%   |          | Temperature            | 370     | Deg F         | 1998/1999      | 390        |
| Expected Annual Hours of Operation | 7,536  | Hours    | Moisture Content       | 11.8%   |               | 2019           | 607.5      |
| Annual Interest Rate               | 5.5%   |          | Actual Flow Rate       | 209,000 | acfm          | Inflation Adj  | 1.56       |
| Expected Equipment Life            | 20     | yrs      | Standardized Flow Rate | 132,954 | scfm @ 68º F  |                |            |
|                                    |        |          | Dry Std Flow Rate      | 117,332 | dscfm @ 68º F |                |            |

#### CONTROL EQUIPMENT COSTS

| Capital Costs                             |              |                |                   |                 |                   |         |              |
|---|--------------|----------------|-------------------|-----------------|-------------------|---------|--------------|
| Direct Capital Costs                      |              |                |                   |                 |                   |         |              |
| Purchased Equipment (A)                   |              |                |                   |                 |                   |         | 635,31       |
| Purchased Equipment Total (B)             | 22%          | of control dev | vice cost (A)     |                 |                   |         | 774,29       |
| Installation - Standard Costs             | 30%          | of purchased   | equip cost (B)    |                 |                   |         | 232,28       |
| Installation - Site Specific Costs        |              |                |                   |                 |                   |         | N            |
| Installation Total                        |              |                |                   |                 |                   |         | 232,28       |
| Total Direct Capital Cost, DC             |              |                |                   |                 |                   |         | 1,006,58     |
| Total Indirect Capital Costs, IC          | 38%          | of purchased   | equip cost (B)    |                 |                   |         | 294,23       |
| Total Capital Investment (TCI) = DC + IC  |              |                |                   |                 |                   |         | <br>1,300,81 |
| Operating Costs                           |              |                |                   |                 |                   |         |              |
| Total Annual Direct Operating Costs       |              | Labor, super   | vision, materials | s, replacemen   | t parts, utilitie | s, etc. | 1,319,64     |
| Total Annual Indirect Operating Costs     |              | Sum indirect   | oper costs + ca   | apital recovery | cost              |         | 301,44       |
| Total Annual Cost (Annualized Capital Cos | t + Operatin | g Cost)        |                   |                 |                   |         | 1,621,08     |

 Notes & Assumptions

 1
 Equipment cost settimate EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2.5.1

 2
 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2

#### Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 4: NOx Control - Flue Gas Reheat for SCR (Thermal Oxidizer)

#### CAPITAL COSTS

|   | 635,31  |
|---|---|
| acking + auxillary equipment EC   | 635,310   |
| • • • • •   | 63,53   |
|   |   |
|   | 43,678  |
|   | 31,766<br>774,294   |
| 22,0  | 114,23  |
|   |   |
| 8% of purchased equip cost (B)  | 61,944  |
|   | 108,40  |
| 4% of purchased equip cost (B)  | 30,972  |
| 2% of purchased equip cost (B)  | 15,48   |
| 1% of purchased equip cost (B)  | 7,74  |
| 1% of purchased equip cost (B)  | 7,743   |
| 30%   | 232,28  |
| Site Specific   | NA  |
|   | NA  |
|   | NA  |
|   | NA  |
|   | 232,28  |
|   | 1,006,58  |
|   |   |
| 10% of purchased equip cost (B)   | 77,42   |
| 5% of purchased equip cost (B)  | 38,71   |
|   | 77,42   |
|   | 15,48   |
|   | 7,74  |
|   | 77,42   |
|   | 294,23  |
|   |   |
| Bags, etc) for Capital Recovery Cost  | 1,300,814<br>1,300,814  |
| 50%   | 1,951,22  |
| 0070  | 1,551,22  |
|   |   |
|   |   |
| 67 52 \$/Ur 0 5 br/8 br chiff 7526 br/vr  | 31.80   |
|   | 4,77  |
|   | .,  |
|   | 31.80   |
| 67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr  | 31,00   |
| 100% of maintenance labor costs   |   |
| 100% of maintenance labor costs   | 31,80   |
| 100% of maintenance labor costs<br>nagement<br>0.08 \$/kwh, 774 kW-hr, 7536 hr/yr, 100% utilization   | 31,80   |
| 100% of maintenance labor costs   | 31,80<br>464,50   |
| 100% of maintenance labor costs<br>nagement<br>0.08 \$/kwh, 774 kW-hr, 7536 hr/yr, 100% utilization   | 31,80<br>464,50<br>754,95   |
| 100% of maintenance labor costs<br>hagement<br>0.08 k/kwh, 774 kW-hr, 7536 hr/yr, 100% utilization<br>3.90 k/mscf, 428 scfm, 7536 hr/yr, 100% utilization   | 31,80<br>464,50<br>754,95<br><b>1,319,64</b>  |
| 100% of maintenance labor costs<br>hagement<br>0.08 \$/kwh, 774 kW-hr, 7536 hr/yr, 100% utilization<br>3.90 \$/mscf, 428 scfm, 7536 hr/yr, 100% utilization<br>60% of total labor and material costs  | 31,80<br>464,50<br>754,95<br><b>1,319,64</b><br>60,11   |
| 100% of maintenance labor costs<br>sagement<br>0.08 \$/kwh, 774 kW-hr, 7536 hr/yr, 100% utilization<br>3.90 \$/mscf, 428 scfm, 7536 hr/yr, 100% utilization<br>60% of total labor and material costs<br>2% of total capital costs (TCI)   | 31,80<br>464,50<br>754,95<br><b>1,319,64</b><br>60,11<br>39,02  |
| 100% of maintenance labor costs<br>hagement<br>0.08 /kwh, 774 kW-hr, 7536 hr/yr, 100% utilization<br>3.90 %/mscf, 428 scfm, 7536 hr/yr, 100% utilization<br>60% of total labor and material costs<br>2% of total capital costs (TCI)<br>1% of total capital costs (TCI)                                       | 31,80<br>464,50<br>754,95<br><b>1,319,64</b><br>60,11:<br>39,02<br>19,51:   |
| 100% of maintenance labor costs<br>lagement<br>0.08 \$/kwh, 774 kW-hr, 7536 hr/yr, 100% utilization<br>3.90 \$/mscf, 428 scfm, 7536 hr/yr, 100% utilization<br>60% of total labor and material costs<br>2% of total capital costs (TCI)<br>1% of total capital costs (TCI)<br>1% of total capital costs (TCI) | 31,80<br>464,50<br>754,95<br><b>1,319,64</b><br>60,11:<br>39,02<br>19,51:<br>19,51:   |
| 100% of maintenance labor costs<br>hagement<br>0.08 /kwh, 774 kW-hr, 7536 hr/yr, 100% utilization<br>3.90 %/mscf, 428 scfm, 7536 hr/yr, 100% utilization<br>60% of total labor and material costs<br>2% of total capital costs (TCI)<br>1% of total capital costs (TCI)                                       | 31,80<br>464,50<br>754,95<br><b>1,319,64</b><br>60,11:<br>39,02<br>19,51:   |
|   | <ul> <li>14% of purchased equip cost (B)</li> <li>4% of purchased equip cost (B)</li> <li>2% of purchased equip cost (B)</li> <li>1% of purchased equip cost (B)</li> <li>30%</li> <li>Site Specific</li> <li>Site Specific</li> <li>Site Specific</li> <li>Site Specific</li> <li>Site Specific</li> <li>9% of purchased equip cost (B)</li> <li>90% of purchased equip cost (B)</li> <li>2% of purchased equip cost (B)</li> <li>1% of purchased equip cost (B)</li> <li>1% of purchased equip cost (B)</li> <li>3% of purchased equip cost (B)</li> <li>10% of purchased equip cost (B)</li> <li>3% of purchased equip cost (B)</li> <li>3% of purchased equip cost (B)</li> <li>3% of purchased equip cost (B)</li> </ul> |

Total Annual Cost (Annualized Capital Cost + Operating Cost)

1,621,087

#### Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 4: NOx Control - Flue Gas Reheat for SCR (Thermal Oxidizer)

| Capital Recovery Fac                  | tors       |               |                 | I                  |              |                 |  |
|---------------------------------------|------------|---------------|-----------------|--------------------|--------------|-----------------|--|
| Primary Installation                  |            |               |                 |                    |              |                 |  |
| Interest Rate                         |            | 5.50%         |                 |                    |              |                 |  |
| Equipment Life                        |            | 20            | years           |                    |              |                 |  |
| CRF                                   |            | 0.0837        |                 |                    |              |                 |  |
|                                       |            |               |                 | -                  |              |                 |  |
| Replacement Catalys<br>Equipment Life | t:         | Catalyst<br>3 | years           |                    |              |                 |  |
| CRF                                   |            | 0.3707        |                 |                    |              |                 |  |
| Rep part cost per unit                |            | 0             | \$/ft3          |                    |              |                 |  |
| Amount Required                       |            | 39            | ft <sup>3</sup> |                    |              |                 |  |
| Catalyst Cost                         |            | 0             | Cost adjuste    | d for freight &    | sales tax    |                 |  |
| Installation Labor                    |            | 0             | Assume Lat      | oor = 15% of ca    | talyst cost  | (basis labor fo | or baghouse replacement)                                 |
| Total Installed Cost                  |            | 0             | Zero out if     | no replacemen      | nt parts ne  | eded            |  |
| Annualized Cost                       |            | 0             |                 |                    |              |                 |  |
|                                       |            |               |                 |                    |              |                 |  |
| Replacement Parts &                   | Equipment: |               |                 |                    |              |                 |  |
| Equipment Life                        |            | 3             |                 |                    |              |                 |  |
| CRF                                   |            | 0.3707        |                 |                    |              |                 |  |
| Rep part cost per unit                |            | 0             | \$ each         |                    |              |                 |  |
| Amount Required                       |            |               | Number          |                    |              |                 |  |
| Total Rep Parts Cost                  |            |               |                 | ed for freight & s |              |                 |  |
| Installation Labor                    |            |               |                 | bag (13 hr total)  |              |                 | OAQPS list replacement times from 5 - 20 min per bag.    |
| Total Installed Cost                  |            |               |                 | no replacemen      | nt parts nee | eded            |  |
| Annualized Cost                       |            | 0             |                 |                    |              |                 |  |
| Electrical Use                        |            |               |                 |                    |              |                 |  |
|                                       | Flow acfm  |               | ΔP in H2O       | Efficiency         | Hp           | kW              |  |
| Blower, Thermal                       | 209,000    |               | 19              | 0.6                |              | 774.3           | EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1 |
| Blower, Catalytic                     | 209,000    |               | 23              | 0.6                |              | 937.4           | EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1 |
|                                       |            |               |                 |                    |              |                 |  |
|                                       |            |               |                 |                    |              |                 |  |

Reagent Use & Other Operating Costs Oxidizers - NA

| Operating Cost Cal   | culations       |                    | Annual hour<br>Utilization R | s of operatio<br>ate: | n:             | 7,536<br>100%  |   |
|----------------------|-----------------|--------------------|------------------------------|-----------------------|----------------|----------------|---|
| Item                 | Unit<br>Cost \$ | Unit of<br>Measure | Use<br>Rate                  | Unit of<br>Measure    | Annual<br>Use* | Annual<br>Cost | Comments  |
| Operating Labor      |                 |                    |                              |                       |                |                |   |
| Op Labor             | 67.53           | \$/Hr              | 0.5                          | hr/8 hr shift         | 471            | 31,807         | \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr            |
| Supervisor           | 15%             | of Op.             |                              |                       | NA             | 4,771          | 15% of Operator Costs                           |
| Maintenance          |                 |                    |                              |                       |                |                |   |
| Maint Labor          | 67.53           | \$/Hr              | 0.5                          | hr/8 hr shift         | 471            | 31,807         | \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr            |
| Maint Mtls           | 100             | % of Maintena      | nce Labor                    |                       | NA             | 31,807         | 100% of Maintenance Labor                       |
| Utilities, Supplies, | Replacements &  | Waste Manag        | ement                        |                       |                |                |   |
| Electricity          | 0.080           | \$/kwh             | 774.3                        | kW-hr                 | 5.835.464      | 464.503        | \$/kwh, 774 kW-hr, 7536 hr/yr, 100% utilization |
| Natural Gas          | 3.90            | \$/mscf            | 428                          | scfm                  | 193.577        |                | \$/mscf. 428 scfm. 7536 hr/vr. 100% utilization |

#### Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 4: NOx Control - Flue Gas Reheat for SCR (Thermal Oxidizer)

#### Flue Gas Re-Heat Equipment Cost Estimate Basis Thermal Oxidizer with 70% Heat Recovery

#### Auxiliary Fuel Use Equation 3.19

| Auxiliary r uer 036 |   |
|---------------------|---|
| T <sub>wi</sub>     | 370 Deg F - Temperature of waste gas into heat recovery           |
| Ts                  | 650 Deg F - Temperature of Flue gas into heat recovery            |
| Tref                | 77 Deg F - Reference temperature for fuel combustion calculations |
| FER                 | 70% Factional Heat Recovery % Heat recovery section efficiency    |
| T <sub>wo</sub>     | 566 Deg F - Temperature of waste gas out of heat recovery         |
| T <sub>fo</sub>     | 454 Deg F - Temperature of flue gas out of heat recovery          |
| -h <sub>caf</sub>   | 21502 Btu/lb Heat of combustion auxiliary fuel (methane)          |
| -h <sub>wg</sub>    | 0 Btu/lb Heat of combustion waste gas                             |
| Cpwg                | 0.2684 Btu/lb - Deg F Heat Capacity of waste gas (air)            |
| $\rho_{wg}$         | 0.0739 lb/scf - Density of waste gas (air) at 77 Deg F            |
| p <sub>af</sub>     | 0.0408 lb/scf - Density of auxiliary fuel (methane) at 77 Deg F   |
| Q <sub>wg</sub>     | 132,954 scfm - Flow of waste gas                                  |
| Q <sub>af</sub>     | 428 scfm - Flow of auxiliary fuel                                 |
| Year                | 2005 Inflation Rate 3.0%  |
| Cost Calculations   | 133,382 scfm Flue Gas Cost in 1989 \$'s \$407,859                 |
|                     | Current Cost Using CHE Plant Cost Index \$635,318                 |
|                     | Heat Rec % A B  |

| -          | i      | Current | Cost Using CHE Plant Cost Index \$635,318 |
|------------|--------|---------|---|
| Heat Rec % | A      | В       |   |
| 0          | 10,294 | 0.2355  | Exponents per equation 3.24               |
| 0.3        | 13,149 | 0.2609  | Exponents per equation 3.25               |
| 0.5        | 17,056 | 0.2502  | Exponents per equation 3.26               |
| 0.7        | 21,342 | 0.2500  | Exponents per equation 3.27               |
|            |        |         |   |

| Indurator   | Flue Gas Heat Capad | ty - Basis | Typical Cor | nposition |         |
|-------------|---------------------|------------|-------------|-----------|---------|
|             | 100 scfm            | 359        | scf/lbmole  |           |         |
|             | Gas Composition     | lb/hr f    | wt %        | Cp Gas    | Cp Flue |
| 28 mw CO    | Ó v %               | 0          |             |           |         |
| 44 mw CO2   | 15 v %              | 184        | 22.0%       | 0.24      | 0.0528  |
| 18 mw H2O   | 10 v %              | 50         | 6.0%        | 0.46      | 0.0276  |
| 28 mw N2    | 60 v %              | 468        | 56.0%       | 0.27      | 0.1512  |
| 32 mw O2    | 15 v %              | 134        | 16.0%       | 0.23      | 0.0368  |
| Cp Flue Gas | 100 v %             | 836        | 100.0%      |           | 0.2684  |

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators (EPA 453/B-96-001)

#### Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency

Air Economics Group Health and Environmental Impacts Division Office of Air Quality Planning and Standards

(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a postcombustion control technology for reducing NO, emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO, within a specific temperature range to produce N<sub>2</sub> and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/thr/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

#### Instructions

Step 1: Please select on the Data Inputs tab and click on the Reset Form button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume (Vol<sub>catalyst</sub>) or flue gas flow rate (Q<sub>flue gas</sub>), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (PM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the SCR Design Parameters tab to see the calculated design parameters and the Cost Estimate tab to view the calculated cost data for the installation and operation of the SCR.

| Data Inputs  |  |   |  |  |
|--|--|---|--|--|
| Enter the following data for your combustion unit:   |  |   |  |  |
| Is the combustion unit a utility or industrial boiler?   |  | What type of fuel does the unit burn?   | 1  |  |
| Is the SCR for a new boiler or retrofit of an existing boiler?   | w1   |   |  |  |
|  |  | _   |  |  |
| Please enter a retrofit factor between 0.8 and 1.5 based on the level of diffier<br>projects of average retrofit difficulty. | culty. Enter 1 for 1.5   | * NOTE: You must document why a retrofit factor of 1.5 is appropriate<br>for the proposed project.  |  |  |
| Complete all of the highlighted data fields:   |  | Provide the following information for coal-fired boiler   | s:   |  |
| What is the maximum heat input rate (QB)?  | 472 MMBtu/hour   | Type of coal burned:  | 1  |  |
| What is the higher heating value (HHV) of the fuel?  | 9,152 Btu/lb   | Enter the sulfur content (%S) = 0.28  | percent by weight  |  |
| What is the estimated actual annual fuel consumption?  | 323,950,000 lbs/year   | 1   |  |  |
| Enter the net plant heat input rate (NPHR)   | 10 MMBtu/MW  |   | default values for HHV and %5. Please enter the actual values<br>e actual value for any parameter is not known, you may use the                    |  |
| If the NPHR is not known, use the default NPHR value:  | Fuel Type Default NPHR   | Coal Type Coal Blend<br>Bituminous 0  | 965 HHV (Btu/lb)   |  |
|  | Coal 10 MMBtu/MW<br>Fuel Oil 11 MMBtu/MW<br>Natural Gas 8.2 MMBtu/MW | Sub-Bituminous<br>Lignite<br>Please click the calculate button to calculate v<br>values based on the data in the table above.                                       | Ori 6.507<br>OS2 6.685<br>weighted average   |  |
| Plant Elevation Enter the following design parameters for the proposed SCR   | 1,100 Feet above sea level   | For coal-fired bollers, you may use either Method<br>catalyst replacement cost. The equations for both<br>and 86 on the <b>Cost Estimate</b> tab. Please select you | methods are shown on rows 85 Method 1  |  |
|  |  |   |  |  |
| Number of days the SCR operates $(t_{\mbox{\tiny SCR}})$   | 314 days   | Number of SCR reactor chambers (n   | 1.cr) 1  |  |
| Number of days the boiler operates $(t_{plant})$   |  | Number of catalyst layers (R <sub>layer</sub> )   | 3  |  |
| Inlet NO <sub>x</sub> Emissions (NOx <sub>in</sub> ) to SCR  | 314 days   | Number of empty catalyst layers (R <sub>e</sub>   |  |  |
| Outlet NO <sub>x</sub> Emissions (NOx <sub>out</sub> ) from SCR  | 0.48 lb/MMBtu<br>0.05 lb/MMBtu                                       | Ammonia Slip (Slip) provided by ver   |  |  |
| Stoichiometric Ratio Factor (SRF)  |  | Volume of the catalyst layers (Vol <sub>cata</sub>  | alyst)   |  |
| *The SRF value of 0.525 is a default value. User should enter actual value, if known.  | 0.525  | (Enter "UNK" if value is not known)<br>Flue gas flow rate (Q <sub>euegas</sub> )<br>(Enter "UNK" if value is not known)   | UNK Cubic feet   |  |
|  |  | (Enter ONK invalue is not known)  | 209,000 acfm   |  |
| Estimated operating life of the catalyst $(H_{catalyst})$  | 20,000 hours   | 1   |  |  |
| Estimated SCR equipment life   | 20 Years*  | Gas temperature at the SCR inlet (T)  | ) 650 °F   |  |
| * For industrial boilers, the typical equipment life is between 20 and 25 years.   |  | Base case fuel gas volumetric flow r  | ate factor (Q <sub>fuel</sub> ) 516 ft <sup>3</sup> /min-MMBtu/hour  |  |
| Concentration of reagent as stored ( $C_{stored}$ )  | 50 percent*  | *The reagent concentration of 50% and density of 71 lbs/cft are default   |  |  |
| Density of reagent as stored (p <sub>stored</sub> )  | 71 lb/cubic feet*  | values for urea reagent. User should enter actual values for reagent, if<br>different from the default values provided.   |  |  |
| Number of days reagent is stored $(t_{\mbox{storage}})$  | 14 days  |   | 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> |  |
| Select the reagent used  |  |   | 20 ΙΔ5/π   |  |

| Enter the cost data for the proposed SCR:                           |  |  |
|---|--|--|
| Desired dollar-year   | 2020   |  |
| CEPCI for 2020  | 607.5 2019 CEPCI Final Value 541.7 2016 CEPCI  | CEPCI = Chemical Engineering Plant Cost Index  |
| Annual Interest Rate (i)  | 5.50 Percent*  |  |
| Reagent (Cost <sub>reag</sub> )                                     | 1.814 \$/gallon for 50% urea   |  |
| Electricity (Cost <sub>elect</sub> )                                | 0.0796 \$/kWh  |  |
| Catalyst cost (CC <sub>replace</sub> )                              | \$/cubic foot (includes removal and disposal/regeneration of existing 255.49 catalyst and installation of new catalyst |  |
| Operator Labor Rate   | 67.53 \$/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 | he 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.

#### 

#### 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<br>used and the reference source |
|--|---------------|---|--|
| Reagent Cost (\$/gallon)                   |               | U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector  | used and the reference source  |
| Reagent Cost (\$/gallon)                   |               | U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector<br>Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and |  |
|  |               | Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5,  |  |
|  |               | Attachment 5-3, January 2017. Available at:   |  |
|  |               | https://www.epa.gov/sites/production/files/2018-05/documents/attachment 5-  |  |
|  |               | nttps://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-  | Refer to the Utility Chem\$ Data tab   |
| Electricity Cost (\$/kWh)                  | 0.0676        | U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published  |  |
|  |               | December 2017. Available at:  |  |
|  |               | https://www.eia.gov/electricity/monthly/epm table grapher.php?t=epmt 5 6 a.   |  |
|  |               |   |  |
|  |               |   |  |
|  |               |   | Refer to the Utility Chem\$ Data tab   |
| Percent sulfur content for Coal (% weight) | 0.41          | 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 http://www.eia.gov/electricity/data/eia923/.  |  |
|  |               |   |  |
|  |               |   | Average of 2015-2019 data  |
| Higher Heating Value (HHV) (Btu/lb)        | 8,826         | 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 http://www.eia.gov/electricity/data/eia923/.  |  |
|  |               |   |  |
|  |               |   | Average of 2015-2019 data  |
| Catalyst Cost (\$/cubic foot)              | 227           | U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector  |  |
|  | 1             | Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation.  |  |
|  | 1             | May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-  |  |
|  |               | sector-modeling-platform-v6.  |  |
|  |               |   |  |
|  |               |   | Refer to the Utility ChemS Data tab  |

## **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 $(Q_B)$ =                 | HHV x Max. Fuel Rate =   | 472              | MMBtu/hour |
| Maximum Annual fuel consumption (mfuel) =                | (QB x 1.0E6 x 8760)/HHV =  | 452,166,084      | lbs/year   |
| Actual Annual fuel consumption (Mactual) =               |  | 323,950,000      | lbs/year   |
| Heat Rate Factor (HRF) =                                 | NPHR/10 =  | 1.00             |            |
| Total System Capacity Factor (CF <sub>total</sub> ) =    | (Mactual/Mfuel) x (tscr/tplant) =  | 0.716            | fraction   |
| Total operating time for the SCR $(t_{op})$ =            | CF <sub>total</sub> x 8760 =   | 7,536            | hours      |
| NOx Removal Efficiency (EF) =                            | (NOx <sub>in</sub> - NOx <sub>out</sub> )/NOx <sub>in</sub> =  | 89.6             | percent    |
| NOx removed per hour =                                   | $NOx_{in} x EF x Q_B =$  | 203.13           | lb/hour    |
| Total NO <sub>x</sub> removed per year =                 | (NOx <sub>in</sub> x EF x Q <sub>B</sub> x t <sub>op</sub> )/2000 =  | 812.46           | tons/year  |
| NO <sub>x</sub> removal factor (NRF) =                   | EF/80 =  | 1.12             |            |
| Volumetric flue gas flow rate (q <sub>flue gas</sub> ) = | Q <sub>fuel</sub> x QB x (460 + T)/(460 + 700)n <sub>scr</sub> =   | 209,000          | acfm       |
| Space velocity (V <sub>space</sub> ) =                   | q <sub>flue gas</sub> /Vol <sub>catalyst</sub> =   | 96.78            | /hour      |
| Residence Time   | 1/V <sub>space</sub>   | 0.01             | hour       |
| Coal Factor (CoalF) =                                    | 1 for oil and natural gas; 1 for bituminous; 1.05 for sub-<br>bituminous; 1.07 for lignite (weighted average is used for<br>coal blends) | 1.05             |            |
| 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 =  | 1.04             |            |
| Atmospheric pressure at sea level (P) =                  | 2116 x [(59-(0.00356xh)+459.7)/518.6] <sup>5.256</sup> x (1/144)* =  | 14.1             | psia       |
| Retrofit Factor (RF)                                     | Retrofit to existing boiler  | 1.50             |            |

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

https://spacengnos/stens.greinasa.gov/caacaton/rocket

#### **Catalyst Data:**

| Parameter   | Equation   | Calculated Value | Units           |
|---|--|------------------|-----------------|
| Future worth factor (FWF) =                                     | (interest rate)(1/((1+ interest rate) <sup>Y</sup> -1) , where Y = $H_{catalyts}/(t_{SCR} \times 24$ hours) rounded to the nearest integer | 0.3157           | Fraction        |
| Catalyst volume (Vol <sub>catalyst</sub> ) =                    | 2.81 x Q <sub>8</sub> x EF <sub>adj</sub> x Slipadj x NOx <sub>adj</sub> x S <sub>adj</sub> x (T <sub>adj</sub> /N <sub>scr</sub> )        | 2,159.47         | Cubic feet      |
| Cross sectional area of the catalyst (A <sub>catalyst</sub> ) = | q <sub>flue gas</sub> /(16ft/sec x 60 sec/min)   | 218              | ft <sup>2</sup> |
| Height of each catalyst layer (H <sub>layer</sub> ) =           | (Vol <sub>catalyst</sub> /(R <sub>layer</sub> x A <sub>catalyst</sub> )) + 1 (rounded to next highest integer)                             | 4                | feet            |

#### SCR Reactor Data:

| Parameter   | Equation   | Calculated Value | Units           |
|---|--|------------------|-----------------|
| Cross sectional area of the reactor (A <sub>SCR</sub> ) =     | 1.15 x A <sub>catalyst</sub>                             | 250              | ft <sup>2</sup> |
| Reactor length and width dimensions for a<br>square reactor = | (A <sub>SCR</sub> ) <sup>0.5</sup>                       | 15.8             | feet            |
| Reactor height =  | $(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$ | 54               | feet            |

#### Reagent Data:

Type of reagent used

Molecular Weight of Reagent (MW) = 60.06 g/mole Density = 71 lb/ft<sup>3</sup>

| Parameter  | Equation  | Calculated Value | Units   |
|--|---|------------------|---|
| Reagent consumption rate (m <sub>reagent</sub> ) = | $(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx} =$       | 139              | lb/hour   |
| Reagent Usage Rate (m <sub>sol</sub> ) =           | m <sub>reagent</sub> /Csol =  | 278              | lb/hour   |
|  | (m <sub>sol</sub> x 7.4805)/Reagent Density                               | 29               | gal/hour  |
| Estimated tank volume for reagent storage =        | (m <sub>sol</sub> x 7.4805 x t <sub>storage</sub> x 24)/Reagent Density = | 9,900            | gallons (storage needed to store a 14 day reagent supply rounded to |

#### **Capital Recovery Factor:**

| Parameter                       | Equation                                      | Calculated Value |
|---------------------------------|---|------------------|
| Capital Recovery Factor (CRF) = | $i(1+i)^{n}/(1+i)^{n} - 1 =$                  | 0.0837           |
|                                 | Where n = Equipment Life and i= Interest Rate |                  |

Urea

| Other parameters              | Equation   | Calculated Value | Units |
|-------------------------------|--|------------------|-------|
| Electricity Usage:            |  |                  |       |
| Electricity Consumption (P) = | A x 1,000 x 0.0056 x (CoalF x HRF) <sup>0.43</sup> = | 270.15           | kW    |
|                               | where A = (0.1 x QB) for industrial boilers.         |                  |       |

| <br><b>n</b> |     |     |   |    |
|--------------|-----|-----|---|----|
| Cos          | t F | STI | m | at |
| 205          | • - |     |   |    |

|  | 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 <sub>cost</sub> ) = | \$20,134,912                                       | in 2020 dollars |  |
| Reagent Preparation Cost (RPC) =                   | \$3,581,809  | in 2020 dollars |  |
| Air Pre-Heater Costs (APHC)* =                     | \$0  | in 2020 dollars |  |

\$4,769,432

\$37,031,999

in 2020 dollars

in 2020 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.

|   | CCD Consider (CCD )  |                              |
|---|--|------------------------------|
| Fee Cool Fined Utility Dellage 205 MMM                                    | SCR Capital Costs (SCR <sub>cost</sub> )   |                              |
| 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:                        | 63 602   |                              |
|   | SCR <sub>cost</sub> = 310,000 x (NRF) <sup>0.2</sup> x (0.1 x Q <sub>B</sub> x CoalF) <sup>0.92</sup> x ELEVF x RF |                              |
|   |  |                              |
| SCR Capital Costs (SCR <sub>cost</sub> ) =                                |  | \$20,134,912 in 2020 dollars |
|   |  |                              |
|   | Reagent Preparation Costs (RPC)  |                              |
| For Coal-Fired Utility Boilers >25 MW:                                    |  |                              |
|   | RPC = 564,000 x (NOx <sub>in</sub> x B <sub>MW</sub> x NPHR x EF) <sup>0.25</sup> x RF                             |                              |
| For Coal-Fired Industrial Boilers >250 MMBtu/hour:                        | 6.7F   |                              |
|   | RPC = 564,000 x (NOx <sub>in</sub> x Q <sub>B</sub> x EF) <sup>0.25</sup> x RF                                     |                              |
|   |  |                              |
| Reagent Preparation Costs (RPC) =   |  | \$3,581,809 in 2020 dollars  |
|   | Air Pre-Heater Costs (APHC)*   |                              |
| For Coal-Fired Utility Boilers >25MW:                                     | All Pre-Heater Costs (APHC)  |                              |
| For Coal-Fired Utility Bollers >25WW:                                     |  |                              |
|   | APHC = 69,000 x ( $B_{MW}$ x HRF x CoalF) <sup>0.78</sup> x AHF x RF   |                              |
| For Coal-Fired Industrial Boilers >250 MMBtu/hour:                        | 0.79   |                              |
|   | APHC = 69,000 x (0.1 x Q <sub>B</sub> x CoalF) <sup>0.78</sup> x AHF x RF  |                              |
|   |  | 40 : 2000                    |
| Air Pre-Heater Costs (APH <sub>cost</sub> ) =                             |  | \$0 in 2020 dollars          |
| * Not applicable - This factor applies only to coal-fired boilers that bu | Irn 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 x ( $B_{MW}$ x HRFx CoalF) <sup>0.42</sup> x ELEVF x RF  |                              |
| For Coal-Fired Industrial Boilers >250 MMBtu/hour:                        |  |                              |
|   | BPC = 529,000 x (0.1 x $Q_{R}$ x CoalF) <sup>0.42</sup> ELEVF x RF   |                              |
|   |  |                              |

Balance of Plant Costs (BOP<sub>cost</sub>) =

Balance of Plant Costs (BPC) =

Total Capital Investment (TCI) =

\$4,769,432 in 2020 dollars

### Annual Costs

### Total Annual Cost (TAC)

### TAC = Direct Annual Costs + Indirect Annual Costs

| Direct Annual Costs (DAC) =           | \$960,949 in 2020 dollars   |
|---------------------------------------|-----------------------------|
| Indirect Annual Costs (IDAC) =        | \$3,104,345 in 2020 dollars |
| Total annual costs (TAC) = DAC + IDAC | \$4,065,293 in 2020 dollars |

|  | Direct Annual Costs (DAC)   |                                  |
|--|---|----------------------------------|
| DAC  | = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Co  | ost) + (Annual Catalyst Cost)    |
| Annual Maintenance Cost =                  | 0.005 × TCl =   | \$185,160 in 2020 dollars        |
| Annual Reagent Cost =                      | $m_{sol} \times Cost_{reag} \times t_{op} =$  | \$400,990 in 2020 dollars        |
| Annual Electricity Cost =                  | $P \times Cost_{elect} \times t_{op} =$   | \$162,055 in 2020 dollars        |
| Annual Catalyst Replacement Cost =         |   | \$212,743 in 2020 dollars        |
| For coal-fired boilers, the following meth | ods may be used to calcuate the catalyst replacement cost   |                                  |
| Method 1 (for all fuel types):             | $n_{scr} x Vol_{cat} x (CC_{replace}/R_{layer}) x FWF$  | * Calculation Method 2 selected. |
| Method 2 (for coal-fired industrial boiler | s): (Q <sub>8</sub> /NPHR) x 0.4 x (CoalF) <sup>2.9</sup> x (NRF) <sup>0.71</sup> x (CC <sub>replace</sub> ) x 35.3 |                                  |
| Direct Annual Cost =                       |   | \$960,949 in 2020 dollars        |

#### Indirect Annual Cost (IDAC) IDAC = Administrative Charges + Capital Recovery Costs

| Administrative Charges (AC) = | 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) = | \$4,766 in 2020 dollars     |
|-------------------------------|--|-----------------------------|
| Capital Recovery Costs (CR)=  | CRF x TCI =  | \$3,099,578 in 2020 dollars |
| Indirect Annual Cost (IDAC) = | AC + CR =  | \$3,104,345 in 2020 dollars |

Cost Effectiveness

| Cost Effectiveness = Total Annual Cost/ NOx Removed/year |  |
|--|--|

| Total Annual Cost (TAC) = | \$4,065,293 per year in 2020 dollars           |
|---------------------------|--|
| NOx Removed =             | 812 tons/year                                  |
| Cost Effectiveness =      | \$5,004 per ton of NOx removed in 2020 dollars |
|                           |  |

^^^Does not include reheat costs

### Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 5: NO<sub>x</sub> Control - Low NOx Burners (LNB) Coal-Fired

Boiler 1

#### Operating Unit:

| Emission Unit Number               | EQUI17 |          | Stack/Vent Number      | STRU25  |               |
|------------------------------------|--------|----------|------------------------|---------|---------------|
| Desgin Capacity                    | 472    | MMBtu/hr | Standardized Flow Rate | 123,889 | scfm @ 32° F  |
| Expected Utiliztion Rate           | 100%   |          | Temperature            | 370     | Deg F         |
| Expected Annual Hours of Operation | 7,536  | Hours    | Moisture Content       | 11.8%   |               |
| Annual Interest Rate               | 5.5%   |          | Actual Flow Rate       | 209,000 | acfm          |
| Expected Equipment Life            | 20     | yrs      | Standardized Flow Rate | 132,954 | scfm @ 68° F  |
|                                    |        |          | Dry Std Flow Rate      | 117,332 | dscfm @ 68° F |

CONTROL EQUIPMENT COSTS

| Capital Costs                            |              |                      |                    |               |                   |  |           |
|--|--------------|----------------------|--------------------|---------------|-------------------|--|-----------|
| Direct Capital Costs                     |              |                      |                    |               |                   |  |           |
| Purchased Equipment (A)                  |              |                      |                    |               |                   |  | 727,000   |
| Purchased Equipment Total (B)            | 22%          | of control device co | ost (A)            |               |                   |  | 886,031   |
|  |              |                      |                    |               |                   |  |           |
| Installation - Standard Costs            | 0%           | of purchased equip   | o cost (B)         |               |                   |  | 710,900   |
| Installation - Site Specific Costs       |              |                      |                    |               |                   |  | 0         |
| Installation Total                       |              |                      |                    |               |                   |  | 710,900   |
| Total Direct Capital Cost, DC            |              |                      |                    |               |                   |  | 1,596,931 |
| Total Indirect Capital Costs, IC         | 52%          | of purchased equip   | o cost (B)         |               |                   |  | 460,736   |
| Total Capital Investment (TCI) = DC + IC |              |                      |                    |               |                   |  | 2,057,668 |
| Operating Costs                          |              |                      |                    |               |                   |  |           |
| Total Annual Direct Operating Costs      |              | Labor, supervision,  | , materials, repla | acement parts | , utilities, etc. |  | 100,192   |
| Total Annual Indirect Operating Costs    |              | Sum indirect oper of | costs + capital n  | ecovery cost  |                   |  | 441,851   |
| Total Annual Cost (Annualized Capital Co | st + Operati | ng Cost              |                    |               |                   |  | 542,043   |

#### Emission Control Cost Calculation

| Pollutant                         | Baseline<br>Emis. T/yr | Cont. Emis.<br>Ib/hr | Cont. Emis.<br>Ib/MMBtu | Cont Emis<br>T/yr | Reduction<br>T/yr | Cont Cost<br>\$/Ton Rem |
|-----------------------------------|------------------------|----------------------|-------------------------|-------------------|-------------------|-------------------------|
| PM10                              |                        | -                    |                         |                   | -                 | NA                      |
| Total Particulates                |                        | -                    |                         |                   | -                 | NA                      |
| Nitrous Oxides (NOx               | 906.9                  | 212.6                | 0.45                    | 801.0             | 105.9             | 5,117                   |
| Sulfur Dioxide (SO <sub>2</sub> ) |                        |                      |                         |                   | -                 | NA                      |

Notes & Assumptions 1 Purchased equipment and installation costs from vendor 2 Assumed 0.5 hr/shift operatior and maintenance labor for LNB 3 Controlled emission factor based on vendor estimated burner performance

## Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 5: NOx Control - Low NOx Burners (LNB) Coal-Fired

#### CAPITAL COSTS

| Direct Capital Costs   |   |   |
|--|---|---|
| Purchased Equipment (A) (1)  |   | 727,000   |
| Purchased Equipment Costs (A) - Absorber +   | packing + auxillary equipment, EC   |   |
| Instrumentation  | 10% of control device cost (A)  | 72,700  |
| MN Sales Taxes   | 6.9% of control device cost (A)   | 49,981  |
| Freight  | 5% of control device cost (A)   | 36,350  |
| Purchased Equipment Total (B)  | 22%   | 886,031   |
| Installation [1]   |   |   |
| Foundations & supports   | 0% of purchased equip cost (B)  | 0   |
| Handling & erection  | 0% of purchased equip cost (B)  | 0   |
| Electrical   | 0% of purchased equip cost (B)  | 0   |
| Piping   | 0% of purchased equip cost (B)  | 0   |
| Insulation   | 0% of purchased equip cost (B   | 0   |
| Painting   | 0% of purchased equip cost (B)<br>0%  | 710.900   |
| Installation Subtotal Standard Expenses  | 0%  | 710,900   |
| Installation Total   |   | 710,900   |
| Total Direct Capital Cost, DC  |   | 1,596,931                                       |
| Indirect Capital Costs   |   |   |
| Engineering, supervision   | 10% of purchased equip cost (B)   | 88,603  |
| Construction & field expenses  | 20% of purchased equip cost (B  | 177,206   |
| Contractor fees  | 10% of purchased equip cost (B  | 88,603  |
| Start-up   | 1% of purchased equip cost (B)  | 8,860   |
| Performance test   | 1% of purchased equip cost (B)  | 8,860   |
| Model Studies  | NA of purchased equip cost (B   | NA  |
| Contingencies  | 10% of purchased equip cost (B)   | 88,603  |
| Total Indirect Capital Costs, IC   | 52% of purchased equip cost (B)   | 460,736   |
| otal Capital Investment (TCI) = DC + IC  |   | 2,057,668                                       |
| Other Development in the second second   | 01-0  | NA  |
| Site Preparation, as required  | Site Specific<br>Site Specific  | NA  |
| Buildings, as required<br>Site Specific - Other  |   | INA   |
| Total Site Specific Costs  | Site Specific   | 0   |
| Adjusted TCI for Replacement Parts (Catalyst, Filte  | r Bags, etc) for Capital Recovery Cos   | 2,057,668                                       |
|  |   |   |
| Total Capital Investment (TCI) with Retrofit Factor  | 50%   | 3,086,501                                       |
| OPERATING COSTS  |   |   |
| Direct Annual Operating Costs, DC  |   |   |
| Operating Labor  |   |   |
| Operator   | 67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr  | 31,807  |
| Supervisor   | 15% 15% of Operator Costs   | 4,771   |
| Maintenance (2)  |   |   |
| Maintenance Labor  | 67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr  | 31,807  |
| Maintenance Materials  | 100% of maintenance labor costs   | 31,807  |
| Utilities, Supplies, Replacements & Waste Ma   |   |   |
| NA   | NA  | -   |
|  |   |   |
| NA   | NA  |   |
| NA   | NA  | -   |
| NA<br>NA   | NA<br>NA  | -<br>-  |
| NA<br>NA<br>NA   | NA<br>NA<br>NA  | -<br>-<br>-                                     |
| NA<br>NA<br>NA   | NA<br>NA<br>NA  |   |
| NA<br>NA<br>NA<br>NA   | NA<br>NA<br>NA  |   |
| NA<br>NA<br>NA   | NA<br>NA<br>NA  |   |
| NA<br>NA<br>NA<br>NA<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs  | NA<br>NA<br>NA<br>NA<br>NA  |   |
| NA<br>NA<br>NA<br>NA<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead  | NA<br>NA<br>NA<br>NA<br>NA<br>60% of total labor and material costs   | 60,115  |
| NA<br>NA<br>NA<br>NA<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs  | NA<br>NA<br>NA<br>NA<br>NA  |   |
| NA<br>NA<br>NA<br>NA<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead  | NA<br>NA<br>NA<br>NA<br>NA<br>60% of total labor and material costs   | 60,115<br>61,730<br>30,865                      |
| NA<br>NA<br>NA<br>NA<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)   | NA<br>NA<br>NA<br>NA<br>NA<br>80% of total labor and material costs<br>2% of total capital costs (TCI)  | 60,115<br>61,730                                |
| NA<br>NA<br>NA<br>NA<br><b>Total Annual Direct Operating Costs</b><br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)   | NA<br>NA<br>NA<br>NA<br>NA<br>60% of total labor and material costs<br>2% of total capital costs (TCI)<br>1% of total capital costs (TCI)   | 60,115<br>61,730<br>30,865                      |
| NA<br>NA<br>NA<br>NA<br>Total Annual Direct Operating Costs<br>Total Annual Direct Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)<br>Insurance (1% total capital costs)         | NA<br>NA<br>NA<br>NA<br>NA<br>80% of total labor and material costs<br>2% of total capital costs (TCI)<br>1% of total capital costs (TCI)<br>1% of total capital costs (TCI)  | 60,115<br>61,730<br>30,865<br>30,865            |
| NA<br>NA<br>NA<br>NA<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property at (1% total capital costs)<br>Insurance (1% total capital costs)<br>Capital Recovery | NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>60% of total labor and material costs<br>2% of total capital costs (TCI)<br>1% of total capital costs (TCI)<br>1% of total capital costs (TCI)<br>8% for a 20-year equipment life and a 5.5% interest rate  | 60,115<br>61,730<br>30,865<br>30,885<br>258,276 |
| NA<br>NA<br>NA<br>NA<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property at (1% total capital costs)<br>Insurance (1% total capital costs)<br>Capital Recovery | NA<br>NA<br>NA<br>NA<br>NA<br>80% of total labor and material costs<br>2% of total capital costs (TCI)<br>1% of total capital costs (TCI)<br>1% of total capital costs (TCI)<br>8% for a 20- year equipment life and a 5.5% interest rate<br>Sum indirect oper costs + capital recovery cos | 60,115<br>61,730<br>30,865<br>30,885<br>258,276 |

\barr.com\projects\Mpls\23 MN\65\2365011\WorkFiles\Air Permitting\Regional Haze\2020 Cost Review\Appendix A - Control Cost Analysis for NOx and SO2.xlsm LNB Summary

Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 5: NOx Control - Low NOx Burners (LNB) Coal-Fired

| Capital Recovery Factors<br>Primary Installation |          |
|--|----------|
| Interest Rate                                    | 5.50%    |
| Equipment Life<br>CRF                            | 20 years |
| CRF  | 0.0837   |

Replacement Parts & Equipment:

Replacement Parts & Equipment:

Electrical Use

#### Reagent Use & Other Operating Costs

| Supervisor 1<br>Maintenance 67<br>Maint Labor 67<br>Maint Mtls<br>Utilities, Supplies, Replacemen<br>Electricity 00.<br>Natural Gas 3            | \$ Measu<br>7.53 \$/Hr<br>15% of Op.<br>7.53 \$/Hr<br>100 % of Mai       | re Rate N<br>0.5 hr/8<br>0.5 hr/8<br>ntenance Labor | leasure<br>3 hr shift<br>3 hr shift | Annual<br>Use*<br>471<br>NA<br>471<br>NA<br>0 | Cost<br>31,807<br>4,771<br>31,807<br>31,807 | Comments<br>SiHr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% of Operator Costs<br>SiHr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of Maintenance Labor |
|--|--|---|-------------------------------------|---|---|--|
| Op Labor 67<br>Supervisor 1<br>Maintenance<br>Maint Labor 67<br>Maint Mtls<br>Utilities, Supplies, Replacemen<br>Electricity 0.<br>Natural Gas 3 | 15% of Op.<br>7.53 \$/Hr<br>100 % of Mai<br>tts & Waste M<br>.080 \$/kwh | 0.5 hr/8<br>ntenance Labor<br>lanagement<br>0.0 kW  | 3 hr shift                          | NA<br>471<br>NA                               | 4,771<br>31,807<br>31,807                   | 15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr  |
| Supervisor 1<br>Maintenance 67<br>Maint Labor 67<br>Maint Mtls<br>Utilities, Supplies, Replacemen<br>Electricity 0.<br>Natural Gas 3             | 15% of Op.<br>7.53 \$/Hr<br>100 % of Mai<br>tts & Waste M<br>.080 \$/kwh | 0.5 hr/8<br>ntenance Labor<br>lanagement<br>0.0 kW  | 3 hr shift                          | NA<br>471<br>NA                               | 4,771<br>31,807<br>31,807                   | 15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr  |
| Maintenance<br>Maint Labor 67<br>Maint Mtls<br>Utilities, Supplies, Replacemen<br>Electricity 0.<br>Natural Gas 3                                | 7.53 \$/Hr<br>100 % of Mai<br>ts & Waste M<br>.080 \$/kwh                | ntenance Labor<br>lanagement<br>0.0 kW              |                                     | 471<br>NA                                     | 31,807<br>31,807                            | \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr   |
| Maint Labor 67<br>Maint Mtls<br>Utilities, Supplies, Replacemen<br>Electricity 0.<br>Natural Gas 3   | 100 % of Mai<br>ts & Waste M<br>.080 \$/kwh                              | ntenance Labor<br>lanagement<br>0.0 kW              |                                     | NA  | 31,807                                      |  |
| Maint Mtls<br>Utilities, Supplies, Replacemen<br>Electricity 0.<br>Natural Gas 3   | 100 % of Mai<br>ts & Waste M<br>.080 \$/kwh                              | ntenance Labor<br>lanagement<br>0.0 kW              |                                     | NA  | 31,807                                      |  |
| Utilities, Supplies, Replacemen<br>Electricity 0.<br>Natural Gas 3   | ts & Waste N<br>.080 \$/kwh  | lanagement<br>0.0 kW                                | -hr                                 |   |   | 100% of Maintenance Labor  |
| Electricity 0.<br>Natural Gas 3  | .080 \$/kwh  | 0.0 kW  | -hr                                 | 0   |   |  |
| Natural Gas 3  |  |   | -hr                                 | 0   |   |  |
|  | 3.90 \$/kscf   | 0.00  |                                     |   | 0   | \$/kwh, 0 kW-hr, 7536 hr/yr, 100% utilization  |
| Water 5  |  |   | m                                   | 0   | 0   | \$/kscf, 0 scfm, 7536 hr/yr, 100% utilization  |
|  | 5.13 \$/kgal   | 0.0 gpr   | n                                   | 0   | 0   | \$/kgal, 0 gpm, 7536 hr/yr, 100% utilization   |
|  |  |   |                                     |   |   |  |

## Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis

### Table 6: NO<sub>x</sub> Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

Boiler 1

#### Operating Unit:

| Emission Unit Number               | EQUI17 |          | Stack/Vent Number      | STRU25  |               |
|------------------------------------|--------|----------|------------------------|---------|---------------|
| Desgin Capacity                    | 472    | MMBtu/hr | Standardized Flow Rate | 123,889 | scfm @ 32° F  |
| Expected Utiliztion Rate           | 100%   |          | Temperature            | 370     | Deg F         |
| Expected Annual Hours of Operation | 7,536  | Hours    | Moisture Conten        | 11.8%   |               |
| Annual Interest Rate               | 5.5%   |          | Actual Flow Rate       | 209,000 | acfm          |
| Expected Equipment Life            | 20     | yrs      | Standardized Flow Rate | 132,954 | scfm @ 68° F  |
|                                    |        |          | Dry Std Flow Rate      | 117,332 | dscfm @ 68° F |

CONTROL EQUIPMENT COSTS

| Capital Costs   |              |   |          |  |  |  |         |           |
|---|--------------|---|----------|--|--|--|---------|-----------|
| Direct Capital Costs  |              |   |          |  |  |  |         |           |
| Purchased Equipment (A)   |              |   |          |  |  |  |         | 1,265,871 |
| Purchased Equipment Total (B)                                       | 22%          | of control device co  | ost (A)  |  |  |  |         | 1,542,780 |
| Installation - Standard Costs<br>Installation - Site Specific Costs | 0%           | of purchased equip  | cost (B) |  |  |  |         | 1,215,900 |
| Installation Total  |              |   |          |  |  |  |         | 1,215,900 |
| Total Direct Capital Cost, DC                                       |              |   |          |  |  |  |         | 2,758,680 |
| Total Indirect Capital Costs, IC                                    | 52%          | of purchased equip  | cost (B) |  |  |  |         | 802,246   |
| Total Capital Investment (TCI) = DC + IC                            |              |   |          |  |  |  |         | 3,560,926 |
| Operating Costs   |              |   |          |  |  |  |         |           |
| Total Annual Direct Operating Costs                                 |              | Labor, supervision, materials, replacement parts, utilities, etc. |          |  |  |  | 100,192 |           |
| Total Annual Indirect Operating Costs                               |              | Sum indirect oper costs + capital recovery cost 720,              |          |  |  |  |         | 720,734   |
| Total Annual Cost (Annualized Capital Co                            | st + Operati | ng Cost   |          |  |  |  |         | 820,926   |

#### Emission Control Cost Calculation

| Pollutant                         | Baseline<br>Emis. T/yr | Cont. Emis.<br>Ib/hr | Cont. Emis.<br>Ib/MMBtu | Cont Emis<br>T/yr | Reduction<br>T/yr | Cont Cost<br>\$/Ton Rem |
|-----------------------------------|------------------------|----------------------|-------------------------|-------------------|-------------------|-------------------------|
| PM10                              |                        | -                    |                         |                   | -                 | NA                      |
| Total Particulates                |                        | -                    |                         |                   | -                 | NA                      |
| Nitrous Oxides (NOx               | 906.9                  | 179.5                | 0.38                    | 676.4             | 230.5             | 3,561                   |
| Sulfur Dioxide (SO <sub>2</sub> ) |                        |                      |                         |                   | -                 | NA                      |

 Notes & Assumptions

 1
 Purchased equipment and installation costs from vendor

 2
 Assumed 0.5 hrishift operation and maintenance labor for LNB

 3
 Controlled emission factor based on vendor estimated burner/OFA performance

Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 6: NOx Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

#### CAPITAL COSTS

| Installation         10% of control device cost (A)         67.5           MN Sales Taxes         6.9% of control device cost (A)         67.5           Purchased Equipment Total (B)         22%         1.552           Institution [1]         0% of purchased equip cost (B)         6.6           Period         0% of purchased equip cost (B)         1.652           Installation Total         1.2753         1.2753           Total Direct Capital Costs         10% of purchased equip cost (B)         1.54           Contruction R field expenses         0% of purchased equip cost (B)         1.54           Contruction R field expenses         10% of purchased equip cost (B)         1.54           Contruction R field expenses         10% of purchased equip cost (B)         1.54           Contrustent R (C) = DC + IC         3.5600         1.54           Total Indirect Capital Costs, IC         52% of purchased equip cost (B)         1.54           Contruction R (C) = DC + IC         3.5600         1.54 <th>Purchased Equipment (A) (1)<br/>Purchased Equipment Costs (A) - Absorber + p</th> <th>acking + auxillary equipment EC</th> <th>1,265,87</th>   | Purchased Equipment (A) (1)<br>Purchased Equipment Costs (A) - Absorber + p   | acking + auxillary equipment EC  | 1,265,87  |
|--|---|--|---|
| M. Sales Taxes         6.9% of control device cost (A)         67.0           Prediat         5% of control device cost (A)         63.3           Purchased Equipment Total (B)         22%         5% of control device cost (A)         63.3           Installation [1]         0% of purchased equip cost (B)         66.4         63.4           Handling & sector         0% of purchased equip cost (B)         66.4         12.155           Poing         0% of purchased equip cost (B)         12.155         12.155           Installation Statical Standard Expenses         0%         12.255         12.255           Installation Total         12.255         12.255         12.255           Installation Total         12.355         154.2         154.2           Construction feet         10% of purchased equip cost (B)         154.2         154.2           Construction feet         10% of purchased equip cost (B)         155.2         154.2           Construction feet         10% of purchased equip cost (B)         155.2         154.2           Total Inforce Capital Costs.         15% of purchased equip cost (B)         155.2           Total Inforce Capital Costs.         15% of purchased equip cost (B)         155.2           Total Inforce Capital Costs.         15% of purchased equip cost (B)  |   |  | 126.58  |
| Purchased Equipment Total (6)     22%     15422       Installation (1)     Foundations Supports     0% of purchased equip cost (8)       Handing & erection     0% of purchased equip cost (8)       Ping     0% of purchased equip cost (8)       matallation Total     12153       Total Direct Capital Costs     0%       Engineering, supervision     10% of purchased equip cost (8)       Installation Total     12153       Total Direct Capital Cost, DC     22% of purchased equip cost (8)       Construction & field expenses     0%       Ordingencies     10% of purchased equip cost (8)       Construction & field expenses     10% of purchased equip cost (8)       Construction & field expenses     10% of purchased equip cost (8)       Construction & field expenses     10% of purchased equip cost (8)       Construction fiel     10% of purchased equip cost (8)       Construction fiel     10% of purchased equip cost (8)       Construction field     10% of   | MN Sales Taxes  | 6.9% of control device cost (A)  | 87,02   |
| Installation [1]         Productions & supports         0% of purchased equip cost (8)           Handling & section         0% of purchased equip cost (8)         1           Electrical         0% of purchased equip cost (8)         1           Pring         0% of purchased equip cost (8)         1           Printing         0% of purchased equip cost (8)         1           Printing         0% of purchased equip cost (8)         1           Installation Subtotal Standard Expenses         0%         1         1           Installation Total         1         1         1         1         1           Contractor from expense         0% of purchased equip cost (8)         1   | Freight   | 5% of control device cost (A)  | 63,29   |
| Foundations & supports     0% of purchased equip cost (B)       Handing & Revention     0% of purchased equip cost (B)       Electrical     0% of purchased equip cost (B)       Parating     0% of purchased equip cost (B)       Installation Subtoral Standard Expanses     0%       Off of purchased equip cost (B)     12753       Installation Total     12753       Installation Total     12753       Indirect Capital Costs     10% of purchased equip cost (B)       Engineering, supervision     10% of purchased equip cost (B)       Construction fee     10% of purchased equip cost (B)       Start-up     1% of purchased equip cost (B)       Contractor fee     10% of purchased equip cost (B)       Total Inferict Capital Costs     10% of purchased equip cost (B)       Contingencies     10% of purchased equip cost (B)       Total Inferict Capital Costs, IC     22% of purchased equip cost (B)       Contingencies     10% of purchased equip cost (B)       Contractor fee     32% of purchased equip cost (B)       Contractor fee     32% of purchased equip cost (B)       Copretaic     1  | Purchased Equipment Total (B)   |  | 1,542,78  |
| Handing & eraction     0% of purchased equip cost (8)       Piping     0% of purchased equip cost (8)       Phing     0% of purchased equip cost (8)       Installation     0% of purchased equip cost (8)       Painting     0% of purchased equip cost (8)       Installation Subtorial Standard Expenses     0%       Installation Subtorial Standard Expenses     0%       Indirect Capital Costs     22766       Contractor foreix     10% of purchased equip cost (8)       Contingencies     10% of purchased equip cost (8)       Total Inference Capital Costs, IC     52% of purchased equip cost (8)       Site Specific     NA       Site Specific     NA       Site Specific     NA       Site Specific     NA       Site Specific     14       M   | Installation [1]  |  |   |
| Electrical       0% of purchased equip cost (B)         Piping       0% of purchased equip cost (B)         Painting       0% of purchased equip cost (B)         Installation Subtoral Standard Exponses       0%         Installation Total       12255         Total Direct Capital Costs       12255         Engineering, supervision       10% of purchased equip cost (B)       154,         Construction K feld exponse       20% of purchased equip cost (B)       154,         Construction K feld exponse       20% of purchased equip cost (B)       154,         Construction K feld exponse       20% of purchased equip cost (B)       154,         Contingencies       10% of purchased equip cost (B)       162,         Contingencies       10% of purchased equip cost (B)       154,         Deprintion       52% of purchased equip cost (B)   |   |  |   |
| Piping         0% of purchased equip cost (8)           Installation         0% of purchased equip cost (8)           Painting         0% of purchased equip cost (8)           Installation Subtoal Standard Expenses         0%           Indirect Capital Costs         2756           Engineering, supervision         10% of purchased equip cost (8)         154.2           Controbution Stell         11% of purchased equip cost (8)         154.2           Controbution Stell         11% of purchased equip cost (8)         154.2           Controbution Stell         11% of purchased equip cost (8)         154.2           Controbution Stell         11% of purchased equip cost (8)         154.2           Controbution Stell         11% of purchased equip cost (8)         154.2           Total Indirect Capital Costs, IC         52% of purchased equip cost (8)         164.2           Total Ste Specific         164.2         3560.2           Differed Tot Replacement Paris (Statayst, Filter Bags, etc) for Capital Recovery  |   |  |   |
| Installation     0% of purchased equip cost (6)       Painting     0% of purchased equip cost (6)       Installation Subtotal Standard Exponse     0%       Installation Total     12153       Installation Total     12253       Indirect Capital Cost, DC     12753       Construction Released equip cost (8)     154,<br>000000000000000000000000000000000000  |   |  |   |
| Parting:     0% of purchased equip cost (B)       Installation Subtoal Standard Expenses     0%       Installation Subtoal Standard Expenses     0%       Indirect Capital Costs     1,2153       Engineering, supervision     10% of purchased equip cost (B)     154,2       Construction & field expense     20% of purchased equip cost (B)     154,2       Construction & field expense     10% of purchased equip cost (B)     154,2       Construction & field expense     10% of purchased equip cost (B)     154,2       Contractor fee     10% of purchased equip cost (B)     154,2       Contractor fee     10% of purchased equip cost (B)     154,2       Contractor fee     10% of purchased equip cost (B)     154,2       Contractor fee     10% of purchased equip cost (B)     154,3       Total Indirect Capital Costs, IC     356,00     160,2       Site Proparation, as required     Site Specific     NA       Site Specific Costs     356,00     356,00       Cost Specific Costs     57,53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr     31,4       Operator     67,53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr     31,4       Operator     67,53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr     31,4       Maintenance (Labor     67,53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr     31,4       Maintenance (Labor     67,53 S/Hr, 0.5 hr/8  |   |  |   |
| Installation Subtotal Standard Expenses         0%         12153           Installation Total         1.2153         1.2153           Total Direct Capital Costs, DC         2.7664         2.7664           Engineering, supervision         2.0% of purchased explp cost (B)         1.542           Contractor fore         2.0% of purchased explp cost (B)         1.542           Contractor fore         2.0% of purchased explp cost (B)         1.542           Start-top         1.1% of purchased explp cost (B)         1.542           Contingencies         1.0% of purchased explp cost (B)         1.542           Contingencies         1.542         5.622           al Capital Investment (TC) = DC + IC         3.5601         5.362           Total Baike Specific         NA         NA           Total Baike Specific Costs         3.5601         3.5601           Operator         6.753 S/H, 0.5 hr/B fr shift, 7536 hr/yr         31.1           Total Annual Operat  |   |  |   |
| Total Direct Capital Cost, DC     2/383       Indirect Capital Cost, DC     2/384       Engineering, supervision     10% of purchased equip cost (8)     154,       Contractor fee     10% of purchased equip cost (8)     154,       Contractor fee     10% of purchased equip cost (8)     154,       Start-up     1% of purchased equip cost (8)     155,       Performance teal     1% of purchased equip cost (8)     154,       Contingencies     10% of purchased equip cost (8)     154,       Start Specific - Costs     3,560,0     NA       Start Specific - Costs     NA     154,       Start Specific - Costs     16% of purchased equip cost (8)     5,341,2       Capital Investment (FCI) with Retroft Factor     50%     5,341,2       Contract Cost potenting Costs, ptc     155, 15% of Operator Costs     4,1       Maintenance Labor     67,53, 5/44, 0.5 hr/8 hr shilt, 7536 hr/yr     31,4       Maintenance Labor     67,53, 5/44, 0.5 hr/8 hr shilt, 7536 hr/yr<   |   |  | 1,215,90  |
| Indirect Capital Costs Engineering, supervision Construction Relet expenses Construction Relet expenses Construction Relet expenses Construction Relet expenses Construction Relet expenses Construction Relet expenses Construction Relet expenses Construction Relet expenses Construction Relet expenses Construction Relet expenses Construction Co | Installation Total  |  | 1,215,90  |
| Engineering, supervision         10% of purchased equip cost (6)         363.           Construction feet         10% of purchased equip cost (6)         363.           Contractor feet         10% of purchased equip cost (8)         154.           Start-up         1% of purchased equip cost (8)         155.           Model Studies         10% of purchased equip cost (8)         155.           Contingencies         10% of purchased equip cost (8)         152.           Cast Indirect Capital Costs, IC         252% of purchased equip cost (8)         152.           Total Indirect Capital Costs, IC         252% of purchased equip cost (8)         152.           Total Indirect Capital Costs, IC         252% of purchased equip cost (8)         152.           Site Programment (FCI) = DC + IC         3560.0         NA           Site Specific         NA         NA           Site Specific         NA         NA           Site Specific         3560.5         5,241.2           Usted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos         3560.5           Supervisor         175.5         51%.10% of Operator Costs         4.1           Operator         67.53         51%.10% of Operator Costs         4.1           Maintenanco Labor         67.53         51   | Total Direct Capital Cost, DC   |  | 2,758,68  |
| Construction & field expenses 20% of purchased equip cost (B) 195.<br>Constructor fees 10% of purchased equip cost (B) 15.<br>Performance test 1% of purchased equip cost (B) 15.<br>Model Studies NA of purchased equip cost (B) 15.<br>Contingencies 10% of purchased equip cost (B) 15.<br>Total Indirect Capital Costs, IC 52% of purchased equip cost (B) 35.<br>Site Preparation, as required Site Specific NA Buildings Specific NA Buildings, as required Site Specific NA Buildings, as required Site Specific NA Buildings, as required Site Specific NA Buildings, as required Site Specific NA Buildings, as required Site Specific NA Buildings, as required Site Specific NA Buildings, as required Site Specific Costs NA Buildings, as required Site Specific NA Buildings, as required Site Specific Costs NA Buildings, as required Site Specific Costs NA Buildings, as required Site Specific Costs NA Buildings, as required Site Specific Costs Site Cost Specific Costs Site Specific Costs Site Specific Costs Site Specific Costs Site Specific Costs Site Specific Costs Site Specific Costs Site Specific Costs Site Specific Costs Site Specific Costs Site Specific Costs Site Specific Costs Site Specific Costs Site Specific Costs Site Site Specific Costs Site Site Specific Costs Site Site Specific Costs Site Site Specific Costs Site Site Specific Costs Site Site Site Site Site Site Site Site  |   |  |   |
| Contractor free: 10% of purchased equip cost (E) 1542<br>Start-up 1% of purchased equip cost (B) 1554<br>Model Studies NA of purchased equip cost (B) 1542<br>Contingencies (C) 252% of purchased equip cost (B) 1542<br>Total Indirect Capital Costs, IC 252% of purchased equip cost (B) 1542<br>Start-preparation, as required Site Specific NA<br>Buildings, as required Site Specific NA<br>Buildings, as required Site Specific NA<br>Buildings, as required Site Specific Site Specific NA<br>Buildings, as required Site Specific Site Specific NA<br>Buildings, as required Site Specific Site Specific NA<br>Buildings, as required Site Specific Site Specific Site Specific Site Specific Costs NA<br>Total Buildings, as required Site Specific Site Specific Site Specific Site Specific Costs NA<br>Buildings, as required Site Specific Site Specific Site Specific Site Specific Costs NA<br>Buildings, as required Site Specific Costs Site Specific Site Specific Costs Site Costs Site Cost Site Specific Costs Site Cost Site Specific Costs Site Specific Site Specific Costs Site Specific Site Specific Costs Site Cost Site Specific Costs Site Specific Site Specific Site Specific Site Specific Site Specific Site Specific Site Specific Site Site Specific Site Site Site Site Site Site Site Site   | Engineering, supervision  |  | 154,27  |
| Start-up       1% of purchased equip cost (B)       15.         Performance test       1% of purchased equip cost (B)       15.         Contingencies       10% of purchased equip cost (B)       15.         Total Indirect Capital Costs, IC       52% of purchased equip cost (B)       15.4.         al Capital Investment (TC) = DC + IC       3.560.0       3.560.0         Site Preparation, as required       Site Specific       NA         Building, as required       Site Specific       NA         Total Site Specific       NA       NA         Site Specific       Site Specific       NA         Direct Annual Operating Costs, DC       0%       5.341.2         Operating Labor       67.53 SiHz, 0.5 hr/8 hr shift, 7536 hr/yr       31.4         Operating Labor       67.53 SiHz, 0.5 hr/8 hr shift, 7536 hr/yr       31.4         Maintenance Labor       67.53 SiHz, 0.5 hr/8 hr shift, 7536 hr/yr       31.4         Maintenance Material       100% of maintenance labor costs       31.4         MA       NA       NA       NA         NA       NA       NA       NA         NA       NA       NA       NA         Maintenance Material       100% of maintenance labor costs       31.4         Maintenance Mater   |   |  |   |
| Performance test     1% of purchased equip cost (8)     15.4       Model Studies     10% of purchased equip cost (8)     154.1       Contingencies     10% of purchased equip cost (8)     152.1       Total Indirect Capital Costs, IC     52% of purchased equip cost (8)     152.1       al Capital Investment (TCI) = DC + IC     3,560.1     3,560.1       Site Preparation, as required     Site Specific     NA       Buildings, as required     Site Specific     NA       Site Specific Costs     3,560.1     NA       Total Adjust Capital Costs, IC     50%     5,341.2       Total Adjust Costs, DC     50%     5,341.2       Operator     67.53 SH4, 0.5 hr/8 hr shift, 7538 hr/yr     31.1       Maintenance Labor     67.53 SH4, 0.5 hr/8 hr shift, 7538 hr/yr     31.3       Operator     67.53 SH4, 0.5 hr/8 hr shift, 7538 hr/yr     31.3       Maintenance Labor     67.53 SH4, 0.5 hr/8 hr shift, 7538 hr/yr     31.3       Utilities, Supplies, Replacements & Waste Management     NA     NA       NA     NA     NA     NA       NA     NA     NA     NA       NA     NA     NA     NA       NA     NA     NA     NA       Maintenance Labor     67.53 SH4, 0.5 hr/8 hr shift, 7538 hr/yr     31.1       Maintenanc  |   |  | 154,27  |
| Model Studies     No of purchased equip cost [0]     1544.       Contingencies     10% of purchased equip cost [0]     1544.       Total Indirect Capital Costs, IC     52% of purchased equip cost [0]     1642.       al Capital Investment (TCI) = DC + IC     3.660.     3.660.       Site Preparation, as required     Site Specific     NA       Building, as required     Site Specific     NA       Site Specific Costs     Jacobia     NA       Data Site Specific Costs     Jacobia     3.660.       Direct Annual Operating Costs, DC     50%     5.341.       Operating Labor     67.53 SHr, 0.5 hr/8 hr shift, 7536 hr/yr     31.4       Operating Labor     67.53 SHr, 0.5 hr/8 hr shift, 7536 hr/yr     31.4       Maintenance (2)     Maintenance     100% of maintenance labor costs     31.3       Minitenance Labor     67.53 SHr, 0.5 hr/8 hr shift, 7536 hr/yr     31.4       Maintenance (2)     Maintenance (3)     31.4       MA     NA     NA     NA       NA     NA     NA     NA       NA     NA     NA     NA     NA       Maintenance (2)     Maintenance (2)     31.4     31.4       Maintenance (2)     NA     NA     NA     NA       NA     NA     NA     NA     NA  |   |  | 15,42   |
| Contigencies     10% of parchased equip cost (E)     194.2       Total Indirect Capital Costs, IC     52% of parchased equip cost (E)     802.2       al Capital Investment (TCI) = DC + IC     35.600.1     NA       Bille Preparation, as required     Site Specific     35.600.1       Total Site Specific Costs     35.600.1     35.600.1       Direct Annual Operating Costs, DC     Operator     67.53 SiHr, 0.5 hr/B hr shift, 7538 hr/yr     31.1       Operator     67.53 SiHr, 0.5 hr/B hr shift, 7538 hr/yr     31.3     31.4       Utilities, Supplies, Replacements & Waste Management     NA     31.4       NA     NA     NA     NA       NA<  |   | 1% or purchased equip cost (B)   | 15,42   |
| Total Indirect Capital Costs, IC     52% of purchased equip cost (8)     8622       al Capital Investment (TC) = DC + IC     3,5603       Site Preparation, as required     Site Specific     NA       Buildings, as required     Site Specific     NA       Site Specific Costs     Site Specific     NA       Justed TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos     3,5603       al Capital Investment (TCI) with Retrofit Factor     50%     5,3412       Portation     67,53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr     31.4       Supervisor     15% 15% of Operator Costs     4.1       Operating Labor     67,53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr     31.4       Maintenance (A)     15% 15% of Operator Costs     4.1       Maintenance (A)     7,53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr     31.4       Utilities, Supplies, Replacements & Waste Managemen     NA     31.4       NA     NA     NA     NA       NA     NA     NA     NA       NA     NA     NA     NA <tr< td=""><td></td><td></td><td>N.</td></tr<>  |   |  | N.  |
| al Capital Investment (TCI) = DC + IC 3,560, Site Preparation, as required Site Specific NA Buildings, as required Site Specific Total Site Specific Total Site Specific Total Site Specific Costs Total Site Specific Costs Indice Costs Direct Annual Operating Costs, DC Operator Supervisor Costs Direct Annual Operating Costs, DC Operator Supervisor Costs Direct Annual Operating Costs, DC Operator NA Maintenance Labor Cost Supervisor NA NA NA NA NA NA NA NA NA NA NA NA NA   |   | 10% of purchased equip cost (B)  | 154,27  |
| Site Preparation, as required         Site Specific         NA           Buildings, as required         Site Specific         NA           Buildings, as required         Site Specific         NA           Total Site Specific Costs         Site Specific         3560           Ustat Of Clor Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos         3,560,7         3,560,7           al Capital Investment (TCI) with Retrofit Factor         50%         5,241,7         50%           Coperating Labor         Operator         67,53 SiHr, 0.5 hr/8 hr shift, 7536 hr/yr         311,8           Operator         67,53 SiHr, 0.5 hr/8 hr shift, 7536 hr/yr         313,1         314,3           Supervisor         15% 15% of Operator Costs         4,2           Maintenance (2)         Maintenance labor         67,53 SiHr, 0.5 hr/8 hr shift, 7536 hr/yr         313,1           Utities, Supplies, Replacements & Waste Management         NA         NA         NA           NA         NA   |   | 32 /v or purchased equip cost (B)  |   |
| Buildingin, as required Site Specific NA<br>Site Specific Other Site Specific Other<br>Total Site Specific Costs<br>Justed TC1 for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos 3,560,<br>al Capital Investment (TC1) with Retrofit Factor 50% 5,41,2<br>EFATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator 67,53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr 31,14<br>Supervisor 15% 15% of Operator Costs 4,<br>Maintenance (2)<br>Maintenance Materials 100% of maintenance labor costs 31,0<br>Utilities, Supplies, Replacements & Waste Management<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | tal Capital Investment (TCI) = DC + IC  |  | 3,560,92  |
| Site Specific - Other     Site Specific       Total Site Specific Costs     3,560,3       Justed TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos     3,560,3       Jal Capital Investment (TCI) with Retrofit Factor     50%     5,341,2       Direct Annual Operating Costs, DC     50%     5,341,2       Operating Labor     67,53 SiHr, 0.5 hr/8 hr shift, 7536 hr/yr     31,4       Operating Costs, DC     67,53 SiHr, 0.5 hr/8 hr shift, 7536 hr/yr     31,4       Maintenance (2)     67,53 SiHr, 0.5 hr/8 hr shift, 7536 hr/yr     31,4       Maintenance (2)     67,53 SiHr, 0.5 hr/8 hr shift, 7536 hr/yr     31,4       Mine Specific Rest     4,4     31,4       Maintenance (2)     67,53 SiHr, 0.5 hr/8 hr shift, 7536 hr/yr     31,4       Mine Specific Rest     100% of maintenance labor costs     31,4       Mine Rest     40,4     31,4       Mine Rest     NA     31,4       Maintenance (2)     67,53 SiHr, 0.5 hr/8 hr shift, 7536 hr/yr     31,4       Mine Rest     100% of maintenance labor costs     31,4       Mine Rest     NA     NA     NA       NA     NA     NA     NA     NA       NA     NA     NA     NA     NA       NA     NA     NA     NA     NA       NA   | Site Preparation, as required   |  |   |
| Total Site Specific Costs         3,560,3           Justed TCI for Replacement Parts (Statilyst, Filter Bags, etc) for Capital Recovery Cos         3,560,3           Jal Capital Investment (TCI) with Retrofit Factor         50%         5,341,2           ERATING COSTS         Direct Annual Operating Costs, DC         0           Operation         67,53         SiHr, 0.5 hr/8 hr shift, 7536 hr/yr         31,1           Supervisor         15%         15% of Operator Costs         4,2           Maintenance Labor         67,53         SiHr, 0.5 hr/8 hr shift, 7536 hr/yr         31,1           Utilities, Supplies, Replacements & Waste Management         NA         31,4           NA         NA         NA         NA  |   |  | NA  |
| uisted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos 3,560,<br>al Capital Investment (TCI) with Retrofit Factor 50% 5,341,<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor 07,53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr 31,4<br>Supervisor 15% 15% of Operator Costs 4,1<br>Maintenance (J) 7,53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr 31,4<br>Maintenance Labor 67,53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr 31,4<br>Maintenance Labor 100% of maintenance labor costs 3,1<br>Uithites, Superles, Replacements & Waste Management<br>NA NA NA NA<br>NA NA NA<br>NA NA NA<br>NA br>NA NA<br>NA NA<br>NA NA<br>NA<br>NA NA<br>NA NA<br>NA<br>NA NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA  | Site Specific - Other   |  |   |
| ERATING COSTS         Direct Annual Operating Costs, DC           Operating Labor         Operating Costs, DC           Operation         67.53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr         31.1           Supervisor         15% 15% of Operator Costs         4.2           Maintenance (2)         Maintenance Materials         31.4           Utilities, Supplies, Replacements & Waste Management         NA         31.4           NA         NA         NA           NA  |   |  |   |
| Operating Labor         67.53 SiHr, 0.5 hr/8 hr shift, 7536 hr/yr         31.4           Supervisor         15% 15% of Operator Costs         4.7           Maintenance (2)         67.53 SiHr, 0.5 hr/8 hr shift, 7536 hr/yr         31.4           Maintenance Materials         67.53 SiHr, 0.5 hr/8 hr shift, 7536 hr/yr         31.4           Maintenance Materials         10% of maintenance labor costs         31.4           Maintenance Materials         10% of maintenance labor costs         31.4           Maintenance Materials         NA         NA           NA         NA         NA   |   |  |   |
| Operator         67.53         SHr), 0.5 hr/8 hr shill, 7536 hr/yr         31.1           Supervicer         15%         15%         Operator Costs         4.1           Maintenance Labor         67.53         SHr), 0.5 hr/8 hr shill, 7536 hr/yr         31.1           Maintenance Labor         67.53         SHr, 0.5 hr/8 hr shill, 7536 hr/yr         31.1           Maintenance Materials         10% of maintenance labor costs         31.3           Utilities, Supplies, Replacements & Waste Management         NA         NA           NA         NA         NA   | tal Capital Investment (TCI) with Retrofit Factor   |  | <u>3,560,92</u><br>5,341,38   |
| Supervisor       15% 15% of Operator Costs       4.;         Maintenance (2)       67.55 8/Hr, 0.5 hr/8 hr shift, 75.36 hr/yr       31.4         Maintenance Materials       100% of maintenance labor costs       31.4         Utilities, Supplies, Replacements & Waste Management       NA       31.4         NA       NA       NA         N  | tal Capital Investment (TCI) with Retrofit Factor   |  |   |
| Maintenance (2)         67.53 StHr, 0.5 hr/8 hr shift, 7536 hr/yr         31.1           Maintenance Labor         67.53 StHr, 0.5 hr/8 hr shift, 7536 hr/yr         31.1           Maintenance Labor         67.53 StHr, 0.5 hr/8 hr shift, 7536 hr/yr         31.1           Utilities, Replacements & Waste Management         31.4           NA         NA           NA         NA <t< td=""><td>tal Capital Investment (TCI) with Retrofit Factor<br/>PERATING COSTS<br/>Direct Annual Operating Costs, DC<br/>Operating Labor</td><td>50%</td><td>5,341,38</td></t<>   | tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor   | 50%  | 5,341,38  |
| Maintenance Labor         67.53 SHY, 0.5 hr/8 hr shift, 7536 hr/yr         31.1           Maintenance Matrialis         100% of maintenance labor costs         31.1           Utilities, Supplies, Replacements & Waste Management         NA         NA           NA         NA         NA   | tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator   | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr  | <b>5,341,38</b><br>31,80  |
| Maintenance Materials     100% of maintenance labor costs     31.6       Vulities, Supplies, Replacements & Waste Management     NA     NA       NA     NA     NA  | tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor   | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr  | 5,341,38  |
| Utilites, Supplies, Replacements & Waste Management NA NA NA NA NA NA NA NA NA NA NA NA NA   | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)  | 50%<br>67.53 \$Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs  | <u>5,341,38</u><br>31,80<br>4,77  |
| NA         NA           NA         <   | tal Capital Investment (TCI) with Retrofit Factor<br>TERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Labor   | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr   | 5,341,38<br>31,80<br>4,77<br>31,80  |
| NA         NA           NA         <   | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance Materials   | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs  | <u>5,341,38</u><br>31,80<br>4,77  |
| NA         NA           Overtead         60% of total abor and material costs           Overtead         2% of total capital costs           Overtead         60% of total capital costs <td>al Capital Investment (TCI) with Retrofit Factor<br/>TERATING COSTS<br/>Direct Annual Operating Costs, DC<br/>Operating Labor<br/>Operator<br/>Supervisor<br/>Maintenance Labor<br/>Maintenance Labor<br/>Maintenance Labor<br/>Maintenance Materials<br/>Utilities, Supplies, Replacements &amp; Waste Mar</td> <td>50%<br/>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br/>15% 15% of Operator Costs<br/>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br/>100% of maintenance labor costs<br/>agarment</td> <td>5,341,38<br/>31,80<br/>4,77<br/>31,80</td>   | al Capital Investment (TCI) with Retrofit Factor<br>TERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar   | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>agarment  | 5,341,38<br>31,80<br>4,77<br>31,80  |
| NA         NA           NA         <   | al Capital Investment (TCI) with Retrofit Factor<br>EFATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Suporvisor<br>Maintenance (2)<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA   | 50%<br>67.53 SHr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 SHr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>agement<br>NA   | 5,341,38<br>31,80<br>4,77<br>31,80  |
| NA         NA           Overthead         00% of total labor and material costs           Overthead         01/4 of total capital costs         01/6 of total capital costs           Property tax (15 total capital costs)         1% of total capital costs         01/6 of total capital costs           Property tax (15 total capital costs)         1% of total capital costs         03/6 of total capital costs           Capital Recevery         1% for total capital costs         445.9  | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenan | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr shift, 7536 hr/yr<br>10% of n.5 hr shift, 7536 hr shift, 7536 hr/yr<br>10% of n.5 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr shift, 7536 hr  | 5,341,38<br>31,80<br>4,77<br>31,80  |
| NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           Overfradit         60% of total labor and material costs           Overfradit         50% of total capital costs           Property tax (/fs total capital costs)         1% of total capital costs           1% of total capital costs         100,1           Capital Recorevry         8% for a 20-yar equipment life and a 55% interest rate   | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Suppovisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA  | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>agement<br>NA<br>NA<br>NA   | 5,341,38<br>31,80<br>4,77<br>31,80  |
| NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           Overfradit         60% of total labor and material costs           Overfradit         50% of total capital costs           Property tax (/fs total capital costs)         1% of total capital costs           1% of total capital costs         100,1           Capital Recorevry         8% for a 20-yar equipment life and a 55% interest rate   | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Mai  | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr shift, 7536 hr/yr<br>100% of n.5 hr shift, 7536 hr  | <b>5,341,38</b><br>31,80<br>4,77<br>31,80<br>31,80  |
| NA         NA           NA         <   | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating<br>Operator<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA   | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>100% of maintenance labor costs<br>100% NA<br>NA<br>NA<br>NA<br>NA<br>NA  | 5,341,38<br>31,80<br>4,77<br>31,80  |
| NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           Overhead         60% of total labor and material costs           Overhead         2% of total capital costs (TCI)         533,<br>Insurance (1% total capital costs)           T% for total capital costs (TCI)         533,<br>Insurance (1% total capital costs)         1% of total capital costs (TCI)         533,  | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA  | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>agement<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | <b>5,341,38</b><br>31,80<br>4,77<br>31,80<br>31,80  |
| NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           Overhead         60% of total labor and material costs           Overhead         2% of total capital costs (TCI)         53,<br>Insurance (1% total capital costs)           1% for total capital costs (TCI)         53,<br>Image are quiptiment life and a 55% interest rate         4449,9   | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 50%<br>67.53 SHr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 SHr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>100% of maintenance labor costs<br>100% NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA  | <b>5,341,38</b><br>31,80<br>4,77<br>31,80<br>31,80  |
| NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           Indirect Operating Costs         100;           Coverhead         60% of total labor and material costs         60;           Administration (2% total capital costs)         1% of total capital costs (TCI)         53,           Property tax (1% total capital costs)         1% of total capital costs (TCI)         53,           Capital Recovery         8% for a 20-year equipment (fe and a 55% interest rate         4445,9   | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>agement<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 31,80<br>4,77<br>31,80<br>31,80   |
| NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           Indirect Operating Costs         100;           Coverhead         60% of total labor and material costs         60;           Administration (2% total capital costs)         1% of total capital costs (TCI)         53,           Property tax (1% total capital costs)         1% of total capital costs (TCI)         53,           Capital Recovery         8% for a 20-year equipment (fe and a 55% interest rate         4445,9   | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>100% of maintenance labor costs<br>100% No<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA  | 5,341,38<br>31,80<br>4,77<br>31,80<br>31,80   |
| NA         NA           NA         NA           NA         NA           NA         NA           NA         NA           Total Annual Direct Operating Costs         100,7           Indirect Operating Costs         2% of total capital costs (TCI)           Overhead         60% of total capital costs (TCI)         53,3           Property tark (VIS total capital costs)         1% of total capital costs (TCI)         53,3           Capital Recovery         8% for a 20-year equipment life and a 55% interest rate         446,9  | al Capital Investment (TCI) with Retrofit Factor<br>EFATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>agement<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 31.80<br>4,77<br>31,80<br>31,80   |
| NA         NA           NA         NA           NA         NA           NA         NA           Total Annual Direct Operating Costs         100;           Indirect Operating Costs         60% of total labor and material costs         60;           Cvertineat         50% of total capital costs (TCI)         106,           Property tack (% total capital costs)         1% of total capital costs (TCI)         53,           Insurance (1% total capital costs)         1% of total capital costs (TCI)         53,           Capital Recovery         8% for a 20-year equipment (fie and a 55% interest rate         446,9   | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 50%<br>67.53 \$Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br><b>bagemen</b><br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA  | 31.80<br>4,77<br>31,80<br>31,80   |
| NA<br>NA         NA<br>NA         NA<br>NA           Total Annual Direct Operating Costs         NA         100,7           Indirect Operating Costs         00%         fotal labor and material costs         00,0           Cverthead         00% of total labor and material costs         00,0         00,0         016,0           Overthead         2% of total capital costs (TCI)         016,0         106,0 <t< td=""><td>al Capital Investment (TCI) with Retrofit Factor<br/>ERATING COSTS<br/>Direct Annual Operating Costs, DC<br/>Operating Labor<br/>Operator<br/>Supervisor<br/>Maintenance (2)<br/>Maintenance (2)<br/>Maintenance Materials<br/>Utilities, Supplies, Replacements &amp; Waste Marr<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA</td><td>50%<br/>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br/>15% 15% of Operator Costs<br/>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br/>100% of maintenance labor costs<br/>agement<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA<br/>NA</td><td>31.80<br/>4,77<br/>31,80<br/>31,80</td></t<>   | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Marr<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA  | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>agement<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 31.80<br>4,77<br>31,80<br>31,80   |
| NA         NA           Total Annual Direct Operating Costs         100,1           Indirect Operating Costs         60% of total labor and material costs         60,0           Overhead         60% of total capital costs (TCI)         60,0           Administration (2% total capital costs)         2% of total capital costs (TCI)         53,3           Property tack (1% total capital costs)         1% of total capital costs (TCI)         53,3           Capital Recovery         8% for a 20-year equipment life and a 55% interest rate         446,9   | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operator<br>Operator<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>100% of main | <b>5,341,38</b><br>31,80<br>4,77<br>31,80<br>31,80  |
| Indirect Operating Costs         60% of Iotal labor and material costs         60,           Overhead         60% of Iotal labor and material costs         60,           Administration (2% Iotal capital costs)         2% of Iotal capital costs         106,           Property tax (% Iotal capital costs)         1% of Iotal capital costs         53,           Insurance (1% Iotal capital costs)         1% of Iotal capital costs (TCI)         53,           Capital Recovery         8% for a 20-year equipment life and a 55% interest rate         446,9  | al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% f5% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>agement<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 31.80<br>4,77<br>31,80<br>31,80   |
| Overhead         60% of total labor and material costs         60,           Administration (2% total capital costs)         2% of total capital costs (TC)         106,           Property tax (1% total capital costs)         1% of total capital costs (TC)         53,           Insurance (1% total capital costs)         1% of total capital costs (TC)         53,           Capital Recovery         8% for 2-0, year equipment life and a 55% interest rate         446,9   | al Capital Investment (TCI) with Retrofit Factor<br>EFATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>10% 0.5 hr/8 hr shift, 7536 hr/yr<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/8 hr/8 hr/8 hr/8 hr/8 hr/8 hr/8  | 5,341,38<br>31,80<br>4,77<br>31,80<br>31,80   |
| Administration (2% total capital costs)         2% of total capital costs (TCI)         106.           Property tax (VK) total capital costs)         1% of total capital costs (TCI)         53.           Insurance (1% total capital costs)         1% of total capital costs (TCI)         53.           Capital Recovery         8% for 2.0-year equipment life and a 5.5% interest rate         44.6.9   | al Capital Investment (TCI) with Retrofit Factor<br>EFATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 50%<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>10% 0.5 hr/8 hr shift, 7536 hr/yr<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/s<br>10% 0.5 hr/8 hr/8 hr/8 hr/8 hr/8 hr/8 hr/8 hr/8  | 31.80<br>4,77<br>31,80<br>31,80   |
| Property tax (1% total capital costs)         1% of total capital costs         53.           Insurance (1% total capital costs)         1% of total capital costs         53.           Capital Recovery         8% for a 20-year equipment life and a 5.5% interest rate         446.9   | al Capital Investment (TCI) with Retrofit Factor EFATING COSTS Direct Annual Operating Costs, DC Operating Labor Operating Labor Supervisor Maintenance (2) Ma  | 50%<br>47.53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>167.53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr<br>107.00 namittenanos labor costs<br>International for the shift of the s   | 5,341,38<br>31,80<br>4,77<br>31,80<br>31,80<br>31,80<br>31,80<br>31,80  |
| Insurance (1% total capital costs) 1% of total capital costs (TCI) 53.4<br>Capital Recovery 8% for a 20- year equipment life and a 5.5% interest rate 446.9  | al Capital Investment (TCI) with Retrofit Factor<br>EFATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 50% 67.53 \$i/H; 0.5 h/B hr shift, 7536 hr/yr<br>15% f5% of Operator Costs 67.53 \$i/H; 0.5 h/B hr shift, 7536 hr/yr<br>10% of maintenance labor costs agermer N N N N N N N N N N N N N N N N N N N   | 5,341,38<br>31,80<br>4,77<br>31,80<br>31,80<br>31,80<br>9<br>100,19<br>60,11  |
| Capital Recovery 8% for a 20- year equipment life and a 5.5% interest rate 446,9   | al Capital Investment (TCI) with Retrofit Factor<br>EFATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Albor<br>Maintenance Materials<br>Utilikes, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA  | 50% 67.53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr 15% 15% of Operator Costs 67.53 S/Hr, 0.5 hr/8 hr shift, 7536 hr/yr 10% of maintenanos labor costs agoment MA A A A A A A A A A A A A A A A A A A  | 5,341,38<br>31,80<br>4,77<br>31,80<br>31,80<br>31,80<br>31,80<br>9,00,19<br>100,19<br>60,111<br>106,82                      |
|  | al Capital Investment (TCI) with Retrofit Factor<br>EFATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 50% 67.53 \$i/H; 0.5 hr/8 hr shift, 7536 hr/y; 15% 67 Operator Costs 67.53 \$i/H; 0.5 hr/8 hr shift, 7536 hr/y; 10% of maintenance labor costs agement N NA NA NA NA NA NA NA NA NA NA NA NA N   | 5,341,38<br>31,80<br>4,77<br>31,80<br>31,80<br>31,80<br>9<br>100,19<br>60,11<br>106,19<br>60,11<br>106,19<br>53,41          |
| Total Annual Indirect Operating Costs Sum indirect oper costs + capital recovery costs   | al Capital Investment (TCI) with Retrofit Factor<br>EFATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Labor<br>Maintenance (2)<br>Maintenance (2)<br>Maintena  | 50% 67.53 \$/H; 0.5 hr/8 hr shift, 7538 hr/yr 15% 15% of Operator Costs 67.53 \$/H; 0.5 hr/8 hr shift, 7538 hr/yr 100% of notatisenace labor costs agement N N N N N N N N N N N N N N N N N N N   | 5,341,38<br>31,80<br>4,77<br>31,80<br>31,80<br>31,80<br>9,00,19<br>100,19<br>53,41<br>53,41<br>53,41                        |
|  | al Capital Investment (TCI) with Retrofit Factor<br>EFATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance (2)<br>Maintenance (2)<br>Maintenance Materials<br>Utilites, Supplies, Replacements & Waste Mar<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA<br>NA   | 50% 67.53 \$/H; 0.5 hr/8 hr shift, 7536 hr/y; 15% 67 Operator Costs 7.53 \$/H; 0.5 hr/8 hr shift, 7536 hr/y; 10% of maintenance labor costs agorement N NA NA NA NA NA NA NA NA NA NA NA NA N  | 5,341,38<br>31,80<br>4,77<br>31,80<br>31,80<br>31,80<br>9<br>100,19<br>60,11<br>106,19<br>60,11<br>106,19<br>53,41<br>53,41 |

\barr.com\projects\Mpls\23 MN\65\2365011\WorkFiles\Air Permitting\Regional Haze\2020 Cost Review\Appendix A - Control Cost Analysis for NOx and SO2.xlsm LNB-OFA Summary

#### Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 6: NOx Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

| Capital Recovery Factors<br>Primary Installation |          |
|--|----------|
| Interest Rate                                    | 5.50%    |
| Equipment Life<br>CRF                            | 20 years |
| CRF  | 0.0837   |

Replacement Parts & Equipment:

Replacement Parts & Equipment:

Electrical Use

#### Reagent Use & Other Operating Costs

| - | - |  |  |  |  |
|---|---|--|--|--|--|
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |
|   |   |  |  |  |  |

| Unit<br>tem         Unit<br>Oct         Unit<br>Measure         Use<br>Rate         Unit<br>Measure         Annual<br>Use         Annual<br>Cost         Comments           Operating Labor<br>Op Labor         07.55 SHr         0.5 hr/8 hr shift         471         31.807 SHr, 0.5 hr/8 hr shift, 7358 hr/yr           Supervisor         15% of Op.         0.5 hr/8 hr shift         471         31.807 SHr, 0.5 hr/8 hr shift, 7358 hr/yr           Maintenance         0.5 hr/8 hr shift         471         31.807 SHr, 0.5 hr/8 hr shift, 7358 hr/yr           Maint Labor         67.55 SHr         0.5 hr/8 hr shift         471         31.807 100% of Maintenance           Waint Mits         100 % of Maintenance Labor         NA         31.807 100% of Maintenance Labor         31.807 100% of Maintenance           Utilities, Supplies, Replacements & Waste Management         0.0 K/Hr         0         0         0 Skwh, 0 K/Hr, 100% utilization           Natural Gas         3.90 Skxcf         0.3 cfm         0         0         0 Skxh, 0 gpm, 7536 hr/yr, 100% utilization           Water         5.13 Skgal         0.0 gpm         0         0 Skgal, 0 gpm, 7536 hr/yr, 100% utilization  | Operating Cost Calculations |               |               | Annual hours of operation:<br>Utilization Rate: |                 |     | 7,536<br>100% |   |
|--|-----------------------------|---------------|---------------|---|-----------------|-----|---------------|---|
| Op Labor         67,53 SHr         0.5 hr/8 hr shift         471         31,807 SHr, 0.5 hr/8 hr shift, 733 hr/yr           Supervisor         15% of Op.         NA         4,771         15% of Operator Costs           Mainteance         67,53 SHr         0.5 hr/8 hr shift         4,771         15% of Operator Costs           Maint Labor         67,53 SHr         0.5 hr/8 hr shift         41         31,807 SHr, 0.5 hr/8 hr shift, 7536 hr/yr           Maint Mils         100 % of Maintenance Labor         NA         31,807 10% of Maintenance Labor         NA           Wittles, Supplies, Replacements & Waste Managemet         NA         31,807 10% of Maintenance Labor         NA           Bittericity         0.080 Sktwd         0 sktwl-         0 sktwdr, 0 schw, 7,736 hr/yr, 100% utilization  | Item                        |               |               |   |                 |     |               | Comments                                      |
| Supervisor         15% of Op.         NA         4,771         15% of Operator Costs           Maintenance         0.5 hr/8 hr shift         4,771         15% of Operator Costs           Maintenance         0.5 hr/8 hr shift         471         31,807 S/HC, 05 hr/8 hr shift, 758 hr/yr           Maint Mits         100 % of Maintenance Labor         NA         31,807 100% of Maintenance Labor           Vitities, Supplies, Replacements & Waste Management         Electricity         0.080 S/kwh         0.04W-hr         0         0         S/kcr () scfm, 7536 hr/yr, 100% utilization           Natural Gas         3.90 S/kscf         0.scfm         0         0         S/kcr () scfm, 7536 hr/yr, 100% utilization  |                             |               |               |   |                 |     |               |   |
| Maint Labor         67.53         SHr         0.5         hr/8 hr shift         471         31.807         SHrH         0.5         hr/8 hr shift         471         31.807         SHrH         0.5         hr/9 hr         SHr         51.807         SHrH         0.5         hr/9 hr         SHr         51.807         SHrH         0.5         hr/9 hr         SHr         31.807         SHrH         0.5         hr/9 hr         SHr         31.807         SHrH         0.5         hr/9 hr         31.807         SHrH         0.5         hr/9 hr         0.5         hr/9 hr <thr 9="" hr<="" thr="">         0.5         0.5         <t< td=""><td></td><td></td><td></td><td>0.5</td><td>5 hr/8 hr shift</td><td></td><td></td><td></td></t<></thr> |                             |               |               | 0.5   | 5 hr/8 hr shift |     |               |   |
| Maint Labor         0.7.53 SHr         0.5. hr/8 hr shift         471         31,807 SHr0, 0.5 hr/8 hr shift, 7536 hr/yr           Maint Mils         100 % of Maintenance Labor         NA         31,807 100% of Maintenance Labor           Vilities, Supplies, Replacements & Waste Management         21         21,007 100% of Maintenance Labor           Electricity         0.080 Sfkwh         0.0 KW-hr         0         0 Sikwh, 0 kW-hr, 7,536 hr/yr, 100% utilization           Natural Gas         3.90 Skscf         0 scf         0         0         Sckcf, 0 scfm, 7536 hr/yr, 100% utilization  |                             | 15%           | of Op.        |   |                 | NA  | 4,771         | 15% of Operator Costs                         |
| Maint Mils         100 % of Maintenance Labor         NA         31,807 100% of Maintenance Labor           Utilities, Supplies, Replacements         & Waste Management         Electricity         0         \$/kwh, 0 kW-hr, 7536 hr/yr, 100% utilization           Natural Gas         3.90 %kscf         0 scfm         0         \$/kscf.0 scfm, 7536 hr/yr, 100% utilization  | Maintenance                 |               |               |   |                 |     |               |   |
| Utilities, Supplies, Replacements & Waste Management         0.00 kW-hr         0         0.8 kW, 0.0 kW-hr, 7536 hr/yr, 100% utilization           Electricity         0.08 kKscf         0 scfm         0         \$kscf, 0 scfm, 7536 hr/yr, 100% utilization           Natural Gas         3.90 kKscf         0 scfm         0         \$kscf, 0 scfm, 7536 hr/yr, 100% utilization  | Maint Labor                 | 67.53         | \$/Hr         | 0.5   | 6 hr/8 hr shift | 471 | 31,807        | \$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr          |
| Electricity         0.080 \$/kwh         0.0 kW-hr         0         0 \$/kwh, 0 kW-hr, 7536 hr/yr, 100% utilization           Natural Gas         3.90 \$/kscf         0 scfm         0         0 \$/kscf, 0 scfm, 7536 hr/yr, 100% utilization   | Maint Mtls                  | 100           | % of Maintena | nce Labor                                       |                 | NA  | 31,807        | 100% of Maintenance Labor                     |
| Natural Gas         3.90 \$/kscf         0 scfm         0         0 \$/kscf, 0 scfm, 7536 hr/yr, 100% utilization  | Utilities, Supplies, R      | eplacements & | Waste Manag   | ement   |                 |     |               |   |
|  | Electricity                 | 0.080         | \$/kwh        | 0.0   | kW-hr           | 0   | 0             | \$/kwh, 0 kW-hr, 7536 hr/yr, 100% utilization |
|  | Natural Gas                 | 3.90          | S/kscf        | c   | ) scfm          | 0   | 0             | \$/kscf. 0 scfm, 7536 hr/vr, 100% utilization |
|  | Water                       | 5 13          | \$/kgal       | 0.0   | apm             | 0   | 0             | \$/kgal_0 gpm_7536 br/yr_100% utilization     |
|  |                             |               |               |   |                 |     |               |   |
|  |                             |               |               |   |                 |     |               |   |
|  |                             |               |               |   |                 |     |               |   |
|  |                             |               |               |   |                 |     |               |   |
|  |                             |               |               |   |                 |     |               |   |

### Air Pollution Control Cost Estimation Spreadsheet For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency Air Economics Group Health and Environmental Impacts Division Office of Air Quality Planning and Standards (June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR torol Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

#### Instructions

Step 1: Please select on the Data Inputs tab and click on the Reset Form button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the SNCR Design Parameters tab to see the calculated design parameters and the Cost Estimate tab to view the calculated cost data for the installation and operation of the SNCR.

| Data Inputs   |
|---|
| Enter the following data for your combustion unit:  |
| Is the combustion unit a utility or industrial boiler? What type of fuel does the unit burn? Coal   |
| Is the SNCR for a new boiler or retrofit of an existing boiler?   |
| 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. |

#### Complete all of the highlighted data fields:

Inlet  $NO_x$  Emissions ( $NOx_{in}$ ) to SNCR

 $\mathsf{Oulet}\ \mathsf{NO}_x\ \mathsf{Emissions}\ (\mathsf{NO}x_{\mathsf{out}})\ \mathsf{from}\ \mathsf{SNCR}$ 

Estimated Normalized Stoichiometric Ratio (NSR)

|   |   | Provide the following information for coal-fired boilers:   |
|---|---|---|
| What is the maximum heat input rate (QB)?             | 472.4 MMBtu/hour  | Type of coal burned: Sub-Bituminous   |
| What is the higher heating value (HHV) of the fuel?   | 9,152 Btu/lb  | Enter the sulfur content (%S) = 0.28 percent by weight  |
| What is the estimated actual annual fuel consumption? | 323,950,000 lbs/year  | or<br>Select the appropriate SO <sub>2</sub> emission rate:<br>Ash content (%Ash):<br>5.84 percent by weight  |
| Is the boiler a fluid-bed boiler?                     | No 🔻  | *The ash content of 5.84% is a default value. See below for data source. Enter actual value, if<br>known.   |
|   |   | For units burning coal blends:  |
| Enter the net plant heat input rate (NPHR)            | 10 MMBtu/MW   | Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please<br>enter the actual values for these parameters in the table below. If the actual value for any<br>parameter is not known, you may use the default values provided.   |
| If the NPHR is not known, use the default NPHR value: | Euel Type         Default NPHR           Coal         10 MM8tu/MW           Fuel Oil         11 MM8tu/MW           Natural Gas         8.2 MM8tu/MW | Financial     according     accor |
| Enter the following design parameters for the propos  | ed SNCR:  |   |
| Number of days the SNCR operates $(t_{\mbox{sNCR}})$  | 314 days  | Plant Elevation 1,100 Feet above sea level  |

The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution

ontrol Cost Manual (as updated March 2019).

Concentration of reagent as stored (C<sub>stored</sub>) 50 Percent Density of reagent as stored (p<sub>stored</sub>) 71 lb/ft<sup>3</sup> Concentration of reagent injected (G<sub>nj</sub>) Densities of typical SNCR reagents: 10 percent Number of days reagent is stored (t<sub>storage</sub>) 14 days 50% urea solution 71 lbs/ft<sup>3</sup> Estimated equipment life 20 Years 29.4% aqueous NH<sub>3</sub> 56 lbs/ft<sup>3</sup> Ŧ Select the reagent used Urea

0.48 lb/MMBtu 0.30 lb/MMBtu

1.30

Nbarr.com/projects/Mpis/23 MN/65/2365011/WorkFiles/Air Permitting/Regional Haze/2020 Cost Review/Appendix A - Control Cost Analysis for NOx and SO2.xlsm SNCR Data Inputs

| Enter the cost data for the proposed SNCR:                        |  |   |
|---|--|---|
| Desired dollar-year   | 2020   |   |
| CEPCI for 2020  | 607.5 2019 Final CEPCI Value 541.7 2016 CEPCI    | CEPCI = Chemical Engineering Plant Cost Index |
|   |  |   |
| Annual Interest Rate (i)  | 5.50 Percent*                                    |   |
| Fuel (Cost <sub>fuel</sub> )                                      | 2.13 \$/MMBtu                                    |   |
| Reagent (Cost <sub>reag</sub> )                                   | 1.81 \$/gallon for a 50 percent solution of urea |   |
| Water (Cost <sub>water</sub> )                                    | 0.0051 \$/gallon                                 |   |
| Electricity (Cost <sub>elect</sub> )                              | 0.0796 \$/kWh                                    |   |
| Ash Disposal (for coal-fired boilers only) (Cost <sub>ash</sub> ) | 63.34 \$/ton                                     |   |

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) =<br>Administrative Charges Factor (ACF) = | 0.015 |  |  |

#### 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 (S/gallon)                    |               | Jourtes for Verlault Value<br>U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector<br>Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and<br>Performance for APC Technologies, SNCR Cost Development Methodology, Chapter<br>5, Attachment 5-4, January 2017. Available at:<br>https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4,<br>_s.ncr_cost_development_methodology.pdf. | used and the reference source   |
| Water Cost (\$/gallon)                     | 0.00417       | Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see<br>2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at<br>http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-<br>brochure-water-watewater-rate-survey.pdf.  |   |
|  |               |   | Refer to the Utility Chem\$ Data tab  |
| Electricity Cost (\$/kWh)                  | 0.0676        | U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published<br>December 2017. Available at:<br>https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.   |   |
|  |               |   | Refer to the Utility Chem\$ Data tab  |
| Fuel Cost (\$/MMBtu)                       | 1.89          | U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4.<br>Published December 2017. Available at:<br>https://www.eia.gov/electricity/annual/pdf/epa.pdf.   |   |
|  |               |   | Refer to the Utility Chem\$ Data tab  |
| Ash Disposal Cost (\$/ton)                 | 48.8          | Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft<br>Demand. July 11, 2017. Available at:<br>http://www.wastebusinessjournal.com/news/wbj20170711A.htm.   |   |
|  |               |   | Refer to the Utility Chem\$ Data tab  |
| Percent sulfur content for Coal (% weight) | 0.41          | Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy<br>Information Administration (EIA) from data reported on EIA Form EIA-923, Power<br>Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.   |   |
|  |               |   | Average of 2015-2019 data   |
| Percent ash content for Coal (% weight)    | 5.84          | Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy<br>Information Administration (EIA) from data reported on EIA Form EIA-923, Power<br>Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.  |   |
|  |               |   | Used default  |
| Higher Heating Value (HHV) (Btu/lb)        | 8,826         | 2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S.<br>Energy Information Administration (EIA) from data reported on EIA Form EIA-923,<br>Power Plant Operations Report. Available at<br>http://www.eia.gov/electricity/data/eia923/.   |   |
|  |               |   | Average of 2015-2019 data   |
| nterest Rate (%)                           | 5.5           | Default bank prime rate   | Used default  |

## **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 <sub>B</sub> ) =         | HHV x Max. Fuel Rate =   | 472              | MMBtu/hour |
| Maximum Annual fuel consumption (mfuel) =                  | (QB x 1.0E6 Btu/MMBtu x 8760)/HHV =  | 452,166,084      | lbs/year   |
| Actual Annual fuel consumption (Mactual) =                 |  | 323,950,000      | lbs/year   |
| Heat Rate Factor (HRF) =                                   | NPHR/10 =  | 1.00             |            |
| Total System Capacity Factor (CF <sub>total</sub> ) =      | (Mactual/Mfuel) x (tSNCR/365) =  | 0.62             | fraction   |
| Total operating time for the SNCR $(t_{op})$ =             | CF <sub>total</sub> x 8760 =   | 7536             | hours      |
| NOx Removal Efficiency (EF) =                              | (NOx <sub>in</sub> - NOx <sub>out</sub> )/NOx <sub>in</sub> =  | 38               | percent    |
| NOx removed per hour =                                     | $NOx_{in} \times EF \times Q_B =$  | 85.03            | lb/hour    |
| Total NO <sub>x</sub> removed per year =                   | (NOx <sub>in</sub> x EF x Q <sub>B</sub> x t <sub>op</sub> )/2000 =                                    | 340.10           | 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) | 1.05             |            |
| 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 =  | 1.04             |            |
| Atmospheric pressure at 1100 feet above sea level<br>(P) = | 2116x[(59-(0.00356xh)+459.7)/518.6] <sup>5.256</sup> x (1/144)*<br>=                                   | 14.1             | psia       |
| Retrofit Factor (RF) =                                     | Retrofit to existing boiler  | 1.50             |            |

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Urea

### **Reagent Data:**

Molecular Weight of Reagent (MW) = 60.06 g/mole Density =

71 lb/gallon

| Parameter  | Equation  | Calculated Value | Units  |
|--|---|------------------|--|
| Reagent consumption rate (m <sub>reagent</sub> ) = | $(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR) =$     | 192              | lb/hour  |
|  | (whre SR = 1 for $NH_3$ ; 2 for Urea)                                     |                  |  |
| Reagent Usage Rate (m <sub>sol</sub> ) =           | m <sub>reagent</sub> /C <sub>sol</sub> =                                  | 384              | lb/hour  |
|  | (m <sub>sol</sub> x 7.4805)/Reagent Density =                             |                  | gal/hour   |
| Estimated tank volume for reagent storage =        | (m <sub>sol</sub> x 7.4805 x t <sub>storage</sub> x 24 hours/day)/Reagent | 12 600           | gallons (storage needed to store a 14 day reagent supply |
|  | Density =   | 15,000           | rounded up to the nearest 100 gallons)                   |

### **Capital Recovery Factor:**

| Parameter                       | Equation                                      | Calculated Value |
|---------------------------------|---|------------------|
| Capital Recovery Factor (CRF) = | $i(1+i)^{n}/(1+i)^{n} - 1 =$                  | 0.0837           |
|                                 | Where n = Equipment Life and i= Interest Rate |                  |

| Parameter  | Equation   | Calculated Value | Units        |
|--|--|------------------|--------------|
| Electricity Usage:   |  |                  |              |
| Electricity Consumption (P) =  | (0.47 x NOx <sub>in</sub> x NSR x Q <sub>8</sub> )/NPHR =        | 13.8             | kW/hour      |
| Water Usage:   |  |                  |              |
| Water consumption (q <sub>w</sub> ) =  | $(m_{sol}/Density of water) \times ((C_{stored}/C_{inj}) - 1) =$ | 184              | gallons/hour |
| Fuel Data:   |  |                  |              |
| Additional Fuel required to evaporate water in<br>injected reagent (ΔFuel) = | Hv x $m_{reagent}$ x ((1/ $C_{inj}$ )-1) =                       | 1.55             | MMBtu/hour   |
|  |  |                  |              |
| Ash Disposal:  |  |                  |              |
| Additional ash produced due to increased fuel consumption ( $\Delta$ ash) =  | (Δfuel x %Ash x 1x10 <sup>6</sup> )/HHV =                        | 9.9              | 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:          |  |
|  | $TCI = 1.3 x (SNCR_{cost} + BOP_{cost})$                   |
| Capital costs for the SNCR (SNCR <sub>cost</sub> ) = | \$2,040,438 in 2020 dollars                                |
| Air Pre-Heater Costs (APH <sub>cost</sub> )* =       | \$0 in 2020 dollars  |
| Balance of Plant Costs (BOP <sub>cost</sub> ) =      | \$3,274,167 in 2020 dollars                                |
| Total Capital Investment (TCI) =                     | \$6,908,987 in 2020 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<sub>cost</sub>)

For Coal-Fired Utility Boilers:

 $SNCR_{cost} = 220,000 \ x \ (B_{MW} \ x \ HRF)^{0.42} \ x \ CoalF \ x \ BTF \ x \ ELEVF \ x \ RF$ For Fuel Oil and Natural Gas-Fired Utility Boilers:

SNCR<sub>cost</sub> = 147,000 x (B<sub>MW</sub> x HRF)<sup>0.42</sup> x ELEVF x 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<sub>cost</sub>) =

\$2,040,438 in 2020 dollars

| Air Pre-Heater Costs (APH <sub>cost</sub> )*                                       |  |  |
|--|--|--|
| For Coal-Fired Utility Boilers:  |  |  |
| APH <sub>cos</sub>   | <sub>t</sub> = 69,000 x (B <sub>MW</sub> x HRF x CoalF) <sup>0.78</sup> x AHF x RF               |  |
| For Coal-Fired Industrial Boilers:   |  |  |
| APH <sub>cost</sub> =  | = 69,000 x (0.1 x Q <sub>8</sub> x HRF x CoalF) <sup>0.78</sup> x AHF x RF                       |  |
|  |  |  |
| Air Pre-Heater Costs (APH <sub>cost</sub> ) =                                      | \$0 in 2020 dollars  |  |
| * Not applicable - This factor applies only to coal-fired bo<br>of sulfur dioxide. | ilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu                      |  |
|  | Balance of Plant Costs (BOP <sub>cost</sub> )  |  |
| For Coal-Fired Utility Boilers:  |  |  |
| BOP <sub>cost</sub> = 32   | $0,000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$              |  |
| For Fuel Oil and Natural Gas-Fired Utility Boilers:                                |  |  |
| BOP <sub>cost</sub> =  | 213,000 x (B <sub>MW</sub> ) <sup>0.33</sup> x (NO <sub>x</sub> Removed/hr) <sup>0.12</sup> x RF |  |
| For Coal-Fired Industrial Boilers:   |  |  |
| BOP <sub>cost</sub> = 320,   | 000 x $(0.1 \text{ x } Q_B)^{0.33}$ x $(NO_x \text{Removed/hr})^{0.12}$ x BTF x RF               |  |
|  |  |  |

For Fuel Oil and Natural Gas-Fired Industrial Boilers:  $BOP_{cost} = 213,000 \ x \ (Q_B/NPHR)^{0.33} \ x \ (NO_x Removed/hr)^{0.12} \ x \ RF$ 

Balance of Plant Costs (BOP<sub>cost</sub>) =

\$3,274,167 in 2020 dollars

\barr.com\projects\Mpls\23 MN\65\2365011\WorkFiles\Air Permitting\Regional Haze\2020 Cost Review\Appendix A - Control Cost Analysis for NOx and SO2.xlsm SNCR Summary

### Annual Costs

#### Total Annual Cost (TAC) TAC = Direct Annual Costs + Indirect Annual Costs

| Direct Annual Costs (DAC) =           | \$699,187 in 2020 dollars   |
|---------------------------------------|-----------------------------|
| Indirect Annual Costs (IDAC) =        | \$581,391 in 2020 dollars   |
| Total annual costs (TAC) = DAC + IDAC | \$1,280,578 in 2020 dollars |

#### Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

| Annual Maintenance Cost = | 0.015 x TCI =  | \$103,635 in 2020 dollars |
|---------------------------|--|---------------------------|
| Annual Reagent Cost =     | q <sub>sol</sub> x Cost <sub>reag</sub> x t <sub>op</sub> =    | \$552,860 in 2020 dollars |
| Annual Electricity Cost = | $P \times Cost_{elect} \times t_{op} =$                        | \$8,291 in 2020 dollars   |
| Annual Water Cost =       | q <sub>water</sub> x Cost <sub>water</sub> x t <sub>op</sub> = | \$7,111 in 2020 dollars   |
| Additional Fuel Cost =    | $\Delta$ Fuel x Cost <sub>fuel</sub> x t <sub>op</sub> =       | \$24,922 in 2020 dollars  |
| Additional Ash Cost =     | $\Delta Ash x Cost_{ash} x t_{op} x (1/2000) =$                | \$2,368 in 2020 dollars   |
| Direct Annual Cost =      |  | \$699,187 in 2020 dollars |

### Indirect Annual Cost (IDAC)

#### IDAC = Administrative Charges + Capital Recovery Costs

| Administrative Charges (AC) = | 0.03 x Annual Maintenance Cost = | \$3,109 in 2020 dollars   |
|-------------------------------|----------------------------------|---------------------------|
| Capital Recovery Costs (CR)=  | CRF x TCI =                      | \$578,282 in 2020 dollars |
| Indirect Annual Cost (IDAC) = | AC + CR =                        | \$581,391 in 2020 dollars |

#### Cost Effectiveness

#### Cost Effectiveness = Total Annual Cost/ NOx Removed/year

| Total Annual Cost (TAC) = | \$1,280,578 per year in 2020 dollars           |
|---------------------------|--|
| NOx Removed =             | 340 tons/year                                  |
| Cost Effectiveness =      | \$3,765 per ton of NOx removed in 2020 dollars |

# Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 7: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

Boiler 1

Operating Unit:

| Emission Unit Number   | EQUI17 |          | Stack/Vent Number      | STRU25  |               |
|------------------------|--------|----------|------------------------|---------|---------------|
| Design Capacity        | 472    | MMBtu/hr | Standardized Flow Rate | 123,889 | scfm @ 32° F  |
| Utilization Rate       | 100%   |          | Temperature            | 370     | Deg F         |
| Annual Operating Hours | 7,536  |          | Moisture Content       | 11.8%   |               |
| Annual Interest Rate   | 5.5%   |          | Actual Flow Rate       | 209,000 | acfm          |
| Equipment Life         | 20     |          | Standardized Flow Rate |         | scfm @ 68° F  |
|                        |        |          | Dry Std Flow Rate      | 117,332 | dscfm @ 68° F |

#### CONTROL EQUIPMENT COSTS

| Capital Costs                            |                 |                  |                     |                 |                   |   |            |
|--|-----------------|------------------|---------------------|-----------------|-------------------|---|------------|
| Direct Capital Costs                     |                 |                  |                     |                 |                   |   |            |
| Purchased Equipment (A)                  |                 |                  |                     |                 |                   |   | 20,384,880 |
| Purchased Equipment Total (B             | 22%             | of control devic | e cost (A           |                 |                   |   | 24,844,072 |
| Installation - Standard Costs            | 74%             | of purchased e   | quip cost (B)       |                 |                   |   | 18,384,613 |
| Installation - Site Specific Costs       |                 |                  |                     |                 |                   |   | NA         |
| Installation Total                       |                 |                  |                     |                 |                   |   | 18,384,61  |
| Total Direct Capital Cost, DC            |                 |                  |                     |                 |                   |   | 43,228,685 |
| Total Indirect Capital Costs, IC         | 52%             | of purchased e   | quip cost (B)       |                 |                   |   | 12,918,917 |
| Total Capital Investment (TCI) = DC + IC |                 |                  | 1                   |                 |                   |   | 56,147,60  |
| Adjusted TCI for Replacment Parts        |                 |                  |                     |                 |                   |   | 55,294,65  |
| TCI with Retrofit Factor                 |                 |                  |                     |                 |                   |   | 82,941,97  |
| Operating Costs                          |                 |                  |                     |                 |                   |   |            |
| Total Annual Direct Operating Cost:      |                 | Labor, supervis  | sion, materials, re | eplacement pa   | rts, utilities, e | t | 1,086,03   |
| Total Annual Indirect Operating Costs    |                 | Sum indirect op  | per costs + capita  | al recovery cos | t                 |   | 10,622,073 |
| Total Annual Cost (Annualized Capital Co | ost + Operating | Cost             |                     |                 |                   |   | 11,708,110 |

#### Emission Control Cost Calculation

|                                   | Max Emis | Annual | Cont Eff | Exit  | Conc. | Cont Emis | Reduction | Cont Cost  |
|-----------------------------------|----------|--------|----------|-------|-------|-----------|-----------|------------|
| Pollutant                         | Lb/Hr    | T/Yr   | %        | Conc. | Units | T/yr      | T/yr      | \$/Ton Rem |
| PM10                              |          |        |          |       |       | 0.0       | -         | NA         |
| PM2.5                             |          |        |          |       |       | 0.0       | -         | NA         |
| Total Particulates                |          |        |          |       |       | 0.0       | -         | NA         |
| Nitrous Oxides (NOx)              |          |        |          |       |       | 0.0       | -         | NA         |
| Sulfur Dioxide (SO <sub>2</sub> ) |          | 785.8  | 90%      |       |       | 78.6      | 707.2     | 16,556     |
| Sulfuric Acid Mist                |          |        |          |       |       | 0.00      | -         | NA         |
| Fluorides                         |          |        |          |       |       | 0.0       | -         | NA         |
| Volatile Organic Compounds (VOC)  |          |        |          |       |       | 0.0       | -         | NA         |
| Carbon Monoxide (CO)              |          |        |          |       |       | 0.0       | -         | NA         |
| Lead (Pb)                         |          |        |          |       |       | 0.00      | -         | NA         |

 Notes & Assumptions

 1 Capital cost estimate based on flow rate of 300,000 sc/m from Northshore Mining Powerhouse #2 2006 BART submittal including anciliary equipment

 2 Costs acated up to design airflow using the 6/10 power law

 3 Costs acated up for Inflation using the Chemical Engineering Plant Cost Index (CEPCI)

 4 Calculations per EPA Air Polution Control Cost Manual 6% Ed 2002, Section 6 Chapter 1

\barr.com\projects\Mpls\23 MNI65/2365011\WorkFiles\Air Permitting\Regional Haze\2020 Cost Review\Appendix A - Control Cost Analysis for NOx and SO2 xlsm SDA Summary

# Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 7: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

