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

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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_2) and nitrogen oxides (NO_x) 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 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 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.

Table 1 – Permitting Emission Limits.

Pollutant	Boiler 1 – EU001	Boiler 2 – EU002	Boiler 3 – EU003
SO_2	127 (0.93 lb/MMBtu)	127 lb/hr (0.93 lb/MMBtu)	154 lb/hr (0.93 lb/MMBtu)
NO_x	99.8 lb/hr (0.73 lb/MMBtu)	99.8 lb/hr (0.73 lb/MMBtu)	120 lb/hr (0.73 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_2 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_2 emission rate from the slightly larger boiler is 0.41 lb/MMBtu and 253 tpy. The average NO_x 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_x 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_2 and NO_x.

SO_2 Formation. SO_2 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_2, however, a small quantity may be further oxidized to form sulfur trioxide (SO_3). Approximately 90% of the sulfur present in the subbituminous coal will be emitted as sulfur oxides (SO_x) 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_2SO_4) forms when SO_2 emissions react with moisture and oxygen in the environment.

NO_x Formation. There are two primary mechanisms of NO_x 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_2) and oxygen (O_2) molecules in the combustion air to react and form thermal NO_x. Because thermal NO_x is primarily a function of combustion temperature, NO_x emission rates vary with burner and source design. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to the N_2 concentration in the flame, the square root of the O_2 concentration in the flame, and the gas residence time[1]. The formation of fuel NO_x from reactions of fuel bound nitrogen and air can 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 2.

Table 2 – Economic Evaluation Criteria.

Economic Parameter	Value
Interest Rate, percent	7[A]
Control Equipment Economic Life, years	15 & 20[B]
Base Labor Cost, $/hr	60[C]
Energy Cost, $/kW-hr	0.06[D]

[A] EPA Air Pollution Control Cost Manual, Seventh Edition, January 2017, Chapter 2, Section 2.4.2.
[B] EPA Memorandum, Calculating Amortized Capital Costs, July 24, 1987, Robert D. Bauman, Chief, Standards and Implementation Branch.
[C] Loaded labor rate obtained from ACSC.
[D] 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

[1] 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_2 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_2 Control Technologies

Control of SO_2 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_2 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_2) 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_2 by a bed of copper oxide.

Throwaway processes such as limestone scrubbing have become widely accepted by the coal-fired 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_2 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_2 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_2 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_2SO_4). 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 calcium-based sorbent such as calcium hydroxide or calcium oxide (lime). Acid gases and SO_2 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:

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

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

As can be seen above, one mole of calcium hydroxide will neutralize one mole of SO_2, 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_2. 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 non-saturated 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_2, 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_2 Control Technology Effectiveness

Effectiveness is measured by the amount of SO_2 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_2 control technology effectiveness.

[2] Karl B. Schnelle, Jr. and Charles A. Brown, Air Pollution Control Technology Handbook, CRC Press, 2002.

Table 3 – SO_2 Control Technology Effectiveness.

Control Technology	Percent SO_2 Reduction[A]	Emission Rate (lb/MMBtu)	Annual Emissions (tpy)	Tons SO_2 Removed (tpy)
Two Identical Boilers (EU001 & 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 (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

[A] 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_2 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_2 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_2 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_2 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_2 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_2 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_2 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.

Table 4 – SO_2 Costs of Compliance – EU001 & EU002 (per Boiler).

Description	Technology Option	
	Dry FGD w/Fabric Filter	DSI
Emission Rate (lb/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 5 – SO_2 Costs of Compliance – EU003.

Description	Technology Option	
	Dry FGD w/Fabric Filter	**DSI**
Emission Rate (lb/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

2.3.3.2 Energy Impact

Use of Dry FGD or DSI to control SO_2 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_x 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 (post-combustion control technology) to control NO_x emissions. The SCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH_3) or urea (CON_2H_4) to reduce the NO_x in the flue gas to N_2 and H_2O. The reagent is injected into the flue gas prior to passage through a catalyst bed, which accelerates the NO_x reduction reaction rate. Use of SCR results in small levels of NH_3 emissions (NH_3 slip). As the catalyst degrades, NH_3 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_2), zirconium oxide (ZrO_2), vanadium pentoxide (V_2O_5), silicon oxide (SiO_2), and zeolites (crystalline alumina silicates).

SCR systems can utilize aqueous NH_3, anhydrous NH_3, or a urea solution to produce NH_3 on demand. Aqueous NH_3 is generally transported and stored in concentrations ranging from 19% to 30% and therefore requires more storage capacity than anhydrous NH_3. Anhydrous NH_3 is nearly 100% pure in concentration and is a gas at normal atmospheric temperature and pressure. Anhydrous NH_3 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_3 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_3 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_3) or urea to reduce the NO_x in the flue gas to N_2 and H_2O. 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_x 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_x emission control on some utility boilers, and can achieve NO_x reduction efficiencies of up to 75%. However, in typical industrial applications SNCR provides 30% to 50% NO_x 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_x burners (LNB), can be used to reduce NO_x 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_x 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_x removal efficiency. The CRK boilers are currently equipped with modern OFA control systems.

2.4.2 NO_x 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.

Table 6 – NO_x Control Technology Effectiveness.

Control Technology	Percent NO_x Reduction	Emission Rate (lb/MMBtu)	Annual Emissions (tpy)	Tons NO_x Removed (tpy)
Two Identical Boilers (EU001 & 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

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_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_x 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_x 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.

Table 7 – NO_x Cost of Compliance – EU001 & EU002 (per Boiler).

Description	Technology Option	
	SCR	SNCR
Emission Rate (lb/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 8 – NO_x Cost of Compliance – EU003.

Description	Technology Option	
	OFA + SCR	OFA + SNCR
Emission Rate (lb/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

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	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	2,654,500	Scaled Quote
Control/Instrumentation[C]	265,500	10% of Equipment Cost
Sales Tax	159,300	6% of Equipment Cost
Freight[C]	132,700	5% of Equipment Cost
Total Equipment Cost (TEC)	**3,212,000**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	2,730,200	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Site Preparation[D]	1,000,000	Estimated
Total Direct Investment (TDI)	6,942,200	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
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**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry FGD Fabric Filter Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	2,022,400	Scaled Quote
Control/Instrumentation[C]	202,200	10% of Equipment Cost
Sales Tax	121,300	6% of Equipment Cost
Freight[C]	101,100	5% of Equipment Cost
Total Equipment Cost (TEC)	**2,447,000**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,810,800	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Site Preparation[D]	1,000,000	Estimated
Total Direct Investment (TDI)	5,257,800	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
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 Indirect Investment (TII)	**1,101,200**	

Total Turnkey Cost (TTC)	**6,359,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry FGD/Fabric Filter Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
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**	

Indirect Annual Costs [C]		
Overhead	473,600	60% of O&M Labor
Administrative Charges	288,500	2% of Total Capital Investment
Property Taxes	144,300	1% of Total Capital Investment
Insurance	144,300	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	885,600	(Capital Investment) x (CFR of 0.10979)
Fabric Filter Annualized Costs[E]	600,200	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**2,536,500**	

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

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters.

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

[D] 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.

[E] 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	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	1,044,400	Vendor Quote
Control/Instrumentation[C]	104,400	10% of Equipment Cost
Sales Tax	62,700	6% of Equipment Cost
Freight[C]	52,200	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,263,700**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,074,100	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Site Preparation[D]	250,000	Estimated (includes electrical upgrade)
Total Direct Investment (TDI)	2,587,800	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
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 Indirect Investment (TII)	**379,100**	

Total Turnkey Cost (TTC)	**2,966,900**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry Sorbent Injection Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
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 [C]		
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[D]	325,700	(Capital Investment) x (CFR of 0.10979)
Indirect Annual Costs (IAC)	**509,400**	
Total Annualized Costs (TAC)	**645,700**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

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

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

Indirect Capital Cost [C]		
Contingency	197,000	3% of TEC
Engineering	656,700	10% of TEC
Construction & Field Expense	328,300	5% of TEC
Contractor Fees	656,700	10% of TEC
Start-up Assistance	131,300	2% of TEC
Performance Test	65,700	1% of TEC
Total Indirect Investment (TII)	**2,035,700**	

Total Turnkey Cost (TTC)	**10,975,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

[D] Estimated by HDR.

Selective Catalytic Reduction Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
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 [C]		
Overhead	29,500	60% of O&M Labor
Administrative Charges	219,500	2% of Total Capital Investment
Property Taxes	109,800	1% of Total Capital Investment
Insurance	109,800	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	1,035,900	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**1,504,500**	
Total Annualized Costs (TAC)	**1,612,400**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

[D] 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	($)[A]	Remarks
Direct Capital Costs		
SNCR Equipment[B]	801,200	Control Cost Manual Spreadsheet
Control/Instrumentation[C]	80,100	10% of Equipment Cost
Sales Tax	48,100	6% of Equipment Cost
Freight[C]	40,100	5% of Equipment Cost
Total Equipment Cost (TEC)	**969,500**	
Total Installation Cost (TIC)/Balance of Plant Cost[B]	1,165,400	Control Cost Manual Spreadsheet
Site Preparation[D]	250,000	Demo and Equipment Relocation
Total Direct Investment (TDI)	**2,384,900**	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	29,100	3% of TEC
Engineering	97,000	10% of TEC
Construction & Field Expense	48,500	5% of TEC
Contractor Fees	97,000	10% of TEC
Start-up Assistance	19,400	2% of TEC
Performance Test	9,700	1% of TEC
Total Indirect Investment (TII)	**300,700**	
Total Turnkey Cost (TTC)	**2,685,600**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost obtained from EPA Air Pollution Control SNCR Spreadsheet.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

[D] Estimated by HDR.

Selective Non-Catalytic Reduction Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
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 [C]		
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[D]	253,500	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**384,000**	
Total Annualized Costs (TAC)	**430,800**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

[D] 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	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	2,986,300	Scaled Quote
Control/Instrumentation[C]	298,600	10% of Equipment Cost
Sales Tax	179,200	6% of Equipment Cost
Freight[C]	149,300	5% of Equipment Cost
Total Equipment Cost (TEC)	**3,613,400**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	3,071,400	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Site Preparation[D]	1,000,000	Estimated
Total Direct Investment (TDI)	7,684,800	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
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**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry FGD Fabric Filter Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	2,275,200	Scaled Quote
Control/Instrumentation[C]	227,500	10% of Equipment Cost
Sales Tax	136,500	6% of Equipment Cost
Freight[C]	113,800	5% of Equipment Cost
Total Equipment Cost (TEC)	**2,753,000**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	2,037,200	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Site Preparation[D]	1,000,000	Estimated
Total Direct Investment (TDI)	5,790,200	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
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 Indirect Investment (TII)	**1,238,800**	
Total Turnkey Cost (TTC)	**7,029,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry FGD/Fabric Filter Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
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 [C]		
Overhead	505,700	60% of O&M Labor
Administrative Charges	319,600	2% of Total Capital Investment
Property Taxes	159,800	1% of Total Capital Investment
Insurance	159,800	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	982,500	(Capital Investment) x (CFR of 0.10979)
Fabric Filter Annualized Costs[E]	663,500	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**2,790,900**	
Total Annualized Costs (TAC)	**3,996,700**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters.

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

[D] 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.

[E] 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	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	1,175,000	Vendor Quote
Control/Instrumentation[C]	117,500	10% of Equipment Cost
Sales Tax	70,500	6% of Equipment Cost
Freight[C]	58,800	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,421,800**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,208,500	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Site Preparation[D]	250,000	Estimated (includes electrical upgrade)
Total Direct Investment (TDI)	2,880,300	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
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 Indirect Investment (TII)	**426,600**	
Total Turnkey Cost (TTC)	**3,306,900**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry Sorbent Injection Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
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**	

Description of Cost	($)[A]	Remarks
Indirect Annual Costs [C]		
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[D]	363,100	(Capital Investment) x (CFR of 0.10979)
Indirect Annual Costs (IAC)	**562,700**	

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

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

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

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

Indirect Capital Cost [C]		
Contingency	228,400	3% of TEC
Engineering	761,400	10% of TEC
Construction & Field Expense	380,700	5% of TEC
Contractor Fees	761,400	10% of TEC
Start-up Assistance	152,300	2% of TEC
Performance Test	76,100	1% of TEC
Total Indirect Investment (TII)	**2,360,300**	

Total Turnkey Cost (TTC)	**12,499,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

[D] Estimated by HDR.

Selective Catalytic Reduction Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
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 [C]		
Overhead	33,500	60% of O&M Labor
Administrative Charges	250,000	2% of Total Capital Investment
Property Taxes	125,000	1% of Total Capital Investment
Insurance	125,000	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	1,179,800	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**1,713,300**	
Total Annualized Costs (TAC)	**1,834,800**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

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

Indirect Capital Cost [C]		
Contingency	31,400	3% of TEC
Engineering	104,800	10% of TEC
Construction & Field Expense	52,400	5% of TEC
Contractor Fees	104,800	10% of TEC
Start-up Assistance	21,000	2% of TEC
Performance Test	10,500	1% of TEC
Total Indirect Investment (TII)	**324,900**	

Total Turnkey Cost (TTC)	**2,890,200**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost obtained from EPA Air Pollution Control SNCR Spreadsheet.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

[D] Estimated by HDR.

Selective Non-Catalytic Reduction Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
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 [C]		
Overhead	25,000	60% of O&M Labor
Administrative Charges	57,800	2% of Total Capital Investment
Property Taxes	28,900	1% of Total Capital Investment
Insurance	28,900	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	272,800	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**413,400**	
Total Annualized Costs (TAC)	**465,900**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

[D] 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 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_2) and nitrogen oxides (NO_x) 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_x 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_2 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_x 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_2 and NO_x.

SO_2 Formation. SO_2 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_2, however, a small quantity may be further oxidized to form sulfur trioxide (SO_3). Approximately 90% of the sulfur present in the subbituminous coal will be emitted as sulfur oxides (SO_x) 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_2SO_4) forms when SO_2 emissions react with moisture and oxygen in the environment.

NO_x Formation. There are two primary mechanisms of NO_x 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_2) and oxygen (O_2) molecules in the combustion air to react and form thermal NO_x. Because thermal NO_x is primarily a function of combustion temperature, NO_x emission rates vary with burner and source design. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to the N_2 concentration in the flame, the square root of the O_2 concentration in the flame, and the gas residence time[1]. The formation of fuel NO_x from reactions of fuel bound nitrogen and air can

[1] 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.

Table 1 – Economic Evaluation Criteria.

Economic Parameter	Value
Interest Rate, percent	7[A]
Control Equipment Economic Life, years	15 & 20[B]
Base Labor Cost, $/hr	60[C]
Energy Cost, $/kW-hr	0.06[D]

[A] EPA Air Pollution Control Cost Manual, Seventh Edition, January 2017, Chapter 2, Section 2.4.2.
[B] Based on Control Equipment Type. EPA Memorandum, Calculating Amortized Capital Costs, July 24, 1987, Robert D. Bauman, Chief, Standards and Implementation Branch.
[C] Loaded labor rate obtained from ACSC.
[D] 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_2 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_2 Control Technologies

Control of SO_2 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_2 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_2) 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_2 by a bed of copper oxide.

Throwaway processes such as limestone scrubbing have become widely accepted by the coal-fired 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_2 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_2 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_2 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_2SO_4). 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 calcium-based sorbent such as calcium hydroxide or calcium oxide (lime). Acid gases and SO_2 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:

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

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

As can be seen above, one mole of calcium hydroxide will neutralize one mole of SO_2, 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_2. 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 non-saturated 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_2, 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_2 Control Technology Effectiveness

Effectiveness is measured by the amount of SO_2 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_2 control technology effectiveness.

Table 2 – SO_2 Control Technology Effectiveness.

Control Technology	Percent SO_2 Reduction[A]	Emission Rate (lb/MMBtu)	Annual Emissions (tpy)	Tons SO_2 Removed (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

[A] 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_2 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.

[2] 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_2 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_2 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_2 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_2 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_2 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_2 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.

Table 3 – SO_2 Costs of Compliance (per boiler).

Description	Technology Option	
	Dry FGD w/Fabric Filter	DSI
Emission Rate (lb/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 ($/ton)	16,100	7,800

2.3.3.2 Energy Impact

Use of Dry FGD or DSI to control SO_2 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_x 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_x 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 (post-combustion control technology) to control NO_x emissions. The SCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH_3) or urea (CON_2H_4) to reduce the NO_x in the flue gas to N_2 and H_2O. The reagent is injected into the flue gas prior to passage through a catalyst bed, which accelerates the NO_x reduction reaction rate. Use of SCR results in small levels of NH_3 emissions (NH_3 slip). As the catalyst degrades, NH_3 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_2), zirconium oxide (ZrO_2), vanadium pentoxide (V_2O_5), silicon oxide (SiO_2), and zeolites (crystalline alumina silicates).

SCR systems can utilize aqueous NH_3, anhydrous NH_3, or a urea solution to produce NH_3 on demand. Aqueous NH_3 is generally transported and stored in concentrations ranging from 19% to 30% and therefore requires more storage capacity than anhydrous NH_3. Anhydrous NH_3 is nearly 100% pure in concentration and is a gas at normal atmospheric temperature and pressure. Anhydrous NH_3 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_3 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_3 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_3) or urea to reduce the NO_x in the flue gas to N_2 and H_2O. 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_x 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_x emission control on some utility boilers, and can achieve NO_x reduction efficiencies of up to 75%. However, in typical industrial applications SNCR provides 30% to 50% NO_x 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_x burners (LNB), can be used to reduce NO_x 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_x 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_x removal efficiency. The EGF boilers are currently equipped with modern OFA control systems.

2.4.2 NO_x 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.

Table 4 – NO_x Control Technology Effectiveness.

Control Technology	Percent NO_x Reduction	Emission Rate (lb/MMBtu)	Annual Emissions (tpy)	Tons NO_x Removed (tpy)
Baseline/OFA	0	0.34	340	NA
SCR	80	0.07	68	272
SNCR	30	0.26	238	102

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_x 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.

Table 5 – NO_x Cost of Compliance (per Boiler).

Description	Technology Option	
	SCR	SNCR
Emission Rate (lb/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 ($/ton)	11,900	6,600

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 systems 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 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	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	4,740,100	Scaled Quote
Control/Instrumentation[C]	474,000	10% of Equipment Cost
Sales Tax	284,400	6% of Equipment Cost
Freight[C]	237,000	5% of Equipment Cost
Total Equipment Cost (TEC)	**5,735,500**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	4,875,200	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Site Preparation[D]	1,000,000	Estimated
Total Direct Investment (TDI)	11,610,700	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
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**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry FGD Fabric Filter Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	3,611,500	Scaled Quote
Control/Instrumentation[C]	361,200	10% of Equipment Cost
Sales Tax	216,700	6% of Equipment Cost
Freight[C]	180,600	5% of Equipment Cost
Total Equipment Cost (TEC)	**4,370,000**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	3,233,800	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Site Preparation[D]	1,000,000	Estimated
Total Direct Investment (TDI)	8,603,800	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
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 Indirect Investment (TII)	**1,966,500**	

Total Turnkey Cost (TTC)	**10,570,300**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry FGD/Fabric Filter Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
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 [C]		
Overhead	675,100	60% of O&M Labor
Administrative Charges	483,800	2% of Total Capital Investment
Property Taxes	241,900	1% of Total Capital Investment
Insurance	241,900	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	1,495,200	(Capital Investment) x (CFR of 0.10979)
Fabric Filter Annualized Costs[E]	997,700	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**4,135,600**	

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

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters.

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

[D] 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.

[E] 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	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	1,865,000	Vendor Quote
Control/Instrumentation[C]	186,500	10% of Equipment Cost
Sales Tax	111,900	6% of Equipment Cost
Freight[C]	93,300	5% of Equipment Cost
Total Equipment Cost (TEC)	**2,256,700**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,918,200	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Site Preparation[D]	450,000	Estimated (includes electrical upgrade)
Total Direct Investment (TDI)	4,624,900	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
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 Indirect Investment (TII)	**677,100**	

Total Turnkey Cost (TTC)	**5,302,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry Sorbent Injection Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
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 [C]		
Overhead	79,500	60% of O&M Labor
Administrative Charges	106,000	2% of Total Capital Investment
Property Taxes	53,000	1% of Total Capital Investment
Insurance	53,000	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	582,100	(Capital Investment) x (CFR of 0.10979)
Indirect Annual Costs (IAC)	**873,600**	

Total Annualized Costs (TAC)	**1,056,100**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

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

[D] 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	($)[A]	Remarks
Direct Capital Costs		
SCR Equipment[B]	10,006,000	Control Cost Manual Spreadsheet
Reagent Preparation Cost[B]	1,980,500	Control Cost Manual Spreadsheet
Control/Instrumentation[C]	1,000,600	10% of Equipment Cost
Sales Tax	600,400	6% of Equipment Cost
Freight[C]	500,300	5% of Equipment Cost
Total Equipment Cost (TEC)	**14,087,800**	
Total Installation Cost (TIC)/Balance of Plant Cost[B]	2,796,900	Control Cost Manual Spreadsheet
Site Preparation[D]	500,000	Demo and Equipment Relocation
Total Direct Investment (TDI)	**17,384,700**	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	422,600	3% of TEC
Engineering	1,408,800	10% of TEC
Construction & Field Expense	704,400	5% of TEC
Contractor Fees	1,408,800	10% of TEC
Start-up Assistance	281,800	2% of TEC
Performance Test	140,900	1% of TEC
Total Indirect Investment (TII)	**4,367,300**	
Total Turnkey Cost (TTC)	**21,752,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

[D] Estimated by HDR.

Selective Catalytic Reduction Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
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 [C]		
Overhead	57,700	60% of O&M Labor
Administrative Charges	435,000	2% of Total Capital Investment
Property Taxes	217,500	1% of Total Capital Investment
Insurance	217,500	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	2,053,200	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**2,980,900**	
Total Annualized Costs (TAC)	**3,245,100**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

[D] 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	($)[A]	Remarks
Direct Capital Costs		
SNCR Equipment[B]	1,196,500	Control Cost Manual Spreadsheet
Control/Instrumentation[C]	119,700	10% of Equipment Cost
Sales Tax	71,800	6% of Equipment Cost
Freight[C]	59,800	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,447,800**	
Total Installation Cost (TIC)/Balance of Plant Cost[B]	1,743,700	Control Cost Manual Spreadsheet
Site Preparation[D]	450,000	Demo and Equipment Relocation
Total Direct Investment (TDI)	**3,641,500**	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	43,400	3% of TEC
Engineering	144,800	10% of TEC
Construction & Field Expense	72,400	5% of TEC
Contractor Fees	144,800	10% of TEC
Start-up Assistance	29,000	2% of TEC
Performance Test	14,500	1% of TEC
Total Indirect Investment (TII)	**448,900**	
Total Turnkey Cost (TTC)	**4,090,400**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost obtained from EPA Air Pollution Control SNCR Spreadsheet.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

[D] Estimated by HDR.

Selective Non-Catalytic Reduction Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
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 [C]		
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
Insurance	40,900	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	386,100	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**584,100**	
Total Annualized Costs (TAC)	**673,300**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

[D] 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.

ArcelorMittal

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 four-factor 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

325 South Lake Avenue
Duluth, MN 55802
218.529.8200
www.barr.com

Regional Haze Four-Factor Analysis Applicability Evaluation

May 29, 2020

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1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency (MPCA) submitted a Request for Information (RFI) Letter[1] to ArcelorMittal Minorca Mine, Inc. (Minorca) to consider potential emissions reduction measures of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) 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)[2]:

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[3] (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_x and SO_2. Minorca has BART emission controls and emission limits for NO_X and SO_2 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[4] and October 2015[5] USEPA Federal Implementation Plan (FIP) rulemaking. (see Section 5)

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[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to ArcelorMittal Minorca Mine Inc.

[2] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[3] USEPA, Regional Haze Rule Requirements – Long Term Strategy for Regional Haze, 40 CFR 52.308(f)(2)

[4] USEPA, Federal Register, 08/15/2012, Page 49308.

[5] 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_2 and NO_X 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.[6] 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_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 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)[7], by July 31, 2020 for the emission units identified in Table 2-1.

[6] 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.

[7] 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 Machine Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	(EQUI 38/EU 026)	NO_X, SO_2

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[8].

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."[9] 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 and determine 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."[10]

The SIP revision must also include the "Long-term strategy for regional haze."[11] 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[12], emission unit retirement and replacement

[8] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[9] 40 CFR 51.308(f)(1)

[10] 40 CFR 51.308(f)(1)(vi)(A)

[11] 40 CFR 51.308(f)(2)

[12] 51.308(f)(2)(iv)(A)

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

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)[15]. The reasonable progress goal is not enforceable but will be considered by USEPA in evaluating the adequacy of the SIP[16].

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*"[17] 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."[18]

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"[19] 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."[20] 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.[21]

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)

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[13] 51.308(f)(2)(iv)(C)

[14] 51.308(f)(2)(iv)(E)

[15] 40 CFR 51.308(f)(3)

[16] 40 CFR 51.308(f)(3)(iii)

[17] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[18] Ibid, page 1.

[19] Ibid.

[20] Ibid, page 9 (emphasis added).

[21] Ibid.

- 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):[22]

$$URP = [(\text{2000-2004 visibility})_{\text{20\% most impaired}} - (\text{natural visibility})_{\text{20\% most impaired}}]/60$$

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.[23] 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…."[24]

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

[22] Ibid, Page 7.

[23] Ibid, Page 50.

[24] 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, 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 periods. 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."[25]

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[26]
- the four statutory factors (to the extent they have been characterized at this point in SIP development)[27]
- potential visibility benefits (also to the extent they have been characterized at this point in SIP development)[28]
- sources already having effective emissions controls in place[29]
- emission reductions at the source due to ongoing air pollution control programs[30]
- in-state emission reductions due to ongoing air pollution control programs that will result in an improvement in visibility[31]

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."[32]

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[25] Ibid, Page 9.
[26] Ibid, Page 10.
[27] Ibid.
[28] Ibid.
[29] Ibid, Page 21.
[30] Ibid, Page 22.
[31] Ibid.
[32] 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[33]:

- 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:[34]

> "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."[35] 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."[36] 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

[33] Ibid, Page 12.