#### CAPITAL COSTS

| Purchased Equipment (A) <sup>(1)</sup>  |  | 20,384,  |
|---|--|--|
| Purchased Equipment Costs (A) - Absorber  | + packing + auxiliary equipment, EC<br>10% of control device cost (A   | 2,038,   |
| State Sales Taxes   | 6.9% of control device cost (A   | 1.401.4  |
| Freight   | 5% of control device cost (A   | 1,019,   |
| Purchased Equipment Total (B)   | 22%  | 24,844,  |
| Installation  |  |  |
| Foundations & supports  | 4% of purchased equip cost (B)   | 993,   |
| Handling & erection   | 50% of purchased equip cost (B)  | 12,422,  |
| Electrical  | 8% of purchased equip cost (B)   | 1,987,   |
| Piping<br>Insulation  | 1% of purchased equip cost (B)<br>7% of purchased equip cost (B)   | 248,<br>1,739,   |
| Painting  | 4% of purchased equip cost (B)   | 993,   |
| Installation Subtotal Standard Expenses   | 74%  | 18,384,  |
| Other Specific Costs (see summary)  |  |  |
| Site Preparation, as required   | N/A Site Specific  |  |
| Buildings, as required  | N/A Site Specific  |  |
| Site Specific - Other   | N/A Site Specific  |  |
| Total Site Specific Costs   |  |  |
| Installation Total  |  | 18,384,  |
| Total Direct Capital Cost, DC   |  | 43,228,  |
| Indirect Capital Costs  | 10% of purchased equip cost (B)  | 2,484,   |
| Engineering, supervision<br>Construction & field expenses   | 20% of purchased equip cost (B)  | 2,464,<br>4,968,   |
| Construction & field expenses<br>Contractor fees  | 10% of purchased equip cost (B)  | 4,908, 2,484,  |
| Start-up  | 1% of purchased equip cost (B)   | 2,404,   |
| Performance test  | 1% of purchased equip cost (B)   | 248,   |
| Model Studies   | N/A of purchased equip cost (B)  |  |
| Contingencies   | 10% of purchased equip cost (B)  | 2,484,   |
| Total Indirect Capital Costs, IC  | 52% of purchased equip cost (B   | 12,918,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill  |  |  |
| al Capital Investment (TCI) = DC + IC   | er Bags, etc) for Capital Recovery Cos   | 55,294,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS   | er Bags, etc) for Capital Recovery Cos   | 55,294,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Filt<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC  | er Bags, etc) for Capital Recovery Cos   | 55,294,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor   | ter Bags, etc) for Capital Recovery Cos<br>50%   | <u>55,294,</u><br>82,941,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator   | ter Bags, etc) for Capital Recovery Cos<br>50%<br>67.53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr   | 55,294,<br>82,941,<br>127,   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor   | ter Bags, etc) for Capital Recovery Cos<br>50%   | 55,294,<br>82,941,<br>127,   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATINC COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance  | ter Bags, etc) for Capital Recovery Cos<br>50%<br>67.53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs  | 55,294,<br>82,941,<br>127,<br>19,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor   | er Bags, etc) for Capital Recovery Cos<br>50%<br>67.53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr   | 55,294,<br>82,941,<br>127,<br>19,<br>63,   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor   | er Bags, etc) for Capital Recovery Cos<br>50%<br>67.53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs  | 55,294,<br>82,941,<br>127.;<br>19,1<br>63,1  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fili<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity   | ter Bags, etc) for Capital Recovery Cos<br>50%<br>67.53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br><b>fanagement</b><br>0.08 \$/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization  | 55,294,<br>82,941,<br>127,<br>19,<br>63,<br>63,<br>226,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operation<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>Compresed Air   | er Bags, etc) for Capital Recovery Cos<br>50%<br>67.53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>Management  | 55,294,<br>82,941,<br>127,<br>19,<br>63,<br>63,<br>226,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fili<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operation<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>Compressed Air<br>N/A   | er Bags, etc) for Capital Recovery Cos<br>50%<br>67:53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br><b>fanagement</b><br>0.06 \$/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization   | 55,294,<br>82,941,<br>127,<br>19,<br>63,<br>63,<br>226,<br>90,   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fili<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operation<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal   | er Bags, etc) for Capital Recovery Cos<br>50%<br>67.53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>fanagement<br>0.08 \$/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/ksc1, 2.0 scfm/kacr/m, 7536 hr/yr, 100% utilization<br>63.34 \$/ton, 0.2 ton/hr, 7536 hr/yr, 100% utilization   | 55,294,<br>82,941,<br>127,<br>19,<br>63,<br>63,<br>226,<br>90,<br>99,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fili<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operation<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste &<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime  | er Bags, etc) for Capital Recovery Cos<br>50%<br>67:53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>68:54 \$/Hr, 10 hr/8 hr/9, 100% utilization<br>0.48 \$/kscf, 2.0 cdm/kr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization  | 55,294,<br>82,941,<br>127,<br>19,<br>63,<br>63,<br>226,<br>90,<br>99,<br>195,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fili<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operation<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilites, Supples, Replacements & Waste &<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags  | er Bags, etc) for Capital Recovery Cos<br>50%<br>67.53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67.53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>fanagement<br>0.08 \$/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/ksc1, 2.0 scfm/kacr/m, 7536 hr/yr, 100% utilization<br>63.34 \$/ton, 0.2 ton/hr, 7536 hr/yr, 100% utilization   | 55,294,<br>82,941,<br>127,<br>19,<br>63,<br>63,<br>226,<br>90,<br>99,<br>195,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fili<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operation<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>N/A   | er Bags, etc) for Capital Recovery Cos<br>50%<br>67:53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>68:54 \$/Hr, 10 hr/8 hr/9, 100% utilization<br>0.48 \$/kscf, 2.0 cdm/kr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization  | 55,294,<br>82,941,<br>127,<br>19,<br>63,<br>63,<br>226,<br>90,<br>99,<br>195,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fili<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operation<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilites, Supples, Replacements & Waste &<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags  | er Bags, etc) for Capital Recovery Cos<br>50%<br>67:53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>68:54 \$/Hr, 10 hr/8 hr/9, 100% utilization<br>0.48 \$/kscf, 2.0 cdm/kr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization  | 55,294,<br>82,941,<br>127,<br>19,<br>63,<br>63,<br>226,<br>90,<br>99,<br>195,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fili<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operation<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supples, Replacements & Waste &<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>N/A   | er Bags, etc) for Capital Recovery Cos<br>50%<br>67:53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>68:54 \$/Hr, 10 hr/8 hr/9, 100% utilization<br>0.48 \$/kscf, 2.0 cdm/kr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization  | 55,294,<br>82,941,<br>127.;<br>19,<br>63,<br>63,<br>226;<br>90;<br>99.;<br>195.  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A   | er Bags, etc) for Capital Recovery Cos<br>50%<br>67:53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>68:54 \$/Hr, 10 hr/8 hr/9, 100% utilization<br>0.48 \$/kscf, 2.0 cdm/kr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization  | 55,294,<br>82,941,<br>127.;<br>19,<br>63,<br>63,<br>226;<br>90;<br>99.;<br>195.  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fili<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operation<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste N<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A   | er Bags, etc) for Capital Recovery Cos<br>50%<br>67:53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>68:54 \$/Hr, 10 hr/8 hr/9, 100% utilization<br>0.48 \$/kscf, 2.0 cdm/kr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization  | 56,147,<br>55,294,<br>82,941,<br>127,<br>197,<br>197,<br>197,<br>197,<br>197,<br>197,<br>199,<br>199   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fili<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A  | er Bags, etc) for Capital Recovery Cos<br>50%<br>67:53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>68:54 \$/Hr, 10 hr/8 hr/9, 100% utilization<br>0.48 \$/kscf, 2.0 cdm/kr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization  | 55,294,<br>82,941,<br>127,<br>19,<br>63,<br>63,<br>63,<br>63,<br>63,<br>90()<br>99,<br>99,<br>195,<br>199,   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fili<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operation<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste N<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A   | er Bags, etc) for Capital Recovery Cos<br>50%<br>67:53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br>15% 15% of Operator Costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>67:53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br>100% of maintenance labor costs<br>68:54 \$/Hr, 10 hr/8 hr/9, 100% utilization<br>0.48 \$/kscf, 2.0 cdm/kr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization<br>138:68 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization  | 55,284,<br>82,941,<br>1277, 19,<br>63,<br>63,<br>90,<br>99,<br>195,<br>199,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste N<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A  | <ul> <li>ter Bags, etc) for Capital Recovery Cos</li> <li>50%</li> <li>67,53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr</li> <li>15% 15% of Operator Costs</li> <li>67,53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr</li> <li>100% of maintenance labor costs</li> <li>8angement</li> <li>0.08 \$/kwh, 378.3 kW-4r, 7536 hr/yr, 100% utilization</li> <li>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization</li> <li>63.4 \$/kscf, 20.2 Schm/kr, 7536 hr/yr, 100% utilization</li> <li>28.60 \$/toag, 3.072 bags, 7536 hr/yr, 100% utilization</li> </ul>   | 55,284,<br>82,941,<br>127,<br>19,<br>63,<br>63,<br>90,<br>90,<br>195,<br>199,<br>105,<br>199,  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fili<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>Total Annual Direct Operating Costs<br>Overhead  | <ul> <li>branch and a straight of the straight</li></ul> | 55,284,<br>82,941,<br>127.,<br>19,<br>63,<br>63,<br>90,<br>99,<br>195,<br>199,<br>1,086,<br>104,<br>104,<br>104,<br>104,<br>104,<br>104,<br>104,<br>104,<br>104,<br>104,<br>104,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>105,<br>10 |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>Compresed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A   | <ul> <li>Bargs, etc) for Capital Recovery Cos</li> <li>50%</li> <li>67.53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr</li> <li>15% 15% of Operator Costs</li> <li>67.53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr</li> <li>100% of maintenance labor costs</li> <li>8anagement</li> <li>0.08 \$/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization</li> <li>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization</li> <li>63.34 \$/hon, 0.2 ton/hr, 7536 hr/yr, 100% utilization</li> <li>28.48 \$/hon, 2.82.2 lb/hr, 7536 hr/yr, 100% utilization</li> <li>28.49 \$/hoag, 3.072 bags, 7536 hr/yr, 100% utilization</li> <li>60% of total labor and material costs</li> <li>2% of total labor and material costs</li> </ul>  | 55,294,<br>82,941,<br>127,<br>194,<br>63,<br>63,<br>63,<br>226,<br>90,<br>90,<br>195,<br>199,<br>199,<br>199,<br>1,086,<br>164,<br>1,688,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>164,<br>1 |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supples, Replacements & Waste M<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A   | <ul> <li>Bags, etc) for Capital Recovery Cos</li> <li>50%</li> <li>67,53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr</li> <li>15% 15% of Operator Costs</li> <li>67,53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr</li> <li>100% of maintenance labor costs</li> <li>67,53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr</li> <li>0.08 \$/kwh, 378.3 k/V-hr, 7536 hr/yr, 100% utilization</li> <li>0.48 \$/kwh, 378.3 k/V-hr, 7536 hr/yr, 100% utilization</li> <li>0.48 \$/kwh, 22 br/hr, 7536 hr/yr, 100% utilization</li> <li>0.48 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization</li> <li>183.68 \$/no, 28.2 b/hr, 7536 hr/yr, 100% utilization</li> <li>28.02 \$/bag, 3.072 bags, 7536 hr/yr, 100% utilization</li> <li>60% of total labor and material costs</li> <li>2% of total appila costs (TCI)</li> <li>1% of total capilal costs (TCI)</li> </ul>  | 55,284,<br>82,941,<br>127,<br>19,<br>63,<br>63,<br>90,<br>99,<br>195,<br>199,<br>1,086,<br>14,4,<br>1,688,<br>829,2  |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>Compresed Air<br>N/A<br>SWD Ispocal<br>Lime<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs) | <ul> <li>Bags, etc) for Capital Recovery Cos</li> <li>50%</li> <li>67.53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr<br/>15% 15% of Operator Costs</li> <li>67.53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr<br/>100% of maintenance labor costs</li> <li>87.83 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr, 100% utilization</li> <li>0.8 \$/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization</li> <li>0.8 \$/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization</li> <li>63.34 \$/hon, 0.2 kon/hr, 7536 hr/yr, 100% utilization</li> <li>183.68 \$/hon, 28.2 Lb/hr, 7536 hr/yr, 100% utilization</li> <li>28.02 \$/bag, 3.072 bags, 7536 hr/yr, 100% utilization</li> <li>60% of total labor and material costs</li> <li>2% of total capital costs (TCI)</li> <li>1% of total capital costs (TCI)</li> <li>1% of total capital costs (TCI)</li> </ul>  | 55,294,<br>82,941,<br>127.<br>191,<br>63,<br>63,<br>90,<br>90,<br>99,<br>195,<br>199,<br>199,<br>199,<br>10,086,<br>829,<br>829,<br>829,<br>829,<br>829,<br>829,<br>829,<br>829,<br>829,<br>829,<br>829,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>82,941,<br>83,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,<br>84,941,941,9451,9451   |
| al Capital Investment (TCI) = DC + IC<br>usted TCI for Replacement Parts (Catalyst, Fill<br>al Capital Investment (TCI) with Retrofit Factor<br>ERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supples, Replacements & Waste M<br>Electricity<br>Compressed Air<br>N/A<br>SW Disposal<br>Lime<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A   | <ul> <li>Bags, etc) for Capital Recovery Cos</li> <li>50%</li> <li>67,53 \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr</li> <li>15% 15% of Operator Costs</li> <li>67,53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr</li> <li>100% of maintenance labor costs</li> <li>67,53 \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr</li> <li>0.08 \$/kwh, 378.3 k/V-hr, 7536 hr/yr, 100% utilization</li> <li>0.48 \$/kwh, 378.3 k/V-hr, 7536 hr/yr, 100% utilization</li> <li>0.48 \$/kwh, 22 br/hr, 7536 hr/yr, 100% utilization</li> <li>0.48 \$/kon, 0.2 ton/hr, 7536 hr/yr, 100% utilization</li> <li>183.68 \$/no, 28.2 b/hr, 7536 hr/yr, 100% utilization</li> <li>28.02 \$/bag, 3.072 bags, 7536 hr/yr, 100% utilization</li> <li>60% of total labor and material costs</li> <li>2% of total appila costs (TCI)</li> <li>1% of total capilal costs (TCI)</li> </ul>  | 55,294,<br>82,941,<br>127.;<br>19,<br>63,<br>63,<br>226;<br>90;<br>99.;<br>195.  |

# Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 7: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

| Primary Installation           |  |
|--------------------------------|--|
| Interest Rate                  | 5.50%  |
| Equipment Life                 | 20 years   |
| CRF                            | 0.0837   |
| Replacement Parts & Equipment: | Filter Bags  |
| Equipment Life                 | 5 years  |
| CRF                            | 0.2342   |
| Rep part cost per unit         | 228.02 \$/bag  |
| Amount Required                | 3072   |
| Total Rep Parts Cost           | 783,794 Cost adjusted for freight & sales tax  |
| Installation Labo              | 69,158 10 min per bag, Labor + Overhead (68% = \$29.65/h EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1 |
|                                |  |
| Total Installed Cost           | 852,952 Zero out if no replacement parts needed lists replacement times from 5 - 20 min per bag.             |

Electrical Use Flow acfm D P in H2O Efficiency Hp kW Incremental electricity increase over with baghouse replacin 2,850,793 scrubber including ducting 209,000 10.00 Blower, Baghouse 2,850,793 Total

#### Reagents and Other Operating Costs

1.30 lb-mole CaO/lb-mole SO2 Lime Use Rate 282.17 lb/hr Lime 1,572 ton/yr GSA unreacted sorbent and reaction byproducts Solid Waste Disposal

#### Operating Cost Calculations

| Utilization R                 | ate 100%      | Annual Ope      | erating Hours | 7,536         |           |               |   |
|-------------------------------|---------------|-----------------|---------------|---------------|-----------|---------------|---|
|                               | Unit          | Unit of         | Use           | Unit of       | Annual    | Annual        | Comments  |
| Item                          | Cost \$       | Measure         | Rate          | Measure       | Use*      | Cost          |   |
| Operating Labor               |               |                 |               |               |           |               |   |
| Op Labor                      | 67.5          | i3 \$/Hr        | 2.0 1         | nr/8 hr shift | 1,884     | \$<br>127,228 | \$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr                  |
| Supervisor                    | 15            | % of Op.        |               |               | NA        | \$<br>19,084  | 15% of Operator Costs                                 |
| Maintenance                   |               |                 |               |               |           |               |   |
| Maint Labor                   | 67.5          | i3 \$/Hr        | 1.0           | nr/8 hr shift | 942       | \$<br>63,614  | \$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr                  |
| Maint Mtls                    | 10            | 0 % of Maintena | ance Labor    |               | NA        | \$<br>63,614  | 100% of Maintenance Labor                             |
| Utilities, Supplies, Replacer | nents & Waste | Management      |               |               |           |               |   |
| Electricity                   | 0.08          | 0 \$/kwh        | 378.3         | W-hr          | 2,850,793 | \$<br>226,923 | \$/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization     |
| Compressed Air                | 0.48          | 1 \$/kscf       | 2 :           | scfm/kacfm    | 189,003   | \$<br>90,981  | \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization |
| Water                         | 5.12          | 9 \$/mgal       | 1             | 3pm           |           |               | \$/mgal, 0 gpm, 7536 hr/yr, 100% utilization          |
| SW Disposal                   | 63.3          | 4 \$/ton        | 0.21 1        | on/hr         | 1,572     | \$<br>99,558  | \$/ton, 0.2 ton/hr, 7536 hr/yr, 100% utilization      |
| Lime                          | 183.6         | i8 \$/ton       | 282.2         | b/hr          | 1,063     | \$<br>195,295 | \$/ton, 282.2 lb/hr, 7536 hr/yr, 100% utilization     |
| Filter Bags                   | 228.0         | 2 \$/bag        | 3,072         | bags          | N/A       | \$<br>199,741 | \$/bag, 3,072 bags, 7536 hr/yr, 100% utilization      |

#### Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 8: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

| Operating Unit:        | Boiler 1 |          |                          |         |               |
|------------------------|----------|----------|--------------------------|---------|---------------|
| Emission Unit Number   |          |          | Stack/Vent Number        |         |               |
| Design Capacity        | 472      | MMBtu/hr | Standardized Flow Rate   | 123,889 | scfm @ 32º F  |
| Utilization Rate       | 100%     |          | Exhaust Temperature      | 370     | Deg F         |
| Annual Operating Hours | 7,536    | hr/yr    | Exhaust Moisture Content | 11.8%   |               |
| Annual Interest Rate   | 5.50%    |          | Actual Flow Rate         | 209,000 | acfm          |
| Control Equipment Life | 20       | yrs      | Standardized Flow Rate   | 132,954 | scfm @ 68° F  |
| Plant Elevation        | 1100     | ft       | Dry Std Flow Rate        | 117,332 | dscfm @ 68º F |
|                        |          |          |                          |         |               |

#### CONTROL EQUIPMENT COSTS

| Capital Costs                                |                 |                      |                      |                       |       |            |
|--|-----------------|----------------------|----------------------|-----------------------|-------|------------|
| Direct Capital Costs                         |                 |                      |                      |                       |       |            |
| Purchased Equipment (A)                      |                 |                      |                      |                       |       | 9,026,849  |
| Purchased Equipment Total (B)                | 22%             | of control device of | ost (A)              |                       |       | 11,001,473 |
| Installation - Standard Costs                | 74%             | of purchased equip   | cost (B)             |                       |       | 8,141,090  |
| Installation - Site Specific Costs           |                 |                      |                      |                       |       | N/A        |
| Installation Total                           |                 |                      |                      |                       |       | 8,141,090  |
| Total Direct Capital Cost, DC                |                 |                      |                      |                       |       | 19,142,562 |
| Total Indirect Capital Costs, IC             | 52%             | of purchased equip   | cost (B)             |                       |       | 5,720,766  |
| Total Capital Investment (TCI) = DC + IC     |                 |                      |                      |                       |       | 24,010,376 |
| Adjusted TCI for Replacement Parts           |                 |                      |                      |                       |       | 24,010,376 |
| Total Capital Investment (TCI) with Retrofit | Factor          |                      |                      |                       |       | 36,015,563 |
| Operating Costs                              |                 |                      |                      |                       |       |            |
| Total Annual Direct Operating Costs          |                 | Labor, supervision   | , materials, replace | ment parts, utilities | , etc | 2,166,769  |
| Total Annual Indirect Operating Costs        |                 | Sum indirect oper    | costs + capital reco | overy cost            |       | 4,818,246  |
| Total Annual Cost (Annualized Capital Cost   | + Operating Cos | st)                  |                      |                       |       | 6,985,015  |

#### **Emission Control Cost Calculation**

|                                  | Max Emis | Annual | Cont Eff | Cont Emis | Reduction | Cont Cost  |
|----------------------------------|----------|--------|----------|-----------|-----------|------------|
| Pollutant                        | Lb/Hr    | Ton/Yr | %        | Ton/Yr    | Ton/Yr    | \$/Ton Rem |
| PM10                             |          |        |          |           |           |            |
| PM2.5                            |          |        |          |           |           |            |
| Total Particulates               |          |        |          |           |           |            |
| Nitrous Oxides (NOx)             |          |        |          |           |           |            |
| Sulfur Dioxide (SO2)             | 208.54   | 785.76 | 70%      | 235.73    | 550.03    | \$12,700   |
| Sulfuric Acid Mist (H2SO4)       |          |        |          |           |           |            |
| Fluorides                        |          |        |          |           |           |            |
| Volatile Organic Compounds (VOC) |          |        |          |           |           |            |
| Carbon Monoxide (CO)             |          |        |          |           |           |            |
| Lead (Pb)                        |          |        |          |           |           |            |

#### Notes & Assumptions

1 Capital cost estimate based on flow rate of 300,000 scfm from Northshore Mining Powerhouse #2 2006 BART submittal including anciliary equipment

Cost scaled up to design airflow using the 6/10 power law
 Cost scaled up to design airflow using the 6/10 power law
 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

### Southern Minnesota Beet Sugar Coop (SMBSC)

# Appendix A - Four-Factor Control Cost Analysis Table 8: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

#### CAPITAL COSTS

| Purchased Equipment (A) (1)  |   | 9,026,84   |
|--|---|--|
| Purchased Equipment Costs (A) - Injection Sy   |   |  |
| Instrumentation  | 10% Included in vendor estimate   | 902,68   |
| State Sales Taxes  | 6.9% of control device cost (A)   | 620,59   |
| Freight  | 5% of control device cost (A)   | 451,34   |
| Purchased Equipment Total (B)  | 22%   | 11,001,47  |
| Installation   | 10/ - f   | 440,05   |
| Foundations & supports   | 4% of purchased equip cost (B)  | 5,500,73   |
| Handling & erection<br>Electrical  | 50% of purchased equip cost (B)<br>8% of purchased equip cost (B)   | 5,500,73   |
| Piping   | 1% of purchased equip cost (B)  | 110,0  |
| Insulation   | 7% of purchased equip cost (B)  |  |
| Painting   | 4% Included in vendor estimate  | 770,10   |
| Painting<br>Installation Subtotal Standard Expenses  | 4% included in vendor estimate<br>74%   | 8,141,09   |
| Other Specific Costs (see summary)   |   |  |
|  | N/A Site Specific   |  |
| Site Preparation, as required<br>Buildings, as required  | N/A Site Specific   |  |
| Lost Production for Tie-In   | N/A Site Specific   |  |
| Total Site Specific Costs  |   | N  |
| Installation Total   |   | 8,141,0  |
| Total Direct Capital Cost, DC  |   | 19,142,5   |
| Indirect Capital Costs   |   |  |
| Engineering, supervision   | 10% of purchased equip cost (B)   | 1,100,14   |
| Construction & field expenses  | 20% of purchased equip cost (B)   | 2,200,2  |
| Contractor fees  | 10% of purchased equip cost (B)   | 1,100,14   |
| Start-up   | 1% of purchased equip cost (B)  | 110,0  |
| Performance test   | 1% of purchased equip cost (B)  | 110,0 <sup>-</sup>   |
| Model Studies  | N/A of purchased equip cost (B)   |  |
|  |   | 1,100,14   |
| Contingencies  | 10% of purchased equip cost (B)   | 1,100,1-   |
| Contingencies<br>Total Indirect Capital Costs, IC  | 10% of purchased equip cost (B)<br>52% of purchased equip cost (B)  | 5,720,76   |
|  |   |  |
| Total Indirect Capital Costs, IC   | 52% of purchased equip cost (B)   | 5,720,76<br>24,863,32  |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC   | 52% of purchased equip cost (B)   | 5,720,76   |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte   | 52% of purchased equip cost (B) r Bags, etc) for Capital Recovery Cost  | 5,720,76<br>24,863,33<br>24,010,33   |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ljusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor  | 52% of purchased equip cost (B) r Bags, etc) for Capital Recovery Cost  | 5,720,76<br>24,863,33<br>24,010,33   |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ljusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS  | 52% of purchased equip cost (B) r Bags, etc) for Capital Recovery Cost  | 5,720,76<br>24,863,33<br>24,010,33   |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>Ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC   | 52% of purchased equip cost (B) r Bags, etc) for Capital Recovery Cost  | 5,720,74<br>24,863,32<br>24,010,33<br>36,015,54  |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ljusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Supervisor   | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%  | 5,720,7<br>24,863,3<br>24,010,3<br>36,015,5<br>127,2   |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance   | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor   | 5,720,7/<br>24,863,3:<br>24,010,3'<br>36,015,5/<br>127,2:<br>19,0'   |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ljusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operation<br>Supervisor<br>Maintenance<br>Maintenance Labor   | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr  | 5,720,74<br>24,863,33<br>24,010,33<br>36,015,54<br>127,22<br>19,00<br>63,6   |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials  | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor  | 5,720,7/<br>24,863,3:<br>24,010,3:<br>36,015,5/<br>127,2:<br>19,0/<br>63,6   |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ljusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor  | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor  | 5,720,77<br>24,863,33<br>24,010,3<br>36,015,59<br>127,22<br>19,00<br>63,6<br>63,6  |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br><b>PERATING COSTS</b><br>Direct Annual Operating Costs, DC<br><b>Operating Labor</b><br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>N/A   | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization   | 5,720,77<br>24,863,33<br>24,010,3<br>36,015,50<br>127,22<br>19,00<br>63,6<br>63,6<br>136,11  |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>tjusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Costs<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>N/A<br>Compressed Air   | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement   | 5,720,77<br>24,863,33<br>24,010,3<br>36,015,50<br>127,22<br>19,00<br>63,6<br>63,6<br>136,11  |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br><b>PERATING COSTS</b><br>Direct Annual Operating Costs, DC<br><b>Operating Labor</b><br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>N/A   | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization   | 5,720,77<br>24,863,3<br>24,010,3<br>36,015,51<br>127,2<br>19,0<br>63,6<br>63,6<br>136,1<br>90,9  |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>N/A<br>Compressed Air<br>N/A  | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization   | 5,720,71<br>24,863,3<br>24,010,3<br>36,015,5<br>127,2<br>19,0<br>63,6<br>63,6<br>136,11<br>90,9<br>90,9<br>222,1   |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>Ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>N/A<br>Compressed Air<br>N/A<br>Solid Waste Disposal   | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization<br>63.34 \$/hon, 0.5 tor/hr, 7536 hr/yr, 100% utilization   | 5,720,71<br>24,863,3<br>24,010,3<br>36,015,51<br>127,2<br>19,0<br>63,6<br>63,6<br>136,1<br>90,9<br>202,1<br>1,244,2  |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>N/A<br>Compressed Air<br>N/A<br>Solid Waste Disposal<br>Trona   | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization<br>63.34 \$/hon, 0.5 ton/hr, 7536 hr/yr, 100% utilization   | 5,720,71<br>24,863,3<br>24,010,3<br>36,015,51<br>127,2<br>19,0<br>63,6<br>63,6<br>136,1<br>90,9<br>202,1<br>1,244,2  |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>Ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Costs<br>Supervisor<br>Maintenance Labor<br>Maintenance Labor<br>M | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization<br>63.34 \$/hon, 0.5 ton/hr, 7536 hr/yr, 100% utilization   | 5,720,7/<br>24,863,3:<br>24,010,3:<br>36,015,54<br>127,22<br>19,00<br>63,6<br>63,6<br>136,1!<br>90,9<br>222,1!<br>1,244,2'   |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>N/A<br>Compressed Air<br>N/A<br>Solid Waste Disposal<br>Trona<br>Filter Bags<br>N/A   | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization<br>63.34 \$/hon, 0.5 ton/hr, 7536 hr/yr, 100% utilization   | 5,720,71<br>24,863,3<br>24,010,3<br>36,015,51<br>127,2<br>19,0<br>63,6<br>63,6<br>136,1<br>90,9<br>202,1<br>1,244,2  |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Aderials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>N/A<br>Solid Waste Disposal<br>Trona<br>Filter Bags<br>N/A<br>N/A  | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization<br>63.34 \$/hon, 0.5 ton/hr, 7536 hr/yr, 100% utilization   | 5,720,71<br>24,863,3<br>24,010,3<br>36,015,51<br>127,2<br>19,0<br>63,6<br>63,6<br>136,1<br>90,9<br>202,1<br>1,244,2  |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Costs, DC<br>Operating Costs, DC  | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization<br>63.34 \$/hon, 0.5 ton/hr, 7536 hr/yr, 100% utilization   | 5,720,74<br>24,863,33<br>24,010,33<br>36,015,54<br>127,22<br>19,00<br>63,6<br>63,6<br>136,14<br>90,94<br>222,11<br>1,244,2*<br>199,74  |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>Ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Costs<br>Maintenance Labor<br>Maintenance Labor   | 52% of purchased equip cost (B)<br>rr Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization<br>63.34 \$/ton, 0.5 ton/hr, 7536 hr/yr, 100% utilization<br>228.02 \$/toag, 3.072 bags, 7536 hr/yr, 100% utilization  | 5,720,77<br>24,863,33<br>24,010,3<br>36,015,59<br>127,22<br>19,00<br>63,6<br>63,6<br>136,11<br>90,9<br>222,11<br>1,244,2<br>199,74   |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Costs<br>Upervisor<br>Maintenance<br>Maintenance<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>NIA<br>Compressed Air<br>NIA<br>Solid Waste Disposal<br>Trona<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A  | 52% of purchased equip cost (B)<br>r Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization<br>63.34 \$/hon, 0.5 ton/hr, 7536 hr/yr, 100% utilization   | 5,720,77<br>24,863,3:<br>24,010,3<br>36,015,57<br>127,2<br>19,0<br>63,6<br>63,6<br>136,11<br>90,9<br>222,11<br>1,244,2<br>199,7<br>2,166,77  |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>Ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Costs<br>Maintenance Labor<br>Maintenance Labor   | 52% of purchased equip cost (B)<br>rr Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization<br>63.34 \$/ton, 0.5 ton/hr, 7536 hr/yr, 100% utilization<br>228.02 \$/toag, 3.072 bags, 7536 hr/yr, 100% utilization  | 5,720,77<br>24,863,3<br>24,010,3<br>36,015,57<br>127,22<br>19,0<br>63,6<br>63,6<br>136,11<br>90,9<br>222,11<br>1,244,2<br>199,7<br>2,166,77<br>164,11  |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operating Labor<br>Operating Costs<br>Supervisor<br>Maintenance<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>N/A<br>Compressed Air<br>N/A<br>Solid Waste Disposal<br>Trona<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>N/A<br>Total Annual Direct Operating Costs<br>Overhead  | 52% of purchased equip cost (B)<br>rr Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>1.50 % of Mailtoenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization<br>285.00 \$/kon, 1.158.8 hr/yr, 7306 hr/yr, 100% utilization<br>285.00 \$/kon, 1.158.8 hr/yr, 7306 hr/yr, 100% utilization<br>285.00 \$/kon, 1.158.8 hr/yr, 7366 hr/yr, 100% utilization<br>28.02 \$/bag, 3.072 bags, 7536 hr/yr, 100% utilization  | 5,720,77<br>24,863,3:<br>24,010,3<br>36,015,57<br>127,2:<br>19,07<br>63,6<br>63,6<br>136,11<br>90,99<br>222,1:<br>1,244,2<br>199,72<br>2,166,77<br>164,11<br>720,3   |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>Ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Labor<br>Maintenance Kerlas<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>N/A<br>Solid Waste Disposal<br>Trona<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>Total Annual Direct Operating Costs<br>Overhead<br>Administration (2% total capital costs)  | 52% of purchased equip cost (B)<br>rr Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization<br>63.34 \$/ton, 0.5 ton/hr, 7536 hr/yr, 100% utilization<br>63.34 \$/ton, 0.5 ton/hr, 7536 hr/yr, 100% utilization<br>285.00 \$/ton, 1.158.6 lip/hr, 7536 hr/yr, 100% utilization<br>228.02 \$/tog, 3,072 bags, 7536 hr/yr, 100% utilization<br>60% of total labor and material costs<br>2% of total capital costs (TCI)  | 5,720,74<br>24,663,33<br>24,010,33<br>36,015,54<br>127,22<br>19,00<br>63,66<br>63,66<br>136,11<br>90,94<br>222,11<br>1,244,22<br>199,74<br>2,166,74<br>164,11<br>720,37<br>360,01,54<br>164,12<br>172,154<br>164,11<br>172,154<br>164,11<br>172,154<br>164,11<br>172,154<br>164,11<br>172,154<br>164,11<br>172,154<br>164,11<br>172,154<br>164,11<br>172,154<br>164,11<br>172,154<br>164,11<br>172,154<br>164,11<br>172,154<br>164,11<br>172,154<br>164,11<br>172,154<br>172,154<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>174,11<br>17 |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>N/A<br>Compressed Air<br>N/A<br>Solid Waste Disposal<br>Trona<br>Filter Bags<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A<br>N/A  | 52% of purchased equip cost (B)<br>rr Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 k/W-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization<br>28.500 \$/kon, 1.158.0 f/b/h, 7536 hr/yr, 100% utilization<br>28.02 \$/bag, 3.072 bags, 7536 hr/yr, 100% utilization<br>228.02 \$/bag, 3.072 bags, 7536 hr/yr, 100% utilization<br>60% of total labor and material costs<br>2% of total capital costs (TC1)<br>1% of total capital costs (TC1)   | 24,863,32<br>24,010,37   |
| Total Indirect Capital Costs, IC<br>tal Capital Investment (TCI) = DC + IC<br>ijusted TCI for Replacement Parts (Catalyst, Filte<br>tal Capital Investment (TCI) with Retrofit Factor<br>PERATING COSTS<br>Direct Annual Operating Costs, DC<br>Operating Labor<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste M<br>Electricity<br>N/A<br>Solid Waste Disposal<br>Trona<br>Filter Bags<br>N/A<br>N/A<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)<br>Property tax (1% total capital costs)  | 52% of purchased equip cost (B)<br>rr Bags, etc) for Capital Recovery Cost<br>50%<br>67.53 \$/Hr<br>0.15 of Op Labor<br>67.53 \$/Hr<br>100 % of Maintenance Labor<br>anagement<br>0.08 \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization<br>0.48 \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization<br>63.34 \$/non, 1158 6/hr/yr, 7536 hr/yr, 100% utilization<br>285.00 \$/non, 11586 ls/hr/yr, 7536 hr/yr, 100% utilization<br>285.00 \$/non, 11586 ls/hr/yr, 7536 hr/yr, 100% utilization<br>285.00 \$/non, 11586 ls/hr/yr, 7536 hr/yr, 100% utilization<br>60% of total labor and material costs<br>2% of total capital costs (TCI)<br>1% of total capital costs (TCI)<br>1% of total capital costs (TCI) | 5,720,7/<br>24,863,3:<br>24,010,3:<br>36,015,5/<br>127,2:<br>19,00<br>63,6:<br>63,6:<br>136,1!<br>90,9!<br>222,1:<br>1,244,2:<br>199,7:<br>2,166,7/<br>164,1:<br>720,3:<br>360,114,3:<br>20,35,114,35   |

\\barr.com\projects\Mpls\23 MNI65l2365011\WorkFiles\Air Permitting\Regional Haze\2020 Cost Review\Appendix A - Control Cost Analysis for NOx and SO2.xlsm DSI Summary

#### Southern Minnesota Beet Sugar Coop (SMBSC) Appendix A - Four-Factor Control Cost Analysis Table 8: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

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

#### Replacement Parts & Equipment: Filter Bags

| Equipment Life         | 5 years  |
|------------------------|--|
| CRF                    | 0.2342   |
| Rep part cost per unit | 228.02 \$/bag  |
| Amount Required        | 3072 Bags  |
| Total Rep Parts Cost   | 783,794 Cost adjusted for freight, sales tax, and bag disposal |
| Installation Labor     | 69,158 20 min per bag  |
| Total Installed Cost   | 852,952  |
| Annualized Cost        | 199,741  |

#### Electrical Use

|        | Flow acfm | D P in H2O | kWhr/yr   |
|--------|-----------|------------|---|
| Blower | 209,000   | 6.00       | Incremental electricity increase over with baghouse replacing<br>1,710,476 scrubber including ducting |
|        |           |            |   |
|        |           |            |   |
|        |           |            |   |
| Total  |           |            | 1,710,476   |

 
 Reagent Use & Other Operating Costs

 Trona use - 1.5 NSR
 208.5

 Solid Waste Disposal
 3,50

 208.54
 lb/hr SO2
 1158.62
 lb/hr Trona

 3,507
 ton/yr DSI unreacted sorbent and reaction byproducts

#### **Operating Cost Calculations**

|            |   | rating Hours   | 7,536   |  |   |  |  |
|------------|---|--|---|--|---|--|--|
| Unit       | Unit of   | Use  | Unit of   | Annual   |   | Annual   | Comments   |
| Cost \$    | Measure   | Rate   | Measure   | Use*   |   | Cost   |  |
|            |   |  |   |  |   |  |  |
| 67.53      | \$/Hr   | 2.0  | hr/8 hr shift   | 1,884  | \$  | 127,228  | \$/Hr, 2.0 hr/8 hr shift, 1,884 hr/yr  |
| 15%        | of Op Labor   |  |   | NA   | \$  | 19,084   | % of Operator Costs  |
|            |   |  |   |  |   |  |  |
| 67.53      | \$/Hr   | 1.0  | hr/8 hr shift   | 942  | \$  | 63,614   | \$/Hr, 1.0 hr/8 hr shift, 942 hr/yr  |
| 100%       | of Maintenance  | Labor  |   | NA   | \$  | 63,614   | 100% of Maintenance Labor  |
| ts & Waste | Management  |  |   |  |   |  |  |
| 0.080      | \$/kwh  | 227.0  | kW-hr   | 1,710,476  | \$  | 136,154  | \$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization  |
|            |   | N/A  | qpm   |  |   |  |  |
| 0.481      | \$/kscf   | 2.0  | scfm/kacfm  | 189,003  | \$  | 90,981   | \$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization  |
|            |   | N/A  | gpm   |  |   |  |  |
| 63.34      | \$/ton  | 0.5  | ton/hr  | 3,507  | \$  | 222,137  | \$/ton, 0.5 ton/hr, 7536 hr/yr, 100% utilization   |
| 285.00     | \$/ton  | 1,158.6  | lb/hr   | 4,366  | \$  | 1,244,217  | \$/ton, 1,158.6 lb/hr, 7536 hr/yr, 100% utilization  |
| 228.02     | \$/bag  | 3,072  | bags  | N/A  | \$  | 199,741  | \$/bag, 3,072 bags, 7536 hr/yr, 100% utilization   |
|            |   |  |   |  |   |  |  |
|            | Cost \$<br>67.53<br>15%<br>67.53<br>100%<br>ts & Waste<br>0.080<br>0.481<br>63.34<br>285.00 | Cost \$ Measure<br>67.53 \$/Hr<br>15% of Op Labor<br>67.53 \$/Hr | Cost \$         Measure         Rate           67.53         \$/Hr         2.0           15%         of Op Labor         2.0           100%         of Maintenance Labor         1.00           100% of Maintenance Labor         227.0           0.808         \$/kwh         227.0           0.481         \$/kscf         2.0           63.34         \$/con         0.5           285.00         \$/kn         1.58.6 | Cost \$         Measure         Rate         Measure           67.53         \$/Hr         2.0 hr/8 hr shift         15% of Op Labor           67.53         \$/Hr         1.0 hr/8 hr shift         10% of Maintenance Labor           100% of Maintenance Labor         1.0 hr/8 hr shift         10% of Maintenance Labor           0.800         \$/kwh         227.0 kW-hr           0.481         \$/kscf         2.0 scfm/kacfm           0.481         \$/kscf         0.0 scfm/kacfm           63.34         \$/kon         0.5 ton/hr           285.00         \$kon         1,158.6 lb/hr | Cost \$         Measure         Rate         Measure         Use*           67.53         \$\mathcal{S}\number of Op Labor         2.0 hr/8 hr shift         1.884           15% of Op Labor         1.0 hr/8 hr shift         1.884           67.53         \$\mathcal{S}\number of Op Labor         422           100% of Maintenance Labor         NA           0.808         \$\mathcal{M}\mathcal{M}\mathcal{S}\number of Maintenance Labor         NA           0.481         \$\mathcal{S}\number of Maintenance Labor         1.710.476           0.481         \$\mathcal{S}\number of Maintenance Labor         189.003           0.481         \$\mathcal{S}\number of Maintenance Labor         189.003           0.481         \$\mathcal{S}\number of Maintenance Maintenance Labor         3.507           0.481         \$\mathcal{S}\number of Maintenance M | Cost \$         Measure         Rate         Measure         Use*           67.53         \$\frac{1}{5\%}\$ of Op Labor         2.0 hr/8 hr shift         1.884         \$           67.53         \$\frac{1}{5\%}\$ of Op Labor         1.0 hr/8 hr shift         942         \$           100% of Maintenance         Labor         NA         \$         \$           0.080         \$/kwh         227.0 kW-hr         1,710.476         \$           0.481         \$/kscf         2.0 scfm/kacfm         18.9003         \$           0.481         \$/kscf         0.0 scfm/kacfm         18.9003         \$           63.34         \$/kon         0.5 ton/hr         3,507         \$           285.00         \$/kon         1,516.6 lb/hr         4,366         \$ | Cost \$         Measure         Rate         Measure         Use*         Cost           67.53 \$/Hr         2.0 hr/8 hr shift         1.884 \$         127.228           15% of Op Labor         1.0 hr/8 hr shift         1.884 \$         19.084           67.53 \$/Hr         1.0 hr/8 hr shift         942 \$         63.614           100% of Maintenance Labor         NA \$         54.63.614           0.600 \$/kwh         227.0 kW-hr         1.710.476 \$         136.154           0.461 \$/kscf         2.0 scfm/kacfm         189.003 \$         90.981           N/A gpm         1.0 hr/8 pm         3.607 \$         2.22.137           0.434 \$/non         0.5 ton/hr         3.507 \$         2.22.137 |



CLEVELAND-CLIFFS INC. United Taconite LLC PO Box 180, Eveleth, MN 55734 P 218.744.7800 clevelandcliffs.com

July 31, 2020

Mr. Hassan Bouchareb Minnesota Pollution Control Agency 520 Lafayette Road North St. Paul, MN 55155-4194

## Re: Four Factor Analysis for United Taconite LLC – Fairlane Plant

Dear Mr. Bouchareb:

United Taconite LLC – Fairlane Plant's (United) received a Request for Information (RFI) from the Minnesota Pollution Control Agency (MPCA), dated January 29, 2020, to conduct a Four-Factor analysis (analysis). This analysis was requested to aid MPCA in preparing for the second planning period updating Minnesota's Regional Haze State Implementation Plan (SIP). This analysis evaluated potential emission control measures for nitrogen oxides (NOx) and sulfur dioxide (SO2) for both of the indurating pellet furnace lines at United. As requested, enclosed you will find the results of that analysis, which was prepared using the U.S. Environmental Protection Agency guidance cited in the RFI.

Please contact me at (218) 744-7849 or at <u>candice.maxwell@clevelandcliffs.com</u> if you have questions about this submittal or require additional information.

Sincerely,

undig Maxwell

Candice Maxwell Area Manager – Environmental Affairs

Enclosure - "Regional Haze Four-Factor Analysis for NOx and SO2 Emission Control"

cc: C. Asgaard, UTAC J. Aagenes, Cleveland-Cliffs L. Koskela, UTAC



# Regional Haze Four-Factor Analysis for NO<sub>x</sub> and SO<sub>2</sub> Emissions Control

Line 1 Pellet Indurating Furnace EQUI 45/EU 040

## Line 2 Pellet Indurating Furnace EQUI 47/EU 042

Prepared for United Taconite LLC – Fairlane Plant

July 31, 2020

325 South Lake Avenue Duluth, MN 55802 218.529.8200 www.barr.com

# Regional Haze Four-Factor Analysis for NO $_{\rm X}$ and SO $_{\rm 2}$ Emissions Control

July 31, 2020

# Contents

| 1 |     | Executive Summary  | 1  |
|---|-----|--|----|
| 2 |     | Introduction   | 7  |
|   | 2.1 | Four-Factor Analysis Regulatory Background                                 | 7  |
|   | 2.2 | UTAC Description   | 8  |
| 3 |     | Existing Controls and Baseline Emission Performance                        | 9  |
|   | 3.1 | Existing Emission Controls   | 9  |
|   | 3.2 | Baseline Emissions Performance   | 9  |
| 4 |     | Four-Factor Analysis Overview  | 11 |
|   | 4.1 | Emission Control Options   | 11 |
|   | 4.2 | Factor #1 – Cost of Compliance   | 12 |
|   | 4.3 | Factor #2 – Time Necessary for Compliance                                  | 14 |
|   | 4.4 | Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance | 14 |
|   | 4.5 | Factor #4 – Remaining Useful Life of the Source                            | 14 |
| 5 |     | NO <sub>x</sub> Four-Factor Analysis                                       | 15 |
|   | 5.1 | NO <sub>x</sub> Control Measures Overview                                  | 15 |
|   | 5.1 | .1 SCR – Post-Scrubber with Conventional Duct Burner Reheat                | 16 |
|   | 5.2 | Factor #1 – Cost of Compliance   | 19 |
|   | 5.3 | Factor #2 – Time Necessary for Compliance                                  | 20 |
|   | 5.4 | Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance | 21 |
|   | 5.4 | l.1 Energy Impacts   | 21 |
|   | 5.4 | I.2 Environmental Impacts  | 21 |
|   | 5.5 | Factor #4 – Remaining Useful Life of the Source                            | 22 |
|   | 5.6 | NO <sub>x</sub> Four-Factor Analysis Conclusion                            | 22 |
| 6 |     | SO <sub>2</sub> Four-Factor Analysis                                       | 23 |
|   | 6.1 | SO <sub>2</sub> Control Measures Overview                                  | 23 |
|   | 6.1 | .1 DSI – With New PM Control   | 23 |
|   | 6.1 | .2 SDA – With New PM Control   | 24 |
|   | 6.1 | .3 GSA – With New PM Control   | 24 |

\\barr.com\projects\Mpls\23 MN\69\23692339 Regional Haze Rule Four-Factor\WorkFiles\4-factor Report\UTAC - RH Four Factor Analysis\_final.docx

| 6.2   | Factor #1 – Cost of Compliance   | 25 |
|-------|--|----|
| 6.3   | Factor #2 – Time Necessary for Compliance                                  | 25 |
| 6.4   | Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance | 26 |
| 6.4.1 | Energy Impacts   | 26 |
| 6.4.2 | Environmental Impacts  | 26 |
| 6.5   | Factor #4 – Remaining Useful Life of the Source                            | 26 |
| 6.6   | SO <sub>2</sub> Four-Factor Analysis Conclusion                            | 27 |

## List of Tables

| Table 1-1 Summary of NO <sub>X</sub> Four-Factor Analysis  | 3  |
|--|----|
| Table 1-2 Summary of SO <sub>2</sub> Four-Factor Analysis  |    |
| Table 2-1 Identified Emission Units  | 7  |
| Table 5-1: NO <sub>X</sub> Control Cost Summary, per Unit Basis  | 20 |
| Table 6-1 Additional SO <sub>2</sub> Control Measures with Potential Application at the Line 2 Indurating Furnace. | 23 |
| Table 6-2: SO <sub>2</sub> Control Cost Summary, Line 2 Indurating Furnace   | 25 |

## List of Figures

| Figure 2-1 | Typical Grate-Kiln | Indurating Furnace    | Configuration |
|------------|--------------------|-----------------------|---------------|
| ingale L   | Typical Grace Rain | induitating Familiace | configuration |

## List of Appendices

Appendix A: Unit Specific Screening Level Cost Summary for Line 1 Control Measures

Appendix B: Unit Specific Screening Level Cost Summary for Line 2 Control Measures

## Abbreviations

| BACT            | Best Available Control Technology                       |
|-----------------|---|
| BART            | Best Available Retrofit Technology                      |
| BWCA            | Boundary Waters Canoe Area                              |
| CAMx            | Comprehensive Air Quality Model with Extensions         |
| CEMS            | Continuous Emissions Monitoring System                  |
| CEPCI           | Chemical Engineering Plant Cost Index                   |
| CPI             | Consumer Price Index                                    |
| DSI             | Dry Sorbent Injection                                   |
| EFGR            | External Flue Gas Recirculation                         |
| EPA             | U.S. Environmental Protection Agency                    |
| ESP             | Electrostatic Precipitator                              |
| FIP             | Federal Implementation Plan                             |
| GSA             | Gas Suspension Absorption                               |
| IMPROVE         | Interagency Monitoring of Protected Visual Environments |
| Isle Royale     | Isle Royale National Park                               |
| LADCO           | Lake Michigan Air Directors Consortium                  |
| LNB             | Low-NO <sub>X</sub> Burners                             |
| LoTOx           | Low Temperature Oxidation                               |
| MPCA            | Minnesota Pollution Control Agency                      |
| NA              | Not Applicable  |
| NO              | Nitric Oxide  |
| NO <sub>X</sub> | Nitrogen Oxides   |
| NSCR            | Non-Selective Catalytic Reduction                       |
| NSM             | Northshore Mining Company                               |
| O <sub>2</sub>  | Oxygen  |
| 0&M             | operating and maintenance                               |
| PM/PM10/PM2.5   | Particulate Matter/PM<10 microns, PM<2.5 microns        |
| PSD             | Prevention of Significant Deterioration                 |
| PPM             | Parts per Million                                       |
| RACT            | Reasonably Available Control Technology                 |
| RFI             | Request for Information                                 |
| RHR             | Regional Haze Rule                                      |
| RSCR            | Regenerative Selective Catalytic Reduction              |
| SCR             | Selective Catalytic Reduction                           |
| SDA             | Spray Dryer Absorption                                  |
| SIP             | State Implementation Plan                               |
| SO <sub>2</sub> | Sulfur Dioxide  |
| SO₃             | Sulfur trioxide   |
| TMDL            | Total Maximum Daily Load                                |
|                 |   |

| tpy       | tons per year                     |
|-----------|-----------------------------------|
| TSD       | Technical Support Document        |
| ULNB      | Ultra Low-NO <sub>X</sub> Burners |
| UTAC      | United Taconite LLC               |
| Voyageurs | Voyageurs National Park           |

# **1 Executive Summary**

In accordance with Minnesota Pollution Control Agency's (MPCA's) January 29, 2020 Request for Information (RFI) Letter,<sup>1</sup> United Taconite LLC Fairlane Plant (UTAC) evaluated potential emission control measures for nitrogen oxides (NO<sub>X</sub>) and sulfur dioxide (SO<sub>2</sub>) for the Line 1 Pellet Indurating Furnace (EQUI 45/EU 040) and Line 2 Pellet Indurating Furnace (EQUI 47/EU 042), collectively referred to as the Line 1 and Line 2 Indurating Furnaces, as part of the state's demonstration of reasonable progress under the Regional Haze Rule (RHR).<sup>2</sup> The analysis considers potential emission control measures by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i) and pursuant to the final U.S. Environmental Protection Agency (EPA) RHR State Implementation Plan (SIP) guidance<sup>3</sup> dated August 20, 2019 (2019 RH SIP Guidance):

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

This report describes the background and analysis for conducting the Four-Factor analysis. Conclusions are summarized in Table 1-1 for NO<sub>X</sub> and Table 1-2 for SO<sub>2</sub>.

The NO<sub>x</sub> Four-Factor analysis evaluated Selective Catalytic Reduction (SCR) with reheating of the exhaust gases using a conventional duct burner. It is important to note that the use of SCR with reheat has not been demonstrated on taconite furnaces or similar sources. Therefore, this technology does not meet the definition of technically feasible. However, according to EPA's 2016 Final Federal Implementation Plan (FIP),<sup>4</sup> EPA expects Minnesota to reevaluate SCR with reheat as a potential option for reasonable progress in future planning periods. It is only due to this statement by EPA that the SCR with reheat control technology is included in the analysis; UTAC does not concur that SCR with reheat is considered technically feasible.

In the Factor #1 – Cost of Compliance analysis, the associated cost-effectiveness (\$ for each ton of emissions reduction) for SCR with reheat far exceeded a reasonable cost-effectiveness thresholds of \$1,193 to \$2,800 per ton for NO<sub>x</sub> emission controls (refer to Sections 4.2 and 5.2 for more information).

<sup>&</sup>lt;sup>1</sup> January 29, 2020 letter from Hassan Bouchareb of MPCA to Candice Maxwell of UTAC.

<sup>&</sup>lt;sup>2</sup> The U.S. Environmental Protection Agency (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>&</sup>lt;sup>3</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

<sup>&</sup>lt;sup>4</sup> Federal Register 81, no. 70 (April 12, 2016); 21675. Available at: https://www.govinfo.gov/app/details/FR-2016-04-12/2016-07818

Therefore, the facility's existing  $NO_X$  emissions performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

The SO<sub>2</sub> Four-Factor Analysis evaluated the following SO<sub>2</sub> emission control measures:

- Dry Sorbent Injection (DSI) with New Particulate Matter (PM) Control
- Spray Dryer Absorption (SDA) with New PM Control
- Gas Suspension Absorption (GSA) with New PM Control

Similar to the NO<sub>x</sub> control technology described above, none of these SO<sub>2</sub> control technologies have been successfully installed on a taconite furnace, and therefore, do not meet the definition of technically feasible. However, EPA required an evaluation of these SO<sub>2</sub> control technologies in the first round of Regional Haze Rule analysis.

In the Factor #1 – Cost of Compliance analysis, the associated cost-effectiveness (\$ for each ton of emissions reduction) for each of the evaluated measures far exceeded a reasonable cost-effectiveness thresholds of \$4,200 to \$5,700 per ton for SO<sub>2</sub> emission controls (refer to Sections 4.2 and 6.2 for more information). Therefore, the facility's existing SO<sub>2</sub> emissions performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

In addition to the four statutory factors, states have the discretion to consider any potential visibility improvements, which is referred to as the "fifth factor." UTAC continues to evaluate visibility benefits associated with possible  $NO_X$  and  $SO_2$  control measures internally and reserves the right to supplement this analysis with information related to visibility benefits and cost per deciview improvement. UTAC plans to conduct CAMx modeling after modeling information from the Lake Michigan Air Directors Consortium (LADCO) is available.

## Table 1-1 Summary of NO<sub>x</sub> Four-Factor Analysis

|   | Factor #                                       | #1 – Cost of Complia                      | ance                                  |  |   |  |  |
|---|--|---|---------------------------------------|--|---|--|--|
| List of<br>Emission<br>Control<br>Measure | Installed Capital<br>Cost (\$)                 | Annualized<br>Operating Cost<br>(\$/year) | Pollution<br>Control Cost<br>(\$/ton) | Factor #2 – Time<br>Necessary for<br>Compliance        | Factor #3 – Energy and Non-Air<br>Quality Environmental Impacts of<br>Compliance  | Factor #4 –<br>Remaining<br>Useful Life of<br>the Source | Does this<br>Analysis Support<br>the Installation<br>of this Emission<br>Control<br>Measure? |
| SCR with<br>Reheat                        | Line 1 - \$43,637,895<br>Line 2 - \$72,550,865 | \$21,350,897<br>\$41,336,088              | \$32,228<br>\$44,115                  | 5 years after SIP<br>promulgation. See<br>Section 5.3. | <ul> <li>Energy         <ul> <li>Increased energy use to overcome the increased differential pressure;</li> <li>Increased indirect emissions at power plant to accommodate the increased energy use.</li> <li>Substantial increase in natural gas usage to reheat the exhaust stream; and</li> <li>Additional electricity is required for the SCR equipment, to vaporize the aqueous ammonia reagent, and for additional fan power.</li> </ul> </li> <li>Environmental         <ul> <li>Unreacted ammonia (a PM<sub>10</sub> precursor) would be emitted to the atmosphere (ammonia slip);</li> <li>Ammonia would combine with NO<sub>X</sub> and SO<sub>2</sub> to form ammonium salts, which would be emitted to the atmosphere as PM<sub>10</sub>;</li> <li>Sulfuric acid mist emissions will increase due to the</li> </ul> </li> </ul> | 20-year control<br>equipment life                        | No   |

| [   | Factor                         | #1 – Cost of Complia                      | ince                                  |   |  |  |  |
|---|--------------------------------|---|---------------------------------------|---|--|--|--|
| List of<br>Emission<br>Control<br>Measure | Installed Capital<br>Cost (\$) | Annualized<br>Operating Cost<br>(\$/year) | Pollution<br>Control Cost<br>(\$/ton) | Factor #2 – Time<br>Necessary for<br>Compliance | Factor #3 – Energy and Non-Air<br>Quality Environmental Impacts of<br>Compliance   | Factor #4 –<br>Remaining<br>Useful Life of<br>the Source | Does this<br>Analysis Support<br>the Installation<br>of this Emission<br>Control<br>Measure? |
|   |                                |   |                                       |   | <ul> <li>oxidation of SO<sub>2</sub> to SO<sub>3</sub> by<br/>the SCR catalyst;</li> <li>Emissions of ammonia,<br/>ammonium sulfates, and<br/>sulfuric acid mist increase<br/>plume visibility and<br/>contribute to regional haze;</li> <li>Increased oxidized mercury<br/>emissions.</li> <li>There are safety risks<br/>associated with the<br/>transportation, handling,<br/>and storage of aqueous<br/>ammonia; and</li> <li>Spent catalyst from the SCR<br/>is typically disposed of in a<br/>landfill; however, catalyst<br/>recycling or reconditioning<br/>may be available.</li> </ul> |  |  |

## Table 1-2 Summary of SO<sub>2</sub> Four-Factor Analysis

|   | Factor #1 – Cost of Compliance       |  |                                    |  |   |   |   |
|---|--------------------------------------|--|------------------------------------|--|---|---|---|
| List of<br>Emission<br>Control<br>Technology            | Installed Capital Cost<br>(\$)       | Annualized<br>Operating<br>Cost<br>(\$/year) | Pollution Control<br>Cost (\$/ton) | Factor #2 – Time<br>Necessary for<br>Compliance        | Factor #3 – Energy and Non-Air<br>Quality Environmental Impacts of<br>Compliance  | Factor #4 –<br>Remaining Useful<br>Life of the Source | Does this<br>Analysis<br>Support the<br>Installation of<br>this Emission<br>Control<br>Measure? |
| Line 1<br>DSI, SDA<br>and GSA<br>with new<br>PM Control | Not applicable – See<br>Section 6.1. | NA   | NA                                 | NA   | NA  | NA  | NA  |
| Line 2<br>DSI with<br>new PM<br>Control                 | \$50,466,157                         | \$10,090,749                                 | \$93,300                           | 5 years after SIP<br>promulgation.<br>See Section 6.3. | Energy<br>Increased energy use to<br>accommodate differential pressure.<br>Increased indirect emissions at<br>power plant to accommodate the<br>increased energy use.<br>Environmental<br>Additional solid waste generation<br>and disposal.<br>Lost production due to loss of<br>recycled dust that contains valuable<br>iron units. | 20-year control<br>equipment life                     | No  |

|  | Factor #1 –                    | Cost of Comp                                 | liance                             |  |   |   |   |
|--|--------------------------------|--|------------------------------------|--|---|---|---|
| List of<br>Emission<br>Control<br>Technology | Installed Capital Cost<br>(\$) | Annualized<br>Operating<br>Cost<br>(\$/year) | Pollution Control<br>Cost (\$/ton) | Factor #2 – Time<br>Necessary for<br>Compliance        | Factor #3 – Energy and Non-Air<br>Quality Environmental Impacts of<br>Compliance  | Factor #4 –<br>Remaining Useful<br>Life of the Source | Does this<br>Analysis<br>Support the<br>Installation of<br>this Emission<br>Control<br>Measure? |
| Line 2<br>SDA with<br>new PM<br>Control      | \$120,947,748                  | \$19,573,967                                 | \$180,891                          | 5 years after SIP<br>promulgation.<br>See Section 6.3. | Energy<br>Increased energy use to<br>accommodate differential pressure.<br>Increased indirect emissions at<br>power plant to accommodate the<br>increased energy use.<br>Environmental<br>Additional solid waste generated<br>and disposed. | 20-year control<br>equipment life                     | No  |
| Line 2<br>GSA with<br>new PM<br>Control      | \$113,793,152                  | \$18,757,651                                 | \$173,347                          | 5 years after SIP<br>promulgation.<br>See Section 6.3. | Increased energy use to<br>accommodate differential pressure.<br>Increased indirect emissions at<br>power plant to accommodate the<br>increased energy use.<br><u>Environmental</u><br>Additional solid waste generation<br>and disposal.   | 20-year control<br>equipment life                     | No  |

# 2 Introduction

This section summarizes the relevant regulatory background and provides a description of UTAC's indurating furnaces.

# 2.1 Four-Factor Analysis Regulatory Background

The RHR published on July 15, 2005 by the 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 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 of achieving 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 January 29, 2020, the MPCA sent an RFI to UTAC. The RFI stated that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) indicate that nitrates and sulfates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of nitrates and sulfates are emissions of NO<sub>X</sub> and SO<sub>2</sub>. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze at Isle Royale, Michigan must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts. As part of the planning process for the SIP development, MPCA is working with the LADCO to evaluate regional emission reductions.

The RFI also identified the UTAC facility as a significant source of  $NO_X$  and  $SO_2$  that is located close enough to BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that UTAC submit a "Four-Factor Analysis" by July 31, 2020 for the emission units identified in Table 2-1 as part of the state's regional haze reasonable progress.

| Unit                     | Unit ID          | Applicable Pollutants |  |  |
|--------------------------|------------------|-----------------------|--|--|
| Line 1 Pellet Induration | EQUI 45 / EU 040 | $NO_X$ and $SO_2$     |  |  |
| Line 2 Pellet Induration | EQUI 47 / EU 042 | $NO_X$ and $SO_2$     |  |  |

The analysis considers potential emission control measures by addressing the four statutory factors, which are laid out in 40 CFR 51.308(f)(2)(i) and explained in the 2019 RH SIP Guidance.<sup>5</sup>

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

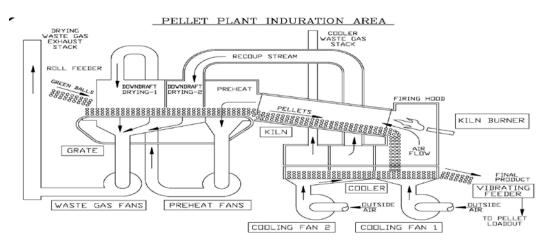
The RFI specified that the "... analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to the final 2019 RH SIP Guidance.

This report presents the Four-Factor Analysis for  $NO_X$  and  $SO_2$  as applied to the review of emission controls at UTAC for the emission units identified in Table 2-1.

## 2.2 UTAC Description

UTAC mines iron ore (magnetite) and produces taconite pellets that are shipped to steel producers for processing in blast furnaces. The iron ore is crushed and routed through several concentration stages including grinding, magnetic separation, and thickening.

The concentrated iron ore slurry is then dewatered, filtered, mixed with bentonite and/or other binding agents, and formed into greenballs, which are fed onto the traveling grate of the indurating furnace. Figure 2-1 depicts a typical grate-kiln indurating furnace configuration, similar to UTAC's Line 1 and Line 2 Indurating Furnaces.



## Figure 2-1 Typical Grate-Kiln Indurating Furnace Configuration

<sup>&</sup>lt;sup>5</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

# 3 Existing Controls and Baseline Emission Performance

This section describes the existing  $NO_X$  and  $SO_2$  emission controls on UTAC's indurating furnaces and the baseline emissions that are used to evaluate the cost-effectiveness for the associated emission control measures.

## 3.1 Existing Emission Controls

In 2006 and 2007, UTAC submitted to MPCA its BART analysis and supplemental analysis that evaluated NO<sub>X</sub> and SO<sub>2</sub> control strategies for the indurating furnaces. MPCA subsequently developed its SIP with certain NO<sub>X</sub> and SO<sub>2</sub> reductions for various facilities state-wide and submitted the SIP to EPA for approval. EPA partially disapproved Minnesota's SIP and promulgated Federal Implementation Plan (FIP) requirements in 2013. UTAC'S 2013 FIP limits were subject to a legal challenge as being technically infeasible and were subsequently replaced with alternate FIP limits that were published in the Federal Register on April 12, 2016.<sup>6</sup> The 2016 FIP imposed NO<sub>X</sub> emission limits on UTAC'S furnaces of 2.8-3.0 lb NO<sub>X</sub>/MMBtu when only natural gas is combusted and 1.5-2.5 lb NO<sub>X</sub>/MMBtu for all other fuels, on a 720-hour rolling average basis. For SO<sub>2</sub>, the 2016 FIP imposed an emission limit of 529 lb SO<sub>2</sub>/hr, based on a 30-day rolling average, for both furnaces combined.

In addition, UTAC proposed NO<sub>X</sub> emission limits in its 2010 Title V Major Amendment that represented a 2,415 ton per year NO<sub>X</sub> reduction from BART baseline levels. MPCA established these reductions as enforceable BART limits for UTAC in the form of an 816 ton and 1,820 ton limit for Line 1 and Line 2, respectively, on a 180-day rolling basis. These limits remain in effect in UTAC'S current Title V permit and, in conjunction with the 2016 FIP emission limits, are reflected in how the facility currently operates with regard to developing baseline, future expected emission levels for this Four-Factor Analysis evaluation.

## 3.2 Baseline Emissions Performance

The Four-Factor Analysis requires the establishment of a baseline scenario for evaluating a potential emission control measure. On page 29 of the 2019 RH SIP Guidance 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

<sup>&</sup>lt;sup>6</sup> Federal Register 81, no. 70 (April 12, 2016); 21675. Available at: https://www.govinfo.gov/app/details/FR-2016-04-12/2016-07818.

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."

Based on EPA guidance, 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. MPCA has recommended utilizing reporting year 2017 emissions as the basis for estimating for 2028 baseline emissions.

The estimated 2028 baseline NO<sub>x</sub> emissions to be used for the Four-Factor Analyses are 1,325 tpy for the Line 1 Indurating Furnace and 1,874 tpy for the Line 2 Indurating Furnace. The 2028 baseline emission values were calculated from the 2017 air emission inventory actual hourly emissions as collected by UTAC's continuous emission monitoring system (CEMS), and adjusted to conform with the FIP limits of 3.0 Ib NOx/MMBtu during periods when only natural gas is combusted, and with the FIP limits of 2.5 Ib NOx/MMBtu during periods when all other fuels are used, including mixed fuel usage.

The estimated 2028 baseline  $SO_2$  emissions to be used for the Four-Factor Analyses are 59.7 tpy for the Line 1 Indurating Furnace and 215.4 tpy for the Line 2 Indurating Furnace, and were based on data collected by UTAC's CEMS used for the 2017 air emission inventory. These emission rates, combined, are substantially less than the BART emission rate of 529 lb/hr (for both furnaces combined), which equates to 2,317 tons per year.

# 4 Four-Factor Analysis Overview

This section summarizes the Four-Factor Analysis approach with respect to the Regional Haze program detailed in the 2019 RH SIP guidance.

# 4.1 Emission Control Options

Prior to completing a Four-Factor Analysis of each emission control measure, all technically feasible emission control options for the indurating furnaces must first be identified. Potentially available emission control measures include both physical and operational changes. Once all technically feasible emission control measures are identified, the facility justifies which emission control measures are reasonable to consider against the four factors, recognizing there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures.

Under normal circumstances, a potential emission control measure must have been previously installed and operated successfully on a similar source under similar physical and operating conditions to be considered technically feasible. However, for the purpose of this technology screening analysis, available control measures which have been commercially demonstrated in other industrial combustion applications, outside of taconite processing, have been considered in this analysis. UTAC does not concede that any technology discussed in this analysis would definitively be technically appropriate for taconite indurating applications. Accordingly, UTAC reserves the right to re-evaluate and modify this analysis to more closely examine the technical appropriateness of utilizing these industrial control measures for the taconite indurating process, if necessary. Novel controls that have not been demonstrated on full-scale, industrial operations are not considered as part of this analysis.

While the 2006 BART report included a comprehensive list of control measures and a rigorous screening of all available  $NO_X$  and  $SO_2$  control technologies; most of the control technologies were excluded from the 2006 BART and subsequent BART analyses because they were not "generally available" or "available to an indurating furnace." A recent review of the availability status confirmed no material changes since the BART reports (i.e., they are still not "generally available" or "available" or "available" or "available to an indurating furnace"). This Four-Factor Analysis is building on the 2006 BART and subsequent BART analyses and only re-evaluating a reasonable set of  $NO_X$  and  $SO_2$  control technologies. Only controls that may be technically feasible were considered. Control technologies with significant adverse environmental impacts were excluded from the set of reasonable control technologies.

The control effectiveness of UTAC's existing emission control measures established in the 2016 FIP are 2.8-3.0 lb NO<sub>X</sub>/MMBtu for natural gas only and a limit of 1.5-2.5 lb NO<sub>X</sub>/MMBtu for all other fuels, on a 720-hour rolling average basis. For SO<sub>2</sub>, the FIP required an aggregate Line 1 and Line 2 Indurating Furnaces emission limit of 529 lb SO<sub>2</sub>/hr, based on a 30-day rolling average. For purposes of this analysis, UTAC evaluated only those control measures that have the potential to achieve an overall pollutant reduction greater than the performance of the existing systems, including optimizations.

An evaluation of the control measures for  $NO_X$  and  $SO_2$  are discussed in Sections 5.1 and 6.1, respectively.

## 4.2 Factor #1 – Cost of Compliance

Factor #1 estimates the capital and annual operating and maintenance (O&M) costs of the control measure. As directed by the 2019 RH SIP Guidance (page 21), the costs of emission controls follow the accounting principles and generic factors from the EPA Air Pollution Control Cost Manual (EPA Control Cost Manual), <sup>7</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 EPA.

The UTAC 2006 BART report established NO<sub>X</sub> and SO<sub>2</sub> cost-effectiveness thresholds of \$1,000 to \$1,300 per ton removed based on the BART final rule, court cases on cost-effectiveness, guidance from other regulatory bodies, and other similar regulatory programs like the Clean Air Interstate Rule (CAIR), and cost-effective air pollution controls in the electric utility industry for large power plants. The lower threshold of \$1,000 per ton in 2006 is scaled to today's dollars using the Chemical Engineering Plant Cost Index (CEPCI).<sup>8</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 \$1,193 per ton. More recently, Pennsylvania Department of Environmental Department established a Reasonably Available Control Technology (RACT) cost-effectiveness of \$2,800 per ton of NO<sub>X</sub> controlled in the 2019 SIP.<sup>9</sup> Therefore, a screening cost-effective threshold range of \$1,193 to \$2,800 would be considered reasonable.

Review of BART cost-effectiveness thresholds for SO<sub>2</sub> were found in the 2014 Texas and Oklahoma RH FIP, citing a cost-effectiveness threshold for SO<sub>2</sub> of \$4,000 to \$5,000 per ton of SO<sub>2</sub> controlled.<sup>10</sup> Adjusting the 2014 threshold to current dollars results in a range of \$4,200 to \$5,700. Therefore, a cost-effective threshold range of \$4,200 to \$5,700 would be considered reasonable.

Generally, if the average cost-effectiveness is greater than an acceptable threshold, the cost is considered to not be reasonable. 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

<sup>&</sup>lt;sup>7</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 <u>https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution</u> as of the date of this report.

<sup>&</sup>lt;sup>8</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 2006 values to January 2020 values.

<sup>&</sup>lt;sup>9</sup> U.S. EPA PADEP SIP, June 10, 2019. <u>https://www.federalregister.gov/documents/2019/05/09/2019-09478/approval-and-promulgation-of-air-quality-implementation-plans-pennsylvania-regulatory-amendments</u>

<sup>&</sup>lt;sup>10</sup> U.S. EPA TX and OK FIP, December 16, 2014. <u>https://www.govinfo.gov/content/pkg/FR-2014-12-16/pdf/2014-</u> 28930.pdf

particularly applicable to a source with existing emission controls with an intermediate or high degree of effectiveness, as is the case with the indurating furnaces due to their existing NO<sub>X</sub> and SO<sub>2</sub> emission controls.

The cost of an emission control measure is derived using capital and annual 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 emission control measures (baseline emissions), as described in Section 3.2, in tons per year (tpy), and 2) expected annual emissions performance through installation of the additional control measure (controlled emissions), also in tpy.

When UTAC was originally constructed, major processing equipment was installed first, and the buildings were erected around the equipment. Due to the very limited space around existing equipment, a 60 percent markup of the total capital investment (i.e., a 1.6 retrofit factor) was included in the costs to account for the retrofit installation. Retrofit installations have increased handling and erection difficulty for many reasons. Access for transportation, laydown space, etc. for new equipment is significantly impeded or restricted. This is because the spaces surrounding the furnaces are congested, or the areas surrounding the building support frequent vehicle traffic or crane access for maintenance. The structural design of the existing building would not support additional equipment on the roof. Additionally, the technologies evaluated in this section are complex and increase the associated installation costs (e.g., ancillary equipment requirements, piping, structural, electrical, demolition, etc.). The use of a retrofit factor has been justified by previous BART projects and with UTAC and the MPCA.<sup>11</sup> Finally, the EPA Air Pollution Control Cost Manual notes that retrofit installations are subjective because the plant designers may not have had the foresight to include additional floor space and room between components for new equipment.<sup>12</sup> Retrofits can impose additional costs to "shoehorn" equipment in existing plant space, which is true for UTAC.

For purposes of calculating cost-effectiveness and as described in Section 3.2, UTAC uses NO<sub>X</sub> 2028 baseline emission values of 1,325 tpy for the Line 1 Indurating Furnace and 1,874 tpy for the Line 2 Indurating Furnace. The 2028 baseline emission values were calculated from the 2017 air emission inventory actual hourly emissions, and adjusted to conform with the FIP limits of 3.0 lb NOx/MMBtu

<sup>&</sup>lt;sup>11</sup> Barr Engineering Co. United Taconite Analysis of Best Available Retrofit Technology. 2006 and U. S. Environmental Protection Agency. Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze (final rule, to be codified at 40 CFR Part 52). Federal Register. January 30, 2014. Vol. 79, 20, p. 5154. EPA–R08–OAR–2012–0026.

<sup>&</sup>lt;sup>12</sup> U.S. Environmental Protection Agency. EPA Air Pollution Control Cost Manual, Sixth Edition, Section 1, Chapter 2.6.4.2 Retrofit Cost Considerations. 2017. <u>https://www.epa.gov/sites/production/files/2017-</u> 12/documents/epaccmcostestimationmethodchapter 7thedition 2017.pdf

during periods when only natural gas is combusted, and with the FIP limits of 2.5 lb NOx/MMBtu during periods when all other fuels are used, including mixed fuel usage.

For SO<sub>2</sub>, the 2028 baseline emissions to be used are 59.7 tpy for the Line 1 Indurating Furnace and 215.4 tpy for the Line 2 Indurating Furnace.

# 4.3 Factor #2 - Time Necessary for Compliance

Factor #2 considers the time needed for UTAC to comply with potential emission control measures. This includes the planning, installation, and commissioning of the selected control based on experiences with similar sources and source-specific factors.

For the purposes of this analysis and if a given NO<sub>x</sub> or SO<sub>2</sub> control measure requires a unit outage as part of its installation, UTAC considers the forecasted outage schedule for the associated units in conjunction with the expected timeframe for engineering and equipment procurement. However, due to the potential control technology project's significant capital expenditure, physical size and complexity, the installation may not be able to be accomplished during scheduled outages and could potentially require additional time beyond a scheduled major outage. In addition, most control technology equipment requires longlead times for design and procurement that could result in the installation occurring outside a scheduled outage or could result in further delays in construction of the project to align with the next scheduled major outage.

# 4.4 Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance

Factor #3 considers the energy and non-air quality environmental impacts of each potential emission control measure. Energy impacts to be considered are the direct energy consumed at the source, in terms of kilowatt-hours or mass of fuels used. Non-air quality environmental impacts may include solid or hazardous waste generation, wastewater discharges from a control device, increased water consumption, and land use. The analysis is conducted based on consideration of site-specific circumstances.

# 4.5 Factor #4 - Remaining Useful Life of the Source

Factor #4 considers the remaining useful life of the source, which is the difference between the date that additional emission controls will be put in place and the date that the facility would be expected to permanently ceases operation. Generally, the remaining useful life of the source is assumed to be longer than the useful life of the emission control measure unless the source is under an enforceable requirement to cease operation. In the presence of an enforceable end date, the cost calculation can use a shorter period to amortize the capital cost.

For the purposes of this evaluation, the remaining useful life for the units are assumed to be longer than the useful life of the evaluated additional emission controls measures. Therefore, the expected useful life of the evaluated control measure is used to calculate the emissions reductions, amortized costs, and the resulting cost per ton removed.

# 5 NO<sub>x</sub> Four-Factor Analysis

This section identifies and describes various NO<sub>x</sub> emission control measures, evaluates the four statutory factors for the Line 1 and Line 2 Indurating Furnaces, considers other factors, and determines if an emission control measure or measures are potentially feasible. Consistent with EPA's guidance and MPCA direction, UTAC has completed a Four-Factor Analysis for NO<sub>x</sub> as described in Sections 5.1 to 5.6.

## 5.1 NO<sub>x</sub> Control Measures Overview

Three mechanisms by which NO<sub>X</sub> production typically forms are thermal, fuel and prompt NO<sub>X</sub> formation. In the case of natural gas combustion, the primary mechanism of NO<sub>X</sub> production is through thermal NO<sub>X</sub> formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air to nitric oxide (NO). The thermal oxidation reaction is as follows:

$$N_2 + O_2 \rightarrow 2NO \tag{1}$$

Downstream of the flame, significant amounts of  $NO_2$  can be formed when NO is mixed with air. The reaction is as follows:

$$2NO + O_2 \rightarrow 2NO_2 \tag{2}$$

Thermal oxidation is a function of the residence time, free oxygen, and peak reaction temperature.

Fuel bound NO<sub>x</sub> is primarily a concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. Natural gas has minimal fuel bound nitrogen which eliminates fuel bound NO<sub>x</sub> as a major concern.

Prompt NO<sub>X</sub> is a form of thermal NO<sub>X</sub> which is generated at the flame boundary. It is the result of reactions between nitrogen and hydrocarbon radicals generated during combustion. Only minor amounts of NO<sub>X</sub> are emitted as prompt NO<sub>X</sub>.

As stated in Section 4.1, this Four-Factor Analysis is building on the 2006 BART and subsequent BART analyses and only re-evaluating a reasonable set of control technologies. A recent review of the availability status confirmed no material changes since the 2006 BART and subsequent BART reports (i.e., they are still not "generally available" or "available to an indurating furnace"). Based on this review, SCR – Post Scrubber with Conventional Duct Burner Reheat was considered for further evaluation as the NO<sub>X</sub> control measure for the Line 1 and Line 2 Indurating Furnaces. The following describes pertinent technical information regarding the technology and whether the technology is technically feasible as applied to the Line 1 and Line 2 Indurating Furnaces.

## 5.1.1 SCR – Post-Scrubber with Conventional Duct Burner Reheat

According to EPA's 2016 Final FIP,<sup>13</sup> a taconite facility in Sweden, LKAB, has implemented and operated an SCR with reheat through a conventional duct burner on a taconite indurating furnace. However, EPA has stated the following:

Alstom, the SCR vendor for LKAB, declined twice to bid on an SCR with reheat at Minntac, citing technical difficulties with the SCR with reheat at LKAB. These difficulties included operating within the narrow temperature range required by SCR with reheat. Further, LKAB is looking into process optimization and better burners to reduce NO<sub>X</sub> as opposed to installing another SCR with reheat in the future.

Past NO<sub>X</sub> control equipment evaluations (2006 BART, 2010 Keetac Best Available Control Technology (BACT), and 2011 Essar BACT reports) considered SCR as technically feasible, whereas in the 2016 Final FIP,<sup>14</sup> EPA considered SCR as technically infeasible and stated the following:

We expect Minnesota and Michigan to reevaluate SCR with reheat as a potential option for making reasonable progress in future planning periods but reject the technology as BART for the Minnesota and Michigan taconite facilities at this time.

Based on the information presented above, UTAC has identified SCR with reheat to carry forward through the Four-Factor Analysis and to be considered whether its installation is necessary to make reasonable progress based on the factors presented below. This analysis should not be interpreted to mean that UTAC considers SCR with reheat to be technically feasible. For a control technology to be considered technically feasible, it must have been previously installed and operated successfully on a similar source under similar physical and operating conditions. No such examples exist. As noted, the LKAB facility is pursuing other NO<sub>X</sub> reduction options instead of SCR with reheat, thereby confirming the control technology has not been proven to be technically feasible.

At this time, the true cost of compliance for SCR with reheat cannot be fully quantified since this technology has not been proven to be technically feasible on a taconite furnace. Therefore, the cost of compliance should be considered a theoretical cost estimate based on the numerous assumptions needed to complete the cost evaluation for the NO<sub>x</sub> emission control measures. Such assumptions include sizing of the equipment, catalyst compatibility, ammonia slip concentration, control efficiency, and many others.

The application of SCR on taconite furnaces differs fundamentally from its application on utility boilers due to the differences in gas composition, dust loading, and chemistry. The most serious issues yet to be resolved with SCR on furnaces include the formation of SO<sub>3</sub> in the reactor, the ability to inject ammonia at

<sup>&</sup>lt;sup>13</sup> Federal Register 81, no. 70 (April 12, 2016); 21675. Available at: https://www.govinfo.gov/app/details/FR-2016-04-12/2016-07818

<sup>14</sup> Ibid

proper molar ratio under non-steady state conditions, the creation of visibility impairing pollutants, the increased oxidation of mercury, the creation of a detached plume, catalyst life, catalyst poisoning, fouling of the bed, and system resistance. Some of these issues, discussed in more detail below, could affect the validity of SCR with reheat control technology and would require extensive testing prior to installation and operation on an existing indurating furnace.

### Sulfur Dioxide and Sulfuric Acid

Some of the issues confronted by utility boilers with SCR systems on units firing sulfur-bearing fuels involve secondary impacts from the SCR system. The taconite industry would expect to experience similar issues when applying SCR technology. These impacts include the formation of SO<sub>3</sub> in the reactor, the emissions of unreacted ammonia from the reactor, and formation of byproducts from the reaction such as ammonia salts and PM<sub>10</sub>. These effects are often interconnected because SO<sub>3</sub> and unreacted ammonia can react within, and downstream of the SCR reactor. The same catalyst that promotes the reactions between ammonia and NO<sub>x</sub> also promotes the oxidation of SO<sub>2</sub> to SO<sub>3</sub>. Typically, a conversion of one to two percent of SO<sub>2</sub> to SO<sub>3</sub> could be expected. It is important to understand that SO<sub>2</sub> oxidation is dependent on other SCR design parameters. When high levels of catalyst activity are needed to target high NO<sub>x</sub> reduction efficiencies and low levels of ammonia slip, or to counteract significant catalyst deactivation rates, SO<sub>2</sub> oxidation rates would be expected to increase. If lower levels of SO<sub>2</sub> oxidation are targeted, NO<sub>X</sub> reduction, ammonia slip, or both must be compromised.<sup>15</sup> The potential increase of PM<sub>10</sub> and PM<sub>2.5</sub> due to the increase in sulfuric acid mist emissions and condensable PM in the form of ammonium sulfate could trigger air permitting. Further, permitting could be complicated by triggering air permitting for NO<sub>x</sub> control technology installation that results in collateral prevention of significant deterioration (PSD) pollutant increases.

There are several reasons why industries are concerned about the level of SO<sub>2</sub> oxidation in an SCR reactor. In the absence of other interactions, downstream equipment that operates below the sulfuric acid dew point can experience severe corrosion. In addition, SO<sub>3</sub> and sulfuric acid mist formed in such equipment can promote the formation of a visible plume, or a blue plume.<sup>16</sup> To meet visible emission limitations, a wet scrubber after the SCR with reheat is essential to control corrosion and to minimize the possibility of a visible plume. Costs associated with the wet scrubber control technology to control SO<sub>3</sub>, sulfuric acid mist, corrosion control, and mitigating potential visible plume, would need to be factored into the cost of control evaluation for SCR with reheat. Due to the uncertainty with the sizing of the wet scrubber, the additional wet scrubber costs have not been incorporated at this time.

<sup>&</sup>lt;sup>15</sup> Cichanowicz, J. E. 1999. What You Should Know Before Specifying SCR. Power Magazine. May/June 1999. pp. 80-81.

<sup>&</sup>lt;sup>16</sup> Moretti, A. L., Triscori, R. J., and Ritzenthaler, D. P. (2006). A System Approach to SO<sub>3</sub> Mitigation. Presented at the "EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium," August 28–31.

### NO<sub>X</sub> Variability and Ammonia Slip

Unlike a typical utility boiler operating at a steady load, taconite indurating furnaces typically experience significant variability in NO<sub>X</sub> concentrations in the exhaust stream. As previously noted, thermal NO<sub>X</sub> formation in an indurating furnace is the dominant mechanism for the formation of NO<sub>X</sub> emissions. The rate of NO<sub>X</sub> generation due to the thermal formation mechanisms indicates that the emissions are directly related to the peak gas temperature. Slight changes in the peak temperatures in the burner flame can have a large impact on the short-term NO<sub>X</sub> concentrations. The NO<sub>X</sub> formation–peak temperature relationship is a primary factor why the variability of NO<sub>X</sub> concentrations experienced in an indurating furnace is greater than in coal-fired boilers.

The NO<sub>x</sub> variability is dependent on the individual indurating furnace design and operations. The differences in the magnitude of the NO<sub>x</sub> variability and the average NO<sub>x</sub> concentrations are due mainly to the differences in oxygen levels and temperature profiles existing within the furnace. An SCR system applied to an indurating furnace will most likely be confronted with highly variable inlet NO<sub>x</sub> loadings and would have to be controlled to ensure the ammonia and NO<sub>x</sub> molar ratio remains consistent during the short-term NO<sub>x</sub> concentration variations. Overfeeding reagent (ammonia or urea) could lead to excessive ammonia slip and the formation of air pollutants such as ammonia sulfate which adversely affects visibility. The requirement for tight ammonia and NO<sub>x</sub> molar ratios would reduce the overall NO<sub>x</sub> control efficiency of an SCR system on an indurating furnace. As noted by Solnhofen cement manufacturing facility management, the NO<sub>x</sub> variability caused a reduction in overall control efficiency. The SCR with reheat could achieve an 80 percent reduction periodically. However, the average control efficiency experienced was 50 percent.<sup>17</sup>

## Mercury Oxidation

In the case of mercury, the SCR oxidizes mercury from its elemental form. Given the propensity for oxidized mercury to deposit near its emission point, the increase in mass of oxidized mercury emissions is expected to result in more local deposition (i.e., increased loading of mercury) and most certainly within northeast Minnesota. An increase in mercury loading to northeast Minnesota is inconsistent with the Statewide Mercury Total Maximum Daily Load (TMDL) study that requires a reduction in loading in order to reduce fish tissue mercury concentrations in the area. In addition, a wet scrubber would be required to control the oxidized mercury formed in the SCR.

## Indurating Furnace Exhaust Dust

Although the SCR system would be located downstream of particulate controls, the SCR catalyst would be exposed to dust and spent SO<sub>2</sub> control reagents. Constituents in the indurating furnace exhaust gas

<sup>&</sup>lt;sup>17</sup> The Experience of SCR at Solnhofen and its Applicability to US Cement Plants, June 6, 2006. <u>http://files.dep.state.pa.us/air/AirQuality/AQPortalFiles/Pollutants/transport/Comments/Lehigh Attachment Solnhofe n.pdf</u>

stream could adversely affect the SCR catalyst and increase adverse pollutant introduction to the exhaust stream.

The indurating furnace dust cannot be removed by normal soot blowing techniques as used in utility boilers due to design differences between utility boilers and indurating furnaces. Therefore, any accumulation of dust in the SCR system will have to be removed by shutting down the SCR system for cleaning. Cleaning of the SCR system could require shutdown of the indurating furnace and result in lost production due to the required maintenance activities. Additional costs would be expected from the lost production to accommodate the maintenance activities that would be in addition to the cost of control estimate for the SCR with reheat NO<sub>X</sub> control technology. The exhaust dust loading could also shorten SCR run time between maintenance shutdowns by causing unacceptable pressure drops across the SCR system as dust accumulates.

Most of the NO<sub>X</sub> reduction in an SCR reactor occurs within the catalyst pores. Sulfuric acid reacts with alkali earth metals to form sulfate compounds, which blind catalyst pores. Iron oxide catalyzes the conversion of SO<sub>2</sub> to sulfuric acid; creating more catalyst blinding compounds.

# 5.2 Factor #1 – Cost of Compliance

UTAC has completed cost estimates for the selected NO<sub>X</sub> emission control measure of SCR with reheat. Due to the limited time available to respond to MPCA's request, conservative assumptions were made in the cost estimates for equipment costs. These include:

- Use of EPA SCR control costs developed for utility boilers, including estimating an equivalent heat input rate using the actual stack flow and calculating an effective heat input using the natural gas F-factor. As noted by non-utility boiler associations such as the Portland Cement Association, the EPA SCR control cost analysis severely underestimates the cost to install and operate an SCR control system on non-utility boiler processes.<sup>18</sup>
- A 2 part per million (ppm) ammonia slip to minimize collateral visibility emissions of ammonia and PM<sub>2.5</sub>
- A control efficiency of 50 percent based on Portland Cement Association report.<sup>19</sup> The Portland Cement Association has performed comprehensive studies. This data was used to demonstrate the uncertainties and challenges associated with control technology transfers from the utility sector to another sector such as Portland Cement manufacturing.

<sup>&</sup>lt;sup>18</sup> Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for use in Portland Cement Industry

<sup>&</sup>lt;sup>19</sup> The Experience of SCR at Solnhofen and its Applicability to US Cement Plants, June 6, 2006. <u>http://files.dep.state.pa.us/air/AirQuality/AQPortalFiles/Pollutants/transport/Comments/Lehigh Attachment Solnhofe n.pdf</u>

See Section 5.1.1 above for detailed discussion for the true cost of compliance. The cost summary spreadsheets for the NO<sub>X</sub> emission control measures are provided in Appendix A for Line 1 Indurating Furnace and Appendix B for Line 2 Indurating Furnace.

The cost-effectiveness analysis compares the annualized cost of the technology per ton of pollutant removed and is evaluated on a 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 and consistent with the typical approach described in the EPA Control Cost Manual,<sup>20</sup> a 20-year life (before new and extensive capital is needed to maintain and repair the equipment) at 5.5 percent interest is assumed in annualizing capital costs.

The resulting cost-effectiveness calculations are summarized in Table 5-1.

| Additional Emission<br>Control Measure | Installed Capital<br>Cost<br>(\$MM) | Annual Operating<br>Costs<br>(\$/yr) | Annual Emissions<br>Reduction<br>(tpy) | Pollution Control<br>Cost-effectiveness<br>(\$/ton) |
|--|-------------------------------------|--------------------------------------|--|---|
| Line 1 - SCR with Reheat               | \$43,637,895                        | \$21,350,897                         | 662.5                                  | \$32,228  |
| Line 2 - SCR with Reheat               | \$72,550,865                        | \$41,336,088                         | 937.0                                  | \$44,115  |

The cost-effectiveness value of SCR with reheat is substantially greater than the  $NO_X$  cost-effectiveness threshold determined in Section 4.2 of \$1,193 to \$2,800 per ton. Therefore, the costs for the SCR with reheat retrofit option is not reasonable.

Sections 5.3 through 5.5 provide a summary of the remaining three statutory factors evaluated for the NO<sub>X</sub> emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

# 5.3 Factor #2 – Time Necessary for Compliance

The amount of time needed for full implementation of the emission control measure varies. Typically, this includes the time needed to develop and approve the new emissions limit into the SIP by state and federal action, time for MPCA to modify UTAC's Title V operating permit to allow construction to commence, then to implement the project necessary to meet the state SIP limit for the emission control measure, including capital funding, construction, tie-in to the process, commissioning, and performance testing.

<sup>&</sup>lt;sup>20</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 <u>https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution</u> as of the date of this report, page 2-26

A state SIP revision is needed to approve a new statistically derived emissions limit methodology based on the emission performance of the new system, e.g. 99 percent UPL. Barr assumes that the revisions would occur within 12 to 18 months after the MPCA submits its regional haze SIP for the second implementation period (approximately 2022 to 2023). After the SIP is promulgated, the technology would require significant resources and a time period of approximately five years to engineer, permit, and install the equipment.

# 5.4 Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air quality environmental impacts associated with the implementation of the aboveidentified NO<sub>x</sub> control measure are summarized below.

## 5.4.1 Energy Impacts

As with all add-on controls, operation of an SCR system results in an increase in energy demand due to the pressure drop across the SCR catalyst. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations. Electricity is required for the SCR equipment, to vaporize the aqueous ammonia reagent, and for additional fan power. Reheating the flue gas for SCR application would also require substantial natural gas usage with an associated increase in direct emissions. The cost of energy required to operate the control devices has been included in the cost analyses found in Appendix A and B.

## 5.4.2 Environmental Impacts

UTAC has considered air quality impacts for regional haze pollutants because they are directly applicable to the goals of this analysis. Overall, there are secondary air quality impacts associated with SCR operation, which diminish some of the benefits of the NO<sub>X</sub> reductions. The associated increase in PM<sub>10</sub> emissions will also increase the difficulty of obtaining a construction air permit (or potentially PSD) permit for the installation. MPCA should consider the increased emission of PM<sub>10</sub>, SO<sub>3</sub>, sulfuric acid mist, and ammonia in any visibility impact analyses associated with SCR installation.

Urea, which is decomposed in an external reactor to form ammonia, would be used in the SCR. The SCR system consists of an ammonia injection system and a catalytic reactor. Unreacted ammonia may escape through to the exhaust gas. This is commonly called "ammonia slip." It is estimated that ammonia slip from an SCR on this size of furnace could be 2-10 ppm; this may be considered to be an environmental impact. The ammonia that is released may also react with other pollutants in the exhaust stream such as NO<sub>X</sub> and SO<sub>2</sub> to create PM<sub>10</sub> in the form of ammonium salts. The SCR catalysts must also be replaced on a routine basis. In some cases, these catalysts may be classified as hazardous waste. This typically requires either returning the material to the manufacturer for recycling and reuse or disposal in permitted landfills.

As previously noted in Section 5.2, the SCR would oxidize mercury resulting in an increase in local deposition of oxidized mercury emissions near the emission source and most certainly within northeast Minnesota. The TMDL study requires a reduction in loading in order to reduce fish tissue mercury concentrations.

Duct burners have adverse environmental impacts because they require additional fuel combustion to reheat the flue gas to the required oxidation temperatures. Therefore, the technology would have increased collateral air emissions (e.g. NO<sub>X</sub>, CO, VOC, PM, GHG, etc.).

Additionally, there are safety concerns associated with the transport and storage of urea or ammonia, including potential spills that can have serious adverse health and environmental impacts.

## 5.5 Factor #4 - Remaining Useful Life of the Source

Because UTAC is assumed to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life, per Section 4.5) is used to calculate emission reductions, amortized costs and cost-effectiveness on a dollar per ton basis.

# 5.6 NO<sub>x</sub> Four-Factor Analysis Conclusion

Based on the analysis conducted in Sections 5.1 through 5.5, UTAC has determined that installation of additional  $NO_X$  emissions measures on the Line 1 and Line 2 Indurating Furnaces beyond those described in Section 3.1 are not feasible.

# 6 SO<sub>2</sub> Four-Factor Analysis

This section identifies and describes various SO<sub>2</sub> emission control measures, evaluates the four statutory factors for the Line 1 and Line 2 Indurating Furnaces, considers other factors, and determines if an emission control measure or measures are necessary to make reasonable progress. Consistent with EPA's guidance and MPCA direction, UTAC has completed a Four-Factor Analysis for SO<sub>2</sub> as described in Sections 6.1 to 6.6.

## 6.1 SO<sub>2</sub> Control Measures Overview

The SO<sub>2</sub> emissions occur as a result of the oxidation of sulfur that is present in the taconite ore and in the fuels combusted. In establishing the 2028 baseline emission rate, the lowest SO<sub>2</sub> concentration that can be reasonably achieved by add-on control technologies is 5 ppm. The 2028 baseline emission rate of 15.7 Ib SO<sub>2</sub>/hr for Line 1 equates to 4.9 ppm SO<sub>2</sub>. The calculation of the equivalent SO<sub>2</sub> concentrations is provided in the cost summary spreadsheets for the SO<sub>2</sub> emission control measures in Appendices A and B. With a 2028 baseline SO<sub>2</sub> concentration of less than 5 ppm, the control technology control efficiency will result in negative values. This is an anomaly of the cost of control evaluation process. Therefore, all of the additional SO<sub>2</sub> control technology options for the Line 1 Indurating Furnace would not be considered feasible. The Four-Factor Analysis has therefore been performed for the Line 2 Indurating Furnace only. Table 6-1 lists the technically feasible SO<sub>2</sub> control technologies for the Line 2 Indurating Furnace.

Table 6-1 Additional SO<sub>2</sub> Control Measures with Potential Application at the Line 2 Indurating Furnace

| Control Measures     |
|----------------------|
| DSI – New PM Control |
| SDA– New PM Control  |
| GSA– New PM Control  |

As noted for each SO<sub>2</sub> control technology, new PM control equipment will be required to achieve the SO<sub>2</sub> control efficiencies and removal. The following describes pertinent technical information regarding each control measure and whether the control measure is technically feasible when applied to the Line 2 Indurating Furnace.

## 6.1.1 DSI – With New PM Control

While DSI has not been demonstrated at an operating taconite indurating furnace, DSI could conceptually be utilized if UTAC were to replace its existing PM controls (wet scrubbers) with controls that are compatible with DSI (e.g., baghouse or electrostatic precipitator (ESP)). Indurating furnace waste gas streams are high in water content and are exhausted at or near dew points. Gases leaving the indurating furnace are currently treated for removal of particulate matter using a wet scrubber. The exhaust temperature is typically in the range of 100°F to 150°F and is saturated with water. For comparison, a

utility boiler exhaust operates at 350°F or higher and is not saturated with water. The indurating furnace waste gas conditions following the existing wet scrubber would plug both the filters and the dust removal system. Therefore, the proposed control train would need to replace the existing wet scrubber with DSI and new PM control. With the removal of the existing wet scrubber and addition of new PM control after the DSI, the DSI control technology is assumed to be potentially technically feasible for Line 2 Indurating Furnace.

The DSI evaluation conclusions vary in past SO<sub>2</sub> control equipment evaluations (2006 BART, 2010 Keetac BACT, 2011 Essar BACT reports, and 2012 EPA BART Determination). The 2006 BART reports and 2012 EPA BART Determination evaluated DSI after the existing scrubbers and concluded that the technology was not technically feasible due to high moisture flue gas resulting in caking and blinding of the associated filter bags. The 2010 Keetac BACT and 2011 Essar BACT reports concluded that DSI was technically feasible but concluded that a GSA was BACT with a baghouse for PM control.

## 6.1.2 SDA – With New PM Control

While an SDA has not been demonstrated at an operating taconite indurating furnace, an SDA could conceptually be utilized if UTAC were to replaces its existing PM controls (wet scrubbers) with controls that are compatible with an SDA (e.g., baghouse or ESP). Similar to the DSI control option, the moisture in the exhaust stream after the existing wet scrubber would plug the dust collection system. Due to the saturated waste gas exhaust, the proposed SDA control technology would require replacement of the wet scrubber with an ESP ahead of the SDA with baghouse control. Therefore, SDA with new PM control is assumed to be potentially technically feasible for Line 2 Indurating Furnace.

The SDA evaluation conclusions vary in past SO<sub>2</sub> control equipment evaluations (2006 BART, 2010 Keetac BACT, 2011 Essar BACT reports, and 2012 EPA BART Determination). All of the facilities' 2006 BART reports (except Northshore Mining Company (NSM) due to NSM already employing wet ESP control technology) and the 2012 EPA BART Determination concluded that SDA was not technically feasible due to the high moisture flue gas. NSM's 2006 BART reports concluded that SDA was not cost-effective on a \$/ton removed basis. The 2010 Keetac BACT report concluded that SDA was technically feasible but stated that GSA was BACT with a baghouse for PM control. The 2011 Essar BACT report concluded that SDA was not cost-effective on a \$/ton removed basis.

## 6.1.3 GSA – With New PM Control

While GSA has not been demonstrated at an operating taconite indurating furnace, there are not strong technical reasons prohibiting the installation and operation at an indurating furnace if alternative PM controls are used instead of wet scrubbers (e.g., baghouse or ESP). Similar to the DSI and SDA control options, the moisture in the exhaust stream would plug the dust collection system. Due to the saturated waste gas exhaust following the wet scrubber, the proposed GSA control technology would require replacement of the wet scrubber with an ESP ahead of the GSA with baghouse control. Therefore, GSA with new PM control is assumed to be potentially technically feasible for Line 2 Indurating Furnace.

GSA was not assessed in the 2006 BART report. The 2010 Keetac BACT report concluded that GSA was technically feasible with a baghouse and was BACT. The 2011 Essar BACT report concluded that GSA was not cost-effective on a \$/ton removed basis. There was an attempted application of GSA at a taconite pelletizing facility in 2018 in Indiana. The facility experienced severe operational issues with the GSA that resulted in an enforcement action for non-compliance, further supporting the uncertainty of the application of GSA on taconite indurating furnace. Regardless, UTAC proceeded to evaluate the control costs of a GSA for the purpose of this analysis.

## 6.2 Factor #1 – Cost of Compliance

UTAC has completed cost estimates for the selected SO<sub>2</sub> emission control measures. Cost summary spreadsheets for the SO<sub>2</sub> emission control measures are provided in Appendix B.

The cost-effectiveness analysis compares the annualized cost of the emission control measure per ton of pollutant removed and is evaluated on a 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 consistent with the typical approach described in the EPA Control Cost Manual,<sup>20</sup> a 20-year life (before new and extensive capital is needed to maintain and repair the equipment) at 5.5 percent interest is assumed in annualizing capital costs.

The resulting cost-effectiveness calculations are summarized in Table 6-2.

| Additional Emission Control<br>Measure | Installed Capital<br>Cost<br>(\$MM) | Annual Operating<br>Costs<br>(\$/yr) | Annual Emissions<br>Reduction<br>(tpy) | Pollution Control<br>Cost-effectiveness<br>(\$/ton) |
|--|-------------------------------------|--------------------------------------|--|---|
| DSI with New PM Control                | \$50,466,157                        | \$10,090,749                         | 108.2                                  | \$93,300  |
| SDA with New PM Control                | \$120,947,748                       | \$19,573,967                         | 108.2                                  | \$180,891   |
| GSA with New PM Control                | \$113,793,152                       | \$18,757,651                         | 108.2                                  | \$173,347   |

## Table 6-2: SO2 Control Cost Summary, Line 2 Indurating Furnace

For Line 2 Indurating Furnace, the cost-effectiveness values for all of the SO<sub>2</sub> emission control measures are substantially greater than the cost-effectiveness threshold determined in Section 4.2 of \$4,200 to \$5,700 per ton. Therefore, the costs for the retrofit options are not reasonable.

Sections 6.3 through 6.5 provide a summary of the remaining three statutory factors evaluated for the SO<sub>2</sub> emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

# 6.3 Factor #2 – Time Necessary for Compliance

The amount of time needed for full implementation of the emission control measure varies. Typically, this includes the time needed to develop and approve the new emissions limit into the SIP by state and federal action, time for MPCA to modify UTAC's Title V operating permit to allow construction to

commence, then to implement the project necessary to meet the state SIP limit for the emission control measure, including capital funding, construction, tie-in to the process, commissioning, and performance testing.

A state SIP revision is needed to approve a new statistically derived emissions limit methodology based on the emission performance of the new system, e.g. 99 percent UPL. Barr assumes that the revisions would occur within 12 to 18 months after the MPCA submits its regional haze SIP for the second implementation period (approximately 2022 to 2023). After the SIP is promulgated, the technology would require significant resources and a time period of approximately five years to engineer, permit, and install the equipment.

# 6.4 Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified SO<sub>2</sub> control measures are summarized below.

## 6.4.1 Energy Impacts

The SO<sub>2</sub> control technologies with new PM control would require additional electricity requirements. Similar to the NO<sub>x</sub> add-on controls, operation of add-on SO<sub>2</sub> control systems with new PM control results in an increase in energy usage due to the higher pressure drop across the baghouse for all three technologies and pressure drop across the reactor for SDA and GSA technologies, material preparation such as grinding reagents, additional material handling equipment such as pumps and blowers, and steam requirements. Power consumption is also affected by reagent utilization, which also affects the control efficiency of the control technology. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations. The cost of energy required to operate the control devices has been included in the cost analyses found in Appendix B.

## 6.4.2 Environmental Impacts

The DSI control technology would generate additional solid waste that would require disposal in permitted landfills. Currently, the collected solids in the wet scrubber is recirculated back into the process. With the removal of the wet scrubber and replacement with DSI control, the DSI reagent would directly mix with the process dust, rendering the dust unsuitable for recycling back into the process, and resulting in increased solids to the landfill as well as a loss in valuable iron units (i.e., decreased pellet production).

# 6.5 Factor #4 – Remaining Useful Life of the Source

Because UTAC is assumed to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life, per Section 4.5) is used to calculate emission reductions, amortized costs and cost-effectiveness on a dollar per ton basis.

# 6.6 SO<sub>2</sub> Four-Factor Analysis Conclusion

Based on the analysis conducted in Sections 6.1 through 6.5, UTAC has determined that installation of additional  $SO_2$  emission measures on the Line 1 and Line 2 Indurating Furnaces beyond those described in Section 3.1 are not feasible.

# Appendix A

Unit-specific Screening Level Cost Summary for Line 1 Control Measures

# Cleveland Cliffs: United Taconite Line 1 Appendix A - Four-Factor Control Cost Analysis Table 1: Cost Summary

NO<sub>x</sub> Control Cost Summary

| Control Technology                              | Control | Controlled     | Emission       | Installed Capital | Annualized           | Pollution Control |
|---|---------|----------------|----------------|-------------------|----------------------|-------------------|
|   | Eff %   | Emissions T/yr | Reduction T/yr | Cost \$           | Operating Cost \$/yr | Cost \$/ton       |
| Selective Catalytic Reduction with Reheat (SCR) | 50%     | 662.5          | 662.5          | \$43,637,895      | \$21,350,897         | \$32,228          |

#### Cleveland Cliffs: United Taconite Line 1 Appendix A - Four-Factor Control Cost Analysis Table 2: Summary of Utility, Chemical and Supply Costs

| Operating Unit:         Line 1           Emission Unit Number         EU 040 |               | Study Year                | 2020       |               |   |  |
|--|---------------|---------------------------|------------|---------------|---|--|
| Stack/Vent Number  | SV 046        |                           |            |               |   |  |
| Item   | Unit Cost     | Units                     | Cost       | Year          | Data Source   | Notes  |
| Operating Labor<br>Maintenance Labor   | 72.12         | \$/hr<br>\$/hr            |            | 2020 2020     | Site-specific labor cost<br>Site-specific labor cost  |  |
| Electricity  | 0.068         | \$/kwh                    | 68.44      |               | Site-specific cost  |  |
| Natural Gas  | 4.98          | \$/kscf                   |            | N/A           | 5-yr average based on natural gas prices (eia.gov)  |  |
| Water  | 0.01          | \$/kgal                   |            | 2019          | Site-specific cost from 2019<br>EPA Air Pollution Control Cost Manual 6th Ed 2002,  |  |
| Compressed Air   | 0.48          | \$/kscf                   | 0.25       | 1998          | Section 6 Chapter 1   | Adjusted for 3% inflation  |
|  |               |                           |            |               |   |  |
| Taconite Pellets Chemicals & Supplies  | 29.1          | \$/LT                     |            | 2020          | Based on Q1 2020 sales margin in earnings report  |  |
| Chemicals & Supplies   |               |                           |            |               | Hydrated lime cost from 2012 Dry Flugas   |  |
| Lime   | 183.68        | \$/ton                    | 145.00     | 2012          | Desulfurization Study for UTAC Lines 1 and 2  | Adjusted for 3% inflation  |
| Urea 500/ Calutian   | 4.04          | ¢/                        | 1.66       | 0017          | EPA Control Cost Manual Chapter 7, 7th Edition<br>default   | Adjusted for 20/ inflation   |
| Urea 50% Solution<br>Trona   | 285.00        | \$/gallon<br>\$/ton       | 1.00       | 2017          | Vendor estimated delivered cost   | Adjusted for 3% inflation  |
| Estimated operating life of the SCR catalyst                                 |               |                           |            |               |   |  |
| (H <sub>catalyst</sub> )   | 8,000         | hours                     |            |               | EPA Control Cost Manual Chapter 7, 7th Edition  |  |
| Catalyst cost (CC replace)   | 249.05        | \$/cubic foot (inc        | 227        | 2017          | EPA Control Cost Manual Chapter 7, 7th Edition<br>default   | Adjusted for 3% inflation  |
| Catalyst Cost (CC replace/   | 246.05        | \$/CUDIC IOOL (INC        | 221        | 2017          | Vendor estimated bag cost from the 2018 Best  |  |
|  |               |                           |            |               | Available Mercury Reduction Technology (BAMRT)  |  |
| Cost per bag   | 116.70        | \$/bag                    | 110        | 2018          | Analysis  | Adjusted for 3% inflation  |
| Other<br>Sales Tax   | 6.875%        | percent                   |            |               | Current MN sales tax rate   |  |
|  | 0.07378       | percent                   |            |               | EPA Control Cost Manual Chapter 7, 7th Edition  |  |
| Interest Rate  | 5.50%         | percent                   |            |               | default   |  |
| Solid Waste Disposal   | 44.35         | \$/ton                    | 41.8       | 2018          | 2018 site specific cost<br>EPA Control Cost Manual Chapter 2, 7th Edition   | Adjusted for 3% inflation  |
|  | 1             |                           |            | 1             | estimates contingencies from 5-15%. Assumed the   |  |
| Contingency  | 10%           | percent                   |            |               | mid range   |  |
|  |               |                           |            |               | CUECost Workbook Version 1.0, USEPA Document  |  |
| Markup on capital cost (Retrofit Factor)                                     | 60%           | percent                   |            |               | Page 2 allows up to a 60% retrofit factor for<br>installations in existing facilities.  |  |
| Operating Information  |               |                           |            |               |   |  |
| Annual Op. Hrs   | 8376          |                           |            |               | Site-specific estimate  |  |
| Utilization Rate<br>Single Furnace Pellet Production Rate                    |               | percent<br>Lton/hr        |            |               | Site-specific estimate Furnace capacity   |  |
| Desgin Capacity  |               | MMBTU/hr                  |            |               | Furnace capacity  |  |
| Equipment Life   | 20            | yrs                       |            |               | Assumed   |  |
| Temperature- After Scrubber  |               | Deg F                     |            |               | Stack test data<br>Site-specific estimate   |  |
| Temperature- Before Scrubber<br>Moisture Content-After Scrubber              | 13.7%         | Deg F                     |            |               | Stack test data   |  |
| Moisture Content-Before Scrubber   | 6.3%          |                           | 1000       | lb H2O/min    | Site-specific estimate  |  |
| Existing Delivities Operate DM inter Operandonites                           | 0.47          |                           |            | 0040          |   |  |
| Existing Pollution Contols PM Inlet Concentraiton                            | 2.17          | gr/dscf dust loa          | d          | 2018          | Site-specific estimate  | Efficiency is used to calculate the increased  |
| Existing Pollution Contols PM Control Efficiency                             | 0.4%          | percent                   |            |               | 2020 TVOP reissuance application PM control<br>efficiency   | baghouse dust loading for DSI because the captured<br>dust cannot be recycled to process with the<br>spent/unreacted reagent. This does not apply to the<br>GSA/SDA because there is an ESP upstream of the<br>absorber. |
| Actual Flow Rate-After Scrubber  | 420,000       |                           |            |               | Site-specific estimate  | absorber.  |
| Actual Flow Rate-Before Scrubber   | 460,000       | acfm                      |            |               | Site-specific estimate  |  |
| Standardized Flow Rate-After Scrubber  | 260,600       | scfm @ 68º F              | 244 400    | scfm @ 32º F  | Calculated from stack temperature and flow data in<br>acfm listed above   |  |
| Standardized flow Nate-Arter Scrubber  | 309,000       | SCIII @ 00-1              | 344,400    | Sciiii @ 32.1 | Calculated from stack temperature and flow data in  |  |
| Standardized Flow Rate-Before Scrubber                                       | 342,085       | scfm @ 68º F              | 318,761    | scfm @ 32º F  | acfm listed above   |  |
| Dry Std Flow Rate-After Scrubber   | 210.005       | dscfm @ 68º F             |            |               | Calculated from stack temperature and flow data in<br>acfm listed above   |  |
| bly Stu How Kate-Alter Scrubber  | 316,905       | usciiii @ 66* F           |            |               | Calculated from stack temperature and flow data in  |  |
| Dry Std Flow Rate-Before Scrubber  | 320,696       | dscfm @ 68º F             |            |               | acfm listed above   |  |
| Fuel higher besting value (HUV)  | 1.022         | DTI l/a of                |            |               | EPA Control Cost Manual Chapter 7, 7th Edition  |  |
| Fuel higher heating value (HHV) Plant Elevation                              | 1,033         | BTU/scf<br>Feet above sea | level      |               | default<br>Site elevation   |  |
| Method 19 Design Factor (SCR)  | 8,710         |                           |            |               | Natural gas F-Factor  |  |
| Technology Control Efficiencies  |               |                           |            |               |   |  |
|  |               |                           |            |               | Control efficiency provided by Solnhofer Portland<br>Cement Works GmbH & Co. KG. Reference "The<br>Experience of SCR at Solhhofen and its Applicability<br>to US Cement Plants, June 6, 2006. According to<br>Portland Cement Association, the EPA 7th Edition<br>SCR control cost data severally underestimates the<br>costs of installation and operation of SCR control<br>technology designed for utility boilers and transfer to<br>Portland Cement kilns. Assumed similar control |  |
| SCR  | 50%           | percent                   |            |               | efficiency to a cement kiln.<br>Calculated control efficiency to determine reduction  | <u> </u>   |
|  |               |                           |            |               | over baseline emissions to 5 ppm outlet per vendor  |  |
| GSA  | -2%           | percent                   |            |               | specifications  |  |
|  | 1             |                           |            | 1             | Calculated control efficiency to determine reduction<br>over baseline emissions to 5 ppm outlet per vendor  |  |
| SDA  | -2%           | percent                   |            | 1             | specifications  |  |
| DSI<br>Existing scrubber SO2 Control Efficiency                              | -2%           | percent                   |            |               | Calculated control efficiency to determine reduction<br>over baseline emissions to 5 ppm outlet per vendor<br>specifications. Note, it is unlikely that DSI can<br>actually achieve 5 ppm SO2 outlet. However, to be<br>conservative it was assume that this could be<br>achieved.<br>Site-specific estimate  |  |
|  | Baseline Emis | sions                     |            |               |   |  |
| Pollutant  | lb/hr         | tpy                       | ppmv       |               | Decelies toy is site energific anti-  |  |
|  |               |                           |            |               | Baseline tpy is site-specific estimate. Lb/hr<br>represents average when furnace was operating at   |  |
| Nitrous Oxides (NOx)   | 348           | 1,325                     | 151        |               | >50% capacity   |  |
|  |               |                           |            |               | Baseline tpy is site-specific estimate. Lb/hr   |  |
| Sulfur Dioxide (SO2)<br>Outlet SO2 controls target                           | 15.7          | 59.7                      | 4.9<br>5.0 |               | represents average when furnace was operating at<br>>50% capacity   |  |
| Sulfur Dioxide (SO2) Uncontrolled with Scrubbers                             |               |                           |            |               |   |  |
| Removed  | 20.9          | 79.6                      | 7          | 1             | SO2 emission rate without the existing scrubbers  | 1  |

#### **Cleveland Cliffs: United Taconite Line 1** Appendix A - Four-Factor Control Cost Analysis Table 3: Selective Catalytic Reduction with Reheat

#### **Operating Unit:** Line 1

| Emission Unit Number               | EU 040 |          | Stack/Vent Number                     | SV 046  |               |
|------------------------------------|--------|----------|---------------------------------------|---------|---------------|
| Design Capacity                    | 190    | MMBtu/hr | Standardized Flow Rate <sup>5</sup>   | 344,400 | scfm @ 32º F  |
| Expected Utilization Rate          | 100%   |          | Exhaust Temperature <sup>5</sup>      | 140     | Deg F         |
| Expected Annual Hours of Operation | 8,376  | Hours    | Exhaust Moisture Content <sup>5</sup> | 13.7%   |               |
| Annual Interest Rate               | 5.5%   |          | Actual Flow Rate <sup>5</sup>         | 420,000 | acfm          |
| Expected Equipment Life            | 20     | yrs      | Standardized Flow Rate <sup>5</sup>   | 369,600 | scfm @ 68º F  |
| Pellet Throughput                  | 250    | LTon/hr  | Dry Std Flow Rate <sup>5</sup>        | 318,965 | dscfm @ 68º F |

#### CONTROL EQUIPMENT COSTS

| Capital Costs                                  |  |                    |               |                   |              |            |
|--|--|--------------------|---------------|-------------------|--------------|------------|
|  |  |                    |               |                   |              |            |
|  |  |                    |               |                   |              |            |
|  |  |                    |               |                   |              |            |
|  |  |                    |               |                   |              |            |
|  |  |                    |               |                   |              |            |
|  |  |                    |               |                   |              |            |
|  |  |                    |               |                   |              |            |
|  |  |                    |               |                   |              |            |
| Total Capital Investment (TCI) with Retrofit   |  |                    |               |                   | SCR Only     | 42,558,186 |
|  |  |                    |               |                   | SCR + Reheat | 43,637,895 |
| Operating Costs                                |  |                    |               |                   |              |            |
| Total Annual Direct Operating Costs            | Labor, supervisio  | n, materials, repl | acement parts | , utilities, etc. | SCR + Reheat | 17,578,490 |
| Total Annual Indirect Operating Costs          | Sum indirect oper  | costs + capital I  | ecovery cost  |                   | SCR + Reheat | 3,772,408  |
| Total Annual Cost (Annualized Capital Cost + O | Total Annual Cost (Annualized Capital Cost + Operating Cost) |                    |               |                   | SCR + Reheat | 21,350,897 |

#### **Emission Control Cost Calculation**

| Pollutant            | Emissions | Annual  | Cont Eff | Cont Emis | Reduction | Cont Cost  |
|----------------------|-----------|---------|----------|-----------|-----------|------------|
|                      | Lb/Hr     | T/Yr    | %        | T/yr      | T/yr      | \$/Ton Rem |
| Nitrous Oxides (NOx) | 348.0     | 1,325.0 | 50%      | 662.5     | 662.5     | 32,228     |

#### Notes & Assumptions

1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 7th Ed SCR Control Cost Spreadsheet (June 2019)

2 TCI includes the cost of a new booster fan
3 For Calculation purposes, duty reflects increased flow rate, not actual duty.
4 CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit factor for installations in existing facilities.
5 Specifications are after scrubber conditions.