[34] Ibid, Page 27.

[35] Ibid, Page 22.

[36] Ibid, Page 25.

analysis of control measures."[37] 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."[38]

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."[39]

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

[37] Ibid.

[38] Ibid.

[39] 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.

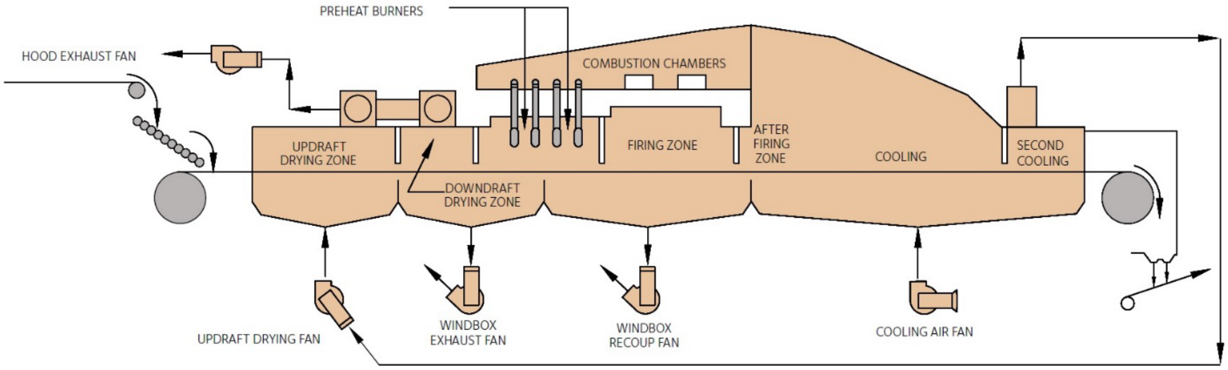

Figure 2-1 Natural Gas Fired Indurating Machine Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers Diagram

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."[40] 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.[41] 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."[42]

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).[43] 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.[44] 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."[45] In

[40] 40 CFR 51.308(f)(1)

[41] 40 CFR 51.308(f)(3)

[42] 40 CFR 51.308(d)(1)

[43] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[44] https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

[45] 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."[46]

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath[47] 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.

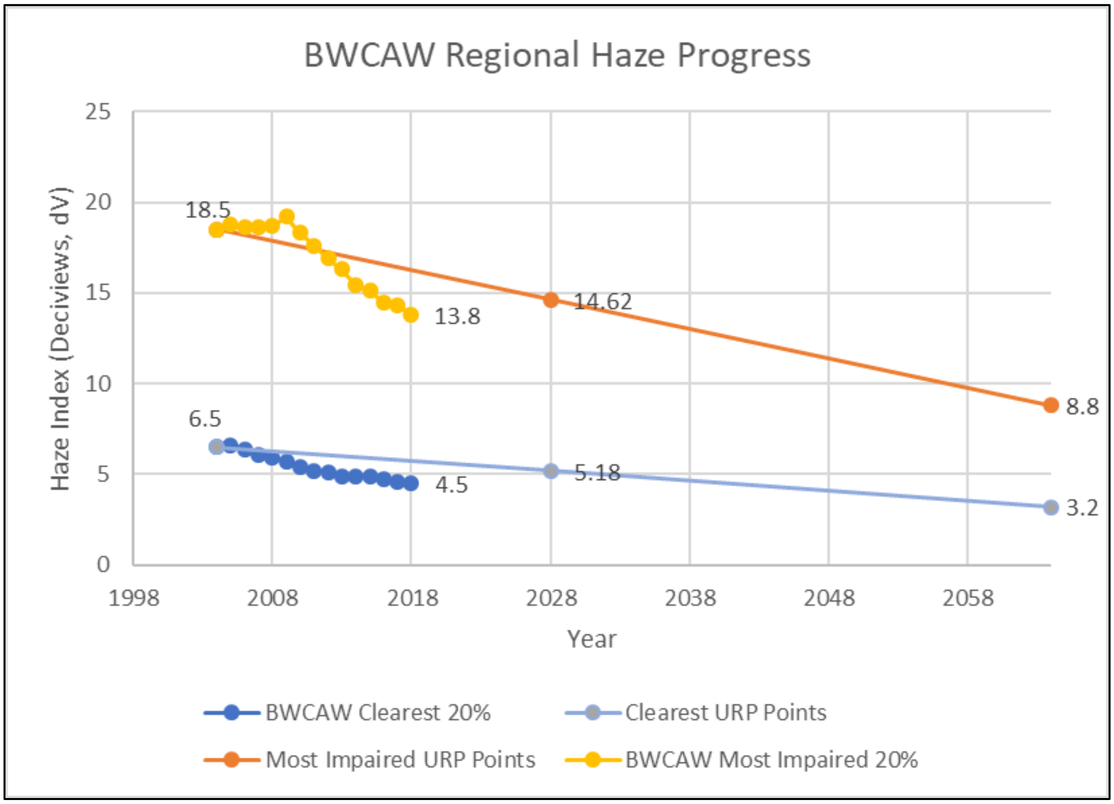

Figure 3-1 Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

[46] USEPA, Federal Register, 01/10/2017, Page 3104

[47] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

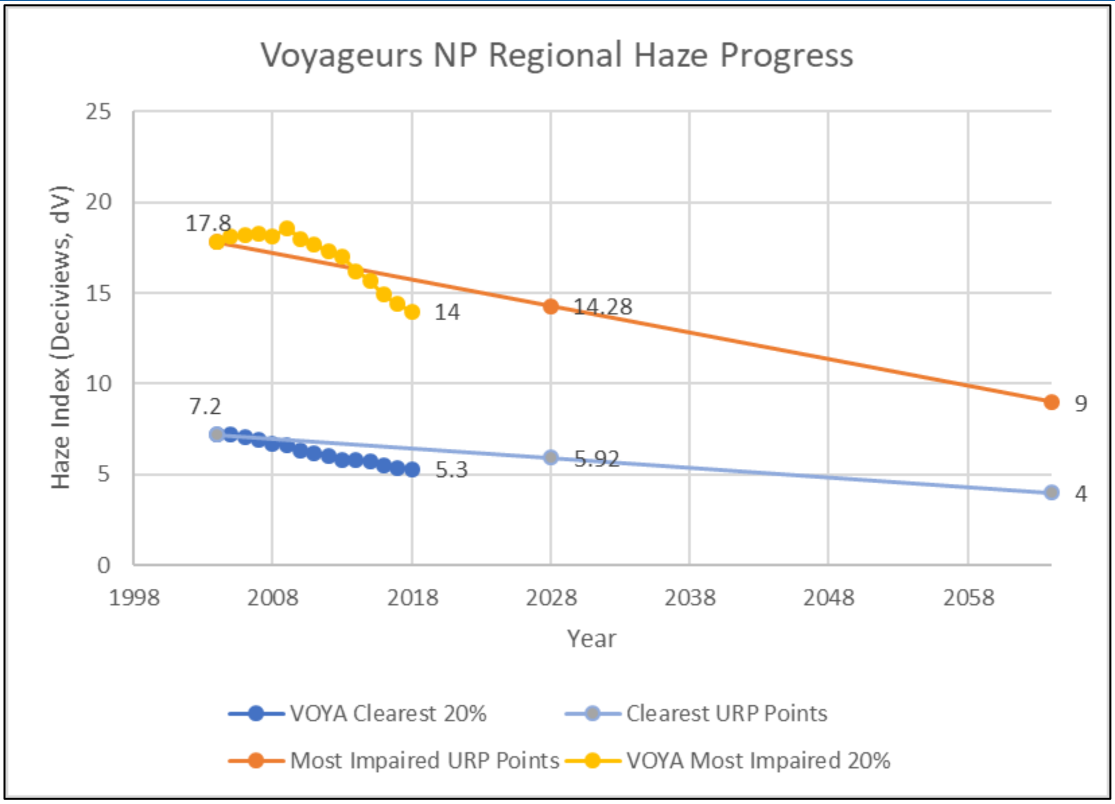

Figure 3-2 Visibility Trend versus URP – Voyageurs National Park (VOYA1)

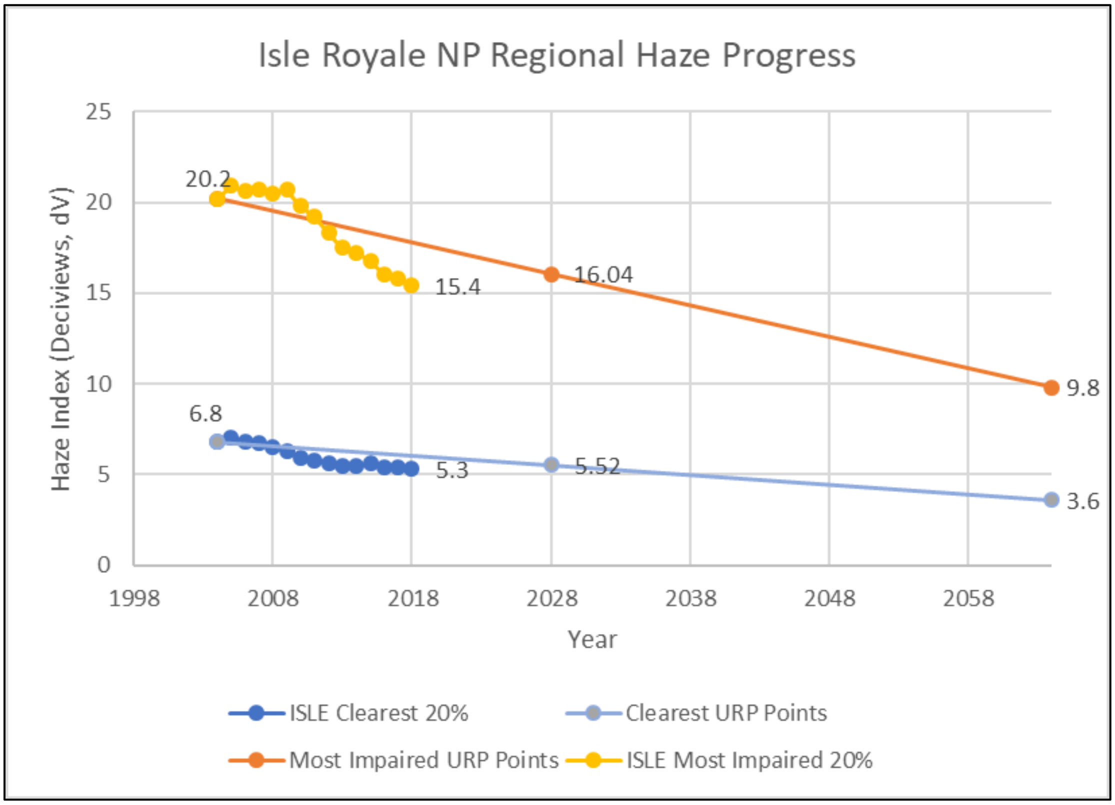

Figure 3-3 Visibility Trend versus URP – Isle Royale National Park (ISLE1)

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[48]. 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
    - 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.

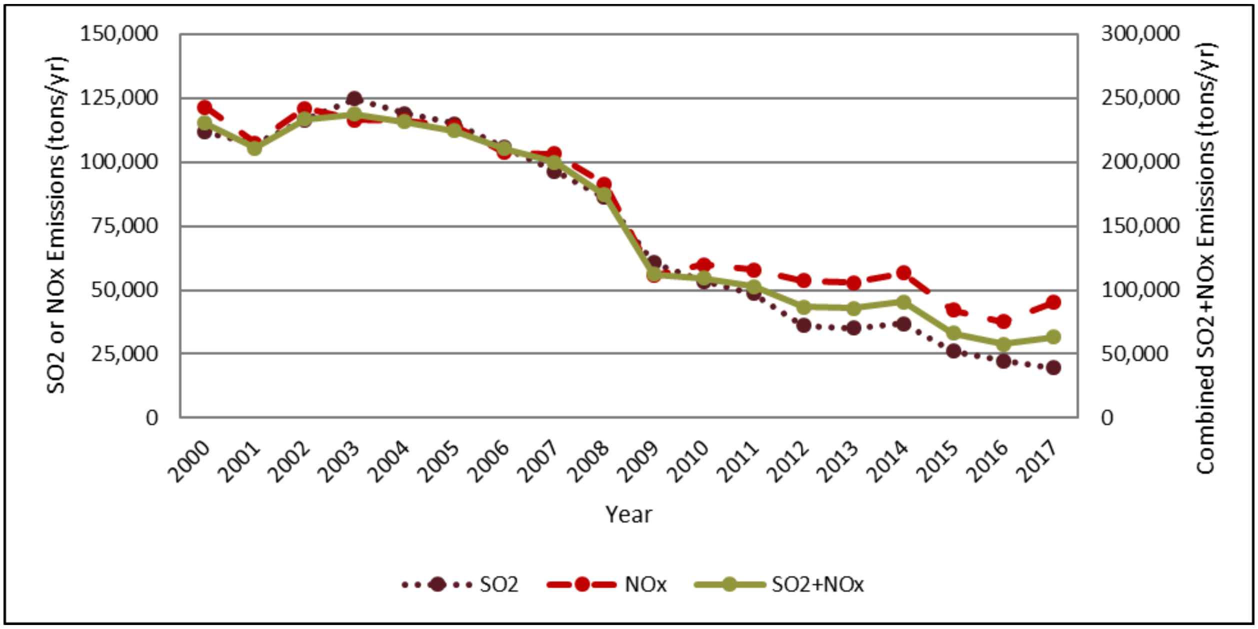

Figure 3-4 Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)

[48] The data for NO_X and SO_2 emissions was downloaded from the MPCA point source emissions inventory (https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data). 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.

Table 3-1 Notable Minnesota Emission Reductions

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_X*
2018	Minntac Line 7: FIP emission limit compliance date for NO_X* MP Boswell: Units 1 & 2 retired from service**
2019	Hibtac Line 1: FIP emission limit compliance date for NO_X* Keetac: FIP emission limit compliance date for NO_X * Minntac Line 4 or 5: FIP emission limit compliance date for NO_X* Utac Line 1: FIP emission limit compliance date for NO_X*
2020	Hibtac Line 2: FIP emission limit compliance date for NO_X* Minntac Line 4 or 5: FIP emission limit compliance date for NO_X* Minorca: FIP emission limit compliance date for NO_X* Utac Line 2: FIP emission limit compliance date for NO_X*
2021	Minntac Line: FIP emission limit compliance date for NO_X* Hibtac Line 3: FIP emission limit compliance date for NO_X*
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***

* 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*[49]
  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*[50]
  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_X emission reductions suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces.

- *Other reasonable techniques*[51]
  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

[49] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 13.

[50] Ibid, Page 14.

[51] 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."[52] 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."[53]

[52] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.
[53] 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.”[54] This section demonstrates that the indurating machine meets USEPA’s BART-required control equipment installation scenario for NO_X and SO_2.

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”[55] for NO_X and SO_2

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_X BART-required Controls

In the preamble to the October 2015 proposed FIP,[56] the USEPA concluded that BART for NO_X from straight-grate furnaces is low-NO_X 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[57]
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure[58]
- Selective Catalytic Reduction (SCR) controls because two vendors declined to bid on NO_x reduction testing for a taconite facility[59]

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[54] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, page 22.

[55] Ibid, page 25.

[56] Federal Register 80, No. 204 (October 22, 2015); 64168. Available at: https://www.govinfo.gov/app/details/FR-2015-10-22/2015-25023

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

[58] Ibid.

[59] Ibid, 49320.

- High-stoichiometric and low-stoichiometric low NO_x burners (LNB) because the technology had never been used on straight-grate furnaces at the time of the determination.[60]

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_X emissions from taconite indurating furnaces.

In accordance with the FIP, Minorca implemented the BART NO_x 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_x emission limit[61] 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[62].

Table 5-1 NO_X Emission Limits

Unit	Unit ID	NO_X Emission Limit[(1)] (lb/MMBtu)	Compliance Date[(2)]
Natural Gas Fired Indurating Machine Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and 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.

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

61 40 CFR 52.1235(b)(1)

62 USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10.

5.2 SO_2 BART-required Controls

In the preamble to the August 2012 proposed FIP[63], the USEPA concluded that BART for SO_2 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[64]
- 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[65]

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

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_2 emissions from taconite indurating furnaces.

In accordance with the FIP, Minorca has continued to operate the BART SO_2 control measures and is complying with the FIP SO_2 emission limit[67], 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_2. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis,

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[63] Federal Register 77, No. 158 (August 15, 2012); 49321. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

[64] Ibid, 49320.

[65] Ibid.

[66] Ibid, 49321.

[67] 40 CFR 52.1235(b)(2)

which further supports eliminating the indurating machine from the requirement to submit a four-factor analysis[68].

Table 5-2 SO_2 Emission Limits

Unit	Unit ID	SO_2 Emission Limit[(1)] (lb/hr)	Compliance Date[(2)]
Natural Gas Fired Indurating Machine Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	(EQUI 38/EU 026)	58.64	April 6, 2018

(1) This limit was established using one year of SO_2 CEMS data in accordance with the procedures outlined within 40 CFR 52.1235(b)(2)(v).

(2) Minorca submitted the revised SO_2 limit request on April 6, 2018 in accordance with 40 CFR 52.1235(b)(2)(v).

[68] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 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_X and SO_2 (see Section 5). As stated in the 2019 Guidance, "it may be reasonable for a state not to select an effectively controlled source."[69] 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_X 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.**

[69] 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")[1] 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[2], to determine the frequency that the trajectories on the "most impaired days"[3] 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).[4] 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.[5] 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[6], Draxler - 1992[7], Draxler and Hess - 1998[8]). 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.

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[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[2] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[3] "Most impaired days" is the 20% most anthropogenically impaired days on an annual basis, measured in deciviews (dv), as provided on MPCA's website.

[4] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[5] https://www.arl.noaa.gov/hysplit/hysplit/

[6] http://www.kenrahn.com/DustClub/Articles/Stohl%201998%20Trajectories.pdf

[7] https://www.arl.noaa.gov/documents/reports/ARL%20TM-195.pdf

[8] 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.

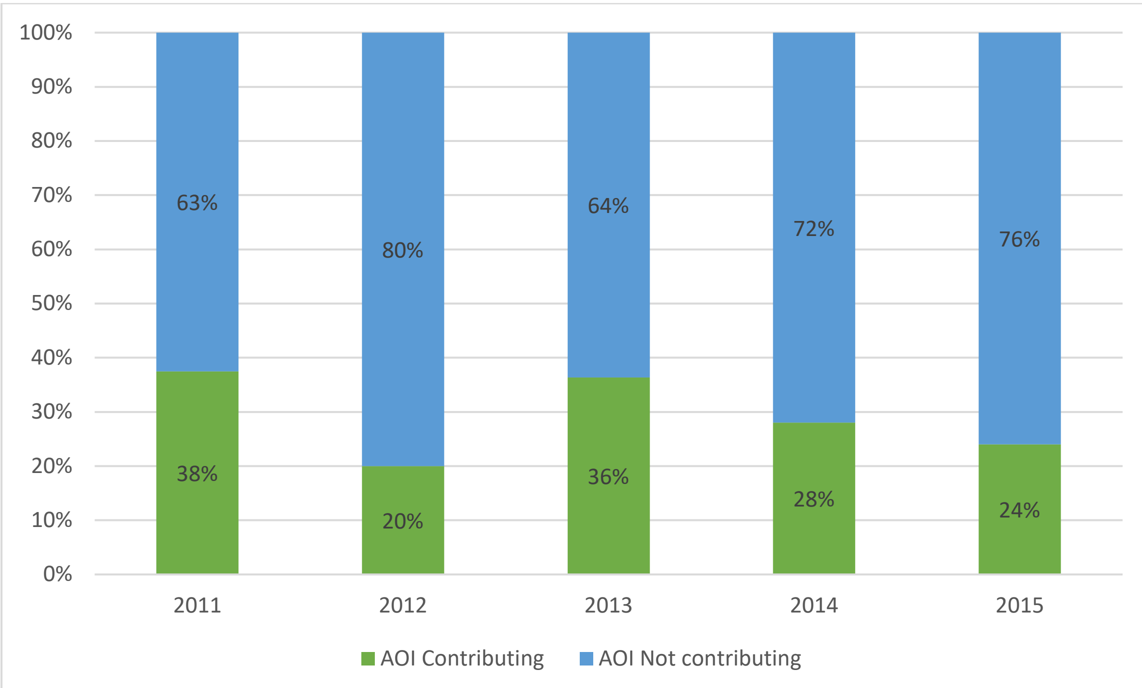

Figure A1 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at BWCA

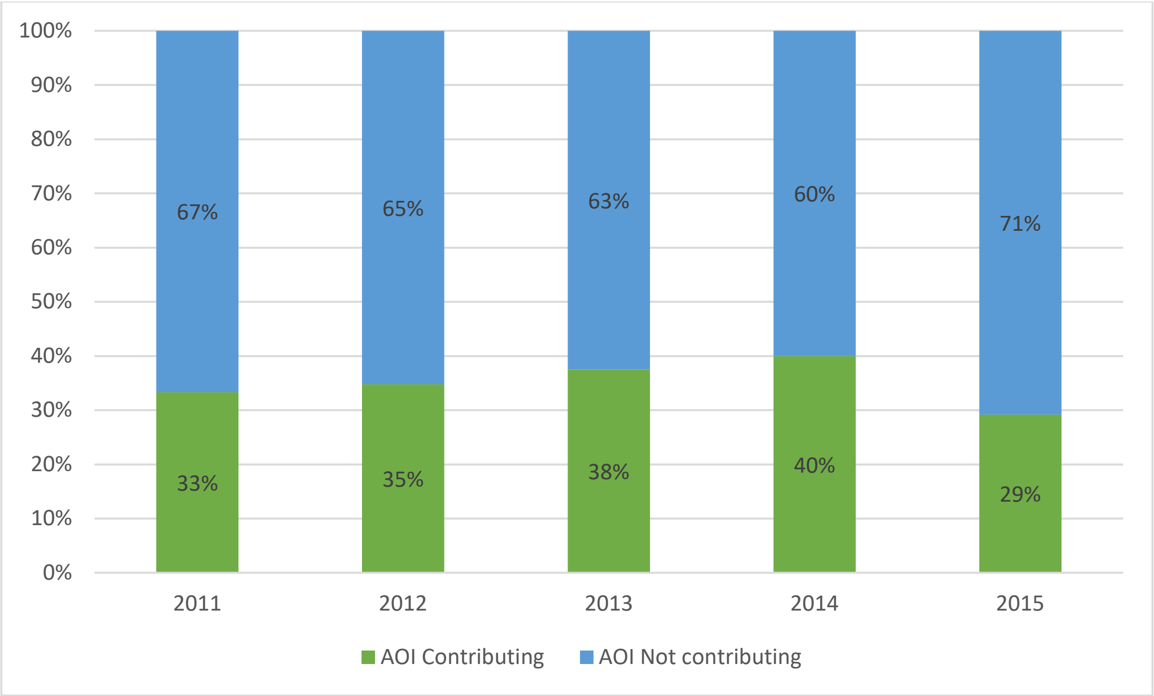

Figure A2 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at Voyageurs

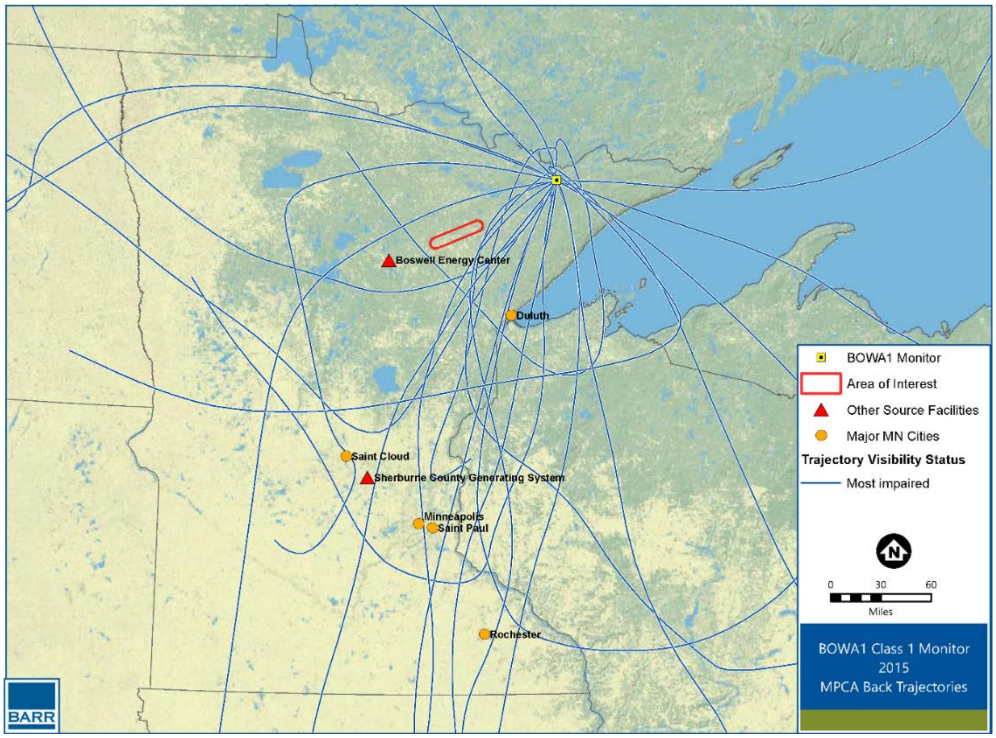

Figure A3 Reverse Trajectories and Other Sources Influencing Visibility at BWCA[9]

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[9] 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 visibility impacts (or a surrogate metric for the impacts)</u>, [and] the in-place emission control measures…"*[10]

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. <u>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</u>. 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 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).*

[10] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 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 $PM_{2.5}$ 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."[11]

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 2nd 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_X 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_X 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_X 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 NOx 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_X 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

[11] 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_X 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_X 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_X 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_X 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_3) is a component of haze associated with NO_X 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."[12] 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."[13]

[12] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.
[13] Ibid, Page 12.