#### **Cleveland Cliffs: United Taconite Line 1** Appendix A - Four-Factor Control Cost Analysis Table 3: Selective Catalytic Reduction with Reheat

#### CAPITAL COSTS

| Total Capital Investment (TCI)                | Refer to the Cost Estimate tab    | 40,113,786 |
|---|-----------------------------------|------------|
| Retrofit factor<br>Lost Production for Tie-In | 60% of TCI, see Cost Estimate tab | 2,444,400  |

Total Capital Investment Retrofit Installed

42,558,186

OPERATING COSTS Direct Annual Operating Costs, DC

| Maintenance                                 |   |           |
|---|---|-----------|
| Annual Maintenance Cost =                   | Refer to the Cost Estimate tab                  | 197,727   |
| Utilities, Supplies, Replacements & Waste   | Management                                      |           |
| Annual Electricity Cost =                   | Refer to the Cost Estimate tab                  | 647,665   |
| Annual Catalyst Replacement Cost =          | Refer to the Cost Estimate tab                  | 763,512   |
| Annual Reagent Cost =                       | Refer to the Cost Estimate tab                  | 381,769   |
| Total Annual Direct Operating Costs         |   | 1,990,673 |
| Indirect Operating Costs                    |   |           |
| Administrative Charges (AC) =               | Refer to the Cost Estimate tab                  | 5,393     |
| Capital Recovery Costs (CR)=                | 0.0837 Refer to the Cost Estimate tab           | 3,562,120 |
| Total Annual Indirect Operating Costs       | Sum indirect oper costs + capital recovery cost | 3,567,513 |
| al Annual Cost (Annualized Capital Cost + O | perating Cost)                                  | 5,558,186 |

#### Cleveland Cliffs: United Taconite Line 1 Appendix A - Four-Factor Control Cost Analysis Table 3: Selective Catalytic Reduction with Reheat

| Capital Recovery Factors       |                                      |                 |                 |  |
|--------------------------------|--------------------------------------|-----------------|-----------------|--|
| Primary Installation           |                                      |                 |                 |  |
| Interest Rate                  | 5.50%                                |                 |                 |  |
| Equipment Life                 | 20 years                             |                 |                 |  |
| CRF                            | 0.0837                               |                 |                 |  |
| <u> </u>                       |                                      |                 |                 |  |
| Replacement Catayst - Ro       | efer to the <i>Cost Estimate Tab</i> |                 |                 |  |
| Annualized Cost                | \$ 763,512                           |                 |                 |  |
| - I have During                | 0.407                                |                 |                 |  |
| Equivalent Duty                | 2,197                                |                 |                 |  |
| Uncontrolled Nox Ib/mmBtu      | 0.158                                |                 |                 |  |
| SCR Capital Cost               |                                      |                 |                 |  |
| Electrical Use                 |                                      |                 |                 |  |
| Reagent Use & Other Operatin   | n Costs                              |                 |                 |  |
| Refer to the Cost Estimate tab |                                      |                 |                 |  |
| Design Basis                   | Max Emis                             |                 | Control Eff (%) |  |
| Nitrous Oxides (NOx)           | Ib/MMBtu<br>0.158 Adjusted Ib/MI     | MBtu            | 50%             |  |
| Actual                         | 100,726 dscf/MMBtu                   |                 |                 |  |
| Method 19 Factor               | 8,710 dscf/MMBtu NG F-FACTO          | R               |                 |  |
| Adjusted Duty                  | 2,197 MMBtu/hr                       |                 |                 |  |
| Operating Cost Calculations    |                                      | s of operation: | 8,376           |  |
| Operating over ouronations     | Utilization Ra                       |                 | 100%            |  |
| Refer to the Cost Estimate tak | )                                    |                 |                 |  |
|                                |                                      |                 |                 |  |
|                                |                                      |                 |                 |  |

**Operating Unit:** 

Line 1

| Emission Unit Number               | EU 040 |          | Stack/Vent Number                     | SV 046  |               | Chemical Engineering |            |
|------------------------------------|--------|----------|---------------------------------------|---------|---------------|----------------------|------------|
|                                    | 190    | MMBtu/hr | Standardized Flow Rate <sup>3</sup>   | 344,400 | scfm @ 32º F  | Chemical Plant       | Cost Index |
| Expected Utilization Rate          | 100%   |          | Exhaust Temperature <sup>3</sup>      | 140     | Deg F         | 1998/1999            | 390        |
| Expected Annual Hours of Operation | 8,376  | Hours    | Exhaust Moisture Content <sup>°</sup> | 13.7%   |               | 2019                 | 607.5      |
| Annual Interest Rate               | 5.5%   |          | Actual Flow Rate <sup>3</sup>         | 420,000 | acfm          | Inflation Adj        | 1.56       |
| Expected Equipment Life            | 20     | yrs      | Standardized Flow Rate <sup>3</sup>   | 369,600 | scfm @ 68º F  |                      |            |
| Pellet Throughput                  | 250    | LTon/hr  | Dry Std Flow Rate <sup>3</sup>        | 318,965 | dscfm @ 68º F |                      |            |

#### CONTROL EQUIPMENT COSTS

| Capital Costs                                |            |               |                  |                 |                   |          |            |
|--|------------|---------------|------------------|-----------------|-------------------|----------|------------|
| Direct Capital Costs                         |            |               |                  |                 |                   |          |            |
| Purchased Equipment (A)                      |            |               |                  |                 |                   |          | 329,582    |
| Purchased Equipment Total (B)                | 22%        | of control de | vice cost (A)    |                 |                   |          | 401,678    |
| Installation - Standard Costs                | 30%        | of purchased  | d equip cost (B) |                 |                   |          | 120,503    |
| Installation - Site Specific Costs           |            |               |                  |                 |                   |          | NA         |
| Installation Total                           |            |               |                  |                 |                   |          | 120,503    |
| Total Direct Capital Cost, DC                |            |               |                  |                 |                   |          | 522,181    |
| Total Indirect Capital Costs, IC             | 38%        | of purchased  | d equip cost (B) |                 |                   |          | 152,637    |
| Total Capital Investment (TCI) with Retrofit |            |               |                  |                 |                   |          | 1,079,709  |
| Operating Costs                              |            |               |                  |                 |                   |          |            |
| Total Annual Direct Operating Costs          |            | Labor, super  | vision, material | s, replacemer   | t parts, utilitie | es, etc. | 15,587,817 |
| Total Annual Indirect Operating Costs        |            | Sum indirect  | oper costs + ca  | apital recovery | / cost            |          | 204,894    |
| Total Annual Cost (Annualized Capital Cost   | + Operatin | g Cost)       |                  |                 |                   |          | 15,792,712 |

 Notes & Assumptions

 1
 Equipment cost estimate EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2.5.1

 2
 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2

 3
 Specifications are after scrubber conditions.

| Direct Capital Costs   |  |   | 200 5  |
|--|--|---|--|
| Purchased Equipment (A) (1)<br>Purchased Equipment Costs (A) - Absorber + p  | acking ± ai  | ivillary equipment EC   | 329,5  |
| Instrumentation  | -  | of control device cost (A)  | 32,9   |
| MN Sales Taxes   |  | of control device cost (A)  | 22,6   |
|  |  |   |  |
| Freight  | 5%<br>22%  | of control device cost (A)  | 16,4<br>401,6  |
| Purchased Equipment Total (B)  | 2270   |   | 401,6  |
| Installation   |  |   |  |
| Foundations & supports   | 8%   | of purchased equip cost (B)   | 32,1   |
| Handling & erection  | 14%  | of purchased equip cost (B)   | 56,2   |
| Electrical   | 4%   | of purchased equip cost (B)   | 16,0   |
| Piping   | 2%   | of purchased equip cost (B)   | 8,0  |
| Insulation   | 1%   | of purchased equip cost (B)   | 4,0  |
| Painting   |  | of purchased equip cost (B)   | 4,0  |
| Installation Subtotal Standard Expenses  | 30%  |   | 120,5  |
|  |  |   |  |
| Site Preparation, as required  |  | Site Specific   | NA   |
| Buildings, as required   |  | Site Specific   | NA   |
| Site Specific - Other  |  | Site Specific   | NA   |
| Total Site Specific Costs<br>Installation Total  |  |   | NA<br>120,5  |
| Total Direct Capital Cost, DC  |  |   | 522,1  |
|  |  |   |  |
| Indirect Capital Costs<br>Engineering, supervision   | 1.0%   | of purchased equip cost (B)   | 40,1   |
| Construction & field expenses  |  | of purchased equip cost (B)   | 20,0   |
| Contractor fees  |  | of purchased equip cost (B)   | 40,1   |
| Start-up   |  | of purchased equip cost (B)   | 8.0  |
| Performance test   |  | of purchased equip cost (B)   | 4,0  |
| Model Studies  |  | of purchased equip cost (B)   |  |
| Contingencies  |  | of purchased equip cost (B)   | 40,1   |
| Total Indirect Capital Costs, IC   | 38%  | of purchased equip cost (B)   | 152,6  |
| tal Capital Investment (TCI) = DC + IC   |  |   | 674,8  |
| justed TCI for Replacement Parts (Catalyst, Filter I   | Bags, etc)   | for Capital Recovery Cost   | 674,8  |
| tal Capital Investment (TCI) with Retrofit Factor  | 60%  | 1.6 Retrofit Factor   | 1,079,7  |
| PERATING COSTS   |  |   |  |
|  |  |   |  |
| Direct Annual Operating Costs, DC  |  |   |  |
| Direct Annual Operating Costs, DC<br>Operating Labor   |  |   |  |
| Operating Labor<br>Operator  |  | \$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr  |  |
| <b>Operating Labor</b><br>Operator<br>Supervisor   |  | \$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>15% of Operator Costs   | 37,7<br>5,6  |
| Operating Labor<br>Operator<br>Supervisor<br>Maintenance   | 15%  | 15% of Operator Costs   | 5,6  |
| Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor  | 15%<br>72.12   | 15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr   | 5,6  |
| Operating Labor<br>Operator<br>Supervisor<br>Maintenance   | 15%<br>72.12<br>100%   | 15% of Operator Costs   | 5,6  |
| Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Man<br>NA  | 15%<br>72.12<br>100%<br>agement<br>NA                                  | 15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>of maintenance labor costs   | 5,6<br>37,7<br>37,7  |
| Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Man  | 15%<br>72.12<br>100%<br>agement<br>NA                                  | 15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr   |  |
| Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Man<br>NA  | 15%<br>72.12<br>100%<br>agement<br>NA                                  | 15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>of maintenance labor costs   | 5,6<br>37,7<br>37,7  |
| Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Manu<br>NA<br>Natural Gas   | 15%<br>72.12<br>100%<br>agement<br>NA                                  | 15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>of maintenance labor costs   | 5,6<br>37,7<br>37,7<br>15,468,8  |
| Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Man<br>NA<br>Natural Gas<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead   | 15%<br>72.12<br>100%<br>agement<br>NA<br>4.98                          | 15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>of maintenance labor costs<br>\$/kscf, 6,181 scfm, 8376 hr/yr, 100% utilization<br>of total labor and material costs   | 5,6<br>37,7<br>37,7<br>15,468,8<br><b>15,587,8</b><br>71,3                         |
| Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Man<br>NA<br>Natural Gas<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)  | 15%<br>72.12<br>100%<br>agement<br>NA<br>4.98<br>60%<br>2%             | 15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>of maintenance labor costs<br>\$/kscf, 6,181 scfm, 8376 hr/yr, 100% utilization<br>of total labor and material costs<br>of total capital costs (TCI)   | 5,6<br>37,7<br>37,7<br>15,468,8<br><u>15,587,8</u><br>71,3<br>21,5                 |
| Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Man<br>Na<br>Natural Gas<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)                        | 15%<br>72.12<br>100%<br>agement<br>NA<br>4.98<br>60%<br>2%<br>1%       | 15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>of maintenance labor costs<br>\$/kscf, 6,181 scfm, 8376 hr/yr, 100% utilization<br>of total labor and material costs<br>of total capital costs (TCI)<br>of total capital costs (TCI)                                 | 5,6<br>37,7<br>37,7<br>15,468,8<br><b>15,587,8</b><br>71,3<br>21,5<br>10,7         |
| Operating Labor<br>Operator<br>Supervisor<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Man<br>NA<br>Natural Gas<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)<br>Insurance (1% total capital costs) | 15%<br>72.12<br>100%<br>agement<br>NA<br>4.98<br>60%<br>2%<br>1%<br>1% | 15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>of maintenance labor costs<br>\$/kscf, 6,181 scfm, 8376 hr/yr, 100% utilization<br>of total labor and material costs<br>of total capital costs (TCI)<br>of total capital costs (TCI)<br>of total capital costs (TCI) | 5,6<br>37,7<br>37,7<br>15,468,8<br><b>15,587,8</b><br>71,3<br>21,5<br>10,7<br>10,7 |
| Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor<br>Maintenance Materials<br>Utilities, Supplies, Replacements & Waste Man<br>Na<br>Natural Gas<br>Total Annual Direct Operating Costs<br>Indirect Operating Costs<br>Overhead<br>Administration (2% total capital costs)<br>Property tax (1% total capital costs)                        | 15%<br>72.12<br>100%<br>agement<br>NA<br>4.98<br>60%<br>2%<br>1%<br>1% | 15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>of maintenance labor costs<br>\$/kscf, 6,181 scfm, 8376 hr/yr, 100% utilization<br>of total labor and material costs<br>of total capital costs (TCI)<br>of total capital costs (TCI)                                 | 5,6<br>37,7<br>37,7<br>15,468,8  |

Total Annual Cost (Annualized Capital Cost + Operating Cost)

15,792,712

| Capital Recovery Fact   |   |   |   |   |   |   |  |
|---|---|---|---|---|---|---|--|
| rimary Installation   |   |   |   |   |   |   |  |
| -   |   | 5 500/  |   |   |   |   |  |
| nterest Rate  |   | 5.50%   |   |   |   |   |  |
| quipment Life   |   |   | years   |   |   |   |  |
| RF  |   | 0.0837  |   |   |   |   |  |
|   |   |   |   |   |   |   |  |
| eplacement Catalyst   | :   | Catalyst  |   |   |   |   |  |
| quipment Life   |   | 3   | years   |   |   |   |  |
| RF  |   | 0.3707  |   |   |   |   |  |
| ep part cost per unit   |   | 0   | \$/ft <sup>3</sup>  |   |   |   |  |
| mount Required  |   | 39  |   |   |   |   |  |
| atalyst Cost  |   |   |   | d for freight &   | ealee tay                                     |   |  |
| stallation Labor  |   |   |   |   |   | asis labor for  | baghouse replacement)  |
|   |   |   |   |   |   |   | baghouse replacementy  |
| otal Installed Cost   |   |   |   | o replacement   | nt parts need                                 | led   |  |
| nnualized Cost  |   | 0   |   |   |   |   |  |
|   |   |   |   |   |   |   |  |
| eplacement Parts & I  | Equipment:  |   |   |   |   |   |  |
| quipment Life   |   | 3   |   |   |   |   |  |
| RF  |   | 0.3707  |   |   |   |   |  |
| Rep part cost per unit  |   |   | \$ each   |   |   |   |  |
| mount Required  |   |   | Number  |   |   |   |  |
| otal Rep Parts Cost   |   |   |   | d for freight &   | sales tax                                     |   |  |
| nstallation Labor   |   |   |   | ag (13 hr total   |   | 9.65/hr   | OAQPS list replacement times from 5 - 20 min per bag.  |
| otal Installed Cost   |   |   |   | o replacemer  |   |   | ,  |
| nnualized Cost  |   | 0   |   |   |   |   |  |
|   |   |   |   |   |   |   |  |
| lectrical Use   |   |   |   |   |   |   |  |
|   | Flow acfm   |   | Δ P in H2O  | Efficiency  | Hp  | kW  |  |
| lower, Thermal  | 420,000   |   | 19  | 0.6   |   | 1,556.1   | EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.  |
| Blower, Catalytic   | 420,000   |   | 23  | 0.6   |   | 1,883.7   | EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.  |
| Dxidizer Type   | thermal   | (catalytic or th  | nermal)   |   |   | 0.0   | Reheat is by duct burner, pressure drop does not apply   |
|   |   |   |   |   |   | 0.0   | Reheat is by duct burner, pressure drop does not apply   |
| Dxidizer Type<br>Reagent Use & Other (<br>Dperating Cost Calcul   | Operating Co  |   | : - NA  | rs of operatio<br>ate:  |   | 0.0<br>8,376<br>100%  |  |
| eagent Use & Other of   | Operating Cc<br>ations<br>Unit  | unit of   | - NA<br>Annual hour<br>Utilization R<br>Use                                       | ate:<br>Unit of   | Annual  | 8,376<br>100%<br>Annual   |  |
| eagent Use & Other (<br>Operating Cost Calcul   | Operating Co<br>ations  | osts Oxidizers  | - NA<br>Annual hour<br>Utilization R  | ate:  |   | 8,376<br>100%   |  |
| eagent Use & Other of<br>Pperating Cost Calcul<br>em<br>Pperating Labor   | Operating Cc<br>ations<br>Unit  | Unit of<br>Measure  | Annual hour<br>Utilization R<br>Use<br>Rate                                       | ate:<br>Unit of   | Annual  | 8,376<br>100%<br>Annual<br>Cost   | Comments   |
| eagent Use & Other (<br>Operating Cost Calcul<br>em   | Operating Co<br>ations<br>Unit<br>Cost \$<br>72.12                                | Unit of<br>Measure  | Annual hour<br>Utilization R<br>Use<br>Rate                                       | ate:<br>Unit of<br>Measure  | Annual<br>Use*                                | 8,376<br>100%<br>Annual<br>Cost<br>37,755   | Comments<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr   |
| Deperating Cost Calcul<br>em<br>perating Labor<br>Dp Labor<br>Uppervisor  | Operating Co<br>ations<br>Unit<br>Cost \$<br>72.12                                | Unit of<br>Measure  | Annual hour<br>Utilization R<br>Use<br>Rate                                       | ate:<br>Unit of<br>Measure  | Annual<br>Use*<br>524                         | 8,376<br>100%<br>Annual<br>Cost<br>37,755   | Comments   |
| eagent Use & Other of<br>operating Cost Calcul<br>em<br>operating Labor<br>jp Labor   | Operating Co<br>ations<br>Unit<br>Cost \$<br>72.12                                | Unit of<br>Measure<br>\$/Hr<br>of Op.   | Annual hour<br>Utilization R<br>Use<br>Rate<br>0.5                                | ate:<br>Unit of<br>Measure  | Annual<br>Use*<br>524                         | 8,376<br>100%<br>Annual<br>Cost<br>37,755<br>5,663                                    | Comments<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr   |
| eagent Use & Other of<br>perating Cost Calcul<br>em<br>perating Labor<br>p Labor<br>upervisor<br>ainitenance  | Operating Co<br>ations<br>Unit<br>Cost \$<br>72.12<br>15%<br>72.12                | Unit of<br>Measure<br>\$/Hr<br>of Op.   | Annual hour<br>Utilization R<br>Use<br>Rate<br>0.5<br>0.5                         | ate:<br>Unit of<br>Measure<br>hr/8 hr shift                           | Annual<br>Use*<br>524<br>NA                   | 8,376<br>100%<br>Annual<br>Cost<br>37,755<br>5,663<br>37,755                          | Comments<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>15% of Operator Costs  |
| eagent Use & Other of<br>perating Cost Calcul<br>em<br>perating Labor<br>p Labor<br>upervisor<br>aintenance<br>aint Labor   | Ations<br>Unit<br>Cost \$<br>72.12<br>15%<br>72.12<br>15%<br>72.12<br>100         | Unit of<br>Measure<br>\$/Hr<br>of Op.<br>\$/Hr<br>% of Mainten                | Annual hour<br>Utilization R<br>Use<br>Rate<br>0.5<br>0.5<br>ance Labor           | ate:<br>Unit of<br>Measure<br>hr/8 hr shift                           | Annual<br>Use*<br>524<br>NA<br>524            | 8,376<br>100%<br>Annual<br>Cost<br>37,755<br>5,663<br>37,755                          | Comments<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr                              |
| eagent Use & Other of<br>perating Cost Calcul<br>em<br>perating Labor<br>p Labor<br>upervisor<br>aintenance<br>aint Labor<br>aint Labor<br>aint Mts               | ations<br>Unit<br>Cost \$<br>72.12<br>15%<br>72.12<br>00<br>00lacements &         | Unit of<br>Measure<br>\$/Hr<br>of Op.<br>\$/Hr<br>% of Mainten                | Annual hour<br>Utilization R<br>Use<br>Rate<br>0.5<br>0.5<br>ance Labor<br>gement | ate:<br>Unit of<br>Measure<br>hr/8 hr shift                           | Annual<br>Use*<br>524<br>NA<br>524            | <b>8,376</b><br>100%<br>Annual<br>Cost<br>37,755<br>5,663<br>37,755<br>37,755         | Comments<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>100% of Maintenance Labor |
| eagent Use & Other of<br>perating Cost Calcul<br>em<br>perating Labor<br>p Labor<br>upervisor<br>aint Labor<br>aint Labor<br>aint Mtls<br>tilities, Supplies, Rep | Ations<br>Unit<br>Cost \$<br>72.12<br>15%<br>72.12<br>100<br>Jacements &<br>0.068 | Unit of<br>Measure<br>\$/Hr<br>of Op.<br>\$/Hr<br>% of Mainten<br>Waste Manag | Annual hour<br>Utilization R<br>Use<br>Rate<br>0.5<br>0.5<br>ance Labor<br>gement | ate:<br>Unit of<br>Measure<br>hr/8 hr shift<br>hr/8 hr shift<br>kW-hr | Annual<br>Use*<br>524<br>NA<br>524<br>NA<br>0 | 8,376<br>100%<br>Annual<br>Cost<br>37,755<br>5,663<br>37,755<br>37,755<br>37,755<br>0 | Comments<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr<br>15% of Operator Costs<br>\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr                              |

#### Flue Gas Re-Heat Equipment Cost Estimate Basis Thermal Oxidizer with 70% Heat Recovery

#### Auxiliary Fuel Use Equation 3.19

| / a/inar y 1 aor 000 | Equation on o   |
|----------------------|---|
| T <sub>wi</sub>      | 140 Deg F - Temperature of waste gas into heat recovery           |
| T <sub>fi</sub>      | 800 Deg F - Temperature of Flue gas into heat recovery            |
| T <sub>ref</sub>     | 77 Deg F - Reference temperature for fuel combustion calculations |
| FER                  | 0% Factional Heat Recovery % Heat recovery section efficiency     |
| T <sub>wo</sub>      | 140 Deg F - Temperature of waste gas out of heat recovery         |
| T <sub>fo</sub>      | 800 Deg F - Temperature of flue gas out of heat recovery          |
| -h <sub>caf</sub>    | 21502 Btu/lb Heat of combustion auxiliary fuel (methane)          |
| -h <sub>wg</sub>     | 0 Btu/lb Heat of combustion waste gas                             |
| C <sub>p wg</sub>    | 0.2684 Btu/lb - Deg F Heat Capacity of waste gas (air)            |
| p <sub>wg</sub>      | 0.0739 lb/scf - Density of waste gas (air) at 77 Deg F            |
| $p_{af}$             | 0.0408 lb/scf - Density of auxiliary fuel (methane) at 77 Deg F   |
| Q <sub>wg</sub>      | 369,600 scfm - Flow of waste gas                                  |
| Q <sub>af</sub>      | 6,181 scfm - Flow of auxiliary fuel                               |

| Cost Calculations | [          | 375,781 | scfm Flue<br>Current | GasCost in 1989 \$'s\$211,583Cost Using CHE Plant Cost Index\$329,582 |
|-------------------|------------|---------|----------------------|---|
|                   | Heat Rec % | A       | В                    |   |
|                   | 0          | 10,294  | 0.2355               | Exponents per equation 3.24   |
|                   | 0.3        | 13,149  | 0.2609               | Exponents per equation 3.25   |
|                   | 0.5        | 17,056  | 0.2502               | Exponents per equation 3.26   |
|                   | 0.7        | 21,342  | 0.2500               | Exponents per equation 3.27   |

| Indurator   | Flue Gas Heat Capac |         |            | nposition |         |
|-------------|---------------------|---------|------------|-----------|---------|
|             | 100 scfm            |         | scf/lbmole |           |         |
|             | Gas Composition     | lb/hr f | wt %       | Cp Gas    | Cp Flue |
| 28 mw CO    | 0 v %               | 0       |            |           |         |
| 44 mw CO2   | 15 v %              | 184     | 22.0%      | 0.24      | 0.0528  |
| 18 mw H2O   | 10 v %              | 50      | 6.0%       | 0.46      | 0.0276  |
| 28 mw N2    | 60 v %              | 468     | 56.0%      | 0.27      | 0.1512  |
| 32 mw O2    | 15 v %              | 134     | 16.0%      | 0.23      | 0.0368  |
| Cp Flue Gas | 100 v %             | 836     | 100.0%     |           | 0.2684  |
|             |                     |         |            |           |         |

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators (EPA 453/B-96-001)

### Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency Air Economics Group Health and Environmental Impacts Division Office of Air Quality Planning and Standards

(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO<sub>x</sub> emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas  $NO_x$  within a specific temperature range to produce  $N_2$  and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

#### Instructions

Step 1: Please select on the Data Inputs tab and click on the Reset Form button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume (Vol<sub>catalyst</sub>) or flue gas flow rate (Q<sub>flue gas</sub>), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the SCR Design Parameters tab to see the calculated design parameters and the Cost Estimate tab to view the calculated cost data for the installation and operation of the SCR.

| Data Inputs   |  |   |
|---|--|---|
| Enter the following data for your combustion unit:  |  |   |
| is the compustion unit a utility of industrial polici :   | ustrial 🔻  | What type of fuel does the unit burn? Natural Gas   |
| Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit   | •  |   |
|   |  | * NOTE: You must document why a retrofit factor of 1.6 is appropriate for<br>the proposed project.  |
| Complete all of the highlighted data fields:<br>Not applicable to units burning fuel oil or natural gas                                   |  |   |
| What is the maximum heat input rate (QB)?   | 2,197 MMBtu/hour   | Type of coal burned: Not Applicable   |
| What is the higher heating value (HHV) of the fuel?<br>*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter ac | 1,033 Btu/scf<br>tual HHV for fuel burned, if known.                                 | Enter the sulfur content (%S) = percent by weight   |
| What is the estimated actual annual fuel consumption?   | 17,816,081,913 scf/Year  |   |
| Operating hours<br>Enter the net plant heat input rate (NPHR)   | 8,376<br>8.2 MMBtu/MW  | Not applicable to units buring fuel oil or natural gas<br>Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values<br>for these parameters in the table below. If the actual value for any parameter is not known, you may use the<br>default values provided. |
| If the NPHR is not known, use the default NPHR value:   | ASSUME DEFAULT<br>Fuel Type Default NPHR<br>Coal 10 MMBtu/MW<br>Fuel Oil 11 MMBtu/MW | Fraction in       Coal Type     Coal Blend     %S     HHV (8tu/lb)       Bituminous     0     1.84     11.841       Sub-Bituminous     0     0.41     8,826       Lignite     0     0.82     6,685  |
| Plant Elevation   | Natural Gas 8.2 MMBtu/MW   | 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          O Method 1         O Method 2         O Not applicable        |

#### Enter the following design parameters for the proposed SCR:

|  |                                  |  | -  |  |
|--|----------------------------------|--|--|--|
| Number of days the SCR operates $(t_{\scriptscriptstyle SCR})$                                     | 349 days                         | Number of SCR reactor chambers (n <sub>scr</sub> )   | 1  |  |
| Number of days the boiler operates $(\ensuremath{t_{\text{plant}}})$                               | 349 days                         | Number of catalyst layers ( $R_{layer}$ )  | 2  |  |
| Inlet $NO_x$ Emissions ( $NOx_{in}$ ) to SCR   | 0.16 lb/MMBtu                    | Number of empty catalyst layers (R <sub>empty</sub> )  | 1  |  |
| Outlet NO <sub>x</sub> Emissions (NOx <sub>out</sub> ) from SCR                                    | 0.08 lb/MMBtu                    | Ammonia Slip (Slip) provided by vendor   | 2  | opm  |
| Stoichiometric Ratio Factor (SRF)  | 0.525                            | Volume of the catalyst layers (Vol <sub>catalyst</sub> )<br>(Enter "UNK" if value is not known)  | UNK  | Cubic feet                                       |
| *The SRF value of 0.525 is a default value. User should enter actual value, if known.              |                                  | Flue gas flow rate (Q <sub>fluegas</sub> )<br>(Enter "UNK" if value is not known)  | 882254                                     | acfm   |
| Estimated operating life of the catalyst (H <sub>catalyst</sub> )<br>Estimated SCR equipment life  | 8,000 hours<br>20 Years*         | Gas temperature at the SCR inlet (T)   | 800  | °F   |
| * For industrial boilers, the typical equipment life is between 20 and 25 years.                   |                                  | Base case fuel gas volumetric flow rate fac  | ctor (Q <sub>fuel</sub> ) 484              | ft <sup>3</sup> /min-MMBtu/hour                  |
| Concentration of reagent as stored ( $C_{stored})$ Density of reagent as stored ( $\rho_{stored})$ | 50 percent*<br>71 lb/cubic feet* | *The reagent concentration of 50% and density of 71 lbs/cft are default<br>values for urea reagent. User should enter actual values for reagent, if<br>different from the default values provided. |  |  |
| Number of days reagent is stored $(t_{storage})$   | 14 days                          | Dens   | sities of typical SCR reagents:            |  |
|  |                                  |  | urea solution<br>% aqueous NH <sub>3</sub> | 71 lbs/ft <sup>3</sup><br>56 lbs/ft <sup>3</sup> |
| Select the reagent used Urea   | •                                |  |  |  |
|  |                                  |  |  |  |

#### Enter the cost data for the proposed SCR:

| Desired dollar-year                    | 2019   |   |
|--|--|---|
| CEPCI for 2019                         | 607.5 2019 final CEPCI value 541.7 2016 CEPCI  | CEPCI = Chemical Engineering Plant Cost Index   |
| Annual Interest Rate (i)               | 5.5 Percent*   | * 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at<br>https://www.federalreserve.gov/releases/h15/.) |
| Reagent (Cost <sub>reag</sub> )        | 1.814 \$/gallon for 50% urea   |   |
| Electricity (Cost <sub>elect</sub> )   | 0.0684 \$/kWh  |   |
| Catalyst cost (CC <sub>replace</sub> ) | \$/cubic foot (includes removal and disposal/regeneration of existing 248.05 catalyst and installation of new catalyst |   |
| Operator Labor Rate                    | 72.12 \$/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) = Administrative Charges Factor (ACF) =

| 0.005 |
|-------|
| 0.03  |

1.325

#### Data Sources for Default Values Used in Calculations:

|  |               |  | If you used your own site-specific values, please enter the value |
|--|---------------|--|---|
| Data Element                               |               | Sources for Default Value  | used and the reference source                                     |
| Reagent Cost (\$/gallon)                   | · · · -       | U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector   |   |
|  | urea solution | Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and  |   |
|  |               | Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5,   |   |
|  |               | Attachment 5-3, January 2017. Available at:  |   |
|  |               | https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-   |   |
| Electricity Cost (\$/kWh)                  | 0.0676        | U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published   |   |
|  |               | December 2017. Available at:   |   |
|  |               | https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.  |   |
|  |               |  |   |
|  |               |  |   |
| Percent sulfur content for Coal (% weight) |               | Not applicable to units burning fuel oil or natural gas  |   |
|  |               |  |   |
|  |               |  |   |
|  |               |  |   |
|  |               |  |   |
| Higher Heating Value (HHV) (Btu/lb)        | 1,033         | 2016 natural gas 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 http://www.eia.gov/electricity/data/eia923/.   |   |
|  |               |  |   |
|  | 227           |  |   |
| 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.<br>May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power- |   |
|  |               | sector-modeling-platform-v6.   |   |
|  |               | sector-modeling-platform-v6.   |   |
|  |               |  |   |
| 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: https://www.epa.gov/airmarkets/documentation-epas-power-   |   |
|  |               | sector-modeling-platform-v6.   |   |
|  |               |  |   |
|  |               |  |   |
| Interest Rate (Percent)                    | 5.5           | Default bank prime rate  |   |
|  |               |  |   |
|  |               |  |   |
|  |               |  |   |

#### 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 <sub>B</sub> ) =       | HHV x Max. Fuel Rate =   | 2,197            | MMBtu/hour |   |
| Maximum Annual fuel consumption (mfuel) =                | (QB x 1.0E6 x 8760)/HHV =  | 18,632,865,038   | scf/Year   | ]   |
| Actual Annual fuel consumption (Mactual) =               |  | 17,816,081,913   | scf/Year   |   |
| Heat Rate Factor (HRF) =                                 | NPHR/10 =  | 0.82             |            |   |
| Total System Capacity Factor (CF <sub>total</sub> ) =    | (Mactual/Mfuel) x (tscr/tplant) =  | 0.956            | fraction   |   |
| Total operating time for the SCR $(t_{op}) =$            | CF <sub>total</sub> x 8760 =   | 8376             | hours      |   |
| NOx Removal Efficiency (EF) =                            | (NOx <sub>in</sub> - NOx <sub>out</sub> )/NOx <sub>in</sub> =  | 50.0             | percent    |   |
| NOx removed per hour =                                   | $NOx_{in} \times EF \times Q_B =$  | 174.00           | lb/hour    |   |
| Total NO <sub>x</sub> removed per year =                 | (NOx <sub>in</sub> x EF x Q <sub>B</sub> x t <sub>op</sub> )/2000 =  | 662.50           | tons/year  |   |
| NO <sub>x</sub> removal factor (NRF) =                   | EF/80 =  | 0.63             |            |   |
| Volumetric flue gas flow rate (q <sub>flue gas</sub> ) = | Q <sub>fuel</sub> x QB x (460 + T)/(460 + 700)n <sub>scr</sub> =   | 882,254          | acfm       |   |
| Space velocity (V <sub>space</sub> ) =                   | q <sub>flue gas</sub> /Vol <sub>catalyst</sub> =   | 143.31           | /hour      |   |
| Residence Time   | 1/V <sub>space</sub>   | 0.01             | hour       |   |
| Coal Factor (CoalF) =                                    | 1 for oil and natural gas; 1 for bituminous; 1.05 for sub-<br>bituminous; 1.07 for lignite (weighted average is used for<br>coal blends) | 1.00             |            |   |
| SO <sub>2</sub> Emission rate =                          | (%S/100)x(64/32)*1x10 <sup>6</sup> )/HHV =   |                  |            | Not applicable; factor applies only to coal-fired boilers |
| Elevation Factor (ELEVF) =                               | 14.7 psia/P =  | 1.06             |            |   |
| Atmospheric pressure at sea level (P) =                  | 2116 x [(59-(0.00356xh)+459.7)/518.6] <sup>5.256</sup> x (1/144)* =  | 13.9             | psia       |   |
| Retrofit Factor (RF)                                     | Retrofit to existing boiler  | 1.60             |            | ]   |

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at

Urea

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) <sup>Y</sup> -1) , where Y = $H_{catalyts}/(t_{SCR} \times 24$ hours) rounded to the nearest integer |                  | Fraction   |
| Catalyst volume (Vol <sub>catalyst</sub> ) =            | 2.81 x Q <sub>8</sub> x EF <sub>adj</sub> x Slipadj x NOx <sub>adj</sub> x S <sub>adj</sub> x (T <sub>adj</sub> /N <sub>scr</sub> )        | 6,156.14         | Cubic feet |
| Cross sectional area of the catalyst $(A_{catalyst}) =$ | q <sub>flue gas</sub> /(16ft/sec x 60 sec/min)   | 919              | ft²        |
| Height of each catalyst layer (H <sub>layer</sub> ) =   | (Vol <sub>catalyst</sub> /(R <sub>layer</sub> x A <sub>catalyst</sub> )) + 1 (rounded to next highest integer)                             | 4                | feet       |

#### SCR Reactor Data:

| Parameter   | Equation   | Calculated Value | Units |
|---|--|------------------|-------|
| Cross sectional area of the reactor (A <sub>SCR</sub> ) = | 1.15 x A <sub>catalyst</sub>                             | 1,057            | ft²   |
| Reactor length and width dimensions for a                 | ( )0.5   | 32.5             | feet  |
| square reactor =  | (A <sub>SCR</sub> ) <sup>0.5</sup>                       | 32.5             | leet  |
| Reactor height =  | $(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$ | 43               | feet  |

#### Reagent Data:

| Туре | of | reagent | used |
|------|----|---------|------|

Molecular Weight of Reagent (MW) = 60.06 g/mole Density = 71 lb/ft<sup>3</sup>

| Parameter  | Equation   | Calculated Value | Units   |
|--|--|------------------|---|
| Reagent consumption rate (m <sub>reagent</sub> ) = | (NOx <sub>in</sub> x Q <sub>B</sub> x EF x SRF x MW <sub>R</sub> )/MW <sub>NOx</sub> = | 119              | lb/hour   |
| Reagent Usage Rate (m <sub>sol</sub> ) =           | m <sub>reagent</sub> /Csol =   | 238              | lb/hour   |
|  | (m <sub>sol</sub> x 7.4805)/Reagent Density  | 25               | gal/hour  |
| Estimated tank volume for reagent storage =        | (m <sub>sol</sub> x 7.4805 x t <sub>storage</sub> x 24)/Reagent Density =              | 8,500            | gallons (storage needed to store a 14 day reagent supply rounded to |

#### Capital Recovery Factor:

| Parameter                              | Equation   | Calculated Value            |
|--|--|-----------------------------|
| Capital Recovery Factor (CRF) =        | $i (1+i)^n / (1+i)^n - 1 =$                                      | 0.0837                      |
|  | Where n = Equipment Life and i= Interest Rate                    |                             |
|  |  |                             |
|  |  |                             |
| Other parameters                       | Equation   | Calculated Value            |
| Other parameters<br>Electricity Usage: | Equation   | Calculated Value            |
|  | Equation<br>A x 1,000 x 0.0056 x (CoalF x HRF) <sup>0.43</sup> = | Calculated Value<br>1129.81 |

**Cost Estimate** 

#### Total Capital Investment (TCI)

|  | TCI for Oil and Natural Gas Boilers  |                 |
|--|--|-----------------|
| For Oil and Natural Gas-Fired Utility Boilers betwee | een 25MW and 500 MW:   |                 |
|  | TCI = 86,380 x (200/B <sub>MW</sub> ) <sup>0.35</sup> x B <sub>MW</sub> x ELEVF x RF |                 |
| For Oil and Natural Gas-Fired Utility Boilers >500   | MW:  |                 |
|  | TCI = 62,680 x $B_{MW}$ x ELEVF x RF   |                 |
| For Oil-Fired Industrial Boilers between 275 and 5   | 5,500 MMBTU/hour :   |                 |
|  | TCI = 7,850 x (2,200/Q <sub>B</sub> ) <sup>0.35</sup> x Q <sub>B</sub> x ELEVF x RF  |                 |
| For Natural Gas-Fired Industrial Boilers between     | 205 and 4,100 MMBTU/hour :   |                 |
|  | TCI = 10,530 x (1,640/Q <sub>B</sub> ) <sup>0.35</sup> x Q <sub>B</sub> x ELEVF x RF |                 |
| For Oil-Fired Industrial Boilers >5,500 MMBtu/ho     | ur:  |                 |
|  | TCI = 5,700 x $Q_8$ x ELEVF x RF   |                 |
| For Natural Gas-Fired Industrial Boilers >4,100 M    | MBtu/hour:   |                 |
|  | $TCI = 7,640 \times Q_B \times ELEVF \times RF$                                      |                 |
|  |  |                 |
| Total Capital Investment (TCI) =                     | \$39,545,414   | in 2019 dollars |

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

| Direct Annual Costs (DAC) =           | \$1,990,673 in 2019 dollars |
|---------------------------------------|-----------------------------|
| Indirect Annual Costs (IDAC) =        | \$3,315,344 in 2019 dollars |
| Total annual costs (TAC) = DAC + IDAC | \$5,306,017 in 2019 dollars |

#### Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

| Annual Maintenance Cost =          | 0.005 x TCl =  | \$197,727 in 2019 dollars   |
|------------------------------------|--|-----------------------------|
| Annual Reagent Cost =              | $m_{sol} \times Cost_{reag} \times t_{op} =$   | \$381,769 in 2019 dollars   |
| Annual Electricity Cost =          | $P \times Cost_{elect} \times t_{on} =$  | \$647,665 in 2019 dollars   |
| Annual Catalyst Replacement Cost = | r x costelect x t <sub>op</sub> -  | \$763,512 in 2019 dollars   |
|                                    |  |                             |
|                                    | n <sub>scr</sub> x Vol <sub>cat</sub> x (CC <sub>replace</sub> /R <sub>layer</sub> ) x FWF |                             |
| Direct Annual Cost =               |  | \$1,990,673 in 2019 dollars |
|                                    |  |                             |
|                                    | Indirect Annual Cost (IDAC)  |                             |
|                                    | IDAC = Administrative Charges + Capital Recovery Costs                                     |                             |
|                                    |  |                             |

| Administrative Charges (AC) = | 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) = | \$5,393 in 2019 dollars     |
|-------------------------------|--|-----------------------------|
| Capital Recovery Costs (CR)=  | CRF x TCI =  | \$3,309,951 in 2019 dollars |
| Indirect Annual Cost (IDAC) = | AC + CR =  | \$3,315,344 in 2019 dollars |

#### Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

| Total Annual Cost (TAC) = | \$5,306,017 per year in 2019 dollars              |
|---------------------------|---|
| NOx Removed =             | 663 tons/year                                     |
| Cost Effectiveness =      | \$8,009.08 per ton of NOx removed in 2019 dollars |
|                           | \$/Ton above does not include reheat costs        |

# Appendix B

Unit-specific Screening Level Cost Summary for Line 2 Control Measures

## Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 1: Cost Summary

### NO<sub>x</sub> Control Cost Summary

| Control Technology                              | Control | Controlled     | Emission       | Installed Capital | Annualized           | Pollution Control |
|---|---------|----------------|----------------|-------------------|----------------------|-------------------|
|   | Eff %   | Emissions T/yr | Reduction T/yr | Cost \$           | Operating Cost \$/yr | Cost \$/ton       |
| Selective Catalytic Reduction with Reheat (SCR) | 50%     | 937.0          | 937.0          | \$72,550,865      | \$41,336,088         | \$44,115          |

### SO<sub>2</sub> Control Cost Summary

| Control Technology                           | Control<br>Eff % | Controlled<br>Emissions T/yr | Emission<br>Reduction T/yr | Installed Capital<br>Cost \$ | Annualized<br>Operating Cost \$/yr | Pollution Control<br>Cost \$/ton |
|--|------------------|------------------------------|----------------------------|------------------------------|------------------------------------|----------------------------------|
| Dry Sorbent Injection (DSI)<br>with Baghouse | 50%              | 107.2                        | 108.2                      | \$50,466,157                 | \$10,090,749                       | \$93,300                         |
| Spray Dry Absorber (SDA)                     | 50%              | 107.2                        | 108.2                      | \$120,947,748                | \$19,573,967                       | \$180,891                        |
| Gas Suspension Absorber<br>(GSA)             | 50%              | 107.2                        | 108.2                      | \$113,793,152                | \$18,757,651                       | \$173,347                        |

#### Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 2: Summary of Utility, Chemical and Supply Costs

| Operating Unit:   | Line 2  |   | Study Year        | 2020         |  |  |
|---|---|---|-------------------|--------------|--|--|
| Emission Unit Number<br>Stack/Vent Number   | EU 042<br>SV 048 & 049                          |   |                   |              |  |  |
|   |   |   |                   |              |  |  |
| Item<br>Operating Labor   | Unit Cost<br>72.12                              | Units<br>\$/hr                              | Cost              | Year<br>2020 | Data Source<br>Site-specific labor cost  | Notes  |
| Maintenance Labor   | 72.12   | \$/hr                                       |                   | 2020         | Site-specific labor cost   |  |
| Electricity   | 0.068   | \$/kwh                                      | 68.44             | 2020         | Site-specific cost   |  |
| Natural Gas   |   | \$/kscf                                     |                   | N/A          | 5-yr average based on natural gas prices (eia.gov)   |  |
| Water   | 0.01  | \$/kgal                                     |                   | 2019         | Site-specific cost from 2019   |  |
| Compressed Air  | 0.48  | \$/kscf                                     | 0.25              | 1998         | EPA Air Pollution Control Cost Manual 6th Ed 2002,<br>Section 6 Chapter 1  | Adjusted for 3% inflation  |
|   |   |   |                   |              |  |  |
| Taconite Pellets Chemicals & Supplies   | 29.1  | \$/LT                                       | -                 | 2020         | Based on Q1 2020 sales margin in earnings report   |  |
|   |   |   |                   |              | Hydrated lime cost from 2012 Dry Flugas  |  |
| Lime  | 183.68  | \$/ton                                      | 145.00            | 2012         | Desulfurization Study for UTAC Lines 1 and 2<br>EPA Control Cost Manual Chapter 7, 7th Edition   | Adjusted for 3% inflation  |
| Urea 50% Solution   | 1.81  | \$/gallon                                   | 1.66              | 2017         | default  | Adjusted for 3% inflation  |
| Trona<br>Estimated operating life of the catalyst (H <sub>catalyst</sub> )  | 285.00  | \$/ton<br>hours                             |                   | 2020         | Vendor estimated delivered cost<br>EPA Control Cost Manual Chapter 7, 7th Edition  |  |
| Estimated operating no or the eataryst (Heataryst)  | 0,000   | nouis                                       |                   |              | EPA Control Cost Manual Chapter 7, 7th Edition   |  |
| Catalyst cost (CC replace)  | 248.05  | \$/cubic foot (inclu                        | 227               | 2017         | default  | Adjusted for 3% inflation  |
|   |   |   |                   |              | Vendor estimated bag cost from the 2018 Best<br>Available Mercury Reduction Technology (BAMRT)   |  |
| Cost per bag  | 116.70  | \$/bag                                      | 110               | 2018         | Analysis   | Adjusted for 3% inflation  |
| Other<br>Sales Tax  | 6.875%  | percent                                     |                   |              | Current MN sales tax rate  |  |
|   |   |   |                   |              | EPA Control Cost Manual Chapter 7, 7th Edition   |  |
| Interest Rate<br>Solid Waste Disposal   |   | percent<br>\$/ton                           | 41.8              | 2018         | default<br>2018 site specific cost   | Adjusted for 3% inflation  |
|   |   |   |                   |              | EPA Control Cost Manual Chapter 2, 7th Edition   |  |
| Contingency   | 10%   | percent                                     |                   |              | estimates contingencies from 5-15%. Assumed the<br>mid range   |  |
| oonangonoy  | 1070  | portouri                                    |                   |              |  |  |
|   |   |   |                   |              | CUECost Workbook Version 1.0, USEPA Document<br>Page 2 allows up to a 60% retrofit factor for  |  |
|   |   |   |                   |              | installations in existing facilities. However, the retrofit  |  |
| Markup on capital cost (Retrofit Factor)  | 609/  | percent                                     |                   |              | factor does not apply to the GSA/SDA because the<br>costs were based on a site-specific estimate.  |  |
| Operating Information   | 00%   | percent                                     |                   |              |  |  |
| Annual Op. Hrs<br>Utilization Rate  | 8376<br>100%                                    | Hours                                       |                   |              | Site-specific estimate<br>Site-specific estimate   |  |
| Single Furnace Pellet Production Rate   | 600   | Lton/hr                                     |                   |              | Furnace capacity   |  |
| Desgin Capacity<br>Equipment Life   |   | MMBTU/hr                                    |                   |              | Furnace capacity<br>Assumed  |  |
| Temperature- After Scrubber   |   | vrs<br>Deg F                                |                   |              | Stack test data  |  |
| Temperature- Before Scrubber  |   | Deg F                                       |                   |              | Site-specific estimate   |  |
| Moisture Content-After Scrubber<br>Moisture Content-Before Scrubber   | 13.1%<br>6.3%                                   |   | 2300              | lb h2o/min   | Stack test data<br>Site-specific estimate  |  |
| Existing Pollution Contols PM Inlet Concentraiton   |   | gr/dscf dust load                           |                   | 2018         | Site-specific estimate   |  |
|   |   |   |                   |              | 2020 TVOP reissuance application PM control  | Efficiency is used to calculate the increased<br>baghouse dust loading for DSI because the captured<br>dust cannot be recycled to process with the<br>spent/unreacted reagent. This does not apply to the<br>GSA/SDA because there is an ESP upstream of the |
| Existing Pollution Contols PM Control Efficiency<br>Actual Flow Rate-After Scrubber                                 | 94%<br>840,000                                  | percent                                     | -                 |              | efficiency<br>Site-specific estimate   | absorber.  |
| Actual Flow Rate-Before Scrubber  | 1,120,210                                       | acfm  |                   |              | Site-specific estimate   |  |
| Standardized Flow Rate-After Scrubber   | 744.161   | scfm @ 68º F                                | 693.423           | scfm @ 32º F | Calculated from stack temperature and flow data in<br>acfm listed above  |  |
|   |   |   |                   |              | Calculated from stack temperature and flow data in   |  |
| Standardized Flow Rate-Before Scrubber  | 778,251   | scfm @ 68º F                                | 725,189           | scfm @ 32º F | acfm listed above<br>Calculated from stack temperature and flow data in  |  |
| Dry Std Flow Rate-After Scrubber  | 646,676   | dscfm @ 68º F                               |                   |              | acfm listed above  |  |
| Dry Std Flow Rate-Before Scrubber   | 729 057   | dscfm @ 68º F                               |                   |              | Calculated from stack temperature and flow data in<br>acfm listed above  |  |
|   |   |   |                   |              | EPA Control Cost Manual Chapter 7, 7th Edition   |  |
| Fuel higher heating value (HHV)<br>Plant Elevation  |   | BTU/scf<br>Feet above sea le                | aval              |              | default<br>Site elevation  |  |
| Method 19 Design Factor (SCR)   |   | dscf/MMBtu                                  | SVCI              |              | Natural gas F-Factor   |  |
| Technology Control Efficiency   |   |   |                   |              | Control efficiency for a cement kiln referenced in the   |  |
|   |   |   |                   |              | EPA Control Cost Manual Chapter 7, 7th Edition.<br>Efficiencies may be as high as 90%, but SCR has<br>not been demonstrated in practice on taconite  |  |
| SCR   | 50%   | %   |                   |              | indurating furnaces.   |  |
|   |   |   |                   |              | Calculated control efficiency to determine reduction<br>over baseline emissions to 5 ppm outlet per vendor   |  |
| GSA   |   | %   |                   |              | specifications   |  |
| GSA   | 50%   |   |                   |              | Calculated control efficiency to determine reduction   |  |
| 65A   | 50%   |   |                   |              | over baseline emissions to 5 ppm outlet per vendor   |  |
| SDA   | 50%   | %   |                   |              | specifications   |  |
|   |   | %   |                   |              | specifications<br>Calculated control efficiency to determine reduction<br>over baseline emissions to 5 ppm outlet per vendor<br>specifications. Note, it is unlikely that DSI can<br>actually achieve 5 ppm SO2 outlet. However, to be   |  |
| SDA<br>DSI  | 50%   | %   |                   |              | specifications<br>Calculated control efficiency to determine reduction<br>over baseline emissions to 5 ppm outlet per vendor<br>specifications. Note, it is unlikely that DSI can<br>actually achieve 5 ppm SO2 outlet. However, to be<br>conservative it was assume that this could be<br>achieved.   |  |
| SDA   | 50%<br>50%<br>25%                               | %   | ons               |              | specifications<br>Calculated control efficiency to determine reduction<br>over baseline emissions to 5 ppm outlet per vendor<br>specifications. Note, it is unlikely that DSI can<br>actually achieve 5 ppm SO2 outlet. However, to be<br>conservative it was assume that this could be  |  |
| SDA<br>DSI  | 50%<br>50%<br>25%                               | %   | ons<br>ppmv       |              | specifications<br>Calculated control efficiency to determine reduction<br>over baseline emissions to 5 ppm outlet per vendor<br>specifications. Note, it is unlikely that DSI can<br>actually achieve 5 ppm SO2 outlet. However, to be<br>conservative it was assume that this could be<br>achieved.<br>Site-specific estimate   |  |
| SDA<br>DSI<br>Existing scrubber SO2 Control Efficiency  | 50%<br>50%<br>25%<br>Max Emis                   | %<br>%<br>Baseline Emissi                   |                   |              | specifications<br>Calculated control efficiency to determine reduction<br>over baseline emissions to 5 ppm outlet per vendor<br>specifications. Note, it is unlikely that DSI can<br>actually achieve 5 ppm SO2 outlet. However, to be<br>conservative it was assume that this could be<br>achieved.<br>Site-specific estimate<br>Baseline tpy is site-specific estimate. Lb/hr  |  |
| SDA<br>DSI<br>Existing scrubber SO2 Control Efficiency  | 50%<br>50%<br>25%<br>Max Emis                   | %<br>%<br>Baseline Emissi                   |                   |              | specifications Calculated control efficiency to determine reduction over baseline emissions to 5 ppm outlet per vendor specifications. Note, It is unlikely that DSI can actually achieve 5 ppm SO2 outlet. However, to be conservative it was assume that this could be achieved. Site-specific estimate Baseline tpy is site-specific estimate. Lb/hr represents average during baseline period when furnace was operating at >50% capacity  |  |
| SDA<br>DSI<br>Existing scrubber SO2 Control Efficiency<br>Pollutant   | 50%<br>50%<br>25%<br>Max Emis<br>Lb/Hr          | %<br>%<br>Baseline Emissi<br>tpy            | ppmv              |              | specifications<br>Calculated control efficiency to determine reduction<br>over baseline emissions to 5 ppm outlet per vendor<br>specifications. Note, it is unlikely that DSI can<br>actually achieve 5 ppm SO2 outlet. However, to be<br>conservative it was assume that this could be<br>achieved.<br>Site-specific estimate<br>Baseline tpy is site-specific estimate. Lb/hr<br>represents average during baseline period when<br>furnace was operating at >50% capacity<br>Baseline tpy is site-specific estimate. Lb/hr   |  |
| SDA<br>DSI<br>Existing scrubber SO2 Control Efficiency<br>Pollutant<br>Nitrous Oxides (NOx)<br>Sulfur Dioxide (SO2) | 50%<br>50%<br>25%<br>Max Emis<br>Lb/Hr          | %<br>%<br>Baseline Emissi<br>tpy            | 93<br>10          |              | specifications Calculated control efficiency to determine reduction over baseline emissions to 5 ppm outlet per vendor specifications. Note, It is unlikely that DSI can actually achieve 5 ppm SO2 outlet. However, to be conservative it was assume that this could be achieved. Site-specific estimate Baseline tpy is site-specific estimate. Lb/hr represents average during baseline period when furnace was operating at >50% capacity  |  |
| SDA<br>DSI<br>Existing scrubber SO2 Control Efficiency<br>Pollutant<br>Nitrous Oxides (NOx)                         | 50%<br>50%<br>25%<br>Max Emis<br>Lb/Hr<br>488.0 | %<br>%<br>Baseline Emissi<br>tpy<br>1,874.0 | <b>рртv</b><br>93 |              | specifications<br>Calculated control efficiency to determine reduction<br>over baseline emissions to 5 ppm outlet per vendor<br>specifications. Note, it is unlikely that DSI can<br>actually achieve 5 ppm SO2 outlet. However, to be<br>conservative it was assume that this could be<br>achieved.<br>Site-specific estimate<br>Baseline top is site-specific estimate. Lb/hr<br>represents average during baseline period when<br>furnace was operating at >50% capacity<br>Baseline top is site-specific estimate. Lb/hr<br>represents average during baseline period when |  |
| SDA DSI Existing scrubber SO2 Control Efficiency Pollutant Nitrous Oxides (NOx) Sulfur Dioxide (SO2)                | 50%<br>50%<br>25%<br>Max Emis<br>Lb/Hr<br>488.0 | %<br>%<br>Baseline Emissi<br>tpy<br>1,874.0 | 93<br>10          |              | specifications<br>Calculated control efficiency to determine reduction<br>over baseline emissions to 5 ppm outlet per vendor<br>specifications. Note, it is unlikely that DSI can<br>actually achieve 5 ppm SO2 outlet. However, to be<br>conservative it was assume that this could be<br>achieved.<br>Site-specific estimate<br>Baseline top is site-specific estimate. Lb/hr<br>represents average during baseline period when<br>furnace was operating at >50% capacity<br>Baseline top is site-specific estimate. Lb/hr<br>represents average during baseline period when |  |

#### Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 3: NO<sub>x</sub> Control - Selective Catalytic Reduction with Reheat

Operating Unit:

Line 2

| Emission Unit Number               | EU 042 |          | Stack/Vent Number                     | SV 048 & 049 |               |
|------------------------------------|--------|----------|---------------------------------------|--------------|---------------|
| Design Capacity                    | 400    | MMBtu/hr | Standardized Flow Rate <sup>5</sup>   | 693,423      | scfm @ 32º F  |
| Expected Utilization Rate          | 100%   |          | Exhaust Temperature <sup>5</sup>      | 136          | Deg F         |
| Expected Annual Hours of Operation | 8,376  | Hours    | Exhaust Moisture Content <sup>5</sup> | 13.1%        |               |
| Annual Interest Rate               | 5.5%   |          | Actual Flow Rate <sup>5</sup>         | 840,000      | acfm          |
| Expected Equipment Life            | 20     | yrs      | Standardized Flow Rate <sup>5</sup>   | 744,161      | scfm @ 68º F  |
| Pellet Throughput                  | 600    | LTon/hr  | Dry Std Flow Rate <sup>5</sup>        | 646,676      | dscfm @ 68º F |

#### CONTROL EQUIPMENT COSTS

| Capital Costs                                |               |                    |                   |               |                    |              |            |
|--|---------------|--------------------|-------------------|---------------|--------------------|--------------|------------|
|  |               |                    |                   |               |                    |              |            |
|  |               |                    |                   |               |                    |              |            |
|  |               |                    |                   |               |                    |              |            |
|  |               |                    |                   |               |                    |              |            |
|  |               |                    |                   |               |                    |              |            |
|  |               |                    |                   |               |                    |              |            |
|  |               |                    |                   |               |                    |              |            |
|  |               |                    |                   |               |                    |              |            |
| Total Capital Investment (TCI) with Retrofit |               |                    |                   |               |                    | SCR Only     | , ,        |
|  |               |                    |                   |               |                    | SCR + Reheat | 72,550,865 |
| Operating Costs                              |               |                    |                   |               |                    |              |            |
| Total Annual Direct Operating Costs          |               | Labor, supervision | materials, repl   | acement parts | s, utilities, etc. | SCR + Reheat | 35,153,534 |
| Total Annual Indirect Operating Costs        |               | Sum indirect oper  | costs + capital i | ecovery cost  |                    | SCR + Reheat | 6,182,554  |
| Total Annual Cost (Annualized Capital Co     | ost + Operati | ng Cost)           |                   |               |                    | SCR + Reheat | 41,336,088 |

#### **Emission Control Cost Calculation**

| Pollutant            | Max Emis | Annual  | Cont Eff | Cont Emis | Reduction | Cont Cost  |
|----------------------|----------|---------|----------|-----------|-----------|------------|
|                      | Lb/Hr    | T/Yr    | %        | T/yr      | T/yr      | \$/Ton Rem |
| Nitrous Oxides (NOx) | 488.0    | 1,874.0 | 50%      | 937.0     | 937.0     | 44,115     |

#### Notes & Assumptions

1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 7th Ed SCR Control Cost Spreadsheet (June 2019)

2 TCI includes the cost of a new booster fan

3 For Calculation purposes, duty reflects increased flow rate, not actual duty.

4 CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit factor for installations in existing facilities.

**5** Specifications are after scrubber conditions.

#### Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 3: NOx Control - Selective Catalytic Reduction with Reheat

#### CAPITAL COSTS

| Total Capital Investment (TCI)                | Refer to the Cost Estimate tab           | 65,411,117 |
|---|--|------------|
| Retrofit factor<br>Lost Production for Tie-In | 60% of TCI, see <i>Cost Estimate</i> tab | 5,866,560  |

Total Capital Investment Retrofit Installed

71,277,677

#### OPERATING COSTS

| - |               |           |           |
|---|---------------|-----------|-----------|
|   | Direct Annual | Operating | Costs, DC |

| Annual Maintenance Cost =                                     |            | Refer to the Cost Estimate tab                                   | 322,20           |
|---|------------|--|------------------|
| Utilities, Supplies, Replacements & Waste                     | Management |  |                  |
| Annual Electricity Cost =                                     | management | Refer to the Cost Estimate tab                                   | 1,313,09         |
| Annual Catalyst Replacement Cost =                            |            | Refer to the Cost Estimate tab                                   | 1,523,87         |
| Annual Reagent Cost =   |            | Refer to the Cost Estimate tab                                   | 559,89           |
| Fotal Annual Direct Operating Costs                           |            |  | 3,719,06         |
| ndirect Operating Costs                                       |            |  |                  |
|   |            |  |                  |
| Administrative Charges (AC) =                                 |            | Refer to the Cost Estimate tab                                   | 6,88             |
| Administrative Charges (AC) =<br>Capital Recovery Costs (CR)= | 0.0837     | Refer to the Cost Estimate tab<br>Refer to the Cost Estimate tab | 6,88<br>5,965,94 |
| <b>U</b>  | 0.0837     |  | ,                |

#### Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 3: NOx Control - Selective Catalytic Reduction with Reheat

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

| Replacement Catayst - Ro                                       | efer to the Cost Estin             | ate Tab   |                        |
|--|------------------------------------|---|------------------------|
|  |                                    |   |                        |
|  |                                    |   |                        |
|  |                                    |   |                        |
|  |                                    |   |                        |
| Annualized Cost  | \$ 1,523,87                        | 2   |                        |
| Equivalent Duty  | 4,455                              |   |                        |
|  |                                    |   |                        |
|  |                                    |   |                        |
|  |                                    |   |                        |
| Uncontrolled Nox lb/mmBtu                                      | 0.115                              |   |                        |
| SCR Capital Cost   |                                    |   |                        |
| Electrical Use   |                                    |   |                        |
|  |                                    |   |                        |
|  |                                    |   |                        |
|  |                                    |   |                        |
|  |                                    |   |                        |
|  |                                    |   |                        |
| Reagent Use & Other Operatin<br>Refer to the Cost Estimate tak | g Costs                            |   |                        |
| Refer to the Cost Estimate tar                                 | )                                  |   |                        |
|  |                                    |   |                        |
|  |                                    |   |                        |
| Design Basis   | Max Emis<br>Ib/MMBtu               |   | Control Eff (%)<br>50% |
| Nitrous Oxides (NOx)   |                                    | 15 Adjusted lb/MMBtu                            | 50%                    |
|  |                                    |   |                        |
| Actual   | 97,001 dscf/MMBtu                  |   |                        |
| Method 19 Factor<br>Adjusted Duty                              | 8,710 dscf/MMBtu<br>4,455 MMBtu/hr | NG F-FACTOR                                     |                        |
|  |                                    |   | 0.070                  |
| Operating Cost Calculations                                    |                                    | Annual hours of operation:<br>Utilization Rate: | 8,376<br>100%          |
|  |                                    |   |                        |
|  |                                    |   |                        |
| Refer to the Cost Estimate tak                                 | )                                  |   |                        |
|  |                                    |   |                        |
|  |                                    |   |                        |
|  |                                    |   |                        |
|  |                                    |   |                        |

**Operating Unit:** 

Line 2

| Emission Unit Number               | EU 042 |          | Stack/Vent Number Stack/Vent Number   | Stack/Vent Number SV 048 & 049 |               |               | Chemical Engineering |  |  |
|------------------------------------|--------|----------|---------------------------------------|--------------------------------|---------------|---------------|----------------------|--|--|
|                                    | 400    | MMBtu/hr | Standardized Flow Rate <sup>3</sup>   | 693,423                        | scfm @ 32º F  | Chemical Plan | Cost Index           |  |  |
| Expected Utilization Rate          | 100%   |          | Exhaust Temperature <sup>3</sup>      | 136                            | Deg F         | 1998/1999     | 390                  |  |  |
| Expected Annual Hours of Operation | 8,376  | Hours    | Exhaust Moisture Content <sup>3</sup> | 13.1%                          |               | 2019          | 607.5                |  |  |
| Annual Interest Rate               | 5.5%   |          | Actual Flow Rate <sup>3</sup>         | 840,000                        | acfm          | Inflation Adj | 1.56                 |  |  |
| Expected Equipment Life            | 20     | yrs      | Standardized Flow Rate <sup>3</sup>   | 744,161                        | scfm @ 68º F  |               |                      |  |  |
| Pellet Throughput                  | 600    | LTon/hr  | Dry Std Flow Rate <sup>3</sup>        | 646,676                        | dscfm @ 68º F |               |                      |  |  |

#### CONTROL EQUIPMENT COSTS

| Capital Costs                              |   |               |                  |                |        |  |            |            |
|--|---|---------------|------------------|----------------|--------|--|------------|------------|
| Direct Capital Costs                       |   |               |                  |                |        |  |            |            |
| Purchased Equipment (A)                    |   |               |                  |                |        |  |            | 388,641    |
| Purchased Equipment Total (B)              | 22%   | of control de | vice cost (A)    |                |        |  |            | 473,656    |
| Installation - Standard Costs              | 30%   | of purchased  | d equip cost (B) |                |        |  |            | 142,097    |
| Installation - Site Specific Costs         |   |               |                  |                |        |  |            | NA         |
| Installation Total                         |   |               |                  |                |        |  |            | 142,097    |
| Total Direct Capital Cost, DC              |   |               |                  |                |        |  |            | 615,753    |
| Total Indirect Capital Costs, IC           | 38%   | of purchased  | d equip cost (B) |                |        |  |            | 179,989    |
| Total Capital Investment (TCI) with Retrof | it  |               |                  |                |        |  |            | 1,273,188  |
| Operating Costs                            |   |               |                  |                |        |  |            |            |
| Total Annual Direct Operating Costs        | Labor, supervision, materials, replacement parts, utilities, etc. |               |                  |                |        |  | 31,434,467 |            |
| Total Annual Indirect Operating Costs      |   |               | oper costs + ca  | pital recovery | / cost |  |            | 209,726    |
| Total Annual Cost (Annualized Capital Co   | st + Operati  | ng Cost)      |                  |                |        |  |            | 31,644,192 |

Notes & Assumptions

1 Equipment cost estimate EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2.5.1
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2
3 Specifications are after scrubber conditions.

|  |                |   | 388,6          |
|--|----------------|---|----------------|
| Purchased Equipment (A) (1)<br>Purchased Equipment Costs (A) - Absorber + p                    | ocking Lou     | villary aquipment EC  | 300,0          |
| Instrumentation  | -              | of control device cost (A)  | 38,8           |
|  |                |   |                |
| MN Sales Taxes   |                | of control device cost (A)  | 26,7           |
| Freight  |                | of control device cost (A)  | 19,4           |
| Purchased Equipment Total (B)  | 22%            |   | 473,6          |
| Installation   |                |   |                |
| Foundations & supports   |                | of purchased equip cost (B)   | 37,8           |
| Handling & erection  |                | of purchased equip cost (B)   | 66,3           |
| Electrical   |                | of purchased equip cost (B)   | 18,9           |
| Piping   |                | of purchased equip cost (B)   | 9,4            |
| Insulation   | 1%             | of purchased equip cost (B)   | 4,7            |
| Painting   | 1%             | of purchased equip cost (B)   | 4,7            |
| Installation Subtotal Standard Expenses  | 30%            |   | 142,0          |
| Site Preparation, as required  |                | Site Specific   | NA             |
| Buildings, as required   |                | Site Specific   | NA             |
| Site Specific - Other  |                | Site Specific   | NA             |
| Total Site Specific Costs  |                |   | NA             |
| Installation Total   |                |   | 142,0          |
| Total Direct Capital Cost, DC  |                |   | 615,           |
| Indirect Capital Costs   |                |   |                |
| Engineering, supervision   |                | of purchased equip cost (B)   | 47,3           |
| Construction & field expenses<br>Contractor fees   |                | of purchased equip cost (B)<br>of purchased equip cost (B)  | 23,0<br>47,3   |
| Start-up   |                | of purchased equip cost (B)   | 9,4            |
| Performance test   |                | of purchased equip cost (B)   | 4,7            |
| Model Studies  | .,.            | of purchased equip cost (B)   | •••            |
| Contingencies  |                | of purchased equip cost (B)   | 47,3           |
| Total Indirect Capital Costs, IC   | 38%            | of purchased equip cost (B)   | 179,9          |
| otal Capital Investment (TCI) = DC + IC<br>djusted TCI for Replacement Parts (Catalyst, Filter | · Bags, etc)   | for Capital Recovery Cost   | 795,7<br>795,7 |
| otal Capital Investment (TCI) with Retrofit Factor   | 60%            | 1.6 Retrofit Factor   | 1,273,1        |
| PERATING COSTS   |                |   | ,,             |
| Direct Annual Operating Costs, DC  |                |   |                |
| Operating Labor<br>Operator  | 70 10          | \$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr  | 37,5           |
| Supervisor   |                | 15% of Operator Costs   | 5,6            |
| Maintenance  | . 270          |   | 0,0            |
| Maintenance Labor  |                | \$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr  | 37,            |
| Maintenance Materials  |                | of maintenance labor costs  | 37,7           |
| Utilities, Supplies, Replacements & Waste Mar<br>NA  | nagement<br>NA |   |                |
| NA<br>Natural Gas  |                | \$/kscf, 12,512 scfm, 8376 hr/yr, 100% utilization  | 31,315,        |
| Total Annual Direct Operating Costs  |                |   | 31,434,4       |
| Indirect Operating Costs   |                |   |                |
| Overhead   | 60%            | of total labor and material costs   | 71,3           |
| Administration (2% total capital costs)  |                | of total capital costs (TCI)  | 15,9           |
| Property tax (1% total capital costs)  |                | of total capital costs (TCI)  | 7,9            |
| Insurance (1% total capital costs)   |                | of total capital costs (TCI)  | 7,9            |
| Capital Recovery   | 0.0837         | for a 20- year equipment life and a 5.5% interest rate<br>Sum indirect oper costs + capital recovery cost | 106,5<br>209,7 |
| Total Annual Indirect Operating Costs  |                |   |                |
| Total Annual Indirect Operating Costs  |                |   |                |

| Oxidizer Type                           | thermal              | (catalytic or the | rmal)            |                   |              | 0.0            | Reheat is by duct burner, pressure drop does not apply   |
|---|----------------------|-------------------|------------------|-------------------|--------------|----------------|--|
| Q. :: Jiana T                           | 6h                   | (astalutia as 11) |                  |                   |              | 0.0            |  |
| Blower, Catalytic                       | 840,000              |                   | 23               | 0.6               |              | 3,767.4        | EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1 |
| Blower, Thermal                         | Flow acfm<br>840,000 |                   | Δ P in H2O<br>19 | Efficiency<br>0.6 | Нр           | kW<br>3,112.2  | EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1 |
| Electrical Use                          | _                    |                   |                  |                   |              | 1.147          |  |
| ninualized Gust                         |                      | U                 |                  |                   |              |                |  |
| Total Installed Cost<br>Annualized Cost |                      | 0 Z<br>0          | ero out if r     | no replacemen     | t parts ne   | eaed           |  |
| Installation Labor                      |                      |                   |                  | ag (13 hr total)  |              |                | OAQPS list replacement times from 5 - 20 min per bag.    |
| Total Rep Parts Cost                    |                      |                   |                  | d for freight & s |              |                |  |
| Amount Required                         |                      |                   | lumber           |                   |              |                |  |
| Rep part cost per unit                  |                      | 0\$               | each             |                   |              |                |  |
| CRF                                     |                      | 0.3707            |                  |                   |              |                |  |
| Equipment Life                          |                      | 3                 |                  |                   |              |                |  |
| Replacement Parts & I                   | Equipment:           |                   |                  |                   |              |                |  |
|   |                      |                   |                  |                   |              |                |  |
| Annualized Cost                         |                      | 0                 |                  |                   |              |                |  |
| Total Installed Cost                    |                      | 0 Z               | ero out if r     | no replacemen     | t parts ne   | eded           |  |
| Installation Labor                      |                      | 0 A               | ssume Lab        | or = 15% of ca    | alyst cost ( | basis labor fo | r baghouse replacement)                                  |
| Catalyst Cost                           |                      |                   |                  | d for freight & s | ales tax     |                |  |
| Amount Required                         |                      | 39 ft             |                  |                   |              |                |  |
| Rep part cost per unit                  |                      | 0\$               | /ft <sup>3</sup> |                   |              |                |  |
| CRF                                     |                      | 0.3707            |                  |                   |              |                |  |
| Equipment Life                          |                      |                   | ears             |                   |              |                |  |
| Replacement Catalyst                    |                      | Catalyst          |                  |                   |              |                |  |
| UKF                                     |                      | 0.0837            |                  |                   |              |                |  |
| Equipment Life<br>CRF                   |                      | 20 y<br>0.0837    | ears             |                   |              |                |  |
| Interest Rate                           |                      | 5.50%             |                  |                   |              |                |  |
| Primary Installation                    |                      | 5 500/            |                  |                   |              |                |  |
| Capital Recovery Fact                   |                      |                   |                  |                   |              |                |  |

ent Use & Other Operating Costs Oxidizers - NA

| Operating Cost Calculations |                 |                    | Annual hours of operatio<br>Utilization Rate: |                    |                | 8,376<br>100%  |  |
|-----------------------------|-----------------|--------------------|---|--------------------|----------------|----------------|--|
| ltem                        | Unit<br>Cost \$ | Unit of<br>Measure | Use<br>Rate                                   | Unit of<br>Measure | Annual<br>Use* | Annual<br>Cost | Comments   |
| Operating Labor             |                 |                    |   |                    |                |                |  |
| Op Labor                    | 72.12           | \$/Hr              | 0.5   | hr/8 hr shift      | 524            | 37,755         | \$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr               |
| Supervisor                  | 15%             | of Op.             |   |                    | NA             | 5,663          | 15% of Operator Costs                              |
| Maintenance                 |                 |                    |   |                    |                |                |  |
| Maint Labor                 | 72.12           | \$/Hr              | 0.5   | hr/8 hr shift      | 524            | 37,755         | \$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr               |
| Maint Mtls                  | 100             | % of Maintena      | nce Labor                                     |                    | NA             | 37,755         | 100% of Maintenance Labor                          |
| Utilities, Supplies, F      | Replacements 8  | Waste Manag        | ement   |                    |                |                |  |
| Electricity                 | . 0.068         | \$/kwh             | 0.0   | kW-hr              | 0              | 0              | \$/kwh, 0 kW-hr, 8376 hr/yr, 100% utilization      |
| Natural Gas                 | 4.98            | \$/kscf            | 12,512  | scfm               | 6.288.261      |                | \$/kscf, 12,512 scfm, 8376 hr/yr, 100% utilization |

Flue Gas Re-Heat Equipment Cost Estimate Basis Thermal Oxidizer with 70% Heat Recovery

| Auxiliary Fuel Use | •  |
|--------------------|--|
| T <sub>wi</sub>    | 136 Deg F - Temperature of waste gas into heat recovery  |
| T <sub>fi</sub>    | 800 Deg F - Temperature of Flue gas into heat recovery   |
| Tref               | 77 Deg F - Reference temperature for fuel combustion calculations  |
| FER                | 0% Factional Heat Recovery % Heat recovery section efficiency  |
| T <sub>wo</sub>    | 136 Deg F - Temperature of waste gas out of heat recovery  |
| T <sub>fo</sub>    | 800 Deg F - Temperature of flue gas out of heat recovery   |
| -h <sub>caf</sub>  | 21502 Btu/lb Heat of combustion auxiliary fuel (methane)   |
| -h <sub>wg</sub>   | 0 Btu/lb Heat of combustion waste gas  |
| C <sub>p wg</sub>  | 0.2684 Btu/lb - Deg F Heat Capacity of waste gas (air)   |
| $ ho_{wg}$         | 0.0739 lb/scf - Density of waste gas (air) at 77 Deg F   |
| $ ho_{af}$         | 0.0408 lb/scf - Density of auxiliary fuel (methane) at 77 Deg F  |
| $Q_{wg}$           | 744,161 scfm - Flow of waste gas   |
| Q <sub>af</sub>    | 12,512 scfm - Flow of auxiliary fuel   |
| Cost Calculations  | 756,674         scfm         Flue Gas         Cost in 1989 \$'s         \$249,498           Current Cost Using CHE         Plant Cost Index         \$388,641           Heat Rec %         A         B |

|            |        | Guileni | COSt OSING OT LE FIAITE COST INDEX |
|------------|--------|---------|------------------------------------|
| Heat Rec % | A      | В       |                                    |
| 0          | 10,294 | 0.2355  | Exponents per equation 3.24        |
| 0.3        | 13,149 | 0.2609  | Exponents per equation 3.25        |
| 0.5        | 17,056 | 0.2502  | Exponents per equation 3.26        |
| 0.7        | 21,342 | 0.2500  | Exponents per equation 3.27        |

| 100 scfm        | 359                                  | scf/lbmole   |   |   |
|-----------------|--------------------------------------|--|---|---|
|                 |                                      | 000,00000  |   |   |
| Bas Composition | lb/hr f                              | wt %   | Cp Gas  | Cp Flue   |
| 0 v %           | 0                                    |  |   |   |
| 15 v %          | 184                                  | 22.0%  | 0.24  | 0.0528  |
| 10 v %          | 50                                   | 6.0%   | 0.46  | 0.0276  |
| 60 v %          | 468                                  | 56.0%  | 0.27  | 0.1512  |
| 15 v %          | 134                                  | 16.0%  | 0.23  | 0.0368  |
| 100 v %         | 836                                  | 100.0%   |   | 0.2684  |
|                 | 15 v %<br>10 v %<br>60 v %<br>15 v % | 15 v %         184           10 v %         50           60 v %         468           15 v %         134 | 15 v %         184         22.0%           10 v %         50         6.0%           60 v %         468         56.0%           15 v %         134         16.0% | 15         v%         184         22.0%         0.24           10         v%         50         6.0%         0.46           60         v%         468         56.0%         0.27           15         v%         134         16.0%         0.23 |

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators (EPA 453/B-96-001)

#### Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency Air Economics Group Health and Environmental Impacts Division Office of Air Quality Planning and Standards

(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO<sub>x</sub> emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO<sub>x</sub> within a specific temperature range to produce  $N_2$  and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

#### Instructions

Step 1: Please select on the Data Inputs tab and click on the Reset Form button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume (Vol<sub>catalyst</sub>) or flue gas flow rate (Q<sub>flue gas</sub>), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the SCR Design Parameters tab to see the calculated design parameters and the Cost Estimate tab to view the calculated cost data for the installation and operation of the SCR.

| Data Inputs   |  |  |   |  |  |  |  |
|---|--|--|---|--|--|--|--|
| Enter the following data for your combustion un   | nit:   |  |   |  |  |  |  |
| Is the combustion unit a utility or industrial boiler?  | Industrial 🗨   |  | What type of fuel does the unit burn? Natural Gas   |  |  |  |  |
| 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 th<br>projects of average retrofit difficulty.                  | e level of difficulty. Enter 1 for                       | 1.6  | * NOTE: You must document why a retrofit factor of 1.6 is appropriate for the proposed project.   |  |  |  |  |
|   | Do not rename this tab - EP<br>CCM spreadsheet has hidde |  |   |  |  |  |  |
| What is the maximum heat input rate (QB)?   | 4,455  | MMBtu/hour   | Not applicable to units burning fuel oil or natural gas       Type of coal burned:       Not Applicable   |  |  |  |  |
| What is the higher heating value (HHV) of the fuel?<br>*HHV value of 1033 Btu/scf is a default value. See below for data so |  | Btu/scf  | Enter the sulfur content (%S) = percent by weight   |  |  |  |  |
| What is the estimated actual annual fuel consumption  |  |  |   |  |  |  |  |
| Operating Hours<br>Enter the net plant heat input rate (NPHR)   | 8,376  | MMBtu/MW   | Not applicable to units buring fuel oil or natural gas<br>Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values<br>for these parameters in the table below. If the actual value for any parameter is not known, you may use the<br>default values provided. |  |  |  |  |
| If the NPHR is not known, use the default NPHR value:   | ASSUME DEFAULT   | Default NPHR<br>10 MMBtu/MW<br>11 MMBtu/MW<br>8.2 MMBtu/MW | Fraction inCoal TypeCoal Blend%SHHV (Btu/lb)Bituminous01.8411,84Sub-Bituminous00.418,820Lignite00.826,68  |  |  |  |  |
| Plant Elevation   | 1,500  | Feet above sea level                                       | 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 <i>Cost Estimate</i> tab. Please select your preferred method:  |  |  |  |  |

#### Enter the following design parameters for the proposed SCR:

| Number of days the SCR operates $(t_{\scriptscriptstyle SCR})$   | 349 days                         | Number of SCR reactor chambers ( $n_s$   | <sub>scr</sub> )                | 1   |
|--|----------------------------------|--|---------------------------------|---|
| Number of days the boiler operates $(t_{plant})$   | 349 days                         | Number of catalyst layers (R <sub>layer</sub> )  |                                 | 2   |
| Inlet $NO_x$ Emissions ( $NOx_{in}$ ) to SCR   | 0.11 lb/MMBtu                    | Number of empty catalyst layers (R <sub>er</sub>   | <sub>mpty</sub> )               | 1   |
| Outlet NO <sub>x</sub> Emissions (NOx <sub>out</sub> ) from SCR  | 0.057 lb/MMBtu                   | Ammonia Slip (Slip) provided by vend   | dor                             | 2 ppm   |
| Stoichiometric Ratio Factor (SRF)  | 0.525                            | Volume of the catalyst layers (Vol <sub>catal</sub><br>(Enter "UNK" if value is not known)   | <sub>lyst</sub> )               | UNK Cubic feet                                |
| *The SRF value of 0.525 is a default value. User should enter actual value, if known.                            |                                  | Flue gas flow rate (Q <sub>fluegas</sub> )<br>(Enter "UNK" if value is not known)  |                                 | 1776357 acfm                                  |
| Estimated operating life of the catalyst $(H_{catalyst})$  | 8,000 hours                      |  | -                               |   |
| Estimated SCR equipment life<br>* For industrial boilers, the typical equipment life is between 20 and 25 years. | 20 Years*                        | Gas temperature at the SCR inlet (T)   | -                               | 800 °F<br>484 ft <sup>3</sup> /min-MMBtu/hour |
|  |                                  | Base case fuel gas volumetric flow ra  | ate factor (Q <sub>fuel</sub> ) |   |
| Concentration of reagent as stored ( $C_{stored}$ ) Density of reagent as stored ( $\rho_{stored}$ )             | 50 percent*<br>71 lb/cubic feet* | *The reagent concentration of 50% and density of 71 lbs/cft are default<br>values for urea reagent. User should enter actual values for reagent, if<br>different from the default values provided. |                                 |   |
| Number of days reagent is stored (t <sub>storage</sub> )   | 14 days                          |  | Densities of typical            | SCR reagents:                                 |
|  |                                  | -  | 50% urea solution               | 71 lbs/ft <sup>3</sup>                        |
|  |                                  |  | 29.4% aqueous NH                | 3 56 lbs/ft <sup>3</sup>                      |
| Select the reagent used Urea   | •                                |  |                                 |   |
|  |                                  |  |                                 |   |
|  |                                  |  |                                 |   |

#### Enter the cost data for the proposed SCR:

| Desired dollar-year                    | 2019   |   |
|--|--|---|
| CEPCI for 2019                         | 607.5 2019 final CEPCI value 541.7 2016 CEPCI  | CEPCI = Chemical Engineering Plant Cost Index   |
| Annual Interest Rate (i)               | 5.5 Percent*   | * 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at<br>https://www.federalreserve.gov/releases/h15/.) |
| Reagent (Cost <sub>reag</sub> )        | 1.814 \$/gallon for 50% urea   |   |
| Electricity (Cost <sub>elect</sub> )   | 0.0684 \$/kWh  |   |
| Catalyst cost (CC <sub>replace</sub> ) | \$/cubic foot (includes removal and disposal/regeneration of existing 248.05 catalyst and installation of new catalyst |   |
| Operator Labor Rate                    | 72.12 \$/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) = Administrative Charges Factor (ACF) =

| 0.005 |
|-------|
| 0.03  |

1.325

#### Data Sources for Default Values Used in Calculations:

|  |               |  | If you used your own site-specific values, please enter the value |
|--|---------------|--|---|
| Data Element                               |               | Sources for Default Value  | used and the reference source                                     |
| Reagent Cost (\$/gallon)                   | · · · -       | U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector   |   |
|  | urea solution | Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and  |   |
|  |               | Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5,   |   |
|  |               | Attachment 5-3, January 2017. Available at:  |   |
|  |               | https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-   |   |
| Electricity Cost (\$/kWh)                  | 0.0676        | U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published   |   |
|  |               | December 2017. Available at:   |   |
|  |               | https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.  |   |
|  |               |  |   |
|  |               |  |   |
| Percent sulfur content for Coal (% weight) |               | Not applicable to units burning fuel oil or natural gas  |   |
|  |               |  |   |
|  |               |  |   |
|  |               |  |   |
|  |               |  |   |
| Higher Heating Value (HHV) (Btu/lb)        | 1,033         | 2016 natural gas 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 http://www.eia.gov/electricity/data/eia923/.   |   |
|  |               |  |   |
|  | 227           |  |   |
| 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.<br>May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power- |   |
|  |               | sector-modeling-platform-v6.   |   |
|  |               | sector-modeling-platform-v6.   |   |
|  |               |  |   |
| 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: https://www.epa.gov/airmarkets/documentation-epas-power-   |   |
|  |               | sector-modeling-platform-v6.   |   |
|  |               |  |   |
|  |               |  |   |
| Interest Rate (Percent)                    | 5.5           | Default bank prime rate  |   |
|  |               |  |   |
|  |               |  |   |
|  |               |  |   |

#### 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 <sub>B</sub> ) =       | HHV x Max. Fuel Rate =   | 4,455            | MMBtu/hour |  |
| Maximum Annual fuel consumption (mfuel) =                | (QB x 1.0E6 x 8760)/HHV =  | 37,776,664,169   | scf/Year   |  |
| Actual Annual fuel consumption (Mactual) =               |  | 36,120,700,808   | scf/Year   |  |
| Heat Rate Factor (HRF) =                                 | NPHR/10 =  | 0.82             |            |  |
| Total System Capacity Factor (CF <sub>total</sub> ) =    | (Mactual/Mfuel) x (tscr/tplant) =  | 0.956            | fraction   |  |
| Total operating time for the SCR $(t_{op})$ =            | CF <sub>total</sub> x 8760 =   | 8376             | hours      |  |
| NOx Removal Efficiency (EF) =                            | (NOx <sub>in</sub> - NOx <sub>out</sub> )/NOx <sub>in</sub> =  | 50.0             | percent    |  |
| NOx removed per hour =                                   | $NOx_{in} \times EF \times Q_B =$  | 255.19           | lb/hour    |  |
| Total NO <sub>x</sub> removed per year =                 | (NOx <sub>in</sub> x EF x Q <sub>B</sub> x t <sub>op</sub> )/2000 =  | 937.00           | tons/year  |  |
| NO <sub>x</sub> removal factor (NRF) =                   | EF/80 =  | 0.63             |            |  |
| Volumetric flue gas flow rate (q <sub>flue gas</sub> ) = | Q <sub>fuel</sub> x QB x (460 + T)/(460 + 700)n <sub>scr</sub> =   | 1,776,357        | acfm       |  |
| Space velocity (V <sub>space</sub> ) =                   | q <sub>flue gas</sub> /Vol <sub>catalyst</sub> =   | 144.57           | /hour      |  |
| Residence Time   | 1/V <sub>space</sub>   | 0.01             | hour       |  |
| Coal Factor (CoalF) =                                    | 1 for oil and natural gas; 1 for bituminous; 1.05 for sub-<br>bituminous; 1.07 for lignite (weighted average is used for<br>coal blends) | 1.00             |            |  |
| SO <sub>2</sub> Emission rate =                          | (%S/100)x(64/32)*1x10 <sup>6</sup> )/HHV =   |                  |            | Not applicable; factor applies only to<br>coal-fired boilers |
| Elevation Factor (ELEVF) =                               | 14.7 psia/P =  | 1.06             |            |  |
| Atmospheric pressure at sea level (P) =                  | 2116 x [(59-(0.00356xh)+459.7)/518.6] <sup>5.256</sup> x (1/144)* =  | 13.9             | psia       |  |
| Retrofit Factor (RF)                                     | Retrofit to existing boiler  | 1.60             |            |  |

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at

Urea

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) <sup>Y</sup> -1), where Y = $H_{catalyts}/(t_{SCR} \times 24$ hours) rounded to the nearest integer |                  | Fraction   |
| Catalyst volume (Vol <sub>catalyst</sub> ) =            | 2.81 x Q <sub>8</sub> x EF <sub>adj</sub> x Slipadj x NOx <sub>adj</sub> x S <sub>adj</sub> x (T <sub>adj</sub> /N <sub>scr</sub> )       | 12,286.86        | Cubic feet |
| Cross sectional area of the catalyst $(A_{catalyst}) =$ | q <sub>flue gas</sub> /(16ft/sec x 60 sec/min)  | 1,850            | ft²        |
| Height of each catalyst layer (H <sub>layer</sub> ) =   | (Vol <sub>catalyst</sub> /(R <sub>layer</sub> x A <sub>catalyst</sub> )) + 1 (rounded to next highest integer)                            | 4                | feet       |

#### SCR Reactor Data:

| Parameter   | Equation   | Calculated Value | Units           |
|---|--|------------------|-----------------|
| Cross sectional area of the reactor (A <sub>SCR</sub> ) =     | 1.15 x A <sub>catalyst</sub>                             | 2,128            | ft <sup>2</sup> |
| Reactor length and width dimensions for a<br>square reactor = | (A <sub>SCR</sub> ) <sup>0.5</sup>                       | 46.1             | feet            |
| Reactor height =  | $(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$ | 43               | feet            |

#### Reagent Data:

| Туре | of | reagent | used |
|------|----|---------|------|

Molecular Weight of Reagent (MW) = 60.06 g/mole Density = 71 lb/ft<sup>3</sup>

| Parameter  | Equation   | Calculated Value | Units   |
|--|--|------------------|---|
| Reagent consumption rate (m <sub>reagent</sub> ) = | (NOx <sub>in</sub> x Q <sub>B</sub> x EF x SRF x MW <sub>R</sub> )/MW <sub>NOx</sub> = | 175              | lb/hour   |
| Reagent Usage Rate (m <sub>sol</sub> ) =           | m <sub>reagent</sub> /Csol =   | 350              | lb/hour   |
|  | (m <sub>sol</sub> x 7.4805)/Reagent Density  | 37               | gal/hour  |
| Estimated tank volume for reagent storage =        | (m <sub>sol</sub> x 7.4805 x t <sub>storage</sub> x 24)/Reagent Density =              | 12,400           | gallons (storage needed to store a 14 day reagent supply rounded to |

#### Capital Recovery Factor:

| Parameter                              | Equation   | Calculated Value |
|--|--|------------------|
| Capital Recovery Factor (CRF) =        | $i (1+i)^n / (1+i)^n - 1 =$                                      | 0.083            |
|  | Where n = Equipment Life and i= Interest Rate                    |                  |
|  |  |                  |
|  |  |                  |
| Other parameters                       | Equation   | Calculated Value |
| Other parameters<br>Electricity Usage: | Equation   | Calculated Value |
|  | Equation<br>A x 1,000 x 0.0056 x (CoalF x HRF) <sup>0.43</sup> = | Calculated Value |

**Cost Estimate** 

#### Total Capital Investment (TCI)

| TCI fo  | r Oil and Natural Gas Boilers   |                 |
|---|---|-----------------|
| For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:    |   |                 |
| TCI = 86,380  | x (200/B <sub>MW</sub> ) <sup>0.35</sup> x B <sub>MW</sub> x ELEVF x RF   |                 |
| For Oil and Natural Gas-Fired Utility Boilers >500 MW:                    |   |                 |
| TCI =   | = 62,680 x B <sub>MW</sub> x ELEVF x RF                                   |                 |
| For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :       |   |                 |
| TCI = 7,850   | x (2,200/Q <sub>B</sub> ) <sup>0.35</sup> x Q <sub>B</sub> x ELEVF x RF   |                 |
| For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour | :   |                 |
| TCI = 10,530  | 0 x (1,640/Q <sub>в</sub> ) <sup>0.35</sup> x Q <sub>в</sub> x ELEVF x RF |                 |
| For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:                       |   |                 |
| TCI   | I = 5,700 x Q <sub>B</sub> x ELEVF x RF                                   |                 |
| For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:               |   |                 |
| TCI   | I = 7,640 x Q <sub>B</sub> x ELEVF x RF                                   |                 |
|   |   |                 |
| Total Capital Investment (TCI) =  | \$64,441,596  | in 2019 dollars |

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

| Direct Annual Costs (DAC) =           | \$3,719,067 in 2019 dollars |
|---------------------------------------|-----------------------------|
| Indirect Annual Costs (IDAC) =        | \$5,400,648 in 2019 dollars |
| Total annual costs (TAC) = DAC + IDAC | \$9,119,716 in 2019 dollars |

#### Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

| 0.005 x TCI =  | \$322,208 in 2019 dollars   |
|--|---|
| m <sub>sol</sub> x Cost <sub>reag</sub> x t <sub>op</sub> =                                | \$559,897 in 2019 dollars   |
| P x Cost <sub>elect</sub> x t <sub>op</sub> =  | \$1,313,090 in 2019 dollars   |
|  | \$1,523,872 in 2019 dollars   |
| n <sub>ser</sub> x Vol <sub>rat</sub> x (CC <sub>reniare</sub> /R <sub>lauer</sub> ) x FWF |   |
|  | \$3,719,067 in 2019 dollars   |
| Indirect Annual Cost (IDAC)  |   |
| IDAC = Administrative Charges + Capital Recovery Costs                                     |   |
|  | m <sub>sol</sub> x Cost <sub>reag</sub> x t <sub>op</sub> =<br>P x Cost <sub>elect</sub> x t <sub>op</sub> =<br>n <sub>scr</sub> x Vol <sub>cat</sub> x (CC <sub>replace</sub> /R <sub>layer</sub> ) x FWF<br>Indirect Annual Cost (IDAC) |

| Administrative Charges (AC) = | 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) = | \$6,887 in 2019 dollars     |
|-------------------------------|--|-----------------------------|
| Capital Recovery Costs (CR)=  | CRF x TCI =  | \$5,393,762 in 2019 dollars |
| Indirect Annual Cost (IDAC) = | AC + CR =  | \$5,400,648 in 2019 dollars |

#### Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

| Total Annual Cost (TAC) = | \$9,119,716 per year in 2019 dollars              |
|---------------------------|---|
| NOx Removed =             | 937 tons/year                                     |
| Cost Effectiveness =      | \$9,732.89 per ton of NOx removed in 2019 dollars |
|                           | \$/Ton above does not include reheat costs        |

# Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 5: Control Dry Sorbent Injection (DSI) with Baghouse

#### **Operating Unit:**

Line 2

| Emission Unit Number   | EU 042 |          | Stack/Vent Number        | SV 048 & 049 |               |
|------------------------|--------|----------|--------------------------|--------------|---------------|
| Design Capacity        | 400    | MMBtu/hr | Standardized Flow Rate   | 725,189      | scfm @ 32º F  |
| Utilization Rate       | 100%   |          | Exhaust Temperature      | 300          | Deg F         |
| Annual Operating Hours | 8,376  | Hours    | Exhaust Moisture Content | 6.3%         |               |
| Annual Interest Rate   | 5.50%  |          | Actual Flow Rate         | 1,120,210    | acfm          |
| Control Equipment Life | 20     | yrs      | Standardized Flow Rate   | 778,251      | scfm @ 68º F  |
| Pellet Throughput      | 600    | LTon/hr  | Dry Std Flow Rate        | 729,057      | dscfm @ 68º F |

#### CONTROL EQUIPMENT COSTS

| CONTINUE EQUI MENT COULD                   |                |               |                    |                 |                     |  |            |
|--|----------------|---------------|--------------------|-----------------|---------------------|--|------------|
| Capital Costs                              |                |               |                    |                 |                     |  |            |
| Direct Capital Costs                       |                |               |                    |                 |                     |  |            |
| Purchased Equipment (A)                    |                |               |                    |                 |                     |  | 9,551,151  |
| Purchased Equipment Total (B)              | 12%            | of control de | vice cost (A)      |                 |                     |  | 10,685,351 |
|  |                |               |                    |                 |                     |  |            |
| Installation - Standard Costs              | 70%            | of purchased  | d equip cost (B)   |                 |                     |  | 7,479,745  |
| Installation - Site Specific Costs         |                |               |                    |                 |                     |  | 11,318,403 |
| Installation Total                         |                |               |                    |                 |                     |  | 18,798,149 |
| Total Direct Capital Cost, DC              |                |               |                    |                 |                     |  | 29,483,499 |
| Total Indirect Capital Costs, IC           | 52%            | of purchased  | d equip cost (B)   |                 |                     |  | 5,556,382  |
| Total Capital Investment (TCI) = DC + IC   |                |               |                    |                 |                     |  | 33,741,308 |
| Total Capital Investment (TCI) with Retrof | it Factor      |               |                    |                 |                     |  | 50,466,157 |
| Operating Costs                            |                |               |                    |                 |                     |  |            |
| Total Annual Direct Operating Costs        |                | Labor, super  | vision, materials, | eplacement par  | ts, utilities, etc. |  | 4,657,379  |
| Total Annual Indirect Operating Costs      |                | Sum indirect  | oper costs + capi  | al recovery cos | t                   |  | 6,740,531  |
| Total Annual Cost (Annualized Capital Co   | ost + Operatir | ng Cost)      |                    |                 |                     |  | 10,090,749 |

#### Emission Control Cost Calculation

| Pollutant                        | Max Emis<br>Lb/Hr | Annual<br>Ton/Yr | Calculation<br>Method | Cont Eff<br>% | Performance<br>Basis | Conc.<br>Units | Cont Emis<br>Ton/Yr | Reduction<br>Ton/Yr | Cont Cost<br>\$/Ton Rem |
|----------------------------------|-------------------|------------------|-----------------------|---------------|----------------------|----------------|---------------------|---------------------|-------------------------|
| PM10                             |                   |                  |                       |               |                      |                |                     |                     |                         |
| PM2.5                            |                   |                  |                       |               |                      |                |                     |                     |                         |
| Total Particulates               |                   |                  |                       |               |                      |                |                     |                     |                         |
| Nitrous Oxides (NOx)             |                   |                  |                       |               |                      |                |                     |                     |                         |
| Sulfur Dioxide (SO2)             | 73.13             | 215.40           | % Removal             | 50%           | NA                   | NA             | 107.19              | 108.21              | \$93,300                |
| Sulfuric Acid Mist (H2SO4)       |                   |                  |                       |               |                      |                |                     |                     |                         |
| Fluorides                        |                   |                  |                       |               |                      |                |                     |                     |                         |
| Volatile Organic Compounds (VOC) |                   |                  |                       |               |                      |                |                     |                     |                         |
| Carbon Monoxide (CO)             |                   |                  |                       |               |                      |                |                     |                     |                         |
| Lead (Pb)                        |                   |                  |                       |               |                      |                |                     |                     |                         |

Notes & Assumptions
Purchased equipment cost from vendor quotes for baghouse and anciliary equipment, adjusted for inflation using the Chemical Engineering Plant Cost Index (CEPCI).
Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

Used 0.6 power law factor to adjust prices based on acfm from vendor bids if applicable
Trona DSI applications typically achieve a 70% SO2 reduction, but the uncontrolled concentrations are too low to achieve this level of control
Electricity demand is the incremental cost for additional power demand with the removal of the existing particulate controls

#### Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 5: Control Dry Sorbent Injection (DSI) with Baghouse

| Purchased Equipment (A) (1)  |  |   |
|--|--|---|
|  | stem + auxiliary equipment, EC   | 9,551,15  |
| Instrumentation  | 0% Included in vendor estimate   |   |
| State Sales Taxes  | 6.9% of control device cost (A)  | 656,64  |
| Freight  | 5% of control device cost (A)  | 477,55  |
| Purchased Equipment Total (B)  | 12%  | 10,685,35   |
| Installation   |  |   |
| Foundations & supports   | 4% of purchased equip cost (B)   | 427,41  |
| Handling & erection  | 50% of purchased equip cost (B)  | 5,342,67  |
| Electrical   | 8% of purchased equip cost (B)<br>1% of purchased equip cost (B)   | 854,82  |
| Piping<br>Insulation   | 7% of purchased equip cost (B)   | 106,85<br>747,97  |
| Painting   | 0% Included in vendor estimate   | 141,01  |
| Installation Subtotal Standard Expenses  | 70%  | 7,479,74  |
| Site specific - Site Prep  | N/A Site Specific  | 94,29   |
| Site specific - Ductwork   | N/A Site Specific  | 3,198,08  |
| Site specific - Buildings  | N/A Site Specific  | 2,159,47  |
| 0  |  | ,,  |
| Lost Production for Tie-In   | N/A Site Specific  | 5,866,560   |
| Total Site Specific Costs  |  | 11,318,40   |
| Installation Total<br>Total Direct Capital Cost, DC  |  | 18,798,14   |
| Total Direct Capital Cost, DC  |  | 29,483,49   |
| Indirect Capital Costs   |  |   |
| Engineering, supervision   | 10% of purchased equip cost (B)  | 1,068,53  |
| Construction & field expenses  | 20% of purchased equip cost (B)  | 2,137,07  |
| Contractor fees  | 10% of purchased equip cost (B)  | 1,068,53  |
| Start-up   | 1% of purchased equip cost (B)   | 106,85  |
| Performance test<br>Model Studies  | 1% of purchased equip cost (B)<br>N/A of purchased equip cost (B)  | 106,85  |
| Contingencies  | 10% of purchased equip cost (B)  | 1,068,53  |
| Total Indirect Capital Costs, IC   | 52% of purchased equip cost (B)  | 5,556,38  |
| tal Capital Investment (TCI) = DC + IC   |  | 35,039,88   |
| ijusted TCI for Replacement Parts (Catalyst, Filte   | r Bags, etc) for Capital Recovery Cost   | 33,741,30   |
| tal Capital Investment (TCI) with Retrofit Factor  | 60% 1.6 Retrofit Factor  | 50,466,15   |
|  |  |   |
| PERATING COSTS   |  |   |
| PERATING COSTS<br>Direct Annual Operating Costs, DC  |  |   |
| Direct Annual Operating Costs, DC<br>Operating Labor   |  |   |
| Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator   | 72.12 \$/Hr  |   |
| Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor   | 72.12 \$/Hr<br>0.15 of Op Labor  |   |
| Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance  | 0.15 of Op Labor   | 22,65   |
| Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor   |  | 22,65<br>75,51  |
| Direct Annual Operating Costs, DC<br>Operating Labor<br>Operator<br>Supervisor<br>Maintenance<br>Maintenance Labor   | 0.15 of Op Labor<br>72.12 \$/Hr<br>100 % of Maintenance Labor  | 22,65<br>75,51  |
| Direct Annual Operating Costs, DC Operating Labor Operator Supervisor Maintenance Labor Maintenance Materials Utilities, Supplies, Replacements & Waste Ma Electricity   | 0.15 of Op Labor<br>72.12 \$/Hr<br>100 % of Maintenance Labor<br>inagement<br>0.07 \$/kwh  | 22,65<br>75,51<br>75,51<br>1,062,94   |
| Direct Annual Operating Costs, DC Operating Labor Operator Supervisor Maintenance Labor Maintenance Materials Utilities, Supplies, Replacements & Waste Materials Electricity Solid Waste Disposal   | 0.15 of Op Labor<br>72.12 \$/Hr<br>100 % of Maintenance Labor<br>inagement<br>0.07 \$/kwh<br>44.35 \$/ton  | 22,65<br>75,51<br>75,51<br>1,062,94<br>2,436,97   |
| Direct Annual Operating Costs, DC Operating Labor Operator Supervisor Maintenance Maintenance Labor Maintenance Materials Utilities, Supplies, Replacements & Waste Mate Electricity   | 0.15 of Op Labor<br>72.12 \$/Hr<br>100 % of Maintenance Labor<br>inagement<br>0.07 \$/kwh  | 22,65<br>75,51<br>76,51<br>1,062,94<br>2,436,97<br>578,97   |
| Direct Annual Operating Costs, DC Operating Labor Operator Supervisor Maintenance Maintenance Labor Maintenance Materials Utilities, Supplies, Replacements & Waste  Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements Utilities, | 0.15 of Op Labor<br>72.12 \$/Hr<br>100 % of Maintenance Labor<br>inagement<br>0.07 \$/kwh<br>44.35 \$/ton<br>285.00 \$/ton<br>29 \$/LTon   | 22,65<br>75,57<br>75,51<br>1,062,94<br>2,436,97<br>578,97<br>253,76<br><b>4,657,3</b> 7   |
| Direct Annual Operating Costs, DC Operating Labor Operator Supervisor Maintenance Labor Maintenance Materials Utilities, Supplies, Replacements & Waste Materials Utilities, Supplies, Replacements & Waste Materials Utilities Solid Waste Disposal Trona Taconite Product Loss Total Annual Direct Operating Costs Savings from Shutdown of Existing Emission C Indirect Operating Costs   | 0.15 of Op Labor<br>72.12 \$/Hr<br>100 % of Maintenance Labor<br>inagement<br>0.07 \$/kwh<br>44.35 \$/ton<br>285.00 \$/ton<br>29 \$/LTon   | 22,65<br>75,51<br>75,51<br>1,062,94<br>2,436,97<br>578,97<br>253,76<br><b>4,657,37</b><br><b>(1,307,16</b>  |
| Direct Annual Operating Costs, DC Operating Labor Operator Supervisor Maintenance Maintenance Labor Maintenance Materials Utilities, Supplies, Replacements & Waste  Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements Utilities, | 0.15 of Op Labor<br>72.12 \$/Hr<br>100 % of Maintenance Labor<br><b>inagement</b><br>0.07 \$/kwh<br>44.35 \$/ton<br>285.00 \$/ton<br>29 \$/LTon  | 22,65<br>75,51<br>75,51<br>1,062,94<br>2,436,97<br>578,97<br>253,78<br>4,657,37<br><b>4,657,37</b><br><b>(1,307,16</b><br>194,81  |
| Direct Annual Operating Costs, DC Operating Labor Operator Supervisor Maintenance Labor Maintenance Labor Maintenance Materials Utilities, Supplies, Replacements & Waste  Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacements & Waster Materials Utilities, Supplies, Replacemen | 0.15 of Op Labor<br>72.12 \$/Hr<br>100 % of Maintenance Labor<br><b>inagement</b><br>0.07 \$/kwh<br>44.35 \$/ton<br>285.00 \$/ton<br>29 \$/LTon<br>Controls<br>60% of total labor and material costs   | 22,65<br>75,51<br>76,51<br>1,062,94<br>2,436,97<br>578,97<br>253,76<br><b>4,657,37</b><br><b>4,657,37</b><br><b>(1,307,16</b><br>194,81<br>1,009,32                     |
| Direct Annual Operating Costs, DC Operating Labor Operator Supervisor Maintenance Maintenance Labor Maintenance Adterials Utilities, Supplies, Replacements & Waste Materials  | 0.15 of Op Labor<br>72.12 \$/Hr<br>100 % of Maintenance Labor<br><b>inagement</b><br>0.07 \$/kwh<br>44.35 \$/ton<br>285.00 \$/ton<br>29 \$/LTon<br><b>Controls</b><br>60% of total labor and material costs<br>2% of total capital costs (TCI)<br>1% of total capital costs (TCI)<br>1% of total capital costs (TCI) | 22,65<br>75,51<br>75,51<br>1,062,94<br>2,436,97<br>578,97<br>253,76<br><b>4,657,37</b><br><b>4,657,37</b><br><b>(1,307,16</b><br>194,81<br>1,009,32<br>504,66<br>504,66 |
| Direct Annual Operating Costs, DC Operating Labor Operator Supervisor Maintenance Labor Maintenance Labor Maintenance Materials Utilities, Supplies, Replacements & Waste Ma Electricity Solid Waste Disposal Trona Taconite Product Loss Total Annual Direct Operating Costs Savings from Shutdown of Existing Emission C Indirect Operating Costs Overhead Administration (2% total capital costs) Property tax (1% total capital costs)   | 0.15 of Op Labor<br>72.12 \$/Hr<br>100 % of Maintenance Labor<br><b>inagement</b><br>0.07 \$/kwh<br>44.35 \$/ton<br>285.00 \$/ton<br>29 \$/LTon<br><b>Controls</b><br>60% of total labor and material costs<br>2% of total capital costs (TCI)<br>1% of total capital costs (TCI)                                    | 194,81<br>1,009,32<br>504,66<br>504,66  |

#### Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 5: Control Dry Sorbent Injection (DSI) with Baghouse

| Capital Recovery Factors       |           |                     |                            |           |   |
|--------------------------------|-----------|---------------------|----------------------------|-----------|---|
| Primary Installation           |           |                     | 1                          |           |   |
| Interest Rate                  |           | 5.50%               |                            |           |   |
| Equipment Life                 |           | 20 years            |                            |           |   |
| CRF                            |           | 0.0837              | 1                          |           |   |
| Replacement Parts & Equipment: | Filter I  | Bags                |                            |           |   |
| Equipment Life                 |           | 5 years             |                            |           |   |
| CRF                            | ,         | 0.2342              |                            |           |   |
| Rep part cost per unit         |           | 117 \$/bag          |                            |           |   |
| Amount Required                |           | 8399 Bags           |                            |           |   |
| Total Rep Parts Cost           |           |                     | ed for freight & sales tax |           |   |
| Installation Labor             | 2         | 01,923 20 min per b | ag                         |           |   |
| Total Installed Cost           | 1,2       | 98,573              |                            |           |   |
| Annualized Cost                | 3         | 04,095              |                            |           |   |
|                                |           |                     |                            |           |   |
| Electrical Use                 |           |                     |                            |           |   |
|                                | Flow acfm | D P in H2O          |                            | kWhr/yr   |   |
|                                |           |                     |                            |           | Incremental electricity increase over with baghouse replacing |
| Blower                         | 1,120,210 | 7.18                |                            |           | scrubber including ducting                                    |
| Air Compressor                 |           |                     |                            | 3,331,191 | Based on Compressor HP  |
|                                |           |                     |                            |           |   |
|                                |           |                     |                            |           |   |
|                                |           |                     |                            |           |   |
|                                |           |                     |                            |           |   |
|                                |           |                     |                            |           |   |

| Total                               | 15,531,098 |
|-------------------------------------|------------|
|                                     |            |
|                                     |            |
| Reagent Use & Other Operating Costs |            |

| <br>Reagent obe a other operating oosts |        |                       |            |                            |               |
|---|--------|-----------------------|------------|----------------------------|---------------|
| Trona use - 1.5 NSR                     | 73.13  | lb/hr SO2             | 485.07     | lb/hr Trona                |               |
| Solid Waste Disposal                    | 53,322 | ton/yr existing scru  | bber inle  | t process dust loading     |               |
| Solid Waste Disposal                    | 1,632  | ton/yr DSI unreacte   | ed sorber  | nt and reaction byproducts | S             |
| Taconite Product Loss                   | 8721   | ton/yr lost iron proc | duction fr | om scrubber replacement    | t by baghouse |
|   |        |                       |            |                            |               |

|  | 0 | perating | Cost | Calculations |
|--|---|----------|------|--------------|
|--|---|----------|------|--------------|

|                        | Utilization Rate | 100%        | Annual Oper    | ating Hours | 8,376         |            |                 |   |
|------------------------|------------------|-------------|----------------|-------------|---------------|------------|-----------------|---|
|                        |                  | Unit        | Unit of        | Use         | Unit of       | Annual     | Annual          | Comments  |
| tem                    |                  | Cost \$     | Measure        | Rate        | Measure       | Use*       | Cost            |   |
| Dperating Labor        |                  |             |                |             |               |            |                 |   |
| Dp Labor               |                  | 72.12       | \$/Hr          | 2.0         | hr/8 hr shift | 2,094      | \$<br>151,019   | \$/Hr, 2.0 hr/8 hr shift, 2,094 hr/yr             |
| Supervisor             |                  | 15%         | of Op Labor    |             |               | NA         | \$<br>22,653    | % of Operator Costs                               |
| laintenance            |                  |             |                |             |               |            |                 |   |
| /laint Labor           |                  | 72.12       | \$/Hr          | 1.0         | hr/8 hr shift | 1,047      | \$<br>75,510    | \$/Hr, 1.0 hr/8 hr shift, 1,047 hr/yr             |
| /laint Mtls            |                  | 100%        | of Maintenance | Labor       |               | NA         | \$<br>75,510    | 100% of Maintenance Labor                         |
| Jtilities, Supplies, I | Replacements & V | Naste Manag | gement         |             |               |            |                 |   |
| lectricity             |                  | 0.068       | \$/kwh         | 1854.2      | kW-hr         | 15,531,098 | \$<br>1,062,948 | \$/kwh, 1,854 kW-hr, 8376 hr/yr, 100% utilization |
| Solid Waste Disposa    | d                | 44.35       | \$/ton         | 6.56        | ton/hr        | 54,954     | \$<br>2,436,978 | \$/ton, 7 ton/hr, 8376 hr/yr, 100% utilization    |
| rona                   |                  | 285.00      | \$/ton         | 485.1       | lb/hr         | 2,031      | \$<br>578,973   | \$/ton, 485 lb/hr, 8376 hr/yr, 100% utilization   |
| aconite Pellets        |                  | 29.100      | \$/LTon        | 1.0         | LT/hr         | 8,721      | \$<br>253,788   | \$/LTon, 1 LT/hr, 8376 hr/yr, 100% utilization    |

#### Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 6 - Spray Dry Absorber (SDA)

#### Operating Unit: Line 2

| Emission Unit Number               | EU 042 |         | Stack/Vent Number      | SV 048 & 049 |               |
|------------------------------------|--------|---------|------------------------|--------------|---------------|
|                                    |        |         |                        |              |               |
| Expected Utilization Rate          | 100%   |         | Temperature            | 300          | Deg F         |
| Expected Annual Hours of Operation | 8,376  | Hours   | Moisture Content       | 6.3%         |               |
| Annual Interest Rate               | 5.5%   |         | Actual Flow Rate       | 1,120,210    | acfm          |
| Expected Equipment Life            | 20     | yrs     | Standardized Flow Rate | 778,251      | scfm @ 68º F  |
| Pellet Throughput                  | 600    | LTon/hr | Dry Std Flow Rate      | 729,057      | dscfm @ 68º F |

#### CONTROL EQUIPMENT COSTS

| CONTROL EQUIPMENT COSTS                    |                |                     |                   |                |                   |             |
|--|----------------|---------------------|-------------------|----------------|-------------------|-------------|
| Capital Costs                              |                |                     |                   |                |                   |             |
| Direct Capital Costs                       |                |                     |                   |                |                   |             |
| Purchased Equipment (A)                    |                |                     |                   |                |                   | 26,325,693  |
| Purchased Equipment Total (B)              | 10%            | of control device c | ost (A)           |                |                   | 28,958,262  |
| Installation - Standard Costs              | 74%            | of purchased equip  | o cost (B)        |                |                   | 21,429,114  |
| Installation - Site Specific Costs         |                |                     |                   |                |                   | 59,029,538  |
| Installation Total                         |                |                     |                   |                |                   | 21,429,114  |
| Total Direct Capital Cost, DC              |                |                     |                   |                |                   | 50,387,376  |
| Total Indirect Capital Costs, IC           | 42%            | of purchased equip  | o cost (B)        |                |                   | 12,162,470  |
| Total Capital Investment (TCI) with Site-s | pecific Costs  |                     |                   |                |                   | 120,947,748 |
| Operating Costs                            |                |                     |                   |                |                   |             |
| Total Annual Direct Operating Costs        |                | Labor, supervision  | , materials, repl | acement parts, | , utilities, etc. | 5,410,769   |
| Total Annual Indirect Operating Costs      |                | Sum indirect oper   | costs + capital i | ecovery cost   |                   | 15,470,358  |
| Savings from Shutdown of Existing Emission | on Controls    |                     |                   |                |                   | (1,307,161) |
| Total Annual Cost (Annualized Capital Co   | ost + Operatin | g Cost)             |                   |                |                   | 19,573,967  |

#### Actual

| Emission Control Cost Calculation  |                   |                | Emissions     |               |                |                   |                   |                         |
|------------------------------------|-------------------|----------------|---------------|---------------|----------------|-------------------|-------------------|-------------------------|
| Pollutant                          | Max Emis<br>Ib/hr | Annual<br>T/Yr | Cont Eff<br>% | Exit<br>Conc. | Conc.<br>Units | Cont Emis<br>T/yr | Reduction<br>T/yr | Cont Cost<br>\$/Ton Rem |
|                                    |                   |                |               |               |                |                   |                   |                         |
| Sulfur Dioxide (SO <sub>2</sub> ): | 51.4              | 215            | 50.2%         | 5             | ppm            | 107.2             | 108               | \$180,891               |

#### Notes & Assumptions

1 Purchased equipment costs from independent review by Zachry Engineering scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)

2 Capital equipment cost includes the items listed below, which are calculated using EPA cost control manual guidance.

- 3 GSA/SDA designed for 5 ppm exit SO2 concentration
- 6/18/2012 email from Candice Maxwell, Cleveland Cliffs in response to EPA Region 5 CAA Section 114 information request for scrubber operating costs. Email reported total annual operating costs for both Scrubbers. Listed value excludes capital recover costs and is pro-rated by scrubber exhaust flow rate. Value includes continuing operations cost, per a 9/26/12 e-mail from Jen Krause, Cleveland Cliffs.
- 5 CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit factor for installations in existing facilities

6 Site specific installation costs from independent review by Zachry Engineering.

7 Labor required for handling of lime shipments entering and exiting the facility. Includes spill prevention/cleanup and truck cleaning.

8 Determined from Table 3.21 of Chapter 3 of EPA's September 1999 Particulate Matter control design guidelines (for ESPs)

9 Labor and maintenance materials are 5% of capital costs per CueCost. "Average process with normal operating conditions should have maintenance labor and material costs" of 5 to 9% of fixed capital investment. (page 134, Plant Design and Economics for Chemical Engineers, Max Peters and Klaus Timmerhaus; McGraw-Hill Book Company)

10 Determined from Table 1.11 of Chapter 1 of EPA's December 1998 Particulate Matter control design guidelines (for FFs and baghouses)

11 Contingency is accounted for under Site Specific Installed Equipment Costs.

#### Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 6 - Spray Dry Absorber (SDA)

| CAPITAL COSTS   |           |   |                                |
|---|-----------|---|--------------------------------|
| Direct Capital Costs  |           |   |                                |
| Purchased Equipment (A)   |           |   |                                |
| Purchased Equipment Costs (A)<br>Instrumentation                        | 10%       | of control device cost (A)                                    | <b>26,325,693</b><br>2,632,569 |
| MN Sales Taxes  |           | of control device cost (A)                                    | 2,052,509                      |
| Freight   |           | of control device cost (A)                                    | 0                              |
| Purchased Equipment Total (B)   | 10%       |   | 28,958,262                     |
|   |           |   |                                |
| Installation  |           |   |                                |
| Foundations & supports  | 4%        | of purchased equip cost (B)                                   | 1,158,330                      |
| Handling & erection   |           | of purchased equip cost (B)                                   | 14,479,131                     |
| Electrical  |           | of purchased equip cost (B)                                   | 2,316,661                      |
| Piping  |           | of purchased equip cost (B)                                   | 289,583                        |
| Insulation  |           | of purchased equip cost (B)                                   | 2,027,078                      |
| Painting<br>Installation Subtotal Standard Expenses                     | 4%<br>74% | of purchased equip cost (B)                                   | 1,158,330<br><b>21,429,114</b> |
| installation Subtotal Standard Expenses                                 | 14/0      |   | 21,423,114                     |
| Total Direct Capital Cost, DC   |           |   | 50,387,376                     |
| Indirect Capital Costs  |           |   |                                |
| Engineering, supervision  | 10%       | of purchased equip cost (B)                                   | 2,895,826                      |
| Construction & field expenses   | 20%       | of purchased equip cost (B)                                   | 5,791,652                      |
| Contractor fees   |           | of purchased equip cost (B)                                   | 2,895,826                      |
| Start-up  |           | of purchased equip cost (B)                                   | 289,583                        |
| Performance test  |           | of purchased equip cost (B)                                   | 289,583                        |
| Model Studies   |           | of purchased equip cost (B)                                   | NA                             |
| Contingencies<br>Total Indirect Capital Costs, IC                       |           | of purchased equip cost (B)<br>of purchased equip cost (B)    | 0<br>12,162,470                |
| Total Capital Investment (TCI) = DC + IC                                | /0        |   | 62,549,846                     |
| TCI Adj for Baghouse Filter Replacement                                 |           |   | 61,918,209                     |
| Retrofit multiplier   | 0%        | of TCI  | 0                              |
| Site Specific Installed Equipment Costs<br>Civil/Structural             |           |   | 1,664,454                      |
| Mechanical Equipment  |           |   | 36,936,333                     |
| Electrical and Control  |           |   | 4,839,425                      |
| Freight   |           |   | 1,350,994                      |
| Total Indirect Costs + Contingencies                                    |           |   | 8,371,773                      |
| Lost Production for Tie-In  | N/A       | Site Specific   | 5,866,560                      |
| Total Site Specific Costs   |           |   | 59,029,538                     |
| Total Capital Investment (TCI) Retrofit Installed                       |           |   | 120,947,748                    |
| OPERATING COSTS   |           |   |                                |
| Direct Annual Operating Costs, DC                                       |           |   |                                |
| Operating Labor   |           |   |                                |
| Operator  | 72.12     | \$/Hr, 5.0 hr/8 hr shift, Annual Operating Hours              | 427,551                        |
| Supervisor  | 15%       | 15% of Operator Costs   | 64,133                         |
| Maintenance   |           |   |                                |
| Maintenance Labor   |           | \$/hr, Maint Labor Use Rate+ESP Maint Labor Use Rate          | 75,510                         |
| Maintenance Materials   |           | of maintenance labor costs + 1% ESP purchase cost             | 285,510                        |
| Utilities, Supplies, Replacements & Waste Manageme<br>Compressed Air \$ |           | \$/kscf   | 539,357                        |
| Electricity   |           | \$/kwh, 6,435 kW-hr, annual operating hours, 100% utilization | 3,688,680                      |
| Filter Bag Replacement  |           | , , , , ,   | 234,119                        |
| Solid Waste Disposal  | 44.35     | \$/ton, 136 lb/hr, annual operating hours, 100% utilization   | 25,228                         |
| Lime  | 183.68    | \$/ton, 92 lb/hr, annual operating hours, 100% utilization    | 70,682                         |
| Total Annual Direct Operating Costs                                     |           |   | 5,410,769                      |
| Savings from Shutdown of Existing Emission Controls                     |           |   | (1,307,161)                    |
| Indirect Operating Costs  |           |   |                                |
| Indirect Operating Costs<br>Overhead                                    | 60%       | of total labor and material costs                             | 511,622                        |
| Administration (2% total capital costs)                                 |           | of total capital costs (TCI)                                  | 2,418,955                      |
| Property tax (1% total capital costs)                                   |           | of total capital costs (TCI)                                  | 1,209,477                      |
| Insurance (1% total capital costs)                                      |           | of total capital costs (TCI)                                  | 1,209,477                      |
| Capital Recovery  |           | for a 20- year equipment life and a 5.5% interest rate        | 10,120,827                     |
| Total Annual Indirect Operating Costs                                   |           | Sum indirect oper costs + capital recovery cost               | 15,470,358                     |
|   |           |   |                                |
| Total Annual Cost (Annualized Capital Cost + Operating Cost             | st)       |   | 19,573,967                     |
| See Summary page for notes and assumptions                              |           |   |                                |

#### Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 6 - Spray Dry Absorber (SDA)

| Capital Recovery Factors                    |                 |                        |                        | 1   |                      |                      |   |
|---|-----------------|------------------------|------------------------|---|----------------------|----------------------|---|
| Primary Installation                        |                 |                        |                        |   |                      |                      |   |
| Interest Rate                               |                 | 5.50%                  |                        |   |                      |                      |   |
| Equipment Life                              |                 |                        | years                  |   |                      |                      |   |
| CRF   |                 | 0.0837                 |                        |   |                      |                      |   |
| Replacement Catalyst:                       |                 |                        |                        |   |                      |                      |   |
| Equipment Life                              |                 | 20                     | years                  |   |                      |                      |   |
| CRF   |                 | 0.0000                 |                        |   |                      |                      |   |
| Rep part cost per unit                      |                 | 0                      | \$/ft <sup>3</sup>     |   |                      |                      |   |
| Amount Required                             |                 | 0                      | ft <sup>3</sup>        |   |                      |                      |   |
| Packing Cost                                |                 |                        |                        | ed for freight &                                      |                      |                      |   |
| Installation Labor                          |                 |                        |                        |   | , ,                  | 0                    | puse replacement)   |
| Total Installed Cost<br>Annualized Cost     |                 | 0                      | Zero out if r          | no replaceme  | nt parts needed      |                      |   |
| Annualizeu Cost                             |                 | 0                      |                        |   |                      |                      |   |
| Replacement Parts & Equip                   | ment: Filter    | Bags and Cag           | es                     |   |                      |                      |   |
| Equipment Life                              |                 | 3                      |                        |   |                      |                      |   |
| CRF   |                 | 0.3707                 |                        |   |                      |                      |   |
| Rep part cost per unit                      |                 | 116.70                 |                        |   |                      |                      | Price of 1 bag plus 1/2 price of 1 cage, from Zachry.                         |
| Amount Required                             |                 |                        | Number<br>Cost adjusts | d for fraight a                                       | coloc to:            |                      | Number of bags, from Ducon proposal.  |
| Total Rep Parts Cost<br>Installation Labor  |                 | 523,745                | COSI AUJUSTE           | ed for freight &                                      | Sales lax            |                      | OAQPS list replacement times from 5 - 20 min per bag.                         |
| Total Installed Cost                        |                 | ,                      | Zero out if r          | no replaceme  | nt parts needed      | 1                    | or tar o not replacement times norm of 20 min per bay.                        |
| Annualized Cost                             |                 | 234,119                |                        |   |                      |                      |   |
|   |                 |                        |                        |   |                      |                      |   |
| Electrical Use                              |                 |                        |                        | <b>F</b> <i>tt</i> <b>i a</b> <sup>1</sup> <b>a a</b> |                      | 1.147                |   |
| Process ID Fan                              | Flow acfm       |                        | Δ P in H2O             | Efficiency  | <b>Hp</b><br>1,500.0 | <b>kW</b><br>1,125.0 | Fan size from Zachry cost estimates.  |
| Process ID Fan                              | -               |                        | -                      | -   | 1,500.0              | 1,125.0              | Fan size from Zachry cost estimates.  |
| Process Booster Fan                         | -               |                        | -                      | -   | 2,500.0              | 1,875.0              | Fan size from Zachry cost estimates.  |
| Process Booster Fan                         | -               |                        | -                      | -   | 2,500.0              | 1,875.0              | Fan size from Zachry cost estimates.  |
|   | Flow            | Liquid SPGR            | Δ P ft H2O             | Efficiency  | Нр                   | kW                   | ·   |
| Circ Pump                                   | 000 gpm         | 1                      | 60                     | 0.7   | -                    | 0.0                  | EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49                     |
| H2O WW Disch                                | 0 gpm           | 1                      | 60                     | 0.7   | -                    | 0.0                  | EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49                     |
|   |                 | SCA                    | Plate Area             |   |                      |                      |   |
|   |                 | ft <sup>2</sup> /kacfm | ft <sup>2</sup>        | kW/ft <sup>2</sup>                                    |                      |                      |   |
| ESP Power                                   |                 | 200                    | 224,042                | 1.94E-03  |                      | 434.6                | EPA Cont Cost Manual 6th ed - Sec 6 Ch 3 Eq 3.48                              |
| Other                                       |                 |                        |                        |   |                      |                      |   |
| Total                                       |                 |                        |                        |   |                      | 6434.6               |   |
|   |                 |                        |                        |   |                      |                      |   |
| Reagent Use & Other Opera                   | ting Costs      |                        |                        |   |                      |                      |   |
|   |                 |                        |                        |   |                      |                      |   |
| Hydrated Lime Use                           |                 | lb/hr SO2 no s         | crubber                |   |                      |                      | lb/hr lime, lime addition   |
| NSR<br>Waste Lime                           | 1.30            |                        |                        |   |                      |                      | lb CaSO3/hr<br>lb/hr waste lime   |
| Total Waste                                 |                 |                        |                        |   |                      |                      | Ib/hr waste   |
|   |                 |                        |                        |   |                      | 100.04               |   |
| An NSR of 1.3 means that 30                 | % more lime     | is injected than       | is needed to           | capture SO2.  |                      |                      |   |
|   |                 |                        |                        |   |                      |                      |   |
| Operating Cost Calculation                  | 6               |                        | Annual hou             | rs of operation                                       |                      | 8,376                |   |
| operating cost culculation                  |                 |                        | Utilization F          | •   |                      | 100%                 |   |
|   | 11 14           | 11-14 - 1              | 11-1                   | 11-14 - 1   | A                    | Am                   | Commonto  |
| Item  | Unit<br>Cost \$ | Unit of<br>Measure     | Use<br>Rate            | Unit of<br>Measure                                    | Annual<br>Use*       | Annual<br>Cost       | Comments  |
| Operating Labor                             |                 |                        |                        |   |                      |                      |   |
| Op Labor BH + ESP                           | 72.12           | \$/Hr                  | 5.0                    | hr/8 hr shift   | 5,235                |                      | \$/Hr, 5.0 hr/8 hr shift, Annual Operating Hours                              |
| Lime Handling Labor                         | 72.12           |                        | 13.3                   | hr/week   | 693.3                |                      | \$/Hr, 13.3 hr/week, Annual Operating Hours                                   |
| Supervisor<br>Maintonance                   | 15%             | of Op.                 |                        |   | NA                   | 64,133               | 15% of Operator Costs   |
| Maintenance                                 | 72.12           | ¢/Цr                   | 1.0                    | hr/8 hr shift   | 1,047                | 75 540               | \$/Hr 1.0 br/8 br shift Appual Operating Hours                                |
| Maint Labor Baghouse<br>Maint Mtls Baghouse |                 | 5/Hr<br>% of Maintena  |                        | TH/OTH SHIT   | 1,047<br>NA          |                      | \$/Hr, 1.0 hr/8 hr shift, Annual Operating Hours<br>100% of Maintenance Labor |
| ESP Maint Mtls and Lbr                      |                 | % of ESP pure          |                        |   | 11/2                 | ,                    | 5% of ESP Purchase Cost   |
| Utilities, Supplies, Replacer               |                 |                        |                        |   |                      | 2.0,000              |   |
| Electricity                                 |                 | \$/kwh                 |                        | kW-hr   | 53,896,557           | 3,688,680            | \$/kwh, 6,435 kW-hr, annual operating hours, 100% utilization                 |
| Water                                       | 0.01            | \$/kgal                | 0.0                    | gpm   | 0                    |                      | \$/kgal, 0 gpm, annual operating hours, 100% utilization                      |
| Solid Waste Disposal                        | 44.35           | \$/ton                 | 135.8                  | lb/hr   | 569                  |                      | \$/ton, 136 lb/hr, annual operating hours, 100% utilization                   |
|   | 400 7           | ¢/top                  | 01.0                   | lb/hr   | 385                  | 70.000               | \$/ton, 92 lb/hr, annual operating hours, 100% utilization                    |
| Lime  | 183.7           | φ/τΟΠ                  | 91.9                   | 10/11   | 000                  |                      |   |
| Filter Bag Replacement                      |                 |                        |                        |   |                      | 234,119              | 2012 Dry FGD Study - Opinion of Probable Cost O&M Costs                       |
| Filter Bag Replacement                      |                 | \$/kscf                |                        | scfm/kacfm  | 1,125,945            | 234,119<br>539,357   | 2012 Dry FGD Study - Opinion of Probable Cost O&M Costs                       |

See Summary page for notes and assumptions

#### Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 7 - Gas Suspension Absorber (GSA)

#### Operating Unit: Line 2

| Emission Unit Number               | EU 042 |         | Stack/Vent Number      | SV 048 & 049 |               |
|------------------------------------|--------|---------|------------------------|--------------|---------------|
|                                    |        |         |                        |              |               |
| Expected Utilization Rate          | 100%   |         | Temperature            | 300          | Deg F         |
| Expected Annual Hours of Operation | 8,376  | Hours   | Moisture Content       | 6.3%         |               |
| Annual Interest Rate               | 5.5%   |         | Actual Flow Rate       | 1,120,210    | acfm          |
| Expected Equipment Life            | 20     | yrs     | Standardized Flow Rate | 778,251      | scfm @ 68º F  |
| Pellet Throughput                  | 600    | LTon/hr | Dry Std Flow Rate      | 729,057      | dscfm @ 68º F |

#### CONTROL EQUIPMENT COSTS

| CONTROL EQUIPMENT COSTS                    |                |                      |                   |                |                 |          |
|--|----------------|----------------------|-------------------|----------------|-----------------|----------|
| Capital Costs                              |                |                      |                   |                |                 |          |
| Direct Capital Costs                       |                |                      |                   |                |                 |          |
| Purchased Equipment (A)                    |                |                      |                   |                |                 | 22,356,8 |
| Purchased Equipment Total (B)              | 10%            | of control device co | ost (A)           |                |                 | 24,592,  |
| Installation - Standard Costs              | 74%            | of purchased equip   | o cost (B)        |                |                 | 18,198,  |
| Installation - Site Specific Costs         |                |                      |                   |                |                 | 61,304,8 |
| Installation Total                         |                |                      |                   |                |                 | 18,198,  |
| Total Direct Capital Cost, DC              |                |                      |                   |                |                 | 42,791,0 |
| Total Indirect Capital Costs, IC           | 42%            | of purchased equip   | o cost (B)        |                |                 | 10,328,  |
| Total Capital Investment (TCI) with Site-s | specific costs |                      |                   |                |                 | 113,793, |
| Operating Costs                            |                |                      |                   |                |                 |          |
| Total Annual Direct Operating Costs        |                | Labor, supervision   | materials, repl   | acement parts, | utilities, etc. | 5,453,   |
| Total Annual Indirect Operating Costs      |                | Sum indirect oper    | costs + capital r | ecovery cost   |                 | 14,611,  |
| Savings from Shutdown of Existing Emissi   | on Controls    |                      |                   |                |                 | (1,307,1 |
| Total Annual Cost (Annualized Capital Co   | ost + Operatin | g Cost)              |                   |                |                 | 18,757,  |

#### Actual

| Emission Control Cost Calculation  |                   |                | Emissions     |               |                |                   |                   |                         |
|------------------------------------|-------------------|----------------|---------------|---------------|----------------|-------------------|-------------------|-------------------------|
| Pollutant                          | Max Emis<br>Ib/hr | Annual<br>T/Yr | Cont Eff<br>% | Exit<br>Conc. | Conc.<br>Units | Cont Emis<br>T/yr | Reduction<br>T/yr | Cont Cost<br>\$/Ton Rem |
|                                    |                   |                |               |               |                |                   |                   |                         |
| Sulfur Dioxide (SO <sub>2</sub> ): | 51.4              | 215            | 50.2%         | 5             | ppm            | 107.2             | 108               | \$173,347               |

#### Notes & Assumptions

1 Purchased equipment costs from independent review by Zachry Engineering scaled for inflation using the Chemical Engineering Plant Cost Index

2 Capital equipment cost includes the items listed below, which are calculated using EPA cost control manual guidance.

3 GSA/SDA designed for 5 ppm exit SO2 concentration

6 //8/2012 email from Candice Maxwell, Cleveland Cliffs in response to EPA Region 5 CAA Section 114 information request for scrubber operating costs.
 Email reported total annual operating costs for both Scrubbers. Listed value excludes capital recover costs and is pro-rated by scrubber exhaust flow rate.
 Value includes continuing operations cost, per a 9/26/12 e-mail from Jen Krause, Cleveland Cliffs.