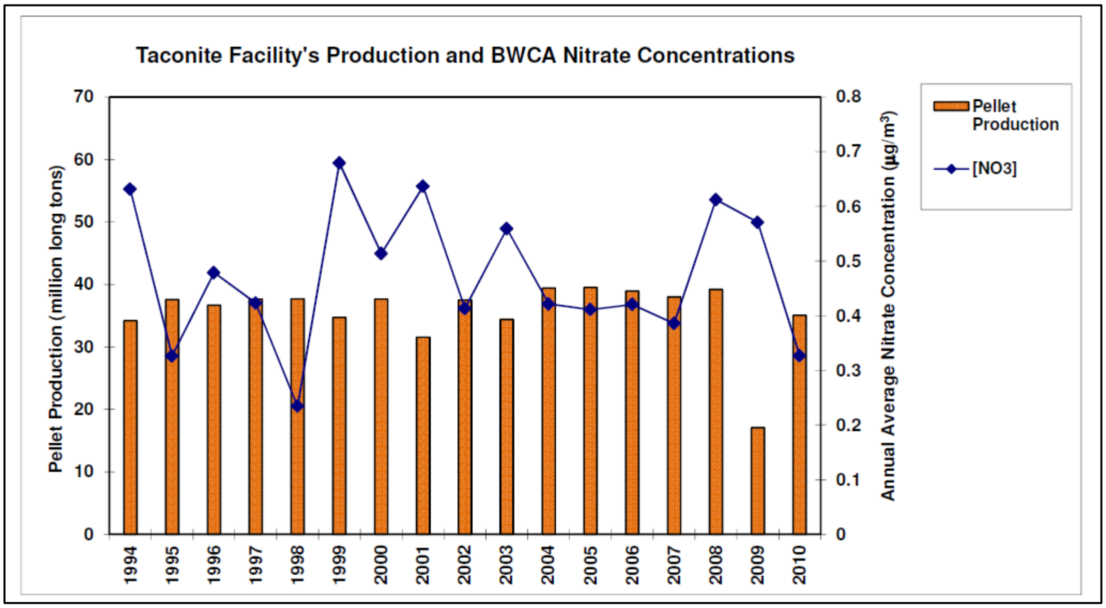

Figure A4 Minnesota Taconite Production and BWCA Nitrate Concentrations 1994-2010 [14]

[14] 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

Table A1 Results from MPCA Hysplit Trajectories for the BOWA1 Monitor

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

Table A2 Results from MPCA Hysplit Trajectories for the VOYA2 Monitor

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

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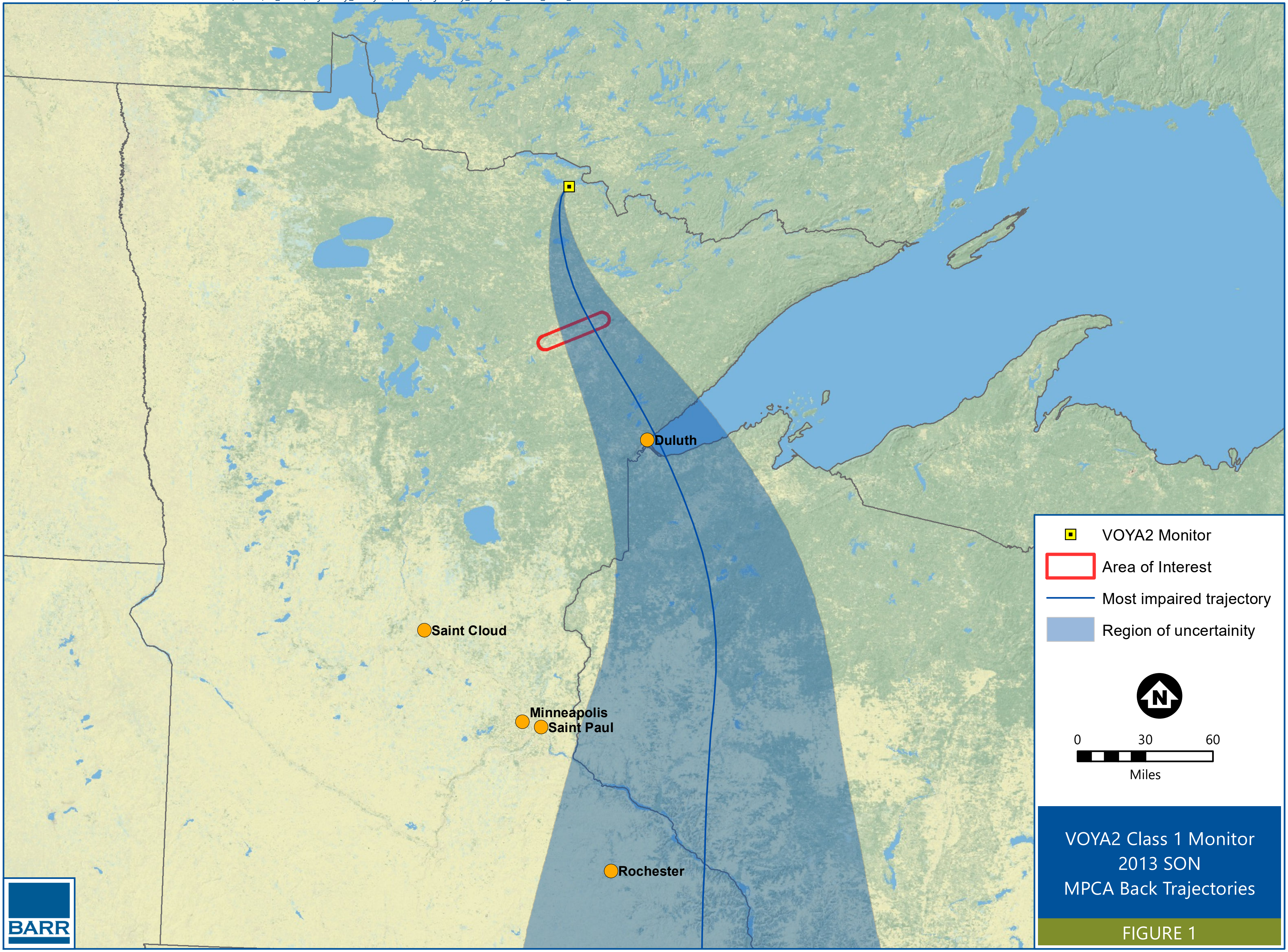
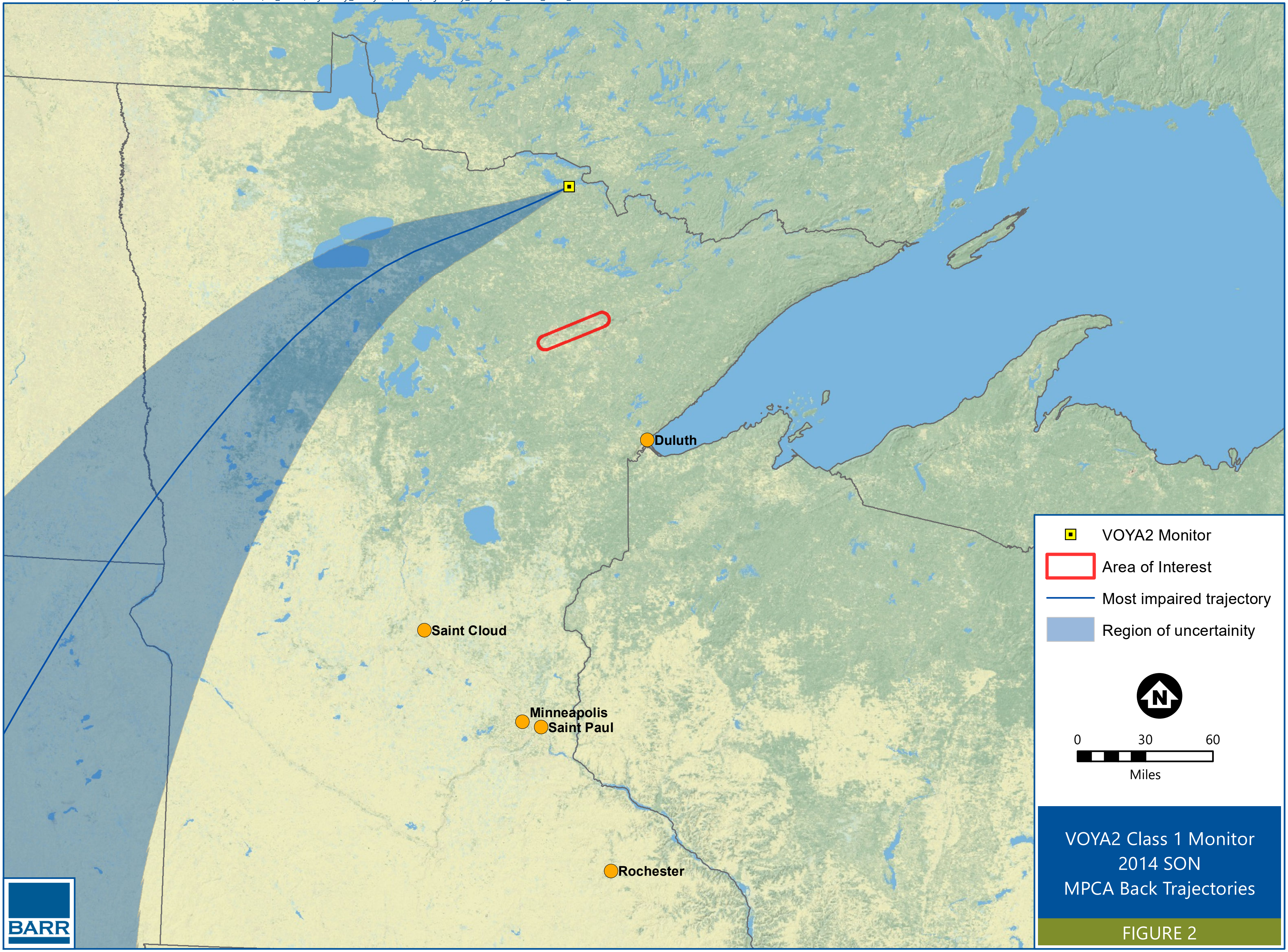


VOYA2 Class 1 Monitor
2013 SON
MPCA Back Trajectories

FIGURE 1



VOYA2 Class 1 Monitor
2014 SON
MPCA Back Trajectories

FIGURE 2

Attachment 2

CAM_X Modeling Report

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engineering and environmental consultants

Technical Memorandum

From: Barr Engineering

Subject: Summary of Comprehensive Air Quality Model with Extensions (CAM_X) 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_X), 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_X, as EPA's approach over-predicted visibility impacts by factors of ten to sixty when compared with the proper CAM_X 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_X Modeling Methodology

The methodology utilized by Barr to complete the CAM_X 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_X modeling system (CAM_X 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_X 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."[1] 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

[1] 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_X 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_X (including Tilden Mining). A list of the sources that were included in the specific PSAT groups can be found in Appendix C: CAM_X 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.

Table 1: Facility Taconite Furnace Emission Summary

Facility	FIP Baseline (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**

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.

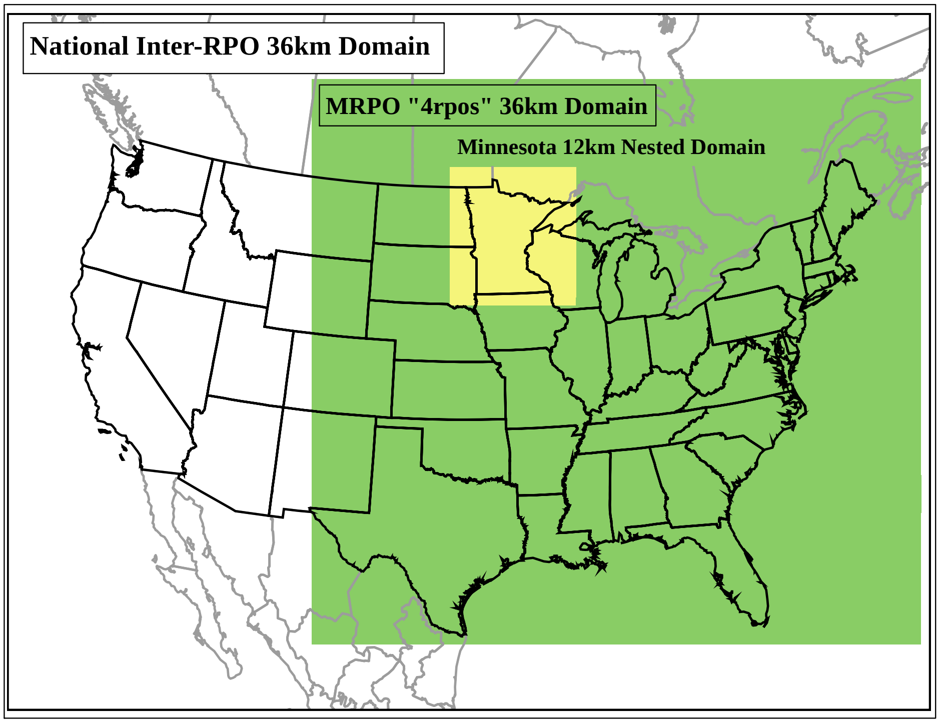

Figure 1. MPCA Modeling Domain

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_X 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_X 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_X/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_X Results

As mentioned above, the CAM_X 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_X 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_X modeling for this project on a facility by facility basis. The first three facilities contain emission reductions for only NO_X: Arcelor Mittal, Hibbing Taconite, and Northshore Mining. These results are summarized in Tables 2-4. United Taconite and Tilden Mining, which have both SO_2 and NO_X emission reductions, have result comparisons that require additional discussion.

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

0.5 dV impact 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)[2],

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

0.1 dV difference was defined by other agencies, such as the northeastern states MANE-VU Regional Planning Organization[3] as the degree of visibility improvement that is too low to justify additional emission controls. In addition, EPA's Regional Haze Rule mentions[4] 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 98th 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_X Modeled Difference).

Table 2: Arcelor Mittal Visibility Impact Comparison

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[2] 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule.

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

[4] 64 FR 35730.

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by 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 Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by 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 Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by 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_X 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^{th} percentile visibility improvement in all cases for the Arcelor Mittal, Hibbing Taconite, and Northshore Mining facilities. The maximum 98^{th} 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^{th} 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.

Table 5: Hibbing Taconite Line-Specific Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 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

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_2 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_X and the revised emission reduction for SO_2. Then, those resultants were averaged for each of the Class I areas to obtain the "updated" EPA all pollutant estimates.

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

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.6		1.40		110%
Voyageurs	0.8		0.85		N/A
Isle Royale	1.1		0.35		320%

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_X 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_X 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_X 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_X 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.[5]

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

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.0		1.29		N/A
Voyageurs	0.5		0.74		N/A
Isle Royale	0.6		0.28		210%

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

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	2.3		0.18		1300%
Voyageurs	1.1		0.08		1400%
Isle Royale	1.6		0.05		3200%

[5] 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.

Table 9: United Taconite Line-Specific Nitrate Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 98% dV
Boundary Waters	Line 1		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

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.

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

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV
Boundary Waters	N/A		0.08
Voyageurs	N/A		0.03
Isle Royale	N/A*		0.17

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

Table 11: Tilden Mining Pollutant-Specific Impact Comparison

Class I Area	CAM_X Sulfate Modeled Difference 98% dV		CAM_X Nitrate Modeled Difference 98% dV
Boundary Waters	0.07		0.01
Voyageurs	0.03		0.00
Isle Royale	0.14		0.02

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_X 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."[6] Our analysis demonstrates that the ratio approach has over-estimated impacts by a factor of ten to sixty for NO_X reductions. When accurately modeled, the NO_X reductions do not yield discernible visibility benefits. To that end, the following pictures from WinHaze Level 1 Visual Air Quality Imaging Modeler

[6] 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[7].

Isle Royale FIP Base – United Taconite

Isle Royale Final FIP – United Taconite

Boundary Waters FIP Base – Hibbing 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_X 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.

[7] 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?

- *<u>For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.</u>*

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.

- *<u>Make the net visibility improvement determination.</u>*

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.

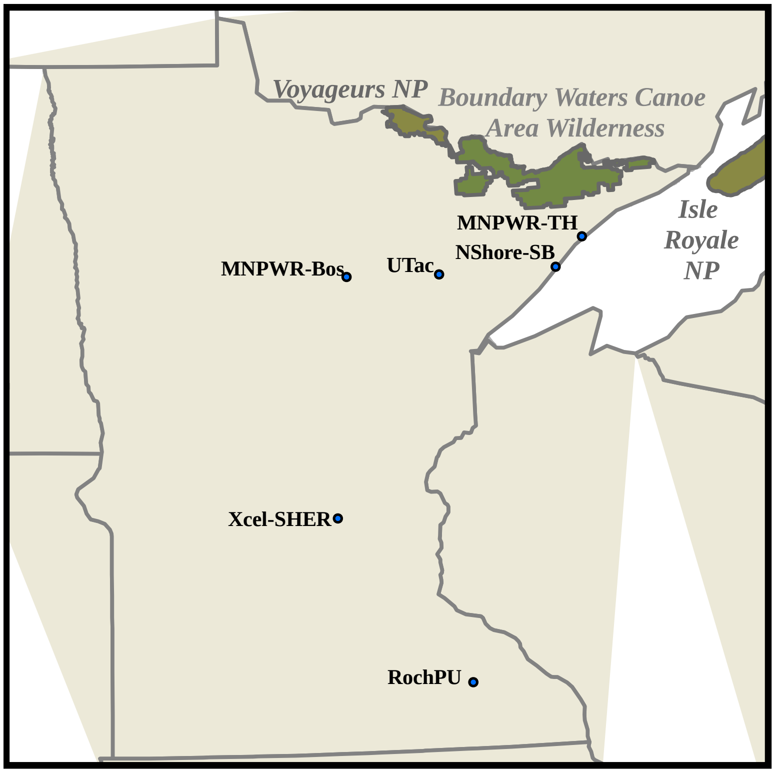
II. Summary of EPA's approach

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[1] 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).

1 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 98th 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 the total visibility impacts that would result from the reduction of PM2.5 concentrations</u>."

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_X 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_X 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^{th} 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_X 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_X 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			Emission Reductions			Emissions	
				Proposed FIP			Baseline - Prop FIP	Baseline - Prop FIP		Final FIP	
	Emission Unit			Baseline	FIP		Emission Tables	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 Combined	NOx	6,888	2,066		**4,821**	**5,259**	[3]		
			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]
	NSM	BART Units Combined	NOx	805	250		**555**	**926**	[9]		
			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]
	TMC	BART Units Combined	NOx	4,707	1,478		3,229	3,229	[18]		
			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 Combined	NOx	5,330	1,599		**3,731**	**3,208**	[26]		
			SO2	4,043	404		3,639	3,639	[26]	529	[28]
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	1,092	[29]	**2,547**	**2,859**	[31]		[32]
			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		EPA Furnace
	FIP Baseline does not match reference		NOx Control %
	FIP Table B emission tables do not match Table C visibility calculation tables		70%

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 Emisssions = 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)

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APPENDIX B: Barr and MPCA CAM_X Modeling Comparison of Results

March 6, 2013

Minnesota Power – Taconite Harbor (BART01)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	94	90	-4	11	9	-2	30	27	-3
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	95	90	-5	11	9	-2	30	27	-3
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-Ence	Base	BART	Differ-ence	Base	BART	Differ-Ence
Days > 0.5 dv	2002	111	60	-51	86	58	-28	48	27	-21
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-Ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	110	61	-49	86	58	-28	47	27	-20
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	77	72	-5	9	8	-1	20	15	-5
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	78	72	-6	9	8	-1	20	15	-5
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	59	44	-15	32	20	-12	8	1	-7
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	63	46	-17	34	20	-14	8	1	-7
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	74	58	-16	53	39	-14	42	30	-12
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	74	59	-15	53	39	-14	42	29	-13
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	0	0	0	0	0	0	0	0	0
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	0	0	0	0	0	0	0	0	0
98th Percentile Δ dv	2002	0.10	0.06	0.04	0.08	0.04	0.04	0.09	0.04	0.05

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APPENDIX C: CAM_X PSAT Source List

March 6, 2013

2009 MPCA Tracked, Elevated Point Sources

RANKTRAC BARTSRC_ID	RECEPTOR 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

(yellow)	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	2703100001	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

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

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APPENDIX D: Summary of CAM_X Elevated Point Source Emissions

March 6, 2013

Summary of CAMx Elevated Point Source Emissions

Facility	Emission Unit ModID	Emission Unit Description	Pollutant	Emissions Proposed FIP Baseline tons/yr	Note(s)	Emissions Final FIP FIP tons/yr	Note(s)	Emission Reductions Baseline - Final FIP 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 Combined	NOx	6,888		2,066		4,821
			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
	NSM	BART Furnaces Combined	NOx	764		229		535
			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 Combined	NOx	5,330		1,599		3,731
			SO2	4,043		1,969		2,074
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	[28]	1,092	[30]	2,547
			SO2	179	[29]	179	[31]	0

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

(yellow)	Facility Furnace Unit Summary or Overall Summary
(green)	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)

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

March 6, 2013

From: Jeffry D. Bennett
Sent: Thursday, January 31, 2013 7:42 PM
To: 'Rosenthal.steven@Epa.gov'
Cc: 'Long, Michael E'
Subject: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: 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

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APPENDIX F: CAMx Modeling Results by Facility

March 6, 2013

Arcelor Mittal CAMx Emissions and Modeling Results

Arcelor Emissions

Unit	EPA FIP Baseline NOx Emission (TPY) [1]	Final FIP NOx Emission (TPY) [1]	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY) [2]	Final FIP SO2 Emission (TPY)[3]	SO2 Emission Difference (TPY)
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)

Arcelor CAMx Results (By Unit) [4]

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Proposed FIP Days > 0.5 dV	Proposed FIP 98% dV	Difference Days >0.5 dV [5]	Difference 98% dV [5]
Boundary Waters						
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
Voyageurs						
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:

0.5 dV impact is the BART eligibility threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required),
1.0 dV difference is the presumed human perceptible level for visibility improvement, and
0.1 dV difference 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 98th 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 98th 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 C Emission Difference = 2,859 TPY NOx)[6]
(EPA Table B Emission Difference = 2,547 TPY NOx)[7]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[8]	CAMx Modeled Difference 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

[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 98th 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 Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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
Voyageurs						
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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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 Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (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)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Voyageurs						
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
Isle Royale						
2002						
Power Boiler #1	3	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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	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.

<u>United Taconite (UTAC) CAMx Emissions and Modeling Results</u>

UTAC Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)[12]	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)[13]	SO2 Emission Difference (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

UTAC CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
<u>Boundary Waters</u>						
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

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[16]	CAMx Modeled Difference 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

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

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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

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_X 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).

UTAC Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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						
Line #1 – NO3	0	0.026	0	0.011	0	0.015
Line #1 – SO4	0	0.150	0	0.072	0	0.078
Line #1 – All	0	0.163	0	0.080	0	0.083

UTAC Line 2 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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 – SO4	16	0.773	6	0.436	10	0.337
Line #2 – All	17	0.786	6	0.446	11	0.340
Isle Royale						
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 Comparison of Sulfate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 2,074 TPY SO2

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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

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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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^{th} percentile NO3 impact when combining both line emission reductions is 0.18 dV, while the maximum 98^{th} percentile SO4 impact for both lines is 1.29 dV. 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 Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1	0	0.141	0	0.037	0	0.104
2005						
Line #1	0	0.097	0	0.042	0	0.055
Voyageurs						
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

Tilden Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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
Voyageurs						
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

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.

Impacts of the taconite plants' NO_X 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 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X 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)[1] 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[2].

The United States Environmental Protection Agency (EPA) has issued a proposed rule[3] to address BART requirements for taconite plants in Minnesota and Michigan that involves emission controls for SO_2 and NO_X. This document addresses the likely visibility impact of taconite plant emissions, specifically NO_X 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[4], the distance limitation is 200-300 km because of the overprediction tendencies[5] 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.

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[1] Regional Haze Regulations; Final Rule. *Federal Register*, *64*, 35713-35774. (July 1, 1999).