5 Retrofit factors are not included because the costs are based on a site-specific estimate

6 Site specific installation costs from independent review by Zachry Engineering.

7 Labor required for handling of lime shipments entering and exiting the facility. Includes spill prevention/cleanup and truck cleaning.

8 Determined from Table 3.21 of Chapter 3 of EPA's September 1999 Particulate Matter control design guidelines (for ESPs)

9 Labor and maintenance materials are 5% of capital costs per CueCost. "Average process with normal operating conditions should have maintenance labor and material costs" of 5 to 9% of fixed capital investment. (page 134, Plant Design and Economics for Chemical Engineers, Max Peters and Klaus Timmerhaus; McGraw-Hill Book Company)

10 Determined from Table 1.11 of Chapter 1 of EPA's December 1998 Particulate Matter control design guidelines (for FFs and baghouses)

11 Contingency and freight are accounted for under Site Specific Installed Equipment Costs.

#### Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 7 - Gas Suspension Absorber (GSA)

| CAPITAL COSTS   |  |                                       |
|---|--|---------------------------------------|
| Direct Capital Costs  |  |                                       |
| Purchased Equipment (A)                                     |  |                                       |
| Purchased Equipment Costs (A)                               |  | 22,356,887                            |
| Instrumentation   | 10% of control device cost (A)   | 2,235,689                             |
| MN Sales Taxes  | 0% of control device cost (A)  | 0                                     |
| Freight   | 0% of control device cost (A)  | 0                                     |
| Purchased Equipment Total (B)                               | 10%  | 24,592,575                            |
| Installation  |  |                                       |
| Foundations & supports                                      | 4% of purchased equip cost (B)   | 983,703                               |
| Handling & erection   | 50% of purchased equip cost (B)  | 12,296,288                            |
| Electrical  | 8% of purchased equip cost (B)   | 1,967,406                             |
| Piping  | 1% of purchased equip cost (B)   | 245,926                               |
| Insulation  | 7% of purchased equip cost (B)   | 1,721,480                             |
| Painting  | 4% of purchased equip cost (B)   | 983,703                               |
| Installation Subtotal Standard Expenses                     | 74%  | 18,198,506                            |
| Total Direct Capital Cost, DC                               |  | 42,791,081                            |
|   |  |                                       |
| Indirect Capital Costs                                      | 10% of purchased equip and (D)   | 0 450 050                             |
| Engineering, supervision                                    | 10% of purchased equip cost (B)<br>20% of purchased equip cost (B)   | 2,459,258                             |
| Construction & field expenses<br>Contractor fees            | 10% of purchased equip cost (B)  | 4,918,515<br>2,459,258                |
| Start-up  | 1% of purchased equip cost (B)   | 2,459,258                             |
| Performance test  | 1% of purchased equip cost (B)   | 245,926                               |
| Model Studies   | NA of purchased equip cost (B)   | NA                                    |
| Contingencies   | 0% of purchased equip cost (B)   | 0                                     |
| Total Indirect Capital Costs, IC                            | 42% of purchased equip cost (B)  | 10,328,882                            |
| Total Capital Investment (TCI) = DC + IC                    |  | 53,119,963                            |
| TCI Adj for Baghouse Filter Replacement                     |  | 52,488,326                            |
| Retrofit multiplier   | 0% of TCI  | 0                                     |
| Site Specific Installed Equipment Costs<br>Civil/Structural |  | 1 664 454                             |
|   |  | 1,664,454                             |
| Mechanical Equipment<br>Electrical and Control              |  | 38,450,302                            |
|   |  | 4,839,425                             |
| Freight<br>Total Indirect Costs + Contingencies             |  | 1,404,916                             |
| Ū   |  | 9,079,168                             |
| Lost Production for Tie-In                                  | N/A Site Specific  | 5,866,560                             |
| Total Site Specific Costs                                   |  | 61,304,825                            |
| Total Capital Investment (TCI) Retrofit Installed           |  | 113,793,152                           |
|   |  |                                       |
| OPERATING COSTS<br>Direct Annual Operating Costs, DC        |  |                                       |
|   |  |                                       |
| Operating Labor   |  |                                       |
| Operator  | 72.12 \$/Hr, 5.0 hr/8 hr shift, Annual Operating Hours   | 427,551                               |
| Supervisor<br>Maintenance                                   | 15% 15% of Operator Costs  | 64,133                                |
| Maintenance Labor   | 72.12 \$/hr, Maint Labor Use Rate+ESP Maint Labor Use Rate   | 75,510                                |
| Maintenance Materials                                       | 100% of maintenance labor costs + 1% ESP purchase cost   | 328,360                               |
| Utilities, Supplies, Replacements & Waste Manageme          |  | 020,000                               |
| Compressed Air \$   | 0.48 \$/kscf   | 539,357                               |
| Electricity   | 0.07 \$/kwh, 6,435 kW-hr, annual operating hours, 100% utilization   | 3,688,680                             |
| Filter Bag Replacement                                      |  | 234,119                               |
| Solid Waste Disposal<br>Lime                                | 44.35 \$/ton, 136 lb/hr, annual operating hours, 100% utilization<br>183.68 \$/ton, 92 lb/hr, annual operating hours, 100% utilization | 25,228<br>70,682                      |
| Line  |  | 70,002                                |
| Total Annual Direct Operating Costs                         |  | 5,453,619                             |
| Savings from Shutdown of Existing Emission Controls         |  | (1,307,161)                           |
| - <b>-</b>  |  |                                       |
| Indirect Operating Costs                                    |  |                                       |
| Overhead  | 60% of total labor and material costs  | 537,332                               |
| Administration (2% total capital costs)                     | 2% of total capital costs (TCI)  | 2,275,863                             |
| Property tax (1% total capital costs)                       | 1% of total capital costs (TCI)  | 1,137,932                             |
| Insurance (1% total capital costs)                          | 1% of total capital costs (TCI)  | 1,137,932                             |
| Capital Recovery<br>Total Annual Indirect Operating Costs   | 0.0837 for a 20- year equipment life and a 5.5% interest rate  | <u>9,522,135</u><br><b>14,611,193</b> |
| Total Annual municul Operating Costs                        | Sum indirect oper costs + capital recovery cost  | 14,011,193                            |
| Total Annual Cost (Annualized Capital Cost + Operating Co   | ost)   | 18,757,651                            |
| See Summary page for notes and assumptions                  | - /  |                                       |
|   |  |                                       |

#### Cleveland Cliffs: United Taconite Line 2 Appendix B - Four-Factor Control Cost Analysis Table 7 - Gas Suspension Absorber (GSA)

|                             |                |                        |                    | 7                  |                   |                  |   |
|-----------------------------|----------------|------------------------|--------------------|--------------------|-------------------|------------------|---|
| Capital Recovery Factors    |                |                        |                    |                    |                   |                  |   |
| Primary Installation        |                |                        |                    |                    |                   |                  |   |
| Interest Rate               |                | 5.50%                  |                    |                    |                   |                  |   |
| Equipment Life              |                |                        | years              |                    |                   |                  |   |
| CRF                         |                | 0.0837                 |                    |                    |                   |                  |   |
|                             |                |                        |                    |                    |                   |                  |   |
| Replacement Catalyst:       |                |                        |                    |                    |                   |                  |   |
| Equipment Life              |                |                        | years              |                    |                   |                  |   |
| CRF                         |                | 0.0000                 |                    |                    |                   |                  |   |
| Rep part cost per unit      |                | 0                      | \$/ft <sup>3</sup> |                    |                   |                  |   |
| Amount Required             |                | 0                      | ft <sup>3</sup>    |                    |                   |                  |   |
| Packing Cost                |                | 0                      | Cost adjuste       | ed for freight &   | sales tax         |                  |   |
| Installation Labor          |                | 0                      | Assume Lat         | oor = 15% of ca    | atalyst cost (bas | is labor for bag | house replacement)  |
| Total Installed Cost        |                | 0                      | Zero out if        | no replacemei      | nt parts neede    | d l              |   |
| Annualized Cost             |                | 0                      |                    |                    |                   |                  |   |
|                             |                |                        |                    |                    |                   |                  |   |
| Replacement Parts & Equip   | ment: Filter B | Bags and Cages         |                    |                    |                   |                  |   |
| Equipment Life              |                | 3                      |                    |                    |                   |                  |   |
| CRF                         |                | 0.3707                 |                    |                    |                   |                  |   |
| Rep part cost per unit      |                | 116.70                 | \$ each            |                    |                   |                  | Price of 1 bag plus 1/2 price of 1 cage, from Zachry.     |
| Amount Required             |                | 4488                   | Number             |                    |                   |                  | Number of bags, from Ducon proposal.                      |
| Total Rep Parts Cost        |                | 523,745                | Cost adjuste       | ed for freight &   | sales tax         |                  |   |
| Installation Labor          |                | 107,892                |                    |                    |                   |                  | OAQPS list replacement times from 5 - 20 min per bag.     |
| Total Installed Cost        |                | 631,637                | Zero out if        | no replacemei      | nt parts neede    | d                |   |
| Annualized Cost             |                | 234,119                |                    |                    |                   |                  |   |
|                             |                |                        |                    |                    |                   |                  |   |
| Electrical Use              |                |                        |                    |                    |                   |                  |   |
|                             | Flow acfm      |                        | Δ P in H2O         | Efficiency         | Нр                | kW               |   |
| Process ID Fan              | -              |                        | -                  | -                  | 1,500.0           | 1,125.0          | Fan size from Zachry cost estimates.                      |
| Process ID Fan              | -              |                        | -                  | -                  | 1,500.0           | 1,125.0          | Fan size from Zachry cost estimates.                      |
| Process Booster Fan         | -              |                        | -                  | -                  | 2,500.0           | 1,875.0          | Fan size from Zachry cost estimates.                      |
| Process Booster Fan         | -              |                        | -                  |                    | 2,500.0           | 1,875.0          | Fan size from Zachry cost estimates.                      |
|                             | Flow           | Liquid SPGR            | Δ P ft H2O         | Efficiency         | Нр                | kW               |   |
| Circ Pump                   | 000 gpm        | 1                      | 60                 | 0.7                | -                 | 0.0              | EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49 |
| H2O WW Disch                | 0 gpm          | . 1                    | 60                 | 0.7                | -                 | 0.0              | EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49 |
|                             |                | SCA1                   | Plate Area         |                    |                   |                  |   |
|                             |                | ft <sup>2</sup> /kacfm | ft <sup>2</sup>    | kW/ft <sup>2</sup> |                   |                  |   |
| ESP Power                   |                | 200                    | 224,042            | 1.94E-03           |                   | 434.6            | EPA Cont Cost Manual 6th ed - Sec 6 Ch 3 Eq 3.48          |
| Other                       |                |                        |                    |                    |                   |                  |   |
| Total                       |                |                        |                    |                    |                   | 6434.6           |   |
|                             |                |                        |                    |                    |                   | 010110           |   |
|                             |                |                        |                    |                    |                   |                  |   |
| Reagent Use & Other Opera   | ating Costs    |                        |                    |                    |                   |                  |   |
| 5 .                         | 5              |                        |                    |                    |                   |                  |   |
| Hydrated Lime Use           | 51.43          | 3 lb/hr SO2 no s       | crubber            |                    |                   | 91.              | 38 lb/hr lime, lime addition                              |
| NSR                         | 1.30           | 0                      |                    |                    |                   | 114.             | 63 lb CaSO3/hr  |
| Waste Lime                  |                |                        |                    |                    |                   |                  | 20 lb/hr waste lime                                       |
| Total Waste                 |                |                        |                    |                    |                   |                  | 34 lb/hr waste  |
|                             |                |                        |                    |                    |                   |                  |   |
| An NSR of 1.3 means that 30 | % more lime is | s injected than is     | needed to c        | apture SO2.        |                   |                  |   |
|                             |                |                        |                    |                    |                   |                  |   |
|                             |                |                        |                    |                    |                   |                  |   |
| Operating Cost Calculation  | s              |                        |                    | irs of operatio    | n:                | 8,3              |   |
|                             |                |                        | Utilization I      | Rate:              |                   | 100              | %   |
|                             |                |                        |                    |                    |                   |                  |   |
|                             | Unit           | Unit of                | Use                | Unit of            | Annual            | Annual           | Comments  |
| Item                        | Cost \$        | Measure                | Rate               | Measure            | Use*              | Cost             |   |
| Operating Labor             |                |                        |                    |                    |                   |                  |   |
| Op Labor BH + ESP           | 72 12          | 2 \$/Hr                | 5.0                | ) hr/8 hr shift    | 5.235             | 377.5            | 48 \$/Hr, 5.0 hr/8 hr shift, Annual Operating Hours       |

| Op Labor BH + ESP           |        | 72.12   | ⊅/HI      | 5.0 nr/8 nr snitt | 5,235              | 377,548 \$/Hr, 5.0 hr/8 hr shift, Annual Operating Hours                |
|-----------------------------|--------|---------|-----------|-------------------|--------------------|---|
| Lime Handling Labor         |        | 72.12   | \$/Hr     | 13.3 hr/week      | 693.3              | 50,003 \$/Hr, 13.3 hr/week, Annual Operating Hours                      |
| Supervisor                  |        | 15%     | of Op.    |                   | NA                 | 64,133 15% of Operator Costs  |
| Maintenance                 |        |         |           |                   |                    |   |
| Maint Labor Baghouse        |        | 72.12   | \$/Hr     | 1.0 hr/8 hr shift | 1,047              | 75,510 \$/Hr, 1.0 hr/8 hr shift, Annual Operating Hours                 |
| Maint Mtls Baghouse         |        | 100     | % of Main | tenance Labor     | NA                 | 75,510 100% of Maintenance Labor  |
| ESP Maint Mtls and Lbr      |        | 5       | % of ESP  | purchase cost     |                    | 252,850 5% of ESP Purchase Cost   |
| Utilities, Supplies, Replac | ements | & Waste | Managem   | ient              |                    |   |
| Electricity                 |        | 0.068   | \$/kwh    | 6434.6 kW-hr      | 53,896,557         | 3,688,680 \$/kwh, 6,435 kW-hr, annual operating hours, 100% utilization |
| Water                       |        | 0.01    | \$/kgal   | 0.0 gpm           | 0                  | 0 \$/kgal, 0 gpm, annual operating hours, 100% utilization              |
| Solid Waste Disposal        |        | 44.35   | \$/ton    | 135.8 lb/hr       | 569                | 25,228 \$/ton, 136 lb/hr, annual operating hours, 100% utilization      |
| Lime                        |        | 183.7   | \$/ton    | 91.9 lb/hr        | 385                | 70,682 \$/ton, 92 lb/hr, annual operating hours, 100% utilization       |
| Filter Bag Replacement      |        |         |           |                   |                    | 234,119 2012 Dry FGD Study - Opinion of Probable Cost O&M Costs         |
| Compressed Air              | \$     | 0.48    | \$/kscf   | 2 scfm/kacfm      | 1,125,945          | 539,357 \$/yr   |
| -                           |        |         |           |                   | *annual use rate i | s in same units of measurement as the unit cost factor                  |

See Summary page for notes and assumptions



# Regional Haze Four-Factor Analysis Applicability Evaluation

# Grate Kiln – Indurator Waste Gas, Phase II (EQUI 97/EU 030)

Prepared for United States Steel Corporation, Minnesota Ore Operations - Keetac

May 29, 2020

325 South Lake Avenue Duluth, MN 55802 218.529.8200 www.barr.com

# Regional Haze Four-Factor Analysis Applicability Evaluation

May 29, 2020

# Contents

| 1 | Executive Summary            |                             |                    |  |    |  |  |  |  |
|---|------------------------------|-----------------------------|--------------------|--|----|--|--|--|--|
| 2 |                              | Int                         | roduct             | ion  | 3  |  |  |  |  |
|   | 2.1                          |                             | Regula             | tory Background  | 3  |  |  |  |  |
|   | ź                            | 2.1.1                       | Min                | nesota's Request for Information (RFI)                                   | 3  |  |  |  |  |
|   | 2                            | 2.1.2                       | SIP                | Revision Requirements  | 4  |  |  |  |  |
|   | 2                            | 2.1.3                       | USE                | PA Guidance for SIP Development  | 5  |  |  |  |  |
|   | 2.1.3.1 Ambient Data Analysi |                             |                    | Ambient Data Analysis  | 6  |  |  |  |  |
|   |                              | 2.1.3.2 Selection of source |                    | Selection of sources for analysis  | 6  |  |  |  |  |
|   |                              | 2.1.                        | .3.2.1             | Estimating Baseline Visibility Impacts for Source Selection              | 8  |  |  |  |  |
|   |                              | 2.1.                        | .3.3               | Sources that Already have Effective Emission Control Technology in Place | 8  |  |  |  |  |
|   | 2.2                          |                             | Facility           | Description  | 9  |  |  |  |  |
| 3 |                              | An                          | alysis o           | of Ambient Data  | 11 |  |  |  |  |
|   | 3.1                          | ,                           | Visibili           | ty Conditions  | 11 |  |  |  |  |
|   | 3.2                          |                             | Regior             | al emissions reductions  | 14 |  |  |  |  |
| 4 |                              | Vis                         | sibility           | Impacts  | 16 |  |  |  |  |
| 5 |                              | Eva                         | aluatio            | n of "Effectively Controlled" Source                                     | 18 |  |  |  |  |
|   | 5.1                          |                             | NO <sub>X</sub> B  | ART-required Controls  | 18 |  |  |  |  |
|   | 5.2                          |                             | SO <sub>2</sub> BA | RT-required Controls   | 19 |  |  |  |  |
| 6 |                              | Conclusion                  |                    |  |    |  |  |  |  |

### List of Tables

| Table 2-1 | Identified Emission Units             | 4  |
|-----------|---------------------------------------|----|
| Table 3-1 | Notable Minnesota Emission Reductions | 15 |
| Table 5-1 | NO <sub>X</sub> Emission Limits       | 19 |
| Table 5-2 | SO <sub>2</sub> Emission Limits       | 20 |

# List of Figures

| Figure 2-2 | Grate Kiln – Indurator Waste Gas, Phase II (EQUI 97/EU 030) Diagram          | 10 |
|------------|--|----|
| Figure 3-1 | Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)             | 12 |
| Figure 3-2 | Visibility Trend versus URP – Voyageurs National Park (VOYA1)                | 13 |
| Figure 3-3 | Visibility Trend versus URP – Isle Royale National Park (ISLE1)              | 13 |
| Figure 3-4 | Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017) | 14 |

# List of Appendices

Appendix A Visibility Impacts

# 1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency (MPCA) submitted a Request for Information (RFI) Letter<sup>1</sup> to United States Steel Corporation, Minnesota Ore Operations – Keetac (Keetac) to consider potential emissions reduction measures of nitrogen oxides (NO<sub>X</sub>) and sulfur dioxide (SO<sub>2</sub>) from the facility's Grate Kiln – Indurator Waste Gas, Phase II (EQUI 97/EU 030) (grate-kiln) by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i), as explained in the August 2019 U.S. EPA Guidance (2019 Guidance)<sup>2</sup>:

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

Emission reduction evaluations addressing these factors are commonly referred to as "four-factor analyses." MPCA set a July 31, 2020 deadline for Keetac to submit a four-factor analysis. The MPCA intends to use the four-factor analyses to evaluate additional control measures as part of the development of the State Implementation Plan (SIP), which must be submitted to United States Environmental Protection Agency (USEPA) by July 31, 2021. The SIP will be prepared to address the second regional haze implementation period, which ends in 2028.

This report considers whether a four-factor analysis is warranted for Keetac because the grate-kiln can be classified as an "effectively controlled" source for  $NO_x$  and  $SO_2$ . The MPCA can exclude such sources for evaluation per the regulatory requirements of the Regional Haze Rule<sup>3</sup> (RHR) and the 2019 Guidance.

This report provides evidence that it would be reasonable for MPCA to exclude Keetac from the group of sources analyzed for control measures for the second implementation period and to withdraw its request for a four-factor analysis for the grate-kiln based on the following points (with additional details provided in cited report sections):

• The grate-kiln meets the BART-required control equipment installation scenario and is an "effectively controlled" source for NO<sub>x</sub> and SO<sub>2</sub>. Keetac has BART emission controls and emission limits for NO<sub>x</sub> and SO<sub>2</sub> in accordance with 40 CFR 52.1235(b)(1) and 52.1235(b)(2), respectively.

<sup>&</sup>lt;sup>1</sup> January 29, 2020 letter from Hassan Bouchareb of MPCA to United States Steel Corporation, Minnesota Ore Operations – Keetac.

<sup>&</sup>lt;sup>2</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019

<sup>&</sup>lt;sup>3</sup> USEPA, Regional Haze Rule Requirements – Long Term Strategy for Regional Haze, 40 CFR 52.308(f)(2)

The associated BART analyses are provided in the August 2012<sup>4</sup> and October 2015<sup>5</sup> USEPA Federal Implementation Plan (FIP) rulemaking. (see Section 5)

- The RHR and the 2019 Guidance both give states the ability to focus their analyses in one implementation period on a set of sources that differ from those analyzed in another implementation period. (see Section 2.1.3.2)
- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress. (see Section 3.1)
- The grate-kiln does not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4)

Additional emission reductions from the grate-kiln at Keetac will not contribute meaningfully to further reasonable progress. Therefore Keetac requests MPCA withdraw its request for a four-factor analysis for the grate-kiln.

<sup>&</sup>lt;sup>4</sup> USEPA, Federal Register, 08/15/2012, Page 49308.

<sup>&</sup>lt;sup>5</sup> USEPA, Federal Register, 10/22/2015, Page 64160.

# 2 Introduction

Section 2.1 discusses the RFI provided to Keetac by MPCA, pertinent regulatory background for regional haze State Implementation Plans (SIP) development and relevant guidance issued by USEPA to assist States in preparing their SIPs, specifically regarding the selection of sources that must conduct an emissions control evaluation. Section 2.2 provides a description of Keetac's indurating furnace.

### 2.1 Regulatory Background

### 2.1.1 Minnesota's Request for Information (RFI)

"Regional haze" is defined at 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic 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 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 initial SIP was informed by best available retrofit technology (BART) analyses that were completed on all BART-subject sources. The second RHR implementation period ends in 2028 and requires development and submittal of a comprehensive SIP update by July 31, 2021.

As part of the second RHR implementation period SIP development, the MPCA sent an RFI to Keetac on January 29, 2020. The RFI stated that data from the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) 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 SO<sub>2</sub> and NO<sub>x</sub> that react with available ammonia. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan.<sup>6</sup> As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFI also stated that Keetac was identified as a significant source of NO<sub>X</sub> and SO<sub>2</sub> and is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that Keetac submit a "four-factors analysis" (herein termed as a "four-factor analysis") evaluating potential emissions control measures, pursuant to 40 CFR 51.308(f)(2)(i)<sup>7</sup>, by July 31, 2020 for the emission units identified in Table 2-1.

<sup>&</sup>lt;sup>6</sup> Although Michigan is responsible for evaluating haze in Isle Royale, it must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts.

<sup>&</sup>lt;sup>7</sup> The four statutory factors are 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts of compliance, and 4) remaining useful life of the source.

### Table 2-1 Identified Emission Units

| Unit  | Unit ID          | Applicable Pollutants             |
|---|------------------|-----------------------------------|
| Grate Kiln – Indurator Waste<br>Gas, Phase II | (EQUI 97/EU 030) | NO <sub>X</sub> , SO <sub>2</sub> |

The RFI to Keetac specified that the "analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to USEPA guidance as issued on August 20, 2019<sup>8</sup>.

### 2.1.2 SIP Revision Requirements

The regulatory requirements for comprehensive revisions to the SIP are provided in 40 CFR 51.308(f). The next revision must be submitted to USEPA by July 31, 2021 and must include a commitment to submit periodic reports describing progress towards the reasonable progress goals as detailed in 40 CFR 51.308(g). The SIP "must address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State."

Each SIP revision is required to address several elements, including "calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress." <sup>9</sup> The baseline conditions are based on monitoring data from 2000 to 2004 while the target conditions for natural visibility are determined using USEPA guidance. The State will then determine the uniform rate of progress (URP) which compares "the baseline visibility condition for the most impaired days to the natural visibility condition for the most impaired days to the natural visibility condition for the uniform rate of visibility improvement (measured in deciviews of improvement per year) that would need to be maintained during each implementation period in order to attain natural visibility conditions by the end of 2064."<sup>10</sup>

The SIP revision must also include the "Long-term strategy for regional haze."<sup>11</sup> The strategy "must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress" towards the natural visibility goal. There are several criteria that must be considered when developing the strategy, including an evaluation of emission controls (the four-factor analysis) at selected facilities to determine emission reductions necessary to make reasonable progress. The SIP must consider other factors in developing its long-term strategy, including: emission reductions due to other air pollution control programs<sup>12</sup>, emission unit retirement and replacement

<sup>&</sup>lt;sup>8</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019

<sup>&</sup>lt;sup>9</sup> 40 CFR 51.308(f)(1)

<sup>&</sup>lt;sup>10</sup> 40 CFR 51.308(f)(1)(vi)(A)

<sup>&</sup>lt;sup>11</sup> 40 CFR 51.308(f)(2)

<sup>&</sup>lt;sup>12</sup> 51.308(f)(2)(iv)(A)

schedules<sup>13</sup>, and the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during the implementation period<sup>14</sup>.

In addition, the SIP must include "reasonable progress goals" that reflect the visibility conditions that are anticipated to be achieved by the end of the implementation period through the implementation of the long term strategy and other requirements of the Clean Air Act (CAA)<sup>15</sup>. The reasonable progress goal is not enforceable but will be considered by USEPA in evaluating the adequacy of the SIP<sup>16</sup>.

### 2.1.3 USEPA Guidance for SIP Development

On August 20, 2019, the USEPA issued "*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*"<sup>17</sup> USEPA's primary goal in issuing the 2019 Guidance was to help states develop "approvable" SIPs. EPA also stated that the document supports key principles in SIP development, such as "leveraging emission reductions achieved through CAA and other programs that further improve visibility in protected areas."<sup>18</sup>

The 2019 Guidance says SIPs must be "consistent with applicable requirements of the CAA and EPA regulations, and are the product of reasoned decision-making"<sup>19</sup> but also emphasizes States' discretion and flexibility in the development of their SIPs. For instance, the 2019 Guidance states, "A key flexibility of the regional haze program is that a state is *not* required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures."<sup>20</sup> The 2019 Guidance notes this flexibility to not consider every emission source stems directly from CAA § 169A(b)(2) and 40 CFR § 51.308(f)(2)(i), the section of the RHR the MPCA cites in its letter.<sup>21</sup>

The 2019 Guidance lists eight key process steps that USEPA anticipates States will follow when developing their SIPs. This report focuses on the selection of sources which must conduct a four-factor analysis and references the following guidance elements which impact the selection:

- Ambient data analysis (Step 1), including the progress, degradation and URP glidepath checks (Step 7)
- Selection of sources for analysis (Step 3), with a focus on:
  - Estimating baseline visibility impacts for source selection (Step 3b)

<sup>21</sup> Ibid.

<sup>&</sup>lt;sup>13</sup> 51.308(f)(2)(iv)(C)

<sup>&</sup>lt;sup>14</sup> 51.308(f)(2)(iv)(E)

<sup>15 40</sup> CFR 51.308(f)(3)

<sup>&</sup>lt;sup>16</sup> 40 CFR 51.308(f)(3)(iii)

 <sup>&</sup>lt;sup>17</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019
 <sup>18</sup> Ibid, page 1.

<sup>&</sup>lt;sup>19</sup> Ibid.

<sup>&</sup>lt;sup>20</sup> Ibid, page 9 (emphasis added).

• Sources that already have effective emission control technology in place (Step 3f)

#### 2.1.3.1 Ambient Data Analysis

As stated in Section 2.1.2, the RHR requires each state with a Class I area to calculate the baseline, current, and natural visibility conditions as well as to determine the visibility progress to date and the URP. The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). The guidance provides the following equation for calculating the Uniform Rate of Progress (URP):<sup>22</sup>

#### URP = [(2000-2004 visibility)<sub>20% most impaired</sub> - (natural visibility)<sub>20% most impaired</sub>]/60

The visibility from 2000-2004 represents the baseline period, and the natural visibility goal is in 2064, which is why the URP is calculated over a 60-year period.

At the end of the SIP development process a State must estimate the visibility conditions for the end of the implementation period and then must complete a comparison of the reasonable progress goals to the baseline visibility conditions and the URP glidepath. The guidance explains that the RHR does not define the URP as the target for "reasonable progress" and further states that if the 2028 estimate is below the URP glidepath, that does not exempt the State from considering the four-factor analysis for select sources.<sup>23</sup> However, the current visibility conditions compared to the URP glidepath will be a factor when determining the reasonable progress goal.

In Section 3, Barr evaluates the visibility improvement progress to date at BWCA, Voyageurs and Isle Royale using the IMPROVE network visibility data from MPCA's website. This analysis was conducted to document the current visibility conditions compared to the URP, which can provide insight into the amount of emission reductions necessary to have the 2028 visibility conditions below the URP.

#### 2.1.3.2 Selection of sources for analysis

The 2019 Guidance emphasizes that the RHR provides flexibility in selecting sources that must conduct an emission control measures analysis:

"...a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures...."<sup>24</sup>

The 2019 Guidance goes on to justify this approach (emphasis added):

"Selecting a set of sources for analysis of control measures in each implementation period is also consistent with the Regional Haze Rule, which sets up an iterative planning process and anticipates that a state may not need to analyze control measures for all its sources in a given SIP revision. Specifically, section 51.308(f)(2)(i) of the Regional Haze Rule requires a SIP to include a

<sup>&</sup>lt;sup>22</sup> Ibid, Page 7.

<sup>&</sup>lt;sup>23</sup> Ibid, Page 50.

<sup>&</sup>lt;sup>24</sup> Ibid, Page 9.

description of the criteria the state has used to determine the sources or groups of sources it evaluated for potential controls. Accordingly, <u>it is reasonable and permissible for a state to</u> <u>distribute its own analytical work, and the compliance expenditures of source owners, over time</u> <u>by addressing some sources in the second implementation period and other sources in later</u> <u>periods</u>. For the sources that are not selected for an analysis of control measures for purposes of the second implementation period, it may be appropriate for a state to consider whether measures for such sources are necessary to make reasonable progress in later implementation periods."<sup>25</sup>

The 2019 Guidance further states that there is not a list of factors that a state must consider when selecting sources to evaluate control measures, but the state must choose factors and apply them in a reasonable way to make progress towards natural visibility. The guidance details several factors that could be considered, including:

- the in-place emission control measures and, by implication, the emission reductions that are possible to achieve at the source through additional measures<sup>26</sup>
- the four statutory factors (to the extent they have been characterized at this point in SIP development)<sup>27</sup>
- potential visibility benefits (also to the extent they have been characterized at this point in SIP development)<sup>28</sup>
- sources already having effective emissions controls in place<sup>29</sup>
- emission reductions at the source due to ongoing air pollution control programs<sup>30</sup>
- in-state emission reductions due to ongoing air pollution control programs that will result in an improvement in visibility<sup>31</sup>

Furthermore, the 2019 Guidance states that "An initial assessment of projected visibility impairment in 2028, considering growth and on-the books controls, can be a useful piece of information for states to consider as they decide how to select sources for control measure evaluation."<sup>32</sup>

<sup>&</sup>lt;sup>25</sup> Ibid, Page 9.

<sup>&</sup>lt;sup>26</sup> Ibid, Page 10.

<sup>27</sup> Ibid.

<sup>&</sup>lt;sup>28</sup> Ibid.

<sup>&</sup>lt;sup>29</sup> Ibid, Page 21.

<sup>&</sup>lt;sup>30</sup> Ibid, Page 22.

<sup>&</sup>lt;sup>31</sup> Ibid.

<sup>&</sup>lt;sup>32</sup> Ibid, Page 10.

#### 2.1.3.2.1 Estimating Baseline Visibility Impacts for Source Selection

When selecting sources to conduct an emission control evaluation, the 2019 Guidance says that the state may use a "reasonable surrogate metrics of visibility impacts." The guidance provides the following techniques to consider and says that "other reasonable techniques" may also be considered<sup>33</sup>:

- Emissions divided by distance (Q/d)
- Trajectory analyses
- Residence time analyses
- Photochemical modeling

In regards to documenting the source selection process, the 2019 Guidance states:<sup>34</sup>

"EPA recommends that this documentation and description provide both a summary of the state's source selection approach and a detailed description of how the state used technical information to select a reasonable set of sources for an analysis of control measures for the second implementation period. The state could include qualitative and quantitative information such as: the basis for the visibility impact thresholds the state used (if applicable), additional factors the state considered during its selection process, and any other relevant information."

In Section 4, Barr presents a trajectory analysis using data from the IMPROVE monitoring network as presented on MPCA's website and photochemical modeling results to demonstrate that it is not appropriate to select the taconite indurating furnaces as sources subject to the emissions control measures analysis because reducing the emissions will not have a large impact on visibility. Section 4 also presents information from the IMPROVE monitoring system which demonstrates that there was not a noticeable improvement in visibility in 2009 when the taconite plants experienced a production curtailment due to a recession which indicates that the reduction of pollutants from taconite facilities will not result in a discernable visibility improvement in the Class 1 areas.

#### 2.1.3.3 Sources that Already have Effective Emission Control Technology in Place

The 2019 Guidance identified eight example scenarios and described the associated rationale for when sources should be considered "effectively controlled" and that states can exclude similar sources from needing to complete a "four-factor analysis."<sup>35</sup> One of the "effectively controlled" scenarios is for "BART-eligible units that installed and began operating controls to meet BART emission limits for the first implementation period."<sup>36</sup> USEPA caveats this scenario by clarifying that "states may not categorically exclude all BART-eligible sources, or all sources that installed BART control, as candidates for selection for

<sup>&</sup>lt;sup>33</sup> Ibid, Page 12.

<sup>&</sup>lt;sup>34</sup> Ibid, Page 27.

<sup>&</sup>lt;sup>35</sup> Ibid, Page 22.

<sup>&</sup>lt;sup>36</sup> Ibid, Page 25.

analysis of control measures."<sup>37</sup> USEPA further notes that "a state might, however, have a different, reasonable basis for not selecting such sources [BART-eligible and non-BART eligible units that implement BART controls] for control measure analysis."<sup>38</sup>

In Section 5, Barr presents an evaluation of the BART-eligible units scenario and demonstrates that the grate-kiln is an "effectively controlled" source for both  $NO_X$  and  $SO_2$ . Thus, a four-factor analysis is not warranted for this source because, as USEPA notes, "it may be unlikely that there will be further available reasonable controls for such sources."<sup>39</sup>

## 2.2 Facility Description

Keetac mines iron ore (magnetite) and produces taconite pellets that are shipped to steel producers for processing in blast furnaces. The iron ore is crushed and routed through several concentration stages including grinding, magnetic separation, and thickening.

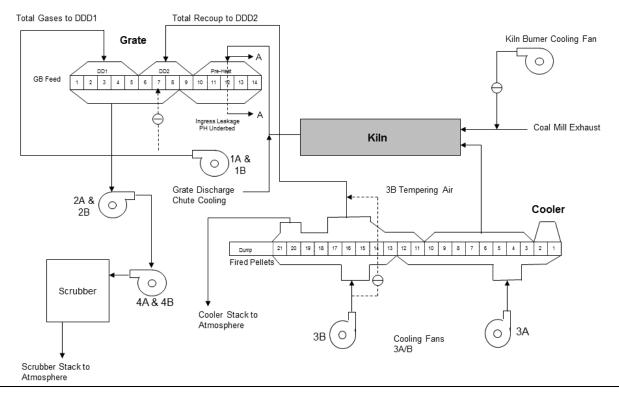
A concentrated iron ore slurry is dewatered by vacuum disc filters, mixed with bentonite, and conveyed to balling drums. Greenballs produced in the balling drums are fed to the traveling grate prior to entering the kiln. The traveling grate consists of drying and preheat zones. After greenballs pass through the traveling grate, they enter the kiln where pellets are heated to approximately 2,400 degrees Fahrenheit to facilitate the conversion of magnetite to hematite. After the kiln, the fired pellets are sent to an annular cooler where ambient air is blown through the pellets, which allows them to be safely discharged onto rubber belting. The heated waste gas from the kiln and annular cooler are used for the drying and heating zones on the traveling grate.

Keetac operates a single preheat grate/induration kiln (grate-kiln) furnace. Waste gas from the furnace is controlled by dual venturi wet scrubbers and is vented through a single stack. Figure 2-1 includes a sketch of Keetac's grate-kiln furnace design.

<sup>37</sup> Ibid.

<sup>&</sup>lt;sup>38</sup> Ibid.

<sup>&</sup>lt;sup>39</sup> Ibid.



Keetac – Simplified Furnace Process Flow Diagram

Figure 2-1 Grate Kiln – Indurator Waste Gas, Phase II (EQUI 97/EU 030) Diagram

# 3 Analysis of Ambient Data

As described in Section 2.1.2, the SIP must consider visibility conditions (baseline, current, and natural visibility), progress to date, and the URP. This requirement is referred to as Step 1 on the 2019 Guidance (see Section 2.1.3.1). This information informs the State's long term strategy for regional haze, as required by 51.308(f)(2), and the reasonable progress goals, as required by 51.308(3).

Section 3.1 provides analysis of visibility conditions based on data from the IMPROVE monitoring network at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1) and Section 3.2 addresses regional emission reductions. Consistent with 51.308(f)(2)(iv), the regional emission reductions summary considers emission reductions that have occurred but are not yet reflected in the available 5-year average monitoring data set and future emission reductions that will occur prior 2028, which is the end of the second SIP implementation period.

### 3.1 Visibility Conditions

As summarized in Section 2.1.2, the RHR requires that the SIP include an analysis "of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."<sup>40</sup> This data will be used in the SIP to establish reasonable progress goals (expressed in deciviews) that reflect the visibility conditions that are projected to be achieved by the end of the implementation period (2028) as a result of the implementation of the SIP and the implementation of other regulatory requirements.<sup>41</sup> The reasonable progress goal is determined by comparing the baseline visibility conditions to natural visibility conditions and determining the uniform rate of visibility improvement needed to attain natural visibility conditions by 2064. The SIP "must consider the uniform rate of improvement in visibility and the emission-reduction measures needed to achieve it for the period covered by the implementation plan."<sup>42</sup>

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).<sup>43</sup> The available regional haze monitoring data was compared to the uniform rate of progress and to the possible reasonable progress goals for the SIP for the implementation period, which ends in 2028. As described in Section 2.1.3.1, the visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). USEPA issued guidance for tracking visibility progress, including the methods for selecting the "most impaired days," on December 20, 2018.<sup>44</sup> Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms) could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."<sup>45</sup> In

<sup>40 40</sup> CFR 51.308(f)(1)

<sup>&</sup>lt;sup>41</sup> 40 CFR 51.308(f)(3)

<sup>&</sup>lt;sup>42</sup> 40 CFR 51.308(d)(1)

<sup>&</sup>lt;sup>43</sup> <u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze visibility metrics public/Visibilityprogress</u>

<sup>&</sup>lt;sup>44</sup> https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

<sup>45</sup> USEPA, Federal Register, 05/04/2016, Page 26948

addition, the RHR allows a state to account for international emissions "to avoid any perception that a state should be aiming to compensate for impacts from international anthropogenic sources."<sup>46</sup>

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath<sup>47</sup> at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1). Regional haze impairment has been declining since 2009 for all three Class I areas that are tracked by MPCA. Impacts to the most impaired days at BWCA and Isle Royale fell below the expected 2028 URP goal in 2016 and have continued trending downward since. Voyageurs impaired days fell below the 2028 URP in 2018 and is also on a downward trend.

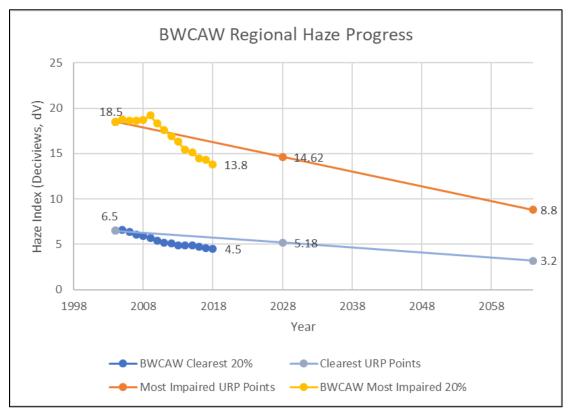


Figure 3-1 Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

<sup>&</sup>lt;sup>46</sup> USEPA, Federal Register, 01/10/2017, Page 3104

<sup>&</sup>lt;sup>47</sup><u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze\_visibility\_metrics\_public/Visibilitypro</u> gress

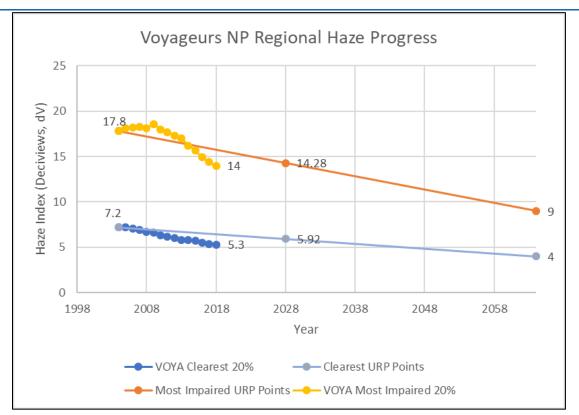


Figure 3-2 Visibility Trend versus URP – Voyageurs National Park (VOYA1)

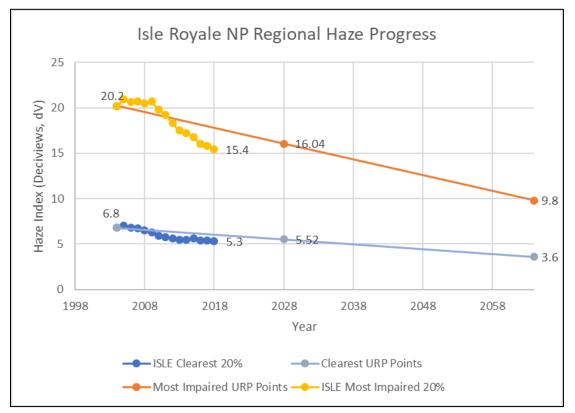


Figure 3-3 Visibility Trend versus URP – Isle Royale National Park (ISLE1)

### 3.2 Regional emissions reductions

The visibility improvement shown in Figure 3-1 through Figure 3-3 correlates with  $SO_2$  and  $NO_x$  emissions decreases from Minnesota's top twenty emission stationary sources, as shown in Figure 3-4<sup>48</sup>. These emission reductions are a result of multiple substantial efforts from the regulated community, including:

- Installation of BART controls during the first implementation period
- Emission reductions at electric utility combustion sources due to new rules and regulations, including:
  - o Acid Rain Rules
  - o Cross State Air Pollution Rule (CASPR)
  - Mercury and Air Toxics Standards (MATS)
- Electric utility combustion sources undergoing fuel changes (e.g., from coal and to natural gas)
- Increased generation of renewable energy, which decreases reliance on combustion sources

Since many of these emission reduction efforts are due to federal regulations and national trends in electrical generation, similar emission reduction trends are likely occurring in other states.

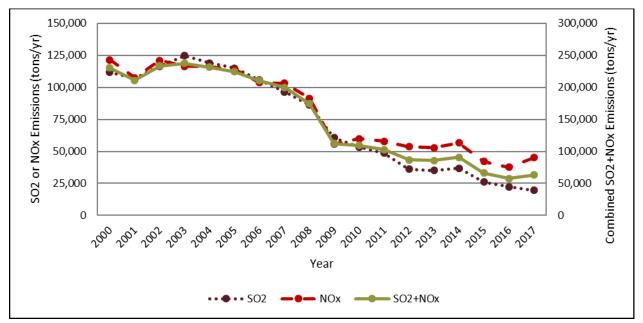


Figure 3-4 Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)

 $<sup>^{48}</sup>$  The data for NO<sub>X</sub> and SO<sub>2</sub> emissions was downloaded from the MPCA point source emissions inventory (<u>https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data</u>). The permitted facilities that had the 20 highest cumulative emissions from 2000-2017 in MN were chosen for the graphics, along with all six taconite facilities (whether or not they were in the top 20 of the state).

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath, so the emissions represented in the most recent data set (2018) is from 2014-2018. However, as shown in Table 3-1, additional emission reductions have occurred since 2014 and are not fully represented in the 5-year visibility data yet. Additionally, several stationary sources have scheduled future emission reductions which will occur prior to 2028. Combined, these current and scheduled emission reductions will further improve visibility in the Class I areas, ensuring the trend stays below the URP. Even without these planned emissions reductions, the 2018 visibility data is already below the 2028 glidepath. As such, MPCA's second SIP implementation period strategy should be commensurate with the region's visibility progress and it would be reasonable for MPCA to not include the taconite indurating furnaces when "reasonably select[ing] a set of sources for an analysis of control measures," and such decision is supported by the 2019 Guidance.

| Year | Additional Emissions Reductions Expected/Projected   |  |
|------|--|--|
| 2015 | MP Laskin: converted from coal to natural gas <sup>(1)</sup>   |  |
| 2017 | Minntac Line 6: FIP emission limit compliance date for $NO_X^{(2)}$  |  |
| 2018 | Minntac Line 7: FIP emission limit compliance date for $NO_X^{(2)}$<br>MP Boswell: Units 1 & 2 retired from service <sup>(1)</sup>   |  |
| 2019 | Hibtac Line 1: FIP emission limit compliance date for $NO_X^{(2)}$<br>Keetac: FIP emission limit compliance date for $NO_X^{(2)}$<br>Minntac Line 4 or 5: FIP emission limit compliance date for $NO_X^{(2)}$<br>Utac Line 1: FIP emission limit compliance date for $NO_X^{(2)}$  |  |
| 2020 | Hibtac Line 2: FIP emission limit compliance date for $NO_X^{(2)}$<br>Minntac Line 4 or 5: FIP emission limit compliance date for $NO_X^{(2)}$<br>Minorca: FIP emission limit compliance date for $NO_X^{(2)}$<br>Utac Line 2: FIP emission limit compliance date for $NO_X^{(2)}$ |  |
| 2021 | Minntac Line: FIP emission limit compliance date for $NO_X^{(2)}$<br>Hibtac Line 3: FIP emission limit compliance date for $NO_X^{(2)}$  |  |
| 2023 | Xcel: Sherco Unit 2 Retirement <sup>(3)</sup>  |  |
| 2026 | Xcel: Sherco Unit 1 Retirement <sup>(3)</sup>  |  |
| 2028 | Xcel: Allen S. King Plant Retirement <sup>(3)</sup>  |  |
| 2030 | Xcel: Sherco Unit 3 Retirement, Xcel target to emit 80% less carbon by 2030 <sup>(3)</sup>   |  |
| 2050 | Xcel: Energy targeting carbon free generation by 2050 <sup>(3)</sup>   |  |

#### Table 3-1 Notable Minnesota Emission Reductions

(1) Minnesota Power - Integrated Resource Plan 2015-2029

(2) FIP is the regional haze Federal Implementation Plan detailed in 40 CFR 52.1235

(3) Xcel Energy - Upper Midwest Integrated Resource Plan 2020-2034.

# **4 Visibility Impacts**

As described in Section 2.1.3.2, the 2019 Guidance outlines criteria to evaluate when selecting sources that must complete an analysis of emission controls. The 2019 Guidance is clear that a state does not need to evaluate all sources of emissions but "may reasonably select a set of sources for an analysis of control measures" to make progress towards natural visibility.

As described in Section 2.1.3.2.1, the 2019 Guidance provides recommendations on selecting sources by estimating baseline visibility impacts. Three of the options for estimating baseline visibility impacts are analyzed below:

#### • Trajectory analyses<sup>49</sup>

In general, these analyses consider the wind direction and the location of the Class I areas to identify which sources tend to emit pollutants upwind of Class I areas. The 2019 Guidance says that a state can consider "back trajectories" which "start at the Class I area and go backwards in time to examine the path that emissions took to get to the Class I areas." Section A1.1 of Appendix A, describes the back trajectory analysis and concludes the taconite indurating furnaces were a marginal contributor to the "most impaired" days from 2009 and 2011-2015. The trajectory analysis also indicates many sources other than the taconite facilities were significant contributors to the "most impaired" days.

#### • Photochemical modeling<sup>50</sup>

The 2019 Guidance says, "states can also use a photochemical model to quantify source or source sector visibility impacts." CAMx modeling was previously conducted to identify visibility impacts in Class I areas from Minnesota taconite facilities from NOx emission reductions. This analysis is summarized in Section A1.2 of Appendix A which concludes the Class I areas near the Iron Range will not experience any observable visibility improvements from NO<sub>x</sub> emission reductions suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces.

• Other reasonable techniques<sup>51</sup>

In addition to the two analyses described above which estimate the baseline visibility impacts, Section A1.3 of Appendix A evaluates the actual visibility data against the 2009 economic recession impacts on visibility, when taconite facilities curtailed production. This curtailment resulted in a decrease in emissions from the collective group of taconite plant and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this curtailment period was compared to monitoring data during more typical production at the taconite plants to estimate the taconite facilities' actual (rather than modeled) impact on haze. This analysis concludes "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It

<sup>&</sup>lt;sup>49</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 13.

<sup>&</sup>lt;sup>50</sup> Ibid, Page 14.

<sup>&</sup>lt;sup>51</sup> Ibid, Page 12.

is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions."<sup>52</sup> The report further notes "high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states."<sup>53</sup>

<sup>&</sup>lt;sup>52</sup> AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.

<sup>&</sup>lt;sup>53</sup> Ibid, Page 12.

# 5 Evaluation of "Effectively Controlled" Source

As described in Section 2.1.3.3, the 2019 Guidance acknowledges that states may forgo requiring facilities to complete the detailed four-factor analysis if the source already has "effective emission control technology in place."<sup>54</sup> This section demonstrates that the grate-kiln meets USEPA's BART-required control equipment installation scenario for NO<sub>X</sub> and SO<sub>2</sub>.

The grate-kiln meets this scenario as an "effectively controlled source" because:

- The grate-kiln is a BART-eligible unit, as determined by Minnesota's December 2009 Regional Haze Plan, and is regulated under 40 CFR 52.1235 (Approval and Promulgation of Implementation Plans – Subpart Y Minnesota – Regional Haze)
- The grate-kiln has controls and must "meet BART emission limits for the first implementation period"  $^{55}$  for NOx and SO2
- In 2016, EPA promulgated a revised FIP that included, among other things, BART requirements to effectively control NOx and SO2 for the grate kiln<sup>56</sup>

The following sections describe USEPA's BART determinations, the associated controls that were implemented as BART, and the resulting BART emission limits for  $NO_X$  and  $SO_2$ .

### 5.1 NO<sub>x</sub> BART-required Controls

In the August 2012 proposed rule FR notice preamble,<sup>57</sup> the USEPA concluded that BART for NO<sub>X</sub> from grate-kiln furnaces is low-NO<sub>X</sub> burner technology. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- External and Induced Flue Gas Recirculation Burners due to the high oxygen content of the flue gas;
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure;
- Alternate Fuels due to the uncertainty of environmental and economic benefits; and

<sup>&</sup>lt;sup>54</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, page 22.

<sup>&</sup>lt;sup>55</sup> Ibid, page 25.

<sup>&</sup>lt;sup>56</sup> See Federal Register 81, No. 70 (April 12, 2016) 21672. Although the 2012 FIP and the revised 2016 FIP limits for the grate kiln are in litigation, the outcome of that litigation will include BART and what is considered "effectively controlled." In any case, any resolution of the case, if reached, is subject to public comment. It would be premature, inefficient and inappropriate to unsurp EPA efforts at this juncture.

<sup>&</sup>lt;sup>57</sup> Federal Register 77, No. 158 (August 15, 2012); 49311. Available at: <u>https://www.govinfo.gov/app/details/FR-</u> 2012-08-15/2012-19789

• Selective Catalytic Reduction (SCR) controls because of two SCR vendors declining to bid on NO<sub>x</sub> reduction testing at the U.S. Steel Minntac facility.<sup>58</sup>

Because the technical feasibility determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for NO<sub>X</sub> emissions from taconite indurating furnaces.

The 2016 FIP requires that , Keetac effectively limit NOx emisisons. During the FIP process EPA conducted a robust review of NOx control technologies to determine what was feasible for Keetac to implement. Since the 2016 BART FIP is still in the implementation phase, it is premature and inappropriate to perform another analysis until the requirements of the 2016 FIP have been completed. <sup>59</sup> Thus, the grate-kiln is considered an "effectively controlled source" in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for NO<sub>X</sub>. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the grate-kiln from the requirement to submit a four-factor analysis.

#### Table 5-1 NO<sub>X</sub> Emission Limits

| Unit  | Unit ID          | NO <sub>x</sub><br>Emission Limit <sup>(1)</sup><br>(lb/MMBtu) | Compliance Date( <sup>2</sup> ) |
|---|------------------|--|---------------------------------|
| Grate Kiln – Indurator Waste Gas, Phase<br>II | (EQUI 97/EU 030) | 1.5  | September 2019                  |

(1) However, for any 30, or more, consecutive days when only natural gas is used a limit of 1.2 lbs NOX/MMBtu, based on a 30-day rolling average, shall apply.

(2) Keetac is effectively controlled pursuant to the 2016 revised FIP that is currently under appeal by U. S. Steel. Any resolution of the appeal would indicate whether effective controls are in place at Keetac.

## 5.2 SO<sub>2</sub> BART-required Controls

In the preamble to the August 2012 proposed FIP<sup>61</sup>, the USEPA concluded that BART for SO<sub>2</sub> emissions from the grate-kiln at Keetac is existing controls. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

• Dry Sorbent Injection and Spray Dryer Absorption because the high moisture content of the exhaust would lead to baghouse filter cake saturation and filter plugging

<sup>&</sup>lt;sup>58</sup> Ibid, 49323.

<sup>&</sup>lt;sup>59</sup> Although the 2012 FIP and 2016 FIP revision remain in litigation, the litigation pertains specifically to the determination of BART and what is considered effectively controlled. It would be inapprorrpiate and inefficient to unsurp EPA's determination at this juncture.

<sup>&</sup>lt;sup>60</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 10.

<sup>&</sup>lt;sup>61</sup> Federal Register 77, No. 158 (August 15, 2012); 49325. Available at: <u>https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789</u>

- Alternative Fuels for units burning coal by switching fuels due to the uncertainty of alternative fuel costs, the potential of replacing one visibility impairment pollutant for another, and that BART cannot mandate a fuel switch;
- Coal drying/processing because this requires excess heat source or low-pressure steam, which was not available at Keetac
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure<sup>62</sup>

In addition, USEPA eliminated Wet Walled Electrostatic Precipitator (WWESP) and secondary (polishing) wet scrubber technologies because they were not cost-effective.<sup>63</sup>

Because the technical feasibility and cost effectiveness determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for SO<sub>2</sub> emissions from taconite indurating furnaces.

In accordance with the FIP, Keetac has continued to operate the BART SO<sub>2</sub> control measures and is complying with the FIP SO<sub>2</sub> emission limit<sup>64</sup>, as shown in Table 5-2. Thus, the grate-kiln is considered an "effectively controlled source" in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for SO<sub>2</sub>. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the grate-kiln from the requirement to submit a four-factor analysis<sup>65</sup>.

#### Table 5-2 SO<sub>2</sub> Emission Limits

| Unit                                       | Unit ID          | SO <sub>2</sub><br>Emission Limit<br>(Ib/hr) | Compliance Date |
|--|------------------|--|-----------------|
| Grate Kiln – Indurator Waste Gas, Phase II | (EQUI 97/EU 030) | 225  | June 8, 2013    |

<sup>&</sup>lt;sup>62</sup> Ibid, 49324.

<sup>63</sup> Ibid.

<sup>64 40</sup> CFR 52.1235(b)(2)

<sup>&</sup>lt;sup>65</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 10.

# 6 Conclusion

The preceding sections of this report support the following conclusions:

- The grate-kiln meets the BART-required control equipment installation scenario and is an "effectively controlled" source for NO<sub>X</sub> and SO<sub>2</sub> (see Section 5). As stated in the 2019 Guidance, "it may be reasonable for a state not to select an effectively controlled source." <sup>66</sup> Therefore, it would be reasonable and compliant with USEPA requirements to exclude Keetac from further assessments of additional emission control measures.
- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress (see Section 3):
  - Visibility has improved at all three monitors (BOWA1, VOYA2, and ISLE1) compared to the baseline period
  - Visibility has been below the URP since 2012
  - The 2018 visibility data is below the URP for 2028
  - Additional emissions reductions have continued throughout the region and are not fully reflected in the available 5-year average (2014-2018) monitoring dataset
  - Additional emission reductions are scheduled to occur in the region prior to 2028, including ongoing transitions of area EGUs from coal to natural gas or renewable sources, as well as the installation of low-NO<sub>X</sub> burners throughout the taconite industry
- The grate-kiln does not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4).

The combination of these factors provides sufficient justification for MPCA to justify to USEPA Keetac's exclusion from the group of sources required to conduct a four-factor analysis for this implementation period. Thus, the MPCA should withdraw its request for a four-factor analysis for the grate-kiln.

<sup>&</sup>lt;sup>66</sup> Ibid, Page 22

Appendices

Appendix A

Visibility Impacts

# A1 Visibility Impacts

### A1.1 Trajectory Analysis

The August 2019 U.S. EPA Guidance ("2019 Guidance" or "the Guidance")<sup>1</sup> says that the state may use a "reasonable surrogate metrics of visibility impacts" when selecting sources to conduct an four-factor analysis and cites trajectory analysis as an example of a reasonable technique. This analysis considers reverse trajectories, as provided on MPCA's website<sup>2</sup>, to determine the frequency that the trajectories on the "most impaired days"<sup>3</sup> overlapped with a specific area of influence (AOI) on the Iron Range. Data from 2011-2015 were analyzed as this was the most recent five-year period where the taconite facilities were operating under typical production rates.

A particle trajectory analysis is an analysis of the transport path of a particular air mass, including the associated particles within the air mass, to see if the air mass traveled over certain locations from specific source locations. The MPCA tracks visibility via the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area Wilderness (BWCA), Voyageurs National Park (Voyageurs) and Isle Royale National Park (Isle Royale).<sup>4</sup> MPCA's website includes a tool which analyzes reverse trajectories from BWCA and Voyageurs for the "most impaired days" and the clearest days for 2007-2016 to show the regional influence on visibility. The reverse trajectories included in the MPCA tool were developed using the NOAA Hysplit model.<sup>5</sup> The trajectories consist of a single back trajectory for each day of interest, beginning at 18:00 and running back 48 hours with a starting height of 10 meters.

The MPCA Hysplit reverse trajectories from the "most impaired days" were analyzed to identify whether trajectories overlapped with an AOI from certain taconite facilities on the Iron Range. In order to be conservative, Barr estimated an "uncertainty region" for each trajectory based on 20% of the distance traveled for every 10km along the trajectory pathway. This method is consistent with other scientific studies analyzing reverse trajectories and trajectories associated with the NOAA Hysplit model (Stohl - 1998<sup>6</sup>, Draxler - 1992<sup>7</sup>, Draxler and Hess - 1998<sup>8</sup>). For the purpose of this analysis, the Iron Range AOI was defined as a line connecting the stack at the U. S. Steel Keetac facility with the stack at the ArcelorMittal Minorca Mine and a 3-mile radius surrounding the line. This analysis considers how often the MPCA reverse trajectories overlap the Iron Range AOI on the "most impaired days" to quantitatively determine if the emissions from the Iron Range may have been a contributor to impaired visibility. Attachment 1 to Appendix A includes tables with the annual and seasonal results of this analysis as well as two example figures showing trajectories that cross, and do not cross, the Iron Range AOI.

<sup>&</sup>lt;sup>1</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019

<sup>&</sup>lt;sup>2</sup> <u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze\_visibility\_metrics\_public/Regionalinfluence</u>

<sup>&</sup>lt;sup>3</sup> "Most impaired days" is the 20% most anthropogenically impaired days on an annual basis, measured in deciviews (dv), as provided on MPCA's website.

<sup>&</sup>lt;sup>4</sup> <u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze\_visibility\_metrics\_public/Regionalinfluence</u>

<sup>&</sup>lt;sup>5</sup> https://www.arl.noaa.gov/hysplit/hysplit/

<sup>&</sup>lt;sup>6</sup> <u>http://www.kenrahn.com/DustClub/Articles/Stohl%201998%20Trajectories.pdf</u>

<sup>&</sup>lt;sup>7</sup> https://www.arl.noaa.gov/documents/reports/ARL%20TM-195.pdf

<sup>&</sup>lt;sup>8</sup> https://www.arl.noaa.gov/documents/reports/MetMag.pdf

As shown in Figure A1 and Figure A2, reverse trajectories from BWCA and Voyageurs in 2011-2015 did not overlap the Iron Range AOI on 62-80%, and 56-71% of "most impaired days", respectively. This means the taconite industry did not influence visibility at BWCA and Voyageurs on the majority of "most impaired days" and suggest that sources other than the taconite facilities are larger contributors to visibility impairment at these sites. Furthermore, the origins of many of the "most impaired day" reverse trajectories are beyond the Iron Range AOI and thus have influences, depending on the trajectory, from other sources (e.g., Boswell Energy Center, Sherburne County Generating Station) or cities such as Duluth, St. Cloud, the Twin Cities, and Rochester as shown in Figure A3.

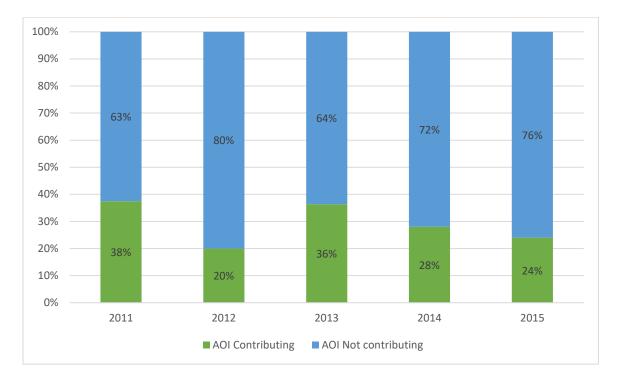


Figure A1 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at BWCA

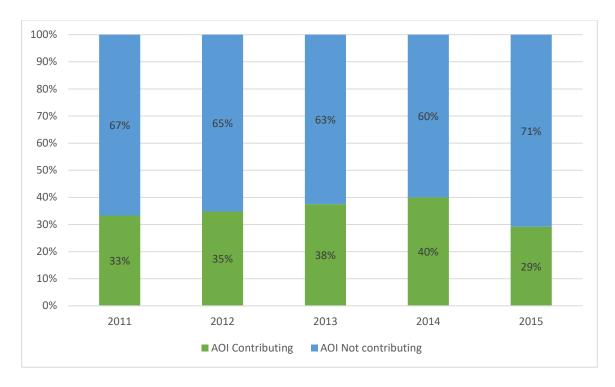


Figure A2 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at Voyageurs

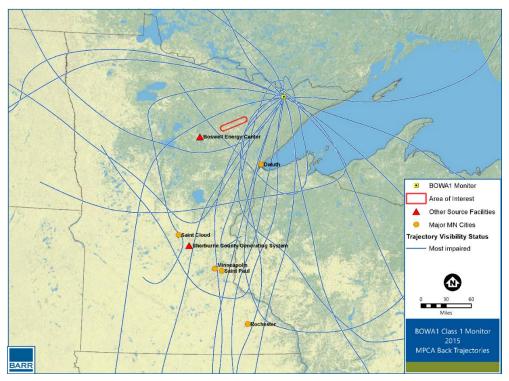


Figure A3 Reverse Trajectories and Other Sources Influencing Visibility at BWCA<sup>9</sup>

<sup>9</sup> Source: ArcGIS 10.7.1, 2020-05-14 13:31 File:

I:\Client\US\_Steel\Trajectory\_Analysis\Maps\Trajectory\_Routes\_BOWA1\_2015\_zoom.mxd User: ADS

## A1.2 Photochemical Modeling

As part of the requirement to determine the sources to include and how to determine the potential visibility improvements to consider as part of this selection, the 2019 Guidance provided some specific guidance on the use of current and previous photochemical modeling analyses (emphasis added):

"A state opting to select a set of sources to analyze must reasonably choose factors and apply them in a reasonable way given the statutory requirement to make reasonable progress toward natural visibility. Factors could include but are not limited to baseline source emissions, <u>baseline source</u> <u>visibility impacts (or a surrogate metric for the impacts)</u>, [and] the in-place emission control measures..."<sup>10</sup>

The Guidance lists options for the evaluation of source visibility impacts from least rigorous to most rigorous as: (1) emissions divided by distance (Q/d), (2) trajectory analyses, (3) residence time analyses, and (4) photochemical modeling (zero-out and/or source apportionment). It appears that MPCA selected the least rigorous (Q/d) for inclusion of sources in the four-factor analyses. The most rigorous is described below (emphases added):

"Photochemical modeling. In addition to these non-modeling techniques, states can also use a photochemical model to quantify source or source sector visibility impacts. In 2017, EPA finalized revisions to 40 CFR Part 51 Appendix W, Guideline on Air Quality Models. As part of that action, EPA stated that photochemical grid models should be the generally preferred approach for estimating source impacts on secondary PM concentrations. The existing SIP Modeling Guidance provides recommendations on model setup, including selecting air quality models, meteorological modeling, episode selection, the size of the modeling domain, the grid size and number of vertical layers, and evaluating model performance. EPA Regional offices are available to provide an informal review of a modeling protocol before a state or multijurisdictional organization begins the modeling.

The SIP Modeling Guidance focuses on the process for calculating RPGs using a photochemical grid model. The SIP Modeling Guidance does not specifically discuss using photochemical modeling outputs for estimating daily light extinction impacts for a single source or source sector. However, the approach on which the SIP Modeling Guidance is based can also be applied to a specific source or set of sources. <u>The first step in doing this is to estimate the impact of the source or set of sources</u> <u>on daily concentrations of PM species.</u>

The simplest approach to quantifying daily PM species impacts with a photochemical grid model is to perform brute force "zero-out" model runs, which involves at least two model runs: one "baseline" run with all emissions and one run with emissions of the source(s) of interest removed from the baseline simulation. The difference between these simulations provides an estimate of the PM species impact of the emissions from the source(s).

<sup>&</sup>lt;sup>10</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 10

An alternative approach to quantifying daily PM species impacts is photochemical source apportionment. Some photochemical models have been developed with a photochemical source apportionment capability, which tracks emissions from specific sources or groups of sources and/or source regions through chemical transformation, transport, and deposition processes to estimate the apportionment of predicted PM<sub>2.5</sub> species concentrations. Source apportionment can "tag" and track emissions sources by any combination of region and sector, or by individual source. For example, PM species impacts can be tracked from any particular source category in the U.S., or from individual states or counties. Individual point sources can also be tracked."<sup>11</sup>

As part of the previous regional haze planning evaluation, and to provide comments on USEPA's disapproval of the Minnesota SIP and the subsequent Regional Haze Federal Implementation Plan (FIP) (Docket EPA-R05-OAR-2010-0954 & EPA-R05-OAR-2010-0037), Barr completed photochemical modeling of ArcelorMittal and Cleveland-Cliffs' taconite operations in 2013 using CAMx source apportionment (see Attachment 2). The basis of the CAMx modeling was the Minnesota modeling analyses, which were completed as part of the regional haze SIP, including Plume in Grid (PiG) evaluations of sources included in BART analyses. This modeling included 2002 and 2005 baseline periods with projected emissions to 2018 (the first implementation planning period for the regional haze SIPs and a strong surrogate for the baseline period for the 2<sup>nd</sup> planning period). Therefore, the analysis completed is one of the best available surrogates for the potential visibility impacts from the sources that were "tagged" as part of those comments. It is important to note that the MPCA modeling analysis did not require any additional controls for taconite sources under BART. Further, the CAMx modeling that Barr conducted showed that the impact from NO<sub>X</sub> emissions from the Minnesota taconite facilities had very limited visibility impacts on the three Upper Midwest Class I areas.

Specifically, the results from executing CAMx concluded that the Class I areas near the Iron Range will not experience any observable visibility improvements from NO<sub>x</sub> emission reductions that were suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces. The modeling analysis showed that the scalar method that USEPA used to forecast the visibility improvements was inadequate to determine the visibility impacts from taconite sources. The CAMx predicted impacts for every furnace line were at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

In addition, the large amount of potential NO<sub>X</sub> emission reductions from the FIP baseline to the final FIP (>10,000 tons per year from modeled Minnesota taconite operations) was not impactful from a visibility modeling perspective. This finding provides specific source modeling evidence that additional NO<sub>X</sub> emission reductions from any or all of the taconite operations are likely not helpful for visibility improvements at the Upper Midwest Class I areas. This is particularly true given the current amount of NO<sub>X</sub> emissions generated by the taconite sources as part of the current baseline.

The 2019 Guidance addresses how states should select sources that must conduct a four-factor analysis. The RHR suggests that states can use a photochemical model to quantify facility or even stack visibility impacts. The previous CAMx modeling was conducted for the 2018 projection year and the results are

<sup>&</sup>lt;sup>11</sup> Ibid, Page 14.

especially helpful in the current visibility impact assessment to determine if the EPA's four-factor applicability analysis is necessary. Aside from the fact that the NO<sub>X</sub> reductions of taconite indurating furnaces do not result in visibility improvements, the emissions from these sources have been trending downward from 2013 to present. These reductions are related to the recent installation of low NO<sub>X</sub> burners on the taconite indurating furnaces and the overall Minnesota state reductions from the switch from coal- to natural gas-fired power plants. Thus, it is reasonable to conclude that additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility at the Class 1 areas nor is it anticipated to be necessary to reach the 2028 target visibility goal.

In summary, the exclusion of the taconite sources from the four factor analysis for NOx is reasonable, supported by the previous CAMx modeling performed for 2018 projected emissions that conclude additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility, and in line with the Guidance regarding selection of sources based on previous modeling analyses and the additional NO<sub>x</sub> reductions anticipated in Minnesota.

## A1.3 Visibility Impacts During 2009 Recession

During the economic recession in 2009, the Iron Range experienced a reduction in taconite production. This resulted in a decrease in emissions from the collective group of taconite plants and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this period was compared to monitoring data during more typical production at the taconite plants to estimate the actual (rather than modeled) impact on haze. This assessment was completed in 2012 (herein termed as "the 2012 analysis") and submitted by Cliffs as a comment to proposed Minnesota regional haze requirements (Docket: EPA-R05-OAR-2010-0037), included as Attachment 3. The 2012 analysis focused on the likely visibility impact of NO<sub>x</sub> emissions from the taconite indurating furnaces.

Observations noted in the 2012 analysis highlighted that concentrations of visibility impairing pollutants do not appear to closely track with actual emissions from taconite facilities. For example, nitrate (NO<sub>3</sub>) is a component of haze associated with NO<sub>x</sub> emissions that are emitted from a number of sources, including the indurating furnaces at the taconite facilities. As shown in Figure A4, the 2012 analysis compared taconite facility production rates to nitrate concentration for 1994-2010 at the BWCA monitor. The 2012 analysis concludes that "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions."<sup>12</sup> The report further notes that "high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states."<sup>13</sup>

<sup>&</sup>lt;sup>12</sup> AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10. <sup>13</sup> Ibid, Page 12.

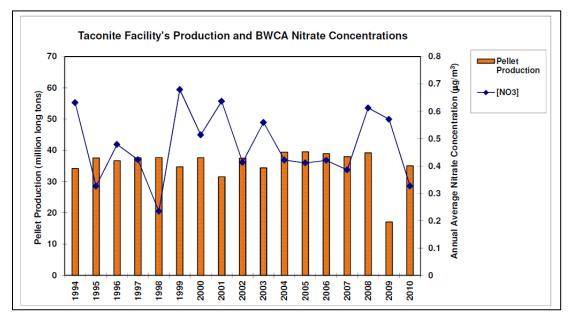


Figure A4 Minnesota Taconite Production and BWCA Nitrate Concentrations 1994-2010<sup>14</sup>

<sup>&</sup>lt;sup>14</sup> AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 9

## Attachments

# Attachment 1

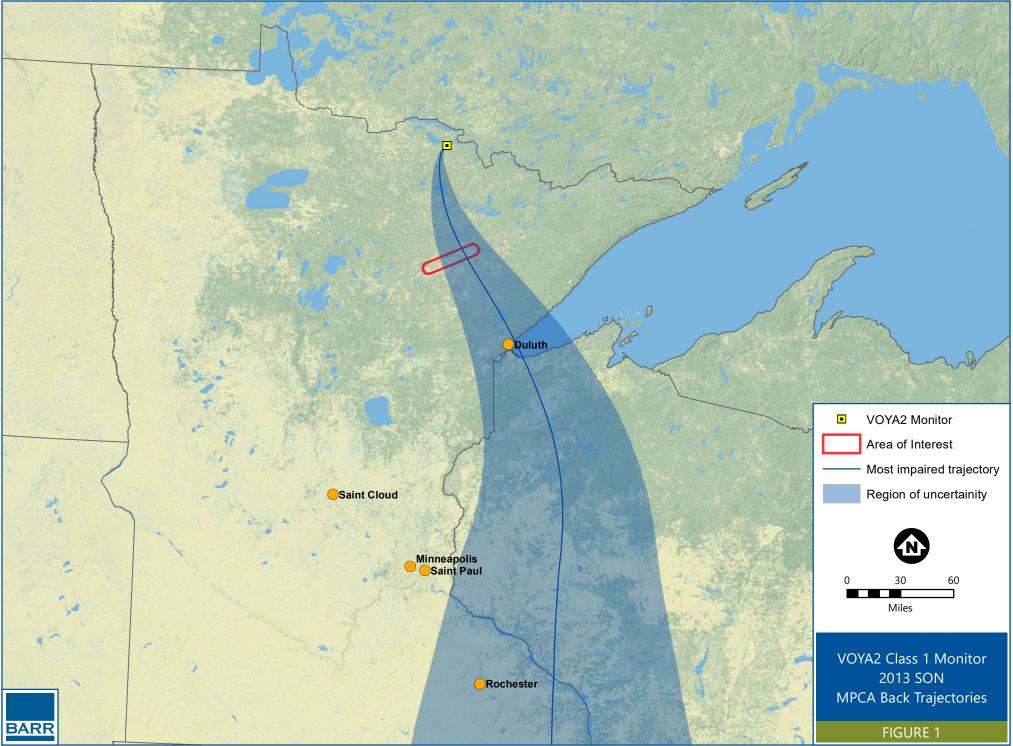
Trajectory Analysis Summary Tables and Reverse Trajectory Example Figures

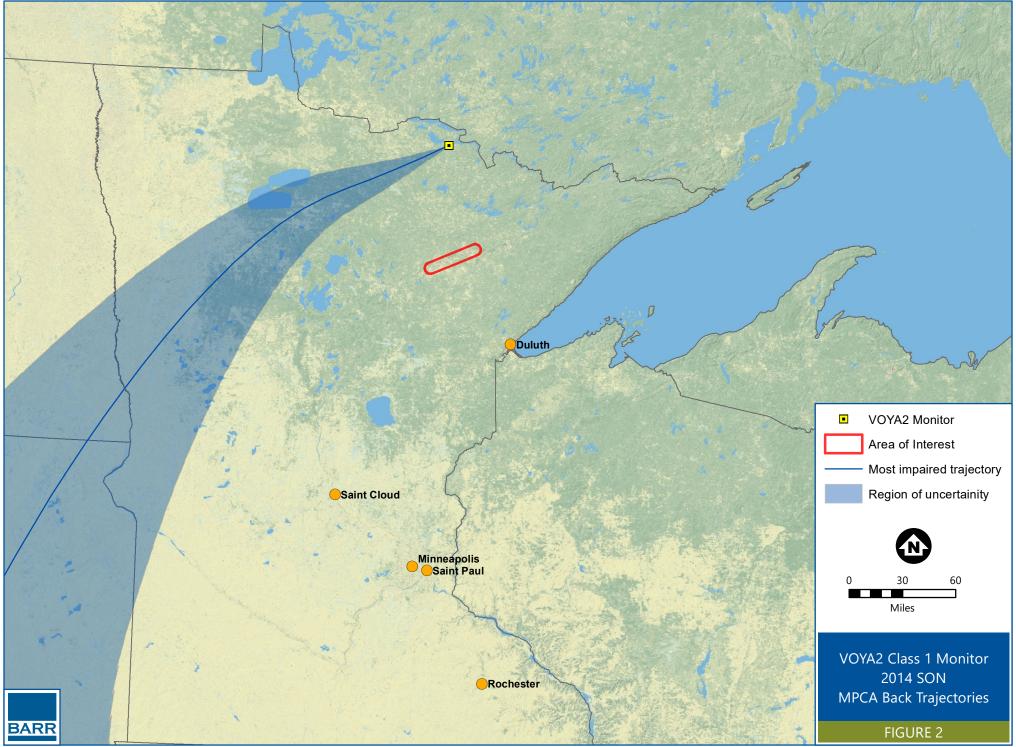
| Year | Time Period  | Most Impaired<br>Days | "Most Impaired" Trajectories<br>With Uncertainty Region<br>Crossing Iron Range AOI<br>(%) |
|------|--------------|-----------------------|---|
|      | Winter (DJF) | 9                     | 44%   |
|      | Spring (MAM) | 8                     | 38%   |
| 2011 | Summer (JJA) | 4                     | 0%  |
|      | Fall (SON)   | 3                     | 67%   |
|      | Total        | 24                    | 38%   |
|      | Winter (DJF) | 13                    | 23%   |
|      | Spring (MAM) | 4                     | 0%  |
| 2012 | Summer (JJA) | 1                     | 0%  |
|      | Fall (SON)   | 7                     | 29%   |
|      | Total        | 25                    | 20%   |
|      | Winter (DJF) | 9                     | 44%   |
|      | Spring (MAM) | 5                     | 60%   |
| 2013 | Summer (JJA) | 3                     | 0%  |
|      | Fall (SON)   | 5                     | 20%   |
|      | Total        | 22                    | 36%   |
|      | Winter (DJF) | 9                     | 33%   |
|      | Spring (MAM) | 8                     | 13%   |
| 2014 | Summer (JJA) | 2                     | 0%  |
|      | Fall (SON)   | 6                     | 50%   |
|      | Total        | 25                    | 28%   |
|      | Winter (DJF) | 13                    | 15%   |
| 2015 | Spring (MAM) | 3                     | 67%   |
|      | Summer (JJA) | 1                     | 0%  |
|      | Fall (SON)   | 8                     | 25%   |
|      | Total        | 25                    | 24%   |

Table A1 Results from MPCA Hysplit Trajectories for the BOWA1 Monitor

| Year | Months       | Most Impaired<br>Days | "Most Impaired" Trajectories<br>With Uncertainty Region<br>Crossing Iron Range AOI<br>(%) |
|------|--------------|-----------------------|---|
|      | Winter (DJF) | 8                     | 38%   |
|      | Spring (MAM) | 7                     | 29%   |
| 2011 | Summer (JJA) | 4                     | 25%   |
|      | Fall (SON)   | 5                     | 40%   |
|      | Total        | 24                    | 33%   |
|      | Winter (DJF) | 13                    | 23%   |
|      | Spring (MAM) | 3                     | 67%   |
| 2012 | Summer (JJA) | 0                     | 0%  |
|      | Fall (SON)   | 7                     | 43%   |
|      | Total        | 23                    | 35%   |
|      | Winter (DJF) | 9                     | 22%   |
|      | Spring (MAM) | 5                     | 40%   |
| 2013 | Summer (JJA) | 3                     | 0%  |
|      | Fall (SON)   | 7                     | 71%   |
|      | Total        | 24                    | 38%   |
|      | Winter (DJF) | 10                    | 50%   |
|      | Spring (MAM) | 7                     | 43%   |
| 2014 | Summer (JJA) | 2                     | 0%  |
|      | Fall (SON)   | 6                     | 33%   |
|      | Total        | 25                    | 40%   |
|      | Winter (DJF) | 14                    | 21%   |
| 2015 | Spring (MAM) | 4                     | 50%   |
|      | Summer (JJA) | 1                     | 100%  |
|      | Fall (SON)   | 5                     | 20%   |
|      | Total        | 24                    | 29%   |

 Table A2
 Results from MPCA Hysplit Trajectories for the VOYA2 Monitor





Attachment 2

CAM<sub>X</sub> Modeling Report



## **Technical Memorandum**

- From: Barr Engineering
- Subject: Summary of Comprehensive Air Quality Model with Extensions (CAM<sub>x</sub>) Analyses Performed to Evaluate the EPA Regional Haze Federal Implementation Plan for Taconite Facilities
   Date: March 6, 2013

#### **Executive Summary**

Barr Engineering conducted air modeling to predict the impact of  $NO_x$  reductions from certain taconite furnaces in Minnesota and Michigan. Using EPA's preferred Comprehensive Air Quality Model with Extensions (CAM<sub>x</sub>), the model results demonstrate that the Class I areas near these furnaces will experience no perceptible visibility improvements from  $NO_x$  emission reductions envisioned by EPA in the recent Regional Haze FIP at the furnaces. The analysis strongly suggests that the scalar method that EPA used to predict visibility improvements under significant time constraints was an inadequate substitute for CAM<sub>x</sub>, as EPA's approach over-predicted visibility impacts by factors of <u>ten to sixty</u> when compared with the proper CAM<sub>x</sub> analysis. The basis for EPA's technical analysis of the visibility improvements for their proposed emission changes must therefore be dismissed as unsupportable, and the results of this analysis should be used instead. This analysis ultimately supports the conclusions of the States of Michigan and Minnesota in their Regional Haze SIPs, that experimental low  $NO_x$  burner retrofits did not meet the criteria for BART. The imperceptible visibility improvements associated with  $NO_x$  reductions from these furnaces cannot justify the cost or the operational risks of changing burners.

#### **Discussion**

This memorandum provides a summary of the methodology and results from photochemical modeling analyses conducted to support the Cliffs Natural Resources (CNR) and Arcelor Mittal (Arcelor) response to the United States Environmental Protection Agency (EPA) final Regional Haze Federal Implementation Plan (FIP) for taconite facilities. Further, it provides a basis for comment on the proposed disapproval of the Minnesota and Michigan State Implementation Plans for taconite Best Available Retrofit Technology (BART) at the above mentioned facilities. This memorandum also includes an appendix with a summary of the BART visibility improvement requirements and a review of the EPA "scalar" method in the proposed and final FIP for determining the visibility improvement from taconite emission reductions. Further, the memorandum contrasts EPA's findings with the modeling analysis conducted and previously requested by CNR as part of its comments on the proposed FIP. The modeling evaluated emission differences at all the CNR and Arcelor taconite facilities.

Ultimately, this memorandum provides results demonstrating no perceptible visibility improvement from the  $NO_x$  emission reductions proposed and subsequently finalized by EPA in the Regional Haze FIP for the CNR and Arcelor facilities.

#### I. CAM<sub>x</sub> Modeling Methodology

The methodology utilized by Barr to complete the CAM<sub>x</sub> modeling was identical to the methods utilized by the Minnesota Pollution Control Agency (MPCA) in performing the 2002 and 2005 baseline and BART SIP modeling in 2009. This included the use of the CAM<sub>x</sub> modeling system (CAM<sub>x</sub> v5.01 - air quality model, MM5 - meteorological model, and EMS-2003 - emissions model) with meteorological data, low-level emission data, initial and boundary condition files, and other input files received directly from MPCA. Modifications to the emissions within the elevated point source input files used by MPCA were accomplished for the taconite facility furnace stacks to reflect the differences in the FIP baseline and final FIP control scenarios. In addition, the CAM<sub>x</sub> run scripts used to execute the model were provided by MPCA for each of the four calendar quarters (Jan-Mar, Apr-Jun, Jul-Sep, and Oct-Dec) along with the post-processing scripts used to estimate the visibility impacts for each scenario.

An important fact is that the results from the MPCA modeling for Minnesota's regional haze State Implementation Plan (SIP) development were also utilized by EPA in the "scalar" method proposed in the FIP. These results were subsequently defended by EPA in the final FIP stating "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."<sup>1</sup> The methods utilized by MPCA represent not only an EPA-approved approach for SIP submittal, but also formed the basis of the visibility determinations made by EPA in the proposed and final FIP. However, since EPA did not conduct its own modeling and provided only the "scalar" results, there are substantial and inherent flaws in the EPA-estimated visibility impacts. These flaws are detailed in Appendix A to this memorandum which includes a review of the EPA scalar approach. Since the modeling reported here used identical methods to the MPCA analyses, it is consistent with the underlying data that was used in

<sup>&</sup>lt;sup>1</sup> Federal Register, Volume 78, Number 25, page 8721, February 6, 2013

the EPA FIP method for estimating visibility impact. Further, this modeling provides specific technical analyses regarding the estimated effects of CNR and Arcelor taconite unit emission reductions in the final FIP on the relevant Class I areas. To effectively evaluate the impact of NOx reductions on regional haze, this level of analyses should have been conducted by EPA before publishing and finalizing the taconite BART FIP for Minnesota and Michigan.

Nonetheless, the first step in any photochemical modeling exercise is to ensure that the modeling results can be replicated to ensure no errors in the data transfer or modeling setup. Barr worked with MPCA to obtain the 2002 and 2005 modeling input files, run scripts, and post-processing files to allow for the validation of the Barr modeling system. To be clear, the modeling comparison scenario used the exact same files provided by MPCA with no adjustments. Given the length of time required to complete the modeling analyses, this step focused on the 2002 dataset and evaluated the results from the 2002 baseline and 2002 Minnesota BART SIP. The information provided by MPCA to complete this comparison was contained in the document: "Visibility Improvement Analysis of Controls Implemented due to BART Determinations on Emission Units Subject-to-BART", October 23, 2009. The results of the comparison are contained in Appendix B: Barr and MPCA CAM<sub>X</sub> Modeling Comparison of Results. As expected with any photochemical model comparison running four different quarterly simulations using two different computer systems and Fortran compilers, there are insignificant differences in the end values. The overall comparison of the results was very favorable and showed excellent agreement between the four modeled datasets (i.e. 2002 baseline and 2002 BART SIP, each from MPCA and Barr).

After successful confirmation of the consistency check of the Barr modeling system to the MPCA system, the modeling focused on the specific emission changes in the MPCA elevated point source files. As with most regional modeling applications, there were 36 "core" point source files for each scenario. This set corresponds to three files per month (Saturday, Sunday, and weekday) for all twelve months. Emission information from each file was extracted for all the CNR and Arcelor taconite facilities in Minnesota to confirm the emission totals used by MPCA in the SIP baseline and BART SIP control scenarios. The emission summary data for each unit matched the summary tables within the MPCA BART SIP modeling. Also, the emission sources from Tilden Mining Company in Michigan were identified and information extracted to allow for the same type of modeling as was conducted for the Minnesota facilities.

The next step was to include United Taconite Line 1 in the baseline and FIP modeling files. Line 1 was not originally included in the MPCA modeling because it was not operational in the 2002 base year.

Therefore, the information for that source was obtained from MPCA-provided 2018 elevated point source files and incorporated into the 36 core elevated point source files. This allowed all the CNR and Arcelor furnace lines within the FIP to be evaluated as part of this modeling analysis. To that end, each CNR and Arcelor BART-eligible source was specifically identified and labeled for processing to track modeled impacts using plume-in-grid treatment and the Particulate Source Apportionment Technology (PSAT) contained within CAM<sub>x</sub> (including Tilden Mining). A list of the sources that were included in the specific PSAT groups can be found in Appendix C: CAM<sub>x</sub> PSAT Source List.

As part of the identification and labeling process, the MPCA BART SIP elevated point source files were converted from binary input files to ascii text files using the BIN2ASC program. (NOTE: by using the BART SIP point source files, all other Minnesota BART-eligible sources were included in this modeling exercise using their BART SIP emissions to isolate the impacts of the CNR and Arcelor units.) Then, a Fortran90 program was developed to adjust the hourly emissions from each applicable source to correspond to the sum of annual emissions within each of the following scenarios: EPA FIP baseline and EPA final FIP. It is important to note that the temporal factors for each source were not modified from the original MPCA-provided inventory files (i.e. no changes to the monthly or day-of-week factors). This emission approach allowed for the exact set of emissions within each of the scenarios to be modeled. After the emissions within the text file were adjusted, the emissions were checked for accuracy. Then, each file was converted back to binary input from ASCII text using the ASC2BIN program. The emission summary for each unit/scenario combination is contained in Appendix D: Summary of  $CAM_x$ Elevated Point Source Emissions. Appendix D also provides a reference list for the emissions from the proposed FIP, Final FIP (where applicable), and calculation methodology where EPA did not provide sufficient information to calculate emissions. Table 1 contains a facility summary for all taconite furnaces under each scenario.

As stated previously, one of the outcomes of these analyses was the comparison of EPA's scalar approach to specific photochemical modeling using EPA's emission reduction assumptions within the FIP rulemakings. These modeling analyses make no judgment as to the achievability of these emission reductions. CNR and Arcelor dispute that these NOx reductions are achievable for all furnaces. These modeling analyses are, therefore, a conservative evaluation of EPA's predicted NOx reductions – not the actual NOx reductions achievable by the application of BART.

4

| Facility          | FIP Baseline (TPY) |        | Final Fl | IP (TPY) | Difference (TPY) |        |  |
|-------------------|--------------------|--------|----------|----------|------------------|--------|--|
|                   | SO2                | NOx    | SO2      | NOx      | SO2              | NOx    |  |
| Arcelor Mittal    | 179                | 3,639  | 179      | 1,092    | 0                | 2,547  |  |
| Hibbing Taconite  | 570                | 6,888  | 570      | 2,066    | 0                | 4,821  |  |
| United Taconite   | 4,043              | 5,330  | 1,969    | 1,599    | 2,074            | 3,731  |  |
| Northshore Mining | 73                 | 764    | 73       | 229      | 0                | 535    |  |
| Tilden Mining     | 1,153              | 4,613  | 231      | 1,384    | 922              | 3,229  |  |
| Total             | 6,018              | 21,233 | 3,022    | 6,370    | 2,996            | 14,863 |  |

 Table 1: Facility Taconite Furnace Emission Summary

Two other issues should be noted here.

1. The first is the nested 12-km modeling domain selected by MPCA (illustrated in Figure 1) along with the specific "receptors" used for identification of the relevant Isle Royale Class I area and their use for determination of impacts from Tilden Mining Company. The Tilden Mining source was not included in the MPCA fine grid as it was not part of the Minnesota SIP. However, the elevated point source file includes the sources in the entire 36 km domain (including Tilden). As such, the Tilden emissions were available for estimation of specific visibility impacts. The receptors selected by MPCA only included the western half of the Isle Royale Class I area because that is the portion of the area closest to the Minnesota sources. However, the size of the grid cells (e.g. 12 and 36 km) provides a large number of potential receptors at all the Class I areas and little variation among receptors is expected at the distance between Tilden and Isle Royale. Thus, the modeling data should adequately represent the visibility impact at the entire Isle Royale Class I area.

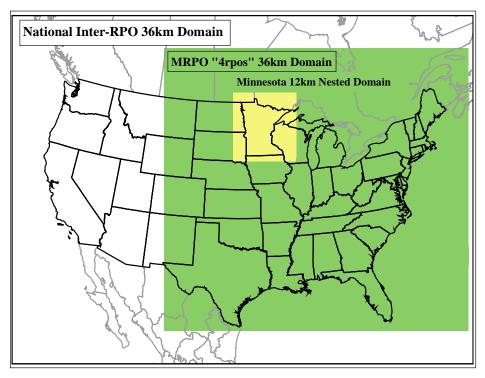


Figure 1. MPCA Modeling Domain

2. The second issue is the inconsistency between the emission reduction estimates used by EPA in the calculation of their scalar visibility benefits (i.e. Tables V-C of the proposed and final FIP) and the emission reductions calculated in the facility-specific sections of the proposed FIP. EPA's flawed calculation methodology did not use the appropriate emission reductions. In order to calculate the emissions for evaluation of the final FIP in the CAM<sub>x</sub> modeling, Barr was left with utilizing the limited information provided in the proposed and final FIP rulemaking. The lack of information and the errors and inconsistencies within the dataset were highlighted in the information request on January 31, 2013 to EPA (included in Appendix E). As of the time of this memorandum, no response by EPA has been received by Barr. Further, given the time required to complete the modeling, assumptions were made that were conservative to calculate the FIP emissions. For example, the final FIP references a 65% NO<sub>x</sub> reduction from Tilden Mining Company due to the switch to natural gas firing, but that was not consistent with the other gas-fired kilns (proposed FIP reduction was 70% with the same 1.2 lb NO<sub>x</sub>/MMBTU emission limit). Therefore, to provide the maximum emission reductions, the 70% control was utilized for all the CNR and Arcelor taconite furnaces.

#### II. Summary of CAM<sub>X</sub> Results

As mentioned above, the CAM<sub>x</sub> model was executed for each calendar quarter of 2002 and 2005 using the adjusted emissions for each scenario. The results were then post-processed to calculate visibility impacts for each scenario in deciviews (dV). All these results are provided in Appendix F: CAM<sub>x</sub> Results by Facility. For the purposes of this memorandum, the following tables compare EPA's estimates of annual average impact contained within the proposed FIP with the results generated by the CAM<sub>x</sub> modeling for this project on a facility by facility basis. The first three facilities contain emission reductions for only NO<sub>x</sub>: Arcelor Mittal, Hibbing Taconite, and Northshore Mining. These results are summarized in Tables 2-4. United Taconite and Tilden Mining, which have both SO<sub>2</sub> and NO<sub>x</sub> emission reductions, have result comparisons that require additional discussion.

The context of these results includes the following visibility impact thresholds:

<u>0.5 dV impact</u> is the BART eligibility and contribute to visibility impairment threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required)<sup>2</sup>,

1.0 dV difference is the presumed human perceptible level for visibility improvement, and

<u>0.1 dV difference</u> was defined by other agencies, such as the northeastern states MANE-VU Regional Planning Organization<sup>3</sup> as the degree of visibility improvement that is too low to justify additional emission controls. In addition, EPA's Regional Haze Rule mentions<sup>4</sup> that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

The first two columns within Tables 2-4 and 6-8 provide the difference in 98<sup>th</sup> percentile visibility improvement from the baseline to the FIP control emissions, while the third column provides a measure of over-estimation when using the EPA scalar approach (i.e. % Over Estimation by EPA = EPA Estimated Difference / CAM<sub>x</sub> Modeled Difference).

Table 2: Arcelor Mittal Visibility Impact Comparison

<sup>&</sup>lt;sup>2</sup> 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule.

<sup>&</sup>lt;sup>3</sup> As documented by various states; see, for example, <u>www.mass.gov/dep/air/priorities/hazebart.doc</u>, which indicates a visibility impact of less than 0.1 delta-dv is considered "de minimis".

<sup>&</sup>lt;sup>4</sup> 64 FR 35730.

| Class I Area    | EPA Estimated | EPA Estimated |            | % Over        |
|-----------------|---------------|---------------|------------|---------------|
|                 | Difference    |               | Difference | Estimation by |
|                 | 98% dV        |               | 98% dV     | EPA           |
| Boundary Waters | 1.7           |               | 0.1        | 1500%         |
| Voyageurs       | 0.9           |               | 0.09       | 1000%         |
| Isle Royale     | 1.1           |               | 0.03       | 3700%         |

Table 3: Hibbing Taconite Visibility Impact Comparison

| Class I Area    | EPA Estimated |  | CAM <sub>X</sub> Modeled |  | % Over        |
|-----------------|---------------|--|--------------------------|--|---------------|
|                 | Difference    |  | Difference               |  | Estimation by |
|                 | 98% dV        |  | 98% dV                   |  | EPA           |
| Boundary Waters | 3.2           |  | 0.19                     |  | 1700%         |
| Voyageurs       | 1.7           |  | 0.11                     |  | 1500%         |
| Isle Royale     | 2.1           |  | 0.04                     |  | 5300%         |

Table 4: Northshore Mining Visibility Impact Comparison

| Class I Area    | EPA Estimated        | CAM <sub>X</sub> Modeled |  | % Over               |
|-----------------|----------------------|--------------------------|--|----------------------|
|                 | Difference<br>98% dV | Difference<br>98% dV     |  | Estimation by<br>EPA |
| Boundary Waters | 0.6                  | 0.01                     |  | 6000%                |
| Voyageurs       | 0.3                  | 0.01                     |  | 3000%                |
| Isle Royale     | 0.4                  | 0.01                     |  | 4000%                |

As pointed out in the previous comments on this proposed FIP, these results clearly demonstrate that the NOx reductions proposed in the FIP will not provide a perceptible visibility improvement. Additionally, it demonstrates that the EPA methodology using scalars severely overestimated the visibility impact from NO<sub>x</sub> emission reductions at these taconite furnaces in northeast Minnesota. Even when using maximum emission reductions from EPA's baseline, the EPA estimates grossly over predicted the potential dV improvement by over <u>10 times</u> the predicted 98<sup>th</sup> percentile visibility improvement in all cases for the Arcelor Mittal, Hibbing Taconite, and Northshore Mining facilities. The maximum 98<sup>th</sup> percentile visibility improvement predicted by the source specific tracking for any one line was 0.1 dV (Arcelor Mittal Line 1 on Boundary Waters). The minimum 98<sup>th</sup> percentile visibility improvement was 0.01 dV (Northshore Mining on Isle Royale). Further, the results presented in Table 5 for the individual furnace line impacts at Hibbing Taconite illustrate de minimis visibility improvement at all the Class I areas evaluated.

| Class I Area    | Furnace Line | CAM <sub>x</sub> Modeled<br>Difference<br>98% dV |
|-----------------|--------------|--|
| Boundary Waters | Line 1       | 0.04   |
|                 | Line 2       | 0.05   |
|                 | Line 3       | 0.08   |
| Voyageurs       | Line 1       | 0.03   |
|                 | Line 2       | 0.04   |
|                 | Line 3       | 0.04   |
| Isle Royale     | Line 1       | 0.01   |
|                 | Line 2       | 0.01   |
|                 | Line 3       | 0.01   |

Table 5: Hibbing Taconite Line-Specific Visibility Impacts

Overall, all the facilities with only  $NO_X$  emission reductions predict visibility improvement from each furnace line at or below the de minimis visibility improvement threshold of 0.1 delta-dV.

Due to the sizable change in the United Taconite SO<sub>2</sub> emission reductions from the proposed FIP to the final FIP; the visibility improvement was re-calculated using EPA's apparent methodology from the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NO<sub>X</sub> and the revised emission reduction for SO<sub>2</sub>. Then, those resultants were averaged for each of the Class I areas to obtain the "updated" EPA all pollutant estimates.

| Class I Area    | Amended EPA | CAM <sub>X</sub> Modeled | % Over        |
|-----------------|-------------|--------------------------|---------------|
|                 | Estimated   | Difference               | Estimation by |
|                 | Difference  | 98% dV                   | EPA           |
|                 | 98% dV      |                          |               |
| Boundary Waters | 1.6         | 1.40                     | 110%          |
| Voyageurs       | 0.8         | 0.85                     | N/A           |
| Isle Royale     | 1.1         | 0.35                     | 320%          |

 Table 6: United Taconite Visibility Impact Comparison (All Pollutants)

The comparison of the total modeling effort including both pollutant reductions is surprisingly similar (except for Isle Royale). However, when the individual pollutant impacts are examined, the problem with EPA's methodology is more clearly understood. The sulfate impacts are estimated more closely to the CAM<sub>x</sub> results, while the nitrate impacts are grossly overestimated similar to the first three facilities.

The methodology used to isolate the sulfate and nitrate impacts separately from the current CAM<sub>x</sub> results prioritizes the sulfate and nitrate impacts as part of three separate post-processing runs (all pollutants, sulfate, and nitrate). The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall United Taconite impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO<sub>x</sub> control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.1 dV; total = 0.15 dV) and would not show up as part of the overall visibility change. As detailed in the comments to the proposed FIP, it is also important to note the high probability that the maximum impacts from NO<sub>x</sub> emission reduction occur during the winter months when Isle Royale is closed to visitors and visitation at the other Class I areas is significantly reduced from summertime maximum conditions.<sup>5</sup>

| Table 7: United Taconite Visibility Impact Comparison (Surfate Impact) |             |  |                          |  |            |  |  |  |
|--|-------------|--|--------------------------|--|------------|--|--|--|
| Class I Area   | Amended EPA |  | CAM <sub>X</sub> Modeled |  | % Over     |  |  |  |
|  | Estimated   |  | Difference               |  | Estimation |  |  |  |
|  | Difference  |  | 98% dV                   |  | by EPA     |  |  |  |
|  | 98% dV      |  |                          |  | -          |  |  |  |
| Boundary Waters  | 1.0         |  | 1.29                     |  | N/A        |  |  |  |
| Voyageurs  | 0.5         |  | 0.74                     |  | N/A        |  |  |  |
| Isle Royale  | 0.6         |  | 0.28                     |  | 210%       |  |  |  |

 Table 7: United Taconite Visibility Impact Comparison (Sulfate Impact)

Table 8: United Taconite Visibility Impact Comparison (Nitrate Impact)

| Class I Area    | Amended EPA | CAM <sub>X</sub> Modeled |  | % Over     |
|-----------------|-------------|--------------------------|--|------------|
|                 | Estimated   | Difference               |  | Estimation |
|                 | Difference  | 98% dV                   |  | by EPA     |
|                 | 98% dV      |                          |  |            |
| Boundary Waters | 2.3         | 0.18                     |  | 1300%      |
| Voyageurs       | 1.1         | 0.08                     |  | 1400%      |
| Isle Royale     | 1.6         | 0.05                     |  | 3200%      |

<sup>&</sup>lt;sup>5</sup> Cliffs Natural Resources (September 28, 2012), EPA-R05-OAR-0037-0045 Att. M

In the same manner as Hibbing Taconite, United Taconite's individual furnace lines were evaluated. As mentioned in the previous paragraph, the results in Table 9 for nitrate impact are biased toward higher nitrate impacts due to the sorting of the data to maximize nitrate impact.

| Class I Area    | Furnace Line | CAM <sub>x</sub> Modeled<br>Difference |
|-----------------|--------------|--|
| Boundary Waters | Line 1       | 98% dV<br>0.05                         |
|                 | Line 2       | 0.1                                    |
| Voyageurs       | Line 1       | 0.02                                   |
|                 | Line 2       | 0.06                                   |
| Isle Royale     | Line 1       | 0.02                                   |
|                 | Line 2       | 0.03                                   |

Table 9: United Taconite Line-Specific Nitrate Visibility Impacts

Nonetheless, as seen for all the other furnace lines, the results for United Taconite's predicted visibility impact are at or below the deminimis threshold for visibility improvement.

Since Tilden Mining Company was not evaluated using the same methodology as the Minnesota taconite facilities, there are no specific EPA data to compare with the  $CAM_X$  results. However, it is important to understand that the results are very similar to the other results regarding the impact of  $NO_X$  emission reductions on these Class I areas.

| Class I Area    | <b>EPA</b> Estimated | CAM <sub>X</sub> Modeled |
|-----------------|----------------------|--------------------------|
|                 | Difference 98%       | Difference               |
|                 | dV                   | 98% dV                   |
| Boundary Waters | N/A                  | 0.08                     |
| Voyageurs       | N/A                  | 0.03                     |
| Isle Royale     | N/A*                 | 0.17                     |

Table 10: Tilden Mining Visibility Impact Comparison (All Pollutants)

\*EPA estimated that the proposed FIP results in 0.501 dV visibility improvement at Isle Royale from emission reduction at Tilden Mining

|                 | 0                        |                          |
|-----------------|--------------------------|--------------------------|
| Class I Area    | CAM <sub>X</sub> Sulfate | CAM <sub>x</sub> Nitrate |
|                 | Modeled                  | Modeled                  |
|                 | Difference               | Difference               |
|                 | 98% dV                   | 98% dV                   |
| Boundary Waters | 0.07                     | 0.01                     |
| Voyageurs       | 0.03                     | 0.00                     |
| Isle Royale     | 0.14                     | 0.02                     |

Table 11: Tilden Mining Pollutant-Specific Impact Comparison

The visibility impacts from  $NO_X$  emission reductions at Tilden are consistent with the other modeling results and further demonstrate that significant emission reductions of NOx (3,229 tpy for Tilden) result in no visibility improvements.

#### III. Conclusions

Overall, the results from the three facilities with only  $NO_X$  emission reductions (Hibbing Taconite, Northshore Mining, and Arcelor Mittal) and the pollutant-specific comparisons for United Taconite and Tilden Mining illustrate that nearly 15,000 tons per year of  $NO_X$  reductions, even if they were technically and/or economically achievable, provide imperceptible visibility impacts at the Minnesota or nearby Michigan Class I areas. In all cases, the CAMx-predicted impacts for every furnace line are at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

The fact that NO<sub>x</sub> emission reductions do not provide perceptible visibility improvement was understood by MPCA when they proposed existing control and good combustion practices as BART for taconite furnaces in northeast Minnesota. This finding has been confirmed by this detailed modeling analysis. EPA, to its credit, does not claim that its scalar "ratio" approach for predicting visibility improvement is accurate. In the final FIP, EPA provided, "Therefore, even if the ratio approach was over-estimating visibility improvement by a factor of two or three, the expected benefits would still be significant."<sup>6</sup> Our analysis demonstrates that the ratio approach has over-estimated impacts by a factor of ten to sixty for NO<sub>x</sub> reductions. When accurately modeled, the NO<sub>x</sub> reductions do not yield discernible visibility benefits. To that end, the following pictures from WinHaze Level 1 Visual Air Quality Imaging Modeler

<sup>&</sup>lt;sup>6</sup> Federal Register, Volume 78, Number 25, page 8720, February 6, 2013

(version 2.9.9.1) provide a visual reference for the  $CAM_X$  predicted visibility impairment from the maximum nitrate impacting facility at Isle Royale and Boundary Waters<sup>7</sup>.



Isle Royale FIP Base - United Taconite



Boundary Waters FIP Base - Hibbing Taconite



Isle Royale Final FIP – United Taconite



Boundary Waters Final FIP – Hibbing Taconite

Given the size of the predicted visibility impacts (both less than 0.2 dV improvement), these pictures illustrate no discernible visibility improvement from NO<sub>X</sub> reductions at either Class I area.

Ultimately, Minnesota and Michigan reached their visibility assessments in different ways, but this modeled analysis supports their conclusion that low  $NO_X$  burner technology is not BART for the furnaces modeled at Arcelor Mittal - Minorca, Hibbing Taconite, Northshore Mining Company, United Taconite, and Tilden Mining. Therefore, EPA should approve the sections of the SIPs establishing  $NO_X$  BART on this basis.

<sup>&</sup>lt;sup>7</sup> Voyageurs National Park pictures are not contained within the WinHaze program



resourceful. naturally. engineering and environmental consultants

# APPENDIX A: Visibility Impact Requirements and EPA's Scalar Approach for Estimating Visibility Impacts within the Taconite FIP

March 6, 2013

### I. Summary of Visibility Impact Requirements

The relevant language related to the specific BART visibility impact modeling approach from 40 CFR 51 Appendix Y (herein, Appendix Y), *Guidelines for BART Determinations Under the Regional Haze Rule,* is provided here, in italics with some language underlined for emphasis:

5. Step 5: How should I determine visibility impacts in the BART determination?

• For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.

Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emission rates are calculated as a percentage of pre-control emission rates. For example, if the 24-hr pre-control emission rate is 100 lb/hr of SO[2], then the post control rate is 5 lb/hr if the control efficiency being evaluated is 95 percent.

• Make the net visibility improvement determination.

Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. You have flexibility to assess visibility improvements due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment. Suggestions for making the determination are:

• Use of a comparison threshold, as is done for determining if BART-eligible sources should be subject to a BART determination. Comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g., the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing an x percent change in improvement).

• Compare the 98th percent days for the pre- and post-control runs.

Note that each of the modeling options may be supplemented with source apportionment data or source apportionment modeling.

It should be noted that Appendix Y is a guideline for state air quality agencies to proceed with modeling of BART sources. Therefore, these are not requirements, but recommended practices for evaluation of visibility impacts. Significant discretion was given to each state regarding the use of these methods. To that end, the Minnesota Pollution Control Agency applied a different modeling system than the EPA-approved model (CALPUFF) for BART evaluations. Discussed below, the new modeling system was subsequently used by EPA as part of their FIP proposal.

Further, an excerpt from the Clean Air Act, Part C, Subpart II is provided below to establish the basis for the Appendix Y regulations related to visibility improvement.

### II. Summary of EPA's approach

Specific language from the proposed and final FIPs are provided in *italics* along with comments.

EPA relied on visibility improvement modeling conducted by the Minnesota Pollution Control Agency (MPCA) and recorded in MPCA's document "Visibility Improvement Analysis of Controls Due to BART Determinations on Emission Unit's Subject to BART", October 23, 2009 [attached]. The visibility improvement modeling conducted by MPCA utilized the Comprehensive Air Quality Model with Extensions (CAMx) air quality model with the Mesoscale Meteorological Model (MM5) and the Emission Modeling System (EMS-2003). Within the CAMx modeling system, MPCA used the Particulate Source Apportionment Tool (PSAT) and included evaluation of all the elevated point emissions<sup>1</sup> at each facility with best available retrofit technology (BART) units. The impacts from MPCA State Implementation Plan (SIP) BART controls were determined by subtracting the impact difference between the 2002/2005 base case and 2002/2005 BART control case for each facility. EPA used the impacts from four of the six facilities modeled by MPCA (Minnesota Power – Boswell Energy Center, Minnesota Power – Taconite Harbor, Northshore Mining – Silver Bay, United Taconite). The other two facilities modeled by MPCA were utility sources (Rochester Public Utilities – Silver Lake and Xcel Energy – Sherburne Generating Plant). The locations of these sources are presented below in Figure A-1 (obtained from the MPCA 2009 document).

<sup>&</sup>lt;sup>1</sup> Elevated point emissions include only sources with plume rise above 50m.

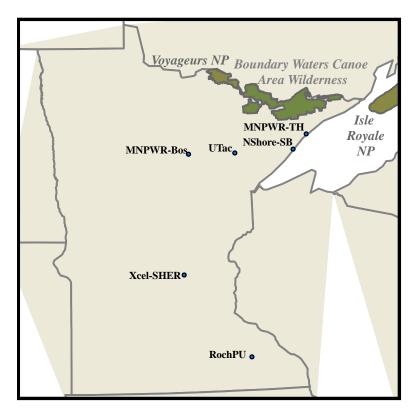


Figure A-1: Minnesota Facilities with BART-Determinations Assessed

In order to avoid the time and effort necessary for specific modeling of the units that EPA proposed to include in the FIP, EPA then used the average visibility impact from these four facilities to calculate two metrics for visibility improvement. The first metric is a ratio of number of days with greater than 0.5 deciview (dV) visibility divided separately by the change in  $SO_2$  and  $NO_x$  emissions at each facility (i.e. one ratio for change in  $SO_2$  emissions and one ratio for change in  $NO_x$  emissions). The second metric was calculated in the same fashion, but with 98<sup>th</sup> percentile visibility change divided by the change in  $SO_2$  and  $NO_x$  emissions at each facility. These ratios were then multiplied by the estimated FIP emission reductions for the taconite facilities (including UTAC and Northshore Mining). It is important to note that there were no  $NO_x$  emission reductions modeled from any of the taconite facilities and the only source of  $SO_2$  emission reductions from the taconite facilities was the UTAC facility.

Within the final FIP, EPA provided some additional statements that further clarified the agency's confidence regarding the use of the scalar approach for estimating visibility improvements.

### III. Specific Issues Regarding EPA's Visibility Impact Estimates

Clean Air Act Section 169(A)(g)(2) – "In determining the best available retrofit technology the State (or the Administrator in determining emission limitations which reflect such technology) shall 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 the source, and the <u>degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.</u>"

Proposed FIP Page 49329 – Column 1 – "The discussion below uses MPCA's emissions data and modeled visibility impact data to derive visibility impact ratios as a function of changes in emissions of NOx and SO2 at MPCA-modeled facilities. These visibility-emission ratios were then applied to the BART-based emission changes for the source subject to this BART rule to derive possible visibility impacts."

Issues – EPA's shortcut methodology does not provide an accurate assessment of potential visibility impacts from taconite emission units subject to BART, and cannot be relied upon for several reasons stated below. The use of emission change vs. visibility impact ratios is not scientifically accurate even for a single source, much less several sources in other locations, and illustrates EPA's haste for the development of the FIP without proper modeling procedures. According to a plain language reading of the Clean Air Act section above and the best-practice recommendations within Appendix Y, the state and EPA were required to conduct a thorough evaluation of the impacts associated with the changes in emissions for each BART technology at the relevant units within each taconite facilities. EPA's methodology does not result in a thorough evaluation. If such an analysis were submitted to EPA by the state, it would be rejected as inadequate. The same should apply to EPA's analysis of the visibility improvement calculations.

MPCA used an appropriate model for estimating visibility impacts from five utility sources and one taconite source, all subject to BART, in northern Minnesota. EPA took that analyses and attempted to justify its outcomes based on its flawed methodology. Alone, the differences between the emission profiles for utility sources and taconite sources and their different locations relative to the Class I areas should preclude this type of evaluation. The difference in the emissions profile relationship between  $NO_X$  and  $SO_2$  emissions is extremely important due to the interactive and competitive nature of the two pollutants for available ammonia ( $NH_3$ ) to form ammonium nitrate or ammonium sulfate.

In addition, there are important seasonal differences in the tendency for sulfates or nitrates to be important for haze formation. Nitrates are only important in winter because significant particle formation occurs only in cold weather; oxides of nitrogen react primarily to form ozone in the summer months. On the other hand, oxidation of  $SO_2$  to sulfate is most effective in summer with higher rates of photochemical and aqueous phase reactions. Due to the much different seasonal preferences for these two haze components, a one-size-fits-all scaling approach based upon annual averages that is insensitive to the season of the year is wholly inappropriate.

It is important to note that the only  $NO_x$  emission reductions used in the EPA scalar analyses were from utility sources. This occurred because the MPCA SIP did not include  $NO_x$  emission reductions from the United Taconite units. Therefore, the variation in emission profiles and stack parameters between utility boiler emission sources and taconite furnaces introduce another source of error with the EPA methodology.

Further, as shown in Figure A-1, the location of these sources with respect to the relevant Class I areas also causes significant problems with the EPA evaluation. The modeled visibility impacts from each source are a direct function of the wind direction. When two sources are not in the same direction with respect to the area, there is no possible way to accurately reflect the impact from the two different sources on receptor locations on any given day. For example, elevated impacts on the Voyageurs National Park from Northshore Mining would not happen on the same days as any of the other taconite sources in Minnesota.

Additionally, notwithstanding the inaccuracies of EPA's average scalar methodology, a review of the calculation of the visibility change to emission reduction ratios (i.e. MPCA-calculated visibility changes divided by  $SO_2$  and  $NO_X$  SIP emission reductions) was conducted. This review uncovered calculation/typographical errors in the tables that were used to develop the average visibility change metrics. These simple calculation errors were subsequently corrected in the final FIP, but another inconsistency was not. The emission reductions used for  $NO_X$  within the scalar visibility calculations (Table V-C.xx) do not match the emission reduction tables in the proposed FIP (Table V – B.yy) for each facility. In one case (Northshore Mining Company), the visibility improvement reductions are greater than the baseline emissions. The attached table provides the baseline, proposed FIP, and final FIP information contained within the EPA rulemakings and docket for each taconite furnace and facility. Ultimately, even if the scalar approach used by EPA was valid, the rulemaking record is inaccurate and incomplete for the calculation of visibility impacts due to these inconsistencies.

Further, the calculation methodology for the two facilities with  $SO_2$  and  $NO_X$  reductions (United Taconite and US Steel – Minntac) appears to utilize another invalid assumption. Also, the proposed FIP does not provide a clear explanation of the calculation of the scaled visibility impacts for these two facilities (Page 49332 – Column 1):

"To calculate the visibility impacts for the Minnesota source facilities covered by this FIP proposed rule, we multiplied the total estimated BART NOx and SO2 emission reductions for each subject facility by the appropriate visibility factor/emission change ratios in Table V-C.9 and <u>combined the results to estimate</u> the total visibility impacts that would result from the reduction of PM2.5 concentrations."

In Tables V-C.14 and V-C.16, the calculation of the visibility change with the two different pollutants is not explicitly provided within the FIP. Based on the use of the average visibility changes ("combined results") in the attached tables, one can generate "estimated visibility impacts" that are close to the values provided in the FIP tables. This pollutant averaging approach is not valid due to the previous comments regarding the interactive nature of the reaction mechanisms for ammonium nitrate and ammonium sulfate.

Proposed FIP Page 49331 – Column 1 – "The above visibility factor/emission change ratio data show significant variation from source-to-source and between impacted Class I areas. This variation is caused by differences in the relative location of the source (relative to the locations of the Class I areas), variations in background sources, variations in transport patterns on high haze factors, and other factors that we cannot assess without detailed modeling of the visibility impacts for the sources as a function of pollutant emission type."

Issue – EPA correctly establishes the significant variation in the ratio data and clearly distinguishes some (but not all) of the problems with the approach used to determine visibility impacts. Other problems include the differences in modeled utility source stack parameters vs. taconite stack parameters, the different inter-pollutant ratios at each facility, and the differences in visibility impacts due to on-going changes in emissions from 2002/2005 to current/future emission levels. Furthermore, EPA identifies the solution to solve this problem within their statement regarding "detailed modeling of the visibility impacts". This detailed modeling exercise was completed for BART-eligible Cliffs Natural Resources and Arcelor Mittal facilities in northeast Minnesota and Michigan to provide a clear record of the visibility improvements associated with the final FIP. This modeling demonstrates the lack of visibility improvement from nearly 15,000 tons per year of NO<sub>X</sub> emission reductions and provides sufficient evidence to support the Minnesota and Michigan State Implementation Plans which called for good combustion practices as BART for NO<sub>X</sub> at these facilities.

Proposed FIP Page 49333, Column 2 – "Each BART determination is a function of consideration of visibility improvement and other factors for the individual unit, but in general EPA's assessment of visibility impacts finds that technically feasible controls that are available at a reasonable cost for taconite plants can be expected to provide a visibility benefit that makes those controls warranted."

Issue – EPA's statement regarding visibility benefit from the FIP  $NO_X$  emission reductions are vastly overestimated based on updated  $CAM_X$  modeling for the Cliffs Natural Resources and Arcelor Mittal taconite furnaces. The modeling results evaluating the 98<sup>th</sup> percentile visibility improvements obtained from these emission reductions are generally less than 10% of the EPA estimates. Therefore, these  $NO_X$  controls are not warranted for visibility improvement in northeast Minnesota and Michigan.

Final FIP Page 8720, Column 2 – "EPA's analysis shows that based on all of the BART factors, including visibility, the selected controls are warranted. If highly reasonable and cost-effective controls had been available but visibility benefits were slight, EPA would have rejected those controls."

Issue – EPA describes exactly the situation with respect to "slight visibility benefits". Therefore, given the new information regarding the very slight modeled impact of  $NO_x$  emission reductions, EPA should reject those reductions as necessary under the BART program. Also, in the final FIP, EPA criticizes both MPCA and MDEQ for ignoring relevant information on Low  $NO_x$  Burner (LNB) technology. Now, given the length of time necessary and extensive effort required to generate this new visibility improvement data, EPA should reconsider its position on LNB as producing visibility benefits. This would allow EPA to support the original findings for these facilities within both the MPCA and MDEQ SIP with respect to  $NO_x$  emission limits. Final FIP Page 8720, Column 3 – "EPA's proposed rule acknowledged the uncertainty associated with the visibility impact ratio approach, but noted that despite the uncertainties, the Agency was confident that the information was adequate to assess potential visibility improvements due to emission reductions at the specific facilities."

"Given the geographic proximity of the taconite facilities to those that were modeled, EPA believes that the ratio approach provide adequate assurance of the visibility improvements that can be expected from the proposed emission reductions."

"In the proposed rule's summary of the impacts at Boundary Waters, Voyageurs, and Isle Royale, these values ranged from 1.3 to 7.1 dVs of improvement with between 17 and 93 fewer days above the 0.5 dV threshold. Therefore, even if the ratio approach was over-estimating visibility improvements by a factor of two or three, the expected benefits would still be significant."

Final FIP Page 8721, Column 3 – "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."

Issue – EPA again chose to ignore the specific technical issues discussed above regarding the use of the ratio approach and has incorrectly assumed that this approach will provide an accurate assessment of the visibility benefits from the Cliffs and Arcelor taconite facilities. Based on the refined  $CAM_x$  modeling results using a conservative estimate of EPA's final FIP emission reduction scenario, it is obvious that the ratio approach does not provide any assurance of the visibility improvements. Further, the estimates for visibility improvement are over-estimated by between a factor of ten and sixty. Therefore, the impacts are not "significant" as referenced in EPA's response to comment within the final FIP rulemaking. The lack of technical validity contained within the EPA scalar approach is alarming. Even more alarming is the agency's refusal to conduct the type of detailed analyses necessary to allow for a technically valid answer on a rulemaking that will cost the taconite industry millions of dollars.

#### **IV. Summary**

The CAM<sub>x</sub> modeling approach undertaken by Cliffs and Arcelor provides the best approximation of the visibility improvements from the emission reductions within the final FIP. This method replaces the use of the average ratio approach used by EPA with refined, photochemical modeling for the Cliffs and Arcelor facilities. The results of the analysis confirm the findings of the MPCA in its 2009 SIP that  $NO_x$  emission reductions do not have sufficient impact to warrant further consideration. At this point, we affirm that EPA's simple assessment is not credible, and any visibility improvement conclusions for  $NO_x$  are not technically sound. The visibility improvement results estimated by EPA using the ratio approach are between ten and sixty times greater than the results generated using the CAM<sub>x</sub> modeling system. In essence, the modeling conducted here provides EPA another opportunity to support the findings of the MPCA and MDEQ SIPs with respect to  $NO_x$  emissions impacts at the Cliffs and Arcelor facilities.

# Cliffs Natural Resources and Arcelor Mittal Taconite FIP Emission Summary

|  |                   |                    |           | Emissions |              |         | Emiss                  | Emissions              |         |           |          |
|--|-------------------|--------------------|-----------|-----------|--------------|---------|------------------------|------------------------|---------|-----------|----------|
|  |                   |                    |           |           | Proposed FIP | ,       | Baseline -<br>Prop FIP | Baseline -<br>Prop FIP |         | Final FIP |          |
|  |                   | Emission Unit      |           | Baseline  | FIP          |         | <b>Emission Tables</b> | Visibility Calcs       |         |           |          |
| Facility   | ModID             | Description        | Pollutant | tons/yr   | tons/yr      | Note(s) | tons/yr                | tons/yr                | Note(s) | lb/hr     | Note(s)  |
| Hibbing Taconite Company          [4]         [4]         [5]         HI         Northshore Mining Company         [2]         [2]         Tilden Mining Company         [1]         [3]         [5]         United Taconite         [2]         [2]         [2]         [3]         [4]         [4]         [1]         [2]         [2]         [2]         [2]         [2]         [2]         [2]         [2]         [2]         [2]         [3]         [4]         [5]         [6]         [7]         [8]         [9]         [1]         [1]         [2]         [2]         [2]         [2]         [2]         [2]         [3]         [4]         [5]         [6]         [7]         [8]         [9]         [ | {3}               | Line 1             | NOx       | 2,497     | 749          | [1]     | 1,748                  |                        |         |           | [4]      |
|  |                   |                    | SO2       | 202       | 202          | [2]     | 0                      |                        |         | 82.6      | [5]      |
|  | {4}               | Line 2             | NOx       | 2,144     | 643          | [1]     | 1,500                  |                        |         |           | [4]      |
|  |                   |                    | SO2       | 180       | 180          | [2]     | 0                      |                        |         | 82.6      | [5]      |
|  | {5}               | Line 3             | NOx       | 2,247     | 674          | [1]     | 1,573                  |                        |         |           | [4]      |
|  |                   |                    | SO2       | 188       | 188          | [2]     | 0                      |                        |         | 82.6      | [5]      |
|  | HTC               | BART Units         | NOx       | 6,888     | 2,066        |         | 4,821                  | 5,259                  | [3]     |           |          |
|  |                   | Combined           | SO2       | 570       | 570          |         | 0                      | 0                      | [3]     | 247.8     |          |
| Northshore Mining Company  |                   | Process Boiler 1/2 | NOx       | 41        | 21           | [6]     | 21                     |                        |         |           | [10]     |
|  |                   |                    | SO2       |           |              |         |                        |                        |         |           |          |
|  | {24}              | Furnace 11         | NOx       | 386       | 116          | [7]     | 270                    |                        |         |           | [11]     |
|  |                   |                    | SO2       | 38        | 38           | [8]     | 0                      |                        |         | 19.5      | [12]     |
|  | {25}              | Furnace 12         | NOx       | 378       | 113          | [7]     | 264                    |                        |         |           | [11]     |
|  |                   |                    | SO2       | 35        | 35           | [8]     | 0                      |                        |         | 19.5      | [12]     |
|  | <mark>NSM</mark>  | BART Units         | NOx       | 805       | 250          |         | 555                    | 926                    | [9]     |           |          |
|  |                   | Combined           | SO2       | 73        | 73           |         | 0                      | 0                      | [9]     | 39        |          |
| Tilden Mining Company  | {1}               | Boiler #1/2        | NOx       | 79        | 79           | [13]    | 0                      |                        |         |           |          |
|  |                   |                    | SO2       | 0         | 0            | [14]    | 0                      |                        |         |           | [19]     |
|  | {3}               | Ore Dryer # 1      | NOx       | 15        | 15           | [15]    | 0                      |                        |         |           |          |
|  |                   |                    | SO2       | 34        | 34           | [15]    | 0                      |                        |         |           | [20]     |
|  | {5}               | Furnace #1         | NOx       | 4,613     | 1,384        | [16]    | 3,229                  |                        |         |           | [21]     |
|  |                   |                    | SO2       | 1,153     | 115          | [17]    | 1,038                  |                        |         | 55        | [22][23] |
|  | <mark>TMC</mark>  | BART Units         | NOx       | 4,707     | 1,478        |         | 3,229                  | 3,229                  | [18]    |           |          |
|  |                   | Combined           | SO2       | 1,187     | 150          |         | 1,038                  | 1,038                  | [18]    |           |          |
| United Taconite  | {26}              | Line 1             | NOx       | 1,643     | 493          | [24]    | 1,150                  |                        |         |           | [27]     |
|  |                   |                    | SO2       | 1,293     | 129          | [25]    | 1,164                  |                        |         | 155       | [28]     |
|  | {24}              | Line 2             | NOx       | 3,687     | 1,106        | [24]    | 2,581                  |                        |         |           | [27]     |
|  |                   |                    | SO2       | 2,750     | 275          | [25]    | 2,475                  |                        |         | 374       | [28]     |
|  | UTAC              | BART Units         | NOx       | 5,330     | 1,599        |         | 3,731                  | 3,208                  | [26]    |           |          |
|  |                   | Combined           | SO2       | 4,043     | 404          |         | 3,639                  | 3,639                  | [26]    | 529       | [28]     |
| Arcelor Mittal   | <mark>ARC</mark>  | Line 1             | NOx       | 3,639     | 1,092        | [29]    | 2,547                  | 2,859                  | [31]    |           | [32]     |
|  | <mark>{12}</mark> |                    | SO2       | 179       | 179          | [30]    | 0                      | 0                      | [31]    | 38.2      | [33]     |

| TOTAL BART UNIT | NOx | 21,369 | 6,485 | 14,884 | 15,481 |
|-----------------|-----|--------|-------|--------|--------|
|                 | SO2 | 6,053  | 1,376 | 4,677  | 4,677  |

Facility BART Unit Summary or Overall Summary

FIP Baseline does not match reference

FIP Table B emission tables do not match Table C visibility calculation tables

#### Notes:

- [1] HTC Line 1-3 USEPA FIP NOx Baseline Emissions Proposed FIP Table V B.24; Proposed FIP NOx Emissions = 70% Control from Baseline
  - Typographical Error in Table V B.24 for Line 1 Baseline Emissions (2,143.5 TPY Proposed FIP; should have been 2,497 TPY)
- [2] HTC Line 1-3 USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V B.27
- [3] HTC USEPA Proposed BART FIP Table V C.11
- [4] HTC Furnace Lines USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
- [5] HTC Furnace Lines USEPA final BART combined limit of 247.8 lb SO2/hr [82.6 lb/hr each for Lines 1 to 3] (30-day rolling avg); can be adjusted based on CEMs data.
- [6] NSM Process Boilers 1&2 NOx Emissions from Proposed FIP Table V B.12 (p49318); LNB 50% Control from Baseline of 41.2 tons/year
- [7] NSM Furnace 11/12 NOx Emissions (Baseline and Proposed FIP Control) from Proposed FIP Table V B.8; FIP Emissions = 70% Control from Baseline
- [8] NSM Furnace 11/12 No Additional SO2 Control Applied by Proposed FIP; Baseline FIP Emission Rate from Table V B.10
- [9] NSM USEPA Proposed BART FIP Table V C.12
- [10] NSM Process Boilers 1&2 USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) [No additional control].
- [11] NSM Furnace 11/12 USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
- [12] NSM Furnace 11/12 USEPA final BART combined limit of 39.0 lb SO2/hr (30-day rolling average); must be adjusted based on CEMs data.
- [13] Tilden Process Boilers 1 & 2 NOx Baseline Emissions Proposed FIP Table V B.38
- [14] Tilden Process Boilers 1 & 2 SO2 Baseline Emissions Proposed FIP Table V B.37 (0.25 TPY)
- [15] Tilden Dryer #1 Emissions from Proposed FIP Table V B.39 (SO2) and Table V B.40 (NOx) 34.07 TPY SO2, 15.1 TPY NOx
- [16] Tilden Furnace 1 NO2 Baseline and Proposed FIP Control Emissions Proposed FIP Table V B.34 (FIP Emissions = 70% Control from Baseline)
- [17] Tilden Furnace 1 Proposed FIP SO2 Emissions Table V-B.36; Spray Dry Absorption 90%; Proposed FIP Text says 95% Control or 5 ppm; Baseline Emissions Back-calculated from 90% control
- [18] Tilden Furnace 1 USEPA did not calculate visibility improvement for Tilden (Used emission difference Baseline Proposed FIP)
- [19] Tilden USEPA Final BART limit of 1.2%S in fuel combusted by Process Boiler #1 and #2
- [20] Tilden USEPA Final BART limit of 1.5%S in fuel combusted by Ore Dryer #1
- [21] Tilden Furnace 1- USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only); NOx emissions referenced in final FIP text as 65% control from baseline (page 8721)
- [22] Tilden Furnace 1 USEPA Final BART restriction Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs; SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
- [23] Tilden Furnace 1 USEPA Final BART Modeling File (Part of Final Rulemaking Docket) Conducted by NPS 55 lb/hr SO2
- [24] UTAC Line 1-2 USEPA NOx Baseline Emissions Proposed FIP Table V B.14; Proposed FIP NOx Emissions = 70% Control from Baseline
- [25] UTAC Line 1-2 USEPA proposed FIP Baseline SO2 Emissions Table V B.17; 90% Control in Table, but 95% Control within text Proposed FIP (page 49319)
- [26] UTAC USEPA Proposed BART FIP Table V C.13
- [27] UTAC Line 1-2 USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)
- [28] UTAC Line 1-2 USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr Line 1 & 374 lb/hr Line 2).
- [29] Arcelor USEPA proposed FIP Baseline NOx Emissions Table V B.19; Proposed FIP NOx Emissions = 70% Control from Baseline
- [30] Arcelor USEPA proposed FIP Baseline SO2 Emissions Table V B.21
- [31] Arcelor USEPA Proposed BART FIP Table V C.10
- [32] Arcelor USEPA Final BART SO2 Limit of 38.16 lb/hr for Arcelor.
- [33] Arcelor USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)

EPA Furnace NOx Control % 70%



resourceful. naturally. engineering and environmental consultants

# APPENDIX B: Barr and MPCA CAM<sub>x</sub> Modeling Comparison of Results

March 6, 2013

## Minnesota Power – Taconite Harbor (BART01)

#### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |                           |      |                 |      | Class I Are | ea              |             |      |                 |
|-----------------------------|----------|---------------------------|------|-----------------|------|-------------|-----------------|-------------|------|-----------------|
| <b>PM</b> <sub>2</sub> .    | 5        | Boundary Waters Voyageurs |      |                 |      |             | <b>S</b>        | Isle Royale |      |                 |
| Parameter                   | Met Year | Base                      | BART | Differ-<br>ence | Base | BART        | Differ-<br>ence | Base        | BART | Differ-<br>ence |
| Days > 0.5 dv               | 2002     | 94                        | 90   | -4              | 11   | 9           | -2              | 30          | 27   | -3              |
| 98th Percentile $\Delta dv$ | 2002     | 9.2                       | 8.3  | -0.9            | 0.8  | 0.7         | -0.1            | 2.2         | 1.9  | -0.3            |

#### Barr

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |                           |      |                 |      | Class I Are | a               |             |      |                 |
|-----------------------------|----------|---------------------------|------|-----------------|------|-------------|-----------------|-------------|------|-----------------|
| <b>PM</b> <sub>2.</sub>     | 5        | Boundary Waters Voyageurs |      |                 |      |             |                 | Isle Royale |      |                 |
| Parameter                   | Met Year | Base                      | BART | Differ-<br>ence | Base | BART        | Differ-<br>ence | Base        | BART | Differ-<br>ence |
| Days > 0.5 dv               | 2002     | 95                        | 90   | -5              | 11   | 9           | -2              | 30          | 27   | -3              |
| 98th Percentile $\Delta dv$ | 2002     | 9.14                      | 8.25 | -0.89           | 0.82 | 0.68        | -0.14           | 2.22        | 1.88 | -0.34           |

### Minnesota Power – Boswell (BART04)

#### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                      |                 |      |      |                 |      | Class I Are | ea              |             |      |                 |
|-------------------------|-----------------|------|------|-----------------|------|-------------|-----------------|-------------|------|-----------------|
| $\mathbf{PM}_{2}$ .     | Boundary Waters |      |      | ers Voyageurs   |      |             |                 | Isle Royale |      |                 |
| Parameter               | Met Year        | Base | BART | Differ-<br>Ence | Base | BART        | Differ-<br>ence | Base        | BART | Differ-<br>Ence |
| Days > 0.5 dv           | 2002            | 111  | 60   | -51             | 86   | 58          | -28             | 48          | 27   | -21             |
| 98th Percentile<br>∆ dv | 2002            | 4.3  | 2.4  | -1.9            | 4.4  | 2.7         | -1.8            | 2.0         | 1.0  | -1.0            |

Barr

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |                 | Class I Area |                 |           |      |                 |      |             |                 |  |
|-----------------------------|----------|-----------------|--------------|-----------------|-----------|------|-----------------|------|-------------|-----------------|--|
| PM <sub>2.</sub>            | 5        | Boundary Waters |              |                 | Voyageurs |      |                 |      | Isle Royale |                 |  |
| Parameter                   | Met Year | Base            | BART         | Differ-<br>Ence | Base      | BART | Differ-<br>ence | Base | BART        | Differ-<br>ence |  |
| Days > 0.5 dv               | 2002     | 110             | 61           | -49             | 86        | 58   | -28             | 47   | 27          | -20             |  |
| 98th Percentile $\Delta dv$ | 2002     | 4.27            | 2.37         | -1.90           | 4.43      | 2.65 | -1.78           | 1.96 | 0.98        | -0.98           |  |

# Northshore Mining – Silver Bay (BART05)

### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |                           |      |                 |      | Class I Are | ea              |      |      |                 |
|-----------------------------|----------|---------------------------|------|-----------------|------|-------------|-----------------|------|------|-----------------|
| <b>PM</b> <sub>2</sub> .    | 5        | Boundary Waters Voyageurs |      |                 |      |             | Isle Royale     |      |      |                 |
| Parameter                   | Met Year | Base                      | BART | Differ-<br>ence | Base | BART        | Differ-<br>ence | Base | BART | Differ-<br>ence |
| Days > 0.5 dv               | 2002     | 77                        | 72   | -5              | 9    | 8           | -1              | 20   | 15   | -5              |
| 98th Percentile $\Delta dv$ | 2002     | 3.96                      | 3.79 | -0.17           | 0.6  | 0.5         | -0.1            | 0.9  | 0.7  | -0.2            |

#### Barr

### Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |                           |      |                 |      | Class I Are | a               |      |      |                 |
|-----------------------------|----------|---------------------------|------|-----------------|------|-------------|-----------------|------|------|-----------------|
| <b>PM</b> <sub>2.</sub>     | 5        | Boundary Waters Voyageurs |      |                 |      |             | Isle Royale     |      |      |                 |
| Parameter                   | Met Year | Base                      | BART | Differ-<br>ence | Base | BART        | Differ-<br>ence | Base | BART | Differ-<br>ence |
| Days > 0.5 dv               | 2002     | 78                        | 72   | -6              | 9    | 8           | -1              | 20   | 15   | -5              |
| 98th Percentile $\Delta dv$ | 2002     | 3.96                      | 3.78 | -0.18           | 0.63 | 0.50        | -0.13           | 0.90 | 0.73 | -0.17           |

## **United Taconite (BART26)**

### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                      |          |                           |      |                 |      | Class I Are | a               |      |             |                 |  |
|-------------------------|----------|---------------------------|------|-----------------|------|-------------|-----------------|------|-------------|-----------------|--|
| $\mathbf{PM}_{2.}$      | 5        | Boundary Waters Voyageurs |      |                 |      |             | <b>S</b>        |      | Isle Royale |                 |  |
| Parameter               | Met Year | Base                      | BART | Differ-<br>ence | Base | BART        | Differ-<br>ence | Base | BART        | Differ-<br>ence |  |
| Days > 0.5 dv           | 2002     | 59                        | 44   | -15             | 32   | 20          | -12             | 8    | 1           | -7              |  |
| 98th Percentile<br>∆ dv | 2002     | 3.0                       | 1.7  | -1.3            | 1.8  | 0.8         | -0.9            | 0.6  | 0.3         | -0.3            |  |

Barr

## Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |                 |      |                 |      | Class I Are | a               |             |      |                 |
|-----------------------------|----------|-----------------|------|-----------------|------|-------------|-----------------|-------------|------|-----------------|
| $\mathbf{PM}_{2.}$          | 5        | Boundary Waters |      |                 |      | Voyageur    | 5               | Isle Royale |      |                 |
| Parameter                   | Met Year | Base            | BART | Differ-<br>ence | Base | BART        | Differ-<br>ence | Base        | BART | Differ-<br>ence |
| Days > 0.5 dv               | 2002     | 63              | 46   | -17             | 34   | 20          | -14             | 8           | 1    | -7              |
| 98th Percentile $\Delta dv$ | 2002     | 3.02            | 1.69 | -1.33           | 1.78 | 0.85        | -0.93           | 0.59        | 0.28 | -0.31           |

## Xcel Sherburne (BART13)

#### MPCA

## Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                      |          |      | Class I Area |                 |      |          |                 |             |      |                 |  |  |  |
|-------------------------|----------|------|--------------|-----------------|------|----------|-----------------|-------------|------|-----------------|--|--|--|
| $\mathbf{PM}_{2.}$      | 5        | B    | oundary Wa   | aters           |      | Voyageur | s               | Isle Royale |      |                 |  |  |  |
| Parameter               | Met Year | Base | BART         | Differ-<br>ence | Base | BART     | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |  |
| Days > 0.5 dv           | 2002     | 74   | 58           | -16             | 53   | 39       | -14             | 42          | 30   | -12             |  |  |  |
| 98th Percentile<br>∆ dv | 2002     | 2.5  | 1.9          | -0.6            | 2.2  | 1.7      | -0.5            | 1.4         | 1.0  | -0.4            |  |  |  |

#### Barr

## Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |                           |      |                 |      | Class I Are | ea              |      |      |                 |
|-----------------------------|----------|---------------------------|------|-----------------|------|-------------|-----------------|------|------|-----------------|
| $\mathbf{PM}_{2}$ .         | 5        | Boundary Waters Voyageurs |      |                 |      | Isle Royale |                 |      |      |                 |
| Parameter                   | Met Year | Base                      | BART | Differ-<br>ence | Base | BART        | Differ-<br>ence | Base | BART | Differ-<br>ence |
| <b>Days</b> > 0.5 dv        | 2002     | 74                        | 59   | -15             | 53   | 39          | -14             | 42   | 29   | -13             |
| 98th Percentile $\Delta dv$ | 2002     | 2.48                      | 1.90 | -0.58           | 2.18 | 1.65        | -0.53           | 1.44 | 1.06 | -0.38           |

## **Rochester Public Utilities (BART07)**

### MPCA

## Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |                           |      |                 |      | Class I Are | a               |             |      |                 |
|-----------------------------|----------|---------------------------|------|-----------------|------|-------------|-----------------|-------------|------|-----------------|
| $\mathbf{PM}_{2.}$          | 5        | Boundary Waters Voyageurs |      |                 |      |             |                 | Isle Royale |      |                 |
| Parameter                   | Met Year | Base                      | BART | Differ-<br>ence | Base | BART        | Differ-<br>ence | Base        | BART | Differ-<br>ence |
| Days > 0.5 dv               | 2002     | 0                         | 0    | 0               | 0    | 0           | 0               | 0           | 0    | 0               |
| 98th Percentile $\Delta dv$ | 2002     | 0.1                       | 0.1  | 0.0             | 0.1  | 0.0         | 0.0             | 0.1         | 0.0  | 0.0             |

Barr

## Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| PM <sub>2.5</sub>           |          |                 | Class I Area |                 |           |      |                 |             |      |                 |  |  |
|-----------------------------|----------|-----------------|--------------|-----------------|-----------|------|-----------------|-------------|------|-----------------|--|--|
|                             |          | Boundary Waters |              |                 | Voyageurs |      |                 | Isle Royale |      |                 |  |  |
| Parameter                   | Met Year | Base            | BART         | Differ-<br>ence | Base      | BART | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |
| Days > 0.5 dv               | 2002     | 0               | 0            | 0               | 0         | 0    | 0               | 0           | 0    | 0               |  |  |
| 98th Percentile $\Delta dv$ | 2002     | 0.10            | 0.06         | 0.04            | 0.08      | 0.04 | 0.04            | 0.09        | 0.04 | 0.05            |  |  |



# APPENDIX C: CAM<sub>X</sub> PSAT Source List

March 6, 2013

# 2009 MPCA Tracked, Elevated Point Sources

| RANKTRAC   | RECEPTOR      |                 |                                      |
|------------|---------------|-----------------|--------------------------------------|
| BARTSRC_ID | BARTSRC_ID    | Facility ID     | Facility Name [1]                    |
| 1          | 2             | 2703100001      | Minnesota Power - Taconite Harbor    |
| 2          | 3             | 2703700003      | XCEL - Black Dog                     |
| 3          | 4             | 2705300015      | XCEL - Riverside                     |
| 4          | 5             | 2706100004      | Minnesota Power - Boswell            |
| 5          | 6             | 2707500003      | Northshore Mining Co - Silver Bay    |
| 6          | 7             | 2709900001      | Austin Utilities - NE Power Station  |
| 7          | 8             | 2710900011      | Rochester Public Utilities           |
| 8          | 9             | 2711100002      | Otter Tail Power - Hoot Lake         |
| 9          | 10            | 2712300012      | XCEL - High Bridge                   |
| 10         | 11            | 2713700013      | Minnesota Power - Laskin             |
| 11         | 12            | 2713700027      | Hibbing Public Utilities             |
| 12         | 13            | 2713700028      | Virginia Dept of Public Utilities    |
| 13         | 14            | 2714100004      | XCEL - Sherburne Generating Plant    |
| 14         | 15            | 2716300005      | XCEL - Allen S. King                 |
| 15         | 16            | 2701700002      | Sappi - Cloquet                      |
| 16         | 17            | 2703700011      | Flint Hill Resources - Pine Bend     |
| 17         | 18            | 2706100001      | Blandin Paper / Rapids Energy        |
| 18         | 19            | 2707100002      | Boise Cascade - International Falls  |
| 19         | 20            | 2713700005      | US Steel - Minntac                   |
| 20         | 21            | 2713700015      | Minnesota Power - ML Hibbard         |
| 21         | 22            | 2713700022      | Duluth Steam Cooperative             |
| 22         | 23            | 2713700031      | Georgia Pacific - Duluth             |
| 23         | 24            | 2713700061      | Hibbing Taconite                     |
| 24         | 25            | 2713700062      | Arcelor Mittal                       |
| 25         | 26            | 2713700063      | US Steel - Keetac                    |
| 26         | 27            | 2713700113      | United Taconite - Fairlane Plant [2] |
| 27         | 28            | 2700900011      | International Paper - Sartell        |
| 28         | 29            | 2716300003      | Marathon Ashland Petroleum           |
| 29         | 30            | 2713700083      | Potlatch - Cook                      |
| 30         | 31            | 2706100010      | Potlatch - Grand Rapids              |
|            |               |                 |                                      |
|            | Included in M | IPCA BART SIP M | Iodeling Report                      |

|     | Included in MPCA BART SIP Modeling Report          |
|-----|--|
| [1] | MPCA tracked all point sources on a facility-basis |

[2] MPCA Emissions did not Include UTAC Line 1

# 2012/2013 Barr Tracked, Elevated Point Sources

| Output ID | BARTSRC ID | Facility ID | Facility / Unit Name [3]                      |
|-----------|------------|-------------|---|
| MNPWTH    | 2          | -           | Minnesota Power - Taconite Harbor             |
| XCELBD    | 3          | 2703700003  | XCEL - Black Dog                              |
| XCELRV    | 4          | 2705300015  | XCEL - Riverside                              |
| MNPWBO    | 5          | 2706100004  | Minnesota Power - Boswell                     |
| NSMSBU    | 6          | 2707500003  | Northshore Mining Co - Silver Bay (All Other) |
| AUSTIN    | 7          | 2709900001  | Austin Utilities - NE Power Station           |
| ROCHPU    | 8          | 2710900011  | Rochester Public Utilities                    |
| OTTRHL    | 9          | 2711100002  | Otter Tail Power - Hoot Lake                  |
| XCELHB    | 10         | 2712300012  | XCEL - High Bridge                            |
| MNPWLS    | 11         | 2713700013  | Minnesota Power - Laskin                      |
| HIBBPU    | 12         | 2713700027  | Hibbing Public Utilities                      |
| VIRGPU    | 13         | 2713700028  | Virginia Dept of Public Utilities             |
| XCELSB    | 14         | 2714100004  | XCEL - Sherburne Generating Plant             |
| XCELAK    | 15         | 2716300005  | XCEL - Allen S. King                          |
| SAPPIC    | 16         | 2701700002  | Sappi - Cloquet                               |
| FHRPNB    | 17         | 2703700011  | Flint Hill Resources - Pine Bend              |
| BLNPAP    | 18         | 2706100001  | Blandin Paper / Rapids Energy                 |
| BOISEC    | 19         | 2707100002  | Boise Cascade - International Falls           |
| MINNTC    | 20         | 2713700005  | US Steel - Minntac                            |
| MNPWHB    | 21         | 2713700015  | Minnesota Power - ML Hibbard                  |
| DULSTM    | 22         | 2713700022  | Duluth Steam Cooperative                      |
| GEOPAC    | 23         | 2713700031  | Georgia Pacific - Duluth                      |
| HIBTAC    | 24         | 2713700061  | Hibbing Taconite (All Other)                  |
| ARCELR    | 25         | 2713700062  | Arcelor Mittal (All Other)                    |
| KEETAC    | 26         | 2713700063  | US Steel - Keetac                             |
| UTACFP    | 27         | 2713700113  | United Taconite - Fairlane Plant (All Other)  |
| INTPAP    | 28         | 2700900011  | International Paper - Sartell                 |
| MARTHN    | 29         | 2716300003  | Marathon Ashland Petroleum                    |
| POTLTC    | 30         | 2713700083  | Potlatch - Cook                               |
| POTLTG    | 31         | 2706100010  | Potlatch - Grand Rapids                       |
| TILDEN    | 32         | 26103B4885  | Tilden Mining Company (All Other)             |
| NSMPB1    | 33         | 2707500003  | Northshore Mining - Power Boiler 1            |
| NSMPB2    | 34         | 2707500003  | Northshore Mining - Power Boiler 2            |
| NSMF11    | 35         | 2707500003  | Northshore Mining - Furnace 11                |
| NSMF12    | 36         | 2707500003  | Northshore Mining - Furnace 12                |
| UTACL1    | 37         | 2713700113  | United Taconite - Line 1                      |
| UTACL2    | 38         | 2713700113  | United Taconite - Line 2                      |
| ARCLN1    | 39         | 2713700062  | Arcelor Mittal - Line 1                       |
| HBTCF1    | 40         | 2713700061  | Hibbing Taconite - Line 1                     |
| HBTCF2    | 41         | 2713700061  | Hibbing Taconite - Line 2                     |
| HBTCF3    | 42         | 2713700061  | Hibbing Taconite - Line 3                     |
| TILDL1    | 43         | 26103B4885  | Tilden Mining - Line 1                        |

Included in Barr Output Evaluation

Barr tracked furnace stacks and other noted stacks on a unit-basis while all other stacks were included in the "All Other" stacks

[3]



# APPENDIX D: Summary of CAM<sub>x</sub> Elevated Point Source Emissions

March 6, 2013

# Summary of CAMx Elevated Point Source Emissions

|                           |                   |                    |           | Emissi         | ons      | Emiss   | sions   | Emission Reductions  |
|---------------------------|-------------------|--------------------|-----------|----------------|----------|---------|---------|----------------------|
|                           |                   |                    |           | Propose        | ed FIP   | Fina    | I FIP   | Baseline - Final FIP |
|                           |                   | Emission Unit      | Pollutant | Baseline       |          | FIP     |         |                      |
| Facility                  | ModID             | Description        |           | tons/yr        | Note(s)  | tons/yr | Note(s) | tons/yr              |
| Hibbing Taconite Company  | {3}               | Line 1             | NOx       | 2,497          | [1]      | 749     | [3]     | 1,748                |
|                           |                   |                    | SO2       | 202            | [2]      | 202     | [4]     | 0                    |
|                           | {4}               | Line 2             | NOx       | 2,144          | [1]      | 643     | [3]     | 1,500                |
|                           |                   |                    | SO2       | 180            | [2]      | 180     | [4]     | 0                    |
|                           | {5}               | Line 3             | NOx       | 2,247          | [1]      | 674     | [3]     | 1,573                |
|                           |                   |                    | SO2       | 188            | [2]      | 188     | [4]     | 0                    |
|                           | HTC               | BART Furnaces      | NOx       | 6,888          |          | 2,066   |         | 4,821                |
|                           |                   | Combined           | SO2       | 570            |          | 570     |         | 0                    |
| Northshore Mining Company |                   | Process Boiler 1/2 | NOx       | 41             | [5]      | 41      | [8]     | 0                    |
|                           |                   |                    | SO2       |                |          |         |         |                      |
|                           | {24}              | Furnace 11         | NOx       | 386            | [6]      | 116     | [9]     | 270                  |
|                           |                   |                    | SO2       | 38             | [7]      | 38      | [10]    | 0                    |
|                           | {25}              | Furnace 12         | NOx       | 378            | [6]      | 113     | [9]     | 264                  |
|                           |                   |                    | SO2       | 35             | [7]      | 35      | [10]    | 0                    |
|                           | <mark>NSM</mark>  | BART Furnaces      | NOx       | 764            |          | 229     |         | 535                  |
|                           |                   | Combined           | SO2       | 73             |          | 73      |         | 0                    |
| Tilden Mining Company     | {1}               | Boiler #1/2        | NOx       | 79             | [11]     | 79      | [16]    | 0                    |
|                           |                   |                    | SO2       | 0              | [12]     | 0       | [17]    | 0                    |
|                           | {3}               | Ore Dryer # 1      | NOx       | 15             | [13]     | 15      | [18]    | 0                    |
|                           |                   |                    | SO2       | 34             | [13]     | 34      | [19]    | 0                    |
|                           | {5}               | Furnace #1         | NOx       | 4,613          | [14]     | 1,384   | [20]    | 3,229                |
|                           |                   |                    | SO2       | 1,153          | [15]     | 231     | [21]    | 922                  |
|                           | TMC               | BART Furnace       | NOx       | 4,613          |          | 1,384   |         | 3,229                |
|                           |                   |                    | SO2       | 1,153          |          | 231     |         | 922                  |
| United Taconite           | {26}              | Line 1             | NOx       | 1,643          | [22][23] | 493     | [26]    | 1,150                |
|                           |                   |                    | SO2       | 1,293          | [25]     | 577     | [27]    | 716                  |
|                           | {24}              | Line 2             | NOx       | 3,687          | [22][24] | 1,106   | [26]    | 2,581                |
|                           |                   |                    | SO2       | 2,750          | [25]     | 1,392   | [27]    | 1,357                |
|                           | UTAC              | BART Furnaces      | NOx       | 5 <i>,</i> 330 |          | 1,599   |         | 3,731                |
|                           |                   | Combined           | SO2       | 4,043          |          | 1,969   |         | 2,074                |
| Arcelor Mittal            | ARC               | Line 1             | NOx       | <u>3,639</u>   | [28]     | 1,092   | [30]    | 2,547                |
|                           | <mark>{12}</mark> |                    | SO2       | 179            | [29]     | 179     | [31]    | 0                    |

| TOTAL BART | NOx | 21,233 | ( | 6,370 | 14,863 |
|------------|-----|--------|---|-------|--------|
| Furnaces   | SO2 | 6,018  | 3 | 3,022 | 2,996  |

Fac

Facility Furnace Unit Summary or Overall Summary

FIP Baseline does not match reference

#### Notes:

- [1] HTC Line 1-3 USEPA FIP NOx Baseline Emissions Proposed FIP Table V B.24
- [2] HTC Line 1-3 USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V B.27
- [3] HTC Line 1-3 USEPA Proposed FIP NOx = 70% control from Baseline Table V B.24; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
- [4] HTC Line 1-3 USEPA Final FIP no additional SO2 control (Final FIP = Baseline Emissions)
- [5] NSM Process Boilers 1&2 NOx Emissions from Proposed FIP Table V B.12 (p49318)
- [6] NSM Furnace 11/12 NOx Emissions from Proposed FIP Table V B.8
- [7] NSM Furnace 11/12 SO2 Baseline FIP Emission Rate from Proposed FIP Table V B.10
- [8] NSM Process Boilers #1 and #2 USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) No additional control.
- [9] NSM Furnace 11/12 USEPA Proposed FIP NOx = 70% control from Baseline Table V B.8; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
- [10] NSM Furnace 11/12 no Additional SO2 Control Applied by Proposed or Final FIP (Final FIP = Baseline Emissions)
- [11] Tilden Process Boilers 1 & 2 NOx Baseline Emissions Proposed FIP Table V B.38
- [12] Tilden Process Boilers 1 & 2 SO2 Baseline Emissions Proposed FIP Table V B.37 (0.25 TPY)
- [13] Tilden Dryer #1 Emissions from Proposed FIP Table V B.39 (SO2) and Table V B.40 (NOx) 34.07 TPY SO2, 15.1 TPY NOx
- [14] Tilden Furnace 1 NO2 Baseline Proposed FIP Table V B.34
- [15] Tilden Furnace 1 SO2 Baseline Proposed FIP Projected SO2 Emission Reductions Table V-B.36; Baseline Emissions Back-calculated from 90% control
- [16] Tilden Process Boilers 1 & 2 No additional NOx control (Final FIP = Baseline Emissions)
- [17] Tilden Process Boilers 1 & 2 USEPA Final BART limit of 1.2%S in fuel No additional SO2 control (Final FIP = Baseline Emissions)
- [18] Tilden Ore Dryer #1 No additional NOx control (Final FIP = Baseline Emissions)
- [19] Tilden Ore Dryer #1 USEPA Final BART limit of 1.5%S in fuel No additional SO2 control (Final FIP = Baseline Emissions)
- [20] Tilden Furnace 1 USEPA Proposed FIP NOx = 70% control from Baseline Table V B.34; Final FIP (1.2 or 1.5 lb/MMBTU) NOx emissions referenced in final FIP text at 65% control from baseline (page 8721); but that is not consistent with the remaining facilities Modeled emissions assumed 70% control to provide maximum emission reductions
- [21] Tilden USEPA Final BART restriction Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs; SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
- [22] UTAC USEPA FIP NOx Baseline Emissions Proposed FIP Table V B.14
- [23] UTAC Line 1 NOx Permit limit specified in permit 13700113-005 1,655 TPY, issued 8/19/2010, page A-49 (reference from USEPA 114 Request Question 6)
- [24] UTAC Line 2 NOx Permit limit specified in permit 13700113-005 3,692 TPY, issued 8/19/2010, page A-56 (reference from USEPA 114 Request Question 6)
- [25] UTAC Line 1&2 USEPA proposed FIP Baseline SO2 Emissions Table V B.17; 90% Control in Table, 95% Control within text Proposed FIP (page 49319) Modeled baseline emissions back-calculated from 90% Control; SO2 Reductions match Table V - C.13 in Proposed FIP
- [26] UTAC Line 1&2 USEAP Proposed FIP NOx = 70% Control from Baseline Table V B.14; Final FIP (1.2 or 1.5 lb/MMBTU) Modeled emissions assumed 70% control to provide maximum emission reductions
- [27] UTAC Line 1&2 USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr Line 1 & 374 lb/hr Line 2) 30-day rolling average. Modeled Final FIP emissions used the limits and 85% operating factor to calculate the annual emissions (designed to maximize reductions)
- [28] Arcelor Line 1 USEPA proposed FIP Baseline NOx Emissions Table V B.19
- [29] Arcelor Line 1 USEPA proposed FIP Baseline SO2 Emissions Table V B.21
- [30] Arcelor Line 1 Proposed FIP NOx = 70% Control from Baseline Table V B.19; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
- [31] Arcelor Line 1 USEPA Final FIP no additional SO2 control (Final FIP = Baseline Emissions)



# APPENDIX E: Electronic Mail Requests - Proposed and Final FIP Emission Clarifications

From:Jeffry D. BennettSent:Thursday, January 31, 2013 7:42 PMTo:'Rosenthal.steven@Epa.gov'Cc:'Long, Michael E'Subject:Clarification Regarding Emissions within the Final Taconite BART FIPAttachments:EPA\_FIP\_Emission\_Summary\_01292013.xls

Steve,

Pursuant to our conversation last week regarding the baseline and controlled emission inventories within the proposed and final BART FIP for taconite furnaces, this e-mail is designed to request clarification regarding certain information contained in the rule. To that end, attached you will find a spreadsheet that summarizes and documents (to the maximum extent possible) the emission inventory data within the FIP rulemakings.

Specifically at this time, we are requesting:

(1) verification of the UTAC baseline NOx information for Line 1 and Line 2 ('Summary' Tab, Cells E30 and E32),

(2) clarification of the differences between the information contained in Columns H and I of the spreadsheet, Column H contains the difference between the FIP baseline and proposed FIP control emissions and was calculated from information within Table V-B.xx\* - NOx or SO2 facility specific emission data. The Column I information contains the emission reductions obtained from Table V-C.yy visibility improvement estimate tables. For each facility, these two columns should match, but the NOx information does not. Ultimately, the bases for Table V-C.yy data is the component that is missing.

\*Note: for Hibbing Taconite Line 1, a typographical error was discovered in Table V-B.24 and corrected in the spreadsheet.

(3) EPA's estimates of final FIP emissions on a tons/year basis with the corresponding emission reductions (i.e. FIP baseline – final FIP control) expected by EPA. This information would replace the "?" in Columns L and M of the spreadsheet. Along with the estimates, documentation of their bases would be extremely beneficial. For example, NOx could include either a % reduction from baseline or MMBTU/hour, Hours/year, and the appropriate lb NOx/MMBTU limit.

If you have any questions regarding these requests, feel free to contact Mike Long or myself. Thank you for your time.

Jeffry D. Bennett, PE Senior Air Quality Engineer Jefferson City office: 573.638.5033 cell: 573.694.0674 JBennett@barr.com www.barr.com From: Jeffry D. Bennett
Sent: Thursday, February 14, 2013 12:02 PM
To: 'Robinson.randall@Epa.gov'
Subject: FW: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: EPA\_FIP\_Emission\_Summary\_01292013.xls

#### Randy,

I talked with Steve Rosenthal yesterday about the taconite BART FIP emissions (see e-mail below). He told me that you "wrote the section on visibility improvement" and suggested I contact you about item 2 and a portion of the information requested in item 3. Barr Engineering is contracted with Cliffs Natural Resources and Arcelor Mittal to provide their taconite facilities with technical support regarding the FIP. At this point, we are trying to summarize and document the bases for the SO2 and NOx emissions that were used in the EPA baseline, the proposed FIP, and the final FIP for all their facilities.

The attached spreadsheet that I sent Steve previously includes the summary. Item 2 is related to differences between the NOx emission reductions used in the ratio visibility improvement calculations in the proposed FIP (Table V – C.yy) and the emission reductions in Table V – B.xx for each facility. Steve thought you would have the information about the basis for the Table V – C.yy reductions.

Item 3 is requesting information about the final FIP emission reductions. Specifically, you would probably have information regarding the emissions for Tilden Mining and United Taconite (UTAC) from the CALPUFF modeling completed by Trent Wickman referenced in the final FIP rulemaking docket. Please give me a call to discuss this at your earliest convenience. We are attempting to finalize the summary by COB tomorrow. Thanks for any help you can provide.

Jeffry D. Bennett, PE Senior Air Quality Engineer Jefferson City office: 573.638.5033 cell: 573.694.0674 JBennett@barr.com www.barr.com



resourceful. naturally. engineering and environmental consultants

# APPENDIX F: CAMx Modeling Results by Facility

March 6, 2013

### Arcelor Mittal CAMx Emissions and Modeling Results

#### **Arcelor Emissions**

| Unit   | EPA FIP   | Final FIP | NOx        | EPA FIP   | Final FIP | SO2        |
|--------|-----------|-----------|------------|-----------|-----------|------------|
|        | Baseline  | NOx       | Emission   | Baseline  | SO2       | Emission   |
|        | NOx       | Emission  | Difference | SO2       | Emission  | Difference |
|        | Emission  | (TPY) [1] | (TPY)      | Emission  | (TPY)[3]  | (TPY)      |
|        | (TPY) [1] |           |            | (TPY) [2] |           |            |
| Line 1 | 3,639     | 1,092     | 2,547      | 179       | 179       | 0          |
|        |           |           |            |           |           |            |
| TOTAL  | 3,639     | 1,092     | 2,547      | 179       | 179       | 0          |

[1] FIP Baseline and Control NOx Emissions from EPA Proposed FIP Table V-B.19 – Projected Annual NOx Emission Reductions [TPY].

[2] FIP Baseline SO2 Emissions are from EPA Proposed FIP Table V-B.21 – Annual SO2 Emissions [TPY]

[3] No SO2 emission reductions in Final FIP (i.e. EPA Baseline = Final FIP control)

| Class I Area     | EPA FIP       | EPA FIP  | Proposed   | Proposed   | Difference | Difference |
|------------------|---------------|----------|------------|------------|------------|------------|
|                  | Baseline Days | Baseline | FIP Days > | FIP 98% dV | Days >0.5  | 98% dV [5] |
|                  | >0.5 dV       | 98% dV   | 0.5 dV     |            | dV [5]     | 00/00.000  |
| Boundary Waters  |               | 00,00    |            |            |            |            |
| 2002             |               |          |            |            |            |            |
| Line #1          | 30            | 0.789    | 18         | 0.713      | 12         | 0.076      |
| Facility Total   | 43            | 0.99     | 35         | 0.96       | 8          | 0.03       |
| 2005             |               |          |            |            |            |            |
| Line #1          | 7             | 0.491    | 3          | 0.326      | 4          | 0.165      |
| Facility Total   | 19            | 0.74     | 8          | 0.55       | 11         | 0.19       |
| <u>Voyageurs</u> |               |          |            |            |            |            |
| 2002             |               |          |            |            |            |            |
| Line #1          | 1             | 0.287    | 0          | 0.202      | 1          | 0.085      |
| Facility Total   | 1             | 0.34     | 0          | 0.22       | 1          | 0.12       |
| 2005             |               |          |            |            |            |            |
| Line #1          | 0             | 0.182    | 0          | 0.122      | 0          | 0.060      |
| Facility Total   | 0             | 0.22     | 0          | 0.16       | 0          | 0.06       |
| Isle Royale      |               |          |            |            |            |            |
| 2002             |               |          |            |            |            |            |
| Line #1          | 0             | 0.075    | 0          | 0.053      | 0          | 0.022      |
| Facility Total   | 0             | 0.09     | 0          | 0.06       | 0          | 0.03       |
| 2005             |               |          |            |            |            |            |
| Line #1          | 0             | 0.049    | 0          | 0.033      | 0          | 0.016      |
| Facility Total   | 0             | 0.06     | 0          | 0.04       | 0          | 0.02       |

[4] Visibility benchmarks:

<u>0.5 dV impact</u> is the BART eligibility threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required),

<u>1.0 dV difference</u> is the presumed human perceptible level for visibility improvement, and <u>0.1 dV difference</u> was defined by other agencies as the degree of visibility improvement that is too low to justify additional emission controls. Also, EPA's Regional Haze Rule mentions that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

[5] These two columns provide the difference in predicted days >0.5 dV and 98<sup>th</sup> percentile visibility improvement from the baseline to the FIP control emissions. The annual average number of days with > 0.5 dV improvement at all the Class I areas is considerably less than EPA's estimate (11 to 53). Also, the averages of the 98<sup>th</sup> percentile differences are **10 to 37 times less** than the predicted improvement by EPA. Note: the table below formed the basis for EPA's inclusion of control necessary at Arcelor Mittal.

#### Arcelor Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

| (EPA Table B Emission Difference – 2,547 TPT NOX)[7] |                             |            |  |                 |              |  |  |  |
|--|-----------------------------|------------|--|-----------------|--------------|--|--|--|
| Class I Area   | EPA Estimated EPA Estimated |            |  | CAMx Modeled    | CAMx Modeled |  |  |  |
|  | Difference Days             | Difference |  | Difference Days | Difference   |  |  |  |
|  | >0.5 dV                     | 98% dV     |  | >0.5 dV[8]      | 98% dV       |  |  |  |
| Boundary Waters                                      | 24                          | 1.7        |  | 10              | 0.11         |  |  |  |
|  |                             |            |  |                 |              |  |  |  |
| Voyageurs  | 11                          | 0.9        |  | 1               | 0.09         |  |  |  |
|  |                             |            |  |                 |              |  |  |  |
| Isle Royale  | 18                          | 1.1        |  | 0               | 0.03         |  |  |  |

(EPA Table C Emission Difference = 2,859 TPY NOx)[6] (EPA Table B Emission Difference = 2,547 TPY NOx)[7]

[6] Emission Difference Obtained from EPA Proposed FIP Table V-C.10 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Arcelor Mittal.

[7] Emission Difference Obtained from EPA Proposed FIP Table V-B.19.

[8] The number of days with visibility >0.5 deciviews (dV) can be a misleading indicator as illustrated by the Arcelor Mittal and Northshore Mining results (below). The 98<sup>th</sup> percentile visibility improvement at Boundary Waters during the 2002 modeled year was 0.03 dV. However, the modeling predicts this insignificant change will result in eight more days of "good visibility", defined as days with visibility at or below the 0.5 deciview threshold. Further, the Northshore Mining results at Isle Royale indicate a miniscule 0.01 deciviews, or one hundred times less than a perceptible improvement to visibility. Nonetheless, the modeling predicts this insignificant change will result in two more days of "good visibility". In both circumstances, this does not mean that the visibility change was discernible. The model gives credit for an improved day when the predicted impairment falls from 0.51 to 0.50 deciviews, but that improvement is illusory because at 0.51 deciviews people do not perceive a regional haze problem. The difference in visibility from natural background when evaluating the baseline could have several days near the 0.5 dV "contribute to visibility degradation" threshold, but well less than the 1 dV "cause visibility degradation" threshold. Then, a very small change in visibility from the baseline to the controlled emission scenario (~0.01 – 0.1 dV) could cause a large number of days to be less than the 0.5 dV benchmark without producing any real benefit to visibility.

# Hibbing Taconite (HibTac) CAMx Emissions and Modeling Results

#### **HibTac Emissions**

| Unit   | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|--------|----------|-----------|------------|----------|-----------|------------|
|        | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|        | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|        | Emission | (TPY)     | (TPY)      | Emission | (TPY)     | (TPY)      |
|        | (TPY)    |           |            | (TPY)    |           |            |
| Line 1 | 2,497    | 749       | 1,748      | 202      | 202       | 0          |
| Line 2 | 2,144    | 643       | 1,500      | 180      | 180       | 0          |
| Line 3 | 2,247    | 674       | 1,573      | 188      | 188       | 0          |
|        |          |           |            |          |           |            |
| TOTAL  | 6,888    | 2,066     | 4,822      | 570      | 570       | 0          |

#### HibTac CAMx Results (By Unit)

| Class I Area           | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|------------------------|---------------|----------|-----------|-----------|------------|------------|
|                        | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Boundary Waters</u> |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line 1                 | 1             | 0.337    | 1         | 0.305     | 0          | 0.032      |
| Line 2                 | 2             | 0.287    | 0         | 0.260     | 2          | 0.027      |
| Line 3                 | 1             | 0.318    | 0         | 0.245     | 2          | 0.073      |
| Facility Total         | 33            | 1.10     | 22        | 0.96      | 11         | 0.14       |
| 2005                   |               |          |           |           |            |            |
| Line 1                 | 0             | 0.217    | 0         | 0.158     | 0          | 0.057      |
| Line 2                 | 0             | 0.203    | 0         | 0.124     | 0          | 0.079      |
| Line 3                 | 0             | 0.223    | 0         | 0.140     | 0          | 0.083      |
| Facility Total         | 14            | 0.85     | 11        | 0.62      | 3          | 0.23       |
| <u>Voyageurs</u>       |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line 1                 | 0             | 0.197    | 0         | 0.168     | 0          | 0.029      |
| Line 2                 | 0             | 0.197    | 0         | 0.159     | 0          | 0.038      |
| Line 3                 | 0             | 0.211    | 0         | 0.163     | 0          | 0.048      |
| Facility Total         | 18            | 0.67     | 10        | 0.61      | 8          | 0.06       |
| 2005                   |               |          |           |           |            |            |
| Line 1                 | 0             | 0.126    | 0         | 0.102     | 0          | 0.024      |
| Line 2                 | 0             | 0.122    | 0         | 0.085     | 0          | 0.037      |
| Line 3                 | 0             | 0.133    | 0         | 0.103     | 0          | 0.030      |
| Facility Total         | 8             | 0.51     | 5         | 0.36      | 3          | 0.15       |

| Class I Area       | EPA FIP              | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|--------------------|----------------------|----------|-----------|-----------|------------|------------|
|                    | <b>Baseline Days</b> | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                    | >0.5 dV              | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Isle Royale</u> |                      |          |           |           |            |            |
| 2002               |                      |          |           |           |            |            |
| Line 1             | 0                    | 0.053    | 0         | 0.047     | 0          | 0.006      |
| Line 2             | 0                    | 0.045    | 0         | 0.036     | 0          | 0.009      |
| Line 3             | 0                    | 0.046    | 0         | 0.037     | 0          | 0.009      |
| Facility Total     | 0                    | 0.16     | 0         | 0.13      | 0          | 0.03       |
|                    |                      |          |           |           |            |            |
| 2005               |                      |          |           |           |            |            |
| Line 1             | 0                    | 0.038    | 0         | 0.027     | 0          | 0.011      |
| Line 2             | 0                    | 0.034    | 0         | 0.022     | 0          | 0.012      |
| Line 3             | 0                    | 0.037    | 0         | 0.026     | 0          | 0.011      |
| Facility Total     | 0                    | 0.13     | 0         | 0.09      | 0          | 0.04       |

#### HibTac Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 5,259 TPY NOx)[8] (EPA Table B Emission Difference = 4,822 TPY NOx)[9]

| 1217110010 2 211100 | (               |               |  |                 |              |  |  |  |  |
|---------------------|-----------------|---------------|--|-----------------|--------------|--|--|--|--|
| Class I Area        | EPA Estimated   | EPA Estimated |  | CAMx Modeled    | CAMx Modeled |  |  |  |  |
|                     | Difference Days | Difference    |  | Difference Days | Difference   |  |  |  |  |
|                     | >0.5 dV         | 98% dV        |  | >0.5 dV         | 98% dV       |  |  |  |  |
| Boundary Waters     | 44              | 3.2           |  | 7               | 0.19         |  |  |  |  |
|                     |                 |               |  |                 |              |  |  |  |  |
| Voyageurs           | 21              | 1.7           |  | 5               | 0.11         |  |  |  |  |
|                     |                 |               |  |                 |              |  |  |  |  |
| Isle Royale         | 26              | 2.1           |  | 0               | 0.04         |  |  |  |  |

[8] Emission Difference Obtained from EPA Proposed FIP Table V-C.11 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Hibbing Taconite.

[9] Emission Difference Obtained from EPA Proposed FIP Table V-B.24.

# Northshore Mining CAMx Emissions and Modeling Results

#### Northshore Emissions

| Unit            | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|-----------------|----------|-----------|------------|----------|-----------|------------|
|                 | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|                 | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|                 | Emission | (TPY)     | (TPY)      | Emission | (TPY)     | (TPY)      |
|                 | (TPY)    |           |            | (TPY)    |           |            |
| Power Boiler #1 | 676      | 676       | 0          | 681      | 681       | 0          |
| Power Boiler #2 | 1,093    | 1,093     | 0          | 1,098    | 1,098     | 0          |
| Furnace 11      | 386      | 116       | 270        | 38       | 38        | 0          |
| Furnace 12      | 378      | 113       | 265        | 35       | 35        | 0          |
|                 |          |           |            |          |           |            |
| FURNACES        | 764      | 229       | 535        | 73       | 73        | 0          |
| TOTAL           | 2,533    | 1,998     | 535        | 1,852    | 1,852     | 0          |

#### Northshore CAMx Results (By Unit)

| NOT LISTORE CAN        | x Results (by O |          |           |           |            |            |
|------------------------|-----------------|----------|-----------|-----------|------------|------------|
| Class I Area           | EPA FIP         | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|                        | Baseline Days   | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV         | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Boundary Waters</u> |                 |          |           |           |            |            |
| 2002                   |                 |          |           |           |            |            |
| Power Boiler #1        | 32              | 1.487    | 32        | 1.499     | 0          | -0.012     |
| Power Boiler #2        | 49              | 2.087    | 49        | 2.097     | 0          | -0.010     |
| Furnace 11             | 0               | 0.136    | 0         | 0.139     | 0          | -0.003     |
| Furnace 12             | 0               | 0.133    | 0         | 0.122     | 0          | 0.011      |
| Facility Total         | 73              | 4.16     | 72        | 4.14      | 1          | 0.02       |
|                        |                 |          |           |           |            |            |
| 2005                   |                 |          |           |           |            |            |
| Power Boiler #1        | 13              | 0.640    | 13        | 0.654     | 0          | -0.014     |
| Power Boiler #2        | 22              | 0.926    | 23        | 0.911     | 0          | 0.015      |
| Furnace 11             | 0               | 0.087    | 0         | 0.067     | 0          | 0.020      |
| Furnace 12             | 0               | 0.082    | 0         | 0.076     | 0          | 0.006      |
| Facility Total         | 51              | 1.67     | 50        | 1.68      | 1          | -0.01      |
| Voyageurs              |                 |          |           |           |            |            |
| 2002                   |                 |          |           |           |            |            |
| Power Boiler #1        | 1               | 0.196    | 1         | 0.196     | 0          | 0.000      |
| Power Boiler #2        | 1               | 0.293    | 1         | 0.293     | 0          | 0.000      |
| Furnace 11             | 0               | 0.016    | 0         | 0.013     | 0          | 0.003      |
| Furnace 12             | 0               | 0.015    | 0         | 0.013     | 0          | 0.002      |
| Facility Total         | 8               | 0.51     | 8         | 0.51      | 0          | 0.00       |

| Class I Area            | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|-------------------------|---------------|----------|-----------|-----------|------------|------------|
|                         | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                         | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Voyageurs</u>        |               |          |           |           |            |            |
| 2005                    |               |          |           |           |            |            |
| Power Boiler #1         | 0             | 0.188    | 0         | 0.193     | 0          | -0.005     |
| Power Boiler #2         | 1             | 0.244    | 1         | 0.247     | 0          | -0.003     |
| Furnace 11              | 0             | 0.020    | 0         | 0.018     | 0          | 0.002      |
| Furnace 12              | 0             | 0.021    | 0         | 0.016     | 0          | 0.004      |
| Facility Total          | 6             | 0.47     | 6         | 0.46      | 0          | 0.01       |
| Ida Davala              |               |          |           |           |            |            |
| Isle Royale             |               |          |           |           |            |            |
| 2002<br>Power Boiler #1 | 3             | 0.204    | 2         | 0.204     | 0          | 0.000      |
|                         |               | 0.294    | 3         | 0.294     | 0          | 0.000      |
| Power Boiler #2         | 6             | 0.412    | 6         | 0.408     | 0          | 0.004      |
| Furnace 11              | 0             | 0.034    | 0         | 0.028     | 0          | 0.006      |
| Furnace 12              | 0             | 0.037    | 0         | 0.029     | 0          | 0.008      |
| Facility Total          | 16            | 0.75     | 15        | 0.74      | 1          | 0.00       |
|                         |               |          |           |           |            |            |
| 2005                    |               |          |           |           |            |            |
| Power Boiler #1         | 3             | 0.180    | 3         | 0.180     | 0          | 0.000      |
| Power Boiler #2         | 4             | 0.320    | 4         | 0.322     | 0          | -0.002     |
| Furnace 11              | 0             | 0.036    | 0         | 0.023     | 0          | 0.013      |
| Furnace 12              | 0             | 0.034    | 0         | 0.022     | 0          | 0.012      |
| Facility Total          | 10            | 0.57     | 8         | 0.55      | 2          | 0.02       |

#### Northshore Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 926 TPY NOx)[10] (EPA Table B Emission Difference = 535 TPY NOx)[11]

| Class I Area           | EPA Estimated   | EPA Estimated |            | CAMx Modeled | CAMx Modeled |  |  |  |
|------------------------|-----------------|---------------|------------|--------------|--------------|--|--|--|
|                        | Difference Days | Difference    | Difference |              | Difference   |  |  |  |
|                        | >0.5 dV         | 98% dV        |            | >0.5 dV      | 98% dV       |  |  |  |
| <b>Boundary Waters</b> | 8               | 0.6           |            | 1            | 0.01         |  |  |  |
|                        |                 |               |            |              |              |  |  |  |
| Voyageurs              | 4               | 0.3           |            | 0            | 0.01         |  |  |  |
|                        |                 |               |            |              |              |  |  |  |
| Isle Royale            | 5               | 0.4           |            | 2            | 0.01         |  |  |  |

[10]Emission Difference Obtained from EPA Proposed FIP Table V-C.12 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Northshore Mining.

[11]Emission Difference Obtained from EPA Proposed FIP Table V-B.8; further the emission reductions in Table C exceed the FIP baseline in Table B by 142 TPY.

### United Taconite (UTAC) CAMx Emissions and Modeling Results

#### **UTAC Emissions**

| Unit   | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|--------|----------|-----------|------------|----------|-----------|------------|
|        | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|        | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|        | Emission | (TPY)     | (TPY)[12]  | Emission | (TPY)[13] | (TPY)      |
|        | (TPY)    |           |            | (TPY)    |           |            |
| Line 1 | 1,643    | 493       | 1,150      | 1,293    | 577       | 716        |
| Line 2 | 3,687    | 1,106     | 2,581      | 2,750    | 1,392     | 1,358      |
|        |          |           |            |          |           |            |
| TOTAL  | 5,330    | 1,599     | 3,731      | 4,043    | 1,969     | 2,074      |

[12]NOx emission difference was calculated using 70% emission reduction from EPA Baseline within the proposed FIP (corresponding to 1.2 lb NOx/MMBTU); to ensure maximum emission reductions were evaluated there was no change to the final FIP emissions to reflect the final FIP limit of 1.5 lb NOx/MMBTU.

[13]Final FIP SO2 Emissions were calculated using the final FIP limit of 529 lb/hr with an operating factor of 85%; this was done to maximize the emission reductions while using a reasonable operating factor

| OTAC CANA RESU         |               |          | 1         |           |            |            |
|------------------------|---------------|----------|-----------|-----------|------------|------------|
| Class I Area           | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|                        | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b> |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line #1                | 22            | 1.294    | 10        | 0.674     | 12         | 0.620      |
| Line #2                | 45            | 2.744    | 30        | 1.556     | 15         | 1.189      |
| Facility Total         | 76            | 4.22     | 55        | 2.37      | 21         | 1.85       |
|                        |               |          |           |           |            |            |
| 2005                   |               |          |           |           |            |            |
| Line #1                | 11            | 0.610    | 2         | 0.303     | 9          | 0.307      |
| Line #2                | 26            | 1.294    | 15        | 0.678     | 11         | 0.616      |
| Facility Total         | 52            | 2.52     | 34        | 1.57      | 18         | 0.95       |
| Voyageurs              |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line #1                | 12            | 0.606    | 2         | 0.307     | 10         | 0.299      |
| Line #2                | 26            | 1.452    | 15        | 0.771     | 11         | 0.681      |
| Facility Total         | 42            | 2.10     | 26        | 1.11      | 16         | 0.99       |
|                        |               |          |           |           |            |            |
| 2005                   |               |          |           |           |            |            |
| Line #1                | 4             | 0.331    | 1         | 0.181     | 3          | 0.150      |
| Line #2                | 17            | 0.786    | 6         | 0.446     | 11         | 0.340      |
| Facility Total         | 33            | 1.47     | 14        | 0.76      | 19         | 0.71       |

#### UTAC CAMx Results (By Unit)

| Class I Area       | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|--------------------|---------------|----------|-----------|-----------|------------|------------|
|                    | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                    | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Isle Royale</u> |               |          |           |           |            |            |
| 2002               |               |          |           |           |            |            |
| Line #1            | 0             | 0.255    | 0         | 0.117     | 0          | 0.138      |
| Line #2            | 8             | 0.518    | 0         | 0.266     | 8          | 0.252      |
| Facility Total     | 13            | 0.81     | 3         | 0.41      | 10         | 0.40       |
|                    |               |          |           |           |            |            |
| 2005               |               |          |           |           |            |            |
| Line #1            | 0             | 0.163    | 0         | 0.080     | 0          | 0.083      |
| Line #2            | 1             | 0.322    | 0         | 0.184     | 1          | 0.138      |
| Facility Total     | 10            | 0.57     | 0         | 0.28      | 10         | 0.29       |

#### UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 3,208 TPY NOx and 3,639 TPY SO2)[14] (EPA Table B Emission Difference = 3,731 TPY NOx and 3,639 TPY SO2)[15]

| Class I Area    | EPA Estimated   | EPA Estimated  |  | CAMx Modeled    | CAMx Modeled |  |  |  |
|-----------------|-----------------|----------------|--|-----------------|--------------|--|--|--|
|                 | Difference Days | lys Difference |  | Difference Days | Difference   |  |  |  |
|                 | >0.5 dV         | 98% dV         |  | >0.5 dV[16]     | 98% dV[16]   |  |  |  |
| Boundary Waters | 29              | 1.9            |  | 20              | 1.40         |  |  |  |
|                 |                 |                |  |                 |              |  |  |  |
| Voyageurs       | 12              | 0.99           |  | 18              | 0.85         |  |  |  |
|                 |                 |                |  |                 |              |  |  |  |
| Isle Royale     | 14              | 1.16           |  | 10              | 0.35         |  |  |  |

[14]Emission Difference Obtained from EPA Proposed FIP Table V-C.13 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for United Taconite.

[15]Emission Difference Obtained from EPA Proposed FIP Table V-B.14 (SO2) and V-B.17 (NOx) – NOx reductions are not consistent

[16]Baseline – final FIP Emission Reductions -> 3,731 TPY NOx and 2,074 TPY SO2

The United Taconite comparison table above does not provide an "apples to apples" comparison. As noted, the EPA estimated visibility benefits include more SO2 emission reductions (proposed FIP) than are included in the final FIP. This table was amended to include the revised SO2 emission reductions using EPA's apparent methodology within the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NOx and the revised emission reduction for SO2. Then, those resultants were averaged for each of the Class I areas to obtain the amended EPA estimates below to provide for the appropriate comparison of EPA's method.

| Amended UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with |
|---|
| CAMx Modeling Analyses  |

| Class I Area    | EPA Estimated   | EPA Estimated |  | CAMx Modeled    | CAMx Modeled |  |  |
|-----------------|-----------------|---------------|--|-----------------|--------------|--|--|
|                 | Difference Days | Difference    |  | Difference Days | Difference   |  |  |
|                 | >0.5 dV         | 98% dV        |  | >0.5 dV         | 98% dV       |  |  |
| Boundary Waters | 22              | 1.6           |  | 20              | 1.40         |  |  |
|                 |                 |               |  |                 |              |  |  |
| Voyageurs       | 10              | 0.8           |  | 18              | 0.85         |  |  |
|                 |                 |               |  |                 |              |  |  |
| Isle Royale     | 14              | 1.1           |  | 10              | 0.35         |  |  |

Final FIP Emission Difference = 3,731 TPY NOx and 2,074 TPY SO2

As discussed above, the SO4 and NO3 visibility benefits were combined by EPA. The following tables provide a modeled comparison of the impacts sorted by SO4 and NO3 on a line-specific basis, then combined for both lines. The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall UTAC impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO<sub>x</sub> control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.15 dV; total = 0.20 dV) and would not show up as part of the overall visibility change (see Line 2 – 2002 Boundary Waters results).

| Class I Area                   | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|--------------------------------|---------------|----------|-----------|-----------|------------|------------|
|                                | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                                | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b>         |               |          |           |           |            |            |
| 2002                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.106    | 0         | 0.059     | 0          | 0.047      |
| Line #1 – SO4                  | 22            | 1.294    | 10        | 0.674     | 12         | 0.620      |
| Line #1 – All                  | 22            | 1.294    | 10        | 0.674     | 12         | 0.620      |
|                                |               |          |           |           |            |            |
| 2005                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.136    | 0         | 0.083     | 0          | 0.053      |
| Line #1 – SO4                  | 8             | 0.571    | 2         | 0.280     | 6          | 0.291      |
| Line #1 – All                  | 11            | 0.610    | 2         | 0.303     | 9          | 0.307      |
| Voyageurs                      |               |          |           |           |            |            |
| 2002                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.040    | 0         | 0.017     | 0          | 0.023      |
| Line #1 – SO4                  | 11            | 0.582    | 2         | 0.301     | 9          | 0.281      |
| Line #1 – All                  | 12            | 0.606    | 2         | 0.307     | 10         | 0.299      |
|                                |               |          |           |           |            |            |
| 2005                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.048    | 0         | 0.027     | 0          | 0.021      |
| Line #1 – SO4                  | 4             | 0.330    | 1         | 0.155     | 3          | 0.175      |
| Line #1 – All                  | 4             | 0.331    | 1         | 0.181     | 3          | 0.150      |
| Isle Royale                    |               |          |           |           |            |            |
| 2002                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.033    | 0         | 0.015     | 0          | 0.018      |
| Line #1 – SO4                  | 0             | 0.216    | 0         | 0.104     | 0          | 0.112      |
| Line #1 – All                  | 0             | 0.255    | 0         | 0.117     | 0          | 0.138      |
| 2005                           |               |          |           |           |            |            |
| <b>2005</b><br>Line #1 – NO3   | 0             | 0.026    | 0         | 0.011     | 0          | 0.015      |
| Line #1 – NO3                  | 0             | 0.026    | 0         | 0.011     | 0          | 0.015      |
| Line #1 – SO4<br>Line #1 – All | 0             |          |           |           |            |            |
| Line #1 – All                  | U             | 0.163    | 0         | 0.080     | 0          | 0.083      |

UTAC Line 1 – Pollutant Specific Modeling Results

| Class I Area           | EPA FIP              | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|------------------------|----------------------|----------|-----------|-----------|------------|------------|
|                        | <b>Baseline Days</b> | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV              | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b> |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 1                    | 0.237    | 0         | 0.090     | 1          | 0.147      |
| Line #2 – SO4          | 44                   | 2.679    | 28        | 1.547     | 16         | 1.132      |
| Line #2 – All          | 45                   | 2.744    | 30        | 1.556     | 15         | 1.189      |
|                        |                      |          |           |           |            |            |
| 2005                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 1                    | 0.195    | 0         | 0.091     | 1          | 0.104      |
| Line #2 – SO4          | 25                   | 1.196    | 15        | 0.659     | 10         | 0.539      |
| Line #2 – All          | 26                   | 1.294    | 15        | 0.678     | 11         | 0.616      |
| Voyageurs              |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.104    | 0         | 0.031     | 0          | 0.073      |
| Line #2 – SO4          | 25                   | 1.446    | 15        | 0.768     | 10         | 0.678      |
| Line #2 – All          | 26                   | 1.452    | 15        | 0.771     | 11         | 0.681      |
| 2005                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.083    | 0         | 0.033     | 0          | 0.050      |
| Line #2 – NOS          | 16                   | 0.083    | 6         | 0.436     | 10         | 0.337      |
| Line #2 – 304          | 10                   | 0.786    | 6         | 0.430     | 10         | 0.337      |
|                        |                      |          |           |           |            |            |
| <u>Isle Royale</u>     |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.054    | 0         | 0.018     | 0          | 0.036      |
| Line #2 – SO4          | 7                    | 0.469    | 0         | 0.245     | 7          | 0.224      |
| Line #2 – All          | 8                    | 0.518    | 0         | 0.266     | 8          | 0.252      |
| 2005                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.046    | 0         | 0.016     | 0          | 0.030      |
| Line #2 – SO4          | 1                    | 0.319    | 0         | 0.166     | 1          | 0.153      |
| Line #2 – All          | 1                    | 0.322    | 0         | 0.184     | 1          | 0.138      |

UTAC Line 2 – Pollutant Specific Modeling Results

# UTAC Comparison of Sulfate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

|                 | Difference = $2,07$ + | 111302        |                 |              |
|-----------------|-----------------------|---------------|-----------------|--------------|
| Class I Area    | EPA Estimated         | EPA Estimated | CAMx Modeled    | CAMx Modeled |
|                 | Difference Days       | Difference    | Difference Days | Difference   |
|                 | >0.5 dV               | 98% dV        | >0.5 dV         | 98% dV       |
| Boundary Waters | 14                    | 1.0           | 22              | 1.29         |
|                 |                       |               |                 |              |
| Voyageurs       | 6                     | 0.5           | 16              | 0.74         |
|                 |                       |               |                 |              |
| Isle Royale     | 8                     | 0.6           | 4               | 0.28         |

Final FIP Emission Difference = 2,074 TPY SO2

# UTAC Comparison of Nitrate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 3,731 TPY NOx

| Class I Area    | EPA Estimated   | EPA Estimated | CAMx Modeled    | CAMx Modeled |
|-----------------|-----------------|---------------|-----------------|--------------|
|                 | Difference Days | Difference    | Difference Days | Difference   |
|                 | >0.5 dV         | 98% dV        | >0.5 dV         | 98% dV       |
| Boundary Waters | 31              | 2.3           | 1               | 0.18         |
|                 |                 |               |                 |              |
| Voyageurs       | 15              | 1.1           | 0               | 0.08         |
|                 |                 |               |                 |              |
| Isle Royale     | 20              | 1.6           | 0               | 0.05         |

The maximum 98<sup>th</sup> percentile NO3 impact when combining both line emission reductions is <u>0.18 dV</u>, while the maximum 98<sup>th</sup> percentile SO4 impact for both lines is <u>1.29 dV</u>. Based on these results, it is evident that the SO4 impact on the Class I areas provides the vast majority of the predicted CAMx estimates of visibility improvement. This finding is consistent with MPCA's original finding for BART in the 2009 SIP that NOx emission reductions do not provide substantive visibility improvement.

# Tilden Mining CAMx Emissions and Modeling Results

#### **Tilden Emissions**

| Unit   | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|--------|----------|-----------|------------|----------|-----------|------------|
|        | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|        | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|        | Emission | (TPY)     | (TPY)      | Emission | (TPY)     | (TPY)      |
|        | (TPY)    |           |            | (TPY)    |           |            |
| Line 1 | 4,613    | 1,384     | 3,229      | 1,153    | 231       | 922        |
|        |          |           |            |          |           |            |
| TOTAL  | 4,613    | 1,384     | 3,229      | 1,153    | 231       | 922        |

#### Tilden CAMx Results (By Unit)

| Class I Area           | EPA FIP       | EPA FIP  | Final FIP  | Final FIP | Difference | Difference |
|------------------------|---------------|----------|------------|-----------|------------|------------|
|                        | Baseline Days | Baseline | Days > 0.5 | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV       | 98% dV   | dV         |           | dV         |            |
| <b>Boundary Waters</b> |               |          |            |           |            |            |
| 2002                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.141    | 0          | 0.037     | 0          | 0.104      |
|                        |               |          |            |           |            |            |
| 2005                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.097    | 0          | 0.042     | 0          | 0.055      |
|                        |               |          |            |           |            |            |
| <u>Voyageurs</u>       |               |          |            |           |            |            |
| 2002                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.042    | 0          | 0.011     | 0          | 0.031      |
|                        |               |          |            |           |            |            |
| 2005                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.041    | 0          | 0.010     | 0          | 0.031      |
|                        |               |          |            |           |            |            |
| Isle Royale            |               |          |            |           |            |            |
| 2002                   |               |          |            |           |            |            |
| Line #1                | 1             | 0.300    | 0          | 0.094     | 1          | 0.206      |
|                        |               |          |            |           |            |            |
| 2005                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.211    | 0          | 0.070     | 0          | 0.141      |

| Class I Area           | EPA FIP              | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|------------------------|----------------------|----------|-----------|-----------|------------|------------|
|                        | <b>Baseline Days</b> | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV              | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b> |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.031    | 0         | 0.013     | 0          | 0.018      |
| Line #1 – SO4          | 0                    | 0.102    | 0         | 0.022     | 0          | 0.080      |
| Line #1 – All          | 0                    | 0.141    | 0         | 0.037     | 0          | 0.104      |
| 2005                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.045    | 0         | 0.042     | 0          | 0.003      |
| Line #1 – SO4          | 0                    | 0.087    | 0         | 0.019     | 0          | 0.068      |
| Line #1 – All          | 0                    | 0.097    | 0         | 0.042     | 0          | 0.055      |
| Vouggourg              |                      |          |           |           |            |            |
| Voyageurs<br>2002      |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.002    | 0         | 0.001     | 0          | 0.001      |
| Line #1 – SO4          | 0                    | 0.041    | 0         | 0.011     | 0          | 0.030      |
| Line #1 – All          | 0                    | 0.042    | 0         | 0.011     | 0          | 0.031      |
| 2005                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.005    | 0         | 0.003     | 0          | 0.002      |
| Line #1 – SO4          | 0                    | 0.039    | 0         | 0.008     | 0          | 0.031      |
| Line #1 – All          | 0                    | 0.041    | 0         | 0.010     | 0          | 0.031      |
| Isle Royale            |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.084    | 0         | 0.038     | 0          | 0.046      |
| Line #1 – SO4          | 1                    | 0.197    | 0         | 0.052     | 1          | 0.145      |
| Line #1 – All          | 1                    | 0.300    | 0         | 0.094     | 1          | 0.206      |
| 2005                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.043    | 0         | 0.047     | 0          | -0.004     |
| Line #1 – SO4          | 0                    | 0.176    | 0         | 0.040     | 0          | 0.136      |
| Line #1 – All          | 0                    | 0.211    | 0         | 0.070     | 0          | 0.141      |

Tilden Line 1 – Pollutant Specific Modeling Results

Attachment 3

2012 AECOM Report



# Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

Robert Paine and David Heinold, AECOM

September 28, 2012

#### Executive Summary

This report reviews several aspects of the visibility assessment that is part of any Best Available Retrofit Technology (BART) assessment. The crux of this analysis focuses upon two opportunistic emission reductions that have resulted in no perceptible visibility benefits, while a straightforward application of EPA's modeling procedures would predict a substantial visibility benefit. These actual emission reduction cases include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in Minnesota in 2009.

There are several reasons why there is an inconsistency between the real world and the modeling results:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clean, which exaggerates the impact of emission sources. Overly clean natural conditions can erroneously indicate that some states are missing the 2018 milestone for achieving progress toward an impossible goal by the year 2064.
- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations that are detailed in this report. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.
- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.
- The modeled base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

September 2012



Impacts of the taconite plants' NO<sub>x</sub> emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5  $\frac{1}{2}$  months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO<sub>x</sub> controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to increases in haze due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, as well as the impacts of Michigan sources on Minnesota's Class I areas indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.



#### Introduction

Best Available Retrofit Technology (BART) is part of the Clean Air Act (Appendix Y of 40 CFR Part 51) as a requirement related to visibility and the 1999 Regional Haze Rule (RHR)<sup>1</sup> that applies to existing stationary sources. Sources eligible for BART were those from 26 source categories with a potential to emit over 250 tons per year of any air pollutant, and that were placed into operation between August 1962 and August 1977. Final BART implementation guidance for regional haze was published in the Federal Register on July 6, 2005<sup>2</sup>.

The United States Environmental Protection Agency (EPA) has issued a proposed rule<sup>3</sup> to address BART requirements for taconite plants in Minnesota and Michigan that involves emission controls for SO<sub>2</sub> and NO<sub>x</sub>. This document addresses the likely visibility impact of taconite plant emissions, specifically NO<sub>x</sub> emissions, for impacts at Prevention of Significant Deterioration (PSD) Class I areas that the RHR addresses.

#### Locations of Emission Sources and PSD Class I Areas

Figure 1 shows the location of BART-eligible taconite plants in Minnesota and Michigan addressed in EPA's proposed rule, as well as Class I areas within 500 km of these sources. In most applications of EPA's preferred dispersion model for visibility impacts, CALPUFF<sup>4</sup>, the distance limitation is 200-300 km because of the overprediction tendencies<sup>5</sup> for further distances. The overprediction occurs because of extended travel times that often involve at least a full day, during which there can be significant wind shear influences on plume spreading that the model and the meteorological wind field does not accommodate. With larger travel distances, there are higher uncertainties in the predictions of any model, either CALPUFF or a regional photochemical model. Therefore, a reasonable upper limit for establishing the impact of the taconite sources would be 500 km, with questionable results beyond 200-300 km from the source. In this case, the Class I areas involved are those shown in Figure 1. All other PSD Class I areas are much further away. It is noteworthy that EPA's visibility improvement assessment considered only three Class I areas: Voyageurs National Park, Boundary Waters Canoe Area Wilderness, and Isle Royale National Park.

September 2012

<sup>&</sup>lt;sup>1</sup> Regional Haze Regulations; Final Rule. *Federal Register*, *64*, 35713-35774. (July 1, 1999).

<sup>&</sup>lt;sup>2</sup> Federal Register. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, Vol. 70. (July 6, 2005)

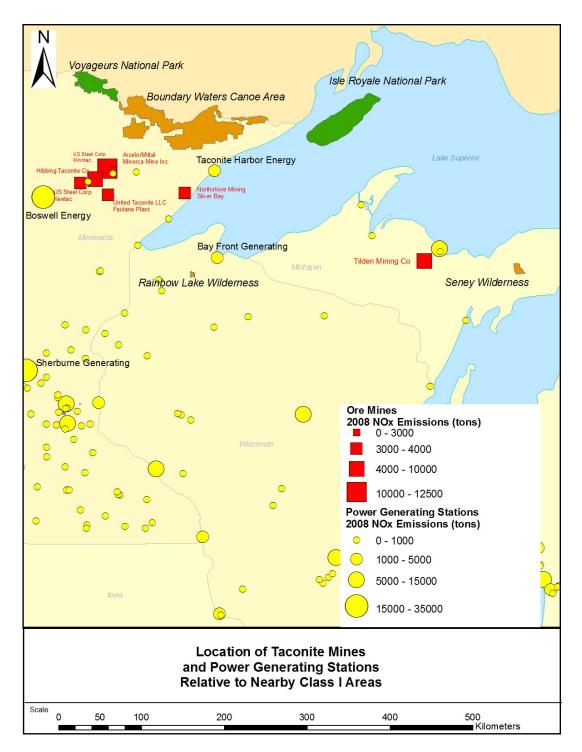
<sup>&</sup>lt;sup>3</sup> 77FR49308, August 15, 2012.

<sup>&</sup>lt;sup>4</sup> CALPUFF Dispersion Model, 2000. <u>http://www.epa.gov/scram001</u> (under 7th Modeling Conference link to Earth Tech web site).

<sup>&</sup>lt;sup>5</sup> As documented in Appendix D of the IWAQM Phase 2 document, available at www.epa.gov/scram001/7thconf/calpuff/phase2.pdf.



Figure 1 Location of Emission Sources Relative To PSD Class I Areas in Minnesota and Michigan





#### Overprediction Tendency of Visibility Assessment Modeling for BART Emission Reductions

A particularly challenging part of the BART process is the lack of well-defined criteria for determining whether a proposed emission reduction is sufficient, because the criteria for determining BART are somewhat subjective in several aspects, such as what controls are cost-effective and the degree to which the related modeled reductions in haze are sufficient. In addition, the calculations of the visibility improvements, which are intrinsic to establishing the required BART controls, are subject to considerable uncertainty due both to the inherent uncertainty in model predictions and model input parameters. Alternative approaches for applying for technical options and chemistry algorithms in the United States Environmental Protection Agency's (EPA's) preferred CALPUFF model can result in a large range in the modeled visibility improvement. The degree of uncertainty is especially large when NO<sub>x</sub> emission controls are considered as a BART option because modeling secondary formation of ammonium nitrate is quite challenging. Accurately modeling the effects of NO<sub>x</sub> controls on visibility is very important because they are often very expensive to install and operate. As a collateral effect that needs to be taken into account for BART decisions, such controls can also complicate energy efficiency objectives and strategies to control greenhouse gases and other pollutants. In this paper we discuss why EPA's preferred application of CALPUFF would likely overestimate the predicted visibility impact of emissions, especially NO<sub>x</sub>, and the associated effectiveness of NO<sub>x</sub> emission controls. Overestimates of the benefits of emissions reduction are evident from the following observations, which are discussed in this document:

- Natural background extinction used in CALPOST to calculate a source's haze impacts is underestimated, which has the effect of exaggerating the impact, which is computed relative to these defined conditions. Natural conditions also dictate how well each state is adhering to the 2018 milestone for achieving progress toward this goal by the year 2064. If the specification of natural conditions is underestimated to the extent that it is not attainable regardless of contributions from U.S. anthropogenic sources, then some states will be penalized for not achieving sufficient progress toward an impossible goal. Appendix A discusses this point in more detail.
- The chemistry in the current EPA-approved version of CALPUFF overestimates winter nitrate haze, especially in conjunction with the specification of high ammonia background concentrations. This conservatism is exacerbated by CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, CALPUFF modeling will credit BART emission reductions with more visibility improvements than will really occur.
- There are examples where actual significant emission reductions have occurred, where CALPUFF modeling as conducted for BART would predict significant visibility improvements, but no perceptive changes in haze occurred.

#### Visibility Impact of NO<sub>x</sub> Emissions – Unique Aspects and Seasonality

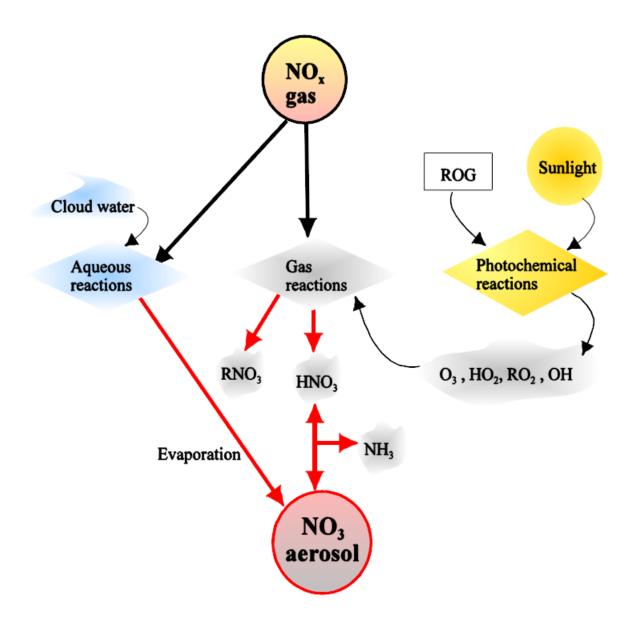
The oxidation of NO<sub>X</sub> to total nitrate (TNO<sub>3</sub>) depends on the NO<sub>X</sub> concentration, ambient ozone concentration, and atmospheric stability. Some of the TNO<sub>3</sub> is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state with HNO<sub>3</sub> gas that is a function

September 2012



of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 2<sup>6</sup>. It is important to realize that both CALPUFF and regional photochemical models tend to overpredict nitrate formation, especially in winter. A more detailed discussion of this issue is provided in Appendix B.

#### Figure 2 CALPUFF II NO<sub>x</sub> Oxidation



<sup>6</sup> Figure 2-32 from CALPUFF Users Guide, available at <u>http://www.src.com/calpuff/download/CALPUFF\_UsersGuide.pdf</u>.

Page 6 of 45



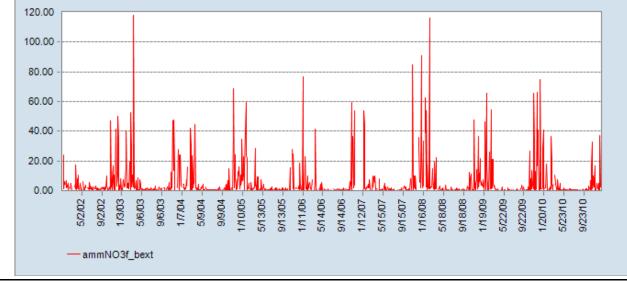
In CALPUFF, total nitrate  $(TNO_3 = HNO_3 + NO_3)$  is partitioned into each species according to the equilibrium relationship between gaseous  $HNO_3$  and  $NO_3$  aerosol. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate strongly depends on availability of  $NH_3$  to form ammonium nitrate. A summary of the conditions affecting nitrate formation is provided below:

- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium nitrate is formed;
- Sulfate preferentially scavenges ammonia over nitrates.

For this BART analysis, the effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various  $NO_X$  control options. For parts of the country where sulfate concentrations are relatively high and ammonia emissions are quite low, the atmosphere is likely to be in an ammonia-limited regime relative to nitrate formation. Therefore,  $NO_X$  emission controls are not very effective in improving regional haze, especially if there is very little ambient ammonia available.

In many cases, the BART visibility assessments ignore the haze increases that occur due to the additional power generation required to operate the control equipment. For  $NO_x$  controls, for example, the warm season emissions have minimal visibility impact, but the associated  $SO_2$  emissions from the power generation required to run the controls will increase sulfate haze. These effects have not been considered in the visibility assessment modeling.

It is evident from haze composition plots available from Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors that nitrate haze is confined to winter months. This is clearly shown in Figure 3, which is a timeline of nitrate haze extinction from Boundary Waters Canoe Area Wilderness. Similar patterns are evident for the other Class I areas plotted in Figure 1. The impact of NO<sub>X</sub> emissions during the non-winter months (e.g., April through October) is very low.



#### Figure 3 Boundary Water Canoe Area Wilderness Ammonium Nitrate Extinction, 2002-2010

September 2012

Page 7 of 45



The occurrence of significant nitrate haze only in the winter months has implications for the effectiveness of haze reductions relative to park attendance. The BART Rule addresses the seasonal issue as follows: "Other ways that visibility improvement may be assessed to inform the control decisions would be to examine distributions of the daily impacts, determine if the time of year is important (e.g., high impacts are occurring during tourist season) . . . "

In this case, the high nitrate impacts are not occurring during the tourist season, especially for the waterdominant Class I areas in Minnesota (Voyageurs and Boundary Waters) that freeze in winter. In fact, for Voyageurs National Park, the typical monthly attendance<sup>7</sup> for an off-season month (November) is only 0.2% that of a peak-season month (July). This is obviously due in part to the brutal winter weather in northern Minnesota (and Michigan) and the lack of boating access to frozen water bodies.

Operations at the Michigan Class I areas in winter are even more restricted. Isle Royale National Park is one of the few national parks to <u>totally close</u><sup>8</sup> during the winter (generally, during the period of November 1 through April 15). The closure is due to the extreme winter weather conditions and difficulty of access from the mainland across a frozen Lake Superior, for the protection of wildlife, and for the safety and protection of potential visitors. Due to this total closure, there is very little nitrate haze impact in this park during the seasons of the year that it is open, and haze issues for Isle Royale National Park will not be further considered in this report.

The Seney Wilderness Area Visitor Center is open<sup>9</sup> only during the period of May 15th to mid-October. Various trails are generally only open during the same period. The tour loops are closed in the fall, winter, and spring to allow migrating and nesting birds a place to rest or nest undisturbed, and because of large amounts of snow. Although portions of the park are open in the winter, the visitation is greatly reduced due to no visitor center access, no trail or tour loop access, and the severe weather.

#### Effect of 2009 Recession on Haze in Affected PSD Class I Areas

The effect on haze of a significant (50%) emission reduction from the taconite plants that actually occurred in early 2009 and lasted throughout calendar year 2009 is discussed in this section. This emission reduction was not due to environmental regulations, but rather economic conditions, and affected all pollutants being emitted by the collective group of Minnesota taconite plants, as well as regional power production that is needed to operate the taconite plants.

The annual taconite production<sup>10</sup> from the Minnesota taconite plants in recent years is plotted in Figure 4, along with annual average nitrate concentrations at the nearest Class I area, Boundary Waters Canoe Area (BWCA). The figure shows that the nitrate measured in the park did not respond to the reduction in emissions from the taconite plants. Figures 5 and 6 show the time series<sup>11</sup> of nitrate and sulfate haze in

<sup>&</sup>lt;sup>7</sup> As documented at <u>http://www.gorp.com/parks-guide/voyageurs-national-park-outdoor-pp2-guide-cid9423.html</u>.

<sup>&</sup>lt;sup>8</sup> As noted at <u>http://www.nps.gov/isro/planyourvisit/hours.htm</u>.

<sup>&</sup>lt;sup>9</sup> As noted at <u>http://www.fws.gov/midwest/seney/visitor\_info.html</u>.

<sup>&</sup>lt;sup>10</sup> Production data is available from taxes levied on taconite production, and the data was supplied by BARR Engineering through a personal communication with Robert Paine of AECOM.

<sup>&</sup>lt;sup>11</sup> Available from the VIEWS web site at http://views.cira.colostate.edu/web/.



the BWCA over the past several years. Figures for other affected Class I areas (Voyageurs, Seney, and Isle Royale) are shown in Appendix C.

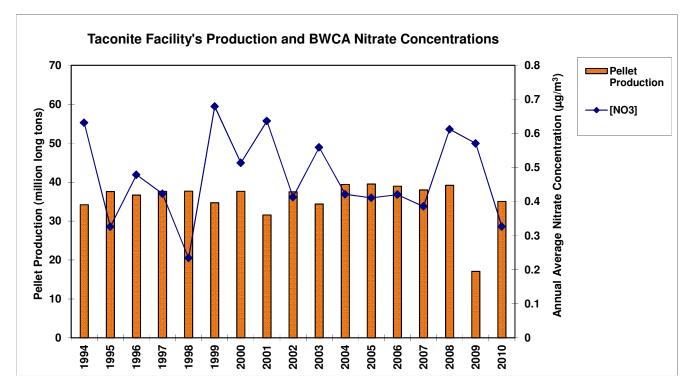
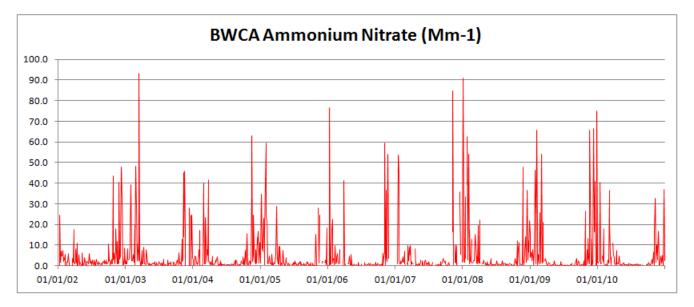




Figure 5 Time Series of Nitrate Haze at Boundary Waters Canoe Area (2002-2010)



September 2012



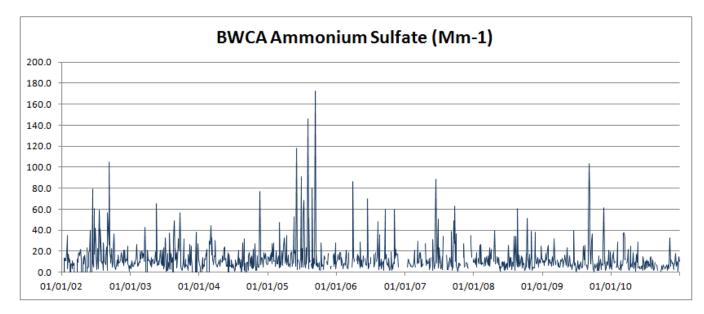


Figure 6 Time Series of Sulfate Haze at Boundary Waters Canoe Area (2002-2010)

It is evident from this information that the haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions.

It is instructive to review the haze composition time series plots for BWCA for 2008, 2009, and 2010, as shown in Figures 7, 8, and 9.

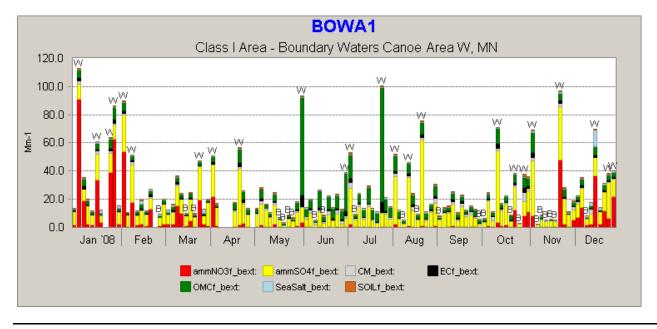


Figure 7 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2008

September 2012



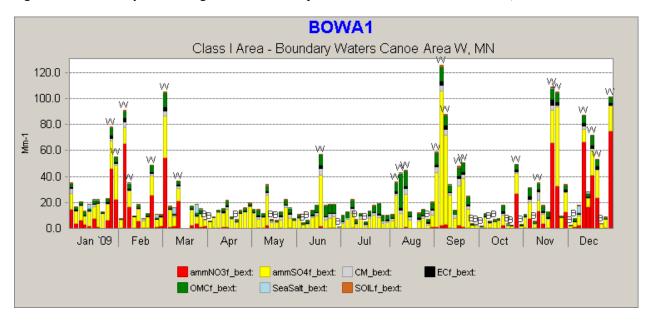
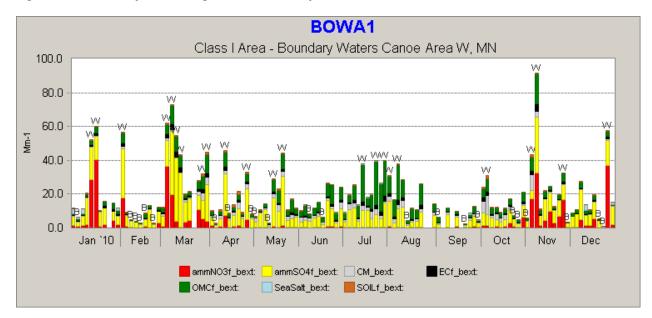




Figure 9 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2010



As has been mentioned above, it is evident that the nitrate haze (red bars) is only important during the colder months (November through March). It is also evident that haze from forest fires (green bars) is predominant in the warm weather months, but varies from year to year according to the frequency of wildfires. For example, 2008 was a year of high occurrences of wildfires, while 2009 saw a low frequency, and 2010 was more normal.

September 2012



The curtailment of taconite plant activity lasted from early 2009 through December 2009, peaking in the summer of 2009. Even so, we see the highest sulfate haze days (yellow bars) in September 2009 when taconite production was half of normal activity. Also, we note high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states.

These findings suggest that reduction of emissions from the taconite plants will likely have minimal effects on haze in the nearby Class I areas. The fact that the various plants are distributed over a large area means that individual plumes are isolated and generally do not combine with others.

At least one other emission reduction opportunity to determine the effect on visibility improvement has occurred; this is related to the shutdown of the Mohave Generating Station in 2005, and its effect upon visibility in the Grand Canyon National Park. The discussion in Appendix D indicates that although CALPUFF modeling predicted substantial visibility benefits, very little change has occurred since 2005.

Other reasons that visibility assessment models such as CALPUFF could overpredict impacts are listed below.

- 1) The CALPUFF base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.
- 2) The way that the predicted concentrations are accounted for in the CALPOST output overstate the impact for even the case where the CALPUFF predictions are completely accurate. The way that CALPOST works is that the peak 24-hour prediction <u>anywhere</u> in a Class I area is the only information saved for each predicted day. The predicted impact for each day is effectively assumed to be a) always in the same place; and b) in all portions of the Class I area. Therefore, the 98<sup>th</sup> percentile day's prediction could be comprised of impacts in 8 different places that are all erroneously assumed to be co-located.
- 3) CALPUFF does not simulate dispersion and transport accurately over a full diurnal cycle, during which significant wind direction shear can occur (and is not properly accounted for by CALPUFF). This can result in plumes that are more cohesive than actually occur.
- 4) As discussed above, it is well established that nitrate predictions are often overstated by CALPUFF v. 5.8, especially in winter.
- 5) Natural conditions as input to CALPOST are not attainable, and their use will exaggerate the simulated visibility impacts of modeled emissions.

#### Interstate Non-Interference with Regional Haze Rule SIPs from Taconite Plant Emissions

An issue that is a recurring one for a number of state implementation plans (SIPs) is whether emissions from one state can interfere with haze reduction plans for downwind states. For Minnesota, it would be expected that emission reductions undertaken to reduce haze in Minnesota Class I areas (Voyageurs and Boundary Waters) would also act to reduce haze in other Class I areas. In the case of Minnesota's

September 2012



taconite plant emissions, earlier discussions of the potentially affected Class I areas indicated that only the Class I areas in northern Michigan (Isle Royale National Park and Seney Wilderness Area) are close enough and in a general predominant wind direction to merit consideration. The closer of these two parks, Isle Royale, is closed to the public from November 1 through April 15, and haze effects there would not be affected by NO<sub>X</sub> emissions because those effects are only important in the winter. Since Minnesota's Class I areas are located generally upwind of Michigan sources, the impact of Michigan sources on these Class I areas is expected to be small. This is confirmed in the Particulate Matter Source Apportionment Technology (PSAT) plots shown below.

Regional photochemical modeling studies<sup>12</sup> conducted by the CENRAP Regional Planning Organization, of which Minnesota is a part, shows contributions of various states as well as international contributions for haze impacts in the Michigan Class I areas. Relevant figures from the Iowa RHR SIP report for 2018 emission inventory haze impacts are reproduced below for Isle Royale National Park (Figure 10) and Seney Wilderness Area (Figure 11).

The modeling conducted for this analysis, using CAMx, shows that the relative contribution to haze for all Minnesota sources to sulfate haze in Isle Royale National Park is low, consisting of only 10% of the sulfate haze. The effect of 2018 emissions from Minnesota sources at the more distant Seney Wilderness Area is even lower, with the state's emissions ranking 9<sup>th</sup> among other jurisdictions analyzed for this Class I area. Therefore, it is apparent that Minnesota sources, and certainly the subset including taconite plants, would not be expected to interfere with other state's progress toward the 2018 milestone associated with the Regional Haze Rule.

Figures 12 and 13, reproduced from the Iowa RHR SIP report for Boundary Waters and Voyageurs, respectively, indicate that Michigan sources rank 11<sup>th</sup> and 12<sup>th</sup>, respectively, for haze impacts in these two areas for projected 2018 emissions. Therefore, as expected, Michigan sources are not expected to interfere with Minnesota's RHR SIP for progress in 2018.

<sup>&</sup>lt;sup>12</sup> See, for example, the Iowa State Implementation Plan for Regional Haze report at <u>http://www.iowadnr.gov/portals/idnr/uploads/air/insidednr/rulesandplanning/rh\_sip\_final.pdf</u>, Figures 11.3 and 11.4.

AECOM

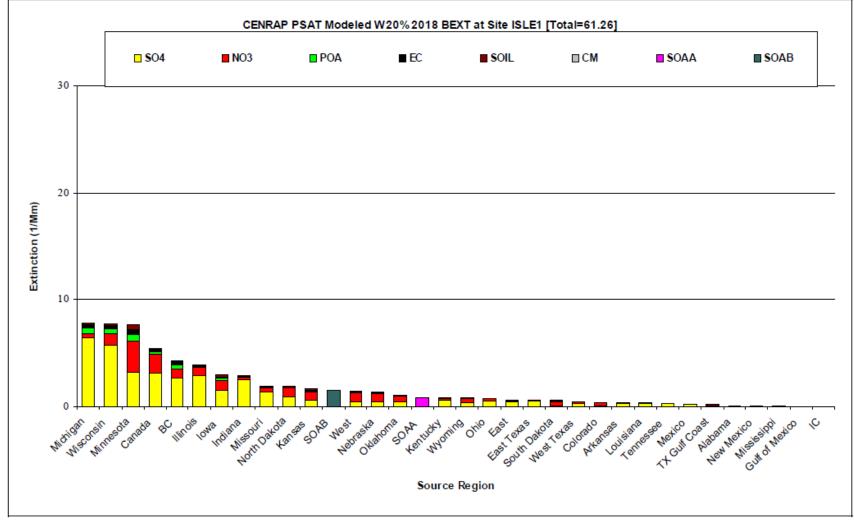


Figure 10 PSAT Results from CENRAP CAMx Modeling for Isle Royale National Park

Figure 11.3. Source apportion contributions by region and pollutant to ISLE in 2018.

September 2012

Page 14 of 45

www.aecom.com

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas



Figure 11 PSAT Results from CENRAP CAMx Modeling for Seney Wilderness Area

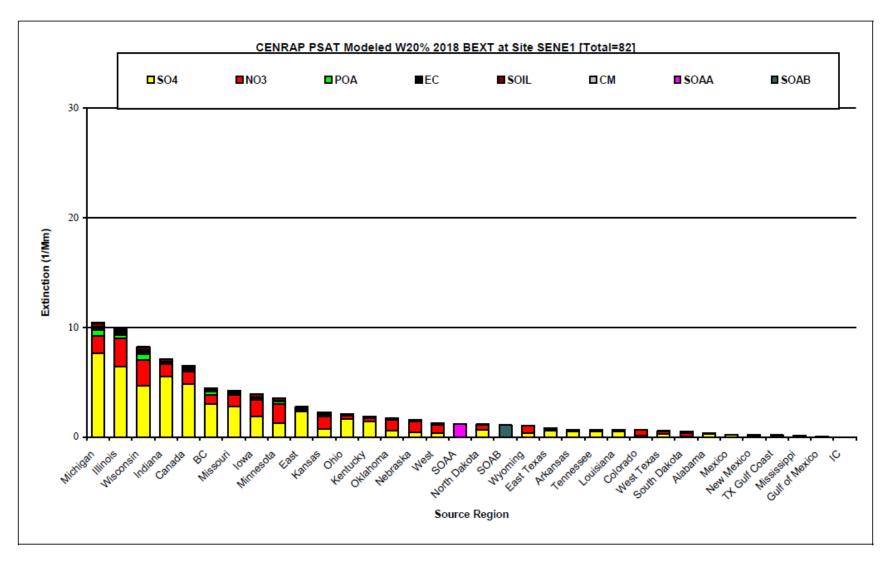


Figure 11.4. Source apportion contributions by region and pollutant to SENE in 2018.

September 2012

Page 15 of 45



Figure 12 PSAT Results from CENRAP CAMx Modeling for Boundary Waters Canoe Area Wilderness

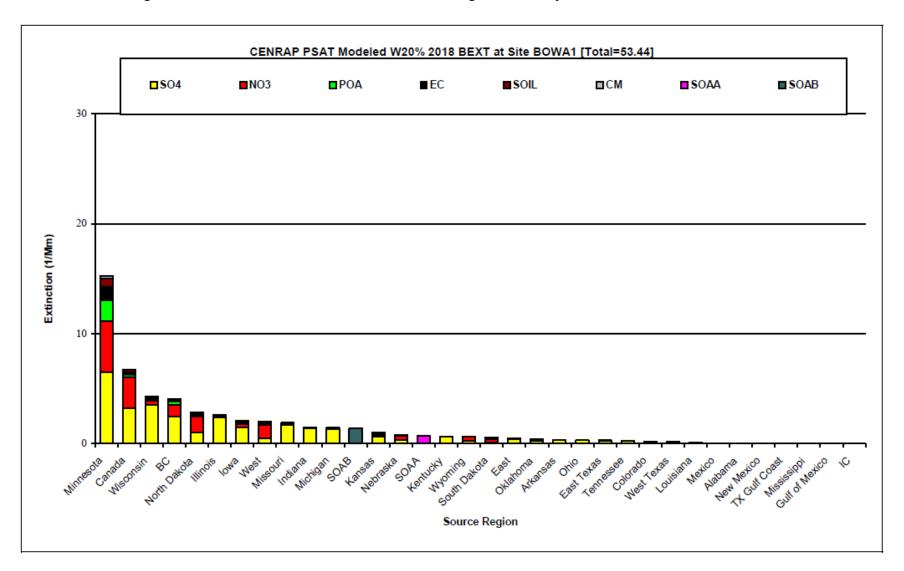


Figure 11.1. Source apportion contributions by region and pollutant to BOWA in 2018.

September 2012

Page 16 of 45



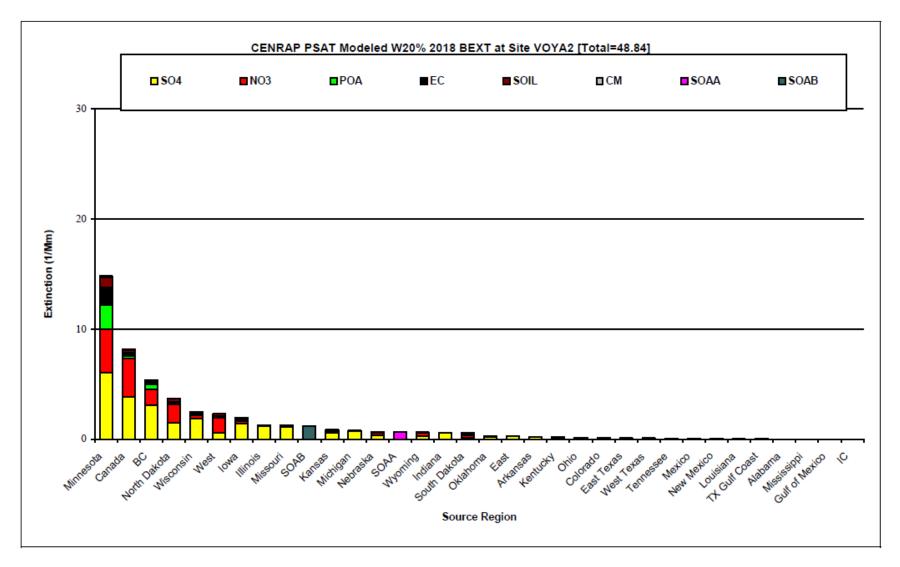


Figure 11.2. Source apportion contributions by region and pollutant to VOYA in 2018.

September 2012

Page 17 of 45

#### CONCLUSIONS

EPA's preferred modeling tools to assess the visibility improvement from BART controls will likely overestimate the predicted visibility improvement. While this is expected for all pollutants, it is especially true for  $NO_X$  emission controls. This occurs for several reasons:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clear, which exaggerates the impact of emission sources. Overly clean natural conditions can lead to the erroneous conclusion that some states are not adhering to the 2018 milestone because they need to achieve progress toward an impossible goal by the year 2064.
- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.
- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.
- The modeled base case scenario is always a worst-case emission rate, assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

Impacts of the taconite plants' NO<sub>x</sub> emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5  $\frac{1}{2}$  months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO<sub>x</sub> controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to visibility disbenefits due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

Evidence of models' tendency for overprediction are provided in examples of actual significant emission reductions that have resulted in virtually no perceptive changes in haze, while visibility assessment modeling as conducted for BART would predict significant visibility improvements. These examples include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in 2009.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, and vice versa indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

## **APPENDIX A**

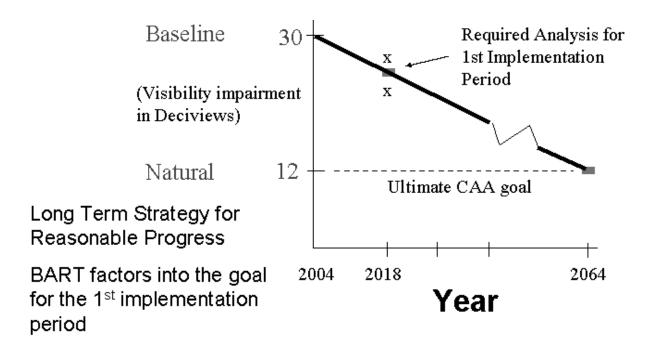
## THE REGIONAL HAZE RULE GOAL OF NATURAL CONDITIONS

An important consideration in the ability for a state to meet the 2018 Uniform Rate of Progress (URP) goal is the definition of the end point goal of "natural conditions" for the worst 20% haze days; see Figure A-1, which illustrates this concept). Note that while achieving improved visibility for the worst 20% haze days, the RHR also stipulates that there should not be deterioration of visibility for the best 20%, or clearest, days. One way to define that goal would be the elimination of all man-made emissions. This raises some other questions, such as:

- To what categories of emissions does the RHR pertain?
- Does the current definition of natural conditions include non-anthropogenic or uncontrollable emissions?

The default natural background assumed by EPA in their 2003 guidance document<sup>13</sup> is not realistic. The discussion in this section explains why EPA's default natural conditions significantly understate the true level of natural haze, including the fact that there are contributors of haze that are not controllable (and that are natural) that should be included in the definition of natural visibility conditions. In addition, one important aspect of the uncontrollable haze, wildfires, is further discussed regarding the biased quantification of its contribution to natural haze due to suppression of wildfires during the 20<sup>th</sup> century.

#### Figure A-1: Illustration of the Uniform Rate of Progress Goal



Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

September 2012

<sup>&</sup>lt;sup>13</sup> Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule, (U.S. Environmental Protection Agency, September 2003). <u>http://www.epa.gov/ttncaaa1/t1/memoranda/rh\_envcurhr\_gd.pdf</u>.

In its RHR SIP, North Dakota<sup>14</sup> noted in Section 9.7 that,

"Achieving natural conditions will require the elimination of all anthropogenic sources of emissions. Given current technology, achieving natural conditions is an impossibility. Any estimate of the number of years necessary to achieve natural visibility conditions would require assumptions about future energy sources, technology improvements for sources of emissions, and every facet of human behavior that causes visibility impairing emissions. The elimination of all SO<sub>2</sub> and NO<sub>x</sub> emissions in North Dakota will not achieve the uniform rate of progress for this [2018], or any future planning period. Any estimate of the number of years to achieve natural conditions is questionable because of the influence of out-of-state sources."

It will be extremely difficult, if not impossible, to eliminate all anthropogenic emissions, even if natural conditions are accurately defined. It will be even more daunting to try to reach the goal if natural conditions are significantly understated, and as a result, states are asked to control sources that are simply not controllable. It is clear that the use of EPA default natural conditions leads to unworkable and absurd results for one state's (North Dakota's) ability to determine the rate of progress toward an unattainable goal. The definition of natural conditions that can be reasonably attained for a reasonable application of USEPA's Regional Haze Rule should be revised for all states.

The objective of the following discussion is to summarize recent modeling studies of natural visibility conditions and to suggest how such studies can be used in evaluating the uniform rate of progress in reducing haze to attain natural visibility levels. In addition, the distinction between natural visibility and policy relevant background visibility is discussed. Treatment of this issue by other states, such as Texas, is also discussed.

#### **Regional Haze Issues for Border States**

There are similarities between the Regional Haze Rule (RHR) challenges for border states such as North Dakota and Texas in that both states have significant international and natural contributions to regional haze in Class I areas in their states. The Texas Commission on Environmental Quality (TCEQ) has introduced alternative RHR glide paths to illustrate the State's rate of progress toward the RHR goals. Since TCEQ has gone through the process of a RHR State Implementation Plan (SIP) development and comment period, it is instructive to look at the TCEQ approach, the comments provided by the Federal Land Managers to TCEQ, and TCEQ's reaction to the comments.

Similarities to be considered for the RHR SIP development in border states, such as North Dakota and Texas, include the items listed below.

• These states have Class I areas for which a considerable fraction of the regional haze is due to international transport or transport from other regions of the United States.

21

<sup>&</sup>lt;sup>14</sup> North Dakota Dep. of Health, 2010. North Dakota State Implementation Plan for Regional Haze. <u>http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Main%20SIP%20Sections%201-12.pdf</u>.

- As a result, there is a substantial reduction in SO<sub>2</sub> and NO<sub>x</sub> emissions from the BART-eligible sources in each state, but this reduction results in a relatively small impact on regional haze mitigation. Additional emission reductions would, therefore, have a minimal benefit on visibility improvement at substantial cost.
- In the Regional Haze SIP development, these states have attempted to account for the effects of anthropogenic emissions that they can control in alternative analyses. These analysis result in a finding that the in-state emission reductions come closer to meeting the Uniform Rate of Progress glide path goals for 2018. However, due to the low probability of impact of these sources on the worst 20% days, the effectiveness of in-state emission controls on anthropogenic sources subject to controls is inherently limited.

TCEQ decided that coarse and fine PM measured at the Class I areas were due to natural causes (especially on the worst 20% days), and adjusted the natural conditions endpoint accordingly. The Federal Land Managers (FLMs) agreed with this approach for the most part<sup>15</sup>, but suggested that 80% of these concentrations would be due to natural causes, and 20% would be due to anthropogenic causes. TCEQ determined from a sensitivity analysis that the difference in these two approaches was too small to warrant a re-run of their analysis, but it is important that the FLMs agreed to a state-specific modification of the natural conditions endpoint, and this substantially changed the perceived rate of progress of the SIP plan toward the altered natural conditions endpoint.

Although the TCEQ did not address other particulate matter components in this same way, a review of air parcel back trajectories previously available from the IMPROVE web site (<u>http://views.cira.colostate.edu/web/</u>) suggests that other components, such as organic matter due to wildfires, could be substantially due to natural causes, so that this component should also be considered as at least partially natural.

The TCEQ discussed the issue of how emissions from Mexico could interfere with progress on the RHR, but they did not appear to adjust the glide path based upon Mexican emissions. On the other hand, in its weight of evidence analysis, North Dakota did evaluate adjustments based upon anthropogenic emissions that could not be controlled from Canadian sources, but did not take into account any specific particulate species that are generally not emitted by major anthropogenic sources of SO<sub>2</sub> and NO<sub>x</sub>.

#### **Natural Haze Levels**

The Regional Haze Rule establishes the goal that natural visibility conditions should be attained in Federal Class I areas by the year 2064. Additionally, the states are required to determine the uniform rate of progress (URP) of visibility improvement necessary to attain the natural visibility goal by 2064. Finally, each state must develop a SIP identifying reasonable control measures that will be adopted well before 2018 to reduce source emissions of visibility-impairing particulate matter (PM) and its precursors (SO<sub>2</sub> and NO<sub>x</sub>).

Estimates of natural haze levels have been developed by the EPA for visibility planning purposes and are described in the above-referenced EPA 2003 document. The natural haze estimates were based on ambient data analysis of selected PM species for days with good visibility and are shown in Table A-1.

<sup>&</sup>lt;sup>15</sup> See Appendix 2-2 at <u>http://www.tceq.state.tx.us/implementation/air/sip/bart/haze\_appendices.html</u>.

These estimates were derived from Trijonis<sup>16</sup> and use two different sets of natural concentrations for the eastern and western U.S. Tombach<sup>17</sup> provides a detailed review and discussion of uncertainty in the USEPA natural PM estimates. Natural visibility can be calculated using the IMPROVE equation which calculates the light scattering caused by each

# Table A-1: Average Natural Levels of Aerosol Components from Table 2-1 of Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (EPA, 2003)

|                               | Average Natura | Average Natural Concentration |                   |                                    |
|-------------------------------|----------------|-------------------------------|-------------------|------------------------------------|
|                               | West (µg/m³)   | East (µg/m³)                  | – Error<br>Factor | Extinction<br>Efficiency<br>(m²/g) |
| Ammonium sulfate <sup>b</sup> | 0.12           | 0.23                          | 2                 | 3                                  |
| Ammonium nitrate              | 0.10           | 0.10                          | 2                 | 3                                  |
| Organic carbon mass °         | 0.47           | 1.40                          | 2                 | 4                                  |
| Elemental carbon              | 0.02           | 0.02                          | 2-3               | 10                                 |
| Soil                          | 0.50           | 0.50                          | 1½ - 2            | 1                                  |
| Coarse Mass                   | 3.0            | 3.0                           | 1½ - 2            | 0.6                                |

a: After Trijonis, see footnote 12

b: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were  $0.1 \ \mu g/m^3$  and  $0.2 \ \mu g/m^3$  of ammonium bisulfate.

c: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.5 µg/m<sup>3</sup> and 1.5 µg/m<sup>3</sup> of organic compounds.

component of PM. After much study, changes in the IMPROVE equation and in the method for calculating natural visibility were developed in 2005 and are described by Pitchford et al.<sup>18</sup>

The EPA guidance also makes provision for refined estimates of site-specific natural haze that differ from the default values using either data analysis or model simulations. However, most states have continued to use the default natural haze levels for calculating the progress toward natural visibility conditions.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>16</sup> Trijonis, J. C. Characterization of Natural Background Aerosol Concentrations. Appendix A in Acidic Deposition: State of Science and Technology. Report 24. Visibility: Existing and Historical Conditions -- Causes and Effects. J. C. Trijonis, lead author. National Acid Precipitation Assessment Program: Washington, DC, 1990.

<sup>&</sup>lt;sup>17</sup> Tombach, I., (2008) *Natural Haze Levels Sensitivity -- Assessment of Refinements to Estimates of Natural Conditions,* Report to the Western Governors Association, January 2008, available at <a href="http://www.wrapair.org/forums/aamrf/projects/NCB/index.html">http://www.wrapair.org/forums/aamrf/projects/NCB/index.html</a>.

<sup>&</sup>lt;sup>18</sup> Pitchford, M., Malm, W., Schichtel, B., Kumar, N., Lowenthal, D., Hand, J., Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data, J. Air & Waste Manage, Assoc. 57: 1326 – 1336, 2007.

Tombach and Brewer<sup>19</sup> reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach<sup>8</sup> also reviewed estimates of natural haze levels and proposed that, instead of using two sets of default natural PM concentrations for the eastern and western US, a large number of sensitivity zones should be developed that reflect regional variability in natural PM sources. Tombach<sup>8</sup> also suggested that modeling studies are a possible approach to further revise estimates of natural PM concentrations.

Previous modeling studies have shown that the estimates of natural visibility described above for "clean" days will differ from the results of model simulations when United States anthropogenic emissions are totally eliminated (Tonnesen et al., 2006<sup>20</sup>; Koo et al., 2010<sup>21</sup>), especially when natural wild fire emissions are included in the model simulation. Because the URP is calculated using model simulations of PM on the 20% of days with the worst visibility, wild fires and other extreme events can result in estimated levels of natural haze (even without any contribution of US anthropogenic sources) that can be significantly greater than the natural levels used in the EPA guidance for URP calculation. This could make it difficult or impossible for states to identify emissions control measures sufficient to demonstrate the URP toward attaining visibility goals because the endpoint is unachievable even if all US anthropogenic emissions are eliminated, as North Dakota has already determined even for the interim goal in 2018.