[2] Federal Register. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, Vol. 70. (July 6, 2005)

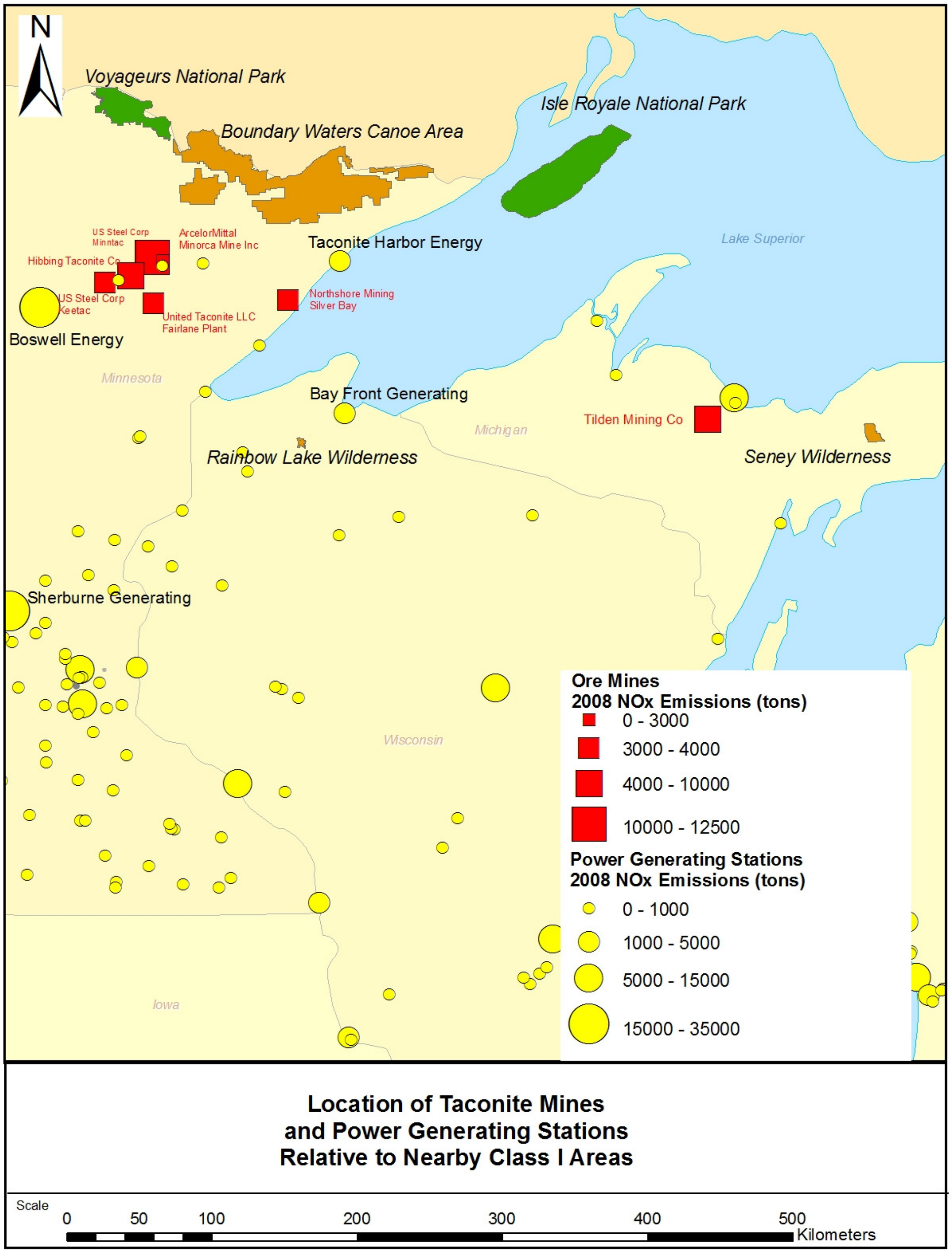
[3] 77FR49308, August 15, 2012.

[4] CALPUFF Dispersion Model, 2000. http://www.epa.gov/scram001 (under 7th Modeling Conference link to Earth Tech web site).

[5] As documented in Appendix D of the IWAQM Phase 2 document, available at www.epa.gov/scram001/7thconf/calpuff/**phase2**.pdf.

AECOM

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_X emission controls are considered as a BART option because modeling secondary formation of ammonium nitrate is quite challenging. Accurately modeling the effects of NO_X 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_X, and the associated effectiveness of NO_X 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.

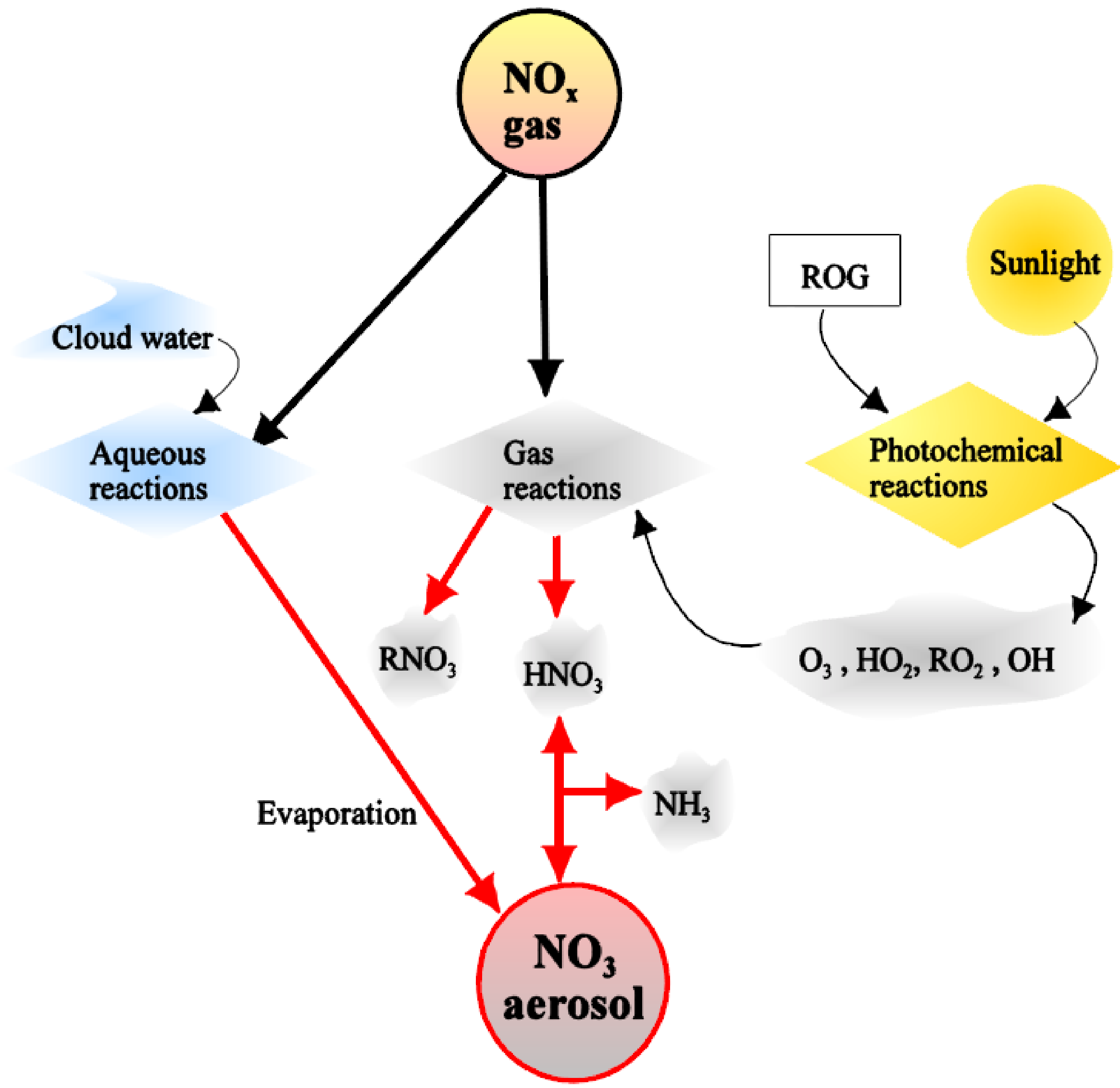
- There are examples where actual significant emission reductions have occurred, where CALPUFF modeling as conducted for BART would predict significant visibility improvements, but no perceptive changes in haze occurred.

Visibility Impact of NO_X Emissions – Unique Aspects and Seasonality

The oxidation of NO_X to total nitrate (TNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the TNO_3 is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state with HNO_3 gas that is a function

of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 2[6]. 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_x Oxidation



[6] Figure 2-32 from CALPUFF Users Guide, available at http://www.src.com/calpuff/download/CALPUFF_UsersGuide.pdf.

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:

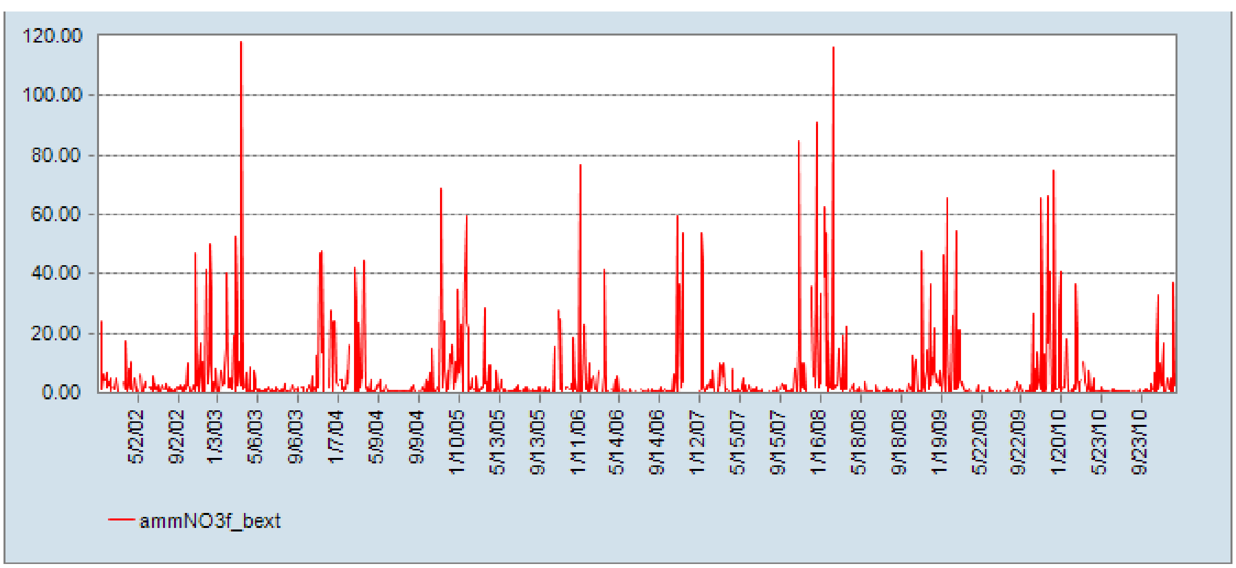
- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium 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_X 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



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 water-dominant Class I areas in Minnesota (Voyageurs and Boundary Waters) that freeze in winter. In fact, for Voyageurs National Park, the typical monthly attendance[7] 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 totally close[8] 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[9] 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[10] 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[11] of nitrate and sulfate haze in

[7] As documented at http://www.gorp.com/parks-guide/voyageurs-national-park-outdoor-pp2-guide-cid9423.html.

[8] As noted at http://www.nps.gov/isro/planyourvisit/hours.htm.

[9] As noted at http://www.fws.gov/midwest/seney/visitor_info.html.

[10] 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.

[11] 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 4 Minnesota Taconite Production and BWCA Nitrate Concentrations

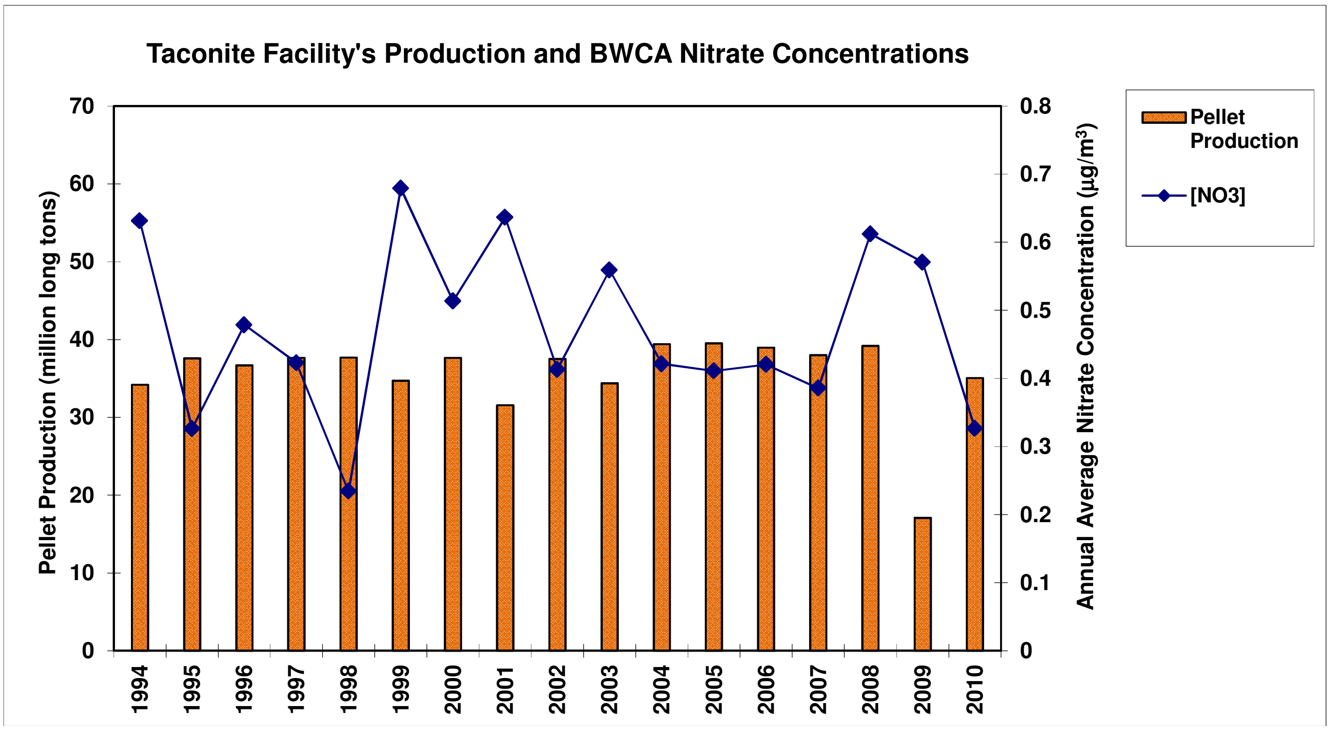


Figure 5 Time Series of Nitrate Haze at Boundary Waters Canoe Area (2002-2010)