### Previous Suppression of Wildfire Activity and its Effect upon the EPA Default Natural Conditions

Throughout history, except for the past few decades, fires have been used to clear land, change plant and tree species, sterilize land, maintain certain types of habitat, among other purposes. Native Americans used fires as a technique to maintain certain pieces of land or to improve habitats. Although early settlers often used fires in the same way as the Native Americans, major wildfires on public domain land were largely ignored and were often viewed as an opportunity to open forestland for grazing.

Especially large fires raged in North America during the 1800s and early 1900s. The public was becoming slowly aware of fire's potential for life-threatening danger. Federal involvement in trying to control forest fires began in the late 1890s with the hiring of General Land Office rangers during the fire season. When the management of the forest reserves (now called national forests) was transferred to the newly formed Forest Service in 1905, the agency took on the responsibility of creating professional standards for firefighting, including having more rangers and hiring local people to help put out fires.

Since the beginning of the 20<sup>th</sup> century, fire suppression has resulted in a buildup of vegetative "fuels" and catastrophic wildfires. Recent estimates of background visual range, such as Trijonis<sup>16</sup>, have underestimated the role of managed fire on regional haze. Since about 1990, various government agencies have increased prescribed burning to reduce the threat of dangerous wildfires, and the

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>19</sup> Tombach, I., and Brewer, P. (2005). Natural Background Visibility and Regional Haze Goals in the Southeastern United States. *J. Air & Waste Manage. Assoc. 55*, 1600-1620.

<sup>&</sup>lt;sup>20</sup> Tonnesen, G., Omary, M., Wang, Z., Jung, C.J., Morris, R., Mansell, G., Jia, Y., Wang, B., and Z. Adelman (2006) Report for the Western Regional Air Partnership Regional Modeling Center, University of California Riverside, Riverside, California, November. (<u>http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC 2006 report FINAL.pdf</u>).

<sup>&</sup>lt;sup>21</sup> Koo B., C.J. Chien, G. Tonnesen, R. Morris , J. Johnson, T. Sakulyanontvittaya, P. Piyachaturawat, and G.Yarwood, 2010. Natural emissions for regional modeling of background ozone and particulate matter and impacts on emissions control strategies. <u>Atm. Env.</u>, 44, 2372-2382.

increased haze due to these fires is often more of an impairment to visibility than industrial sources, especially for  $NO_X$  reductions that are only effective in winter, the time of the lowest tourist visitation in most cases.

The National Park Service indicates at <u>http://www.nps.gov/thro/parkmgmt/firemanagement.htm</u> for the Theodore Roosevelt National Park that:

"For most of the 20<sup>th</sup> Century, wildfires were extinguished immediately with the assumption that doing so would protect lives, property, and natural areas. However, following the unusually intense fire season of 1988, agencies including the National Park Service began to rethink their policies." Even this policy is not always successful, as experienced by the USDA Forest Service<sup>22</sup> in their management of wildfires near the Boundary Waters Canoe Area that can contribute significantly to visibility degradation during the peak tourist season. In this case, even small fires, if left unchecked, have been known to evolve into uncontrollable fires and then require substantial resources to extinguish.

EPA's 2003 "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" acknowledges that wildfires are a contributor to natural visibility conditions, but the data used in estimates of natural conditions were taken during a period of artificial fire suppression so that the true impact of natural wildfires is understated. The report notes that "data should be available for EPA and States to develop improved estimates of the contribution of fire emissions to natural visibility conditions in mandatory Federal Class I areas over time." As noted by several studies noted above, the impact due to natural fire levels is underestimated in the EPA natural visibility conditions include the distortion of Reasonable Progress analyses and also to BART modeling results that overestimate the visibility improvement achievable from NO<sub>X</sub> emission reductions due to the use of inaccurate natural visibility conditions.

### **Recommendations for an Improved Estimate of Visibility Natural Conditions**

A reasonable approach would be to combine the effects of the uncontrollable particulate matter components and the emissions from international sources to determine a new glide path endpoint that is achievable by controlling (only) U.S. anthropogenic emissions. To compute this new endpoint, regional photochemical modeling using CMAQ or CAMx could be conducted for the base case (already done) and then for a future endpoint case that has no U.S. anthropogenic emissions, but with natural particulate matter emissions (e.g., dust, fires, organic matter) as well as fine particulate, SO<sub>2</sub> and NO<sub>x</sub> emissions associated with all non-U.S. sources set to the current baseline levels. The simulation should include an higher level of wildfire activity than in the recent past to reflect a truer level of fire activity before manmade suppression in the 20<sup>th</sup> century. Then, states could use a relative reduction factor (RRF) approach to determine the ratio of the haze impacts between the base case and the reasonable future case, and then apply the RRF values to the baseline haze to obtain a much more reasonable "natural conditions" haze endpoint. The more accurate natural background would also result in a reduction in the degree to which CALPUFF modeling overstates visibility improvement from emission reductions.

<sup>&</sup>lt;sup>22</sup> See explanation at <u>http://www.msnbc.msn.com/id/48569985/ns/us\_news-environment/t/forest-service-gets-more-aggressive-small-fires/</u>.

# **APPENDIX B**

# MODEL OVERPREDICTION ISSUES FOR WINTERTIME NITRATE HAZE

This appendix includes a discussion of CALPUFF predictions for nitrate haze, followed by more general issues with CALPUFF predictions.

### **CALPUFF Predictions of Nitrate Haze**

Secondary pollutants such as nitrates and sulfates contribute to light extinction in Class I areas. The CALPUFF model was approved by EPA for use in BART determinations to evaluate the effect of these pollutants on visibility in Class I areas. CALPUFF version 5.8 (the current guideline version) uses the EPA-approved MESOPUFF II chemical reaction mechanism to convert SO<sub>2</sub> and NO<sub>x</sub> emissions to secondary sulfate and nitrate. This section describes how secondary pollutants, specifically nitrate, are formed and the factors affecting their formation, especially as formulated in CALPUFF.

In the CALPUFF model, the oxidation of NO<sub>x</sub> to nitric acid (HNO<sub>3</sub>) depends on the NO<sub>x</sub> concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration. In CALPUFF, total nitrate (TNO<sub>3</sub> = HNO<sub>3</sub> + NO<sub>3</sub>) is partitioned into gaseous HNO<sub>3</sub> and NO<sub>3</sub> particles according to the equilibrium relationship between the two species. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate particles *strongly* depends on availability of NH<sub>3</sub> to form ammonium nitrate, as shown in Figure 6<sup>23</sup>. The figure on the left shows that with 1 ppb of available ammonia and fixed temperature and humidity (for example, 275 K and 80% humidity), only 50% of the total nitrate is in the form of particulate matter. When the available ammonia is increased to 2 ppb, as shown in the figure on the right, as much as 80% of the total nitrate is in the particulate form. Figure B-1 also shows that colder temperatures and higher relative humidity favor particulate nitrate formation. A summary of the conditions affecting nitrate formation are listed below:

- Colder temperature and higher relative humidity create more favorable conditions to form nitrate particulate matter in the form of ammonium nitrate;
- Warmer temperatures and lower relative humidity create less favorable conditions for nitrate particulate matter resulting in a small fraction of total nitrate in the form of ammonium nitrate;
- Ammonium sulfate formation preferentially scavenges available atmospheric ammonia over ammonium nitrate formation. In air parcels where sulfate concentrations are high and ambient ammonia concentrations are low, there is less ammonia available to react with nitrate, and less ammonium nitrate is formed.

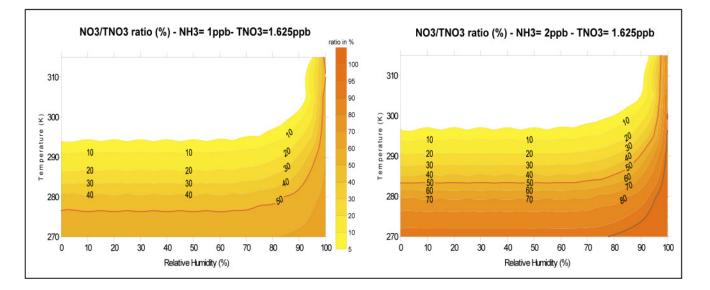
The effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various  $NO_x$  control options. For the reasons discussed above, the seasons with lower temperatures are the most likely to be most important for ammonium nitrate formation when regional haze is more effectively reduced by controlling  $NO_x$ .

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

September 2012

27

<sup>&</sup>lt;sup>23</sup> Scire, Joseph. CALPUFF MODELING SYSTEM. CALPUFF course presented at Chulalongkorn University, Bangkok, Thailand. May 16-20, 2005; slide 40 available at <u>http://aqnis.pcd.go.th/tapce/plan/4CALPUFF%20slides.pdf</u>, accessed March 2011.



## Figure B-1: NO<sub>3</sub>/HNO<sub>3</sub> Equilibrium Dependency on Temperature and Humidity

## Sensitivity of CALPUFF Haze Calculations to Background Ammonia Concentration

In an independent analysis, the Colorado Department of Public Health and Environment (CDPHE) performed a sensitivity modeling analysis to explore the effect of the specified ammonia concentration applied in CALPUFF on the predicted visibility impacts for a source with high NO<sub>x</sub> emissions relative to SO<sub>2</sub> emissions<sup>24</sup>. The results of the sensitivity modeling are shown in Figure B-2. It is noteworthy that the largest sensitivity occurs for specified ammonia input between 1 and 0.1 ppb. In that factor-of-ten range, the difference in the peak visibility impact predicted by CALPUFF is slightly more than a factor of three. This sensitivity analysis shows that the specification of background ammonia is very important in terms of the magnitude of visibility impacts predicted by CALPUFF. The fact that regional, diurnal and seasonal variations of ambient ammonia concentrations are not well-characterized and mechanisms not well-understood effectively limits the effectiveness of CALPUFF in modeling regional haze, especially in terms of the contribution of ammonium nitrate.

It is also noteworthy that CALPUFF version 5.8's demonstrated over-predictions of wintertime nitrate can be mitigated to some extent by using lower winter ammonia background values, although there is not extensive measurement data to determine the ambient ammonia concentrations. This outcome showing the superiority of the monthly-varying background ammonia concentrations was found by Salt River

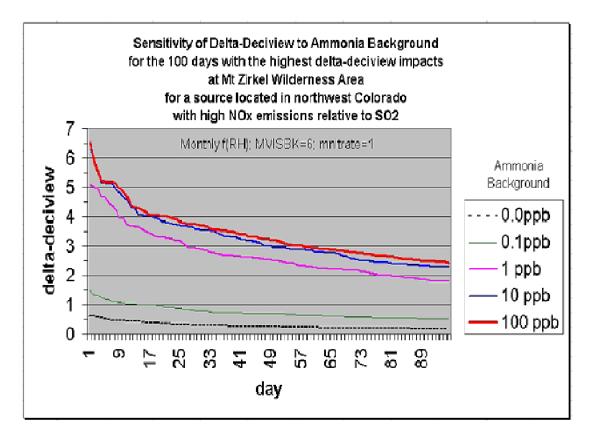
September 2012 Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>24</sup> Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at <u>http://www.colorado.gov/airquality/documents/Draft-</u> ColoradoSupplementalBARTAnalysisCALPUFFProtocol-25June2010.pdf. (2010)

Project in case studies of the Navajo Generating Station impacts on Grand Canyon monitors, as presented<sup>25</sup> to EPA in 2010.

It is important to note that 14 years ago in 1998, when the IWAQM Phase 2 guidance<sup>26</sup> was issued, CALPUFF did not even have the capability of accommodating monthly ammonia background concentrations; only a single value was allowed. Since then, CALPUFF has evolved to be able to receive as input monthly varying ammonia concentrations. EPA's guidance on the recommended input values that are constant all year has not kept pace with the CALPUFF's capability. The weight of evidence clearly indicates that the use of monthly varying ammonia concentrations with lower wintertime values will result in more accurate predictions.

# Figure B-2: CDPHE Plot of Sensitivity of Visibility Impacts Modeled by CALPUFF for Different Ammonia Backgrounds.



<sup>&</sup>lt;sup>25</sup> Salt River Project, 2010. Measurements of Ambient Background Ammonia on the Colorado Plateau and Visibility Modeling Implications. Salt River Project, P.O. Box 52025 PAB352, Phoenix, Arizona 85072.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>26</sup> IWAQM Phase 2 Summary Report and Recommendations (EPA-454/R-98-019), EPA OAQPS, December 1998). <u>http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf</u>.

## Independent Studies of the Effect of Model Chemistry on Nitrate Predictions

The Regional Haze BART Rule acknowledged that CALPUFF tends to overestimate the amount of nitrate that is produced. In particular, the overestimate of ammonium nitrate concentrations on visibility at Class I areas is the greatest in the winter, when temperatures (and visitation) are lowest, the nitrate concentrations are the greatest, and the sulfate concentrations tend to be the least due to reduced oxidation rates of SO<sub>2</sub> to sulfate.

On page 39121, the BART rule<sup>27</sup> stated that: "...the simplified chemistry in the [CALPUFF] model tends to magnify the actual visibility effects of that source."

On page 39123, the BART rule stated that: "We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. In its next review of the Guideline on Air Quality Models, EPA will evaluate these and other newer approaches<sup>28</sup>."

EPA did not conduct such an evaluation, but the discussion below reports on the efforts of other investigators.

A review of independent evaluations of the CALPUFF model is reported here, with a focus on identifying studies that address the nitrate chemistry used in the model. Morris et al.<sup>29</sup> reported that the CALPUFF MESOPUFF II transformation rates were developed using temperatures of 86, 68 and 50 °F. Therefore, the 50 °F minimum temperature used in development of the model could result in overestimating sulfate and nitrate formation in colder conditions. These investigators found that CALPUFF tended to overpredict nitrate concentrations during winter by a factor of about three.

A recent independent study of the CALPUFF performance by Karamchandani et al (referred to here as the KCBB study) is highly relevant to this issue<sup>30</sup>. The KCBB study presented several improvements to the Regional Impacts on Visibility and Acid Deposition (RIVAD) chemistry option in CALPUFF, an alternative treatment that was more amenable to an upgrade than the MESOPUFF II chemistry option. Among other items, the improvements included the replacement of the original CALPUFF secondary particulate matter (PM) modules by newer algorithms that are used in current state-of-the-art regional air quality models such as CMAQ, CMAQ-MADRID, CAMx and REMSAD, and in advanced puff models

<sup>29</sup> Morris, R., Steven Lau and Bonyoung Koo. Evaluation of the CALPUFF Chemistry Algorithms. Presented at A&WMA 98th Annual Conference and Exhibition, June 21-25, 2005 Minneapolis, Minnesota. (2005)

<sup>30</sup> Karamchandani, P., S. Chen, R. Bronson, and D. Blewitt. Development of an Improved Chemistry Version of CALPUFF and Evaluation Using the 1995 SWWYTAF Data Base. Presented at the Air & Waste Management Association Specialty Conference on Guideline on Air Quality Models: Next Generation of Models, October 28-30, 2009, Raleigh, NC. (2009)

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>27</sup> July 6, 2005 Federal Register publication of the Regional Haze BART rule.

<sup>&</sup>lt;sup>28</sup> The next (9<sup>th</sup>) EPA modeling conference was held in 2008, during which the concepts underlying the chemistry upgrades in CALPUFF 6.42 were presented. However, EPA failed to conduct the promised evaluation in its review of techniques at that conference held 4 years ago. As a result of the 10<sup>th</sup> EPA modeling conference held in March 2012, EPA appears to be continuing to rely upon CALPUFF version 5.8, which it admitted in the July 6, 2005 BART rule has serious shortcomings.

such as SCICHEM. In addition, the improvements included the incorporation of an aqueous-phase chemistry module based on the treatment in CMAQ. Excerpts from the study papers describing each of the improvements made to CALPUFF in the KCBB study are repeated below.

### Gas-Phase Chemistry Improvements

The KCBB study applied a correction to CALPUFF in that the upgraded model was modified to keep track of the puff ozone concentrations between time steps. The authors also updated the oxidation rates of  $SO_2$  and nitrogen dioxide (NO<sub>2</sub>) by the hydroxide ion (OH<sup>-</sup>) to the rates employed in contemporary photochemical and regional PM models.

#### Treatment of Inorganic Particulate Matter

The KCBB study scientists noted that the EPA-approved version of CALPUFF currently uses a simple approach to simulate the partitioning of nitrate and sulfate between the gas and particulate phases. In this approach, sulfate is appropriately assumed to be entirely present in the particulate phase, while nitrate is assumed to be formed by the reaction between nitric acid and ammonia.

The KCBB study implemented an additional treatment for inorganic gas-particle equilibrium, based upon an advanced aerosol thermodynamic model referred to as the ISORROPIA model<sup>31</sup>. This model is currently used in several state-of-the-art regional air quality models. With this new module, the improved CALPUFF model developed in the KCBB study includes a treatment of inorganic PM formation that is consistent with the state of the science in air quality modeling, and is critical for the prediction of regional haze due to secondary nitrate formation from NO<sub>X</sub> emissions.

#### Treatment of Organic Particulate Matter

The KCBB study added a treatment for secondary organic aerosols (SOA) that is coupled with the corrected RIVAD scheme described above. The treatment is based on the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID)<sup>32,33</sup>, which treats SOA formation from both anthropogenic and biogenic volatile organic compound emissions.

#### Aqueous-Phase Chemistry

The current aqueous-phase formation of sulfate in both CALPUFF's RIVAD and MESOPUFF II schemes is currently approximated with a simplistic treatment that uses an arbitrary pseudo-first order rate in the presence of clouds (0.2% per hour), which is added to the gas-phase rate. There is no explicit treatment

<sup>33</sup> Pun, B., C. Seigneur, J. Pankow, R. Griffin, and E. Knipping. An upgraded absorptive secondary organic aerosol partitioning module for three-dimensional air quality applications, 24th Annual American Association for Aerosol Research Conference, Austin, TX, October 17-21, 2005. (2005)

September 2012

www.aecom.com

<sup>&</sup>lt;sup>31</sup> Nenes A., Pilinis C., and Pandis S.N. Continued Development and Testing of a New Thermodynamic Aerosol Module for Urban and Regional Air Quality Models, *Atmos. Env.* **1998**, 33, 1553-1560.

<sup>&</sup>lt;sup>32</sup>Zhang, Y., B. Pun, K. Vijayaraghavan, S.-Y. Wu, C. Seigneur, S. Pandis, M. Jacobson, A. Nenes and J.H. Seinfeld. Development and Application of the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID), *J. Geophys. Res.* **2004**, 109, D01202, doi:10.1029/2003JD003501.

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

of aqueous-phase SO<sub>2</sub> oxidation chemistry. The KCBB study incorporated into CALPUFF a treatment of sulfate formation in clouds that is based on the treatment that is used in EPA's CMAQ model.

### CALPUFF Model Evaluation and Sensitivity Tests

The EPA-approved version of CALPUFF and the version with the improved chemistry options were evaluated using the 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database<sup>34</sup>, available from the Wyoming Department of Environmental Quality. The database includes MM5 output for 1995, CALMET and CALPUFF codes and control files, emissions for the Southwest Wyoming Regional modeling domain, and selected outputs from the CALPUFF simulations. Several sensitivity studies were also conducted to investigate the effect of background NH<sub>3</sub> concentrations on model predictions of PM nitrate. Twice-weekly background NH<sub>3</sub> concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH<sub>3</sub> concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

- MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH<sub>3</sub> concentration of 1 ppb for arid land. As discussed previously, the MESOPUFF II algorithm is the basis for the currently approved version of CALPUFF that is being used for BART determinations throughout the United States.
- 2. Improved CALPUFF RIVAD/ARM3 chemistry using background values of NH<sub>3</sub> concentrations based on measurements in the Pinedale, Wyoming area, as described above.

PM sulfate and nitrate were predicted by the two models and compared with actual measured values obtained at the Bridger Wilderness Area site from the IMPROVE network and the Pinedale site from the Clean Air Status and Trends Network (CASTNET). For the two model configurations evaluated in this study, the results for PM sulfate were very similar, which was expected since the improvements to the CALPUFF chemistry were anticipated to have the most impact on PM nitrate predictions. Therefore, the remaining discussion focuses on the performance of each model with respect to PM nitrate.

The EPA-approved CALPUFF model was found to significantly overpredict PM nitrate concentrations at the two monitoring locations, by a factor of two to three. The performance of the version of CALPUFF with the improved RIVAD chemistry was much better, with an overprediction of about 4% at the Pinedale CASTNET site and of about 28% at the Bridger IMPROVE site.

In an important sensitivity analysis conducted within the KCBB study, both the EPA-approved version of CALPUFF and the improved version were run with a constant ammonia background of 1 ppb, as recommended by IWAQM Phase II<sup>35</sup>. The results were similar to those noted above: the improved

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>34</sup> Wyoming Department of Environmental Quality. 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database. Background and database description are available at http://deq.state.wy.us/aqd/prop/2003AppF.pdf. (2010)

<sup>&</sup>lt;sup>35</sup> Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Long-Range Transport Modeling, EPA-454/R-98-019. (1998)

CALPUFF predictions were about two to three times lower than those from the EPA-approved version of CALPUFF. This result is similar to the results using the seasonal observed values of ammonia, and indicates that the sensitivity of the improved CALPUFF model to the ammonia input value is potentially less than that of the current EPA-approved model.

Similar sensitivity was noted by Scire et al. in their original work in the SWWYATF study<sup>36</sup>, in which they tested seasonally varying levels of background ammonia in CALPUFF (using 0.23 ppb in winter, for example; see Figure B-3. The sensitivity modeling for predicting levels of nitrate formation shows very similar results to those reported in the KCBB study.

These findings indicate that to compensate for the tendency of the current EPA-approved version of CALPUFF to overpredict nitrates, the background ammonia values that should be used as input in CALPUFF modeling should be representative of isolated areas (e.g., Class I areas).

On November 3, 2010, TRC released a new version (6.42) of CALPUFF to fix certain coding "bugs" in EPA-approved version 5.8 and to improve the chemistry module. Additional enhancements to CALPUFF version 6.42 have been reported at EPA's 10<sup>th</sup> modeling conference in March 2012 by Scire<sup>37</sup>, who also has conducted recent evaluations of this version in comparison to the regulatory version (5.8). Despite the evidence that this CALPUFF version is a generation ahead of the currently approved version for modeling secondary particulate formation, EPA has not acted to adopt it as a guideline model. Even with evidence provided by independent investigators<sup>29,30</sup> that also indicate that wintertime nitrate estimated by CALPUFF version 5.8 is generally overpredicted by a factor between 2 and 4, EPA has not taken steps to adopt the improved CALPUFF model, noting that extensive peer review, evaluations, and rulemaking are still needed for this adoption to occur. In the meantime, EPA, in retaining CALPUFF version 5.8 as the regulatory model for regional haze predictions, is ignoring the gross degree of overestimation of particulate nitrate and is thus ensuring that regional haze modeling conducted for BART is overly conservative. EPA's delay in adopting CALPUFF version 6.42 will thus result in falsely attributing regional haze mitigation to NO<sub>X</sub> emission reductions.

September 2012 Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas 33

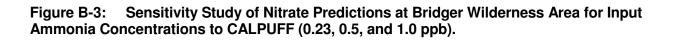
<sup>&</sup>lt;sup>36</sup> Scire, J.S., Z-X Wu, D.G. Strimaitis and G.E. Moore. The Southwest Wyoming Regional CALPUFF Air Quality Modeling Study – Volume I. Prepared for the Wyoming Dept of Environmental Quality. (2001)

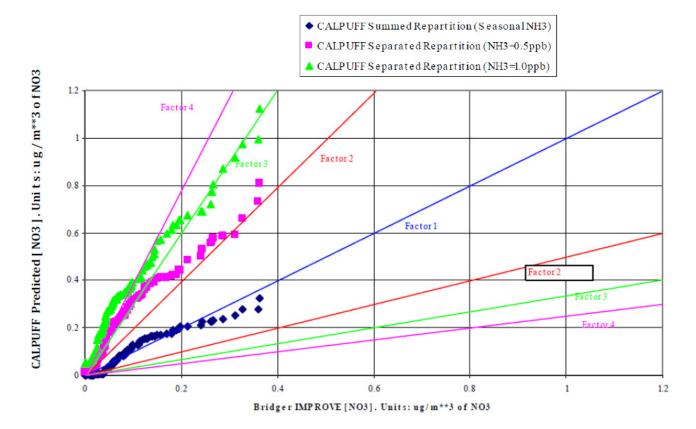
<sup>&</sup>lt;sup>37</sup> Scire, J., 2012. New Developments and Evaluations of the CALPUFF Model. <u>http://www.epa.gov/ttn/scram/10thmodconf/presentations/3-5-CALPUFF Improvements Final.pdf</u>.

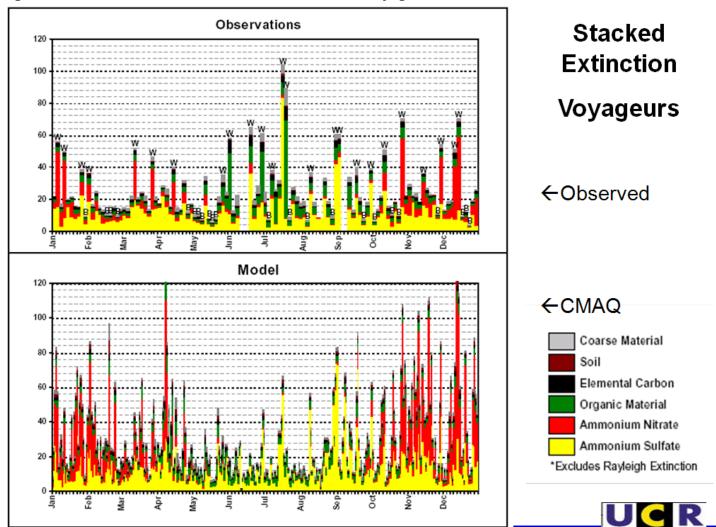
### **OVERPREDICTIONS OF NITRATE HAZE BY REGIONAL PHOTOCHEMICAL MODELS**

The overprediction tendency for modeling of wintertime nitrate haze is not limited to CALPUFF. Even the state-of-the-art regional photochemical models are challenged in getting the right ammonium nitrate concentrations. This is evident in a presentation<sup>38</sup> made by Environ to the CENRAP Regional Planning Organization in 2006. The relevant figures from the Ralph Morris presentation (shown in Figures B-4 and B-5 below) indicate that both CMAQ and CAMx significantly overpredict nitrate haze in winter at Voyageurs National Park, by about a factor of 2. This is shown by the height of the red portion of the composition plot stacked bars between the observed and predicted timelines. It is noteworthy that Minnesota and EPA have relied upon this modeling approach for their BART determinations. Similar to CALPUFF, as discussed above, the agency modeling is prone to significantly overpredicting wintertime nitrate haze, leading to an overestimate of visibility improvement with NO<sub>x</sub> emission reductions.

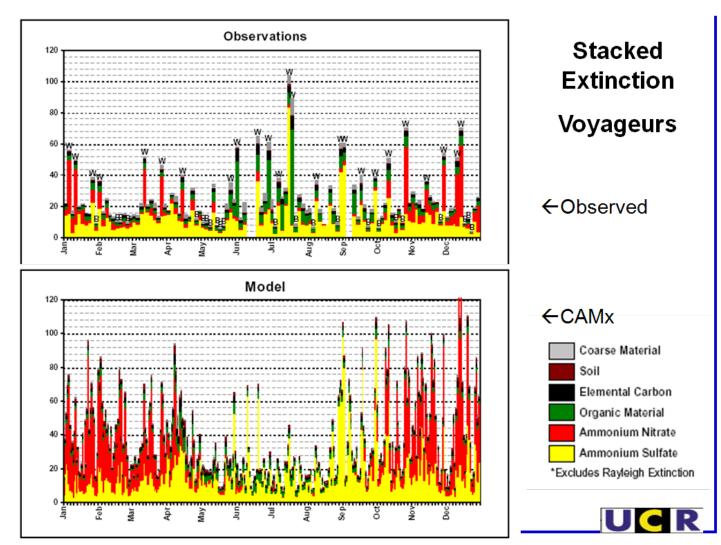
<sup>&</sup>lt;sup>38</sup> <u>http://pah.cert.ucr.edu/aqm/cenrap/meetings.shtml</u>, under "MPE", slides 9 and 10.







### Figure B-4 CMAQ vs. Observed Haze Predictions at Voyageurs National Park



# Figure B-5 CAMx vs. Observed Haze Predictions at Voyageurs National Park

# **APPENDIX C**

Haze Time Series Plots for Voyageurs National Park, Seney Wilderness Area, and Isle Royale National Park

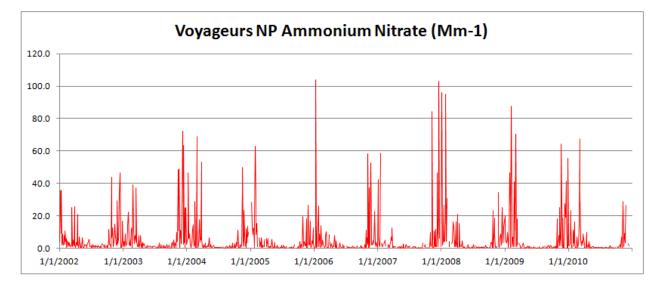
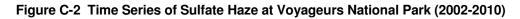
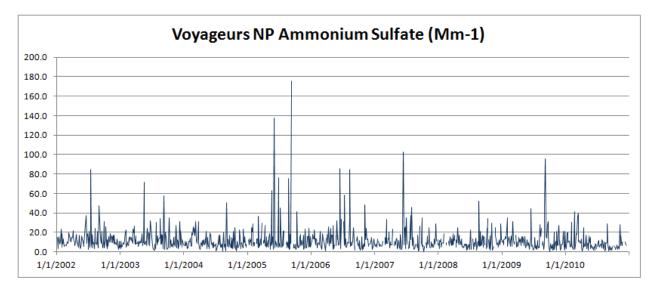
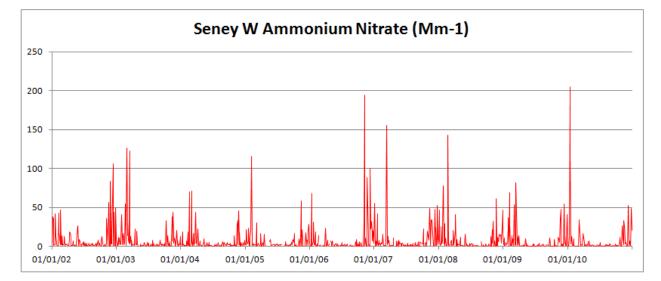


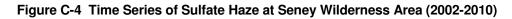
Figure C-1 Time Series of Nitrate Haze at Voyageurs National Park (2002-2010)

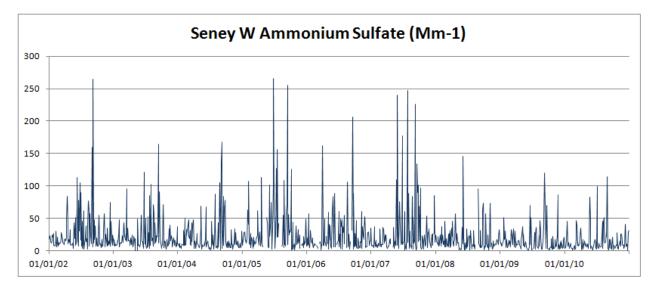


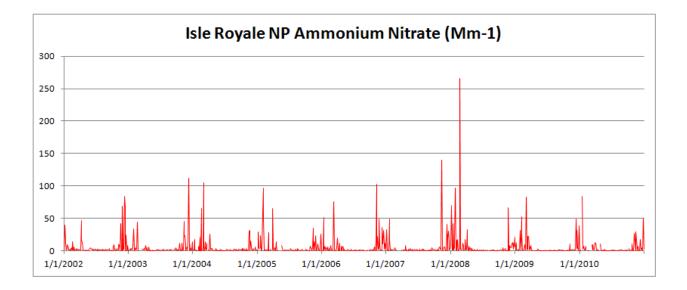




### Figure C-3 Time Series of Nitrate Haze at Seney Wilderness Area (2002-2010)

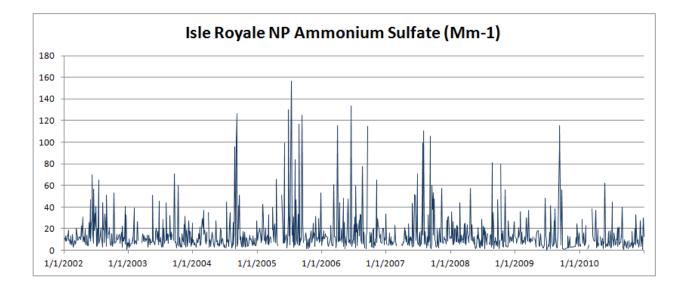






### Figure C-5 Time Series of Nitrate Haze at Isle Royale National Park (2002-2010)

#### Figure C-6 Time Series of Sulfate Haze at Isle Royale National Park (2002-2010)



## APPENDIX D

## EXAMPLE OF VISIBILITY CHANGES AFTER ACTUAL EMISSION REDUCTIONS: SHUTDOWN OF THE MOHAVE GENERATING STATION

The Mohave Generating Station (MGS) shut down at the end of 2005, which should have had a large, beneficial effect (over 2 dv, according to CALPUFF) upon Grand Canyon visibility on the 98<sup>th</sup> percentile worst days. The MGS was a large (1590 MW) coal-fired plant located near the southern tip of Nevada (Laughlin, NV). MGS was placed in operation in the early 1970s, and was retired at the end of 2005 as a result of a consent agreement with the United States Environmental Protection Agency (EPA). The agreement had provided MGS with the option of continued operation if state-of-the-art emissions controls were installed for SO<sub>2</sub> and NOx emissions, but the owners determined that the cost of controls was too high to justify the investment. As a result, the plant was shut down on December 31, 2005 and has not been in operation since then.

As shown in Figure C-1, the MGS location is about 115 km away from the closest point of the Grand Canyon National Park, for which a southwesterly wind is needed to carry the emissions from MGS to most of the park. A multi-year study<sup>39</sup> completed by the EPA in 1999 (Project MOHAVE) indicated that MGS could be a significant contributor to haze in the Grand Canyon. In fact, typical annual emissions from MGS during the last several years of operation were approximately 40,000 tons per year (TPY) of SO<sub>2</sub> and 20,000 TPY of NOx. EPA noted in their Project MOHAVE conclusions that due to this level of emissions of haze precursors and its proximity to the Grand Canyon, MGS was the single largest emission source that could cause regional haze within the Grand Canyon.

Haze observations at three locations in the Grand Canyon (Meadview, Indian Garden, and Hance Camp monitors are available every third day for periods both before and after the plant shut down at the end of 2005. By comparing haze measurements before and after plant shutdown, it may be possible to determine whether the haze in the Grand Canyon has perceptibly changed since 2005 by reviewing the data from these three monitors. The Meadview monitor is at the western edge of the Park, and is relatively close to MGS. The other two IMPROVE monitors are located near some of the most heavily visited areas of the park (Hance Camp, on the South Rim, and Indian Garden, about 1,100 feet lower near the bottom of the canyon).

A 2010 *Atmospheric Environment* paper by Terhorst and Berkman<sup>40</sup> studied the effects of the opportunistic "experiment" afforded by the abrupt shutdown of the largest source affecting the Grand Canyon (according to EPA). The paper noted that Project MOHAVE's conclusions about the effects of MGS on the Grand Canyon visibility were ambiguous. The project's tracer studies revealed that while the MGS emissions did reach the park, particularly in the summer, there was no evidence linking these elevated concentrations with actual visibility impairment; indeed, "correlation between measured tracer concentration and both particulate sulfur and light extinction were virtually nil."

On the other hand, dispersion models produced results inconsistent with the observations. Noting the disconnect between the measurements and model predictions, EPA noted the disparity between the measurements and modeling results, but still appeared to favor the models when it concluded that MGS was the largest sole contributor to visibility impairment in the Grand Canyon.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>39</sup> Pitchford, M., Green, M., Kuhns, H., Scruggs, M., Tombach, I., Malm, W., Farber, R., Mirabella, V., 1999. Project MOHAVE: Final Report. Tech. Rep., U.S. Environmental Protection Agency (EPA).

<sup>&</sup>lt;sup>40</sup> Jonathan Terhorst and Mark Berkman. "Effect of Coal-Fired Power Generation on Visibility in a Nearby National Park," Atmospheric Environment, 44(2010) 2544-2531. This publication is available by request from Mark Berkman at <u>mark.berkman@berkeleyeconomics.com</u>.

According to the authors, the Project Mohave observations were consistent with observations during temporary outages of MGS, for which there were no reports of substantial changes to visibility in the Grand Canyon.

Best Available Retrofit Technology (BART) studies evaluated a possible conversion of MGS to natural gas firing in 2008. These studies used the CALPUFF dispersion model in a manner prescribed by EPA to determine the change in visibility between the baseline emissions associated with coal firing to the natural gas firing alternative. The BART analyses conducted by the Nevada Department of Environmental Protection indicated that large differences in haze would result: an improvement of about 2.4 deciviews for the 98<sup>th</sup> percentile peak day, and a haze reduction to below 0.5 deciview on 186 days over 3 years modeled. Since natural gas firing would eliminate nearly all of the SO<sub>2</sub> emissions (although not all of the NOx emissions) this modeled result would tend to underestimate the visibility improvement that would be anticipated with a total plant shutdown.

Terhorst and Berkman analyzed several statistics to determine the change in sulfate concentrations and visibility in the Grand Canyon between the period 2003-2005 (pre-shutdown) and the period 2006-2008 (post-shutdown). They also considered other areas to determine how other regional and environmental effects might be reflected in changes at the Grand Canyon. Terhorst and Berkman calculated the average visibility over all IMPROVE monitoring days between 2003-2005 and 2006-2008, and determined that the average visibility was unchanged at Meadview, slightly improved on the South Rim (Hance Camp), and slightly worse at Indian Garden. Consistent with the observations of minimal visibility impact of MGS during Project MOHAVE, they concluded that the closure of MGS had a relatively minor effect on visibility in the Grand Canyon. These authors questioned the veracity of CALPUFF modeling (e.g., for BART) in that it predicts relatively large improvements in the Grand Canyon visibility that are not borne out by observations.

Emissions reductions associated with the shutdown of the Mohave Generating Station at the end of 2005 have provided an opportunistic means to discern the effect of retrofitting emission controls on coal-fired power plants in the western United States. In the case of MGS, although EPA had determined that this facility was the single most important contributor to haze in the Grand Canyon National Park and CALPUFF modeling using EPA's BART procedures provided predictions of significant improvements in haze, actual particulate and haze measurements taken before and after the shutdown do not reflect the large reductions that would be anticipated from these studies. This may be due in part to the fact that there are several aspects to the CALPUFF modeling procedures that greatly inflate the predicted haze (as noted below), and therefore, the predicted improvements due to emission reductions.

# AECOM

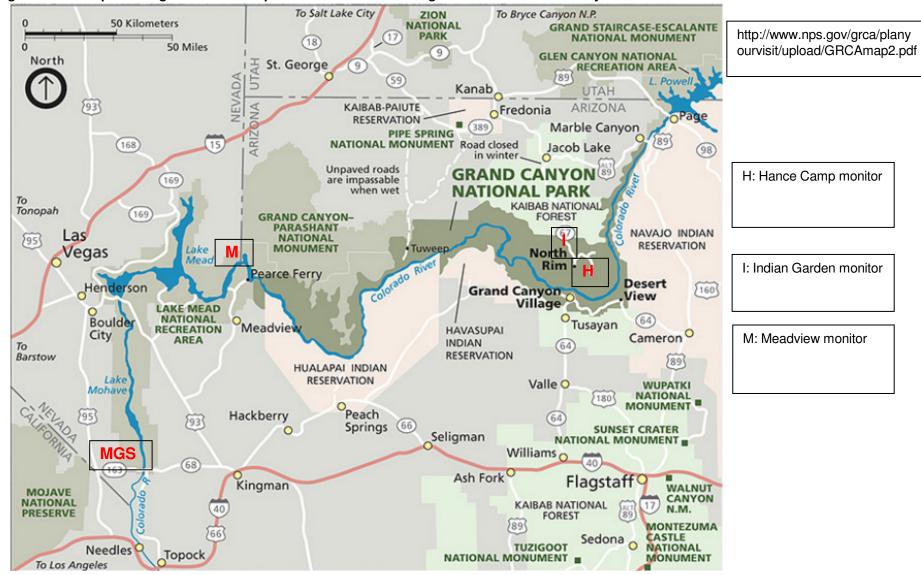


Figure D-1 : Map Showing the Relationship of the Mohave Generating Station to the Grand Canyon National Park

September 2012

Page 45 of 45

www.aecom.com

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas



# Regional Haze Four-Factor Analysis Applicability Evaluation

# **Rotary Kilns Lines 3-7**

Prepared for United States Steel Corporation, Minnesota Ore Operations - Minntac

May 29, 2020

325 South Lake Avenue Duluth, MN 55802 218.529.8200 www.barr.com

# Regional Haze Four-Factor Analysis Applicability Evaluation

May 29, 2020

# Contents

| 1 |                            | Executive Summary1   |                    |  |    |  |
|---|----------------------------|----------------------|--------------------|--|----|--|
| 2 |                            | Introduction         |                    |  |    |  |
|   | 2.1                        |                      | Regula             | tory Background  | 3  |  |
|   | 2                          | 2.1.1                | Min                | nesota's Request for Information (RFI)                                   | 3  |  |
|   | 2                          | 2.1.2                | SIP I              | Revision Requirements  | 4  |  |
|   | 2                          | 2.1.3                | USE                | PA Guidance for SIP Development  | 5  |  |
|   |                            | 2.1                  | .3.1               | Ambient Data Analysis  | 6  |  |
|   |                            | 2.1                  | .3.2               | Selection of sources for analysis  | 6  |  |
|   |                            | 2.1                  | .3.2.1             | Estimating Baseline Visibility Impacts for Source Selection              | 8  |  |
|   |                            | 2.1                  | .3.3               | Sources that Already have Effective Emission Control Technology in Place | 8  |  |
|   | 2.2                        |                      | Facility           | Description  | 9  |  |
| 3 | Analysis of Ambient Data11 |                      |                    | 11   |    |  |
|   | 3.1 Visibility Conditions1 |                      |                    | 11   |    |  |
|   | 3.2                        |                      | Region             | al emissions reductions  | 14 |  |
| 4 |                            | Visibility Impacts16 |                    | 16   |    |  |
| 5 |                            |                      |                    | 18   |    |  |
|   | 5.1                        |                      | NO <sub>X</sub> B  | ART-required Controls  | 18 |  |
|   | 5.2                        |                      | SO <sub>2</sub> BA | RT-required Controls   | 20 |  |
| 6 | Conclusion                 |                      |                    | 22   |    |  |

# List of Tables

| Table 2-1 | Identified Emission Units             | 4  |
|-----------|---------------------------------------|----|
| Table 3-1 | Notable Minnesota Emission Reductions | 15 |
| Table 5-1 | NO <sub>x</sub> Emission Limits       | 20 |
| Table 5-2 | SO <sub>2</sub> Emission Limits       | 21 |

# List of Figures

| Figure 2-1 | Grate-Kiln Furnace Diagram1  | 0 |
|------------|--|---|
| Figure 3-1 | Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)1              | 2 |
| Figure 3-2 | Visibility Trend versus URP – Voyageurs National Park (VOYA1)                  | 3 |
| Figure 3-3 | Visibility Trend versus URP – Isle Royale National Park (ISLE1)1               | 3 |
| Figure 3-4 | Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)14 | 4 |

# List of Appendices

Appendix A Visibility Impacts

# 1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency (MPCA) submitted a Request for Information (RFI) Letter<sup>1</sup> to United States Steel Corporation, Minnesota Ore Operations - Minntac (Minntac) to consider potential emissions reduction measures of nitrogen oxides (NO<sub>X</sub>) and sulfur dioxide (SO<sub>2</sub>) from the facility's indurating furnaces by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i), as explained in the August 2019 U.S. EPA Guidance (2019 Guidance)<sup>2</sup>:

- 1. cost of compliance
- 2. time necessary for compliance
- 3. energy and non-air quality environmental impacts of compliance
- 4. remaining useful life of the source

Emission reduction evaluations addressing these factors are commonly referred to as "four-factor analyses." MPCA set a July 31, 2020 deadline for Minntac to submit a four-factor analysis. The MPCA intends to use the four-factor analyses to evaluate additional control measures as part of the development of the State Implementation Plan (SIP), which must be submitted to United States Environmental Protection Agency (USEPA) by July 31, 2021. The SIP will be prepared to address the second regional haze implementation period, which ends in 2028.

This report considers whether a four-factor analysis is warranted for Minntac because the rotary kilns can be classified as "effectively controlled" sources for  $NO_x$  and  $SO_2$ . The MPCA can exclude such sources for evaluation per the regulatory requirements of the Regional Haze Rule<sup>3</sup> (RHR) and the 2019 Guidance.

This report provides evidence that it would be reasonable for MPCA to exclude Minntac from the group of sources analyzed for control measures for the second implementation period and to withdraw its request for a four-factor analysis for the rotary kilns based on the following points (with additional details provided in cited report sections):

 The rotary kilns meet the BART-required control equipment installation scenario and are "effectively controlled" sources for NO<sub>x</sub> and SO<sub>2</sub>. Minntac has BART emission controls and emission limits for NO<sub>x</sub> and SO<sub>2</sub> in accordance with 40 CFR 52.1235(b)(1) and 52.1235(b)(2), respectively. The associated BART analyses are provided in the August 2012<sup>4</sup> and October 2015<sup>5</sup> USEPA Federal Implementation Plan (FIP) rulemaking. (see Section 5)

<sup>&</sup>lt;sup>1</sup> January 29, 2020 letter from Hassan Bouchareb of MPCA to United States Steel Corporation – Minnesota Ore Operations - Minntac.

<sup>&</sup>lt;sup>2</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019

<sup>&</sup>lt;sup>3</sup> USEPA, Regional Haze Rule Requirements – Long Term Strategy for Regional Haze, 40 CFR 52.308(f)(2)

<sup>&</sup>lt;sup>4</sup> USEPA, Federal Register, 08/15/2012, Page 49308.

<sup>&</sup>lt;sup>5</sup> USEPA, Federal Register, 10/22/2015, Page 64160.

- The RHR and the 2019 Guidance both give states the ability to focus their analyses in one implementation period on a set of sources that differ from those analyzed in another implementation period. (see Section 2.1.3.2)
- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress. (see Section 3.1)
- The rotary kilns do not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4)

Additional emission reductions from the rotary kilns at Minntac will not contribute meaningfully to further reasonable progress. Therefore Minntac requests MPCA withdraw its request for a four-factor analysis for the rotary kilns.

# 2 Introduction

Section 2.1 discusses the RFI provided to Minntac by MPCA, pertinent regulatory background for regional haze State Implementation Plans (SIP) development and relevant guidance issued by USEPA to assist States in preparing their SIPs, specifically regarding the selection of sources that must conduct an emissions control evaluation. Section 2.2 provides a description of Minntac's indurating furnaces.

# 2.1 Regulatory Background

# 2.1.1 Minnesota's Request for Information (RFI)

"Regional haze" is defined at 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic 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 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 initial SIP was informed by best available retrofit technology (BART) analyses that were completed on all BART-subject sources. The second RHR implementation period ends in 2028 and requires development and submittal of a comprehensive SIP update by July 31, 2021.

As part of the second RHR implementation period SIP development, the MPCA sent an RFI to Minntac on January 29, 2020. The RFI stated that data from the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) 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 SO<sub>2</sub> and NO<sub>x</sub> that react with available ammonia. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan.<sup>6</sup> As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFI also stated that Minntac was identified as a significant source of  $NO_X$  and  $SO_2$  and is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that Minntac submit a "four-factors analysis" (herein termed as a "four-factor analysis") evaluating potential emissions control measures, pursuant to 40 CFR 51.308(f)(2)(i)<sup>7</sup>, by July 31, 2020 for the emission units identified in Table 2-1.

<sup>&</sup>lt;sup>6</sup> Although Michigan is responsible for evaluating haze in Isle Royale, it must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts.

<sup>&</sup>lt;sup>7</sup> The four statutory factors are 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts of compliance, and 4) remaining useful life of the source.

#### Table 2-1 Identified Emission Units

| Unit               | Unit ID           | Applicable Pollutants             |  |
|--------------------|-------------------|-----------------------------------|--|
| Line 3 Rotary Kiln | (EQUI 146/EU 225) | NO <sub>x</sub> , SO <sub>2</sub> |  |
| Line 4 Rotary Kiln | (EQUI 279/EU 261) | NO <sub>X</sub> , SO <sub>2</sub> |  |
| Line 5 Rotary Kiln | (EQUI 280/EU 282) | NO <sub>X</sub> , SO <sub>2</sub> |  |
| Line 6 Rotary Kiln | (EQUI 3/EU 315)   | NO <sub>X</sub> , SO <sub>2</sub> |  |
| Line 7 Rotary Kiln | (EQUI 179/EU 334) | NO <sub>X</sub> , SO <sub>2</sub> |  |

The RFI to Minntac specified that the "analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to USEPA guidance as issued on August 20, 2019<sup>8</sup>.

# 2.1.2 SIP Revision Requirements

The regulatory requirements for comprehensive revisions to the SIP are provided in 40 CFR 51.308(f). The next revision must be submitted to USEPA by July 31, 2021 and must include a commitment to submit periodic reports describing progress towards the reasonable progress goals as detailed in 40 CFR 51.308(g). The SIP "must address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State."

Each SIP revision is required to address several elements, including "calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress." <sup>9</sup> The baseline conditions are based on monitoring data from 2000 to 2004 while the target conditions for natural visibility are determined using USEPA guidance. The State will then determine the uniform rate of progress (URP) which compares "the baseline visibility condition for the most impaired days to the natural visibility condition for the most impaired days to the natural visibility condition for the uniform rate of visibility improvement (measured in deciviews of improvement per year) that would need to be maintained during each implementation period in order to attain natural visibility conditions by the end of 2064."<sup>10</sup>

The SIP revision must also include the "Long-term strategy for regional haze."<sup>11</sup> The strategy "must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress" towards the natural visibility goal. There are several criteria that must be considered when developing the strategy, including an evaluation of emission controls (the four-factor analysis) at selected facilities to determine emission reductions necessary to make reasonable progress. The SIP must consider other factors in developing its long-term strategy, including: emission reductions due to other air pollution control programs<sup>12</sup>, emission unit retirement and replacement

<sup>&</sup>lt;sup>8</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019 <sup>9</sup> 40 CFR 51.308(f)(1)

<sup>&</sup>lt;sup>10</sup> 40 CFR 51.308(f)(1)(vi)(A)

<sup>&</sup>lt;sup>11</sup> 40 CFR 51.308(f)(2)

<sup>&</sup>lt;sup>12</sup> 51.308(f)(2)(iv)(A)

schedules<sup>13</sup>, and the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during the implementation period<sup>14</sup>.

In addition, the SIP must include "reasonable progress goals" that reflect the visibility conditions that are anticipated to be achieved by the end of the implementation period through the implementation of the long term strategy and other requirements of the Clean Air Act (CAA)<sup>15</sup>. The reasonable progress goal is not enforceable but will be considered by USEPA in evaluating the adequacy of the SIP<sup>16</sup>.

# 2.1.3 USEPA Guidance for SIP Development

On August 20, 2019, the USEPA issued "*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*"<sup>17</sup> USEPA's primary goal in issuing the 2019 Guidance was to help states develop "approvable" SIPs. EPA also stated that the document supports key principles in SIP development, such as "leveraging emission reductions achieved through CAA and other programs that further improve visibility in protected areas."<sup>18</sup>

The 2019 Guidance says SIPs must be "consistent with applicable requirements of the CAA and EPA regulations, and are the product of reasoned decision-making"<sup>19</sup> but also emphasizes States' discretion and flexibility in the development of their SIPs. For instance, the 2019 Guidance states, "A key flexibility of the regional haze program is that a state is *not* required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures."<sup>20</sup> The 2019 Guidance notes this flexibility to not consider every emission source stems directly from CAA § 169A(b)(2) and 40 CFR § 51.308(f)(2)(i), the section of the RHR the MPCA cites in its letter.<sup>21</sup>

The 2019 Guidance lists eight key process steps that USEPA anticipates States will follow when developing their SIPs. This report focuses on the selection of sources which must conduct a four-factor analysis and references the following guidance elements which impact the selection:

- Ambient data analysis (Step 1), including the progress, degradation and URP glidepath checks (Step 7)
- Selection of sources for analysis (Step 3), with a focus on:
  - Estimating baseline visibility impacts for source selection (Step 3b)

<sup>21</sup> Ibid.

<sup>&</sup>lt;sup>13</sup> 51.308(f)(2)(iv)(C)

<sup>&</sup>lt;sup>14</sup> 51.308(f)(2)(iv)(E)

<sup>15 40</sup> CFR 51.308(f)(3)

<sup>&</sup>lt;sup>16</sup> 40 CFR 51.308(f)(3)(iii)

 <sup>&</sup>lt;sup>17</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019
 <sup>18</sup> Ibid, page 1.

<sup>&</sup>lt;sup>19</sup> Ibid.

<sup>&</sup>lt;sup>20</sup> Ibid, page 9 (emphasis added).

• Sources that already have effective emission control technology in place (Step 3f)

## 2.1.3.1 Ambient Data Analysis

As stated in Section 2.1.2, the RHR requires each state with a Class I area to calculate the baseline, current, and natural visibility conditions as well as to determine the visibility progress to date and the URP. The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). The guidance provides the following equation for calculating the Uniform Rate of Progress (URP):<sup>22</sup>

### URP = [(2000-2004 visibility)<sub>20% most impaired</sub> - (natural visibility)<sub>20% most impaired</sub>]/60

The visibility from 2000-2004 represents the baseline period, and the natural visibility goal is in 2064, which is why the URP is calculated over a 60-year period.

At the end of the SIP development process a State must estimate the visibility conditions for the end of the implementation period and then must complete a comparison of the reasonable progress goals to the baseline visibility conditions and the URP glidepath. The guidance explains that the RHR does not define the URP as the target for "reasonable progress" and further states that if the 2028 estimate is below the URP glidepath, that does not exempt the State from considering the four-factor analysis for select sources.<sup>23</sup> However, the current visibility conditions compared to the URP glidepath will be a factor when determining the reasonable progress goal.

In Section 3, Barr evaluates the visibility improvement progress to date at BWCA, Voyageurs and Isle Royale using the IMPROVE network visibility data from MPCA's website. This analysis was conducted to document the current visibility conditions compared to the URP, which can provide insight into the amount of emission reductions necessary to have the 2028 visibility conditions below the URP.

## 2.1.3.2 Selection of sources for analysis

The 2019 Guidance emphasizes that the RHR provides flexibility in selecting sources that must conduct an emission control measures analysis:

"...a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures...."<sup>24</sup>

The 2019 Guidance goes on to justify this approach (emphasis added):

"Selecting a set of sources for analysis of control measures in each implementation period is also consistent with the Regional Haze Rule, which sets up an iterative planning process and anticipates that a state may not need to analyze control measures for all its sources in a given SIP revision. Specifically, section 51.308(f)(2)(i) of the Regional Haze Rule requires a SIP to include a

<sup>&</sup>lt;sup>22</sup> Ibid, Page 7.

<sup>&</sup>lt;sup>23</sup> Ibid, Page 50.

<sup>&</sup>lt;sup>24</sup> Ibid, Page 9.

description of the criteria the state has used to determine the sources or groups of sources it evaluated for potential controls. Accordingly, <u>it is reasonable and permissible for a state to</u> <u>distribute its own analytical work, and the compliance expenditures of source owners, over time</u> <u>by addressing some sources in the second implementation period and other sources in later</u> <u>periods</u>. For the sources that are not selected for an analysis of control measures for purposes of the second implementation period, it may be appropriate for a state to consider whether measures for such sources are necessary to make reasonable progress in later implementation periods."<sup>25</sup>

The 2019 Guidance further states that there is not a list of factors that a state must consider when selecting sources to evaluate control measures, but the state must choose factors and apply them in a reasonable way to make progress towards natural visibility. The guidance details several factors that could be considered, including:

- the in-place emission control measures and, by implication, the emission reductions that are possible to achieve at the source through additional measures<sup>26</sup>
- the four statutory factors (to the extent they have been characterized at this point in SIP development)<sup>27</sup>
- potential visibility benefits (also to the extent they have been characterized at this point in SIP development)<sup>28</sup>
- sources already having effective emissions controls in place<sup>29</sup>
- emission reductions at the source due to ongoing air pollution control programs<sup>30</sup>
- in-state emission reductions due to ongoing air pollution control programs that will result in an improvement in visibility<sup>31</sup>

Furthermore, the 2019 Guidance states that "An initial assessment of projected visibility impairment in 2028, considering growth and on-the books controls, can be a useful piece of information for states to consider as they decide how to select sources for control measure evaluation."<sup>32</sup>

<sup>&</sup>lt;sup>25</sup> Ibid, Page 9.

<sup>&</sup>lt;sup>26</sup> Ibid, Page 10.

<sup>27</sup> Ibid.

<sup>&</sup>lt;sup>28</sup> Ibid.

<sup>&</sup>lt;sup>29</sup> Ibid, Page 21.

<sup>&</sup>lt;sup>30</sup> Ibid, Page 22.

<sup>&</sup>lt;sup>31</sup> Ibid.

<sup>&</sup>lt;sup>32</sup> Ibid, Page 10.

### 2.1.3.2.1 Estimating Baseline Visibility Impacts for Source Selection

When selecting sources to conduct an emission control evaluation, the 2019 Guidance says that the state may use a "reasonable surrogate metrics of visibility impacts." The guidance provides the following techniques to consider and says that "other reasonable techniques" may also be considered<sup>33</sup>:

- Emissions divided by distance (Q/d)
- Trajectory analyses
- Residence time analyses
- Photochemical modeling

In regards to documenting the source selection process, the 2019 Guidance states:<sup>34</sup>

"EPA recommends that this documentation and description provide both a summary of the state's source selection approach and a detailed description of how the state used technical information to select a reasonable set of sources for an analysis of control measures for the second implementation period. The state could include qualitative and quantitative information such as: the basis for the visibility impact thresholds the state used (if applicable), additional factors the state considered during its selection process, and any other relevant information."

In Section 4, Barr presents a trajectory analysis using data from the IMPROVE monitoring network as presented on MPCA's website and photochemical modeling results to demonstrate that it is not appropriate to select the taconite indurating furnaces as sources subject to the emissions control measures analysis because reducing the emissions will not have a large impact on visibility. Section 4 also presents information from the IMPROVE monitoring system which demonstrates that there was not a noticeable improvement in visibility in 2009 when the taconite plants experienced a production curtailment due to a recession which indicates that the reduction of pollutants from taconite facilities will not result in a discernable visibility improvement in the Class 1 areas.

## 2.1.3.3 Sources that Already have Effective Emission Control Technology in Place

The 2019 Guidance identified eight example scenarios and described the associated rationale for when sources should be considered "effectively controlled" and that states can exclude similar sources from needing to complete a "four-factor analysis."<sup>35</sup> One of the "effectively controlled" scenarios is for "BART-eligible units that installed and began operating controls to meet BART emission limits for the first implementation period."<sup>36</sup> USEPA caveats this scenario by clarifying that "states may not categorically exclude all BART-eligible sources, or all sources that installed BART control, as candidates for selection for

<sup>&</sup>lt;sup>33</sup> Ibid, Page 12.

<sup>&</sup>lt;sup>34</sup> Ibid, Page 27.

<sup>&</sup>lt;sup>35</sup> Ibid, Page 22.

<sup>&</sup>lt;sup>36</sup> Ibid, Page 25.

analysis of control measures."<sup>37</sup> USEPA further notes that "a state might, however, have a different, reasonable basis for not selecting such sources [BART-eligible and non-BART eligible units that implement BART controls] for control measure analysis."<sup>38</sup>

In Section 5, Barr presents an evaluation of the BART-eligible units scenario and demonstrates that the rotary kilns are "effectively controlled" sources for both  $NO_X$  and  $SO_2$ . Thus, a four-factor analysis is not warranted for this source because, as USEPA notes, "it may be unlikely that there will be further available reasonable controls for such sources."<sup>39</sup>

# 2.2 Facility Description

Minntac mines iron ore (magnetite) and produces taconite pellets that are shipped to steel producers for processing in blast furnaces. The iron ore is crushed and routed through several concentration stages including grinding, magnetic separation, and thickening.

A concentrated iron ore slurry is dewatered by vacuum disc filters, mixed with bentonite, and conveyed to balling drums. Greenballs produced in the balling drums are fed to the traveling grate prior to entering the kiln. The traveling grate consists of drying and preheat zones. After greenballs pass through the traveling grate, they enter the kiln where pellets are heated to approximately 2,400 degrees Fahrenheit to facilitate the conversion of magnetite to hematite. After the kiln, the fired pellets are sent to an annular cooler where ambient air is blown through the pellets, which allows them to be safely discharged onto rubber belting. The heated waste gas from the kiln and annular cooler are used for the drying and heating zones on the traveling grate. Minntac operates five grate/induration kiln (grate-kiln) furnaces. Waste gas from each furnace is controlled by a single venturi wet scrubber and is vented through a single stack.

Figure 2-1 includes a generic sketch of Minntac's grate-kiln furnace designs. Note the schematic does not perfectly represent all Minntac furnace lines. Line 3 does not recirculate cooling air back to the drying zone. Lines 6 and 7 are ported kilns that can inject air directly into the pellet bed.

<sup>37</sup> Ibid.

<sup>&</sup>lt;sup>38</sup> Ibid.

<sup>&</sup>lt;sup>39</sup> Ibid.

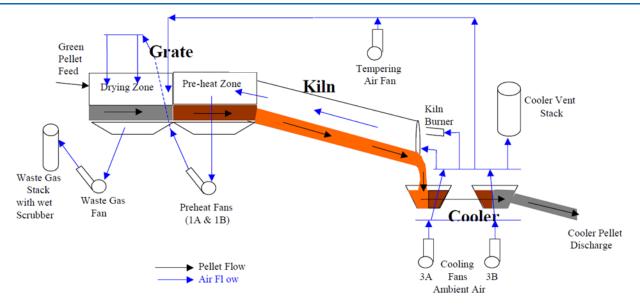


Figure 2-1 Grate-Kiln Furnace Diagram

# 3 Analysis of Ambient Data

As described in Section 2.1.2, the SIP must consider visibility conditions (baseline, current, and natural visibility), progress to date, and the URP. This requirement is referred to as Step 1 on the 2019 Guidance (see Section 2.1.3.1). This information informs the State's long term strategy for regional haze, as required by 51.308(f)(2), and the reasonable progress goals, as required by 51.308(3).

Section 3.1 provides analysis of visibility conditions based on data from the IMPROVE monitoring network at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1) and Section 3.2 addresses regional emission reductions. Consistent with 51.308(f)(2)(iv), the regional emission reductions summary considers emission reductions that have occurred but are not yet reflected in the available 5-year average monitoring data set and future emission reductions that will occur prior 2028, which is the end of the second SIP implementation period.

# 3.1 Visibility Conditions

As summarized in Section 2.1.2, the RHR requires that the SIP include an analysis "of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."<sup>40</sup> This data will be used in the SIP to establish reasonable progress goals (expressed in deciviews) that reflect the visibility conditions that are projected to be achieved by the end of the implementation period (2028) as a result of the implementation of the SIP and the implementation of other regulatory requirements.<sup>41</sup> The reasonable progress goal is determined by comparing the baseline visibility conditions to natural visibility conditions and determining the uniform rate of visibility improvement needed to attain natural visibility conditions by 2064. The SIP "must consider the uniform rate of improvement in visibility and the emission-reduction measures needed to achieve it for the period covered by the implementation plan."<sup>42</sup>

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).<sup>43</sup> The available regional haze monitoring data was compared to the uniform rate of progress and to the possible reasonable progress goals for the SIP for the implementation period, which ends in 2028. As described in Section 2.1.3.1, the visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). USEPA issued guidance for tracking visibility progress, including the methods for selecting the "most impaired days," on December 20, 2018.<sup>44</sup> Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms) could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."<sup>45</sup> In

<sup>40 40</sup> CFR 51.308(f)(1)

<sup>&</sup>lt;sup>41</sup> 40 CFR 51.308(f)(3)

<sup>&</sup>lt;sup>42</sup> 40 CFR 51.308(d)(1)

<sup>&</sup>lt;sup>43</sup> https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze visibility metrics public/Visibilityprogress

<sup>&</sup>lt;sup>44</sup> https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

<sup>45</sup> USEPA, Federal Register, 05/04/2016, Page 26948

addition, the RHR allows a state to account for international emissions "to avoid any perception that a state should be aiming to compensate for impacts from international anthropogenic sources."<sup>46</sup>

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath<sup>47</sup> at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1). Regional haze impairment has been declining since 2009 for all three Class I areas that are tracked by MPCA. Impacts to the most impaired days at BWCA and Isle Royale fell below the expected 2028 URP goal in 2016 and have continued trending downward since. Voyageurs impaired days fell below the 2028 URP in 2018 and is also on a downward trend.

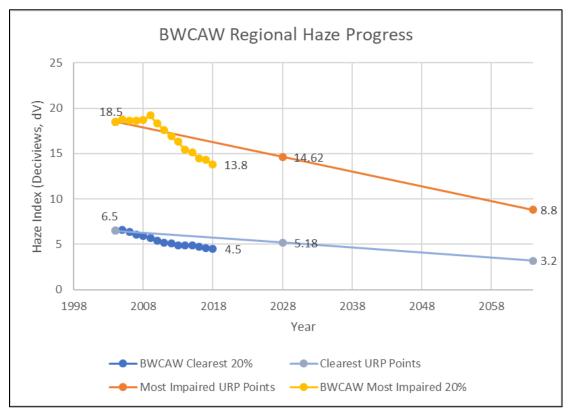


Figure 3-1 Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

<sup>&</sup>lt;sup>46</sup> USEPA, Federal Register, 01/10/2017, Page 3104

<sup>&</sup>lt;sup>47</sup><u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze\_visibility\_metrics\_public/Visibilitypro</u> gress

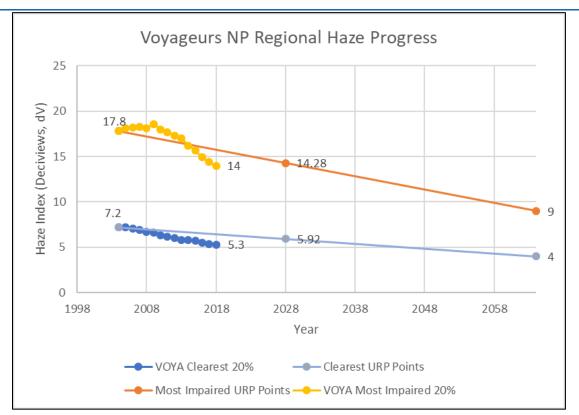


Figure 3-2 Visibility Trend versus URP – Voyageurs National Park (VOYA1)

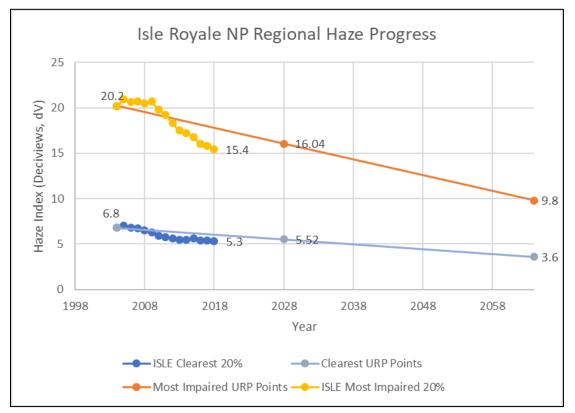


Figure 3-3 Visibility Trend versus URP – Isle Royale National Park (ISLE1)

## 3.2 Regional emissions reductions

The visibility improvement shown in Figure 3-1 through Figure 3-3 correlates with  $SO_2$  and  $NO_x$  emissions decreases from Minnesota's top twenty emission stationary sources, as shown in Figure 3-4<sup>48</sup>. These emission reductions are a result of multiple substantial efforts from the regulated community, including:

- Installation of BART controls during the first implementation period
- Emission reductions at electric utility combustion sources due to new rules and regulations, including:
  - Acid Rain Rules
  - o Cross State Air Pollution Rule (CASPR)
  - Mercury and Air Toxics Standards (MATS)
- Electric utility combustion sources undergoing fuel changes (e.g., from coal and to natural gas)
- Increased generation of renewable energy, which decreases reliance on combustion sources

Since many of these emission reduction efforts are due to federal regulations and national trends in electrical generation, similar emission reduction trends are likely occurring in other states.

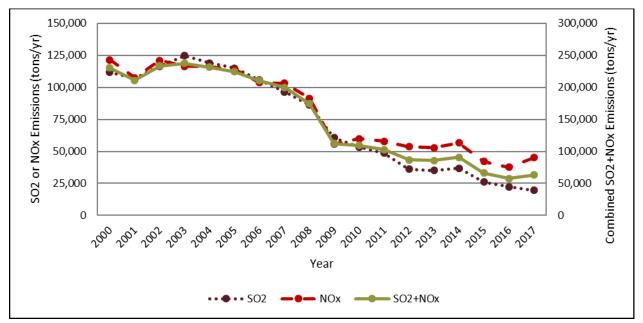


Figure 3-4 Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)

 $<sup>^{48}</sup>$  The data for NO<sub>X</sub> and SO<sub>2</sub> emissions was downloaded from the MPCA point source emissions inventory (<u>https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data</u>). The permitted facilities that had the 20 highest cumulative emissions from 2000-2017 in MN were chosen for the graphics, along with all six taconite facilities (whether or not they were in the top 20 of the state).

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath, so the emissions represented in the most recent data set (2018) is from 2014-2018. However, as shown in Table 3-1, additional emission reductions have occurred since 2014 and are not fully represented in the 5-year visibility data yet. Additionally, several stationary sources have scheduled future emission reductions which will occur prior to 2028. Combined, these current and scheduled emission reductions will further improve visibility in the Class I areas, ensuring the trend stays below the URP. Even without these planned emissions reductions, the 2018 visibility data is already below the 2028 glidepath. As such, MPCA's second SIP implementation period strategy should be commensurate with the region's visibility progress and it would be reasonable for MPCA to not include the taconite indurating furnaces when "reasonably select[ing] a set of sources for an analysis of control measures," and such decision is supported by the 2019 Guidance.

| Year | Additional Emissions Reductions Expected/Projected   |
|------|--|
| 2015 | MP Laskin: converted from coal to natural gas**  |
| 2017 | Minntac Line 6: FIP emission limit compliance date for NO <sub>X</sub> *   |
| 2018 | Minntac Line 7: FIP emission limit compliance date for NO <sub>X</sub> *<br>MP Boswell: Units 1 & 2 retired from service**   |
| 2019 | Hibtac Line 1: FIP emission limit compliance date for $NO_X^*$<br>Keetac: FIP emission limit compliance date for $NO_X^*$<br>Minntac Line 4 or 5: FIP emission limit compliance date for $NO_X^*$<br>Utac Line 1: FIP emission limit compliance date for $NO_X^*$                                      |
| 2020 | Hibtac Line 2: FIP emission limit compliance date for NO <sub>X</sub> *<br>Minntac Line 4 or 5: FIP emission limit compliance date for NO <sub>X</sub> *<br>Minorca: FIP emission limit compliance date for NO <sub>X</sub> *<br>Utac Line 2: FIP emission limit compliance date for NO <sub>X</sub> * |
| 2021 | Minntac Line: FIP emission limit compliance date for NO <sub>X</sub> *<br>Hibtac Line 3: FIP emission limit compliance date for NO <sub>X</sub> *  |
| 2023 | Xcel: Sherco Unit 2 Retirement***  |
| 2026 | Xcel: Sherco Unit 1 Retirement***  |
| 2028 | Xcel: Allen S. King Plant Retirement***  |
| 2030 | Xcel: Sherco Unit 3 Retirement, Xcel target to emit 80% less carbon by 2030***   |
| 2050 | Xcel: Energy targeting carbon free generation by 2050***   |

#### Table 3-1 Notable Minnesota Emission Reductions

\* FIP is the regional haze Federal Implementation Plan detailed in 40 CFR 52.1235

\*\* Minnesota Power - Integrated Resource Plan 2015-2029

\*\*\* Xcel Energy - Upper Midwest Integrated Resource Plan 2020-2034.

# **4 Visibility Impacts**

As described in Section 2.1.3.2, the 2019 Guidance outlines criteria to evaluate when selecting sources that must complete an analysis of emission controls. The 2019 Guidance is clear that a state does not need to evaluate all sources of emissions but "may reasonably select a set of sources for an analysis of control measures" to make progress towards natural visibility.

As described in Section 2.1.3.2.1, the 2019 Guidance provides recommendations on selecting sources by estimating baseline visibility impacts. Three of the options for estimating baseline visibility impacts are analyzed below:

### • Trajectory analyses<sup>49</sup>

In general, these analyses consider the wind direction and the location of the Class I areas to identify which sources tend to emit pollutants upwind of Class I areas. The 2019 Guidance says that a state can consider "back trajectories" which "start at the Class I area and go backwards in time to examine the path that emissions took to get to the Class I areas." Section A1.1 of Appendix A, describes the back trajectory analysis and concludes the taconite indurating furnaces were a marginal contributor to the "most impaired" days from 2009 and 2011-2015. The trajectory analysis also indicates many sources other than the taconite facilities were significant contributors to the "most impaired" days.

### • Photochemical modeling<sup>50</sup>

The 2019 Guidance says, "states can also use a photochemical model to quantify source or source sector visibility impacts." CAMx modeling was previously conducted to identify visibility impacts in Class I areas from Minnesota taconite facilities from NOx emission reductions. This analysis is summarized in Section A1.2 of Appendix A which concludes the Class I areas near the Iron Range will not experience any observable visibility improvements from NO<sub>x</sub> emission reductions suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces.

• Other reasonable techniques<sup>51</sup>

In addition to the two analyses described above which estimate the baseline visibility impacts, Section A1.3 of Appendix A evaluates the actual visibility data against the 2009 economic recession impacts on visibility, when taconite facilities curtailed production. This curtailment resulted in a decrease in emissions from the collective group of taconite plant and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this curtailment period was compared to monitoring data during more typical production at the taconite plants to estimate the taconite facilities' actual (rather than modeled) impact on haze. This analysis concludes "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It

<sup>&</sup>lt;sup>49</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 13.

<sup>&</sup>lt;sup>50</sup> Ibid, Page 14.

<sup>&</sup>lt;sup>51</sup> Ibid, Page 12.

is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions."<sup>52</sup> The report further notes "high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states."<sup>53</sup>

<sup>&</sup>lt;sup>52</sup> AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.

<sup>&</sup>lt;sup>53</sup> Ibid, Page 12.

# 5 Evaluation of "Effectively Controlled" Source

As described in Section 2.1.3.3, the 2019 Guidance acknowledges that states may forgo requiring facilities to complete the detailed four-factor analysis if the source already has "effective emission control technology in place."<sup>54</sup> This section demonstrates that the rotary kilns meet USEPA's BART-required control equipment installation scenario for NO<sub>X</sub> and SO<sub>2</sub>.

The rotary kilns meet this scenario as "effectively controlled" sources because:

- The rotary kilns are BART-eligible units, as determined by Minnesota's December 2009 Regional Haze Plan, and are regulated under 40 CFR 52.1235 (Approval and Promulgation of Implementation Plans – Subpart Y Minnesota – Regional Haze)
- The rotary kilns have controls and must "meet BART emission limits for the first implementation period"  $^{55}$  for NO  $_{\rm X}$  and SO  $_2$
- In 2016, EPA promulgated a revised FIP that included, among other things, BART requirements to effectively control NOx and SO2 for the Minntac grate kilns<sup>56</sup>

The following sections describe USEPA's BART determinations, the associated controls that were implemented as BART, and the resulting BART emission limits for  $NO_X$  and  $SO_2$ .

## 5.1 NO<sub>x</sub> BART-required Controls

In the August 2012 proposed rule FR notice preamble,<sup>57</sup> the USEPA concluded that BART for NO<sub>X</sub> from grate-kiln furnaces is low-NO<sub>X</sub> burner technology. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

• External and Induced Flue Gas Recirculation Burners due to the high oxygen content of the flue gas; <sup>58</sup>

<sup>&</sup>lt;sup>54</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, page 22.

<sup>&</sup>lt;sup>55</sup> Ibid, page 25.

<sup>&</sup>lt;sup>56</sup> See Federal Register 81, No. 70 (April 12, 2016) 21672. Although the 2012 FIP and the revised 2016 FIP limits for the grate kiln are in litigation, the outcome of that litigation will include BART and what is considered "effectively controlled." Most recently, on February 4, 2020 (See Federal Register 85 No. 23 (February 4, 2020) 6125, EPA proposed BART limits for the Minntac kilns, incorporating the requirements of its agreement with U. S. Steel entered in November 2019. In light of these very recent determinations and actions, it would be inappropriate, inefficient and futile to review the determination that was just proposed a couple of months ago.

<sup>&</sup>lt;sup>57</sup> Federal Register 77, No. 158 (August 15, 2012); 49311. Available at: <u>https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789</u>.

<sup>&</sup>lt;sup>58</sup> Ibid, 49312.

- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure;<sup>59</sup>
- Alternate Fuels due to the uncertainty of environmental and economic benefits<sup>60</sup>; and
- Selective Catalytic Reduction (SCR) controls because of two SCR vendors declining to bid on NO<sub>x</sub> reduction testing at the U.S. Steel Minntac facility.<sup>61</sup>

Because the technical feasibility determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for NO<sub>X</sub> emissions from taconite indurating furnaces. Since the 2016 BART FIP is still in the implementation phase, it is premature and inappropriate to perform another analysis until the requirements of the 2016 FIP have been completed.<sup>62</sup>

In accordance with the FIP, Minntac implemented BART  $NO_x$  control measures and the rotary kilns will be or are currently subject to the FIP  $NO_x$  emission limits<sup>63</sup> as shown in Table 5-1. Thus, the rotary kilns are considered an "effectively controlled" sources in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for  $NO_x$ . In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the rotary kilns from the requirement to submit a four-factor analysis<sup>64</sup>.

<sup>59</sup> Ibid.

<sup>&</sup>lt;sup>60</sup> Ibid, 49313.

<sup>61</sup> Ibid.

<sup>&</sup>lt;sup>62</sup> As noted above, the 2012 FIP and the revised 2016 FIP limits for the grate kiln are in litigation. For Minntac, in 2019, EPA just completed its evalutioon and determined what is considered "effectively controlled." Most recently, on February 4, 2020 (See Federal Register 85 No. 23 (February 4, 2020) 6125, EPA proposed BART limits for the Minntac kilns, incorporating the requirements of its agreement with U. S. Steel entered in November 2019. In light of these very recent determinations and actions, it would be inappropriate, inefficient and futile to review the determination that was just proposed a couple of months ago.

<sup>63 40</sup> CFR 52.1235(b)(1)

<sup>&</sup>lt;sup>64</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 10.

#### Table 5-1NOx Emission Limits

| Unit               | Unit ID           | NO <sub>x</sub><br>Emission Limit<br>(lb/MMBtu) | Compliance Date <sup>(1,2)</sup> |
|--------------------|-------------------|---|----------------------------------|
| Line 3 Rotary Kiln | (EQUI 146/EU 225) |   |                                  |
| Line 4 Rotary Kiln | (EQUI 279/EU 261) |   |                                  |
| Line 5 Rotary Kiln | (EQUI 280/EU 282) | 1.6   | September 1, 2019                |
| Line 6 Rotary Kiln | (EQUI 3/EU 315)   |   |                                  |
| Line 7 Rotary Kiln | (EQUI 179/EU 334) |   |                                  |

(1) Compliance date from September 2019 Settlement Agreement. <u>https://s3.amazonaws.com/public-inspection.federalregister.gov/2019-19668.pdf</u>

(2) The revised FIP for Minntac was posted in the Federal Register on February 4, 2020 for public comment. Minntac is awaiting EPA's publication of the final revised FIP. https://www.govinfo.gov/content/pkg/FR-2020-02-04/pdf/2020-01321.pdf

## 5.2 SO<sub>2</sub> BART-required Controls

In the preamble to the August 2012 proposed FIP<sup>65</sup>, the USEPA concluded that BART for SO<sub>2</sub> emissions from the rotary kilns at Minntac is existing controls. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- Dry Sorbent Injection and Spray Dryer Absorption because the high moisture content of the exhaust would lead to baghouse filter cake saturation and filter plugging<sup>66</sup>
- Alternative Fuels for units burning coal by switching fuels due to the uncertainty of alternative fuel costs, the potential of replacing one visibility impairment pollutant for another, and that BART cannot mandate a fuel switch;<sup>67</sup>
- Coal drying/processing because this requires excess heat source or low-pressure steam, which was not available at Minntac<sup>68</sup>
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure<sup>69</sup>
- Caustic, lime, or limestone additives to existing scrubbers operating to increase the pH of the scrubbing liquid due to corrosion concerns of the control system that were not designed to operate at a higher pH. The preamble also cited concerns with additional solids and sulfates that would be discharged to the tailing basin and would require extensive treatment to maintain water

<sup>&</sup>lt;sup>65</sup> Federal Register 77, No. 158 (August 15, 2012); 49314. Available at: <u>https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789</u>

<sup>66</sup> Ibid, 49313

<sup>67</sup> Ibid.

<sup>68</sup> Ibid.

<sup>&</sup>lt;sup>69</sup> Ibid, 49314.

quality and/or would cause an increased blowdown and make-up water rate, which is not available<sup>70</sup>

In addition, USEPA eliminated Wet Walled Electrostatic Precipitator (WWESP) and secondary (polishing) wet scrubber technologies because they were not cost-effective.<sup>71</sup>

Because the technical feasibility and cost effectiveness determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for SO<sub>2</sub> emissions from taconite indurating furnaces.

In accordance with the FIP, Minntac has continued to operate the BART SO<sub>2</sub> control measures and is complying with the FIP SO<sub>2</sub> emission limits<sup>72</sup>, as shown in Table 5-2. Thus, the rotary kilns are considered "effectively controlled" sources in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for SO<sub>2</sub>. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the rotary kilns from the requirement to submit a four-factor analysis<sup>73</sup>.

### Table 5-2 SO<sub>2</sub> Emission Limits

| Unit               | Unit ID           | SO <sub>2</sub><br>Emission Limit<br>(flux pellets) <sup>(1)</sup><br>(lb/hr) | SO <sub>2</sub><br>Emission Limit<br>(mix) <sup>(2)</sup><br>(lb/hr) | SO <sub>2</sub><br>Emission Limit<br>(acid pellets) <sup>(3)</sup><br>(lb/hr) | Compliance<br>Date |
|--------------------|-------------------|---|--|---|--------------------|
| Line 3 Rotary Kiln | (EQUI 146/EU 225) |   |  |   |                    |
| Line 4 Rotary Kiln | (EQUI 279/EU 261) |   |  |   |                    |
| Line 5 Rotary Kiln | (EQUI 280/EU 282) | 498   | 630  | 800   | June 8, 2013       |
| Line 6 Rotary Kiln | (EQUI 3/EU 315)   |   |  |   |                    |
| Line 7 Rotary Kiln | (EQUI 179/EU 334) |   |  |   |                    |

(1) Aggregate limit when all lines are producing flux pellets.

(2) Aggregate limit when Lines 3-5 are producing acid pellets, and Lines 6-7 are producing flux pellets.

(3) Aggregate limit when all lines are producing acid pellets.

<sup>70</sup> Ibid.

<sup>71</sup> Ibid.

<sup>72 40</sup> CFR 52.1235(b)(2)

<sup>&</sup>lt;sup>73</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 10.

# 6 Conclusion

The preceding sections of this report support the following conclusions:

- The rotary kilns meet the BART-required control equipment installation scenario and are "effectively controlled" sources for NO<sub>X</sub> and SO<sub>2</sub> (see Section 5). As stated in the 2019 Guidance, "it may be reasonable for a state not to select an effectively controlled source."<sup>74</sup> Therefore, it would be reasonable and compliant with USEPA requirements to exclude Minntac from further assessments of additional emission control measures.
- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress (see Section 3):
  - Visibility has improved at all three monitors (BOWA1, VOYA2, and ISLE1) compared to the baseline period
  - Visibility has been below the URP since 2012
  - The 2018 visibility data is below the URP for 2028
  - Additional emissions reductions have continued throughout the region and are not fully reflected in the available 5-year average (2014-2018) monitoring dataset
  - Additional emission reductions are scheduled to occur in the region prior to 2028, including ongoing transitions of area EGUs from coal to natural gas or renewable sources, as well as the installation of low-NO<sub>X</sub> burners throughout the taconite industry
- The rotary kilns do not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4).

The combination of these factors provides sufficient justification for MPCA to justify to USEPA Minntac's exclusion from the group of sources required to conduct a four-factor analysis for this implementation period. Thus, the MPCA should withdraw its request for a four-factor analysis for the rotary kilns.

<sup>&</sup>lt;sup>74</sup> Ibid, Page 22

Appendices

Appendix A

Visibility Impacts

# A1 Visibility Impacts

### A1.1 Trajectory Analysis

The August 2019 U.S. EPA Guidance ("2019 Guidance" or "the Guidance")<sup>1</sup> says that the state may use a "reasonable surrogate metrics of visibility impacts" when selecting sources to conduct an four-factor analysis and cites trajectory analysis as an example of a reasonable technique. This analysis considers reverse trajectories, as provided on MPCA's website<sup>2</sup>, to determine the frequency that the trajectories on the "most impaired days"<sup>3</sup> overlapped with a specific area of influence (AOI) on the Iron Range. Data from 2011-2015 were analyzed as this was the most recent five-year period where the taconite facilities were operating under typical production rates.

A particle trajectory analysis is an analysis of the transport path of a particular air mass, including the associated particles within the air mass, to see if the air mass traveled over certain locations from specific source locations. The MPCA tracks visibility via the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area Wilderness (BWCA), Voyageurs National Park (Voyageurs) and Isle Royale National Park (Isle Royale).<sup>4</sup> MPCA's website includes a tool which analyzes reverse trajectories from BWCA and Voyageurs for the "most impaired days" and the clearest days for 2007-2016 to show the regional influence on visibility. The reverse trajectories included in the MPCA tool were developed using the NOAA Hysplit model.<sup>5</sup> The trajectories consist of a single back trajectory for each day of interest, beginning at 18:00 and running back 48 hours with a starting height of 10 meters.

The MPCA Hysplit reverse trajectories from the "most impaired days" were analyzed to identify whether trajectories overlapped with an AOI from certain taconite facilities on the Iron Range. In order to be conservative, Barr estimated an "uncertainty region" for each trajectory based on 20% of the distance traveled for every 10km along the trajectory pathway. This method is consistent with other scientific studies analyzing reverse trajectories and trajectories associated with the NOAA Hysplit model (Stohl - 1998<sup>6</sup>, Draxler - 1992<sup>7</sup>, Draxler and Hess - 1998<sup>8</sup>). For the purpose of this analysis, the Iron Range AOI was defined as a line connecting the stack at the U. S. Steel Keetac facility with the stack at the ArcelorMittal Minorca Mine and a 3-mile radius surrounding the line. This analysis considers how often the MPCA reverse trajectories overlap the Iron Range AOI on the "most impaired days" to quantitatively determine if the emissions from the Iron Range may have been a contributor to impaired visibility. Attachment 1 to Appendix A includes tables with the annual and seasonal results of this analysis as well as two example figures showing trajectories that cross, and do not cross, the Iron Range AOI.

<sup>&</sup>lt;sup>1</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019

<sup>&</sup>lt;sup>2</sup> <u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze\_visibility\_metrics\_public/Regionalinfluence</u>

<sup>&</sup>lt;sup>3</sup> "Most impaired days" is the 20% most anthropogenically impaired days on an annual basis, measured in deciviews (dv), as provided on MPCA's website.

<sup>&</sup>lt;sup>4</sup> <u>https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze\_visibility\_metrics\_public/Regionalinfluence</u>

<sup>&</sup>lt;sup>5</sup> https://www.arl.noaa.gov/hysplit/hysplit/

<sup>&</sup>lt;sup>6</sup> <u>http://www.kenrahn.com/DustClub/Articles/Stohl%201998%20Trajectories.pdf</u>

<sup>&</sup>lt;sup>7</sup> https://www.arl.noaa.gov/documents/reports/ARL%20TM-195.pdf

<sup>&</sup>lt;sup>8</sup> https://www.arl.noaa.gov/documents/reports/MetMag.pdf

As shown in Figure A1 and Figure A2, reverse trajectories from BWCA and Voyageurs in 2011-2015 did not overlap the Iron Range AOI on 62-80%, and 56-71% of "most impaired days", respectively. This means the taconite industry did not influence visibility at BWCA and Voyageurs on the majority of "most impaired days" and suggest that sources other than the taconite facilities are larger contributors to visibility impairment at these sites. Furthermore, the origins of many of the "most impaired day" reverse trajectories are beyond the Iron Range AOI and thus have influences, depending on the trajectory, from other sources (e.g., Boswell Energy Center, Sherburne County Generating Station) or cities such as Duluth, St. Cloud, the Twin Cities, and Rochester as shown in Figure A3.

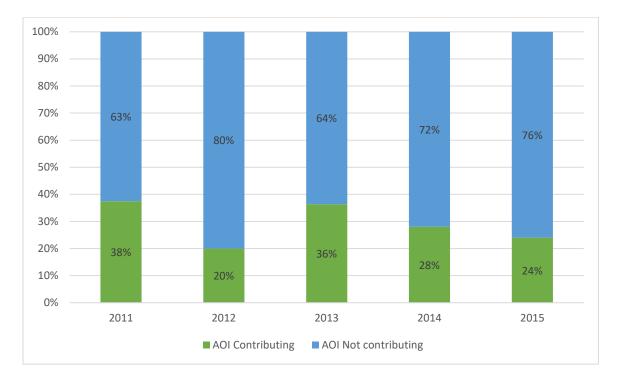


Figure A1 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at BWCA

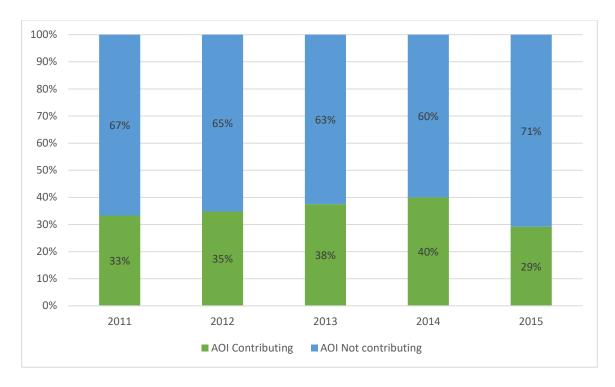


Figure A2 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at Voyageurs

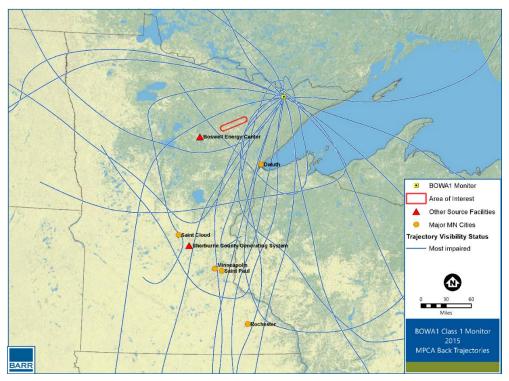


Figure A3 Reverse Trajectories and Other Sources Influencing Visibility at BWCA<sup>9</sup>

<sup>9</sup> Source: ArcGIS 10.7.1, 2020-05-14 13:31 File:

I:\Client\US\_Steel\Trajectory\_Analysis\Maps\Trajectory\_Routes\_BOWA1\_2015\_zoom.mxd User: ADS

## A1.2 Photochemical Modeling

As part of the requirement to determine the sources to include and how to determine the potential visibility improvements to consider as part of this selection, the 2019 Guidance provided some specific guidance on the use of current and previous photochemical modeling analyses (emphasis added):

"A state opting to select a set of sources to analyze must reasonably choose factors and apply them in a reasonable way given the statutory requirement to make reasonable progress toward natural visibility. Factors could include but are not limited to baseline source emissions, <u>baseline source</u> <u>visibility impacts (or a surrogate metric for the impacts)</u>, [and] the in-place emission control measures..."<sup>10</sup>

The Guidance lists options for the evaluation of source visibility impacts from least rigorous to most rigorous as: (1) emissions divided by distance (Q/d), (2) trajectory analyses, (3) residence time analyses, and (4) photochemical modeling (zero-out and/or source apportionment). It appears that MPCA selected the least rigorous (Q/d) for inclusion of sources in the four-factor analyses. The most rigorous is described below (emphases added):

"Photochemical modeling. In addition to these non-modeling techniques, states can also use a photochemical model to quantify source or source sector visibility impacts. In 2017, EPA finalized revisions to 40 CFR Part 51 Appendix W, Guideline on Air Quality Models. As part of that action, EPA stated that photochemical grid models should be the generally preferred approach for estimating source impacts on secondary PM concentrations. The existing SIP Modeling Guidance provides recommendations on model setup, including selecting air quality models, meteorological modeling, episode selection, the size of the modeling domain, the grid size and number of vertical layers, and evaluating model performance. EPA Regional offices are available to provide an informal review of a modeling protocol before a state or multijurisdictional organization begins the modeling.

The SIP Modeling Guidance focuses on the process for calculating RPGs using a photochemical grid model. The SIP Modeling Guidance does not specifically discuss using photochemical modeling outputs for estimating daily light extinction impacts for a single source or source sector. However, the approach on which the SIP Modeling Guidance is based can also be applied to a specific source or set of sources. <u>The first step in doing this is to estimate the impact of the source or set of sources</u> <u>on daily concentrations of PM species.</u>

The simplest approach to quantifying daily PM species impacts with a photochemical grid model is to perform brute force "zero-out" model runs, which involves at least two model runs: one "baseline" run with all emissions and one run with emissions of the source(s) of interest removed from the baseline simulation. The difference between these simulations provides an estimate of the PM species impact of the emissions from the source(s).

<sup>&</sup>lt;sup>10</sup> USEPA, <u>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period</u>, 08/20/2019, Page 10

An alternative approach to quantifying daily PM species impacts is photochemical source apportionment. Some photochemical models have been developed with a photochemical source apportionment capability, which tracks emissions from specific sources or groups of sources and/or source regions through chemical transformation, transport, and deposition processes to estimate the apportionment of predicted PM<sub>2.5</sub> species concentrations. Source apportionment can "tag" and track emissions sources by any combination of region and sector, or by individual source. For example, PM species impacts can be tracked from any particular source category in the U.S., or from individual states or counties. Individual point sources can also be tracked."<sup>11</sup>

As part of the previous regional haze planning evaluation, and to provide comments on USEPA's disapproval of the Minnesota SIP and the subsequent Regional Haze Federal Implementation Plan (FIP) (Docket EPA-R05-OAR-2010-0954 & EPA-R05-OAR-2010-0037), Barr completed photochemical modeling of ArcelorMittal and Cleveland-Cliffs' taconite operations in 2013 using CAMx source apportionment (see Attachment 2). The basis of the CAMx modeling was the Minnesota modeling analyses, which were completed as part of the regional haze SIP, including Plume in Grid (PiG) evaluations of sources included in BART analyses. This modeling included 2002 and 2005 baseline periods with projected emissions to 2018 (the first implementation planning period for the regional haze SIPs and a strong surrogate for the baseline period for the 2<sup>nd</sup> planning period). Therefore, the analysis completed is one of the best available surrogates for the potential visibility impacts from the sources that were "tagged" as part of those comments. It is important to note that the MPCA modeling analysis did not require any additional controls for taconite sources under BART. Further, the CAMx modeling that Barr conducted showed that the impact from NO<sub>X</sub> emissions from the Minnesota taconite facilities had very limited visibility impacts on the three Upper Midwest Class I areas.

Specifically, the results from executing CAMx concluded that the Class I areas near the Iron Range will not experience any observable visibility improvements from NO<sub>x</sub> emission reductions that were suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces. The modeling analysis showed that the scalar method that USEPA used to forecast the visibility improvements was inadequate to determine the visibility impacts from taconite sources. The CAMx predicted impacts for every furnace line were at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

In addition, the large amount of potential NO<sub>X</sub> emission reductions from the FIP baseline to the final FIP (>10,000 tons per year from modeled Minnesota taconite operations) was not impactful from a visibility modeling perspective. This finding provides specific source modeling evidence that additional NO<sub>X</sub> emission reductions from any or all of the taconite operations are likely not helpful for visibility improvements at the Upper Midwest Class I areas. This is particularly true given the current amount of NO<sub>X</sub> emissions generated by the taconite sources as part of the current baseline.

The 2019 Guidance addresses how states should select sources that must conduct a four-factor analysis. The RHR suggests that states can use a photochemical model to quantify facility or even stack visibility impacts. The previous CAMx modeling was conducted for the 2018 projection year and the results are

<sup>&</sup>lt;sup>11</sup> Ibid, Page 14.

especially helpful in the current visibility impact assessment to determine if the EPA's four-factor applicability analysis is necessary. Aside from the fact that the NO<sub>X</sub> reductions of taconite indurating furnaces do not result in visibility improvements, the emissions from these sources have been trending downward from 2013 to present. These reductions are related to the recent installation of low NO<sub>X</sub> burners on the taconite indurating furnaces and the overall Minnesota state reductions from the switch from coal- to natural gas-fired power plants. Thus, it is reasonable to conclude that additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility at the Class 1 areas nor is it anticipated to be necessary to reach the 2028 target visibility goal.

In summary, the exclusion of the taconite sources from the four factor analysis for NOx is reasonable, supported by the previous CAMx modeling performed for 2018 projected emissions that conclude additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility, and in line with the Guidance regarding selection of sources based on previous modeling analyses and the additional NO<sub>x</sub> reductions anticipated in Minnesota.

## A1.3 Visibility Impacts During 2009 Recession

During the economic recession in 2009, the Iron Range experienced a reduction in taconite production. This resulted in a decrease in emissions from the collective group of taconite plants and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this period was compared to monitoring data during more typical production at the taconite plants to estimate the actual (rather than modeled) impact on haze. This assessment was completed in 2012 (herein termed as "the 2012 analysis") and submitted by Cliffs as a comment to proposed Minnesota regional haze requirements (Docket: EPA-R05-OAR-2010-0037), included as Attachment 3. The 2012 analysis focused on the likely visibility impact of NO<sub>x</sub> emissions from the taconite indurating furnaces.

Observations noted in the 2012 analysis highlighted that concentrations of visibility impairing pollutants do not appear to closely track with actual emissions from taconite facilities. For example, nitrate (NO<sub>3</sub>) is a component of haze associated with NO<sub>x</sub> emissions that are emitted from a number of sources, including the indurating furnaces at the taconite facilities. As shown in Figure A4, the 2012 analysis compared taconite facility production rates to nitrate concentration for 1994-2010 at the BWCA monitor. The 2012 analysis concludes that "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions."<sup>12</sup> The report further notes that "high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states."<sup>13</sup>

<sup>&</sup>lt;sup>12</sup> AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10. <sup>13</sup> Ibid, Page 12.

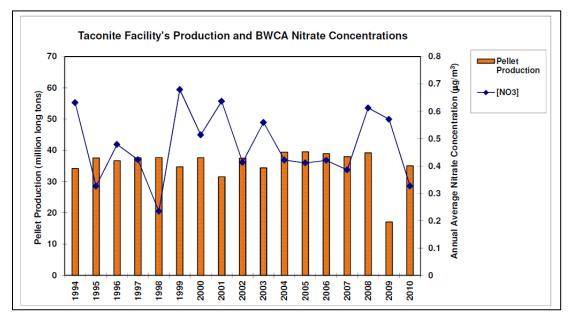


Figure A4 Minnesota Taconite Production and BWCA Nitrate Concentrations 1994-2010<sup>14</sup>

<sup>&</sup>lt;sup>14</sup> AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 9

## Attachments

# Attachment 1

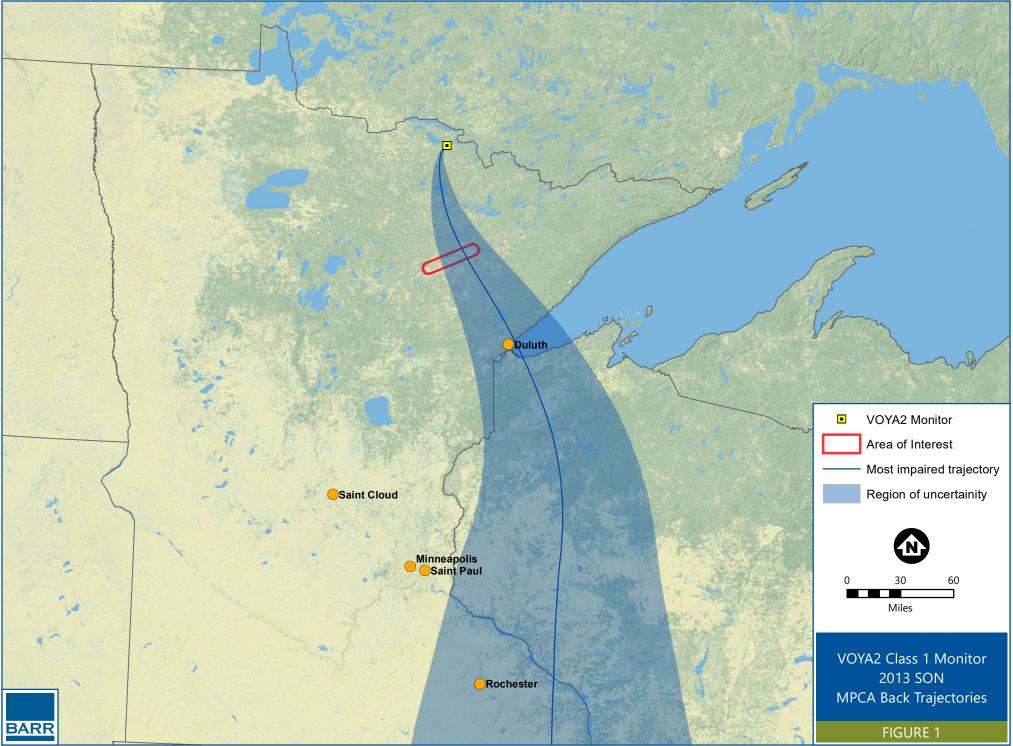
Trajectory Analysis Summary Tables and Reverse Trajectory Example Figures

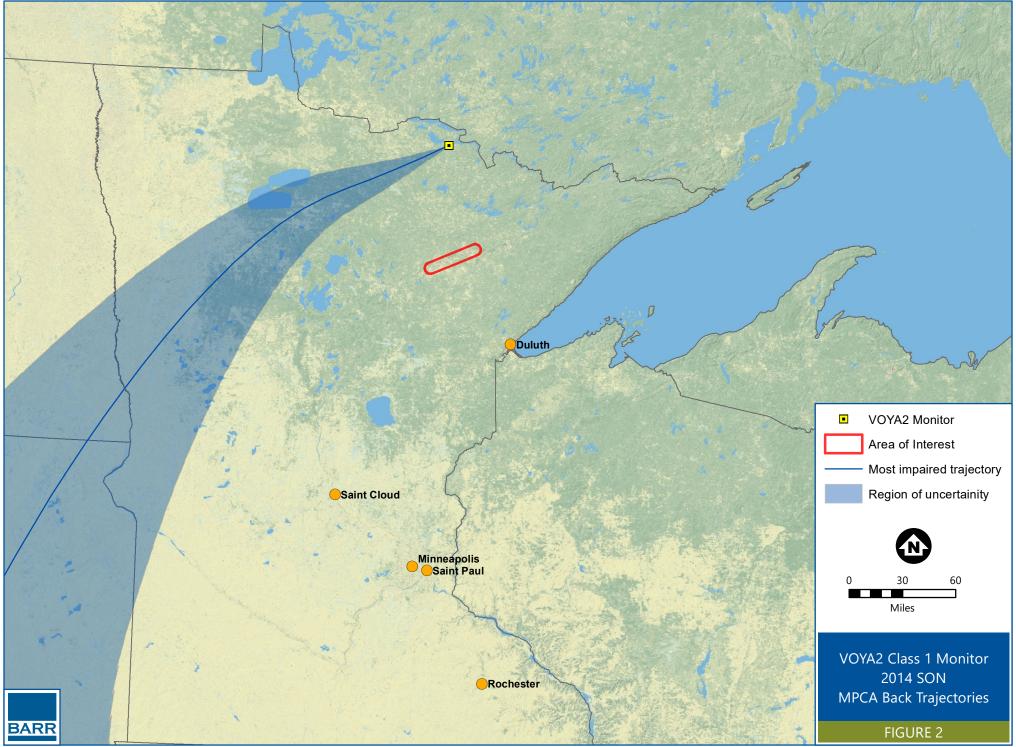
| Year | Time Period  | Most Impaired<br>Days | "Most Impaired" Trajectories<br>With Uncertainty Region<br>Crossing Iron Range AOI<br>(%) |
|------|--------------|-----------------------|---|
|      | Winter (DJF) | 9                     | 44%   |
|      | Spring (MAM) | 8                     | 38%   |
| 2011 | Summer (JJA) | 4                     | 0%  |
|      | Fall (SON)   | 3                     | 67%   |
|      | Total        | 24                    | 38%   |
|      | Winter (DJF) | 13                    | 23%   |
|      | Spring (MAM) | 4                     | 0%  |
| 2012 | Summer (JJA) | 1                     | 0%  |
|      | Fall (SON)   | 7                     | 29%   |
|      | Total        | 25                    | 20%   |
|      | Winter (DJF) | 9                     | 44%   |
|      | Spring (MAM) | 5                     | 60%   |
| 2013 | Summer (JJA) | 3                     | 0%  |
|      | Fall (SON)   | 5                     | 20%   |
|      | Total        | 22                    | 36%   |
|      | Winter (DJF) | 9                     | 33%   |
|      | Spring (MAM) | 8                     | 13%   |
| 2014 | Summer (JJA) | 2                     | 0%  |
|      | Fall (SON)   | 6                     | 50%   |
|      | Total        | 25                    | 28%   |
|      | Winter (DJF) | 13                    | 15%   |
|      | Spring (MAM) | 3                     | 67%   |
| 2015 | Summer (JJA) | 1                     | 0%  |
|      | Fall (SON)   | 8                     | 25%   |
|      | Total        | 25                    | 24%   |

Table A1 Results from MPCA Hysplit Trajectories for the BOWA1 Monitor

| Year | Months       | Most Impaired<br>Days | "Most Impaired" Trajectories<br>With Uncertainty Region<br>Crossing Iron Range AOI<br>(%) |
|------|--------------|-----------------------|---|
|      | Winter (DJF) | 8                     | 38%   |
|      | Spring (MAM) | 7                     | 29%   |
| 2011 | Summer (JJA) | 4                     | 25%   |
|      | Fall (SON)   | 5                     | 40%   |
|      | Total        | 24                    | 33%   |
|      | Winter (DJF) | 13                    | 23%   |
|      | Spring (MAM) | 3                     | 67%   |
| 2012 | Summer (JJA) | 0                     | 0%  |
|      | Fall (SON)   | 7                     | 43%   |
|      | Total        | 23                    | 35%   |
|      | Winter (DJF) | 9                     | 22%   |
|      | Spring (MAM) | 5                     | 40%   |
| 2013 | Summer (JJA) | 3                     | 0%  |
|      | Fall (SON)   | 7                     | 71%   |
|      | Total        | 24                    | 38%   |
|      | Winter (DJF) | 10                    | 50%   |
|      | Spring (MAM) | 7                     | 43%   |
| 2014 | Summer (JJA) | 2                     | 0%  |
|      | Fall (SON)   | 6                     | 33%   |
|      | Total        | 25                    | 40%   |
|      | Winter (DJF) | 14                    | 21%   |
|      | Spring (MAM) | 4                     | 50%   |
| 2015 | Summer (JJA) | 1                     | 100%  |
|      | Fall (SON)   | 5                     | 20%   |
|      | Total        | 24                    | 29%   |

 Table A2
 Results from MPCA Hysplit Trajectories for the VOYA2 Monitor





Attachment 2

CAM<sub>X</sub> Modeling Report



## **Technical Memorandum**

- From: Barr Engineering
- Subject: Summary of Comprehensive Air Quality Model with Extensions (CAM<sub>x</sub>) Analyses Performed to Evaluate the EPA Regional Haze Federal Implementation Plan for Taconite Facilities
   Date: March 6, 2013

### **Executive Summary**

Barr Engineering conducted air modeling to predict the impact of  $NO_x$  reductions from certain taconite furnaces in Minnesota and Michigan. Using EPA's preferred Comprehensive Air Quality Model with Extensions (CAM<sub>x</sub>), the model results demonstrate that the Class I areas near these furnaces will experience no perceptible visibility improvements from  $NO_x$  emission reductions envisioned by EPA in the recent Regional Haze FIP at the furnaces. The analysis strongly suggests that the scalar method that EPA used to predict visibility improvements under significant time constraints was an inadequate substitute for CAM<sub>x</sub>, as EPA's approach over-predicted visibility impacts by factors of <u>ten to sixty</u> when compared with the proper CAM<sub>x</sub> analysis. The basis for EPA's technical analysis of the visibility improvements for their proposed emission changes must therefore be dismissed as unsupportable, and the results of this analysis should be used instead. This analysis ultimately supports the conclusions of the States of Michigan and Minnesota in their Regional Haze SIPs, that experimental low  $NO_x$  burner retrofits did not meet the criteria for BART. The imperceptible visibility improvements associated with  $NO_x$  reductions from these furnaces cannot justify the cost or the operational risks of changing burners.

#### **Discussion**

This memorandum provides a summary of the methodology and results from photochemical modeling analyses conducted to support the Cliffs Natural Resources (CNR) and Arcelor Mittal (Arcelor) response to the United States Environmental Protection Agency (EPA) final Regional Haze Federal Implementation Plan (FIP) for taconite facilities. Further, it provides a basis for comment on the proposed disapproval of the Minnesota and Michigan State Implementation Plans for taconite Best Available Retrofit Technology (BART) at the above mentioned facilities. This memorandum also includes an appendix with a summary of the BART visibility improvement requirements and a review of the EPA "scalar" method in the proposed and final FIP for determining the visibility improvement from taconite emission reductions. Further, the memorandum contrasts EPA's findings with the modeling analysis conducted and previously requested by CNR as part of its comments on the proposed FIP. The modeling evaluated emission differences at all the CNR and Arcelor taconite facilities.

Ultimately, this memorandum provides results demonstrating no perceptible visibility improvement from the  $NO_X$  emission reductions proposed and subsequently finalized by EPA in the Regional Haze FIP for the CNR and Arcelor facilities.

### I. CAM<sub>x</sub> Modeling Methodology

The methodology utilized by Barr to complete the CAM<sub>x</sub> modeling was identical to the methods utilized by the Minnesota Pollution Control Agency (MPCA) in performing the 2002 and 2005 baseline and BART SIP modeling in 2009. This included the use of the CAM<sub>x</sub> modeling system (CAM<sub>x</sub> v5.01 - air quality model, MM5 - meteorological model, and EMS-2003 - emissions model) with meteorological data, low-level emission data, initial and boundary condition files, and other input files received directly from MPCA. Modifications to the emissions within the elevated point source input files used by MPCA were accomplished for the taconite facility furnace stacks to reflect the differences in the FIP baseline and final FIP control scenarios. In addition, the CAM<sub>x</sub> run scripts used to execute the model were provided by MPCA for each of the four calendar quarters (Jan-Mar, Apr-Jun, Jul-Sep, and Oct-Dec) along with the post-processing scripts used to estimate the visibility impacts for each scenario.

An important fact is that the results from the MPCA modeling for Minnesota's regional haze State Implementation Plan (SIP) development were also utilized by EPA in the "scalar" method proposed in the FIP. These results were subsequently defended by EPA in the final FIP stating "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."<sup>1</sup> The methods utilized by MPCA represent not only an EPA-approved approach for SIP submittal, but also formed the basis of the visibility determinations made by EPA in the proposed and final FIP. However, since EPA did not conduct its own modeling and provided only the "scalar" results, there are substantial and inherent flaws in the EPA-estimated visibility impacts. These flaws are detailed in Appendix A to this memorandum which includes a review of the EPA scalar approach. Since the modeling reported here used identical methods to the MPCA analyses, it is consistent with the underlying data that was used in

<sup>&</sup>lt;sup>1</sup> Federal Register, Volume 78, Number 25, page 8721, February 6, 2013

the EPA FIP method for estimating visibility impact. Further, this modeling provides specific technical analyses regarding the estimated effects of CNR and Arcelor taconite unit emission reductions in the final FIP on the relevant Class I areas. To effectively evaluate the impact of NOx reductions on regional haze, this level of analyses should have been conducted by EPA before publishing and finalizing the taconite BART FIP for Minnesota and Michigan.

Nonetheless, the first step in any photochemical modeling exercise is to ensure that the modeling results can be replicated to ensure no errors in the data transfer or modeling setup. Barr worked with MPCA to obtain the 2002 and 2005 modeling input files, run scripts, and post-processing files to allow for the validation of the Barr modeling system. To be clear, the modeling comparison scenario used the exact same files provided by MPCA with no adjustments. Given the length of time required to complete the modeling analyses, this step focused on the 2002 dataset and evaluated the results from the 2002 baseline and 2002 Minnesota BART SIP. The information provided by MPCA to complete this comparison was contained in the document: "Visibility Improvement Analysis of Controls Implemented due to BART Determinations on Emission Units Subject-to-BART", October 23, 2009. The results of the comparison are contained in Appendix B: Barr and MPCA CAM<sub>X</sub> Modeling Comparison of Results. As expected with any photochemical model comparison running four different quarterly simulations using two different computer systems and Fortran compilers, there are insignificant differences in the end values. The overall comparison of the results was very favorable and showed excellent agreement between the four modeled datasets (i.e. 2002 baseline and 2002 BART SIP, each from MPCA and Barr).

After successful confirmation of the consistency check of the Barr modeling system to the MPCA system, the modeling focused on the specific emission changes in the MPCA elevated point source files. As with most regional modeling applications, there were 36 "core" point source files for each scenario. This set corresponds to three files per month (Saturday, Sunday, and weekday) for all twelve months. Emission information from each file was extracted for all the CNR and Arcelor taconite facilities in Minnesota to confirm the emission totals used by MPCA in the SIP baseline and BART SIP control scenarios. The emission summary data for each unit matched the summary tables within the MPCA BART SIP modeling. Also, the emission sources from Tilden Mining Company in Michigan were identified and information extracted to allow for the same type of modeling as was conducted for the Minnesota facilities.

The next step was to include United Taconite Line 1 in the baseline and FIP modeling files. Line 1 was not originally included in the MPCA modeling because it was not operational in the 2002 base year.

Therefore, the information for that source was obtained from MPCA-provided 2018 elevated point source files and incorporated into the 36 core elevated point source files. This allowed all the CNR and Arcelor furnace lines within the FIP to be evaluated as part of this modeling analysis. To that end, each CNR and Arcelor BART-eligible source was specifically identified and labeled for processing to track modeled impacts using plume-in-grid treatment and the Particulate Source Apportionment Technology (PSAT) contained within CAM<sub>x</sub> (including Tilden Mining). A list of the sources that were included in the specific PSAT groups can be found in Appendix C: CAM<sub>x</sub> PSAT Source List.

As part of the identification and labeling process, the MPCA BART SIP elevated point source files were converted from binary input files to ascii text files using the BIN2ASC program. (NOTE: by using the BART SIP point source files, all other Minnesota BART-eligible sources were included in this modeling exercise using their BART SIP emissions to isolate the impacts of the CNR and Arcelor units.) Then, a Fortran90 program was developed to adjust the hourly emissions from each applicable source to correspond to the sum of annual emissions within each of the following scenarios: EPA FIP baseline and EPA final FIP. It is important to note that the temporal factors for each source were not modified from the original MPCA-provided inventory files (i.e. no changes to the monthly or day-of-week factors). This emission approach allowed for the exact set of emissions within each of the scenarios to be modeled. After the emissions within the text file were adjusted, the emissions were checked for accuracy. Then, each file was converted back to binary input from ASCII text using the ASC2BIN program. The emission summary for each unit/scenario combination is contained in Appendix D: Summary of  $CAM_x$ Elevated Point Source Emissions. Appendix D also provides a reference list for the emissions from the proposed FIP, Final FIP (where applicable), and calculation methodology where EPA did not provide sufficient information to calculate emissions. Table 1 contains a facility summary for all taconite furnaces under each scenario.

As stated previously, one of the outcomes of these analyses was the comparison of EPA's scalar approach to specific photochemical modeling using EPA's emission reduction assumptions within the FIP rulemakings. These modeling analyses make no judgment as to the achievability of these emission reductions. CNR and Arcelor dispute that these NOx reductions are achievable for all furnaces. These modeling analyses are, therefore, a conservative evaluation of EPA's predicted NOx reductions – not the actual NOx reductions achievable by the application of BART.

4

| Facility          | FIP Basel | line (TPY) | Final FIP (TPY) |       | Difference (TPY) |        |  |
|-------------------|-----------|------------|-----------------|-------|------------------|--------|--|
|                   | SO2       | NOx        | SO2             | NOx   | SO2              | NOx    |  |
| Arcelor Mittal    | 179       | 3,639      | 179             | 1,092 | 0                | 2,547  |  |
| Hibbing Taconite  | 570       | 6,888      | 570             | 2,066 | 0                | 4,821  |  |
| United Taconite   | 4,043     | 5,330      | 1,969           | 1,599 | 2,074            | 3,731  |  |
| Northshore Mining | 73        | 764        | 73              | 229   | 0                | 535    |  |
| Tilden Mining     | 1,153     | 4,613      | 231             | 1,384 | 922              | 3,229  |  |
| Total             | 6,018     | 21,233     | 3,022           | 6,370 | 2,996            | 14,863 |  |

 Table 1: Facility Taconite Furnace Emission Summary

Two other issues should be noted here.

1. The first is the nested 12-km modeling domain selected by MPCA (illustrated in Figure 1) along with the specific "receptors" used for identification of the relevant Isle Royale Class I area and their use for determination of impacts from Tilden Mining Company. The Tilden Mining source was not included in the MPCA fine grid as it was not part of the Minnesota SIP. However, the elevated point source file includes the sources in the entire 36 km domain (including Tilden). As such, the Tilden emissions were available for estimation of specific visibility impacts. The receptors selected by MPCA only included the western half of the Isle Royale Class I area because that is the portion of the area closest to the Minnesota sources. However, the size of the grid cells (e.g. 12 and 36 km) provides a large number of potential receptors at all the Class I areas and little variation among receptors is expected at the distance between Tilden and Isle Royale. Thus, the modeling data should adequately represent the visibility impact at the entire Isle Royale Class I area.

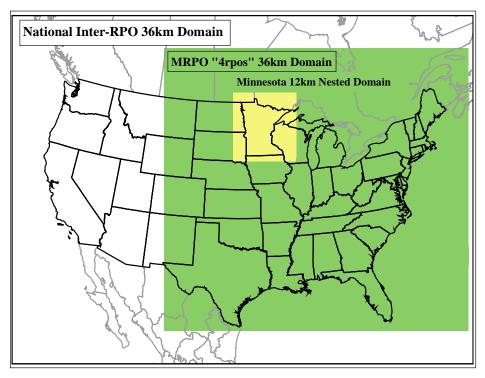


Figure 1. MPCA Modeling Domain

2. The second issue is the inconsistency between the emission reduction estimates used by EPA in the calculation of their scalar visibility benefits (i.e. Tables V-C of the proposed and final FIP) and the emission reductions calculated in the facility-specific sections of the proposed FIP. EPA's flawed calculation methodology did not use the appropriate emission reductions. In order to calculate the emissions for evaluation of the final FIP in the CAM<sub>x</sub> modeling, Barr was left with utilizing the limited information provided in the proposed and final FIP rulemaking. The lack of information and the errors and inconsistencies within the dataset were highlighted in the information request on January 31, 2013 to EPA (included in Appendix E). As of the time of this memorandum, no response by EPA has been received by Barr. Further, given the time required to complete the modeling, assumptions were made that were conservative to calculate the FIP emissions. For example, the final FIP references a 65% NO<sub>x</sub> reduction from Tilden Mining Company due to the switch to natural gas firing, but that was not consistent with the other gas-fired kilns (proposed FIP reduction was 70% with the same 1.2 lb NO<sub>x</sub>/MMBTU emission limit). Therefore, to provide the maximum emission reductions, the 70% control was utilized for all the CNR and Arcelor taconite furnaces.

#### II. Summary of CAM<sub>X</sub> Results

As mentioned above, the CAM<sub>x</sub> model was executed for each calendar quarter of 2002 and 2005 using the adjusted emissions for each scenario. The results were then post-processed to calculate visibility impacts for each scenario in deciviews (dV). All these results are provided in Appendix F: CAM<sub>x</sub> Results by Facility. For the purposes of this memorandum, the following tables compare EPA's estimates of annual average impact contained within the proposed FIP with the results generated by the CAM<sub>x</sub> modeling for this project on a facility by facility basis. The first three facilities contain emission reductions for only NO<sub>x</sub>: Arcelor Mittal, Hibbing Taconite, and Northshore Mining. These results are summarized in Tables 2-4. United Taconite and Tilden Mining, which have both SO<sub>2</sub> and NO<sub>x</sub> emission reductions, have result comparisons that require additional discussion.

The context of these results includes the following visibility impact thresholds:

<u>0.5 dV impact</u> is the BART eligibility and contribute to visibility impairment threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required)<sup>2</sup>,

1.0 dV difference is the presumed human perceptible level for visibility improvement, and

<u>0.1 dV difference</u> was defined by other agencies, such as the northeastern states MANE-VU Regional Planning Organization<sup>3</sup> as the degree of visibility improvement that is too low to justify additional emission controls. In addition, EPA's Regional Haze Rule mentions<sup>4</sup> that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

The first two columns within Tables 2-4 and 6-8 provide the difference in 98<sup>th</sup> percentile visibility improvement from the baseline to the FIP control emissions, while the third column provides a measure of over-estimation when using the EPA scalar approach (i.e. % Over Estimation by EPA = EPA Estimated Difference / CAM<sub>x</sub> Modeled Difference).

Table 2: Arcelor Mittal Visibility Impact Comparison

<sup>&</sup>lt;sup>2</sup> 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule.

<sup>&</sup>lt;sup>3</sup> As documented by various states; see, for example, <u>www.mass.gov/dep/air/priorities/hazebart.doc</u>, which indicates a visibility impact of less than 0.1 delta-dv is considered "de minimis".

<sup>&</sup>lt;sup>4</sup> 64 FR 35730.

| Class I Area    | EPA Estimated | CAM <sub>X</sub> Modeled | % Over        |
|-----------------|---------------|--------------------------|---------------|
|                 | Difference    | Difference               | Estimation by |
|                 | 98% dV        | 98% dV                   | EPA           |
| Boundary Waters | 1.7           | 0.1                      | 1500%         |
| Voyageurs       | 0.9           | 0.09                     | 1000%         |
| Isle Royale     | 1.1           | 0.03                     | 3700%         |

Table 3: Hibbing Taconite Visibility Impact Comparison

| Class I Area    | EPA Estimated | CAM <sub>x</sub> Modeled | % Over        |
|-----------------|---------------|--------------------------|---------------|
|                 | Difference    | Difference               | Estimation by |
|                 | 98% dV        | 98% dV                   | EPA           |
| Boundary Waters | 3.2           | 0.19                     | 1700%         |
| Voyageurs       | 1.7           | 0.11                     | 1500%         |
| Isle Royale     | 2.1           | 0.04                     | 5300%         |

Table 4: Northshore Mining Visibility Impact Comparison

| Class I Area    | EPA Estimated        | CAM <sub>X</sub> Modeled | % Over               |
|-----------------|----------------------|--------------------------|----------------------|
|                 | Difference<br>98% dV | Difference<br>98% dV     | Estimation by<br>EPA |
| Boundary Waters | 0.6                  | 0.01                     | 6000%                |
| Voyageurs       | 0.3                  | 0.01                     | 3000%                |
| Isle Royale     | 0.4                  | 0.01                     | 4000%                |

As pointed out in the previous comments on this proposed FIP, these results clearly demonstrate that the NOx reductions proposed in the FIP will not provide a perceptible visibility improvement. Additionally, it demonstrates that the EPA methodology using scalars severely overestimated the visibility impact from NO<sub>x</sub> emission reductions at these taconite furnaces in northeast Minnesota. Even when using maximum emission reductions from EPA's baseline, the EPA estimates grossly over predicted the potential dV improvement by over <u>10 times</u> the predicted 98<sup>th</sup> percentile visibility improvement in all cases for the Arcelor Mittal, Hibbing Taconite, and Northshore Mining facilities. The maximum 98<sup>th</sup> percentile visibility improvement predicted by the source specific tracking for any one line was 0.1 dV (Arcelor Mittal Line 1 on Boundary Waters). The minimum 98<sup>th</sup> percentile visibility improvement was 0.01 dV (Northshore Mining on Isle Royale). Further, the results presented in Table 5 for the individual furnace line impacts at Hibbing Taconite illustrate de minimis visibility improvement at all the Class I areas evaluated.

| Class I Area    | Furnace Line | CAM <sub>x</sub> Modeled<br>Difference<br>98% dV |
|-----------------|--------------|--|
| Boundary Waters | Line 1       | 0.04   |
|                 | Line 2       | 0.05   |
|                 | Line 3       | 0.08   |
| Voyageurs       | Line 1       | 0.03   |
|                 | Line 2       | 0.04   |
|                 | Line 3       | 0.04   |
| Isle Royale     | Line 1       | 0.01   |
|                 | Line 2       | 0.01   |
|                 | Line 3       | 0.01   |

Table 5: Hibbing Taconite Line-Specific Visibility Impacts

Overall, all the facilities with only  $NO_X$  emission reductions predict visibility improvement from each furnace line at or below the de minimis visibility improvement threshold of 0.1 delta-dV.

Due to the sizable change in the United Taconite SO<sub>2</sub> emission reductions from the proposed FIP to the final FIP; the visibility improvement was re-calculated using EPA's apparent methodology from the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NO<sub>X</sub> and the revised emission reduction for SO<sub>2</sub>. Then, those resultants were averaged for each of the Class I areas to obtain the "updated" EPA all pollutant estimates.

| Class I Area    | Amended EPA | CAM <sub>X</sub> Modeled | % Over        |
|-----------------|-------------|--------------------------|---------------|
|                 | Estimated   | Difference               | Estimation by |
|                 | Difference  | 98% dV                   | EPA           |
|                 | 98% dV      |                          |               |
| Boundary Waters | 1.6         | 1.40                     | 110%          |
| Voyageurs       | 0.8         | 0.85                     | N/A           |
| Isle Royale     | 1.1         | 0.35                     | 320%          |

 Table 6: United Taconite Visibility Impact Comparison (All Pollutants)

The comparison of the total modeling effort including both pollutant reductions is surprisingly similar (except for Isle Royale). However, when the individual pollutant impacts are examined, the problem with EPA's methodology is more clearly understood. The sulfate impacts are estimated more closely to the CAM<sub>x</sub> results, while the nitrate impacts are grossly overestimated similar to the first three facilities.

The methodology used to isolate the sulfate and nitrate impacts separately from the current CAM<sub>x</sub> results prioritizes the sulfate and nitrate impacts as part of three separate post-processing runs (all pollutants, sulfate, and nitrate). The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall United Taconite impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO<sub>x</sub> control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.1 dV; total = 0.15 dV) and would not show up as part of the overall visibility change. As detailed in the comments to the proposed FIP, it is also important to note the high probability that the maximum impacts from NO<sub>x</sub> emission reduction occur during the winter months when Isle Royale is closed to visitors and visitation at the other Class I areas is significantly reduced from summertime maximum conditions.<sup>5</sup>

| Table 7: United Ta | iconite visibility li | mpac | t Comparison (Sulfa      | te Imj | pact)      |
|--------------------|-----------------------|------|--------------------------|--------|------------|
| Class I Area       | Amended EPA           |      | CAM <sub>X</sub> Modeled |        | % Over     |
|                    | Estimated             |      | Difference               |        | Estimation |
|                    | Difference            |      | 98% dV                   |        | by EPA     |
|                    | 98% dV                |      |                          |        | -          |
| Boundary Waters    | 1.0                   |      | 1.29                     |        | N/A        |
| Voyageurs          | 0.5                   |      | 0.74                     |        | N/A        |
| Isle Royale        | 0.6                   |      | 0.28                     |        | 210%       |

 Table 7: United Taconite Visibility Impact Comparison (Sulfate Impact)

Table 8: United Taconite Visibility Impact Comparison (Nitrate Impact)

| Class I Area    | Amended EPA | CAM <sub>X</sub> Modeled | % Over     |
|-----------------|-------------|--------------------------|------------|
|                 | Estimated   | Difference               | Estimation |
|                 | Difference  | 98% dV                   | by EPA     |
|                 | 98% dV      |                          |            |
| Boundary Waters | 2.3         | 0.18                     | 1300%      |
| Voyageurs       | 1.1         | 0.08                     | 1400%      |
| Isle Royale     | 1.6         | 0.05                     | 3200%      |

<sup>&</sup>lt;sup>5</sup> Cliffs Natural Resources (September 28, 2012), EPA-R05-OAR-0037-0045 Att. M

In the same manner as Hibbing Taconite, United Taconite's individual furnace lines were evaluated. As mentioned in the previous paragraph, the results in Table 9 for nitrate impact are biased toward higher nitrate impacts due to the sorting of the data to maximize nitrate impact.

| Class I Area    | Furnace Line | CAM <sub>x</sub> Modeled<br>Difference |
|-----------------|--------------|--|
| Boundary Waters | Line 1       | 98% dV<br>0.05                         |
|                 | Line 2       | 0.1                                    |
| Voyageurs       | Line 1       | 0.02                                   |
|                 | Line 2       | 0.06                                   |
| Isle Royale     | Line 1       | 0.02                                   |
|                 | Line 2       | 0.03                                   |

Table 9: United Taconite Line-Specific Nitrate Visibility Impacts

Nonetheless, as seen for all the other furnace lines, the results for United Taconite's predicted visibility impact are at or below the deminimis threshold for visibility improvement.

Since Tilden Mining Company was not evaluated using the same methodology as the Minnesota taconite facilities, there are no specific EPA data to compare with the  $CAM_X$  results. However, it is important to understand that the results are very similar to the other results regarding the impact of  $NO_X$  emission reductions on these Class I areas.

| Class I Area    | EPA Estimated  | CAM <sub>X</sub> Modeled |
|-----------------|----------------|--------------------------|
|                 | Difference 98% | Difference               |
|                 | dV             | 98% dV                   |
| Boundary Waters | N/A            | 0.08                     |
| Voyageurs       | N/A            | 0.03                     |
| Isle Royale     | N/A*           | 0.17                     |

Table 10: Tilden Mining Visibility Impact Comparison (All Pollutants)

\*EPA estimated that the proposed FIP results in 0.501 dV visibility improvement at Isle Royale from emission reduction at Tilden Mining

|                 | 0                        |                          |
|-----------------|--------------------------|--------------------------|
| Class I Area    | CAM <sub>X</sub> Sulfate | CAM <sub>x</sub> Nitrate |
|                 | Modeled                  | Modeled                  |
|                 | Difference               | Difference               |
|                 | 98% dV                   | 98% dV                   |
| Boundary Waters | 0.07                     | 0.01                     |
| Voyageurs       | 0.03                     | 0.00                     |
| Isle Royale     | 0.14                     | 0.02                     |

Table 11: Tilden Mining Pollutant-Specific Impact Comparison

The visibility impacts from  $NO_X$  emission reductions at Tilden are consistent with the other modeling results and further demonstrate that significant emission reductions of NOx (3,229 tpy for Tilden) result in no visibility improvements.

#### III. Conclusions

Overall, the results from the three facilities with only  $NO_X$  emission reductions (Hibbing Taconite, Northshore Mining, and Arcelor Mittal) and the pollutant-specific comparisons for United Taconite and Tilden Mining illustrate that nearly 15,000 tons per year of  $NO_X$  reductions, even if they were technically and/or economically achievable, provide imperceptible visibility impacts at the Minnesota or nearby Michigan Class I areas. In all cases, the CAMx-predicted impacts for every furnace line are at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

The fact that NO<sub>x</sub> emission reductions do not provide perceptible visibility improvement was understood by MPCA when they proposed existing control and good combustion practices as BART for taconite furnaces in northeast Minnesota. This finding has been confirmed by this detailed modeling analysis. EPA, to its credit, does not claim that its scalar "ratio" approach for predicting visibility improvement is accurate. In the final FIP, EPA provided, "Therefore, even if the ratio approach was over-estimating visibility improvement by a factor of two or three, the expected benefits would still be significant."<sup>6</sup> Our analysis demonstrates that the ratio approach has over-estimated impacts by a factor of ten to sixty for NO<sub>x</sub> reductions. When accurately modeled, the NO<sub>x</sub> reductions do not yield discernible visibility benefits. To that end, the following pictures from WinHaze Level 1 Visual Air Quality Imaging Modeler

<sup>&</sup>lt;sup>6</sup> Federal Register, Volume 78, Number 25, page 8720, February 6, 2013

(version 2.9.9.1) provide a visual reference for the  $CAM_X$  predicted visibility impairment from the maximum nitrate impacting facility at Isle Royale and Boundary Waters<sup>7</sup>.



Isle Royale FIP Base - United Taconite



Boundary Waters FIP Base - Hibbing Taconite



Isle Royale Final FIP – United Taconite



Boundary Waters Final FIP – Hibbing Taconite

Given the size of the predicted visibility impacts (both less than 0.2 dV improvement), these pictures illustrate no discernible visibility improvement from NO<sub>X</sub> reductions at either Class I area.

Ultimately, Minnesota and Michigan reached their visibility assessments in different ways, but this modeled analysis supports their conclusion that low  $NO_X$  burner technology is not BART for the furnaces modeled at Arcelor Mittal - Minorca, Hibbing Taconite, Northshore Mining Company, United Taconite, and Tilden Mining. Therefore, EPA should approve the sections of the SIPs establishing  $NO_X$  BART on this basis.

<sup>&</sup>lt;sup>7</sup> Voyageurs National Park pictures are not contained within the WinHaze program



resourceful. naturally. engineering and environmental consultants

# APPENDIX A: Visibility Impact Requirements and EPA's Scalar Approach for Estimating Visibility Impacts within the Taconite FIP

March 6, 2013

### I. Summary of Visibility Impact Requirements

The relevant language related to the specific BART visibility impact modeling approach from 40 CFR 51 Appendix Y (herein, Appendix Y), *Guidelines for BART Determinations Under the Regional Haze Rule,* is provided here, in italics with some language underlined for emphasis:

5. Step 5: How should I determine visibility impacts in the BART determination?

• For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.

Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emission rates are calculated as a percentage of pre-control emission rates. For example, if the 24-hr pre-control emission rate is 100 lb/hr of SO[2], then the post control rate is 5 lb/hr if the control efficiency being evaluated is 95 percent.

• Make the net visibility improvement determination.

Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. You have flexibility to assess visibility improvements due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment. Suggestions for making the determination are:

• Use of a comparison threshold, as is done for determining if BART-eligible sources should be subject to a BART determination. Comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g., the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing an x percent change in improvement).

• Compare the 98th percent days for the pre- and post-control runs.

Note that each of the modeling options may be supplemented with source apportionment data or source apportionment modeling.

It should be noted that Appendix Y is a guideline for state air quality agencies to proceed with modeling of BART sources. Therefore, these are not requirements, but recommended practices for evaluation of visibility impacts. Significant discretion was given to each state regarding the use of these methods. To that end, the Minnesota Pollution Control Agency applied a different modeling system than the EPA-approved model (CALPUFF) for BART evaluations. Discussed below, the new modeling system was subsequently used by EPA as part of their FIP proposal.

Further, an excerpt from the Clean Air Act, Part C, Subpart II is provided below to establish the basis for the Appendix Y regulations related to visibility improvement.

### II. Summary of EPA's approach

Specific language from the proposed and final FIPs are provided in *italics* along with comments.

EPA relied on visibility improvement modeling conducted by the Minnesota Pollution Control Agency (MPCA) and recorded in MPCA's document "Visibility Improvement Analysis of Controls Due to BART Determinations on Emission Unit's Subject to BART", October 23, 2009 [attached]. The visibility improvement modeling conducted by MPCA utilized the Comprehensive Air Quality Model with Extensions (CAMx) air quality model with the Mesoscale Meteorological Model (MM5) and the Emission Modeling System (EMS-2003). Within the CAMx modeling system, MPCA used the Particulate Source Apportionment Tool (PSAT) and included evaluation of all the elevated point emissions<sup>1</sup> at each facility with best available retrofit technology (BART) units. The impacts from MPCA State Implementation Plan (SIP) BART controls were determined by subtracting the impact difference between the 2002/2005 base case and 2002/2005 BART control case for each facility. EPA used the impacts from four of the six facilities modeled by MPCA (Minnesota Power – Boswell Energy Center, Minnesota Power – Taconite Harbor, Northshore Mining – Silver Bay, United Taconite). The other two facilities modeled by MPCA were utility sources (Rochester Public Utilities – Silver Lake and Xcel Energy – Sherburne Generating Plant). The locations of these sources are presented below in Figure A-1 (obtained from the MPCA 2009 document).

<sup>&</sup>lt;sup>1</sup> Elevated point emissions include only sources with plume rise above 50m.

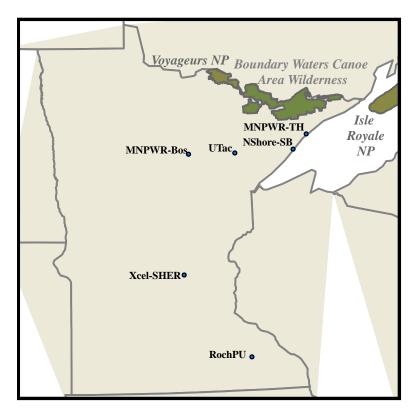


Figure A-1: Minnesota Facilities with BART-Determinations Assessed

In order to avoid the time and effort necessary for specific modeling of the units that EPA proposed to include in the FIP, EPA then used the average visibility impact from these four facilities to calculate two metrics for visibility improvement. The first metric is a ratio of number of days with greater than 0.5 deciview (dV) visibility divided separately by the change in  $SO_2$  and  $NO_x$  emissions at each facility (i.e. one ratio for change in  $SO_2$  emissions and one ratio for change in  $NO_x$  emissions). The second metric was calculated in the same fashion, but with 98<sup>th</sup> percentile visibility change divided by the change in  $SO_2$  and  $NO_x$  emissions at each facility. These ratios were then multiplied by the estimated FIP emission reductions for the taconite facilities (including UTAC and Northshore Mining). It is important to note that there were no  $NO_x$  emission reductions modeled from any of the taconite facilities and the only source of  $SO_2$  emission reductions from the taconite facilities was the UTAC facility.

Within the final FIP, EPA provided some additional statements that further clarified the agency's confidence regarding the use of the scalar approach for estimating visibility improvements.

### III. Specific Issues Regarding EPA's Visibility Impact Estimates

Clean Air Act Section 169(A)(g)(2) – "In determining the best available retrofit technology the State (or the Administrator in determining emission limitations which reflect such technology) shall 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 the source, and the <u>degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.</u>"

Proposed FIP Page 49329 – Column 1 – "The discussion below uses MPCA's emissions data and modeled visibility impact data to derive visibility impact ratios as a function of changes in emissions of NOx and SO2 at MPCA-modeled facilities. These visibility-emission ratios were then applied to the BART-based emission changes for the source subject to this BART rule to derive possible visibility impacts."

Issues – EPA's shortcut methodology does not provide an accurate assessment of potential visibility impacts from taconite emission units subject to BART, and cannot be relied upon for several reasons stated below. The use of emission change vs. visibility impact ratios is not scientifically accurate even for a single source, much less several sources in other locations, and illustrates EPA's haste for the development of the FIP without proper modeling procedures. According to a plain language reading of the Clean Air Act section above and the best-practice recommendations within Appendix Y, the state and EPA were required to conduct a thorough evaluation of the impacts associated with the changes in emissions for each BART technology at the relevant units within each taconite facilities. EPA's methodology does not result in a thorough evaluation. If such an analysis were submitted to EPA by the state, it would be rejected as inadequate. The same should apply to EPA's analysis of the visibility improvement calculations.

MPCA used an appropriate model for estimating visibility impacts from five utility sources and one taconite source, all subject to BART, in northern Minnesota. EPA took that analyses and attempted to justify its outcomes based on its flawed methodology. Alone, the differences between the emission profiles for utility sources and taconite sources and their different locations relative to the Class I areas should preclude this type of evaluation. The difference in the emissions profile relationship between  $NO_X$  and  $SO_2$  emissions is extremely important due to the interactive and competitive nature of the two pollutants for available ammonia ( $NH_3$ ) to form ammonium nitrate or ammonium sulfate.

In addition, there are important seasonal differences in the tendency for sulfates or nitrates to be important for haze formation. Nitrates are only important in winter because significant particle formation occurs only in cold weather; oxides of nitrogen react primarily to form ozone in the summer months. On the other hand, oxidation of  $SO_2$  to sulfate is most effective in summer with higher rates of photochemical and aqueous phase reactions. Due to the much different seasonal preferences for these two haze components, a one-size-fits-all scaling approach based upon annual averages that is insensitive to the season of the year is wholly inappropriate.

It is important to note that the only  $NO_x$  emission reductions used in the EPA scalar analyses were from utility sources. This occurred because the MPCA SIP did not include  $NO_x$  emission reductions from the United Taconite units. Therefore, the variation in emission profiles and stack parameters between utility boiler emission sources and taconite furnaces introduce another source of error with the EPA methodology.

Further, as shown in Figure A-1, the location of these sources with respect to the relevant Class I areas also causes significant problems with the EPA evaluation. The modeled visibility impacts from each source are a direct function of the wind direction. When two sources are not in the same direction with respect to the area, there is no possible way to accurately reflect the impact from the two different sources on receptor locations on any given day. For example, elevated impacts on the Voyageurs National Park from Northshore Mining would not happen on the same days as any of the other taconite sources in Minnesota.

Additionally, notwithstanding the inaccuracies of EPA's average scalar methodology, a review of the calculation of the visibility change to emission reduction ratios (i.e. MPCA-calculated visibility changes divided by  $SO_2$  and  $NO_X$  SIP emission reductions) was conducted. This review uncovered calculation/typographical errors in the tables that were used to develop the average visibility change metrics. These simple calculation errors were subsequently corrected in the final FIP, but another inconsistency was not. The emission reductions used for  $NO_X$  within the scalar visibility calculations (Table V-C.xx) do not match the emission reduction tables in the proposed FIP (Table V – B.yy) for each facility. In one case (Northshore Mining Company), the visibility improvement reductions are greater than the baseline emissions. The attached table provides the baseline, proposed FIP, and final FIP information contained within the EPA rulemakings and docket for each taconite furnace and facility. Ultimately, even if the scalar approach used by EPA was valid, the rulemaking record is inaccurate and incomplete for the calculation of visibility impacts due to these inconsistencies.

Further, the calculation methodology for the two facilities with  $SO_2$  and  $NO_X$  reductions (United Taconite and US Steel – Minntac) appears to utilize another invalid assumption. Also, the proposed FIP does not provide a clear explanation of the calculation of the scaled visibility impacts for these two facilities (Page 49332 – Column 1):

"To calculate the visibility impacts for the Minnesota source facilities covered by this FIP proposed rule, we multiplied the total estimated BART NOx and SO2 emission reductions for each subject facility by the appropriate visibility factor/emission change ratios in Table V-C.9 and <u>combined the results to estimate</u> the total visibility impacts that would result from the reduction of PM2.5 concentrations."

In Tables V-C.14 and V-C.16, the calculation of the visibility change with the two different pollutants is not explicitly provided within the FIP. Based on the use of the average visibility changes ("combined results") in the attached tables, one can generate "estimated visibility impacts" that are close to the values provided in the FIP tables. This pollutant averaging approach is not valid due to the previous comments regarding the interactive nature of the reaction mechanisms for ammonium nitrate and ammonium sulfate.

Proposed FIP Page 49331 – Column 1 – "The above visibility factor/emission change ratio data show significant variation from source-to-source and between impacted Class I areas. This variation is caused by differences in the relative location of the source (relative to the locations of the Class I areas), variations in background sources, variations in transport patterns on high haze factors, and other factors that we cannot assess without detailed modeling of the visibility impacts for the sources as a function of pollutant emission type."

Issue – EPA correctly establishes the significant variation in the ratio data and clearly distinguishes some (but not all) of the problems with the approach used to determine visibility impacts. Other problems include the differences in modeled utility source stack parameters vs. taconite stack parameters, the different inter-pollutant ratios at each facility, and the differences in visibility impacts due to on-going changes in emissions from 2002/2005 to current/future emission levels. Furthermore, EPA identifies the solution to solve this problem within their statement regarding "detailed modeling of the visibility impacts". This detailed modeling exercise was completed for BART-eligible Cliffs Natural Resources and Arcelor Mittal facilities in northeast Minnesota and Michigan to provide a clear record of the visibility improvements associated with the final FIP. This modeling demonstrates the lack of visibility improvement from nearly 15,000 tons per year of NO<sub>X</sub> emission reductions and provides sufficient evidence to support the Minnesota and Michigan State Implementation Plans which called for good combustion practices as BART for NO<sub>X</sub> at these facilities.

Proposed FIP Page 49333, Column 2 – "Each BART determination is a function of consideration of visibility improvement and other factors for the individual unit, but in general EPA's assessment of visibility impacts finds that technically feasible controls that are available at a reasonable cost for taconite plants can be expected to provide a visibility benefit that makes those controls warranted."

Issue – EPA's statement regarding visibility benefit from the FIP  $NO_X$  emission reductions are vastly overestimated based on updated  $CAM_X$  modeling for the Cliffs Natural Resources and Arcelor Mittal taconite furnaces. The modeling results evaluating the 98<sup>th</sup> percentile visibility improvements obtained from these emission reductions are generally less than 10% of the EPA estimates. Therefore, these  $NO_X$  controls are not warranted for visibility improvement in northeast Minnesota and Michigan.

Final FIP Page 8720, Column 2 – "EPA's analysis shows that based on all of the BART factors, including visibility, the selected controls are warranted. If highly reasonable and cost-effective controls had been available but visibility benefits were slight, EPA would have rejected those controls."

Issue – EPA describes exactly the situation with respect to "slight visibility benefits". Therefore, given the new information regarding the very slight modeled impact of  $NO_x$  emission reductions, EPA should reject those reductions as necessary under the BART program. Also, in the final FIP, EPA criticizes both MPCA and MDEQ for ignoring relevant information on Low  $NO_x$  Burner (LNB) technology. Now, given the length of time necessary and extensive effort required to generate this new visibility improvement data, EPA should reconsider its position on LNB as producing visibility benefits. This would allow EPA to support the original findings for these facilities within both the MPCA and MDEQ SIP with respect to  $NO_x$  emission limits. Final FIP Page 8720, Column 3 – "EPA's proposed rule acknowledged the uncertainty associated with the visibility impact ratio approach, but noted that despite the uncertainties, the Agency was confident that the information was adequate to assess potential visibility improvements due to emission reductions at the specific facilities."

"Given the geographic proximity of the taconite facilities to those that were modeled, EPA believes that the ratio approach provide adequate assurance of the visibility improvements that can be expected from the proposed emission reductions."

"In the proposed rule's summary of the impacts at Boundary Waters, Voyageurs, and Isle Royale, these values ranged from 1.3 to 7.1 dVs of improvement with between 17 and 93 fewer days above the 0.5 dV threshold. Therefore, even if the ratio approach was over-estimating visibility improvements by a factor of two or three, the expected benefits would still be significant."

Final FIP Page 8721, Column 3 – "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."

Issue – EPA again chose to ignore the specific technical issues discussed above regarding the use of the ratio approach and has incorrectly assumed that this approach will provide an accurate assessment of the visibility benefits from the Cliffs and Arcelor taconite facilities. Based on the refined  $CAM_x$  modeling results using a conservative estimate of EPA's final FIP emission reduction scenario, it is obvious that the ratio approach does not provide any assurance of the visibility improvements. Further, the estimates for visibility improvement are over-estimated by between a factor of ten and sixty. Therefore, the impacts are not "significant" as referenced in EPA's response to comment within the final FIP rulemaking. The lack of technical validity contained within the EPA scalar approach is alarming. Even more alarming is the agency's refusal to conduct the type of detailed analyses necessary to allow for a technically valid answer on a rulemaking that will cost the taconite industry millions of dollars.

#### **IV. Summary**

The CAM<sub>x</sub> modeling approach undertaken by Cliffs and Arcelor provides the best approximation of the visibility improvements from the emission reductions within the final FIP. This method replaces the use of the average ratio approach used by EPA with refined, photochemical modeling for the Cliffs and Arcelor facilities. The results of the analysis confirm the findings of the MPCA in its 2009 SIP that  $NO_x$  emission reductions do not have sufficient impact to warrant further consideration. At this point, we affirm that EPA's simple assessment is not credible, and any visibility improvement conclusions for  $NO_x$  are not technically sound. The visibility improvement results estimated by EPA using the ratio approach are between ten and sixty times greater than the results generated using the CAM<sub>x</sub> modeling system. In essence, the modeling conducted here provides EPA another opportunity to support the findings of the MPCA and MDEQ SIPs with respect to  $NO_x$  emissions impacts at the Cliffs and Arcelor facilities.

# Cliffs Natural Resources and Arcelor Mittal Taconite FIP Emission Summary

|                           |                   |                    |           |          | Emissions    |         | Emiss                  | ion Reductions         |         | Emissions |          |
|---------------------------|-------------------|--------------------|-----------|----------|--------------|---------|------------------------|------------------------|---------|-----------|----------|
|                           |                   |                    |           |          | Proposed FIP | ,       | Baseline -<br>Prop FIP | Baseline -<br>Prop FIP |         | Final FIP |          |
|                           |                   | Emission Unit      |           | Baseline | FIP          |         | <b>Emission Tables</b> | Visibility Calcs       |         |           |          |
| Facility                  | ModID             | Description        | Pollutant | tons/yr  | tons/yr      | Note(s) | tons/yr                | tons/yr                | Note(s) | lb/hr     | Note(s)  |
| Hibbing Taconite Company  | {3}               | Line 1             | NOx       | 2,497    | 749          | [1]     | 1,748                  |                        |         |           | [4]      |
|                           |                   |                    | SO2       | 202      | 202          | [2]     | 0                      |                        |         | 82.6      | [5]      |
|                           | {4}               | Line 2             | NOx       | 2,144    | 643          | [1]     | 1,500                  |                        |         |           | [4]      |
|                           |                   |                    | SO2       | 180      | 180          | [2]     | 0                      |                        |         | 82.6      | [5]      |
|                           | {5}               | Line 3             | NOx       | 2,247    | 674          | [1]     | 1,573                  |                        |         |           | [4]      |
|                           |                   |                    | SO2       | 188      | 188          | [2]     | 0                      |                        |         | 82.6      | [5]      |
|                           | HTC               | BART Units         | NOx       | 6,888    | 2,066        |         | 4,821                  | 5,259                  | [3]     |           |          |
|                           |                   | Combined           | SO2       | 570      | 570          |         | 0                      | 0                      | [3]     | 247.8     |          |
| Northshore Mining Company |                   | Process Boiler 1/2 | NOx       | 41       | 21           | [6]     | 21                     |                        |         |           | [10]     |
|                           |                   |                    | SO2       |          |              |         |                        |                        |         |           |          |
|                           | {24}              | Furnace 11         | NOx       | 386      | 116          | [7]     | 270                    |                        |         |           | [11]     |
|                           |                   |                    | SO2       | 38       | 38           | [8]     | 0                      |                        |         | 19.5      | [12]     |
|                           | {25}              | Furnace 12         | NOx       | 378      | 113          | [7]     | 264                    |                        |         |           | [11]     |
|                           |                   |                    | SO2       | 35       | 35           | [8]     | 0                      |                        |         | 19.5      | [12]     |
|                           | <mark>NSM</mark>  | BART Units         | NOx       | 805      | 250          |         | 555                    | 926                    | [9]     |           |          |
|                           |                   | Combined           | SO2       | 73       | 73           |         | 0                      | 0                      | [9]     | 39        |          |
| Tilden Mining Company     | {1}               | Boiler #1/2        | NOx       | 79       | 79           | [13]    | 0                      |                        |         |           |          |
|                           |                   |                    | SO2       | 0        | 0            | [14]    | 0                      |                        |         |           | [19]     |
|                           | {3}               | Ore Dryer # 1      | NOx       | 15       | 15           | [15]    | 0                      |                        |         |           |          |
|                           |                   |                    | SO2       | 34       | 34           | [15]    | 0                      |                        |         |           | [20]     |
|                           | {5}               | Furnace #1         | NOx       | 4,613    | 1,384        | [16]    | 3,229                  |                        |         |           | [21]     |
|                           |                   |                    | SO2       | 1,153    | 115          | [17]    | 1,038                  |                        |         | 55        | [22][23] |
|                           | <mark>TMC</mark>  | BART Units         | NOx       | 4,707    | 1,478        |         | 3,229                  | 3,229                  | [18]    |           |          |
|                           |                   | Combined           | SO2       | 1,187    | 150          |         | 1,038                  | 1,038                  | [18]    |           |          |
| United Taconite           | {26}              | Line 1             | NOx       | 1,643    | 493          | [24]    | 1,150                  |                        |         |           | [27]     |
|                           |                   |                    | SO2       | 1,293    | 129          | [25]    | 1,164                  |                        |         | 155       | [28]     |
|                           | {24}              | Line 2             | NOx       | 3,687    | 1,106        | [24]    | 2,581                  |                        |         |           | [27]     |
|                           |                   |                    | SO2       | 2,750    | 275          | [25]    | 2,475                  |                        |         | 374       | [28]     |
|                           | UTAC              | BART Units         | NOx       | 5,330    | 1,599        |         | 3,731                  | 3,208                  | [26]    |           |          |
|                           |                   | Combined           | SO2       | 4,043    | 404          |         | 3,639                  | 3,639                  | [26]    | 529       | [28]     |
| Arcelor Mittal            | <mark>ARC</mark>  | Line 1             | NOx       | 3,639    | 1,092        | [29]    | 2,547                  | 2,859                  | [31]    |           | [32]     |
|                           | <mark>{12}</mark> |                    | SO2       | 179      | 179          | [30]    | 0                      | 0                      | [31]    | 38.2      | [33]     |

| TOTAL BART UNIT | NOx | 21,369 | 6,485 | 14,884 | 15,481 |
|-----------------|-----|--------|-------|--------|--------|
|                 | SO2 | 6,053  | 1,376 | 4,677  | 4,677  |

Facility BART Unit Summary or Overall Summary

FIP Baseline does not match reference

FIP Table B emission tables do not match Table C visibility calculation tables

#### Notes:

- [1] HTC Line 1-3 USEPA FIP NOx Baseline Emissions Proposed FIP Table V B.24; Proposed FIP NOx Emissions = 70% Control from Baseline
  - Typographical Error in Table V B.24 for Line 1 Baseline Emissions (2,143.5 TPY Proposed FIP; should have been 2,497 TPY)
- [2] HTC Line 1-3 USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V B.27
- [3] HTC USEPA Proposed BART FIP Table V C.11
- [4] HTC Furnace Lines USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
- [5] HTC Furnace Lines USEPA final BART combined limit of 247.8 lb SO2/hr [82.6 lb/hr each for Lines 1 to 3] (30-day rolling avg); can be adjusted based on CEMs data.
- [6] NSM Process Boilers 1&2 NOx Emissions from Proposed FIP Table V B.12 (p49318); LNB 50% Control from Baseline of 41.2 tons/year
- [7] NSM Furnace 11/12 NOx Emissions (Baseline and Proposed FIP Control) from Proposed FIP Table V B.8; FIP Emissions = 70% Control from Baseline
- [8] NSM Furnace 11/12 No Additional SO2 Control Applied by Proposed FIP; Baseline FIP Emission Rate from Table V B.10
- [9] NSM USEPA Proposed BART FIP Table V C.12
- [10] NSM Process Boilers 1&2 USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) [No additional control].
- [11] NSM Furnace 11/12 USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
- [12] NSM Furnace 11/12 USEPA final BART combined limit of 39.0 lb SO2/hr (30-day rolling average); must be adjusted based on CEMs data.
- [13] Tilden Process Boilers 1 & 2 NOx Baseline Emissions Proposed FIP Table V B.38
- [14] Tilden Process Boilers 1 & 2 SO2 Baseline Emissions Proposed FIP Table V B.37 (0.25 TPY)
- [15] Tilden Dryer #1 Emissions from Proposed FIP Table V B.39 (SO2) and Table V B.40 (NOx) 34.07 TPY SO2, 15.1 TPY NOx
- [16] Tilden Furnace 1 NO2 Baseline and Proposed FIP Control Emissions Proposed FIP Table V B.34 (FIP Emissions = 70% Control from Baseline)
- [17] Tilden Furnace 1 Proposed FIP SO2 Emissions Table V-B.36; Spray Dry Absorption 90%; Proposed FIP Text says 95% Control or 5 ppm; Baseline Emissions Back-calculated from 90% control
- [18] Tilden Furnace 1 USEPA did not calculate visibility improvement for Tilden (Used emission difference Baseline Proposed FIP)
- [19] Tilden USEPA Final BART limit of 1.2%S in fuel combusted by Process Boiler #1 and #2
- [20] Tilden USEPA Final BART limit of 1.5%S in fuel combusted by Ore Dryer #1
- [21] Tilden Furnace 1- USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only); NOx emissions referenced in final FIP text as 65% control from baseline (page 8721)
- [22] Tilden Furnace 1 USEPA Final BART restriction Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs; SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
- [23] Tilden Furnace 1 USEPA Final BART Modeling File (Part of Final Rulemaking Docket) Conducted by NPS 55 lb/hr SO2
- [24] UTAC Line 1-2 USEPA NOx Baseline Emissions Proposed FIP Table V B.14; Proposed FIP NOx Emissions = 70% Control from Baseline
- [25] UTAC Line 1-2 USEPA proposed FIP Baseline SO2 Emissions Table V B.17; 90% Control in Table, but 95% Control within text Proposed FIP (page 49319)
- [26] UTAC USEPA Proposed BART FIP Table V C.13
- [27] UTAC Line 1-2 USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)
- [28] UTAC Line 1-2 USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr Line 1 & 374 lb/hr Line 2).
- [29] Arcelor USEPA proposed FIP Baseline NOx Emissions Table V B.19; Proposed FIP NOx Emissions = 70% Control from Baseline
- [30] Arcelor USEPA proposed FIP Baseline SO2 Emissions Table V B.21
- [31] Arcelor USEPA Proposed BART FIP Table V C.10
- [32] Arcelor USEPA Final BART SO2 Limit of 38.16 lb/hr for Arcelor.
- [33] Arcelor USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)

EPA Furnace NOx Control % 70%



resourceful. naturally. engineering and environmental consultants

# APPENDIX B: Barr and MPCA CAM<sub>x</sub> Modeling Comparison of Results

March 6, 2013

## Minnesota Power – Taconite Harbor (BART01)

#### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| PM <sub>2.5</sub>           |          |                 | Class I Area |                 |           |      |                 |             |      |                 |  |  |  |
|-----------------------------|----------|-----------------|--------------|-----------------|-----------|------|-----------------|-------------|------|-----------------|--|--|--|
|                             |          | Boundary Waters |              |                 | Voyageurs |      |                 | Isle Royale |      |                 |  |  |  |
| Parameter                   | Met Year | Base            | BART         | Differ-<br>ence | Base      | BART | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |  |
| Days > 0.5 dv               | 2002     | 94              | 90           | -4              | 11        | 9    | -2              | 30          | 27   | -3              |  |  |  |
| 98th Percentile $\Delta dv$ | 2002     | 9.2             | 8.3          | -0.9            | 0.8       | 0.7  | -0.1            | 2.2         | 1.9  | -0.3            |  |  |  |

#### Barr

## Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| PM <sub>2.5</sub>           |          |                   | Class I Area |                 |           |           |       |             |      |                 |  |  |  |
|-----------------------------|----------|-------------------|--------------|-----------------|-----------|-----------|-------|-------------|------|-----------------|--|--|--|
|                             |          | Boundary Waters   |              |                 | Voyageurs |           |       | Isle Royale |      |                 |  |  |  |
| Parameter                   | Met Year | et Year Base BART |              | Differ-<br>ence | Base      | Base BART |       | Base BART   |      | Differ-<br>ence |  |  |  |
| Days > 0.5 dv               | 2002     | 95                | 90           | -5              | 11        | 9         | -2    | 30          | 27   | -3              |  |  |  |
| 98th Percentile $\Delta dv$ | 2002     | 9.14              | 8.25         | -0.89           | 0.82      | 0.68      | -0.14 | 2.22        | 1.88 | -0.34           |  |  |  |

### Minnesota Power – Boswell (BART04)

#### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| <b>PM</b> <sub>2.5</sub> |          |                 | Class I Area |                 |           |      |                 |             |      |                 |  |  |  |
|--------------------------|----------|-----------------|--------------|-----------------|-----------|------|-----------------|-------------|------|-----------------|--|--|--|
|                          |          | Boundary Waters |              |                 | Voyageurs |      |                 | Isle Royale |      |                 |  |  |  |
| Parameter                | Met Year | Base            | BART         | Differ-<br>Ence | Base      | BART | Differ-<br>ence | Base        | BART | Differ-<br>Ence |  |  |  |
| Days > 0.5 dv            | 2002     | 111             | 60           | -51             | 86        | 58   | -28             | 48          | 27   | -21             |  |  |  |
| 98th Percentile<br>∆ dv  | 2002     | 4.3             | 2.4          | -1.9            | 4.4       | 2.7  | -1.8            | 2.0         | 1.0  | -1.0            |  |  |  |

Barr

## Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| <b>PM</b> <sub>2.5</sub>    |          |                 | Class I Area |                 |           |      |                 |             |      |                 |  |  |  |
|-----------------------------|----------|-----------------|--------------|-----------------|-----------|------|-----------------|-------------|------|-----------------|--|--|--|
|                             |          | Boundary Waters |              |                 | Voyageurs |      |                 | Isle Royale |      |                 |  |  |  |
| Parameter                   | Met Year | Base            | BART         | Differ-<br>Ence | Base      | BART | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |  |
| Days > 0.5 dv               | 2002     | 110             | 61           | -49             | 86        | 58   | -28             | 47          | 27   | -20             |  |  |  |
| 98th Percentile $\Delta dv$ | 2002     | 4.27            | 2.37         | -1.90           | 4.43      | 2.65 | -1.78           | 1.96        | 0.98 | -0.98           |  |  |  |

# Northshore Mining – Silver Bay (BART05)

### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| PM <sub>2.5</sub>           |          |                 | Class I Area |                 |           |      |                 |             |      |                 |  |  |  |
|-----------------------------|----------|-----------------|--------------|-----------------|-----------|------|-----------------|-------------|------|-----------------|--|--|--|
|                             |          | Boundary Waters |              |                 | Voyageurs |      |                 | Isle Royale |      |                 |  |  |  |
| Parameter                   | Met Year | Base            | BART         | Differ-<br>ence | Base      | BART | Differ-<br>ence | Base        | BART | Differ-<br>ence |  |  |  |
| Days > 0.5 dv               | 2002     | 77              | 72           | -5              | 9         | 8    | -1              | 20          | 15   | -5              |  |  |  |
| 98th Percentile $\Delta dv$ | 2002     | 3.96            | 3.79         | -0.17           | 0.6       | 0.5  | -0.1            | 0.9         | 0.7  | -0.2            |  |  |  |

#### Barr

## Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |                           | Class I Area |                 |      |                           |       |      |      |                 |  |  |
|-----------------------------|----------|---------------------------|--------------|-----------------|------|---------------------------|-------|------|------|-----------------|--|--|
| <b>PM</b> <sub>2.</sub>     | 5        | Boundary Waters Voyageurs |              |                 |      | Isle Royale               |       |      |      |                 |  |  |
| Parameter                   | Met Year | Base                      | BART         | Differ-<br>ence | Base | Base BART Differ-<br>ence |       | Base | BART | Differ-<br>ence |  |  |
| Days > 0.5 dv               | 2002     | 78                        | 72           | -6              | 9    | 8                         | -1    | 20   | 15   | -5              |  |  |
| 98th Percentile $\Delta dv$ | 2002     | 3.96                      | 3.78         | -0.18           | 0.63 | 0.50                      | -0.13 | 0.90 | 0.73 | -0.17           |  |  |

## **United Taconite (BART26)**

### MPCA

# Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                      |          | Class I Area    |      |                 |                           |     |      |      |                 |      |  |  |
|-------------------------|----------|-----------------|------|-----------------|---------------------------|-----|------|------|-----------------|------|--|--|
| $\mathbf{PM}_{2.}$      | 5        | Boundary Waters |      |                 | Voyageurs Isle Royale     |     |      | e    |                 |      |  |  |
| Parameter               | Met Year | Base            | BART | Differ-<br>ence | Base BART Differ-<br>ence |     | Base | BART | Differ-<br>ence |      |  |  |
| Days > 0.5 dv           | 2002     | 59              | 44   | -15             | 32                        | 20  | -12  | 8    | 1               | -7   |  |  |
| 98th Percentile<br>∆ dv | 2002     | 3.0             | 1.7  | -1.3            | 1.8                       | 0.8 | -0.9 | 0.6  | 0.3             | -0.3 |  |  |

Barr

## Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |      | Class I Area                         |                 |                           |      |       |      |                 |       |  |  |
|-----------------------------|----------|------|--------------------------------------|-----------------|---------------------------|------|-------|------|-----------------|-------|--|--|
| $\mathbf{PM}_{2.}$          | 5        | B    | oundary Waters Voyageurs Isle Royale |                 |                           | e    |       |      |                 |       |  |  |
| Parameter                   | Met Year | Base | BART                                 | Differ-<br>ence | Base BART Differ-<br>ence |      | Base  | BART | Differ-<br>ence |       |  |  |
| Days > 0.5 dv               | 2002     | 63   | 46                                   | -17             | 34                        | 20   | -14   | 8    | 1               | -7    |  |  |
| 98th Percentile $\Delta dv$ | 2002     | 3.02 | 1.69                                 | -1.33           | 1.78                      | 0.85 | -0.93 | 0.59 | 0.28            | -0.31 |  |  |

## Xcel Sherburne (BART13)

### MPCA

## Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                      |          |                 | Class I Area |                 |      |                           |                       |      |      |                 |  |  |
|-------------------------|----------|-----------------|--------------|-----------------|------|---------------------------|-----------------------|------|------|-----------------|--|--|
| $\mathbf{PM}_{2.}$      | 5        | Boundary Waters |              |                 |      | Voyageur                  | Voyageurs Isle Royale |      |      | e               |  |  |
| Parameter               | Met Year | Base            | BART         | Differ-<br>ence | Base | Base BART Differ-<br>ence |                       | Base | BART | Differ-<br>ence |  |  |
| Days > 0.5 dv           | 2002     | 74              | 58           | -16             | 53   | 39                        | -14                   | 42   | 30   | -12             |  |  |
| 98th Percentile<br>∆ dv | 2002     | 2.5             | 1.9          | -0.6            | 2.2  | 1.7                       | -0.5                  | 1.4  | 1.0  | -0.4            |  |  |

#### Barr

## Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |                 | Class I Area |                 |           |                           |       |             |      |                 |  |  |
|-----------------------------|----------|-----------------|--------------|-----------------|-----------|---------------------------|-------|-------------|------|-----------------|--|--|
| $\mathbf{PM}_{2}$ .         | 5        | Boundary Waters |              |                 | Voyageurs |                           |       | Isle Royale |      |                 |  |  |
| Parameter                   | Met Year | Base            | BART         | Differ-<br>ence | Base      | Base BART Differ-<br>ence |       | Base        | BART | Differ-<br>ence |  |  |
| <b>Days</b> > 0.5 dv        | 2002     | 74              | 59           | -15             | 53        | 39                        | -14   | 42          | 29   | -13             |  |  |
| 98th Percentile $\Delta dv$ | 2002     | 2.48            | 1.90         | -0.58           | 2.18      | 1.65                      | -0.53 | 1.44        | 1.06 | -0.38           |  |  |

## **Rochester Public Utilities (BART07)**

### MPCA

## Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |      |            |                                  |      | Class I Are               | a   |      |      |                 |
|-----------------------------|----------|------|------------|----------------------------------|------|---------------------------|-----|------|------|-----------------|
| $\mathbf{PM}_{2.}$          | 5        | B    | oundary Wa | ary Waters Voyageurs Isle Royale |      |                           | e   |      |      |                 |
| Parameter                   | Met Year | Base | BART       | Differ-<br>ence                  | Base | Base BART Differ-<br>ence |     | Base | BART | Differ-<br>ence |
| Days > 0.5 dv               | 2002     | 0    | 0          | 0                                | 0    | 0                         | 0   | 0    | 0    | 0               |
| 98th Percentile $\Delta dv$ | 2002     | 0.1  | 0.1        | 0.0                              | 0.1  | 0.0                       | 0.0 | 0.1  | 0.0  | 0.0             |

Barr

## Number of Days with Results > 0.5 dv and 98<sup>th</sup> Percentile Deciview Value

| DM                          |          |      | Class I Area                   |                 |      |            |             |      |                 |      |  |  |
|-----------------------------|----------|------|--------------------------------|-----------------|------|------------|-------------|------|-----------------|------|--|--|
| $\mathbf{PM}_{2}$ .         | 5        | B    | Boundary Waters Voyageurs Isle |                 |      | Isle Royal | Isle Royale |      |                 |      |  |  |
| Parameter                   | Met Year | Base | BART                           | Differ-<br>ence |      |            | Base        | BART | Differ-<br>ence |      |  |  |
| Days > 0.5 dv               | 2002     | 0    | 0                              | 0               | 0    | 0          | 0           | 0    | 0               | 0    |  |  |
| 98th Percentile $\Delta dv$ | 2002     | 0.10 | 0.06                           | 0.04            | 0.08 | 0.04       | 0.04        | 0.09 | 0.04            | 0.05 |  |  |



# APPENDIX C: CAM<sub>X</sub> PSAT Source List

March 6, 2013

# 2009 MPCA Tracked, Elevated Point Sources

| RANKTRAC   | RECEPTOR      |                 |                                      |
|------------|---------------|-----------------|--------------------------------------|
| BARTSRC_ID | BARTSRC_ID    | Facility ID     | Facility Name [1]                    |
| 1          | 2             | 2703100001      | Minnesota Power - Taconite Harbor    |
| 2          | 3             | 2703700003      | XCEL - Black Dog                     |
| 3          | 4             | 2705300015      | XCEL - Riverside                     |
| 4          | 5             | 2706100004      | Minnesota Power - Boswell            |
| 5          | 6             | 2707500003      | Northshore Mining Co - Silver Bay    |
| 6          | 7             | 2709900001      | Austin Utilities - NE Power Station  |
| 7          | 8             | 2710900011      | Rochester Public Utilities           |
| 8          | 9             | 2711100002      | Otter Tail Power - Hoot Lake         |
| 9          | 10            | 2712300012      | XCEL - High Bridge                   |
| 10         | 11            | 2713700013      | Minnesota Power - Laskin             |
| 11         | 12            | 2713700027      | Hibbing Public Utilities             |
| 12         | 13            | 2713700028      | Virginia Dept of Public Utilities    |
| 13         | 14            | 2714100004      | XCEL - Sherburne Generating Plant    |
| 14         | 15            | 2716300005      | XCEL - Allen S. King                 |
| 15         | 16            | 2701700002      | Sappi - Cloquet                      |
| 16         | 17            | 2703700011      | Flint Hill Resources - Pine Bend     |
| 17         | 18            | 2706100001      | Blandin Paper / Rapids Energy        |
| 18         | 19            | 2707100002      | Boise Cascade - International Falls  |
| 19         | 20            | 2713700005      | US Steel - Minntac                   |
| 20         | 21            | 2713700015      | Minnesota Power - ML Hibbard         |
| 21         | 22            | 2713700022      | Duluth Steam Cooperative             |
| 22         | 23            | 2713700031      | Georgia Pacific - Duluth             |
| 23         | 24            | 2713700061      | Hibbing Taconite                     |
| 24         | 25            | 2713700062      | Arcelor Mittal                       |
| 25         | 26            | 2713700063      | US Steel - Keetac                    |
| 26         | 27            | 2713700113      | United Taconite - Fairlane Plant [2] |
| 27         | 28            | 2700900011      | International Paper - Sartell        |
| 28         | 29            | 2716300003      | Marathon Ashland Petroleum           |
| 29         | 30            | 2713700083      | Potlatch - Cook                      |
| 30         | 31            | 2706100010      | Potlatch - Grand Rapids              |
|            |               |                 |                                      |
|            | Included in M | IPCA BART SIP M | Iodeling Report                      |

|     | Included in MPCA BART SIP Modeling Report          |
|-----|--|
| [1] | MPCA tracked all point sources on a facility-basis |

[2] MPCA Emissions did not Include UTAC Line 1

# 2012/2013 Barr Tracked, Elevated Point Sources

| Output ID | BARTSRC ID | Facility ID | Facility / Unit Name [3]                      |
|-----------|------------|-------------|---|
| MNPWTH    | 2          | -           | Minnesota Power - Taconite Harbor             |
| XCELBD    | 3          | 2703700003  | XCEL - Black Dog                              |
| XCELRV    | 4          | 2705300015  | XCEL - Riverside                              |
| MNPWBO    | 5          | 2706100004  | Minnesota Power - Boswell                     |
| NSMSBU    | 6          | 2707500003  | Northshore Mining Co - Silver Bay (All Other) |
| AUSTIN    | 7          | 2709900001  | Austin Utilities - NE Power Station           |
| ROCHPU    | 8          | 2710900011  | Rochester Public Utilities                    |
| OTTRHL    | 9          | 2711100002  | Otter Tail Power - Hoot Lake                  |
| XCELHB    | 10         | 2712300012  | XCEL - High Bridge                            |
| MNPWLS    | 11         | 2713700013  | Minnesota Power - Laskin                      |
| HIBBPU    | 12         | 2713700027  | Hibbing Public Utilities                      |
| VIRGPU    | 13         | 2713700028  | Virginia Dept of Public Utilities             |
| XCELSB    | 14         | 2714100004  | XCEL - Sherburne Generating Plant             |
| XCELAK    | 15         | 2716300005  | XCEL - Allen S. King                          |
| SAPPIC    | 16         | 2701700002  | Sappi - Cloquet                               |
| FHRPNB    | 17         | 2703700011  | Flint Hill Resources - Pine Bend              |
| BLNPAP    | 18         | 2706100001  | Blandin Paper / Rapids Energy                 |
| BOISEC    | 19         | 2707100002  | Boise Cascade - International Falls           |
| MINNTC    | 20         | 2713700005  | US Steel - Minntac                            |
| MNPWHB    | 21         | 2713700015  | Minnesota Power - ML Hibbard                  |
| DULSTM    | 22         | 2713700022  | Duluth Steam Cooperative                      |
| GEOPAC    | 23         | 2713700031  | Georgia Pacific - Duluth                      |
| HIBTAC    | 24         | 2713700061  | Hibbing Taconite (All Other)                  |
| ARCELR    | 25         | 2713700062  | Arcelor Mittal (All Other)                    |
| KEETAC    | 26         | 2713700063  | US Steel - Keetac                             |
| UTACFP    | 27         | 2713700113  | United Taconite - Fairlane Plant (All Other)  |
| INTPAP    | 28         | 2700900011  | International Paper - Sartell                 |
| MARTHN    | 29         | 2716300003  | Marathon Ashland Petroleum                    |
| POTLTC    | 30         | 2713700083  | Potlatch - Cook                               |
| POTLTG    | 31         | 2706100010  | Potlatch - Grand Rapids                       |
| TILDEN    | 32         | 26103B4885  | Tilden Mining Company (All Other)             |
| NSMPB1    | 33         | 2707500003  | Northshore Mining - Power Boiler 1            |
| NSMPB2    | 34         | 2707500003  | Northshore Mining - Power Boiler 2            |
| NSMF11    | 35         | 2707500003  | Northshore Mining - Furnace 11                |
| NSMF12    | 36         | 2707500003  | Northshore Mining - Furnace 12                |
| UTACL1    | 37         | 2713700113  | United Taconite - Line 1                      |
| UTACL2    | 38         | 2713700113  | United Taconite - Line 2                      |
| ARCLN1    | 39         | 2713700062  | Arcelor Mittal - Line 1                       |
| HBTCF1    | 40         | 2713700061  | Hibbing Taconite - Line 1                     |
| HBTCF2    | 41         | 2713700061  | Hibbing Taconite - Line 2                     |
| HBTCF3    | 42         | 2713700061  | Hibbing Taconite - Line 3                     |
| TILDL1    | 43         | 26103B4885  | Tilden Mining - Line 1                        |

Included in Barr Output Evaluation

Barr tracked furnace stacks and other noted stacks on a unit-basis while all other stacks were included in the "All Other" stacks

[3]



# APPENDIX D: Summary of CAM<sub>x</sub> Elevated Point Source Emissions

March 6, 2013

# Summary of CAMx Elevated Point Source Emissions

|                           |                   |                    |           | Emissi         | ons      | Emiss   | sions   | Emission Reductions  |
|---------------------------|-------------------|--------------------|-----------|----------------|----------|---------|---------|----------------------|
|                           |                   |                    |           | Propose        | ed FIP   | Fina    | I FIP   | Baseline - Final FIP |
|                           |                   | Emission Unit      | Pollutant | Baseline       |          | FIP     |         |                      |
| Facility                  | ModID             | Description        |           | tons/yr        | Note(s)  | tons/yr | Note(s) | tons/yr              |
| Hibbing Taconite Company  | {3}               | Line 1             | NOx       | 2,497          | [1]      | 749     | [3]     | 1,748                |
|                           |                   |                    | SO2       | 202            | [2]      | 202     | [4]     | 0                    |
|                           | {4}               | Line 2             | NOx       | 2,144          | [1]      | 643     | [3]     | 1,500                |
|                           |                   |                    | SO2       | 180            | [2]      | 180     | [4]     | 0                    |
|                           | {5}               | Line 3             | NOx       | 2,247          | [1]      | 674     | [3]     | 1,573                |
|                           |                   |                    | SO2       | 188            | [2]      | 188     | [4]     | 0                    |
|                           | HTC               | BART Furnaces      | NOx       | 6,888          |          | 2,066   |         | 4,821                |
|                           |                   | Combined           | SO2       | 570            |          | 570     |         | 0                    |
| Northshore Mining Company |                   | Process Boiler 1/2 | NOx       | 41             | [5]      | 41      | [8]     | 0                    |
|                           |                   |                    | SO2       |                |          |         |         |                      |
|                           | {24}              | Furnace 11         | NOx       | 386            | [6]      | 116     | [9]     | 270                  |
|                           |                   |                    | SO2       | 38             | [7]      | 38      | [10]    | 0                    |
|                           | {25}              | Furnace 12         | NOx       | 378            | [6]      | 113     | [9]     | 264                  |
|                           |                   |                    | SO2       | 35             | [7]      | 35      | [10]    | 0                    |
|                           | <mark>NSM</mark>  | BART Furnaces      | NOx       | 764            |          | 229     |         | 535                  |
|                           |                   | Combined           | SO2       | 73             |          | 73      |         | 0                    |
| Tilden Mining Company     | {1}               | Boiler #1/2        | NOx       | 79             | [11]     | 79      | [16]    | 0                    |
|                           |                   |                    | SO2       | 0              | [12]     | 0       | [17]    | 0                    |
|                           | {3}               | Ore Dryer # 1      | NOx       | 15             | [13]     | 15      | [18]    | 0                    |
|                           |                   |                    | SO2       | 34             | [13]     | 34      | [19]    | 0                    |
|                           | {5}               | Furnace #1         | NOx       | 4,613          | [14]     | 1,384   | [20]    | 3,229                |
|                           |                   |                    | SO2       | 1,153          | [15]     | 231     | [21]    | 922                  |
|                           | TMC               | BART Furnace       | NOx       | 4,613          |          | 1,384   |         | 3,229                |
|                           |                   |                    | SO2       | 1,153          |          | 231     |         | 922                  |
| United Taconite           | {26}              | Line 1             | NOx       | 1,643          | [22][23] | 493     | [26]    | 1,150                |
|                           |                   |                    | SO2       | 1,293          | [25]     | 577     | [27]    | 716                  |
|                           | {24}              | Line 2             | NOx       | 3,687          | [22][24] | 1,106   | [26]    | 2,581                |
|                           |                   |                    | SO2       | 2,750          | [25]     | 1,392   | [27]    | 1,357                |
|                           | UTAC              | BART Furnaces      | NOx       | 5,330          |          | 1,599   |         | 3,731                |
|                           |                   | Combined           | SO2       | 4,043          |          | 1,969   |         | 2,074                |
| Arcelor Mittal            | ARC               | Line 1             | NOx       | 3 <i>,</i> 639 | [28]     | 1,092   | [30]    | 2,547                |
|                           | <mark>{12}</mark> |                    | SO2       | 179            | [29]     | 179     | [31]    | 0                    |

| TOTAL BART | NOx | 21,233 | 6,370 | 14,863 |
|------------|-----|--------|-------|--------|
| Furnaces   | SO2 | 6,018  | 3,022 | 2,996  |

Fac

Facility Furnace Unit Summary or Overall Summary

FIP Baseline does not match reference

#### Notes:

- [1] HTC Line 1-3 USEPA FIP NOx Baseline Emissions Proposed FIP Table V B.24
- [2] HTC Line 1-3 USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V B.27
- [3] HTC Line 1-3 USEPA Proposed FIP NOx = 70% control from Baseline Table V B.24; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
- [4] HTC Line 1-3 USEPA Final FIP no additional SO2 control (Final FIP = Baseline Emissions)
- [5] NSM Process Boilers 1&2 NOx Emissions from Proposed FIP Table V B.12 (p49318)
- [6] NSM Furnace 11/12 NOx Emissions from Proposed FIP Table V B.8
- [7] NSM Furnace 11/12 SO2 Baseline FIP Emission Rate from Proposed FIP Table V B.10
- [8] NSM Process Boilers #1 and #2 USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) No additional control.
- [9] NSM Furnace 11/12 USEPA Proposed FIP NOx = 70% control from Baseline Table V B.8; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
- [10] NSM Furnace 11/12 no Additional SO2 Control Applied by Proposed or Final FIP (Final FIP = Baseline Emissions)
- [11] Tilden Process Boilers 1 & 2 NOx Baseline Emissions Proposed FIP Table V B.38
- [12] Tilden Process Boilers 1 & 2 SO2 Baseline Emissions Proposed FIP Table V B.37 (0.25 TPY)
- [13] Tilden Dryer #1 Emissions from Proposed FIP Table V B.39 (SO2) and Table V B.40 (NOx) 34.07 TPY SO2, 15.1 TPY NOx
- [14] Tilden Furnace 1 NO2 Baseline Proposed FIP Table V B.34
- [15] Tilden Furnace 1 SO2 Baseline Proposed FIP Projected SO2 Emission Reductions Table V-B.36; Baseline Emissions Back-calculated from 90% control
- [16] Tilden Process Boilers 1 & 2 No additional NOx control (Final FIP = Baseline Emissions)
- [17] Tilden Process Boilers 1 & 2 USEPA Final BART limit of 1.2%S in fuel No additional SO2 control (Final FIP = Baseline Emissions)
- [18] Tilden Ore Dryer #1 No additional NOx control (Final FIP = Baseline Emissions)
- [19] Tilden Ore Dryer #1 USEPA Final BART limit of 1.5%S in fuel No additional SO2 control (Final FIP = Baseline Emissions)
- [20] Tilden Furnace 1 USEPA Proposed FIP NOx = 70% control from Baseline Table V B.34; Final FIP (1.2 or 1.5 lb/MMBTU) NOx emissions referenced in final FIP text at 65% control from baseline (page 8721); but that is not consistent with the remaining facilities Modeled emissions assumed 70% control to provide maximum emission reductions
- [21] Tilden USEPA Final BART restriction Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs; SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
- [22] UTAC USEPA FIP NOx Baseline Emissions Proposed FIP Table V B.14
- [23] UTAC Line 1 NOx Permit limit specified in permit 13700113-005 1,655 TPY, issued 8/19/2010, page A-49 (reference from USEPA 114 Request Question 6)
- [24] UTAC Line 2 NOx Permit limit specified in permit 13700113-005 3,692 TPY, issued 8/19/2010, page A-56 (reference from USEPA 114 Request Question 6)
- [25] UTAC Line 1&2 USEPA proposed FIP Baseline SO2 Emissions Table V B.17; 90% Control in Table, 95% Control within text Proposed FIP (page 49319) Modeled baseline emissions back-calculated from 90% Control; SO2 Reductions match Table V - C.13 in Proposed FIP
- [26] UTAC Line 1&2 USEAP Proposed FIP NOx = 70% Control from Baseline Table V B.14; Final FIP (1.2 or 1.5 lb/MMBTU) Modeled emissions assumed 70% control to provide maximum emission reductions
- [27] UTAC Line 1&2 USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr Line 1 & 374 lb/hr Line 2) 30-day rolling average. Modeled Final FIP emissions used the limits and 85% operating factor to calculate the annual emissions (designed to maximize reductions)
- [28] Arcelor Line 1 USEPA proposed FIP Baseline NOx Emissions Table V B.19
- [29] Arcelor Line 1 USEPA proposed FIP Baseline SO2 Emissions Table V B.21
- [30] Arcelor Line 1 Proposed FIP NOx = 70% Control from Baseline Table V B.19; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
- [31] Arcelor Line 1 USEPA Final FIP no additional SO2 control (Final FIP = Baseline Emissions)



# APPENDIX E: Electronic Mail Requests - Proposed and Final FIP Emission Clarifications

From:Jeffry D. BennettSent:Thursday, January 31, 2013 7:42 PMTo:'Rosenthal.steven@Epa.gov'Cc:'Long, Michael E'Subject:Clarification Regarding Emissions within the Final Taconite BART FIPAttachments:EPA\_FIP\_Emission\_Summary\_01292013.xls

Steve,

Pursuant to our conversation last week regarding the baseline and controlled emission inventories within the proposed and final BART FIP for taconite furnaces, this e-mail is designed to request clarification regarding certain information contained in the rule. To that end, attached you will find a spreadsheet that summarizes and documents (to the maximum extent possible) the emission inventory data within the FIP rulemakings.

Specifically at this time, we are requesting:

(1) verification of the UTAC baseline NOx information for Line 1 and Line 2 ('Summary' Tab, Cells E30 and E32),

(2) clarification of the differences between the information contained in Columns H and I of the spreadsheet, Column H contains the difference between the FIP baseline and proposed FIP control emissions and was calculated from information within Table V-B.xx\* - NOx or SO2 facility specific emission data. The Column I information contains the emission reductions obtained from Table V-C.yy visibility improvement estimate tables. For each facility, these two columns should match, but the NOx information does not. Ultimately, the bases for Table V-C.yy data is the component that is missing.

\*Note: for Hibbing Taconite Line 1, a typographical error was discovered in Table V-B.24 and corrected in the spreadsheet.

(3) EPA's estimates of final FIP emissions on a tons/year basis with the corresponding emission reductions (i.e. FIP baseline – final FIP control) expected by EPA. This information would replace the "?" in Columns L and M of the spreadsheet. Along with the estimates, documentation of their bases would be extremely beneficial. For example, NOx could include either a % reduction from baseline or MMBTU/hour, Hours/year, and the appropriate lb NOx/MMBTU limit.

If you have any questions regarding these requests, feel free to contact Mike Long or myself. Thank you for your time.

Jeffry D. Bennett, PE Senior Air Quality Engineer Jefferson City office: 573.638.5033 cell: 573.694.0674 JBennett@barr.com www.barr.com From: Jeffry D. Bennett
Sent: Thursday, February 14, 2013 12:02 PM
To: 'Robinson.randall@Epa.gov'
Subject: FW: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: EPA\_FIP\_Emission\_Summary\_01292013.xls

#### Randy,

I talked with Steve Rosenthal yesterday about the taconite BART FIP emissions (see e-mail below). He told me that you "wrote the section on visibility improvement" and suggested I contact you about item 2 and a portion of the information requested in item 3. Barr Engineering is contracted with Cliffs Natural Resources and Arcelor Mittal to provide their taconite facilities with technical support regarding the FIP. At this point, we are trying to summarize and document the bases for the SO2 and NOx emissions that were used in the EPA baseline, the proposed FIP, and the final FIP for all their facilities.

The attached spreadsheet that I sent Steve previously includes the summary. Item 2 is related to differences between the NOx emission reductions used in the ratio visibility improvement calculations in the proposed FIP (Table V – C.yy) and the emission reductions in Table V – B.xx for each facility. Steve thought you would have the information about the basis for the Table V – C.yy reductions.

Item 3 is requesting information about the final FIP emission reductions. Specifically, you would probably have information regarding the emissions for Tilden Mining and United Taconite (UTAC) from the CALPUFF modeling completed by Trent Wickman referenced in the final FIP rulemaking docket. Please give me a call to discuss this at your earliest convenience. We are attempting to finalize the summary by COB tomorrow. Thanks for any help you can provide.

Jeffry D. Bennett, PE Senior Air Quality Engineer Jefferson City office: 573.638.5033 cell: 573.694.0674 JBennett@barr.com www.barr.com



resourceful. naturally. engineering and environmental consultants

# APPENDIX F: CAMx Modeling Results by Facility

March 6, 2013

### Arcelor Mittal CAMx Emissions and Modeling Results

#### **Arcelor Emissions**

| Unit   | EPA FIP   | Final FIP | NOx        | EPA FIP   | Final FIP | SO2        |
|--------|-----------|-----------|------------|-----------|-----------|------------|
|        | Baseline  | NOx       | Emission   | Baseline  | SO2       | Emission   |
|        | NOx       | Emission  | Difference | SO2       | Emission  | Difference |
|        | Emission  | (TPY) [1] | (TPY)      | Emission  | (TPY)[3]  | (TPY)      |
|        | (TPY) [1] |           |            | (TPY) [2] |           |            |
| Line 1 | 3,639     | 1,092     | 2,547      | 179       | 179       | 0          |
|        |           |           |            |           |           |            |
| TOTAL  | 3,639     | 1,092     | 2,547      | 179       | 179       | 0          |

[1] FIP Baseline and Control NOx Emissions from EPA Proposed FIP Table V-B.19 – Projected Annual NOx Emission Reductions [TPY].

[2] FIP Baseline SO2 Emissions are from EPA Proposed FIP Table V-B.21 – Annual SO2 Emissions [TPY]

[3] No SO2 emission reductions in Final FIP (i.e. EPA Baseline = Final FIP control)

| Class I Area     | EPA FIP       | EPA FIP  | Proposed   | Proposed   | Difference | Difference |
|------------------|---------------|----------|------------|------------|------------|------------|
|                  | Baseline Days | Baseline | FIP Days > | FIP 98% dV | Days >0.5  | 98% dV [5] |
|                  | >0.5 dV       | 98% dV   | 0.5 dV     |            | dV [5]     | 00/00.000  |
| Boundary Waters  |               | 00,00    |            |            |            |            |
| 2002             |               |          |            |            |            |            |
| Line #1          | 30            | 0.789    | 18         | 0.713      | 12         | 0.076      |
| Facility Total   | 43            | 0.99     | 35         | 0.96       | 8          | 0.03       |
| 2005             |               |          |            |            |            |            |
| Line #1          | 7             | 0.491    | 3          | 0.326      | 4          | 0.165      |
| Facility Total   | 19            | 0.74     | 8          | 0.55       | 11         | 0.19       |
| <u>Voyageurs</u> |               |          |            |            |            |            |
| 2002             |               |          |            |            |            |            |
| Line #1          | 1             | 0.287    | 0          | 0.202      | 1          | 0.085      |
| Facility Total   | 1             | 0.34     | 0          | 0.22       | 1          | 0.12       |
| 2005             |               |          |            |            |            |            |
| Line #1          | 0             | 0.182    | 0          | 0.122      | 0          | 0.060      |
| Facility Total   | 0             | 0.22     | 0          | 0.16       | 0          | 0.06       |
| Isle Royale      |               |          |            |            |            |            |
| 2002             |               |          |            |            |            |            |
| Line #1          | 0             | 0.075    | 0          | 0.053      | 0          | 0.022      |
| Facility Total   | 0             | 0.09     | 0          | 0.06       | 0          | 0.03       |
| 2005             |               |          |            |            |            |            |
| Line #1          | 0             | 0.049    | 0          | 0.033      | 0          | 0.016      |
| Facility Total   | 0             | 0.06     | 0          | 0.04       | 0          | 0.02       |

[4] Visibility benchmarks:

<u>0.5 dV impact</u> is the BART eligibility threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required),

<u>1.0 dV difference</u> is the presumed human perceptible level for visibility improvement, and <u>0.1 dV difference</u> was defined by other agencies as the degree of visibility improvement that is too low to justify additional emission controls. Also, EPA's Regional Haze Rule mentions that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

[5] These two columns provide the difference in predicted days >0.5 dV and 98<sup>th</sup> percentile visibility improvement from the baseline to the FIP control emissions. The annual average number of days with > 0.5 dV improvement at all the Class I areas is considerably less than EPA's estimate (11 to 53). Also, the averages of the 98<sup>th</sup> percentile differences are **10 to 37 times less** than the predicted improvement by EPA. Note: the table below formed the basis for EPA's inclusion of control necessary at Arcelor Mittal.

#### Arcelor Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

| (EPA Table B Emission Difference – 2,547 TPT NOX)[7] |                 |                     |  |                 |              |  |  |  |  |
|--|-----------------|---------------------|--|-----------------|--------------|--|--|--|--|
| Class I Area   | EPA Estimated   | nated EPA Estimated |  | CAMx Modeled    | CAMx Modeled |  |  |  |  |
|  | Difference Days | Difference          |  | Difference Days | Difference   |  |  |  |  |
|  | >0.5 dV         | 98% dV              |  | >0.5 dV[8]      | 98% dV       |  |  |  |  |
| Boundary Waters                                      | 24              | 1.7                 |  | 10              | 0.11         |  |  |  |  |
|  |                 |                     |  |                 |              |  |  |  |  |
| Voyageurs  | 11              | 0.9                 |  | 1               | 0.09         |  |  |  |  |
|  |                 |                     |  |                 |              |  |  |  |  |
| Isle Royale  | 18              | 1.1                 |  | 0               | 0.03         |  |  |  |  |

(EPA Table C Emission Difference = 2,859 TPY NOx)[6] (EPA Table B Emission Difference = 2,547 TPY NOx)[7]

[6] Emission Difference Obtained from EPA Proposed FIP Table V-C.10 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Arcelor Mittal.

[7] Emission Difference Obtained from EPA Proposed FIP Table V-B.19.

[8] The number of days with visibility >0.5 deciviews (dV) can be a misleading indicator as illustrated by the Arcelor Mittal and Northshore Mining results (below). The 98<sup>th</sup> percentile visibility improvement at Boundary Waters during the 2002 modeled year was 0.03 dV. However, the modeling predicts this insignificant change will result in eight more days of "good visibility", defined as days with visibility at or below the 0.5 deciview threshold. Further, the Northshore Mining results at Isle Royale indicate a miniscule 0.01 deciviews, or one hundred times less than a perceptible improvement to visibility. Nonetheless, the modeling predicts this insignificant change will result in two more days of "good visibility". In both circumstances, this does not mean that the visibility change was discernible. The model gives credit for an improved day when the predicted impairment falls from 0.51 to 0.50 deciviews, but that improvement is illusory because at 0.51 deciviews people do not perceive a regional haze problem. The difference in visibility from natural background when evaluating the baseline could have several days near the 0.5 dV "contribute to visibility degradation" threshold, but well less than the 1 dV "cause visibility degradation" threshold. Then, a very small change in visibility from the baseline to the controlled emission scenario (~0.01 – 0.1 dV) could cause a large number of days to be less than the 0.5 dV benchmark without producing any real benefit to visibility.

# Hibbing Taconite (HibTac) CAMx Emissions and Modeling Results

#### **HibTac Emissions**

| Unit   | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|--------|----------|-----------|------------|----------|-----------|------------|
|        | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|        | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|        | Emission | (TPY)     | (TPY)      | Emission | (TPY)     | (TPY)      |
|        | (TPY)    |           |            | (TPY)    |           |            |
| Line 1 | 2,497    | 749       | 1,748      | 202      | 202       | 0          |
| Line 2 | 2,144    | 643       | 1,500      | 180      | 180       | 0          |
| Line 3 | 2,247    | 674       | 1,573      | 188      | 188       | 0          |
|        |          |           |            |          |           |            |
| TOTAL  | 6,888    | 2,066     | 4,822      | 570      | 570       | 0          |

#### HibTac CAMx Results (By Unit)

| Class I Area           | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|------------------------|---------------|----------|-----------|-----------|------------|------------|
|                        | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Boundary Waters</u> |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line 1                 | 1             | 0.337    | 1         | 0.305     | 0          | 0.032      |
| Line 2                 | 2             | 0.287    | 0         | 0.260     | 2          | 0.027      |
| Line 3                 | 1             | 0.318    | 0         | 0.245     | 2          | 0.073      |
| Facility Total         | 33            | 1.10     | 22        | 0.96      | 11         | 0.14       |
| 2005                   |               |          |           |           |            |            |
| Line 1                 | 0             | 0.217    | 0         | 0.158     | 0          | 0.057      |
| Line 2                 | 0             | 0.203    | 0         | 0.124     | 0          | 0.079      |
| Line 3                 | 0             | 0.223    | 0         | 0.140     | 0          | 0.083      |
| Facility Total         | 14            | 0.85     | 11        | 0.62      | 3          | 0.23       |
| <u>Voyageurs</u>       |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line 1                 | 0             | 0.197    | 0         | 0.168     | 0          | 0.029      |
| Line 2                 | 0             | 0.197    | 0         | 0.159     | 0          | 0.038      |
| Line 3                 | 0             | 0.211    | 0         | 0.163     | 0          | 0.048      |
| Facility Total         | 18            | 0.67     | 10        | 0.61      | 8          | 0.06       |
| 2005                   |               |          |           |           |            |            |
| Line 1                 | 0             | 0.126    | 0         | 0.102     | 0          | 0.024      |
| Line 2                 | 0             | 0.122    | 0         | 0.085     | 0          | 0.037      |
| Line 3                 | 0             | 0.133    | 0         | 0.103     | 0          | 0.030      |
| Facility Total         | 8             | 0.51     | 5         | 0.36      | 3          | 0.15       |

| Class I Area       | EPA FIP              | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|--------------------|----------------------|----------|-----------|-----------|------------|------------|
|                    | <b>Baseline Days</b> | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                    | >0.5 dV              | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Isle Royale</u> |                      |          |           |           |            |            |
| 2002               |                      |          |           |           |            |            |
| Line 1             | 0                    | 0.053    | 0         | 0.047     | 0          | 0.006      |
| Line 2             | 0                    | 0.045    | 0         | 0.036     | 0          | 0.009      |
| Line 3             | 0                    | 0.046    | 0         | 0.037     | 0          | 0.009      |
| Facility Total     | 0                    | 0.16     | 0         | 0.13      | 0          | 0.03       |
|                    |                      |          |           |           |            |            |
| 2005               |                      |          |           |           |            |            |
| Line 1             | 0                    | 0.038    | 0         | 0.027     | 0          | 0.011      |
| Line 2             | 0                    | 0.034    | 0         | 0.022     | 0          | 0.012      |
| Line 3             | 0                    | 0.037    | 0         | 0.026     | 0          | 0.011      |
| Facility Total     | 0                    | 0.13     | 0         | 0.09      | 0          | 0.04       |

#### HibTac Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 5,259 TPY NOx)[8] (EPA Table B Emission Difference = 4,822 TPY NOx)[9]

| 1217110010 2 211100 |                 |               |                 |              |
|---------------------|-----------------|---------------|-----------------|--------------|
| Class I Area        | EPA Estimated   | EPA Estimated | CAMx Modeled    | CAMx Modeled |
|                     | Difference Days | Difference    | Difference Days | Difference   |
|                     | >0.5 dV         | 98% dV        | >0.5 dV         | 98% dV       |
| Boundary Waters     | 44              | 3.2           | 7               | 0.19         |
|                     |                 |               |                 |              |
| Voyageurs           | 21              | 1.7           | 5               | 0.11         |
|                     |                 |               |                 |              |
| Isle Royale         | 26              | 2.1           | 0               | 0.04         |

[8] Emission Difference Obtained from EPA Proposed FIP Table V-C.11 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Hibbing Taconite.

[9] Emission Difference Obtained from EPA Proposed FIP Table V-B.24.

# Northshore Mining CAMx Emissions and Modeling Results

### Northshore Emissions

| Unit            | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|-----------------|----------|-----------|------------|----------|-----------|------------|
|                 | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|                 | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|                 | Emission | (TPY)     | (TPY)      | Emission | (TPY)     | (TPY)      |
|                 | (TPY)    |           |            | (TPY)    |           |            |
| Power Boiler #1 | 676      | 676       | 0          | 681      | 681       | 0          |
| Power Boiler #2 | 1,093    | 1,093     | 0          | 1,098    | 1,098     | 0          |
| Furnace 11      | 386      | 116       | 270        | 38       | 38        | 0          |
| Furnace 12      | 378      | 113       | 265        | 35       | 35        | 0          |
|                 |          |           |            |          |           |            |
| FURNACES        | 764      | 229       | 535        | 73       | 73        | 0          |
| TOTAL           | 2,533    | 1,998     | 535        | 1,852    | 1,852     | 0          |

#### Northshore CAMx Results (By Unit)

| NOT LISTORE CAN        | x Results (by O |          |           |           |            |            |
|------------------------|-----------------|----------|-----------|-----------|------------|------------|
| Class I Area           | EPA FIP         | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|                        | Baseline Days   | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV         | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Boundary Waters</u> |                 |          |           |           |            |            |
| 2002                   |                 |          |           |           |            |            |
| Power Boiler #1        | 32              | 1.487    | 32        | 1.499     | 0          | -0.012     |
| Power Boiler #2        | 49              | 2.087    | 49        | 2.097     | 0          | -0.010     |
| Furnace 11             | 0               | 0.136    | 0         | 0.139     | 0          | -0.003     |
| Furnace 12             | 0               | 0.133    | 0         | 0.122     | 0          | 0.011      |
| Facility Total         | 73              | 4.16     | 72        | 4.14      | 1          | 0.02       |
|                        |                 |          |           |           |            |            |
| 2005                   |                 |          |           |           |            |            |
| Power Boiler #1        | 13              | 0.640    | 13        | 0.654     | 0          | -0.014     |
| Power Boiler #2        | 22              | 0.926    | 23        | 0.911     | 0          | 0.015      |
| Furnace 11             | 0               | 0.087    | 0         | 0.067     | 0          | 0.020      |
| Furnace 12             | 0               | 0.082    | 0         | 0.076     | 0          | 0.006      |
| Facility Total         | 51              | 1.67     | 50        | 1.68      | 1          | -0.01      |
| Voyageurs              |                 |          |           |           |            |            |
| 2002                   |                 |          |           |           |            |            |
| Power Boiler #1        | 1               | 0.196    | 1         | 0.196     | 0          | 0.000      |
| Power Boiler #2        | 1               | 0.293    | 1         | 0.293     | 0          | 0.000      |
| Furnace 11             | 0               | 0.016    | 0         | 0.013     | 0          | 0.003      |
| Furnace 12             | 0               | 0.015    | 0         | 0.013     | 0          | 0.002      |
| Facility Total         | 8               | 0.51     | 8         | 0.51      | 0          | 0.00       |

| Class I Area            | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|-------------------------|---------------|----------|-----------|-----------|------------|------------|
|                         | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                         | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Voyageurs</u>        |               |          |           |           |            |            |
| 2005                    |               |          |           |           |            |            |
| Power Boiler #1         | 0             | 0.188    | 0         | 0.193     | 0          | -0.005     |
| Power Boiler #2         | 1             | 0.244    | 1         | 0.247     | 0          | -0.003     |
| Furnace 11              | 0             | 0.020    | 0         | 0.018     | 0          | 0.002      |
| Furnace 12              | 0             | 0.021    | 0         | 0.016     | 0          | 0.004      |
| Facility Total          | 6             | 0.47     | 6         | 0.46      | 0          | 0.01       |
| Ida Davala              |               |          |           |           |            |            |
| Isle Royale             |               |          |           |           |            |            |
| 2002<br>Power Boiler #1 | 3             | 0.204    | 2         | 0.204     | 0          | 0.000      |
|                         |               | 0.294    | 3         | 0.294     | 0          | 0.000      |
| Power Boiler #2         | 6             | 0.412    | 6         | 0.408     | 0          | 0.004      |
| Furnace 11              | 0             | 0.034    | 0         | 0.028     | 0          | 0.006      |
| Furnace 12              | 0             | 0.037    | 0         | 0.029     | 0          | 0.008      |
| Facility Total          | 16            | 0.75     | 15        | 0.74      | 1          | 0.00       |
|                         |               |          |           |           |            |            |
| 2005                    |               |          |           |           |            |            |
| Power Boiler #1         | 3             | 0.180    | 3         | 0.180     | 0          | 0.000      |
| Power Boiler #2         | 4             | 0.320    | 4         | 0.322     | 0          | -0.002     |
| Furnace 11              | 0             | 0.036    | 0         | 0.023     | 0          | 0.013      |
| Furnace 12              | 0             | 0.034    | 0         | 0.022     | 0          | 0.012      |
| Facility Total          | 10            | 0.57     | 8         | 0.55      | 2          | 0.02       |

#### Northshore Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 926 TPY NOx)[10] (EPA Table B Emission Difference = 535 TPY NOx)[11]

| Class I Area           | EPA Estimated   | A Estimated EPA Estimated |  | CAMx Modeled    | CAMx Modeled |  |  |  |  |
|------------------------|-----------------|---------------------------|--|-----------------|--------------|--|--|--|--|
|                        | Difference Days | Difference                |  | Difference Days | Difference   |  |  |  |  |
|                        | >0.5 dV         | 98% dV                    |  | >0.5 dV         | 98% dV       |  |  |  |  |
| <b>Boundary Waters</b> | 8               | 0.6                       |  | 1               | 0.01         |  |  |  |  |
|                        |                 |                           |  |                 |              |  |  |  |  |
| Voyageurs              | 4               | 0.3                       |  | 0               | 0.01         |  |  |  |  |
|                        |                 |                           |  |                 |              |  |  |  |  |
| Isle Royale            | 5               | 0.4                       |  | 2               | 0.01         |  |  |  |  |

[10]Emission Difference Obtained from EPA Proposed FIP Table V-C.12 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Northshore Mining.

[11]Emission Difference Obtained from EPA Proposed FIP Table V-B.8; further the emission reductions in Table C exceed the FIP baseline in Table B by 142 TPY.

## United Taconite (UTAC) CAMx Emissions and Modeling Results

#### **UTAC Emissions**

| Unit   | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|--------|----------|-----------|------------|----------|-----------|------------|
|        | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|        | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|        | Emission | (TPY)     | (TPY)[12]  | Emission | (TPY)[13] | (TPY)      |
|        | (TPY)    |           |            | (TPY)    |           |            |
| Line 1 | 1,643    | 493       | 1,150      | 1,293    | 577       | 716        |
| Line 2 | 3,687    | 1,106     | 2,581      | 2,750    | 1,392     | 1,358      |
|        |          |           |            |          |           |            |
| TOTAL  | 5,330    | 1,599     | 3,731      | 4,043    | 1,969     | 2,074      |

[12]NOx emission difference was calculated using 70% emission reduction from EPA Baseline within the proposed FIP (corresponding to 1.2 lb NOx/MMBTU); to ensure maximum emission reductions were evaluated there was no change to the final FIP emissions to reflect the final FIP limit of 1.5 lb NOx/MMBTU.

[13]Final FIP SO2 Emissions were calculated using the final FIP limit of 529 lb/hr with an operating factor of 85%; this was done to maximize the emission reductions while using a reasonable operating factor

| OTAC CANA RESU         |               |          | 1         |           |            |            |
|------------------------|---------------|----------|-----------|-----------|------------|------------|
| Class I Area           | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|                        | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b> |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line #1                | 22            | 1.294    | 10        | 0.674     | 12         | 0.620      |
| Line #2                | 45            | 2.744    | 30        | 1.556     | 15         | 1.189      |
| Facility Total         | 76            | 4.22     | 55        | 2.37      | 21         | 1.85       |
|                        |               |          |           |           |            |            |
| 2005                   |               |          |           |           |            |            |
| Line #1                | 11            | 0.610    | 2         | 0.303     | 9          | 0.307      |
| Line #2                | 26            | 1.294    | 15        | 0.678     | 11         | 0.616      |
| Facility Total         | 52            | 2.52     | 34        | 1.57      | 18         | 0.95       |
| Voyageurs              |               |          |           |           |            |            |
| 2002                   |               |          |           |           |            |            |
| Line #1                | 12            | 0.606    | 2         | 0.307     | 10         | 0.299      |
| Line #2                | 26            | 1.452    | 15        | 0.771     | 11         | 0.681      |
| Facility Total         | 42            | 2.10     | 26        | 1.11      | 16         | 0.99       |
|                        |               |          |           |           |            |            |
| 2005                   |               |          |           |           |            |            |
| Line #1                | 4             | 0.331    | 1         | 0.181     | 3          | 0.150      |
| Line #2                | 17            | 0.786    | 6         | 0.446     | 11         | 0.340      |
| Facility Total         | 33            | 1.47     | 14        | 0.76      | 19         | 0.71       |

#### UTAC CAMx Results (By Unit)

| Class I Area       | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|--------------------|---------------|----------|-----------|-----------|------------|------------|
|                    | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                    | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <u>Isle Royale</u> |               |          |           |           |            |            |
| 2002               |               |          |           |           |            |            |
| Line #1            | 0             | 0.255    | 0         | 0.117     | 0          | 0.138      |
| Line #2            | 8             | 0.518    | 0         | 0.266     | 8          | 0.252      |
| Facility Total     | 13            | 0.81     | 3         | 0.41      | 10         | 0.40       |
|                    |               |          |           |           |            |            |
| 2005               |               |          |           |           |            |            |
| Line #1            | 0             | 0.163    | 0         | 0.080     | 0          | 0.083      |
| Line #2            | 1             | 0.322    | 0         | 0.184     | 1          | 0.138      |
| Facility Total     | 10            | 0.57     | 0         | 0.28      | 10         | 0.29       |

#### UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 3,208 TPY NOx and 3,639 TPY SO2)[14] (EPA Table B Emission Difference = 3,731 TPY NOx and 3,639 TPY SO2)[15]

| Class I Area    | EPA Estimated   | EPA Estimated |  | CAMx Modeled    | CAMx Modeled |  |  |
|-----------------|-----------------|---------------|--|-----------------|--------------|--|--|
|                 | Difference Days | Difference    |  | Difference Days | Difference   |  |  |
|                 | >0.5 dV         | 98% dV        |  | >0.5 dV[16]     | 98% dV[16]   |  |  |
| Boundary Waters | 29              | 1.9           |  | 20              | 1.40         |  |  |
|                 |                 |               |  |                 |              |  |  |
| Voyageurs       | 12              | 0.99          |  | 18              | 0.85         |  |  |
|                 |                 |               |  |                 |              |  |  |
| Isle Royale     | 14              | 1.16          |  | 10              | 0.35         |  |  |

[14]Emission Difference Obtained from EPA Proposed FIP Table V-C.13 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for United Taconite.

[15]Emission Difference Obtained from EPA Proposed FIP Table V-B.14 (SO2) and V-B.17 (NOx) – NOx reductions are not consistent

[16]Baseline – final FIP Emission Reductions -> 3,731 TPY NOx and 2,074 TPY SO2

The United Taconite comparison table above does not provide an "apples to apples" comparison. As noted, the EPA estimated visibility benefits include more SO2 emission reductions (proposed FIP) than are included in the final FIP. This table was amended to include the revised SO2 emission reductions using EPA's apparent methodology within the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NOx and the revised emission reduction for SO2. Then, those resultants were averaged for each of the Class I areas to obtain the amended EPA estimates below to provide for the appropriate comparison of EPA's method.

| Amended UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with |
|---|
| CAMx Modeling Analyses  |

| Class I Area    | EPA Estimated   | EPA Estimated |  | CAMx Modeled    | CAMx Modeled |  |  |
|-----------------|-----------------|---------------|--|-----------------|--------------|--|--|
|                 | Difference Days | Difference    |  | Difference Days | Difference   |  |  |
|                 | >0.5 dV         | 98% dV        |  | >0.5 dV         | 98% dV       |  |  |
| Boundary Waters | 22              | 1.6           |  | 20              | 1.40         |  |  |
|                 |                 |               |  |                 |              |  |  |
| Voyageurs       | 10              | 0.8           |  | 18              | 0.85         |  |  |
|                 |                 |               |  |                 |              |  |  |
| Isle Royale     | 14              | 1.1           |  | 10              | 0.35         |  |  |

Final FIP Emission Difference = 3,731 TPY NOx and 2,074 TPY SO2

As discussed above, the SO4 and NO3 visibility benefits were combined by EPA. The following tables provide a modeled comparison of the impacts sorted by SO4 and NO3 on a line-specific basis, then combined for both lines. The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall UTAC impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO<sub>x</sub> control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.15 dV; total = 0.20 dV) and would not show up as part of the overall visibility change (see Line 2 – 2002 Boundary Waters results).

| Class I Area                   | EPA FIP       | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|--------------------------------|---------------|----------|-----------|-----------|------------|------------|
|                                | Baseline Days | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                                | >0.5 dV       | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b>         |               |          |           |           |            |            |
| 2002                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.106    | 0         | 0.059     | 0          | 0.047      |
| Line #1 – SO4                  | 22            | 1.294    | 10        | 0.674     | 12         | 0.620      |
| Line #1 – All                  | 22            | 1.294    | 10        | 0.674     | 12         | 0.620      |
|                                |               |          |           |           |            |            |
| 2005                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.136    | 0         | 0.083     | 0          | 0.053      |
| Line #1 – SO4                  | 8             | 0.571    | 2         | 0.280     | 6          | 0.291      |
| Line #1 – All                  | 11            | 0.610    | 2         | 0.303     | 9          | 0.307      |
| Voyageurs                      |               |          |           |           |            |            |
| 2002                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.040    | 0         | 0.017     | 0          | 0.023      |
| Line #1 – SO4                  | 11            | 0.582    | 2         | 0.301     | 9          | 0.281      |
| Line #1 – All                  | 12            | 0.606    | 2         | 0.307     | 10         | 0.299      |
|                                |               |          |           |           |            |            |
| 2005                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.048    | 0         | 0.027     | 0          | 0.021      |
| Line #1 – SO4                  | 4             | 0.330    | 1         | 0.155     | 3          | 0.175      |
| Line #1 – All                  | 4             | 0.331    | 1         | 0.181     | 3          | 0.150      |
| Isle Royale                    |               |          |           |           |            |            |
| 2002                           |               |          |           |           |            |            |
| Line #1 – NO3                  | 0             | 0.033    | 0         | 0.015     | 0          | 0.018      |
| Line #1 – SO4                  | 0             | 0.216    | 0         | 0.104     | 0          | 0.112      |
| Line #1 – All                  | 0             | 0.255    | 0         | 0.117     | 0          | 0.138      |
| 2005                           |               |          |           |           |            |            |
| <b>2005</b><br>Line #1 – NO3   | 0             | 0.026    | 0         | 0.011     | 0          | 0.015      |
| Line #1 – NO3                  | 0             | 0.026    | 0         | 0.011     | 0          | 0.015      |
| Line #1 – SO4<br>Line #1 – All | 0             |          |           |           |            |            |
| Line #1 – All                  | U             | 0.163    | 0         | 0.080     | 0          | 0.083      |

UTAC Line 1 – Pollutant Specific Modeling Results

| Class I Area           | EPA FIP              | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|------------------------|----------------------|----------|-----------|-----------|------------|------------|
|                        | <b>Baseline Days</b> | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV              | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b> |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 1                    | 0.237    | 0         | 0.090     | 1          | 0.147      |
| Line #2 – SO4          | 44                   | 2.679    | 28        | 1.547     | 16         | 1.132      |
| Line #2 – All          | 45                   | 2.744    | 30        | 1.556     | 15         | 1.189      |
|                        |                      |          |           |           |            |            |
| 2005                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 1                    | 0.195    | 0         | 0.091     | 1          | 0.104      |
| Line #2 – SO4          | 25                   | 1.196    | 15        | 0.659     | 10         | 0.539      |
| Line #2 – All          | 26                   | 1.294    | 15        | 0.678     | 11         | 0.616      |
| Voyageurs              |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.104    | 0         | 0.031     | 0          | 0.073      |
| Line #2 – SO4          | 25                   | 1.446    | 15        | 0.768     | 10         | 0.678      |
| Line #2 – All          | 26                   | 1.452    | 15        | 0.771     | 11         | 0.681      |
| 2005                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.083    | 0         | 0.033     | 0          | 0.050      |
| Line #2 – NOS          | 16                   | 0.083    | 6         | 0.436     | 10         | 0.337      |
| Line #2 – 304          | 10                   | 0.786    | 6         | 0.430     | 10         | 0.337      |
|                        |                      |          |           |           |            |            |
| <u>Isle Royale</u>     |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.054    | 0         | 0.018     | 0          | 0.036      |
| Line #2 – SO4          | 7                    | 0.469    | 0         | 0.245     | 7          | 0.224      |
| Line #2 – All          | 8                    | 0.518    | 0         | 0.266     | 8          | 0.252      |
| 2005                   |                      |          |           |           |            |            |
| Line #2 – NO3          | 0                    | 0.046    | 0         | 0.016     | 0          | 0.030      |
| Line #2 – SO4          | 1                    | 0.319    | 0         | 0.166     | 1          | 0.153      |
| Line #2 – All          | 1                    | 0.322    | 0         | 0.184     | 1          | 0.138      |

UTAC Line 2 – Pollutant Specific Modeling Results

# UTAC Comparison of Sulfate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

|                 | Difference = $2,07$ + | 111302        |                 |              |
|-----------------|-----------------------|---------------|-----------------|--------------|
| Class I Area    | EPA Estimated         | EPA Estimated | CAMx Modeled    | CAMx Modeled |
|                 | Difference Days       | Difference    | Difference Days | Difference   |
|                 | >0.5 dV               | 98% dV        | >0.5 dV         | 98% dV       |
| Boundary Waters | 14                    | 1.0           | 22              | 1.29         |
|                 |                       |               |                 |              |
| Voyageurs       | 6                     | 0.5           | 16              | 0.74         |
|                 |                       |               |                 |              |
| Isle Royale     | 8                     | 0.6           | 4               | 0.28         |

Final FIP Emission Difference = 2,074 TPY SO2

# UTAC Comparison of Nitrate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 3,731 TPY NOx

| Class I Area    | EPA Estimated   | EPA Estimated | CAMx Modeled    | CAMx Modeled |
|-----------------|-----------------|---------------|-----------------|--------------|
|                 | Difference Days | Difference    | Difference Days | Difference   |
|                 | >0.5 dV         | 98% dV        | >0.5 dV         | 98% dV       |
| Boundary Waters | 31              | 2.3           | 1               | 0.18         |
|                 |                 |               |                 |              |
| Voyageurs       | 15              | 1.1           | 0               | 0.08         |
|                 |                 |               |                 |              |
| Isle Royale     | 20              | 1.6           | 0               | 0.05         |

The maximum 98<sup>th</sup> percentile NO3 impact when combining both line emission reductions is <u>0.18 dV</u>, while the maximum 98<sup>th</sup> percentile SO4 impact for both lines is <u>1.29 dV</u>. Based on these results, it is evident that the SO4 impact on the Class I areas provides the vast majority of the predicted CAMx estimates of visibility improvement. This finding is consistent with MPCA's original finding for BART in the 2009 SIP that NOx emission reductions do not provide substantive visibility improvement.

# Tilden Mining CAMx Emissions and Modeling Results

# **Tilden Emissions**

| Unit   | EPA FIP  | Final FIP | NOx        | EPA FIP  | Final FIP | SO2        |
|--------|----------|-----------|------------|----------|-----------|------------|
|        | Baseline | NOx       | Emission   | Baseline | SO2       | Emission   |
|        | NOx      | Emission  | Difference | SO2      | Emission  | Difference |
|        | Emission | (TPY)     | (TPY)      | Emission | (TPY)     | (TPY)      |
|        | (TPY)    |           |            | (TPY)    |           |            |
| Line 1 | 4,613    | 1,384     | 3,229      | 1,153    | 231       | 922        |
|        |          |           |            |          |           |            |
| TOTAL  | 4,613    | 1,384     | 3,229      | 1,153    | 231       | 922        |

# Tilden CAMx Results (By Unit)

| Class I Area           | EPA FIP       | EPA FIP  | Final FIP  | Final FIP | Difference | Difference |
|------------------------|---------------|----------|------------|-----------|------------|------------|
|                        | Baseline Days | Baseline | Days > 0.5 | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV       | 98% dV   | dV         |           | dV         |            |
| <b>Boundary Waters</b> |               |          |            |           |            |            |
| 2002                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.141    | 0          | 0.037     | 0          | 0.104      |
|                        |               |          |            |           |            |            |
| 2005                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.097    | 0          | 0.042     | 0          | 0.055      |
|                        |               |          |            |           |            |            |
| <u>Voyageurs</u>       |               |          |            |           |            |            |
| 2002                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.042    | 0          | 0.011     | 0          | 0.031      |
|                        |               |          |            |           |            |            |
| 2005                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.041    | 0          | 0.010     | 0          | 0.031      |
|                        |               |          |            |           |            |            |
| Isle Royale            |               |          |            |           |            |            |
| 2002                   |               |          |            |           |            |            |
| Line #1                | 1             | 0.300    | 0          | 0.094     | 1          | 0.206      |
|                        |               |          |            |           |            |            |
| 2005                   |               |          |            |           |            |            |
| Line #1                | 0             | 0.211    | 0          | 0.070     | 0          | 0.141      |

| Class I Area           | EPA FIP              | EPA FIP  | Final FIP | Final FIP | Difference | Difference |
|------------------------|----------------------|----------|-----------|-----------|------------|------------|
|                        | <b>Baseline Days</b> | Baseline | Days      | 98% dV    | Days >0.5  | 98% dV     |
|                        | >0.5 dV              | 98% dV   | > 0.5 dV  |           | dV         |            |
| <b>Boundary Waters</b> |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.031    | 0         | 0.013     | 0          | 0.018      |
| Line #1 – SO4          | 0                    | 0.102    | 0         | 0.022     | 0          | 0.080      |
| Line #1 – All          | 0                    | 0.141    | 0         | 0.037     | 0          | 0.104      |
| 2005                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.045    | 0         | 0.042     | 0          | 0.003      |
| Line #1 – SO4          | 0                    | 0.087    | 0         | 0.019     | 0          | 0.068      |
| Line #1 – All          | 0                    | 0.097    | 0         | 0.042     | 0          | 0.055      |
| Vouggourg              |                      |          |           |           |            |            |
| Voyageurs<br>2002      |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.002    | 0         | 0.001     | 0          | 0.001      |
| Line #1 – SO4          | 0                    | 0.041    | 0         | 0.011     | 0          | 0.030      |
| Line #1 – All          | 0                    | 0.042    | 0         | 0.011     | 0          | 0.031      |
| 2005                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.005    | 0         | 0.003     | 0          | 0.002      |
| Line #1 – SO4          | 0                    | 0.039    | 0         | 0.008     | 0          | 0.031      |
| Line #1 – All          | 0                    | 0.041    | 0         | 0.010     | 0          | 0.031      |
| Isle Royale            |                      |          |           |           |            |            |
| 2002                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.084    | 0         | 0.038     | 0          | 0.046      |
| Line #1 – SO4          | 1                    | 0.197    | 0         | 0.052     | 1          | 0.145      |
| Line #1 – All          | 1                    | 0.300    | 0         | 0.094     | 1          | 0.206      |
| 2005                   |                      |          |           |           |            |            |
| Line #1 – NO3          | 0                    | 0.043    | 0         | 0.047     | 0          | -0.004     |
| Line #1 – SO4          | 0                    | 0.176    | 0         | 0.040     | 0          | 0.136      |
| Line #1 – All          | 0                    | 0.211    | 0         | 0.070     | 0          | 0.141      |

Tilden Line 1 – Pollutant Specific Modeling Results

Attachment 3

2012 AECOM Report



# Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

Robert Paine and David Heinold, AECOM

September 28, 2012

#### Executive Summary

This report reviews several aspects of the visibility assessment that is part of any Best Available Retrofit Technology (BART) assessment. The crux of this analysis focuses upon two opportunistic emission reductions that have resulted in no perceptible visibility benefits, while a straightforward application of EPA's modeling procedures would predict a substantial visibility benefit. These actual emission reduction cases include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in Minnesota in 2009.

There are several reasons why there is an inconsistency between the real world and the modeling results:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clean, which exaggerates the impact of emission sources. Overly clean natural conditions can erroneously indicate that some states are missing the 2018 milestone for achieving progress toward an impossible goal by the year 2064.
- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations that are detailed in this report. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.
- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.
- The modeled base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

September 2012



Impacts of the taconite plants' NO<sub>x</sub> emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5  $\frac{1}{2}$  months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO<sub>x</sub> controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to increases in haze due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, as well as the impacts of Michigan sources on Minnesota's Class I areas indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.



# Introduction

Best Available Retrofit Technology (BART) is part of the Clean Air Act (Appendix Y of 40 CFR Part 51) as a requirement related to visibility and the 1999 Regional Haze Rule (RHR)<sup>1</sup> that applies to existing stationary sources. Sources eligible for BART were those from 26 source categories with a potential to emit over 250 tons per year of any air pollutant, and that were placed into operation between August 1962 and August 1977. Final BART implementation guidance for regional haze was published in the Federal Register on July 6, 2005<sup>2</sup>.

The United States Environmental Protection Agency (EPA) has issued a proposed rule<sup>3</sup> to address BART requirements for taconite plants in Minnesota and Michigan that involves emission controls for SO<sub>2</sub> and NO<sub>x</sub>. This document addresses the likely visibility impact of taconite plant emissions, specifically NO<sub>x</sub> emissions, for impacts at Prevention of Significant Deterioration (PSD) Class I areas that the RHR addresses.

# Locations of Emission Sources and PSD Class I Areas

Figure 1 shows the location of BART-eligible taconite plants in Minnesota and Michigan addressed in EPA's proposed rule, as well as Class I areas within 500 km of these sources. In most applications of EPA's preferred dispersion model for visibility impacts, CALPUFF<sup>4</sup>, the distance limitation is 200-300 km because of the overprediction tendencies<sup>5</sup> for further distances. The overprediction occurs because of extended travel times that often involve at least a full day, during which there can be significant wind shear influences on plume spreading that the model and the meteorological wind field does not accommodate. With larger travel distances, there are higher uncertainties in the predictions of any model, either CALPUFF or a regional photochemical model. Therefore, a reasonable upper limit for establishing the impact of the taconite sources would be 500 km, with questionable results beyond 200-300 km from the source. In this case, the Class I areas involved are those shown in Figure 1. All other PSD Class I areas are much further away. It is noteworthy that EPA's visibility improvement assessment considered only three Class I areas: Voyageurs National Park, Boundary Waters Canoe Area Wilderness, and Isle Royale National Park.

September 2012

<sup>&</sup>lt;sup>1</sup> Regional Haze Regulations; Final Rule. *Federal Register*, *64*, 35713-35774. (July 1, 1999).

<sup>&</sup>lt;sup>2</sup> Federal Register. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, Vol. 70. (July 6, 2005)

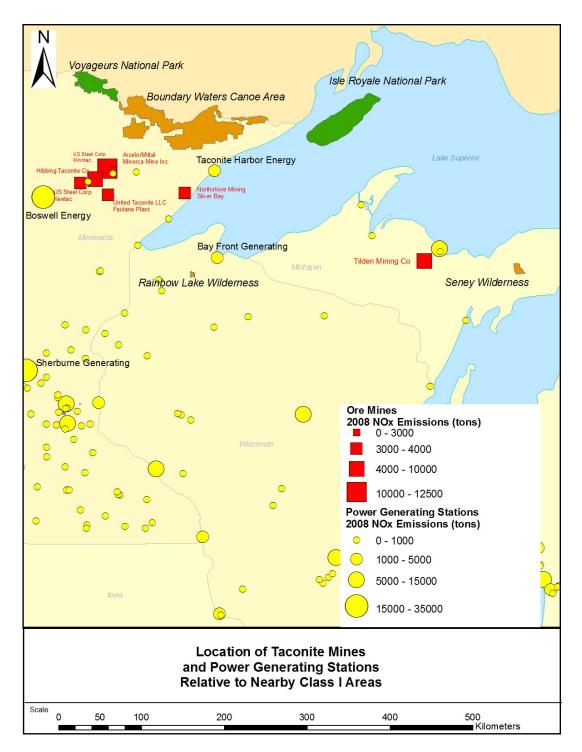
<sup>&</sup>lt;sup>3</sup> 77FR49308, August 15, 2012.

<sup>&</sup>lt;sup>4</sup> CALPUFF Dispersion Model, 2000. <u>http://www.epa.gov/scram001</u> (under 7th Modeling Conference link to Earth Tech web site).

<sup>&</sup>lt;sup>5</sup> As documented in Appendix D of the IWAQM Phase 2 document, available at www.epa.gov/scram001/7thconf/calpuff/phase2.pdf.



Figure 1 Location of Emission Sources Relative To PSD Class I Areas in Minnesota and Michigan





# Overprediction Tendency of Visibility Assessment Modeling for BART Emission Reductions

A particularly challenging part of the BART process is the lack of well-defined criteria for determining whether a proposed emission reduction is sufficient, because the criteria for determining BART are somewhat subjective in several aspects, such as what controls are cost-effective and the degree to which the related modeled reductions in haze are sufficient. In addition, the calculations of the visibility improvements, which are intrinsic to establishing the required BART controls, are subject to considerable uncertainty due both to the inherent uncertainty in model predictions and model input parameters. Alternative approaches for applying for technical options and chemistry algorithms in the United States Environmental Protection Agency's (EPA's) preferred CALPUFF model can result in a large range in the modeled visibility improvement. The degree of uncertainty is especially large when NO<sub>x</sub> emission controls are considered as a BART option because modeling secondary formation of ammonium nitrate is quite challenging. Accurately modeling the effects of NO<sub>x</sub> controls on visibility is very important because they are often very expensive to install and operate. As a collateral effect that needs to be taken into account for BART decisions, such controls can also complicate energy efficiency objectives and strategies to control greenhouse gases and other pollutants. In this paper we discuss why EPA's preferred application of CALPUFF would likely overestimate the predicted visibility impact of emissions, especially NO<sub>x</sub>, and the associated effectiveness of NO<sub>x</sub> emission controls. Overestimates of the benefits of emissions reduction are evident from the following observations, which are discussed in this document:

- Natural background extinction used in CALPOST to calculate a source's haze impacts is underestimated, which has the effect of exaggerating the impact, which is computed relative to these defined conditions. Natural conditions also dictate how well each state is adhering to the 2018 milestone for achieving progress toward this goal by the year 2064. If the specification of natural conditions is underestimated to the extent that it is not attainable regardless of contributions from U.S. anthropogenic sources, then some states will be penalized for not achieving sufficient progress toward an impossible goal. Appendix A discusses this point in more detail.
- The chemistry in the current EPA-approved version of CALPUFF overestimates winter nitrate haze, especially in conjunction with the specification of high ammonia background concentrations. This conservatism is exacerbated by CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, CALPUFF modeling will credit BART emission reductions with more visibility improvements than will really occur.
- There are examples where actual significant emission reductions have occurred, where CALPUFF modeling as conducted for BART would predict significant visibility improvements, but no perceptive changes in haze occurred.

# Visibility Impact of NO<sub>x</sub> Emissions – Unique Aspects and Seasonality

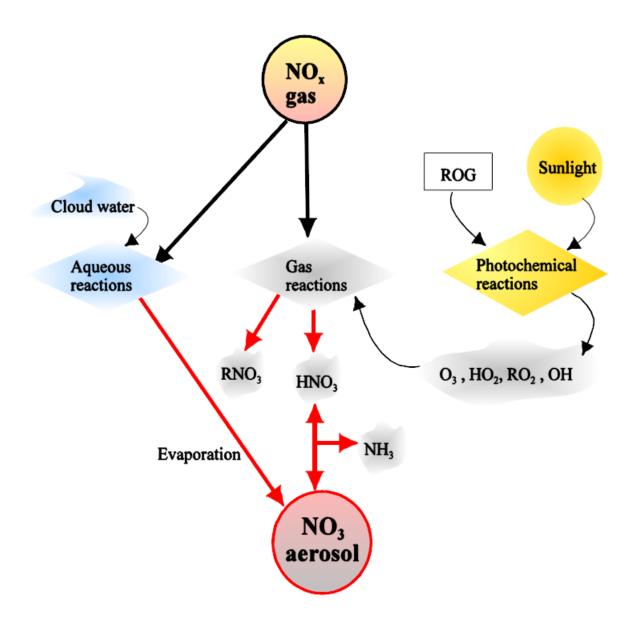
The oxidation of NO<sub>X</sub> to total nitrate (TNO<sub>3</sub>) depends on the NO<sub>X</sub> concentration, ambient ozone concentration, and atmospheric stability. Some of the TNO<sub>3</sub> is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state with HNO<sub>3</sub> gas that is a function

September 2012



of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 2<sup>6</sup>. It is important to realize that both CALPUFF and regional photochemical models tend to overpredict nitrate formation, especially in winter. A more detailed discussion of this issue is provided in Appendix B.

# Figure 2 CALPUFF II NO<sub>x</sub> Oxidation



<sup>6</sup> Figure 2-32 from CALPUFF Users Guide, available at <u>http://www.src.com/calpuff/download/CALPUFF\_UsersGuide.pdf</u>.

Page 6 of 45



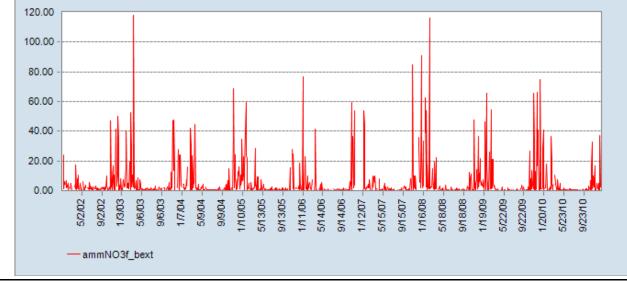
In CALPUFF, total nitrate  $(TNO_3 = HNO_3 + NO_3)$  is partitioned into each species according to the equilibrium relationship between gaseous  $HNO_3$  and  $NO_3$  aerosol. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate strongly depends on availability of  $NH_3$  to form ammonium nitrate. A summary of the conditions affecting nitrate formation is provided below:

- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium nitrate is formed;
- Sulfate preferentially scavenges ammonia over nitrates.

For this BART analysis, the effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various  $NO_X$  control options. For parts of the country where sulfate concentrations are relatively high and ammonia emissions are quite low, the atmosphere is likely to be in an ammonia-limited regime relative to nitrate formation. Therefore,  $NO_X$  emission controls are not very effective in improving regional haze, especially if there is very little ambient ammonia available.

In many cases, the BART visibility assessments ignore the haze increases that occur due to the additional power generation required to operate the control equipment. For  $NO_x$  controls, for example, the warm season emissions have minimal visibility impact, but the associated  $SO_2$  emissions from the power generation required to run the controls will increase sulfate haze. These effects have not been considered in the visibility assessment modeling.

It is evident from haze composition plots available from Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors that nitrate haze is confined to winter months. This is clearly shown in Figure 3, which is a timeline of nitrate haze extinction from Boundary Waters Canoe Area Wilderness. Similar patterns are evident for the other Class I areas plotted in Figure 1. The impact of NO<sub>X</sub> emissions during the non-winter months (e.g., April through October) is very low.



#### Figure 3 Boundary Water Canoe Area Wilderness Ammonium Nitrate Extinction, 2002-2010

September 2012

Page 7 of 45



The occurrence of significant nitrate haze only in the winter months has implications for the effectiveness of haze reductions relative to park attendance. The BART Rule addresses the seasonal issue as follows: "Other ways that visibility improvement may be assessed to inform the control decisions would be to examine distributions of the daily impacts, determine if the time of year is important (e.g., high impacts are occurring during tourist season) . . . "

In this case, the high nitrate impacts are not occurring during the tourist season, especially for the waterdominant Class I areas in Minnesota (Voyageurs and Boundary Waters) that freeze in winter. In fact, for Voyageurs National Park, the typical monthly attendance<sup>7</sup> for an off-season month (November) is only 0.2% that of a peak-season month (July). This is obviously due in part to the brutal winter weather in northern Minnesota (and Michigan) and the lack of boating access to frozen water bodies.

Operations at the Michigan Class I areas in winter are even more restricted. Isle Royale National Park is one of the few national parks to <u>totally close</u><sup>8</sup> during the winter (generally, during the period of November 1 through April 15). The closure is due to the extreme winter weather conditions and difficulty of access from the mainland across a frozen Lake Superior, for the protection of wildlife, and for the safety and protection of potential visitors. Due to this total closure, there is very little nitrate haze impact in this park during the seasons of the year that it is open, and haze issues for Isle Royale National Park will not be further considered in this report.

The Seney Wilderness Area Visitor Center is open<sup>9</sup> only during the period of May 15th to mid-October. Various trails are generally only open during the same period. The tour loops are closed in the fall, winter, and spring to allow migrating and nesting birds a place to rest or nest undisturbed, and because of large amounts of snow. Although portions of the park are open in the winter, the visitation is greatly reduced due to no visitor center access, no trail or tour loop access, and the severe weather.

# Effect of 2009 Recession on Haze in Affected PSD Class I Areas

The effect on haze of a significant (50%) emission reduction from the taconite plants that actually occurred in early 2009 and lasted throughout calendar year 2009 is discussed in this section. This emission reduction was not due to environmental regulations, but rather economic conditions, and affected all pollutants being emitted by the collective group of Minnesota taconite plants, as well as regional power production that is needed to operate the taconite plants.

The annual taconite production<sup>10</sup> from the Minnesota taconite plants in recent years is plotted in Figure 4, along with annual average nitrate concentrations at the nearest Class I area, Boundary Waters Canoe Area (BWCA). The figure shows that the nitrate measured in the park did not respond to the reduction in emissions from the taconite plants. Figures 5 and 6 show the time series<sup>11</sup> of nitrate and sulfate haze in

<sup>&</sup>lt;sup>7</sup> As documented at <u>http://www.gorp.com/parks-guide/voyageurs-national-park-outdoor-pp2-guide-cid9423.html</u>.

<sup>&</sup>lt;sup>8</sup> As noted at <u>http://www.nps.gov/isro/planyourvisit/hours.htm</u>.

<sup>&</sup>lt;sup>9</sup> As noted at <u>http://www.fws.gov/midwest/seney/visitor\_info.html</u>.

<sup>&</sup>lt;sup>10</sup> Production data is available from taxes levied on taconite production, and the data was supplied by BARR Engineering through a personal communication with Robert Paine of AECOM.

<sup>&</sup>lt;sup>11</sup> Available from the VIEWS web site at http://views.cira.colostate.edu/web/.



the BWCA over the past several years. Figures for other affected Class I areas (Voyageurs, Seney, and Isle Royale) are shown in Appendix C.

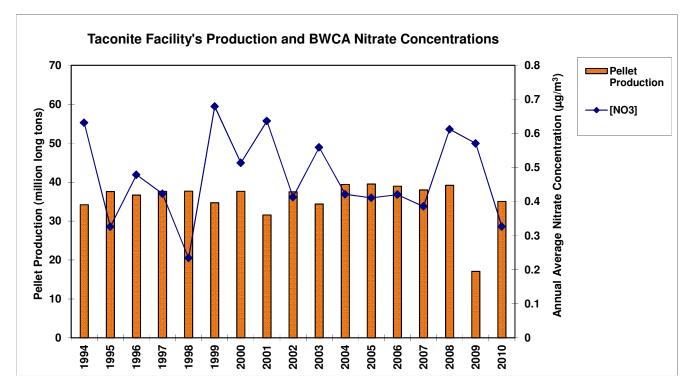
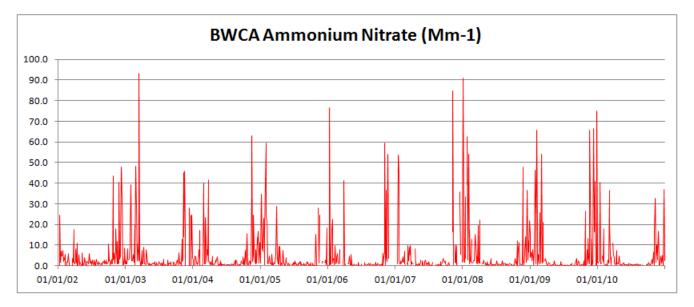




Figure 5 Time Series of Nitrate Haze at Boundary Waters Canoe Area (2002-2010)



September 2012



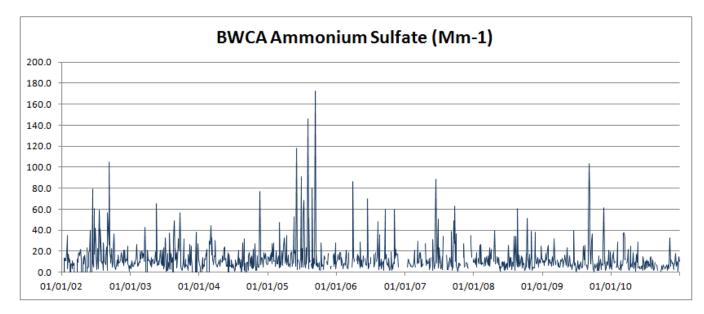


Figure 6 Time Series of Sulfate Haze at Boundary Waters Canoe Area (2002-2010)

It is evident from this information that the haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions.

It is instructive to review the haze composition time series plots for BWCA for 2008, 2009, and 2010, as shown in Figures 7, 8, and 9.

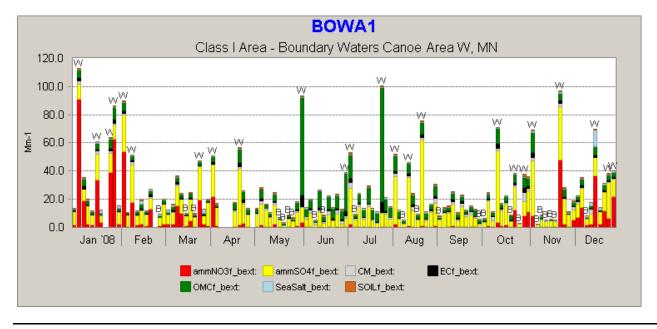


Figure 7 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2008

September 2012



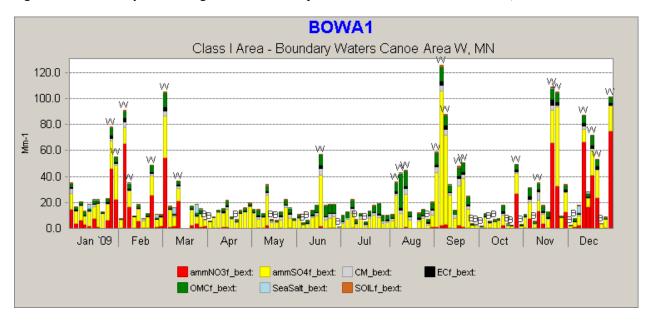
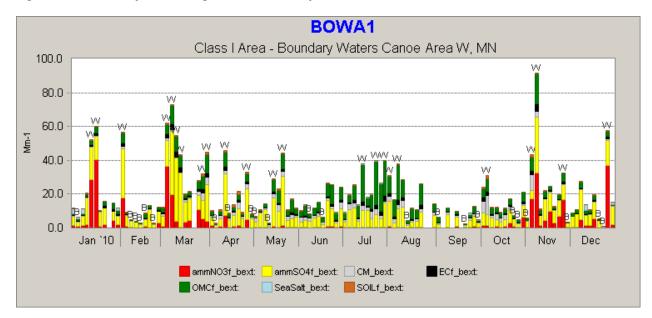




Figure 9 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2010



As has been mentioned above, it is evident that the nitrate haze (red bars) is only important during the colder months (November through March). It is also evident that haze from forest fires (green bars) is predominant in the warm weather months, but varies from year to year according to the frequency of wildfires. For example, 2008 was a year of high occurrences of wildfires, while 2009 saw a low frequency, and 2010 was more normal.

September 2012



The curtailment of taconite plant activity lasted from early 2009 through December 2009, peaking in the summer of 2009. Even so, we see the highest sulfate haze days (yellow bars) in September 2009 when taconite production was half of normal activity. Also, we note high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states.

These findings suggest that reduction of emissions from the taconite plants will likely have minimal effects on haze in the nearby Class I areas. The fact that the various plants are distributed over a large area means that individual plumes are isolated and generally do not combine with others.

At least one other emission reduction opportunity to determine the effect on visibility improvement has occurred; this is related to the shutdown of the Mohave Generating Station in 2005, and its effect upon visibility in the Grand Canyon National Park. The discussion in Appendix D indicates that although CALPUFF modeling predicted substantial visibility benefits, very little change has occurred since 2005.

Other reasons that visibility assessment models such as CALPUFF could overpredict impacts are listed below.

- 1) The CALPUFF base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.
- 2) The way that the predicted concentrations are accounted for in the CALPOST output overstate the impact for even the case where the CALPUFF predictions are completely accurate. The way that CALPOST works is that the peak 24-hour prediction <u>anywhere</u> in a Class I area is the only information saved for each predicted day. The predicted impact for each day is effectively assumed to be a) always in the same place; and b) in all portions of the Class I area. Therefore, the 98<sup>th</sup> percentile day's prediction could be comprised of impacts in 8 different places that are all erroneously assumed to be co-located.
- 3) CALPUFF does not simulate dispersion and transport accurately over a full diurnal cycle, during which significant wind direction shear can occur (and is not properly accounted for by CALPUFF). This can result in plumes that are more cohesive than actually occur.
- 4) As discussed above, it is well established that nitrate predictions are often overstated by CALPUFF v. 5.8, especially in winter.
- 5) Natural conditions as input to CALPOST are not attainable, and their use will exaggerate the simulated visibility impacts of modeled emissions.

# Interstate Non-Interference with Regional Haze Rule SIPs from Taconite Plant Emissions

An issue that is a recurring one for a number of state implementation plans (SIPs) is whether emissions from one state can interfere with haze reduction plans for downwind states. For Minnesota, it would be expected that emission reductions undertaken to reduce haze in Minnesota Class I areas (Voyageurs and Boundary Waters) would also act to reduce haze in other Class I areas. In the case of Minnesota's

September 2012



taconite plant emissions, earlier discussions of the potentially affected Class I areas indicated that only the Class I areas in northern Michigan (Isle Royale National Park and Seney Wilderness Area) are close enough and in a general predominant wind direction to merit consideration. The closer of these two parks, Isle Royale, is closed to the public from November 1 through April 15, and haze effects there would not be affected by NO<sub>X</sub> emissions because those effects are only important in the winter. Since Minnesota's Class I areas are located generally upwind of Michigan sources, the impact of Michigan sources on these Class I areas is expected to be small. This is confirmed in the Particulate Matter Source Apportionment Technology (PSAT) plots shown below.

Regional photochemical modeling studies<sup>12</sup> conducted by the CENRAP Regional Planning Organization, of which Minnesota is a part, shows contributions of various states as well as international contributions for haze impacts in the Michigan Class I areas. Relevant figures from the Iowa RHR SIP report for 2018 emission inventory haze impacts are reproduced below for Isle Royale National Park (Figure 10) and Seney Wilderness Area (Figure 11).

The modeling conducted for this analysis, using CAMx, shows that the relative contribution to haze for all Minnesota sources to sulfate haze in Isle Royale National Park is low, consisting of only 10% of the sulfate haze. The effect of 2018 emissions from Minnesota sources at the more distant Seney Wilderness Area is even lower, with the state's emissions ranking 9<sup>th</sup> among other jurisdictions analyzed for this Class I area. Therefore, it is apparent that Minnesota sources, and certainly the subset including taconite plants, would not be expected to interfere with other state's progress toward the 2018 milestone associated with the Regional Haze Rule.

Figures 12 and 13, reproduced from the Iowa RHR SIP report for Boundary Waters and Voyageurs, respectively, indicate that Michigan sources rank 11<sup>th</sup> and 12<sup>th</sup>, respectively, for haze impacts in these two areas for projected 2018 emissions. Therefore, as expected, Michigan sources are not expected to interfere with Minnesota's RHR SIP for progress in 2018.

<sup>&</sup>lt;sup>12</sup> See, for example, the Iowa State Implementation Plan for Regional Haze report at <u>http://www.iowadnr.gov/portals/idnr/uploads/air/insidednr/rulesandplanning/rh\_sip\_final.pdf</u>, Figures 11.3 and 11.4.

AECOM

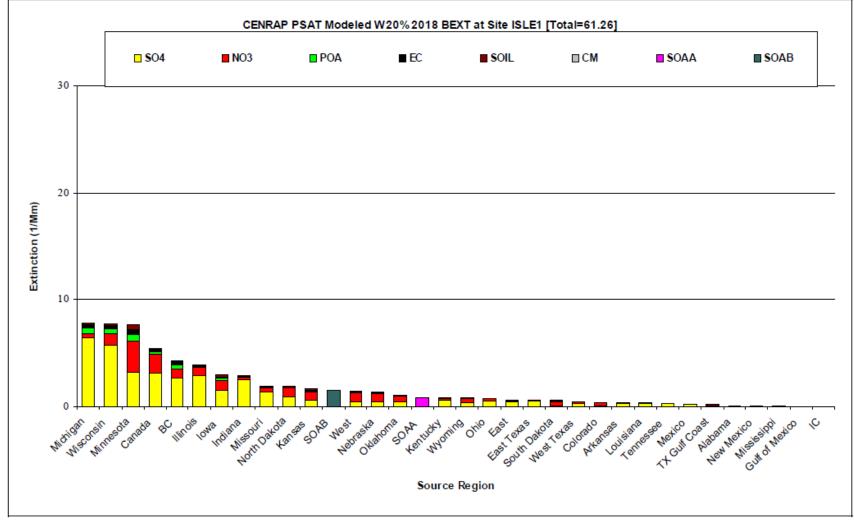


Figure 10 PSAT Results from CENRAP CAMx Modeling for Isle Royale National Park

Figure 11.3. Source apportion contributions by region and pollutant to ISLE in 2018.

September 2012

Page 14 of 45

www.aecom.com

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas



Figure 11 PSAT Results from CENRAP CAMx Modeling for Seney Wilderness Area

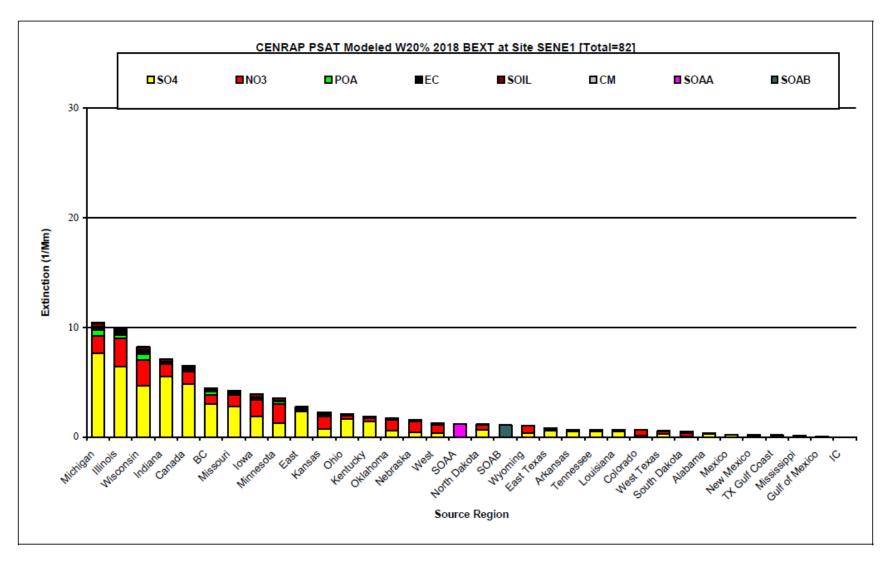


Figure 11.4. Source apportion contributions by region and pollutant to SENE in 2018.

September 2012

Page 15 of 45



Figure 12 PSAT Results from CENRAP CAMx Modeling for Boundary Waters Canoe Area Wilderness

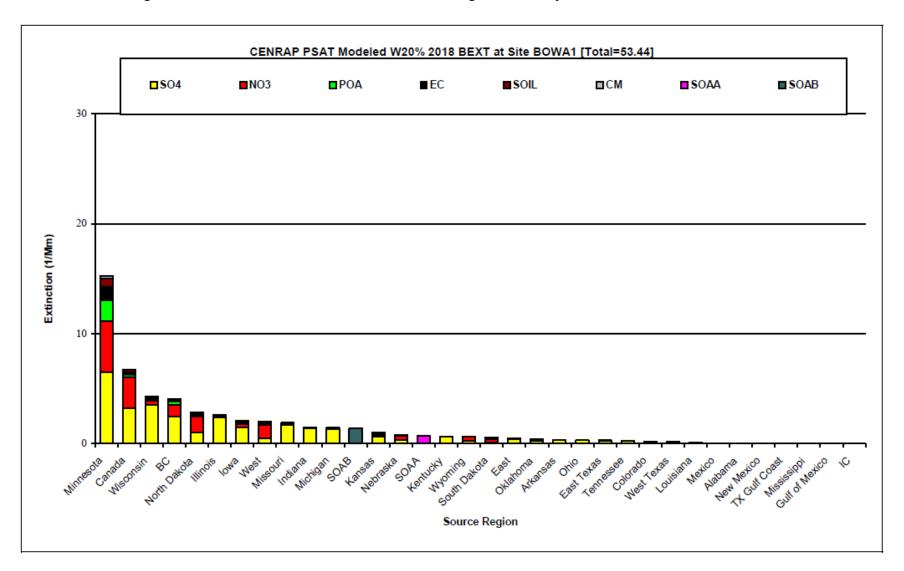


Figure 11.1. Source apportion contributions by region and pollutant to BOWA in 2018.

September 2012

Page 16 of 45



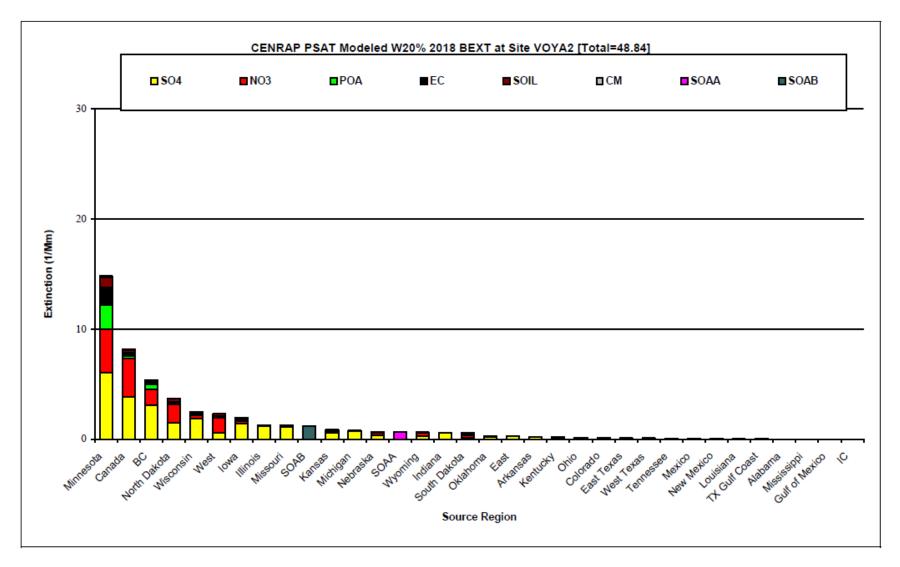


Figure 11.2. Source apportion contributions by region and pollutant to VOYA in 2018.

September 2012

Page 17 of 45

#### CONCLUSIONS

EPA's preferred modeling tools to assess the visibility improvement from BART controls will likely overestimate the predicted visibility improvement. While this is expected for all pollutants, it is especially true for  $NO_X$  emission controls. This occurs for several reasons:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clear, which exaggerates the impact of emission sources. Overly clean natural conditions can lead to the erroneous conclusion that some states are not adhering to the 2018 milestone because they need to achieve progress toward an impossible goal by the year 2064.
- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.
- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.
- The modeled base case scenario is always a worst-case emission rate, assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

Impacts of the taconite plants' NO<sub>x</sub> emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5  $\frac{1}{2}$  months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO<sub>x</sub> controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to visibility disbenefits due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

Evidence of models' tendency for overprediction are provided in examples of actual significant emission reductions that have resulted in virtually no perceptive changes in haze, while visibility assessment modeling as conducted for BART would predict significant visibility improvements. These examples include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in 2009.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, and vice versa indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

# **APPENDIX A**

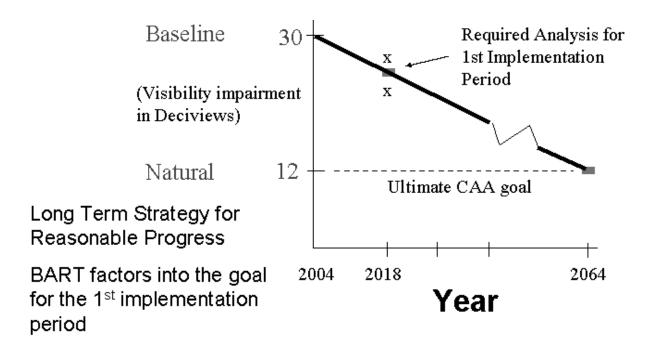
# THE REGIONAL HAZE RULE GOAL OF NATURAL CONDITIONS

An important consideration in the ability for a state to meet the 2018 Uniform Rate of Progress (URP) goal is the definition of the end point goal of "natural conditions" for the worst 20% haze days; see Figure A-1, which illustrates this concept). Note that while achieving improved visibility for the worst 20% haze days, the RHR also stipulates that there should not be deterioration of visibility for the best 20%, or clearest, days. One way to define that goal would be the elimination of all man-made emissions. This raises some other questions, such as:

- To what categories of emissions does the RHR pertain?
- Does the current definition of natural conditions include non-anthropogenic or uncontrollable emissions?

The default natural background assumed by EPA in their 2003 guidance document<sup>13</sup> is not realistic. The discussion in this section explains why EPA's default natural conditions significantly understate the true level of natural haze, including the fact that there are contributors of haze that are not controllable (and that are natural) that should be included in the definition of natural visibility conditions. In addition, one important aspect of the uncontrollable haze, wildfires, is further discussed regarding the biased quantification of its contribution to natural haze due to suppression of wildfires during the 20<sup>th</sup> century.

# Figure A-1: Illustration of the Uniform Rate of Progress Goal



Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

September 2012

<sup>&</sup>lt;sup>13</sup> Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule, (U.S. Environmental Protection Agency, September 2003). <u>http://www.epa.gov/ttncaaa1/t1/memoranda/rh\_envcurhr\_gd.pdf</u>.

In its RHR SIP, North Dakota<sup>14</sup> noted in Section 9.7 that,

"Achieving natural conditions will require the elimination of all anthropogenic sources of emissions. Given current technology, achieving natural conditions is an impossibility. Any estimate of the number of years necessary to achieve natural visibility conditions would require assumptions about future energy sources, technology improvements for sources of emissions, and every facet of human behavior that causes visibility impairing emissions. The elimination of all SO<sub>2</sub> and NO<sub>x</sub> emissions in North Dakota will not achieve the uniform rate of progress for this [2018], or any future planning period. Any estimate of the number of years to achieve natural conditions is questionable because of the influence of out-of-state sources."

It will be extremely difficult, if not impossible, to eliminate all anthropogenic emissions, even if natural conditions are accurately defined. It will be even more daunting to try to reach the goal if natural conditions are significantly understated, and as a result, states are asked to control sources that are simply not controllable. It is clear that the use of EPA default natural conditions leads to unworkable and absurd results for one state's (North Dakota's) ability to determine the rate of progress toward an unattainable goal. The definition of natural conditions that can be reasonably attained for a reasonable application of USEPA's Regional Haze Rule should be revised for all states.

The objective of the following discussion is to summarize recent modeling studies of natural visibility conditions and to suggest how such studies can be used in evaluating the uniform rate of progress in reducing haze to attain natural visibility levels. In addition, the distinction between natural visibility and policy relevant background visibility is discussed. Treatment of this issue by other states, such as Texas, is also discussed.

#### **Regional Haze Issues for Border States**

There are similarities between the Regional Haze Rule (RHR) challenges for border states such as North Dakota and Texas in that both states have significant international and natural contributions to regional haze in Class I areas in their states. The Texas Commission on Environmental Quality (TCEQ) has introduced alternative RHR glide paths to illustrate the State's rate of progress toward the RHR goals. Since TCEQ has gone through the process of a RHR State Implementation Plan (SIP) development and comment period, it is instructive to look at the TCEQ approach, the comments provided by the Federal Land Managers to TCEQ, and TCEQ's reaction to the comments.

Similarities to be considered for the RHR SIP development in border states, such as North Dakota and Texas, include the items listed below.

• These states have Class I areas for which a considerable fraction of the regional haze is due to international transport or transport from other regions of the United States.

21

<sup>&</sup>lt;sup>14</sup> North Dakota Dep. of Health, 2010. North Dakota State Implementation Plan for Regional Haze. <u>http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Main%20SIP%20Sections%201-12.pdf</u>.

- As a result, there is a substantial reduction in SO<sub>2</sub> and NO<sub>x</sub> emissions from the BART-eligible sources in each state, but this reduction results in a relatively small impact on regional haze mitigation. Additional emission reductions would, therefore, have a minimal benefit on visibility improvement at substantial cost.
- In the Regional Haze SIP development, these states have attempted to account for the effects of anthropogenic emissions that they can control in alternative analyses. These analysis result in a finding that the in-state emission reductions come closer to meeting the Uniform Rate of Progress glide path goals for 2018. However, due to the low probability of impact of these sources on the worst 20% days, the effectiveness of in-state emission controls on anthropogenic sources subject to controls is inherently limited.

TCEQ decided that coarse and fine PM measured at the Class I areas were due to natural causes (especially on the worst 20% days), and adjusted the natural conditions endpoint accordingly. The Federal Land Managers (FLMs) agreed with this approach for the most part<sup>15</sup>, but suggested that 80% of these concentrations would be due to natural causes, and 20% would be due to anthropogenic causes. TCEQ determined from a sensitivity analysis that the difference in these two approaches was too small to warrant a re-run of their analysis, but it is important that the FLMs agreed to a state-specific modification of the natural conditions endpoint, and this substantially changed the perceived rate of progress of the SIP plan toward the altered natural conditions endpoint.

Although the TCEQ did not address other particulate matter components in this same way, a review of air parcel back trajectories previously available from the IMPROVE web site (<u>http://views.cira.colostate.edu/web/</u>) suggests that other components, such as organic matter due to wildfires, could be substantially due to natural causes, so that this component should also be considered as at least partially natural.

The TCEQ discussed the issue of how emissions from Mexico could interfere with progress on the RHR, but they did not appear to adjust the glide path based upon Mexican emissions. On the other hand, in its weight of evidence analysis, North Dakota did evaluate adjustments based upon anthropogenic emissions that could not be controlled from Canadian sources, but did not take into account any specific particulate species that are generally not emitted by major anthropogenic sources of SO<sub>2</sub> and NO<sub>x</sub>.

# **Natural Haze Levels**

The Regional Haze Rule establishes the goal that natural visibility conditions should be attained in Federal Class I areas by the year 2064. Additionally, the states are required to determine the uniform rate of progress (URP) of visibility improvement necessary to attain the natural visibility goal by 2064. Finally, each state must develop a SIP identifying reasonable control measures that will be adopted well before 2018 to reduce source emissions of visibility-impairing particulate matter (PM) and its precursors (SO<sub>2</sub> and NO<sub>x</sub>).

Estimates of natural haze levels have been developed by the EPA for visibility planning purposes and are described in the above-referenced EPA 2003 document. The natural haze estimates were based on ambient data analysis of selected PM species for days with good visibility and are shown in Table A-1.

<sup>&</sup>lt;sup>15</sup> See Appendix 2-2 at <u>http://www.tceq.state.tx.us/implementation/air/sip/bart/haze\_appendices.html</u>.

These estimates were derived from Trijonis<sup>16</sup> and use two different sets of natural concentrations for the eastern and western U.S. Tombach<sup>17</sup> provides a detailed review and discussion of uncertainty in the USEPA natural PM estimates. Natural visibility can be calculated using the IMPROVE equation which calculates the light scattering caused by each

# Table A-1: Average Natural Levels of Aerosol Components from Table 2-1 of Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (EPA, 2003)

|                               | Average Natura | Average Natural Concentration |                   |                                    |
|-------------------------------|----------------|-------------------------------|-------------------|------------------------------------|
|                               | West (µg/m³)   | East (µg/m³)                  | – Error<br>Factor | Extinction<br>Efficiency<br>(m²/g) |
| Ammonium sulfate <sup>b</sup> | 0.12           | 0.23                          | 2                 | 3                                  |
| Ammonium nitrate              | 0.10           | 0.10                          | 2                 | 3                                  |
| Organic carbon mass °         | 0.47           | 1.40                          | 2                 | 4                                  |
| Elemental carbon              | 0.02           | 0.02                          | 2-3               | 10                                 |
| Soil                          | 0.50           | 0.50                          | 1½ - 2            | 1                                  |
| Coarse Mass                   | 3.0            | 3.0                           | 1½ - 2            | 0.6                                |

a: After Trijonis, see footnote 12

b: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.1  $\mu$ g/m<sup>3</sup> and 0.2  $\mu$ g/m<sup>3</sup> of ammonium bisulfate.

c: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.5 µg/m<sup>3</sup> and 1.5 µg/m<sup>3</sup> of organic compounds.

component of PM. After much study, changes in the IMPROVE equation and in the method for calculating natural visibility were developed in 2005 and are described by Pitchford et al.<sup>18</sup>

The EPA guidance also makes provision for refined estimates of site-specific natural haze that differ from the default values using either data analysis or model simulations. However, most states have continued to use the default natural haze levels for calculating the progress toward natural visibility conditions.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>16</sup> Trijonis, J. C. Characterization of Natural Background Aerosol Concentrations. Appendix A in Acidic Deposition: State of Science and Technology. Report 24. Visibility: Existing and Historical Conditions -- Causes and Effects. J. C. Trijonis, lead author. National Acid Precipitation Assessment Program: Washington, DC, 1990.

<sup>&</sup>lt;sup>17</sup> Tombach, I., (2008) *Natural Haze Levels Sensitivity -- Assessment of Refinements to Estimates of Natural Conditions,* Report to the Western Governors Association, January 2008, available at <a href="http://www.wrapair.org/forums/aamrf/projects/NCB/index.html">http://www.wrapair.org/forums/aamrf/projects/NCB/index.html</a>.

<sup>&</sup>lt;sup>18</sup> Pitchford, M., Malm, W., Schichtel, B., Kumar, N., Lowenthal, D., Hand, J., Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data, J. Air & Waste Manage, Assoc. 57: 1326 – 1336, 2007.

Tombach and Brewer<sup>19</sup> reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach<sup>8</sup> also reviewed estimates of natural haze levels and proposed that, instead of using two sets of default natural PM concentrations for the eastern and western US, a large number of sensitivity zones should be developed that reflect regional variability in natural PM sources. Tombach<sup>8</sup> also suggested that modeling studies are a possible approach to further revise estimates of natural PM concentrations.

Previous modeling studies have shown that the estimates of natural visibility described above for "clean" days will differ from the results of model simulations when United States anthropogenic emissions are totally eliminated (Tonnesen et al., 2006<sup>20</sup>; Koo et al., 2010<sup>21</sup>), especially when natural wild fire emissions are included in the model simulation. Because the URP is calculated using model simulations of PM on the 20% of days with the worst visibility, wild fires and other extreme events can result in estimated levels of natural haze (even without any contribution of US anthropogenic sources) that can be significantly greater than the natural levels used in the EPA guidance for URP calculation. This could make it difficult or impossible for states to identify emissions control measures sufficient to demonstrate the URP toward attaining visibility goals because the endpoint is unachievable even if all US anthropogenic emissions are eliminated, as North Dakota has already determined even for the interim goal in 2018.

# Previous Suppression of Wildfire Activity and its Effect upon the EPA Default Natural Conditions

Throughout history, except for the past few decades, fires have been used to clear land, change plant and tree species, sterilize land, maintain certain types of habitat, among other purposes. Native Americans used fires as a technique to maintain certain pieces of land or to improve habitats. Although early settlers often used fires in the same way as the Native Americans, major wildfires on public domain land were largely ignored and were often viewed as an opportunity to open forestland for grazing.

Especially large fires raged in North America during the 1800s and early 1900s. The public was becoming slowly aware of fire's potential for life-threatening danger. Federal involvement in trying to control forest fires began in the late 1890s with the hiring of General Land Office rangers during the fire season. When the management of the forest reserves (now called national forests) was transferred to the newly formed Forest Service in 1905, the agency took on the responsibility of creating professional standards for firefighting, including having more rangers and hiring local people to help put out fires.

Since the beginning of the 20<sup>th</sup> century, fire suppression has resulted in a buildup of vegetative "fuels" and catastrophic wildfires. Recent estimates of background visual range, such as Trijonis<sup>16</sup>, have underestimated the role of managed fire on regional haze. Since about 1990, various government agencies have increased prescribed burning to reduce the threat of dangerous wildfires, and the

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>19</sup> Tombach, I., and Brewer, P. (2005). Natural Background Visibility and Regional Haze Goals in the Southeastern United States. *J. Air & Waste Manage. Assoc. 55*, 1600-1620.

<sup>&</sup>lt;sup>20</sup> Tonnesen, G., Omary, M., Wang, Z., Jung, C.J., Morris, R., Mansell, G., Jia, Y., Wang, B., and Z. Adelman (2006) Report for the Western Regional Air Partnership Regional Modeling Center, University of California Riverside, Riverside, California, November. (<u>http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC 2006 report FINAL.pdf</u>).

<sup>&</sup>lt;sup>21</sup> Koo B., C.J. Chien, G. Tonnesen, R. Morris , J. Johnson, T. Sakulyanontvittaya, P. Piyachaturawat, and G.Yarwood, 2010. Natural emissions for regional modeling of background ozone and particulate matter and impacts on emissions control strategies. <u>Atm. Env.</u>, 44, 2372-2382.

increased haze due to these fires is often more of an impairment to visibility than industrial sources, especially for  $NO_X$  reductions that are only effective in winter, the time of the lowest tourist visitation in most cases.

The National Park Service indicates at <u>http://www.nps.gov/thro/parkmgmt/firemanagement.htm</u> for the Theodore Roosevelt National Park that:

"For most of the 20<sup>th</sup> Century, wildfires were extinguished immediately with the assumption that doing so would protect lives, property, and natural areas. However, following the unusually intense fire season of 1988, agencies including the National Park Service began to rethink their policies." Even this policy is not always successful, as experienced by the USDA Forest Service<sup>22</sup> in their management of wildfires near the Boundary Waters Canoe Area that can contribute significantly to visibility degradation during the peak tourist season. In this case, even small fires, if left unchecked, have been known to evolve into uncontrollable fires and then require substantial resources to extinguish.

EPA's 2003 "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" acknowledges that wildfires are a contributor to natural visibility conditions, but the data used in estimates of natural conditions were taken during a period of artificial fire suppression so that the true impact of natural wildfires is understated. The report notes that "data should be available for EPA and States to develop improved estimates of the contribution of fire emissions to natural visibility conditions in mandatory Federal Class I areas over time." As noted by several studies noted above, the impact due to natural fire levels is underestimated in the EPA natural visibility conditions include the distortion of Reasonable Progress analyses and also to BART modeling results that overestimate the visibility improvement achievable from NO<sub>X</sub> emission reductions due to the use of inaccurate natural visibility conditions.

# **Recommendations for an Improved Estimate of Visibility Natural Conditions**

A reasonable approach would be to combine the effects of the uncontrollable particulate matter components and the emissions from international sources to determine a new glide path endpoint that is achievable by controlling (only) U.S. anthropogenic emissions. To compute this new endpoint, regional photochemical modeling using CMAQ or CAMx could be conducted for the base case (already done) and then for a future endpoint case that has no U.S. anthropogenic emissions, but with natural particulate matter emissions (e.g., dust, fires, organic matter) as well as fine particulate, SO<sub>2</sub> and NO<sub>x</sub> emissions associated with all non-U.S. sources set to the current baseline levels. The simulation should include an higher level of wildfire activity than in the recent past to reflect a truer level of fire activity before manmade suppression in the 20<sup>th</sup> century. Then, states could use a relative reduction factor (RRF) approach to determine the ratio of the haze impacts between the base case and the reasonable future case, and then apply the RRF values to the baseline haze to obtain a much more reasonable "natural conditions" haze endpoint. The more accurate natural background would also result in a reduction in the degree to which CALPUFF modeling overstates visibility improvement from emission reductions.

<sup>&</sup>lt;sup>22</sup> See explanation at <u>http://www.msnbc.msn.com/id/48569985/ns/us\_news-environment/t/forest-service-gets-more-aggressive-small-fires/</u>.

# **APPENDIX B**

# MODEL OVERPREDICTION ISSUES FOR WINTERTIME NITRATE HAZE

This appendix includes a discussion of CALPUFF predictions for nitrate haze, followed by more general issues with CALPUFF predictions.

# **CALPUFF Predictions of Nitrate Haze**

Secondary pollutants such as nitrates and sulfates contribute to light extinction in Class I areas. The CALPUFF model was approved by EPA for use in BART determinations to evaluate the effect of these pollutants on visibility in Class I areas. CALPUFF version 5.8 (the current guideline version) uses the EPA-approved MESOPUFF II chemical reaction mechanism to convert SO<sub>2</sub> and NO<sub>x</sub> emissions to secondary sulfate and nitrate. This section describes how secondary pollutants, specifically nitrate, are formed and the factors affecting their formation, especially as formulated in CALPUFF.

In the CALPUFF model, the oxidation of NO<sub>x</sub> to nitric acid (HNO<sub>3</sub>) depends on the NO<sub>x</sub> concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration. In CALPUFF, total nitrate (TNO<sub>3</sub> = HNO<sub>3</sub> + NO<sub>3</sub>) is partitioned into gaseous HNO<sub>3</sub> and NO<sub>3</sub> particles according to the equilibrium relationship between the two species. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate particles *strongly* depends on availability of NH<sub>3</sub> to form ammonium nitrate, as shown in Figure 6<sup>23</sup>. The figure on the left shows that with 1 ppb of available ammonia and fixed temperature and humidity (for example, 275 K and 80% humidity), only 50% of the total nitrate is in the form of particulate matter. When the available ammonia is increased to 2 ppb, as shown in the figure on the right, as much as 80% of the total nitrate is in the particulate form. Figure B-1 also shows that colder temperatures and higher relative humidity favor particulate nitrate formation. A summary of the conditions affecting nitrate formation are listed below:

- Colder temperature and higher relative humidity create more favorable conditions to form nitrate particulate matter in the form of ammonium nitrate;
- Warmer temperatures and lower relative humidity create less favorable conditions for nitrate particulate matter resulting in a small fraction of total nitrate in the form of ammonium nitrate;
- Ammonium sulfate formation preferentially scavenges available atmospheric ammonia over ammonium nitrate formation. In air parcels where sulfate concentrations are high and ambient ammonia concentrations are low, there is less ammonia available to react with nitrate, and less ammonium nitrate is formed.

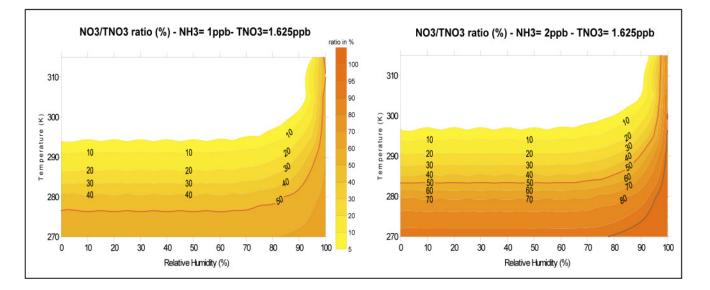
The effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various  $NO_x$  control options. For the reasons discussed above, the seasons with lower temperatures are the most likely to be most important for ammonium nitrate formation when regional haze is more effectively reduced by controlling  $NO_x$ .

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

September 2012

27

<sup>&</sup>lt;sup>23</sup> Scire, Joseph. CALPUFF MODELING SYSTEM. CALPUFF course presented at Chulalongkorn University, Bangkok, Thailand. May 16-20, 2005; slide 40 available at <u>http://aqnis.pcd.go.th/tapce/plan/4CALPUFF%20slides.pdf</u>, accessed March 2011.



# Figure B-1: NO<sub>3</sub>/HNO<sub>3</sub> Equilibrium Dependency on Temperature and Humidity

# Sensitivity of CALPUFF Haze Calculations to Background Ammonia Concentration

In an independent analysis, the Colorado Department of Public Health and Environment (CDPHE) performed a sensitivity modeling analysis to explore the effect of the specified ammonia concentration applied in CALPUFF on the predicted visibility impacts for a source with high NO<sub>x</sub> emissions relative to SO<sub>2</sub> emissions<sup>24</sup>. The results of the sensitivity modeling are shown in Figure B-2. It is noteworthy that the largest sensitivity occurs for specified ammonia input between 1 and 0.1 ppb. In that factor-of-ten range, the difference in the peak visibility impact predicted by CALPUFF is slightly more than a factor of three. This sensitivity analysis shows that the specification of background ammonia is very important in terms of the magnitude of visibility impacts predicted by CALPUFF. The fact that regional, diurnal and seasonal variations of ambient ammonia concentrations are not well-characterized and mechanisms not well-understood effectively limits the effectiveness of CALPUFF in modeling regional haze, especially in terms of the contribution of ammonium nitrate.

It is also noteworthy that CALPUFF version 5.8's demonstrated over-predictions of wintertime nitrate can be mitigated to some extent by using lower winter ammonia background values, although there is not extensive measurement data to determine the ambient ammonia concentrations. This outcome showing the superiority of the monthly-varying background ammonia concentrations was found by Salt River

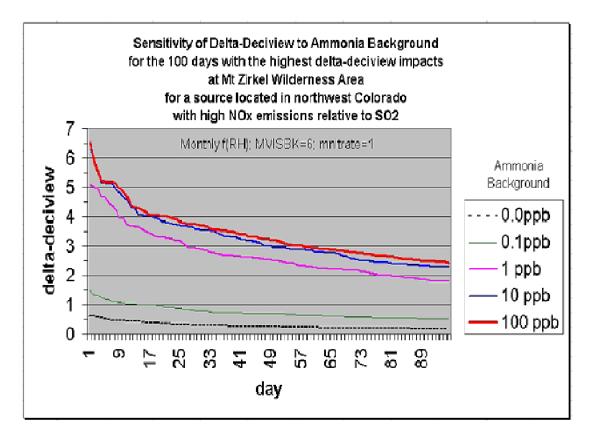
September 2012 Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>24</sup> Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at <u>http://www.colorado.gov/airquality/documents/Draft-</u> ColoradoSupplementalBARTAnalysisCALPUFFProtocol-25June2010.pdf. (2010)

Project in case studies of the Navajo Generating Station impacts on Grand Canyon monitors, as presented<sup>25</sup> to EPA in 2010.

It is important to note that 14 years ago in 1998, when the IWAQM Phase 2 guidance<sup>26</sup> was issued, CALPUFF did not even have the capability of accommodating monthly ammonia background concentrations; only a single value was allowed. Since then, CALPUFF has evolved to be able to receive as input monthly varying ammonia concentrations. EPA's guidance on the recommended input values that are constant all year has not kept pace with the CALPUFF's capability. The weight of evidence clearly indicates that the use of monthly varying ammonia concentrations with lower wintertime values will result in more accurate predictions.

# Figure B-2: CDPHE Plot of Sensitivity of Visibility Impacts Modeled by CALPUFF for Different Ammonia Backgrounds.



<sup>&</sup>lt;sup>25</sup> Salt River Project, 2010. Measurements of Ambient Background Ammonia on the Colorado Plateau and Visibility Modeling Implications. Salt River Project, P.O. Box 52025 PAB352, Phoenix, Arizona 85072.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>26</sup> IWAQM Phase 2 Summary Report and Recommendations (EPA-454/R-98-019), EPA OAQPS, December 1998). <u>http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf</u>.

# Independent Studies of the Effect of Model Chemistry on Nitrate Predictions

The Regional Haze BART Rule acknowledged that CALPUFF tends to overestimate the amount of nitrate that is produced. In particular, the overestimate of ammonium nitrate concentrations on visibility at Class I areas is the greatest in the winter, when temperatures (and visitation) are lowest, the nitrate concentrations are the greatest, and the sulfate concentrations tend to be the least due to reduced oxidation rates of SO<sub>2</sub> to sulfate.

On page 39121, the BART rule<sup>27</sup> stated that: "...the simplified chemistry in the [CALPUFF] model tends to magnify the actual visibility effects of that source."

On page 39123, the BART rule stated that: "We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. In its next review of the Guideline on Air Quality Models, EPA will evaluate these and other newer approaches<sup>28</sup>."

EPA did not conduct such an evaluation, but the discussion below reports on the efforts of other investigators.

A review of independent evaluations of the CALPUFF model is reported here, with a focus on identifying studies that address the nitrate chemistry used in the model. Morris et al.<sup>29</sup> reported that the CALPUFF MESOPUFF II transformation rates were developed using temperatures of 86, 68 and 50 °F. Therefore, the 50 °F minimum temperature used in development of the model could result in overestimating sulfate and nitrate formation in colder conditions. These investigators found that CALPUFF tended to overpredict nitrate concentrations during winter by a factor of about three.

A recent independent study of the CALPUFF performance by Karamchandani et al (referred to here as the KCBB study) is highly relevant to this issue<sup>30</sup>. The KCBB study presented several improvements to the Regional Impacts on Visibility and Acid Deposition (RIVAD) chemistry option in CALPUFF, an alternative treatment that was more amenable to an upgrade than the MESOPUFF II chemistry option. Among other items, the improvements included the replacement of the original CALPUFF secondary particulate matter (PM) modules by newer algorithms that are used in current state-of-the-art regional air quality models such as CMAQ, CMAQ-MADRID, CAMx and REMSAD, and in advanced puff models

<sup>29</sup> Morris, R., Steven Lau and Bonyoung Koo. Evaluation of the CALPUFF Chemistry Algorithms. Presented at A&WMA 98th Annual Conference and Exhibition, June 21-25, 2005 Minneapolis, Minnesota. (2005)

<sup>30</sup> Karamchandani, P., S. Chen, R. Bronson, and D. Blewitt. Development of an Improved Chemistry Version of CALPUFF and Evaluation Using the 1995 SWWYTAF Data Base. Presented at the Air & Waste Management Association Specialty Conference on Guideline on Air Quality Models: Next Generation of Models, October 28-30, 2009, Raleigh, NC. (2009)

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>27</sup> July 6, 2005 Federal Register publication of the Regional Haze BART rule.

<sup>&</sup>lt;sup>28</sup> The next (9<sup>th</sup>) EPA modeling conference was held in 2008, during which the concepts underlying the chemistry upgrades in CALPUFF 6.42 were presented. However, EPA failed to conduct the promised evaluation in its review of techniques at that conference held 4 years ago. As a result of the 10<sup>th</sup> EPA modeling conference held in March 2012, EPA appears to be continuing to rely upon CALPUFF version 5.8, which it admitted in the July 6, 2005 BART rule has serious shortcomings.

such as SCICHEM. In addition, the improvements included the incorporation of an aqueous-phase chemistry module based on the treatment in CMAQ. Excerpts from the study papers describing each of the improvements made to CALPUFF in the KCBB study are repeated below.

## Gas-Phase Chemistry Improvements

The KCBB study applied a correction to CALPUFF in that the upgraded model was modified to keep track of the puff ozone concentrations between time steps. The authors also updated the oxidation rates of  $SO_2$  and nitrogen dioxide (NO<sub>2</sub>) by the hydroxide ion (OH<sup>-</sup>) to the rates employed in contemporary photochemical and regional PM models.

### Treatment of Inorganic Particulate Matter

The KCBB study scientists noted that the EPA-approved version of CALPUFF currently uses a simple approach to simulate the partitioning of nitrate and sulfate between the gas and particulate phases. In this approach, sulfate is appropriately assumed to be entirely present in the particulate phase, while nitrate is assumed to be formed by the reaction between nitric acid and ammonia.

The KCBB study implemented an additional treatment for inorganic gas-particle equilibrium, based upon an advanced aerosol thermodynamic model referred to as the ISORROPIA model<sup>31</sup>. This model is currently used in several state-of-the-art regional air quality models. With this new module, the improved CALPUFF model developed in the KCBB study includes a treatment of inorganic PM formation that is consistent with the state of the science in air quality modeling, and is critical for the prediction of regional haze due to secondary nitrate formation from NO<sub>X</sub> emissions.

### Treatment of Organic Particulate Matter

The KCBB study added a treatment for secondary organic aerosols (SOA) that is coupled with the corrected RIVAD scheme described above. The treatment is based on the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID)<sup>32,33</sup>, which treats SOA formation from both anthropogenic and biogenic volatile organic compound emissions.

### Aqueous-Phase Chemistry

The current aqueous-phase formation of sulfate in both CALPUFF's RIVAD and MESOPUFF II schemes is currently approximated with a simplistic treatment that uses an arbitrary pseudo-first order rate in the presence of clouds (0.2% per hour), which is added to the gas-phase rate. There is no explicit treatment

<sup>33</sup> Pun, B., C. Seigneur, J. Pankow, R. Griffin, and E. Knipping. An upgraded absorptive secondary organic aerosol partitioning module for three-dimensional air quality applications, 24th Annual American Association for Aerosol Research Conference, Austin, TX, October 17-21, 2005. (2005)

September 2012

www.aecom.com

<sup>&</sup>lt;sup>31</sup> Nenes A., Pilinis C., and Pandis S.N. Continued Development and Testing of a New Thermodynamic Aerosol Module for Urban and Regional Air Quality Models, *Atmos. Env.* **1998**, 33, 1553-1560.

<sup>&</sup>lt;sup>32</sup>Zhang, Y., B. Pun, K. Vijayaraghavan, S.-Y. Wu, C. Seigneur, S. Pandis, M. Jacobson, A. Nenes and J.H. Seinfeld. Development and Application of the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID), *J. Geophys. Res.* **2004**, 109, D01202, doi:10.1029/2003JD003501.

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

of aqueous-phase SO<sub>2</sub> oxidation chemistry. The KCBB study incorporated into CALPUFF a treatment of sulfate formation in clouds that is based on the treatment that is used in EPA's CMAQ model.

# CALPUFF Model Evaluation and Sensitivity Tests

The EPA-approved version of CALPUFF and the version with the improved chemistry options were evaluated using the 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database<sup>34</sup>, available from the Wyoming Department of Environmental Quality. The database includes MM5 output for 1995, CALMET and CALPUFF codes and control files, emissions for the Southwest Wyoming Regional modeling domain, and selected outputs from the CALPUFF simulations. Several sensitivity studies were also conducted to investigate the effect of background NH<sub>3</sub> concentrations on model predictions of PM nitrate. Twice-weekly background NH<sub>3</sub> concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH<sub>3</sub> concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

- MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH<sub>3</sub> concentration of 1 ppb for arid land. As discussed previously, the MESOPUFF II algorithm is the basis for the currently approved version of CALPUFF that is being used for BART determinations throughout the United States.
- 2. Improved CALPUFF RIVAD/ARM3 chemistry using background values of NH<sub>3</sub> concentrations based on measurements in the Pinedale, Wyoming area, as described above.

PM sulfate and nitrate were predicted by the two models and compared with actual measured values obtained at the Bridger Wilderness Area site from the IMPROVE network and the Pinedale site from the Clean Air Status and Trends Network (CASTNET). For the two model configurations evaluated in this study, the results for PM sulfate were very similar, which was expected since the improvements to the CALPUFF chemistry were anticipated to have the most impact on PM nitrate predictions. Therefore, the remaining discussion focuses on the performance of each model with respect to PM nitrate.

The EPA-approved CALPUFF model was found to significantly overpredict PM nitrate concentrations at the two monitoring locations, by a factor of two to three. The performance of the version of CALPUFF with the improved RIVAD chemistry was much better, with an overprediction of about 4% at the Pinedale CASTNET site and of about 28% at the Bridger IMPROVE site.

In an important sensitivity analysis conducted within the KCBB study, both the EPA-approved version of CALPUFF and the improved version were run with a constant ammonia background of 1 ppb, as recommended by IWAQM Phase II<sup>35</sup>. The results were similar to those noted above: the improved

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>34</sup> Wyoming Department of Environmental Quality. 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database. Background and database description are available at http://deq.state.wy.us/aqd/prop/2003AppF.pdf. (2010)

<sup>&</sup>lt;sup>35</sup> Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Long-Range Transport Modeling, EPA-454/R-98-019. (1998)

CALPUFF predictions were about two to three times lower than those from the EPA-approved version of CALPUFF. This result is similar to the results using the seasonal observed values of ammonia, and indicates that the sensitivity of the improved CALPUFF model to the ammonia input value is potentially less than that of the current EPA-approved model.

Similar sensitivity was noted by Scire et al. in their original work in the SWWYATF study<sup>36</sup>, in which they tested seasonally varying levels of background ammonia in CALPUFF (using 0.23 ppb in winter, for example; see Figure B-3. The sensitivity modeling for predicting levels of nitrate formation shows very similar results to those reported in the KCBB study.

These findings indicate that to compensate for the tendency of the current EPA-approved version of CALPUFF to overpredict nitrates, the background ammonia values that should be used as input in CALPUFF modeling should be representative of isolated areas (e.g., Class I areas).

On November 3, 2010, TRC released a new version (6.42) of CALPUFF to fix certain coding "bugs" in EPA-approved version 5.8 and to improve the chemistry module. Additional enhancements to CALPUFF version 6.42 have been reported at EPA's 10<sup>th</sup> modeling conference in March 2012 by Scire<sup>37</sup>, who also has conducted recent evaluations of this version in comparison to the regulatory version (5.8). Despite the evidence that this CALPUFF version is a generation ahead of the currently approved version for modeling secondary particulate formation, EPA has not acted to adopt it as a guideline model. Even with evidence provided by independent investigators<sup>29,30</sup> that also indicate that wintertime nitrate estimated by CALPUFF version 5.8 is generally overpredicted by a factor between 2 and 4, EPA has not taken steps to adopt the improved CALPUFF model, noting that extensive peer review, evaluations, and rulemaking are still needed for this adoption to occur. In the meantime, EPA, in retaining CALPUFF version 5.8 as the regulatory model for regional haze predictions, is ignoring the gross degree of overestimation of particulate nitrate and is thus ensuring that regional haze modeling conducted for BART is overly conservative. EPA's delay in adopting CALPUFF version 6.42 will thus result in falsely attributing regional haze mitigation to NO<sub>X</sub> emission reductions.

September 2012 Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas 33

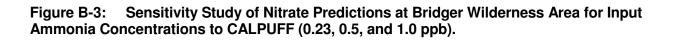
<sup>&</sup>lt;sup>36</sup> Scire, J.S., Z-X Wu, D.G. Strimaitis and G.E. Moore. The Southwest Wyoming Regional CALPUFF Air Quality Modeling Study – Volume I. Prepared for the Wyoming Dept of Environmental Quality. (2001)

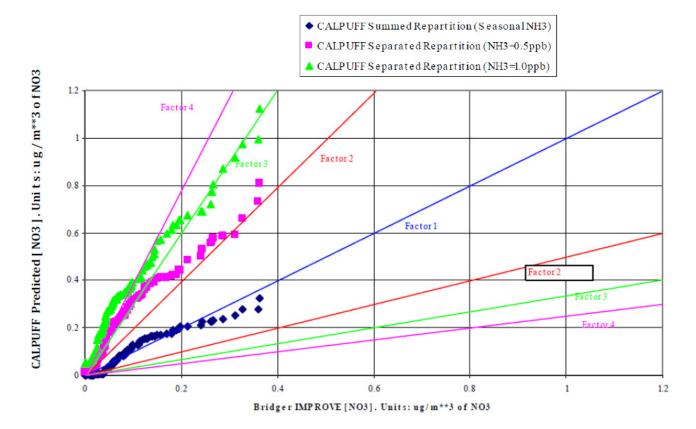
<sup>&</sup>lt;sup>37</sup> Scire, J., 2012. New Developments and Evaluations of the CALPUFF Model. <u>http://www.epa.gov/ttn/scram/10thmodconf/presentations/3-5-CALPUFF Improvements Final.pdf</u>.

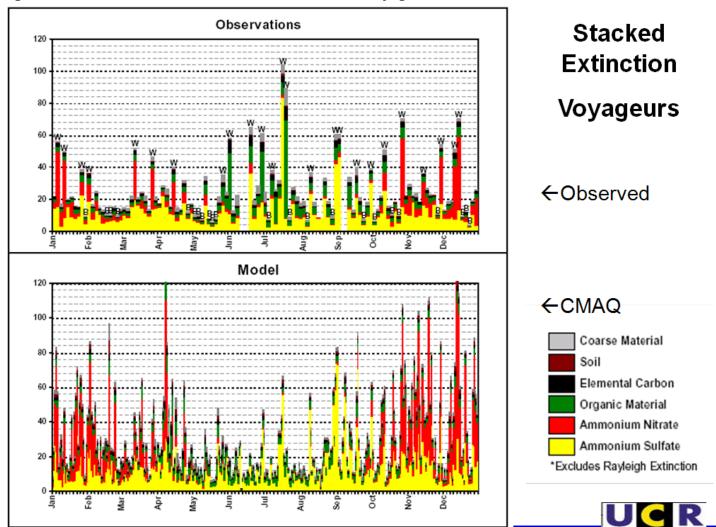
# **OVERPREDICTIONS OF NITRATE HAZE BY REGIONAL PHOTOCHEMICAL MODELS**

The overprediction tendency for modeling of wintertime nitrate haze is not limited to CALPUFF. Even the state-of-the-art regional photochemical models are challenged in getting the right ammonium nitrate concentrations. This is evident in a presentation<sup>38</sup> made by Environ to the CENRAP Regional Planning Organization in 2006. The relevant figures from the Ralph Morris presentation (shown in Figures B-4 and B-5 below) indicate that both CMAQ and CAMx significantly overpredict nitrate haze in winter at Voyageurs National Park, by about a factor of 2. This is shown by the height of the red portion of the composition plot stacked bars between the observed and predicted timelines. It is noteworthy that Minnesota and EPA have relied upon this modeling approach for their BART determinations. Similar to CALPUFF, as discussed above, the agency modeling is prone to significantly overpredicting wintertime nitrate haze, leading to an overestimate of visibility improvement with NO<sub>x</sub> emission reductions.

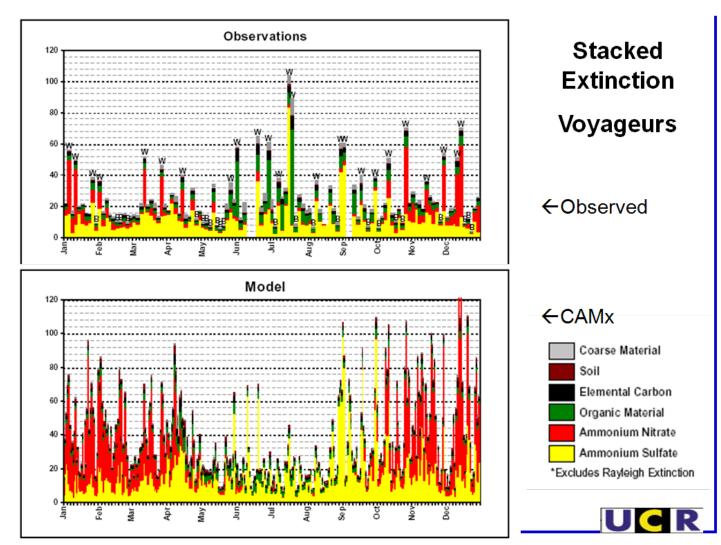
<sup>&</sup>lt;sup>38</sup> <u>http://pah.cert.ucr.edu/aqm/cenrap/meetings.shtml</u>, under "MPE", slides 9 and 10.







# Figure B-4 CMAQ vs. Observed Haze Predictions at Voyageurs National Park



# Figure B-5 CAMx vs. Observed Haze Predictions at Voyageurs National Park

# **APPENDIX C**

Haze Time Series Plots for Voyageurs National Park, Seney Wilderness Area, and Isle Royale National Park

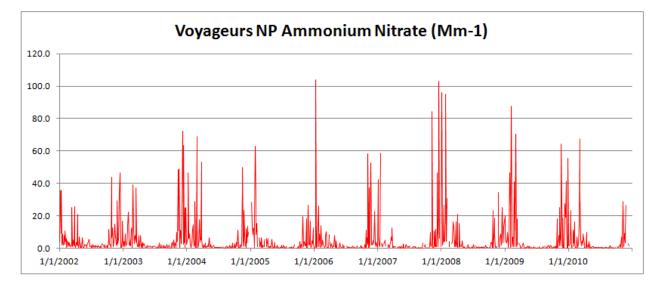
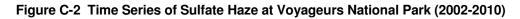
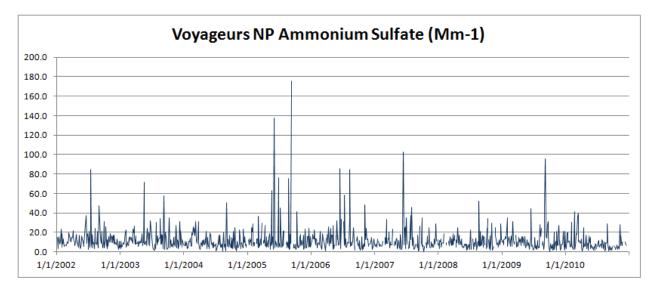
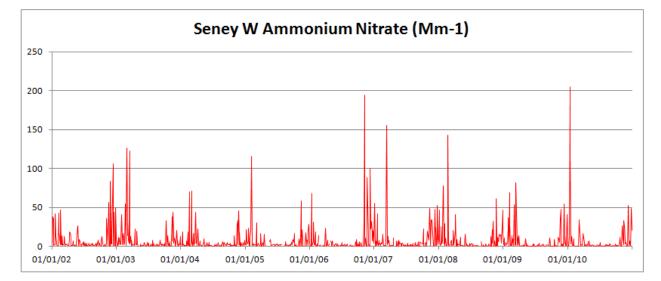


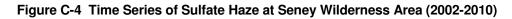
Figure C-1 Time Series of Nitrate Haze at Voyageurs National Park (2002-2010)

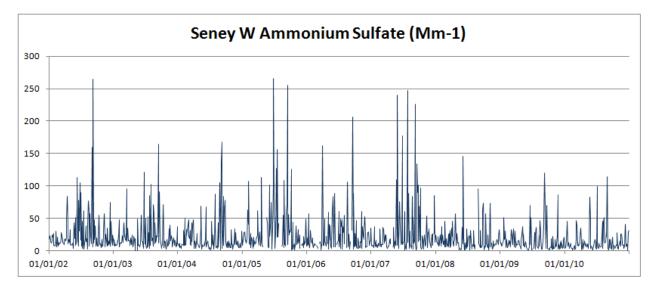


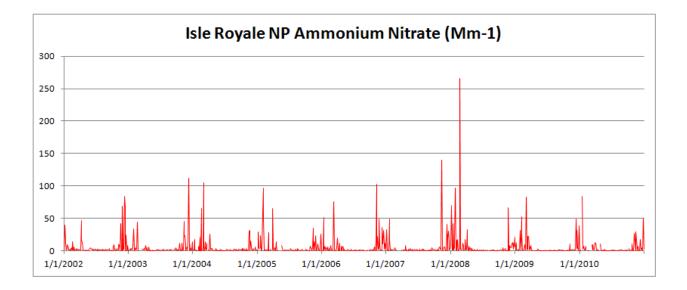




# Figure C-3 Time Series of Nitrate Haze at Seney Wilderness Area (2002-2010)

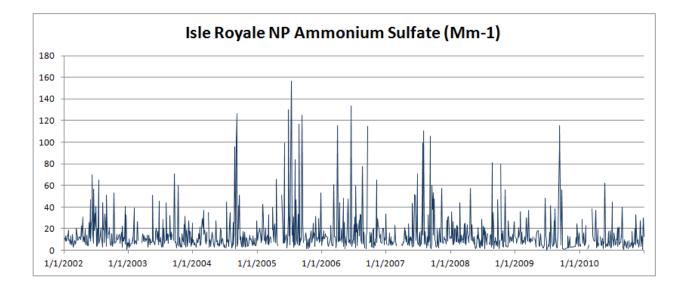






# Figure C-5 Time Series of Nitrate Haze at Isle Royale National Park (2002-2010)

### Figure C-6 Time Series of Sulfate Haze at Isle Royale National Park (2002-2010)



# APPENDIX D

# EXAMPLE OF VISIBILITY CHANGES AFTER ACTUAL EMISSION REDUCTIONS: SHUTDOWN OF THE MOHAVE GENERATING STATION

The Mohave Generating Station (MGS) shut down at the end of 2005, which should have had a large, beneficial effect (over 2 dv, according to CALPUFF) upon Grand Canyon visibility on the 98<sup>th</sup> percentile worst days. The MGS was a large (1590 MW) coal-fired plant located near the southern tip of Nevada (Laughlin, NV). MGS was placed in operation in the early 1970s, and was retired at the end of 2005 as a result of a consent agreement with the United States Environmental Protection Agency (EPA). The agreement had provided MGS with the option of continued operation if state-of-the-art emissions controls were installed for SO<sub>2</sub> and NOx emissions, but the owners determined that the cost of controls was too high to justify the investment. As a result, the plant was shut down on December 31, 2005 and has not been in operation since then.

As shown in Figure C-1, the MGS location is about 115 km away from the closest point of the Grand Canyon National Park, for which a southwesterly wind is needed to carry the emissions from MGS to most of the park. A multi-year study<sup>39</sup> completed by the EPA in 1999 (Project MOHAVE) indicated that MGS could be a significant contributor to haze in the Grand Canyon. In fact, typical annual emissions from MGS during the last several years of operation were approximately 40,000 tons per year (TPY) of SO<sub>2</sub> and 20,000 TPY of NOx. EPA noted in their Project MOHAVE conclusions that due to this level of emissions of haze precursors and its proximity to the Grand Canyon, MGS was the single largest emission source that could cause regional haze within the Grand Canyon.

Haze observations at three locations in the Grand Canyon (Meadview, Indian Garden, and Hance Camp monitors are available every third day for periods both before and after the plant shut down at the end of 2005. By comparing haze measurements before and after plant shutdown, it may be possible to determine whether the haze in the Grand Canyon has perceptibly changed since 2005 by reviewing the data from these three monitors. The Meadview monitor is at the western edge of the Park, and is relatively close to MGS. The other two IMPROVE monitors are located near some of the most heavily visited areas of the park (Hance Camp, on the South Rim, and Indian Garden, about 1,100 feet lower near the bottom of the canyon).

A 2010 *Atmospheric Environment* paper by Terhorst and Berkman<sup>40</sup> studied the effects of the opportunistic "experiment" afforded by the abrupt shutdown of the largest source affecting the Grand Canyon (according to EPA). The paper noted that Project MOHAVE's conclusions about the effects of MGS on the Grand Canyon visibility were ambiguous. The project's tracer studies revealed that while the MGS emissions did reach the park, particularly in the summer, there was no evidence linking these elevated concentrations with actual visibility impairment; indeed, "correlation between measured tracer concentration and both particulate sulfur and light extinction were virtually nil."

On the other hand, dispersion models produced results inconsistent with the observations. Noting the disconnect between the measurements and model predictions, EPA noted the disparity between the measurements and modeling results, but still appeared to favor the models when it concluded that MGS was the largest sole contributor to visibility impairment in the Grand Canyon.

September 2012

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

<sup>&</sup>lt;sup>39</sup> Pitchford, M., Green, M., Kuhns, H., Scruggs, M., Tombach, I., Malm, W., Farber, R., Mirabella, V., 1999. Project MOHAVE: Final Report. Tech. Rep., U.S. Environmental Protection Agency (EPA).

<sup>&</sup>lt;sup>40</sup> Jonathan Terhorst and Mark Berkman. "Effect of Coal-Fired Power Generation on Visibility in a Nearby National Park," Atmospheric Environment, 44(2010) 2544-2531. This publication is available by request from Mark Berkman at <u>mark.berkman@berkeleyeconomics.com</u>.

According to the authors, the Project Mohave observations were consistent with observations during temporary outages of MGS, for which there were no reports of substantial changes to visibility in the Grand Canyon.

Best Available Retrofit Technology (BART) studies evaluated a possible conversion of MGS to natural gas firing in 2008. These studies used the CALPUFF dispersion model in a manner prescribed by EPA to determine the change in visibility between the baseline emissions associated with coal firing to the natural gas firing alternative. The BART analyses conducted by the Nevada Department of Environmental Protection indicated that large differences in haze would result: an improvement of about 2.4 deciviews for the 98<sup>th</sup> percentile peak day, and a haze reduction to below 0.5 deciview on 186 days over 3 years modeled. Since natural gas firing would eliminate nearly all of the SO<sub>2</sub> emissions (although not all of the NOx emissions) this modeled result would tend to underestimate the visibility improvement that would be anticipated with a total plant shutdown.

Terhorst and Berkman analyzed several statistics to determine the change in sulfate concentrations and visibility in the Grand Canyon between the period 2003-2005 (pre-shutdown) and the period 2006-2008 (post-shutdown). They also considered other areas to determine how other regional and environmental effects might be reflected in changes at the Grand Canyon. Terhorst and Berkman calculated the average visibility over all IMPROVE monitoring days between 2003-2005 and 2006-2008, and determined that the average visibility was unchanged at Meadview, slightly improved on the South Rim (Hance Camp), and slightly worse at Indian Garden. Consistent with the observations of minimal visibility impact of MGS during Project MOHAVE, they concluded that the closure of MGS had a relatively minor effect on visibility in the Grand Canyon. These authors questioned the veracity of CALPUFF modeling (e.g., for BART) in that it predicts relatively large improvements in the Grand Canyon visibility that are not borne out by observations.

Emissions reductions associated with the shutdown of the Mohave Generating Station at the end of 2005 have provided an opportunistic means to discern the effect of retrofitting emission controls on coal-fired power plants in the western United States. In the case of MGS, although EPA had determined that this facility was the single most important contributor to haze in the Grand Canyon National Park and CALPUFF modeling using EPA's BART procedures provided predictions of significant improvements in haze, actual particulate and haze measurements taken before and after the shutdown do not reflect the large reductions that would be anticipated from these studies. This may be due in part to the fact that there are several aspects to the CALPUFF modeling procedures that greatly inflate the predicted haze (as noted below), and therefore, the predicted improvements due to emission reductions.

# AECOM

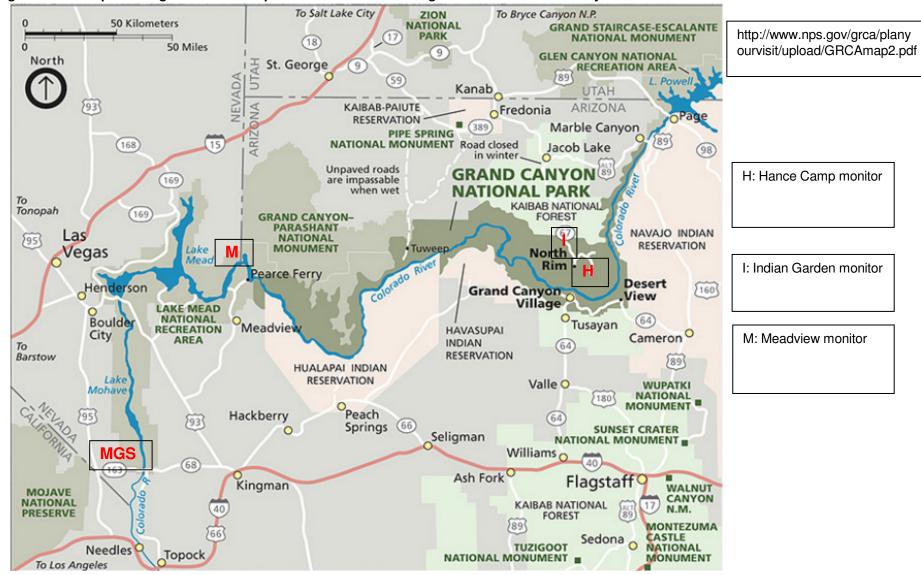


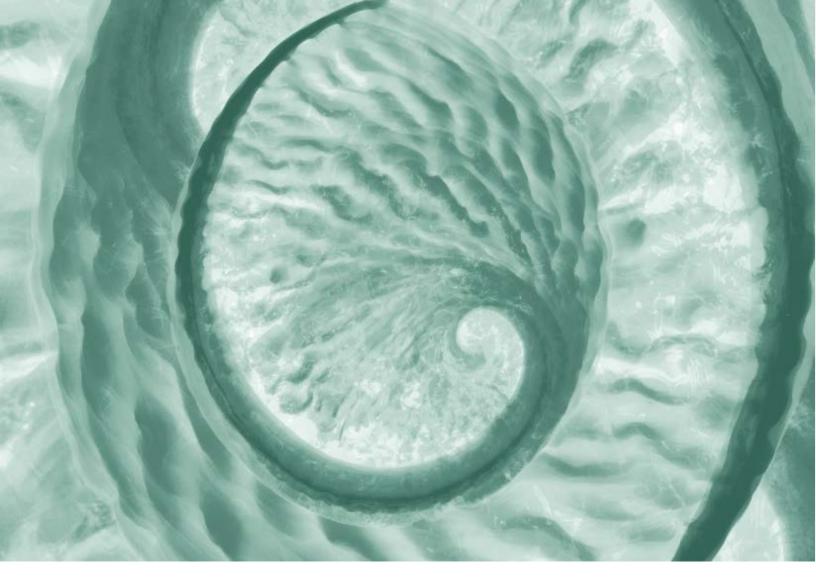
Figure D-1 : Map Showing the Relationship of the Mohave Generating Station to the Grand Canyon National Park

September 2012

Page 45 of 45

www.aecom.com

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas



# Four Factor Analysis

City of Virginia Department of Public Utilities Virginia, Minnesota

14 July 2020 Project No.: 0542312



| Document details  | This document documents the four factor analysis of the nitrogen oxide (NOx) emissions from Boiler #11 located at the City of Virginia Department of Public Utilities facility in Virginia, Minnesota. |
|-------------------|--|
| Document title    | Four Factor Analysis   |
| Document subtitle | City of Virginia Department of Public Utilities  |
| Project No.       | 0542312  |
| Date              | 14 July 2020   |
| Version           | FINAL  |
| Author            | Curnow   |
| Client Name       | City of Virginia   |

# CONTENTS

| 1. | INTRO   | DUCTIO    | Ν                                   | .1 |  |  |  |
|----|---|-----------|-------------------------------------|----|--|--|--|
| 2. | PLANT   | DESCR     | IPTION                              | .2 |  |  |  |
|    | <ul> <li>2.1 Nitrogen Oxide Emissions</li></ul> |           |                                     |    |  |  |  |
|    | 2.2   | Historica | Nitrogen Oxide Emissions Boiler #11 | .3 |  |  |  |
| 3. | FOUR-   | FACTOF    | RANALYSIS                           | .3 |  |  |  |
|    | 3.1   | Nitrogen  | Oxide Control Technology            | 3  |  |  |  |
|    |   | 3.1.2     | LNB                                 | 5  |  |  |  |
|    |   | 3.1.3     | OFA                                 | 5  |  |  |  |
|    |   | 3.1.4     | SNCR                                | 5  |  |  |  |
|    |   | 3.1.5     | SCR                                 |    |  |  |  |
|    | 3.2   |           | nmary                               |    |  |  |  |
|    | 3.3   | Time to I | mplement NO <sub>x</sub> Controls   | 7  |  |  |  |
|    | 3.4   |           | Quality Impacts                     |    |  |  |  |
|    | 3.5   | Remainir  | ng Useful Life                      | .8 |  |  |  |
| 4. | SUMM  | ARY       |                                     | .8 |  |  |  |

| ANUAL |
|-------|
|       |
| 41    |

# List of Tables

| Table 1: Continuous NO <sub>x</sub> Emission Monitor for Boiler #11                      | 3 |
|--|---|
| Table 2: Historical NO <sub>x</sub> Emissions for Boiler #11                             | 3 |
| Table 3: Boiler #11 SCR NO <sub>x</sub> Control Cost Estimate Summary                    | 7 |
| Table 4: Impacts of Potential NO <sub>x</sub> Add-on Control Technologies for Boiler #11 | 8 |

#### 1. INTRODUCTION

Under 40 Code of Federal Regulation Part 52 Subpart P (Subpart P) Section 51.308, states are required to develop a long-term strategy for regional haze. Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for those areas located outside the State that may be affected by emissions from the State. The long-term strategy must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress toward achieving natural visibility conditions in the affected Class I Federal area.

Subpart P, Section 51.308(f)(2)(i) requires the State to evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering four factors:

- Cost of compliance.
- 2. Time necessary for compliance.
- Energy and non-air quality environmental impacts of compliance. 3.
- Remaining useful life of any potentially affected emission unit. 4.

The State Implementation Plan must include a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress. Revisions to the Minnesota regional haze implementation plan are due to the United States Environmental Protection Agency (USEPA) by July 31, 2021, and the implementation period is 10 years to demonstrate progress toward attaining the visibility goals.

In a letter dated January 29, 2020, the Minnesota Pollution Control Agency (MPCA) requested that the Virginia Department of Public Utilities (VDPU) conduct a four-factor analysis of the nitrogen oxide (NOx) and sulfur dioxide (SO<sub>2</sub>) emissions from Boiler #9 (EQUI 3 / EU 003) and Boiler #11 (EQUI 16 / EU 006). In subsequent conversations with the MPCA, Boiler #9 was removed from the requirement to perform the analysis since VDPU plans to be shutting the boiler down in the near future. This analysis focuses only on Boiler #11 and only for NO<sub>x</sub>. The listing of SO<sub>2</sub> as a pollutant from the wood boiler that needed to be analyzed was confirmed by the MPCA to be a typographical error in the MPCA request letter. Sulfur dioxide is not a pollutant that is emitted in large quantities from wood combustion due to the low amounts of sulfur contained in the fuel source.

The Class 1 areas in proximity to VDPU are Boundary Waters Canoe Area Wilderness and Voyageurs National Park (Voyageurs). The Boundary Waters Canoe Area Wilderness is approximately 29 miles from VDPU at the closest point and over 54 miles to the center of the wilderness area. Voyageurs is approximately 54 miles from VDPU at the closest point and over 67 miles to the center of the park. A site location map showing the VDPU and Boiler #11 stack relative to the Class 1 areas is provided in appendix A.

This report documents the four-factor analysis for controlling NO<sub>x</sub> emissions from Boiler #11 at VDPU. A brief description of VDPU and Boiler #11 emissions is provided in Section 2 of the report. Section 3 of this report includes the four-factor analysis. Subsections in Section 3 include:

Information on technically feasible control technology available for NO<sub>x</sub> reductions and the cost of control.

- The time schedule necessary for implementing a control strategy is described in general terms accounting for project approval, engineering design, bidding, procurement/contracting, construction, and commissioning.
- The non-air guality impacts of compliance are identified and costs estimated to the extent possible. These include truck traffic, electrical use, solid waste generation, and water use.
- The remaining useful life of Boiler #11 is discussed in terms of the maintenance of the unit and projects for remaining life of the unit before a major overhaul or replacement is due.
- Finally, a summary of the information presented in Section 3 of the report. A general discussion of cost effectiveness is included in the summary section. This discussion is based on review of published information on the reasonableness cost per ton of NO<sub>x</sub> and SO<sub>2</sub> removed as related to visibility improvement.

Finally, a summary of the four-factor analysis is presented in Section 4 of the report. A general discussion of cost effectiveness is included in the summary section. This discussion is based on review of published information on the reasonableness cost per ton of NO<sub>x</sub> removed as related to visibility improvement.

#### 2. PLANT DESCRIPTION

The VDPU operates a co-generation facility for the city of Virginia. The facility has the ability to generate electricity and steam. If electricity is generated, it would be sold to the electrical grid. Steam is used for space heating of nearby businesses, schools, and residences. The VDPU is considered a district heating plant and is located in downtown Virginia, in close proximity to its steam customers.

VDPU operates in accordance with a federal Part 70 Permit number 13700028-101, issued on March 21. 2019. The emission units at the facility consist of two coal-fired boilers Boiler #7 (EQUI 2) and Boiler 9 EQUI 3) [formerly known as EU001 & EU003], a natural gas-fired boiler Boiler #10 (EQUI 4) [formerly known as EU004], a wood-fired boiler Boiler #11 (EQUI 16) [formerly known as EU006], fuel storage and transfer systems, and ash handling systems.

On May 11, 2020 a permit modification application was submitted to the MPCA which included the planned decommissioning of coal-fired Boiler #9. The permitting to remove Boiler #9 from the operating permit is currently on hold with the MPCA, however, VDPU considers the boiler permanently retired. The boiler is currently not operational due to mechanical issues. Furthermore, the air operating permit will not allow Boiler #9 to be operated past September 2020 because the stack height has not been raised which was a condition of demonstrating compliance with the 1-hour SO<sub>2</sub> national ambient air quality standard. Boiler #9 has not been operated since April 30, 2019. Because Boiler #9 is effectively retired, it is not included in the four factor analysis.

Boiler #11 was permitted in 2005 and was required to demonstrate Best Available Control Technology (BACT) and compliance with the National Ambient Air Quality Standards in place at that time (Permit No. 13700028-005). A gas burner was permitted (Permit No. 13700028-011) and installed in 2015 to assist in stabilizing combustion to lower carbon monoxide (CO) emissions. Due to the fluctuation of the moisture content of the wood fuel being received the combustion efficiency was experiencing swings which lead to CO emissions exceeding permit limits too frequently.

Boiler #11 uses selective non-catalytic reduction for NO<sub>x</sub> control and a multi-cyclone followed by an electrostatic precipitator for particulate matter control. The boiler is also equipped with an opacity monitor, NO<sub>x</sub> monitor, and CO monitor,

#### 2.1 Nitrogen Oxide Emissions

Selective Non-Catalytic Reduction (SNCR) was determined to be BACT when Boiler #11 was originally permitted in 2005. A review of recent NO<sub>x</sub> monitor reading information is listed in Table 1.

| Value Description  | NO <sub>x</sub> (ppm) | NO <sub>x</sub> (Ib/MMBtu) |
|--------------------|-----------------------|----------------------------|
| Minimum            | 39.4                  | 0.094                      |
| Maximum            | 80.2                  | 0.175 <sup>1</sup>         |
| Range <sup>2</sup> | 40.8                  | 0.081                      |
| Average            | 54.1                  | 0.121                      |

# Table 1: Continuous NO<sub>x</sub> Emission Monitor for Boiler #11

1 Permit limit for Boiler #11 is 0.15 lb/MMBtu based on a 30-day average. The value show in this table is one instance in time not a 30 day average.

2 Range is the difference between the highest (maximum) and the lowest (minimum) within a set of numbers.

The potential emissions of NO<sub>x</sub> for Boiler #11 while burning wood are 34.5 pounds and hour and 120 tons per year. The NO<sub>x</sub> emissions from wood combustion are higher than if wood and natural gas combustion were occurring simultaneously. When both wood and natural gas are being combusted in Boiler #11 the potential NO<sub>x</sub> hourly emission rate is 27.11 pounds and the potential annual emission rate is 119 tons.

The potential and actual emission rates for NO<sub>x</sub> while burning natural gas are based on USEPA AP-42 Emission Factors. The actual emission rates for NO<sub>x</sub> are based on the CEM. The potential NO<sub>x</sub> emission rate is based on a permit limit.

#### 2.2 Historical Nitrogen Oxide Emissions Boiler #11

The actual annual NO<sub>x</sub> emissions for Boiler #11 have decreased each year from 2016 to 2019, during which time the average annual emissions were 63.21 tons per year (tpy). Table 2 provides the actual annual NO<sub>x</sub> emission rates from 2016 to 2019 for Boiler #11.

| Year | NO <sub>x</sub> (tpy) |
|------|-----------------------|
| 2016 | 89.9                  |
| 2017 | 82.84                 |
| 2018 | 42.03                 |
| 2019 | 38.05                 |

# Table 2: Historical NO<sub>x</sub> Emissions for Boiler #11

#### 3. FOUR-FACTOR ANALYSIS

The following is the four-factor analysis. The following subsections present information on the cost of supplemental NO<sub>x</sub> control, the time necessary to implement controls, the energy and non-air quality environmental impacts of implementing controls, and the remaining useful life of Boiler #11.

#### 3.1 Nitrogen Oxide Control Technology

A BACT analysis was completed for Boiler #11 when it was initially permitted in 2005. That analysis indicated that SNCR and a NO<sub>x</sub> emission rate of 0.15 pounds per million (MM) British thermal units was BACT. An excerpt from the technical support document that was attached to the operating permit is provided below.

# MPCA Technical Support Document, Permit Action Number: 13700028-005 Page 17 of 64, 7/11/2005

Nitrogen oxide controls from the RBLC database records indicate a wide range of technologies as BACT, including no control, combustion control, SNCR and SCR. Again the most stringent control, SCR appears in the permit for RBLC record OH-0269, however that facility has not been constructed and the permit has expired. BACT emission rates range from 0.15 to 0.40 pounds per million Btu. excluding OH-0269 which has not been constructed. The lowest BACT emission rate for a constructed and operating facility is 0.15 lbs/MMBtu from the District Energy St. Paul facility, which employs SNCR technology.

In August 2010 the EPA published Documentation for Integrated Planning Model (IPM) Base Case that included NO<sub>x</sub> emission control information prepared by an engineering firm Sargent and Lundy (EPA 2020) https://www.epa.gov/airmarkets/documentation-integrated-planning-model-ipm-base-case-v410. Sargent and Lundy performed a complete bottom-up engineering reassessment of the cost and performance assumptions NO<sub>x</sub> emission controls for large utility coal fired boilers. The study is not directly relatable to smaller wood boiler, but the identified control technologies available for NO<sub>x</sub> control would be the same.

Available control options identified are:

- Low NO<sub>x</sub> burner (LNB) without over fire air (OFA),
- LNB with OFA,
- OFA
- Selective Catalytic Reduction (SCR)
- SNCR

A new search of the United States Environmental Protection Agency RACT/BACT/LAER Clearinghouse (RBLC) was conducted on June 30, 2020, to identify what NO<sub>x</sub> control strategies are in place for woodfired/natural gas boilers around the country and what emission levels represent the BACT. BACT limits are emission rates and are determined on a case-by-case basis. The BACT emission rates are used in this report for comparison purposes only and do not represent an applicable standard.

A RBLC search for Process Type 12.120 Industrial Boiler firing Biomass (includes wood and wood waste) and Process Type 11.120 Utility and Large Industrial Boiler firing Biomass (includes wood and wood waste) for January 1, 2010 through June 30, 2020 found 19 entries. Of the 19 entries found in the RBLC 10 were noted as having SNCR and 7 indicated SCR. The seven entries that indicated SCR was being used for control, only one, Berlin Station LLC, which has a rated capacity of 1,013 Million British thermal units (MMBtu)/hour (over 4 times large than Boiler #11) has been built and is operating. The Berlin Station boiler was the only boiler able to be confirmed was actually built with SCR. The boiler was required to comply with the Lowest Achievable Emission Rate (LAER) requirements. The Boiler's noted as having SCR are much larger in capacity (464 MMBtu/hour to 1,200 MMBtu/hour) than Boiler #11 (230 MMBtu/hour). The other entries found were listed as having low NO<sub>x</sub> burners. Some boilers also indicated over fire air as part of the boiler design. A summary of the RBLC entries is attached as Appendix B.

LNB - Low NO<sub>x</sub> burners control the fuel and air mixture in order to create larger and more branched flames. This reduces the peak flame temperature and in turn reduces NO<sub>x</sub> formation.

Over Fire Air Systems - Additional NO<sub>x</sub> reduction can be achieved by integrating staged combustion (overfire air) into the overall system. OFA can be used by itself but is most often used in conjunction with other NO<sub>x</sub> reduction systems.

**SNCR** - Like the SCR system, SNCR also converts NO<sub>x</sub> into nitrogen and water. However, no catalyst is used, instead the reagent is injected at a high temperature.

SCR – SCR uses a liquid reducing agent in combination with a catalyst to convert NOx into nitrogen and water. The reducing agent most commonly used is ammonia.

#### 3.1.2 LNB

The wood fired boiler is a stoker boiler which means a solid fuel (in this case wood) is mechanically fed into the combustion chamber and the fuel sits on top of a grate during combustion. The wood that is added is in chip form which is around 3 inches in size. LNB is not a fuel delivery option for this type of a solid fuel. LNB is not technically feasible and eliminated from additional discussion for wood combustion.

The natural gas burners, installed in 2015 to stabilize combustion are LNB. Natural gas is being used to manage the moisture content of the wood-fuel source. Natural gas is not the primary fuel and not the focus of this analysis.

#### 3.1.3 **OFA**

OFA system is a design feature of boilers to ensure adequate air to promote combustion efficiency. In Boiler #11, air for combustion is supplied from two separate sources, undergate air and overfire air. The undergate air supplies 60 percent of the required combustion air while the OFA makes up the remaining 40 percent. The OFA system provides combustion air to a serious of fixed nozzles that penetrate the furnace front and rear walls. There are three elevations of nozzles on the front wall and four elevations of nozzles on the rear wall. The nozzles are optimized to inject air above the grate into a zone where suspension burning takes place. Different nozzle elevations are used to optimize combustion while minimizing emissions from combustion. Both systems are required to be operating when wood is being combusted.

A portion of the operator's manual provided by Foster Wheeler, which provides a detailed description of the OFA system is provided in Appendix C. The air permit for Boiler #11 does not list OFA as a pollution control device because it is considered a factor of boiler design not an add-on control system.

Compliance with 40 Code of Federal Regulation Part 63 Subpart DDDD National Emission Standards for Hazardous Air Pollutants for Major Sources; Industrial, Commercial, and Institutional Boilers and Process Heater more commonly referred to as "Boiler MACT" requires Boiler #11 to be tuned annually. The tuneups focus on boiler efficiency, which is related to air emissions.

#### 3.1.4 **SNCR**

Boiler #11 has a SNCR system for NO<sub>x</sub> reduction, and as such no additional discussion on this technology is provided since it is already in use.

#### 3.1.5 SCR

SCR is the highest-performing control option currently available. According to the USEPA Air Pollution Control Technology Fact Sheet for SCR (EPA-452/F-03-032), SCR is capable of NO<sub>x</sub> reduction efficiencies in the range of 70 to 90% (ICAC, 2000). A copy of the USEPA fact sheet is provided in Appendix D. Higher reductions are noted by USEPA as possible but generally not cost-effective. SCR makes use of a catalyst with ammonia injection. The catalyst improves the efficiency of the chemical

reduction of NO<sub>x</sub> by ammonia. The SCR is designed to evenly distribute the flow of NO<sub>x</sub> across a catalyst surface, and provide thorough mixing of the injected ammonia to facilitate reduction and thus removal of  $NO_x$ . The catalyst requires gas at a sufficient temperature for the chemical reaction to occur. The boiler exhaust gas also requires particulate removal prior to the SCR to prevent fouling of the catalyst.

The potential use of SCR for control of NO<sub>x</sub> from the Boiler #11 was evaluated as BACT when the boiler was originally permitted in 2005. The BACT analysis completed as part of the 2005 permit action indicated that SCR was an infeasible NO<sub>x</sub> control option for a wood-fired boiler. The reason the technology was considered infeasible was because of the higher levels of silicates and other constituents found in biomass fuels which lead to rapid fouling of the catalyst bed, greatly reducing the effectiveness of the SCR system, and leading to significant down time and expense in replacing the catalyst.

The RBLC review completed for this analysis did note some wood-fired boilers that have been permitted with SCR. The boilers listed as using SCR for NO<sub>x</sub> control are all much larger than Boiler #11 and most likely, operate at a higher capacity factor. Two of the entries that cited SCR were noted the basis for the technology as a requirement to permit at LAER. Boiler #11's primary function at VDPU is to serve the district heating system. VDPU does have some demand for steam in the summer but the majority of the steam production is during the heating season. The VDPU steam customer base continues to decrease as some former entities are relocating outside of the service area or transitioning to their own onsite steam production/heat production.

#### 3.2 Cost Summary

SCR is the only NO<sub>x</sub> reduction technology reviewed for cost since Boiler #11 already uses SNCR and the boiler design includes OFA. Low NO<sub>x</sub> burners are not applicable to wood. The natural gas fired combustion stabilization burners are low NO<sub>x</sub> but the combustion stabilizing burners are not part of this assessment. No other technology was found for application to this boiler system.

In order for an SCR to work on Boiler #11, the current ESP system would need to be replaced with a hot side ESP or, as an alternative, the air stream could be reheated to achieve sufficient temperature for the catalyst reaction. Catalysts require temperatures ranging from 480 degrees Fahrenheit (°F) to 800°F (ICAC, 1997). The exhaust temperature entering the existing ESP is at about 400 °F and would not be expected to change significantly upon the exit of the ESP.

As indicated earlier, SCR is typically applied to large coal and natural gas fired electrical utility boilers sized larger than what VDPU operates. The fact sheet does say SCR can be effective for large industrial boilers if the capacity factor is high enough. USEPA only refers to applying SCR technology to coal and natural gas fired boilers.

USEPA directly states that capital costs for SCR are significantly higher than other types of NOx controls due to the large volume of catalyst that is required. The cost of the catalyst is listed as \$283/cubic foot (ft<sup>3</sup>). In addition, retrofitting SCR to an existing unit can increase costs by over 30 percent (EPA, 2002).

Table 3 summarizes the cost of retrofitting Boiler #11 with an SCR NO control system. Costs are based on the USEPA "Air Pollution Control Technology Fact Sheet" for SCR, Table 1a Summary of Cost Information in \$/MMBtu/hr (1999 Dollars) for Industrial Oil, Gas, and Wood boilers. The fact sheet is included as Appendix D.

| Parameter   | SCR                |
|---|--------------------|
| Capital Cost  | \$1,150,000        |
| 30% Retrofit Add-on   | \$345,000          |
| O&M Cost  | \$103,500          |
| Annual Cost   | \$161,000          |
| SCR Subtotal (1999 \$)  | \$1,759,500        |
| SCR Subtotal Adjusted for 2020 \$ <sup>a</sup>  | \$2,707,803        |
| Pre-heater for exhaust <sup>b</sup>   | Cost not available |
| Emission reduction (85% total which is 53.2% above the existing SNCR system at 31.8%) | 53.2%              |
| Emission reduction <sup>c</sup> (tpy)   | 42.07              |
| Cost of emission reduction (\$/ton)   | \$64,364+          |

a According to the Bureau of Labor Statistics consumer prices in 2017 were 47.13% higher than in 1999. The inflation rate between 2017 and 2020 averaged 1.51% per year.

b Preheater for exhaust in lieu of a hot side ESP. The cost for the preheater was not available but listed in the table in order to identify it as another cost with both capital and operating impacts.

c Emission reduction is based on 2016 emissions of 89.9 tons of NO<sub>x</sub> which could be reduced by another 53.2% potentially by retrofitting Boiler #11 with SCR for NO<sub>x</sub> reduction.

The cost to retro fit Boiler #11 with SCR would be 64,364 per ton of NO<sub>x</sub> removed. That value does not include the cost to increase the heat of the ESP exhaust to a sufficient temperature for the catalyst. Since the dissolution of the Xcel Power Purchase Agreement for renewable power, the wood boiler has seen a reduction in use as evident in the summary of historical actual emissions. The trend of reduced operation for Boiler #11 is expected to continue.

# 3.3 Time to Implement NO<sub>x</sub> Controls

To implement SCR would involve the following steps and durations:

- Budgetary design and project approval (12 months),
- Detailed engineering design and bid documents (6-9 months),
- Bid solicitation, evaluation and selection (3-4 months),
- Procurement/contracting (3-4 months),
- Construction (6-10 months), and
- Commissioning (2-3 months).

This leads to an overall schedule of 32-42 months from concept to operation.

# 3.4 Non-Air Quality Impacts

This section outlines in general terms the non-air quality related impacts that would result from implementing SCR on Boiler #11. Table 4 shows the impacts in general terms. For example, SCR uses a catalyst which are made from various ceramic materials such as titanium oxide or oxides of base metals

(such as vanadium, molybdenum and tungsten), zeolites, or various precious metals. Mining to obtain catalyst materials has environmental implications

| Technology                    | SCR |
|-------------------------------|-----|
| Electrical Energy Consumption | Yes |
| Transportation Impacts        | Yes |
| Solid Waste Generation        | Yes |
| Increased Water Consumption   | Yes |

In addition, retrofitting Boiler #11 to support SCR will result in greenhouse gas (GHG) emissions from, construction, truck traffic, material manufacturing, and electrical use. Assuming that the electricity to power the control systems is from some fossil fuel-fried generation, then the increased electrical demand would result in GHG emissions.

# 3.5 Remaining Useful Life

Boiler #11 began operating in 2006 and the expectation is that it will last about 25 years with proper maintenance. That means the remaining useful life of Boiler #11 is greater than 10 years.

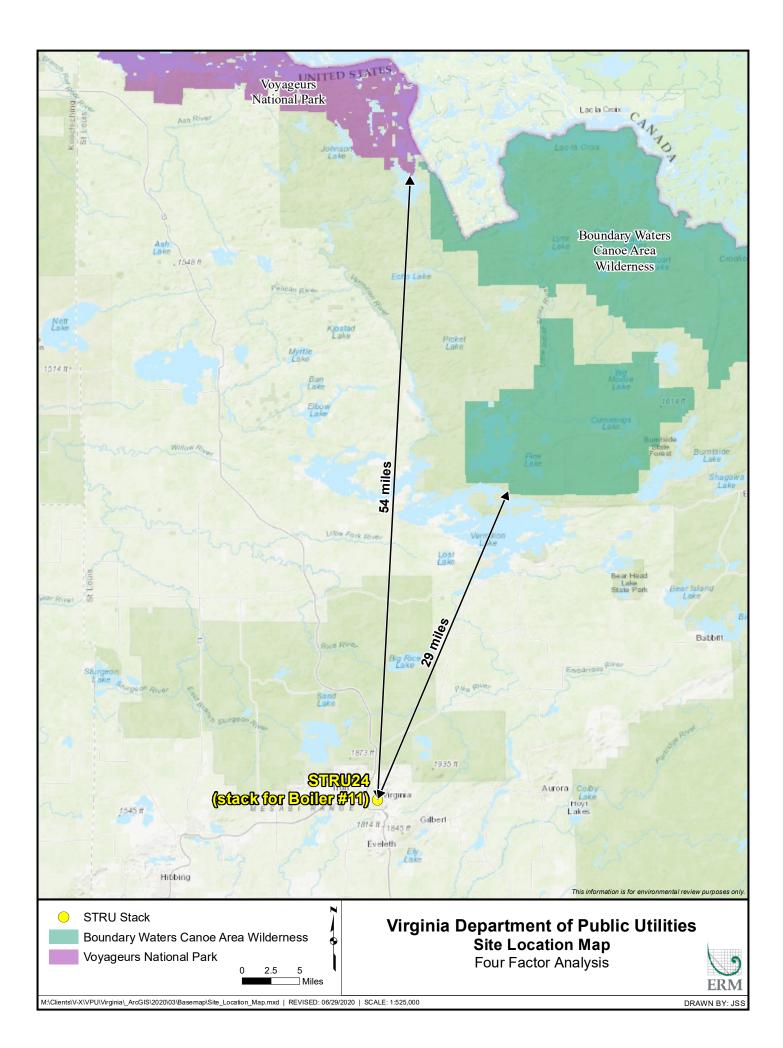
# 4. SUMMARY

Review of available information suggests that the cost criteria for visibility improvement is less than that for BACT; however, the target values for economic feasibility are generally not published and are evaluated on a case-by-case basis. The USEPA 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) provides guidance for states to establish control evaluation criteria, such as:

"...measures that cost less than \$X/ton and that result in either (1) a visibility benefit greater than Y deciview at the most impacted Class I area or (2) cumulative visibility benefits across multiple affected Class I areas greater than Z deciview."

In the case of additionally controlling NO<sub>x</sub> emissions from the Boiler #11 at VDPU, the only available technology would be to replace the SNCR system with SCR. The cost of a SCR system has been calculated to be to the SNCR is over \$63,364 per ton of NO<sub>x</sub> removal. This level of cost effectiveness would not be considered cost effective for BACT control, and should be considered cost-prohibitive for visibility protection.

# APPENDIX A SITE LOCATION MAP



APPENDIX B RACT/BACT/LAER SUMMARY

# Appendix B Reasonably Available Control Tecnology, Best Available Control Technology, Lowest Available Emission Rate Clearinghouse RBLC Database Summary - EPA Database Accessed on June 30, 2020

# **Wood-Fired Boilers**

| RBLC ID | Company   | Boiler Size<br>(MMBtu/hr) | Pollutant       | Limit | Units     | Technology   |       | Permit Issuance Date | Process<br>Type <sup>1</sup> |
|---------|---|---------------------------|-----------------|-------|-----------|--|-------|----------------------|------------------------------|
| ME-0040 | Robbins Lumber, Inc.  | 167.3                     | NO <sub>x</sub> | 25.1  | lb/hr     | Flue Gas Recirculation (FGR)/Selective Non-catalytic Reduction (SNCR)  | BACT  | 6/30/2017            | 12.120                       |
| MI-0425 | Arauco North America Grayling Particleboard   | 110                       | NO <sub>x</sub> | 95    | lb/hr     | Good combustion practices, low NO <sub>x</sub> burners (LNB)   | BACT  | 5/9/2017             | 12.120                       |
| MI-0421 | Arauco North America Grayling Particleboard   | 110                       | NO <sub>x</sub> | 95    | lb/hr     | Good combustion practices, LNB   | BACT  | 8/26/2016            | 12.120                       |
| SC-0149 | Klausner Holding USA, Inc.  | 120                       | NO <sub>x</sub> | 0.14  | lb/MMBtu  | SNCR   | Other | 1/3/2013             | 12.120                       |
| FL-0332 | Highlands Envirofuels (HEF), LLC<br>Highlands Biorefinery and Cogeneration Plant      | 458.5                     | NO <sub>x</sub> | 0.1   | lb/MMBtu  | SNCR with urea or $NH_3$ injection, and LNB  | BACT  | 9/23/2011            | 12.120                       |
| FL-0322 | Southeast Renewable Fuels (SRF), LLC<br>Sweet Sorghum-to-Ethanol Advanced Biorefinery | 536                       | NO <sub>x</sub> | 0.1   | h/N/N/Rtu | Good combustion practices, SNCR, Selective Catalytic Reduction (SCR), or combination with urea or $NH_3$ injection | BACT  | 12/23/2010           | 12.120                       |
| AR-0161 | Sun Bio Material Company  | 1,200                     | NO <sub>x</sub> | 0.06  | lb/MMBtu  | SCR  | BACT  | 9/23/2019            | 11.120                       |
| FL-0359 | US Sugar Corporation  | 1,077                     | NO <sub>x</sub> | 0.1   | lb/MMBtu  | SNCR (NH <sub>3</sub> injection)   |       | 11/29/2016           | 11.120                       |
| KS-0034 | Abengoa Bioenergy Biomass of Kansas (ABBK)  | 500                       | NO <sub>x</sub> | 0.3   | lb/MMBtu  | SCR and Over-fire system (OFA)   | BACT  | 5/27/2014            | 11.120                       |
| CA-1225 | Sierra Pacific Industries   | 468                       | NO <sub>x</sub> | 0.13  | lb/MMBtu  | SNCR   | BACT  | 4/25/2014            | 11.120                       |
| VT-0039 | North Springfield Sustainable Energy Project, LLC                                     | 464                       | NO <sub>x</sub> | 0.03  | lb/MMBtu  | Bubbling fluidized bed boiler design and SCR   | BACT  | 4/19/2013            | 11.120                       |
| GA-0141 | Ogethorpe Power Corporation<br>Warren County Biomass Energy Facility                  | 341                       | NO <sub>x</sub> | 0.1   | lb/MMBtu  | SNCR   | BACT  | 12/17/2010           | 11.120                       |
| VT-0037 | Beaver Wood Energy Fair Haven, LLC  | 482                       | NO <sub>x</sub> | 0.03  | lb/MMBtu  | Good combustion control and SCR  | BACT  | 2/10/2012            | 11.120                       |
| ME-0037 | Verso Bucksport, LLC  | 817                       | NO <sub>x</sub> | 0.15  | lb/MMBtu  | SNCR   | BACT  | 11/29/2010           | 11.120                       |
| CA-1203 | Sierra Pacific Industries   | 335.7                     | NO <sub>x</sub> | 80    | ppm       | SNCR   | BACT  | 8/30/2010            | 11.120                       |
| NH-0018 | Berlin Station, LLC<br>Burgess Biopower   | 1,013                     | NO <sub>x</sub> | 0.06  | lb/MMBtu  | IBtuSCR with $NH_3$ injection <sup>2</sup> LAER $7/26/2010$  |       | 7/26/2010            | 11.120                       |
| CT-0156 | NRG Energy  | 600                       | NO <sub>x</sub> | 0.06  | lb/MMBtu  | Regenerative SCR   | LAER  | 4/6/2010             | 11.120                       |
| AL-0250 | Boise White Paper, LLC  | 435                       | NO <sub>x</sub> | 0.3   | lb/MMBtu  | LNB  | BACT  | 3/23/2010            | 11.120                       |
| TX-0553 | Lindale Renewable Energy, LLC   | 1,256                     | NO <sub>x</sub> | 0.15  | lb/MMBtu  | SNCR   | BACT  | 1/8/2010             | 11.120                       |

EPA Website: https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en

<sup>1</sup>The process codes searched were 12.100 Industrial-size boilers/furnaces - Solid Fuel & Solid Fuel Mixes (> 100 MMBtu/hr to 250 MMBtu/hr) and 11.120 - Utility - and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr) - <sup>2</sup>This entry is the only facility listed in the RBLC database under the process categories searched, that has been confirmed to have been built and is using an SCR for NO<sub>x</sub> control.

Notes:

The terms "RACT," "BACT," and "LAER" are acronyms for different program requirements under the NSR program.

RACT, or Reasonably Available Control Technology, is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas).

BACT, or Best Available Control Technology, is required on major new or modified sources in clean areas (i.e., attainment areas).

LAER, or Lowest Achievable Emission Rate, is required on major new or modified sources in non-attainment areas.

APPENDIX C EXCERPTS FROM FOSTER WHEELER OPERATORS MANUAL



The grate is fed onto the grate by means of two pneumatic fuel distributors situated on the furnace front wall. These are located above the grate and are evenly spaced across the width of the boiler. Each distributor receives litter from a metering feeder and blows it into the furnace using a variable pressure air stream.

The feeders are set up using a pulse air, rotating damper to regulate the front to back fuel trajectory onto the grate. Conveying air used by the feeders is supplied by a separate distributor air fan.

### **1) Fuel Feeders**

The boiler is equipped with two variable speed twin screw feeders that are used to regulate fuel feed to each pneumatic distributor. These are located above and in close proximity to each fuel distributor.

Biomass fuel is metered into the boiler at a controlled rate set by load demand. The feeders are supplied with integral fuel bins that receive biomass from the plant conveyor.

### m) Primary Air System (HTUsee Air & Flue Gas System DescriptionUTH)

A single variable speed motor driven FD fan provides combustion air to the grate. The fan is furnished with an inlet filter, venturi metering section and inlet silencer. Airflow control is split ranged using variable speed with inlet damper control at low load. The output of the fan is regulated from load demand from the combustion control system.

Air discharged from the fan is heated in the undergrate air heater prior to entering the undergrate air plenums.

### n) Secondary Air System (JUsee Air & Flue Gas System DescriptionUTH)

A single variable speed motor driven FD fan provides combustion air to the overfire air nozzles above the grate. The fan is furnished with an inlet duct, venturi metering section, intake silencer and inlet control damper. Airflow control is split ranged using variable speed with inlet damper control at low load. The output of the fan is regulated from load demand from the combustion control system.

Discharge air is heated and directed to a series of overfire air nozzles on the front and rear furnace walls.

### o) Distributor Air Fan

A single, constant speed distributor air fan is furnished to supply ambient air to the fuel distributors. The fan is set up to supply a constant amount of air and is unregulated by the operator.



### General

The following description should be read in conjunction with drawing No. <u>113925V-</u> <u>0202</u> Air & Flue Gas P&ID.

### Note:

FWL terminal points are designated as "TP FWL".

### **Combustion Air System**

Air for combustion is supplied from two separate sources, undergrate air and overfire air. Each system is sized to deliver approximately 60% and 40% respectively of the required total combustion air. It is necessary that both systems be in operation to operate the boiler when firing biomass fuel.

### Undergrate air

The undergrate air system provides combustion air to the under the grate air zones. A forced draft fan delivers ambient air to the grate taken from inside the building via an intake duct. The incoming air stream to the fan is metered through a venturi section 11FE-510, equipped with flow transmitter 11FT 510 (by others) and flow switch 11FSH 510 (by others). An intake silencer 11EDS 511 is furnished for noise attenuation downstream of the metering venturi.

An inlet louver damper 11EJM 511is furnished for low load control of airflow. This is driven by air operated actuator 11FY 510 in response to a 4-20mA control signal from the DCS combustion controls. The actuator is provided with open/closed limit switches 11ZSL510/ZSH 510 for proof of closed and purge positions.

The variable speed undergrate air fan is driven by an electric motor, 11MV 510 equipped with winding temperature thermostats. The fan is also equipped with bearing temperature monitors 11TE 510A/B.

The FD fan is equipped with a variable speed drive for discharge capacity control that is spilt ranged for operation with the inlet louver control damper. Fan speed is controlled from the characterized 4-20mA combustion control signal.

Pressure at the FD fan discharge is monitored by pressure transmitter 11PT 510 prior to being directed through a tubular air heater 11ESE 510 that is utilised to preheat the undergrate air. This is necessary with all high moisture fuels for optimum combustion conditions. The temperature of air leaving the air heater is unregulated and varies with load. Temperature is measured by transmitter 11TT 512.

The grate is divided into three separate air zones from front to back. These, in turn are subdivided into LH and RH sections for a total of six independent zones. Air to each zone can be biased by individual manual inlet dampers. Control of these dampers allows the

operator to manually bias the air split, front to back and side to side for optimum burning and emissions control.

WHEELER

Thermocouples 11TE 721A/B/C & 11TE 722 A/B/C are provided on the underside of the grate for temperature monitoring and alarm purposes.

### **Overfire Air**

FOSTE

The overfire air system provides combustion air to a series of fixed nozzles that penetrate the furnace front and rear walls. There are three elevations of nozzles on the front wall and four elevations on the rear wall (see DSCo. Manual for details). These are optimized during commissioning and set up to inject air above the grate into a zone where suspension burning takes place. Different nozzle elevations are selected in order to provide optimum combustion conditions with minimum emissions.

Secondary air is drawn from inside the boiler building through an intake duct. The duct is equipped with a venturi section 11FE 515 and transmitter 11FT 515 (by others) for flow metering purposes. A silencer 11EDS 510 is provided on the fan intake for noise attenuation purposes.

An inlet louver damper 11EJM 510 is furnished for low load control of airflow. This is driven by air operated actuator 11FY 515 in response to a 4-20mA control signal from the DCS combustion controls. The actuator is provided with open/closed limit switches 11ZSL 515/ZSH 515 for proof of closed and purge positions.

The overfire air fan is driven by a variable speed electric motor 11MV 515 equipped with winding temperature thermostats. The motor is also equipped with bearing temperature detectors TE-A-09-006A/006B.

The fan is equipped with inboard and outboard bearing temperature detectors 11TE 515A/B.

The overfire air fan is equipped with a variable speed drive for discharge capacity control that is spilt ranged for operation with the inlet louver control damper. Fan speed is controlled from the characterized 4-20mA combustion control signal.

Pressure at the overfire air fan discharge is monitored by pressure transmitter 11PT 515 prior to being directed through a tubular air heater 11ESE 511 that is utilised to preheat the overfire air. The temperature of air leaving the air heater is unregulated and varies with load. Temperature is measured by transmitter 11TT 517.

Preheated air is routed through a series of ducts to the front and rear overfire air nozzles into the furnace. Isolation dampers are provided on the nozzles for operational flexibility since some nozzles, or complete nozzle elevations may not be used during normal operation.

# APPENDIX D USEPA AIR CONTROL TECHNOLOGY FACT SHEET



# Air Pollution Control Technology Fact Sheet

Name of Technology: Selective Catalytic Reduction (SCR)

Type of Technology: Control Device - Chemical reduction via a reducing agent and a catalyst.

Applicable Pollutants: Nitrogen Oxides (NOx)

**Achievable Emission Limits/Reductions:** SCR is capable of NOx reduction efficiencies in the range of 70% to 90% (ICAC, 2000). Higher reductions are possible but generally are not cost-effective.

### Applicable Source Type: Point

**Typical Industrial Applications:** Stationary fossil fuel combustion units such as electrical utility boilers, industrial boilers, process heaters, gas turbines, and reciprocating internal combustion engines. In addition, SCR has been applied to nitric acid plants. (ICAC, 1997)

### **Emission Stream Characteristics:**

- a. Combustion Unit Size: In the United States, SCR has been applied to coal- and natural gasfired electrical utility boilers ranging in size from 250 to 8,000 MMBtu/hr (25 to 800 MW) (EPA, 2002). SCR can be cost effective for large industrial boilers and process heaters operating at high to moderate capacity factors (>100 MMBtu/hr or >10MW for coal-fired and >50 MMBtu/hr or >5MW for gas-fired boilers). SCR is a widely used technology for large gas turbines.
- b. Temperature: The NOx reduction reaction is effective only within a given temperature range. The optimum temperature range depends on the type of catalyst used and the flue gas composition. Optimum temperatures vary from 480°F to 800°F (250°C to 427°C) (ICAC, 1997). Typical SCR systems tolerate temperature fluctuations of ± 200°F (± 90°C) (EPA, 2002).
- c. Pollutant Loading: SCR can achieve high reduction efficiencies (>70%) on NOx concentrations as low as 20 parts per million (ppm). Higher NOx levels result in increased performance; however, above 150 ppm, the reaction rate does not increase significantly (Environex, 2000). High levels of sulfur and particulate matter (PM) in the waste gas stream will increase the cost of SCR.
- d. Other Considerations: Ammonia slip refers to emissions of unreacted ammonia that result from incomplete reaction of the NOx and the reagent. Ammonia slip may cause: 1) formation of ammonium sulfates, which can plug or corrode downstream components, and 2) ammonia absorption into fly ash, which may affect disposal or reuse of the ash. In the U.S., permitted ammonia slip levels are typically 2 to 10 ppm. Ammonia slip at this levels do not result in plume formation or human health hazards. Process optimization after installation can lower slip levels.

Waste gas streams with high levels of PM may require a sootblower. Sootblowers are installed in the SCR reactor to reduce deposition of particulate onto the catalyst. It also reduces fouling of downstream equipment by ammonium sulfates.

The pressure of the waste gas decreases significantly as it flows across the catalyst. Application of SCR generally requires installation a new or upgraded induced draft fan to recover pressure.

**Emission Stream Pretreatment Requirements:** The flue gas may require heating to raise the temperature to the optimum range for the reduction reaction. Sulfur and PM may be removed from the waste gas stream to reduce catalyst deactivation and fouling of downstream equipment.

### **Cost Information:**

Capital costs are significantly higher than other types of NOx controls due to the large volume of catalyst that is required. The cost of catalyst is approximately  $10,000 \text{ s/m}^3$  (283 s/ft<sup>3</sup>). A 350 MMBtu/hr natural gas-fired boiler operating at 85% capacity requires approximately  $17 \text{ m}^3$  (600 ft<sup>3</sup>). For the same sized coal-fired boiler, the required catalyst is on the order of 42 m<sup>3</sup> (1,500 ft<sup>3</sup>). (NESCAUM 2000).

SCR is a proprietary technology and designs on large combustion units are site specific. Retrofit of SCR on an existing unit can increase costs by over 30% (EPA, 2002). The increase in cost is primarily due to ductwork modification, the cost of structural steel, and reactor construction. Significant demolition and relocation of equipment may be required to provide space for the reactor.

The O&M costs of using SCR are driven by the reagent usage, catalyst replacement, and increased electrical power usage. SCR applications on large units (>100 MMBtu/hr) generally require 20,000 to 100,000 gallons of reagent per week (EPA, 2002). The catalyst operating life is on the order of 25,000 hours for coal-fired units and 40,000 hours for oil- and gas-fired units (EPA, 2002). A catalyst management plan can be developed so that only a fraction of the total catalyst inventory, rather than the entire volume, is replaced at any one time. This distributes the catalyst replacement and disposal costs more evenly over the lifetime of the system. O&M costs are greatly impacted by the capacity factor of the unit and annual versus seasonal control of  $NO_x$ .

O&M cost and the cost per ton of pollutant removed is greatly impacted by the capacity factor and whether SCR is utilized seasonally or year round.

| Unit Type                              | Capital Cost    | O&M Cost <sup>d</sup> | Annual Cost <sup>d</sup> | Cost per Ton of<br>Pollutant Removed |  |
|--|-----------------|-----------------------|--------------------------|--------------------------------------|--|
|  | (\$/MMBtu)      | (\$/MMBtu)            | (\$/MMBtu)               | (\$/ton)                             |  |
| Industrial Coal Boiler                 | 10,000 - 15,000 | 300                   | 1,600                    | 2,000 - 5,000                        |  |
| Industrial Oil, Gas, Wood <sup>c</sup> | 4,000 - 6,000   | 450                   | 700                      | 1,000 - 3,000                        |  |
| Large Gas Turbine                      | 5,000 - 7,500   | 3,500                 | 8,500                    | 3,000 - 6,000                        |  |
| Small Gas Turbine                      | 17,000 - 35,000 | 1,500                 | 3,000                    | 2,000 - 10,000                       |  |

| Table 1a: Summary of Cost Information in \$/MMBtu/hr | (1999 Dollars) a, b |
|--|---------------------|
|--|---------------------|

|                                    | Capital Cost  | O&M Cost <sup>d</sup> | Annual Cost <sup>d</sup> | Cost per Ton of<br>Pollutant Removed |
|------------------------------------|---------------|-----------------------|--------------------------|--------------------------------------|
| Unit Type                          | (\$/MW)       | (\$/MW)               | (\$/MW)                  | (\$/ton)                             |
| Industrial Coal Boiler             | 1,000 - 1,500 | 30                    | 160                      | 2,000 - 5,000                        |
| Industrial Oil, Gas, Wood $^\circ$ | 400 - 600     | 45                    | 70                       | 1,000 - 3,000                        |
| Large Gas Turbine                  | 500 - 750     | 350                   | 850                      | 3,000 - 6,000                        |
| Small Gas Turbine                  | 1,700- 3,500  | 150                   | 300                      | 2,000 - 10,000                       |

Table 1b: Summary of Cost Information in \$/MW (1999 Dollars)<sup>a, b</sup>

<sup>a</sup> (ICAC, 1997; NESCAUM, 2000; EPA, 2002)

<sup>b</sup> Assumes 85% capacity factor and annual control of NOx

<sup>°</sup> SCR installed on wood fired boiler assumes a hot side electrostatic precipitator for PM removal

<sup>d</sup> Coal and oil O&M and annual costs are based on 350MMBtu boiler, and gas turbine O&M and annual costs are based on 75 MW and 5 MW turbine

# Theory of Operation:

The SCR process chemically reduces the NOx molecule into molecular nitrogen and water vapor. A nitrogen based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and reagent diffuse through the catalyst. The reagent reacts selectively with the NOx within a specific temperature range and in the presence of the catalyst and oxygen.

Temperature, the amount of reducing agent, injection grid design and catalyst activity are the main factors that determine the actual removal efficiency. The use of a catalyst results in two primary advantages of the SCR process over the SNCR: higher NOx control efficiency and reactions within a lower and broader temperature range. The benefits are accompanied by a significant increase in capital and operating costs. The catalyst is composed of active metals or ceramics with a highly porous structure. Catalysts configurations are generally ceramic honeycomb and pleated metal plate (monolith) designs. The catalyst composition, type, and physical properties affect performance, reliability, catalyst quantity required, and cost. The SCR system supplier and catalyst supplier generally guarantee the catalyst life and performance. Newer catalyst designs increase catalyst activity, surface area per unit volume, and the temperature range for the reduction reaction.

Catalyst activity is a measure of the NOx reduction reaction rate. Catalyst activity is a function of many variables including catalyst composition and structure, diffusion rates, mass transfer rates, gas temperature, and gas composition. Catalyst deactivation is caused by:

- poisoning of active sites by flue gas constituents,
- thermal sintering of active sites due to high temperatures within reactor,
- blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter, and
- erosion due to high gas velocities.

As the catalyst activity decreases, NOx removal decreases and ammonia slip increases. When the ammonia slip reaches the maximum design or permitted level, new catalyst must be installed. There are several different locations downstream of the combustion unit where SCR systems can be installed. Most coal-fired applications locate the reactor downstream of the economizer and upstream of the air heater and particulate control devices (hot-side). The flue gas in this location is usually within the optimum temperature window for NOx reduction reactions using metal oxide catalysts. SCR may be applied after PM and sulfur removal

equipment (cold-side), however, reheating of the flue gas may be required, which significantly increases the operational costs.

SCR is very cost-effective for natural gas fired units. Less catalyst is required since the waste gas stream has lower levels of NOx, sulfur, and PM. Combined-cycle natural gas turbines frequently use SCR technology for NOx reduction. A typical combined-cycle SCR design places the reactor chamber after the superheater within a cavity of the heat recovery steam generator system (HRSG). The flue gas temperature in this area is within the operating range for base metal-type catalysts.

SCR can be used separately or in combination with other NOx combustion control technologies such as low NOx burners (LNB) and natural gas reburn (NGR). SCR can be designed to provide NOx reductions year-round or only during ozone season.

# Advantages:

- Higher NOx reductions than low-NOx burners and Selective Non-Catalytic Reduction (SNCR)
- Applicable to sources with low NOx concentrations
- Reactions occur within a lower and broader temperature range than SNCR.
- Does not require modifications to the combustion unit

# Disadvantages:

- Significantly higher capital and operating costs than low-NOx burners and SNCR
- Retrofit of SCR on industrial boilers is difficult and costly
- Large volume of reagent and catalyst required.
- May require downstream equipment cleaning.
- Results in ammonia in the waste gas stream which may impact plume visibility, and resale or disposal of ash.

# **References:**

EPA, 1998. U.S. Environmental Protection Agency, Innovative Strategies and Economics Group, "Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis", Prepared by Pechan-Avanti Group, Research Triangle Park, NC. 1998.

EPA, 1999. US Environmental Protection Agency, Clean Air Technology Center. "Technical Bulletin: Nitrogen Oxides (NOx), Why and How They Are Controlled". Research Triangle Park, NC. 1998.

EPA, 2002. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. *EPA Air Pollution Control Cost Manual Section 4 Chapter 2*. EPA 452/B-02-001. 2002. http://www.epa.gov/ttn/catc/dir1/cs4-2ch2.pdf

Gaikwad, 2000. Gaikwad, Kurtides, and DePriest. "Optimizing SCR Reactor Design for Future Operating Flexibility". Presented at the Institute of Clean Air Companies Forum 2000. Washington D.C.

ICAC, 1997. Institute of Clean Air Companies, Inc. "White Paper: Selective Catalytic Reduction (SCR) Control of NOx Emissions". Washington, D.C. 1997.

ICAC, 2000. Institute of Clean Air Companies. "Optimizing SCR Reactor Design for Future Operating Flexibility". Washington, D.C. 2000.

NESCAUM, 2002. Northeast States for Coordinated Air Use Management. "Status Reports on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines: Technologies & Cost Effectiveness". Boston, MA. 2002.

OTAG 1998. OTAG Emissions Inventory Workgroup. "OTAG Technical Supporting Document: Chapter 5." Raleigh, North Carolina, US Environmental Protection Agency. 1998.

# ERM has over 160 offices across the following countries and territories worldwide

Argentina Australia Belgium Brazil Canada Chile China Colombia France Germany Ghana Guyana Hong Kong India Indonesia Ireland Italy Japan Kazakhstan Kenya Malaysia Mexico Mozambique Myanmar

The Netherlands New Zealand Norw ay Panama Peru Poland Portugal Puerto Rico Romania Russia Senegal Singapore South Africa South Korea Spain Sw eden Sw itzerland Taiw an Tanzania Thailand UAE UK US Vietnam

### ERM's Minneapolis Office

222 South 9<sup>th</sup> Street Suite 2900 Minneapolis, MN

T: 612.347.6789

www.erm.com





414 Nicollet Mall Minneapolis, MN 55401

July 29, 2020

sent via e-mail

Hassan M. Bouchareb Minnesota Pollution Control Agency 520 Lafayette Road North St. Paul, MN 55155

RE: Request for Information- Regional Haze Rule, Reasonable Progress Xcel Energy-Allen S. King Generating Plant

Dear Mr. Bouchareb,

This letter is in response to your request for information (RFI) addressed to me dated January 29, 2020. This letter requested a "Four Factor Analysis" (Analysis) for Xcel Energy's Allen S. King Plant Unit 1 (EQUI 68) to assist in the development of Minnesota's Regional Haze State Implementation Plan (SIP). On February 10, 2020, Xcel Energy spoke with you about this RFI and the need for an Analysis given the planned retirement of this unit effectively reducing emissions from these unit to zero by the end of 2028. You indicated that if the retirement dates were made enforceable that an Analysis would not be necessary. This response provides an update on our efforts to secure an enforceable retirement date for Allen S. King Plant Unit 1.

Xcel Energy continues to lead the clean energy transition with a plan that will reduce our carbon emissions in the Upper Midwest 80% by 2030 and help us achieve our vision of 100% carbon-free electricity by 2050. The key to this transition of reducing carbon while keeping bills affordable is retiring our coal fired units by 2030. As we operate the coal fired units until their retirement, we will not only continue to reduce carbon emissions, but also emissions of sulfur dioxide and oxides of nitrogen, through seasonal dispatch (idling units in spring and fall months when demand is low and renewable energy is high).

Xcel Energy proposed to retire Allen S. King Plant Unit 1 by December 31, 2028 to the Minnesota Public Utility Commission (MPUC). A key part of this retirement process is to gain MPUC approval to do so. The mechanism for gaining this approval is the Integrated Resource Plan (IRP) Filing process with the MPUC. Xcel Energy continues to work with the MPUC to gain approval of our IRP filing. At this time the MPUC has not yet approved the IRP filing and, as a result, we are not able to commit to an enforceable retirement date for this unit. Once the MPUC has approved the retirement plans for Allen S. King Unit 1, Xcel Energy commits to incorporating the retirement date into the air permit if the permit is open at that time or to filing for an Administrative Order with the MPCA which will commit the unit to a retirement date of no later than December 31, 2028. The MPUC is expected to issue a final order on the Xcel Energy IRP filing by mid-2021.

Please notify me if the MPCA requires a retirement commitment earlier than this anticipated final order date.

If you have additional questions, please contact either me (612.269.9015 or richard.a.rosvold@xcelenergy.com) or Patti Leaf from my staff (612.964.1176 or patricia.b.leaf@xcelenergy.com).

Richard A. Rosvold Director Environmental Services

CC: Deepa de Alwis, MPCA Cory Boeck, MPCA Kari Palmer, MPCA Brian Behm Randy Capra Patrick Flowers Patricia Leaf



414 Nicollet Mall Minneapolis, MN 55401

July 29, 2020

sent via e-mail

Hassan M. Bouchareb Minnesota Pollution Control Agency 520 Lafayette Road North St. Paul, MN 55155

RE: Request for Information- Regional Haze Rule, Reasonable Progress Xcel Energy- Sherburne County Generating Plant

Dear Mr. Bouchareb,

This letter is in response to your request for information (RFI) to me dated January 29, 2020. That letter requested a "Four Factor Analysis" (Analysis) for Xcel Energy's Sherburne County Generating Units 1, 2 and 3 (EQUI72, EQUI74 and EQUI73) to assist in the development of Minnesota's Regional Haze State Implementation Plan (SIP). On February 10, 2020, Xcel Energy spoke with you about this RFI and the need for an Analysis given the planned retirement of these units effectively reducing emissions from these units to zero by 2030. You indicated that if the retirement dates were made enforceable that an Analysis would not be necessary. This response provides an update on our efforts to secure enforceable retirement dates for Sherburne County Generating Units 1, 2 and 3.

Xcel Energy continues to lead the clean energy transition with a plan that will reduce our carbon emissions in the Upper Midwest 80% by 2030 and help us achieve our vision of 100% carbon-free electricity by 2050. The key to this transition of reducing carbon while keeping bills affordable is retiring our coal fired units by 2030. As we operate the coal fired units until their retirement, we will not only continue to reduce carbon emissions, but also emissions of sulfur dioxide (SO<sub>2</sub>) and oxides of nitrogen (NO<sub>x</sub>), through seasonal dispatch (idling units in spring and fall months when demand is low and renewable energy is high).

Xcel Energy proposed and has received approval from the Minnesota Public Utility Commission (MPUC) through the Integrated Resource Plan (IRP) Filing to retire Sherburne County Generating Unit 2 by December 31, 2023 and Unit 1 by December 31, 2026. Xcel Energy has worked with Joe Carlson, MPCA, to incorporate the retirement dates for Sherco Units 1 and 2 into the Xcel Energy-Sherburne County Generating Plant Air Permit 14100004-101. The permit is currently going through the renewal process and is on public notice as of 7/14/2020. The retirement dates have been incorporated into the permit:

Sherco Unit 1: December 31, 2026 (Permit Condition 5.57.1) Sherco Unit 2: December 31, 2023 (Permit Condition 5.58.1)

Xcel Energy has also proposed to the MPUC through the IRP Filing to retire Sherburne County Unit 3 by December 31, 2030 but has not yet received MPUC approval. Xcel Energy continues to work with the MPUC to gain approval of our IRP filing. In that the MPUC has not yet approved the IRP filing, we are not yet able to commit to an enforceable retirement date for this unit. Once the MPUC has approved the retirement plan for Sherburne County Unit 3, Xcel Energy commits to incorporating the retirement date into the air permit if the permit is open at that time or to enter into an Administrative Order (AO) with the MPCA which will commit the unit to a retirement date of no later than December 31, 2030, or complete some other action with the MPCA to secure an enforceable retirement date to support the MPCA's Regional Haze SIP. As the Agency is aware, this unit is coowned by Xcel Energy and Southern Minnesota Municipal Power Agency (SMMPA). SMMPA, as co-owner, is also willing to commit to an enforceable retirement date for Unit 3, subject to approval by its regulatory body. The MPUC is expected to issue a final order on the Xcel Energy IRP filing mid-2021. Considering the planned retirement of Unit 3 by December 31, 2030 there will be only 2 years of useful life remaining and any investments in the unit would bear a high compliance cost.

For reference, Unit 3 has already reduced emissions to support Minnesota's regional haze goals. In 2016, as part of the Reasonably Attributable Visibility Impairment (RAVI) Settlement for the Sherco Plant, Xcel Energy accepted an SO<sub>2</sub> limit for Unit 3 of 0.29 pounds SO<sub>2</sub>/Million Btu (MBtu), on a 30-day rolling average effective June 1, 2017 even though it was not part of the original RAVI discussion. For context, the Unit 3 average 30-day rolling SO<sub>2</sub> emission rate from the effective date through June 30, 2020 is 0.22 pounds SO<sub>2</sub>/MBtu, well below the permitted SO<sub>2</sub> emission rate limit. Outside the RAVI settlement, Unit 3 has a NO<sub>x</sub> emission rate permit limit of 0.50 pounds NO<sub>x</sub>/MBtu, on a 30-day rolling average. The actual emission rate runs well below this limit. Average emissions based on the same time period outlined above for SO<sub>2</sub> emissions are 0.12 pounds NO<sub>x</sub>/MBtu, approximately 25% of the units permitted NO<sub>x</sub> limit.

As requested, it has been verified that emissions of sulfur dioxide and oxides of nitrogen for Unit 3 are projected to be <u>significantly</u> lower in 2028, 2029 and 2030 than they were in 2016.

Please notify me if the MPCA requires a retirement commitment earlier than this anticipated final order date.

If you have additional questions, please contact either me (612.269.9015 or richard.a.rosvold@xcelenergy.com) or Patti Leaf from my staff (612.964.1176 or patricia.b.leaf@xcelenergy.com).

Richard A. Rosvold Director Environmental Services

CC: Deepa de Alwis, MPCA Cory Boeck, MPCA Kari Palmer, MPCA Randy Capra Patrick Flowers Patricia Leaf Michael Mitchell Peter Reinarts, SMMPA