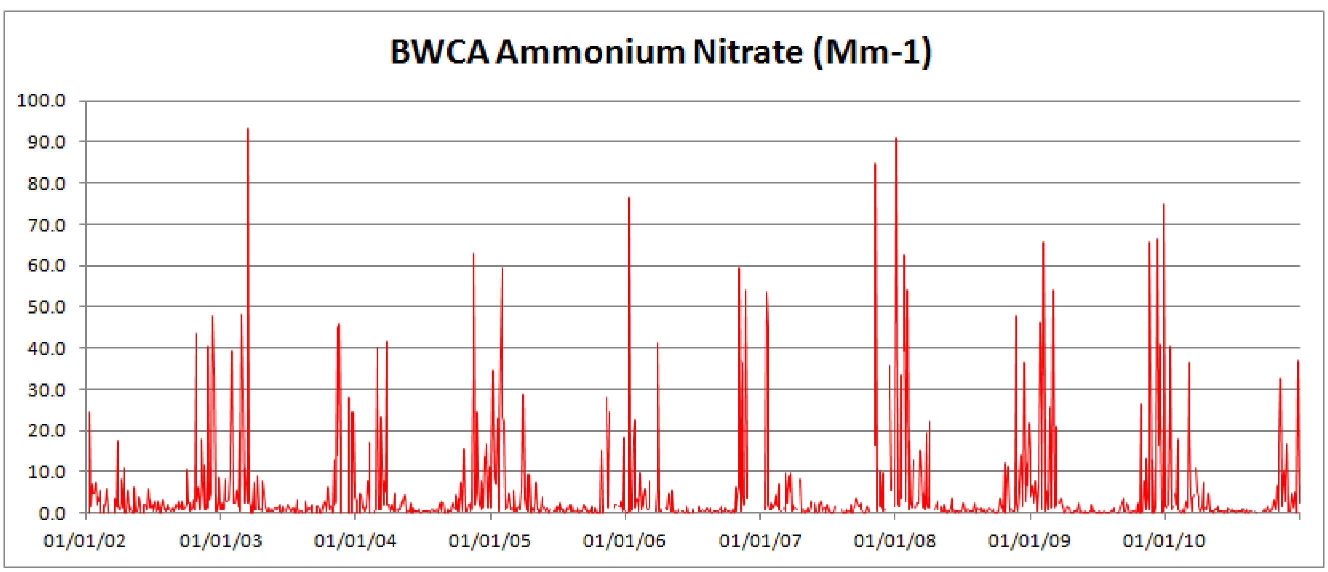
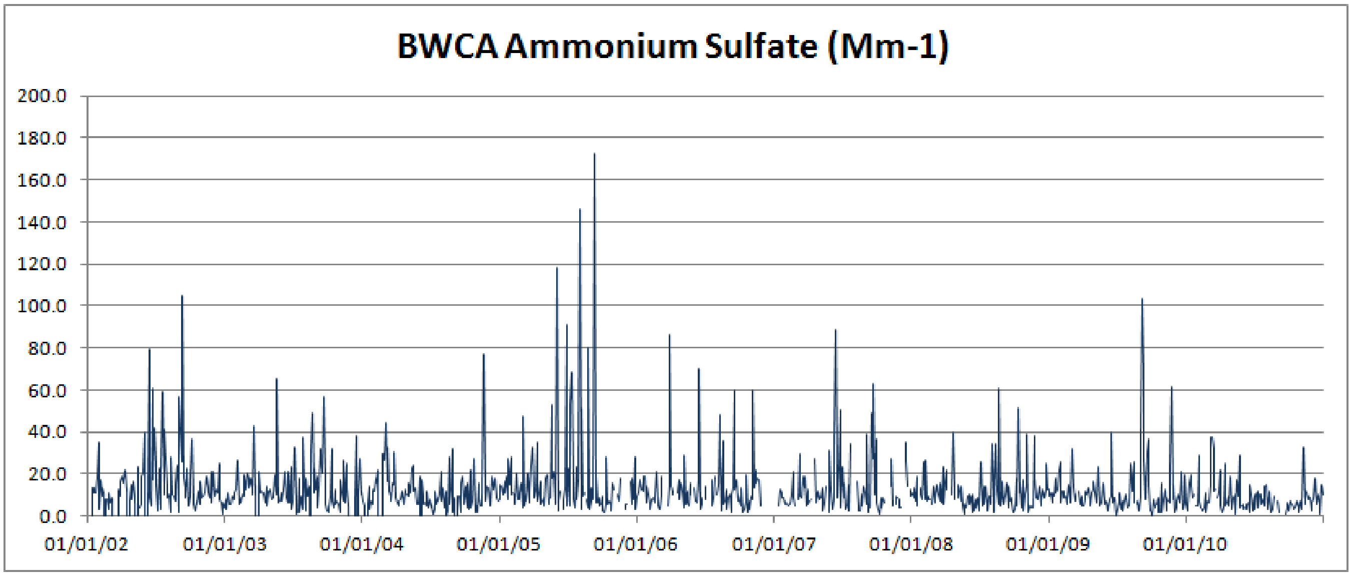


Figure 6 Time Series of Sulfate Haze at Boundary Waters Canoe Area (2002-2010)



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

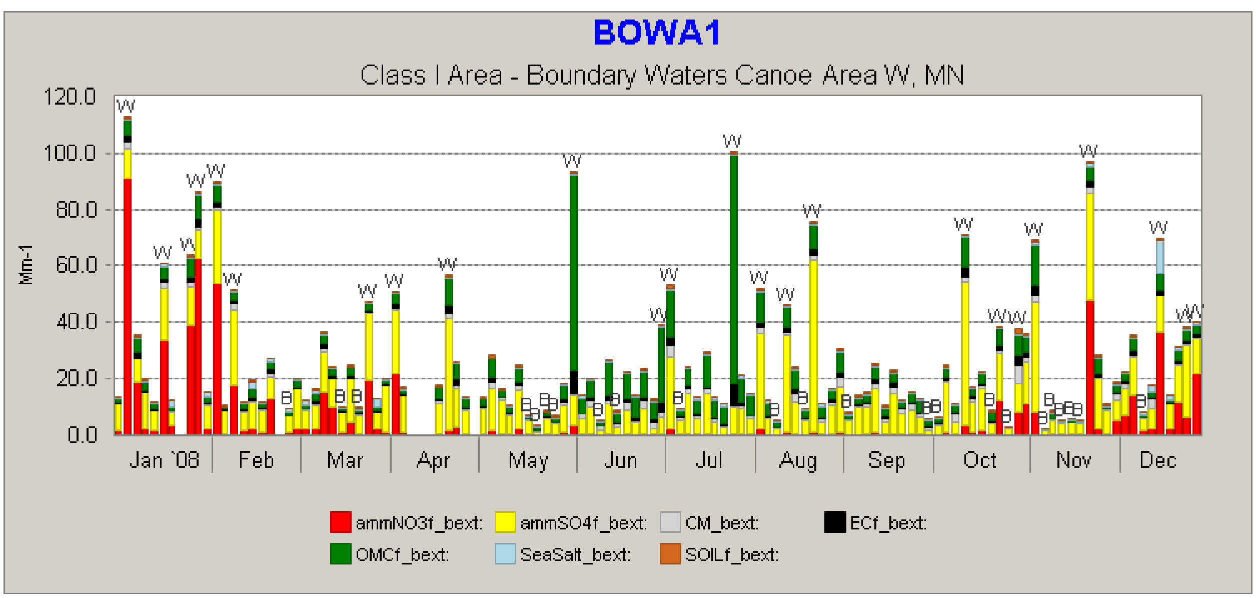


Figure 8 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2009

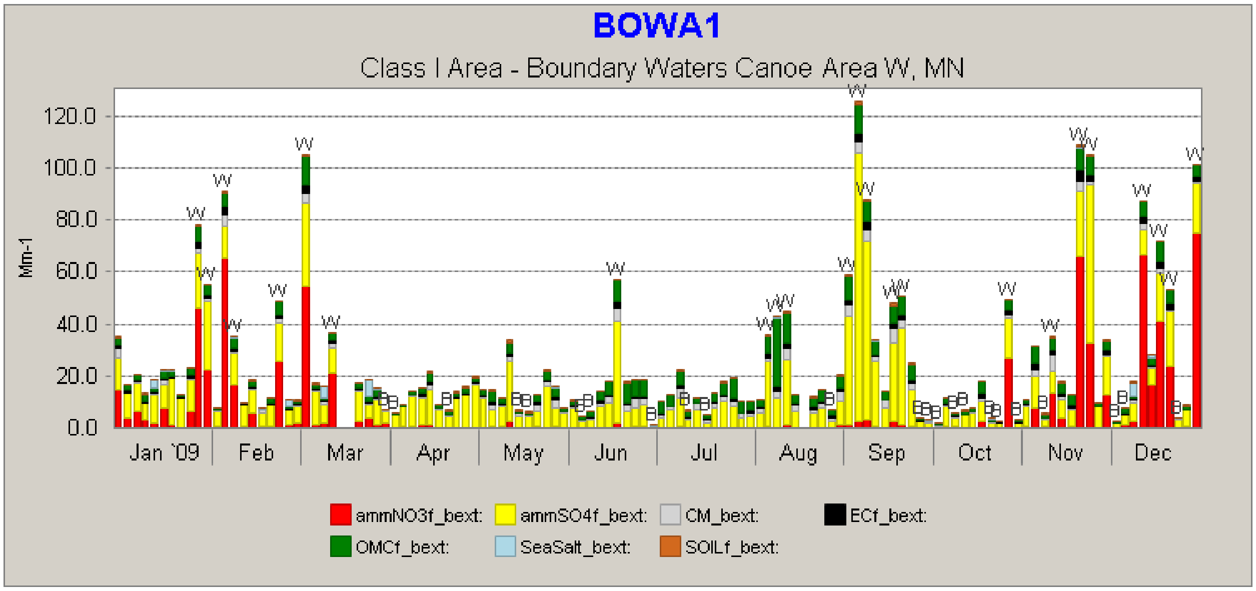
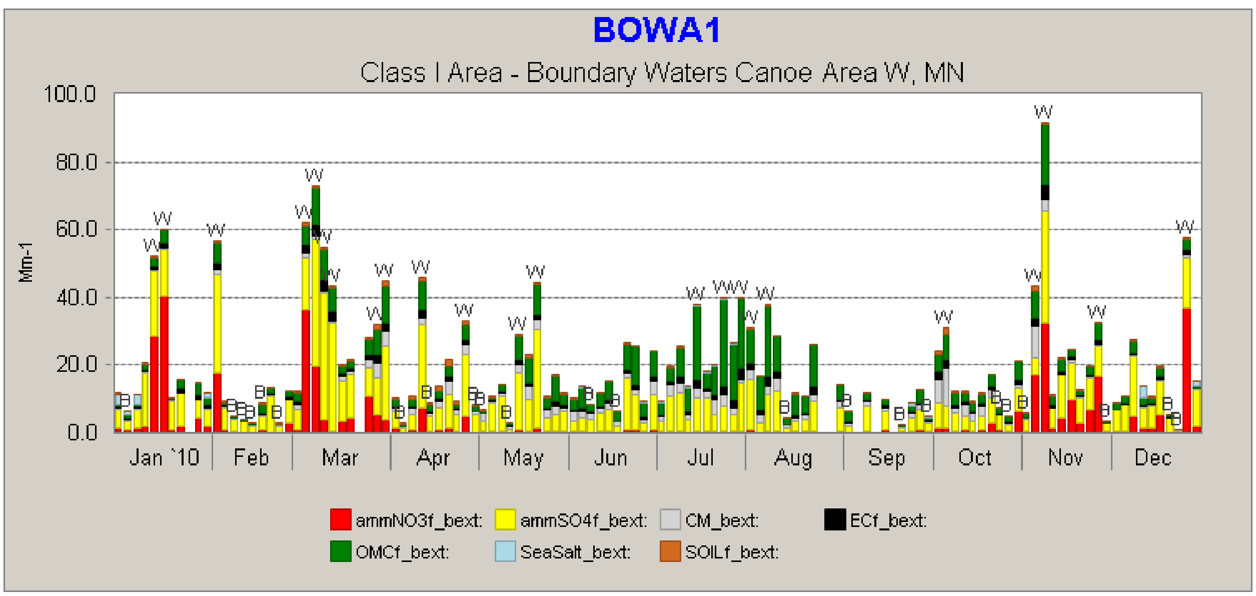


Figure 9 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2010



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.

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 anywhere 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 98th 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

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_X 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[12] 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 9th 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 11th and 12th, 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.

[12] See, for example, the Iowa State Implementation Plan for Regional Haze report at http://www.iowadnr.gov/portals/idnr/uploads/air/insidednr/rulesandplanning/rh_sip_final.pdf, Figures 11.3 and 11.4.

Figure 10 PSAT Results from CENRAP CAMx Modeling for Isle Royale National Park

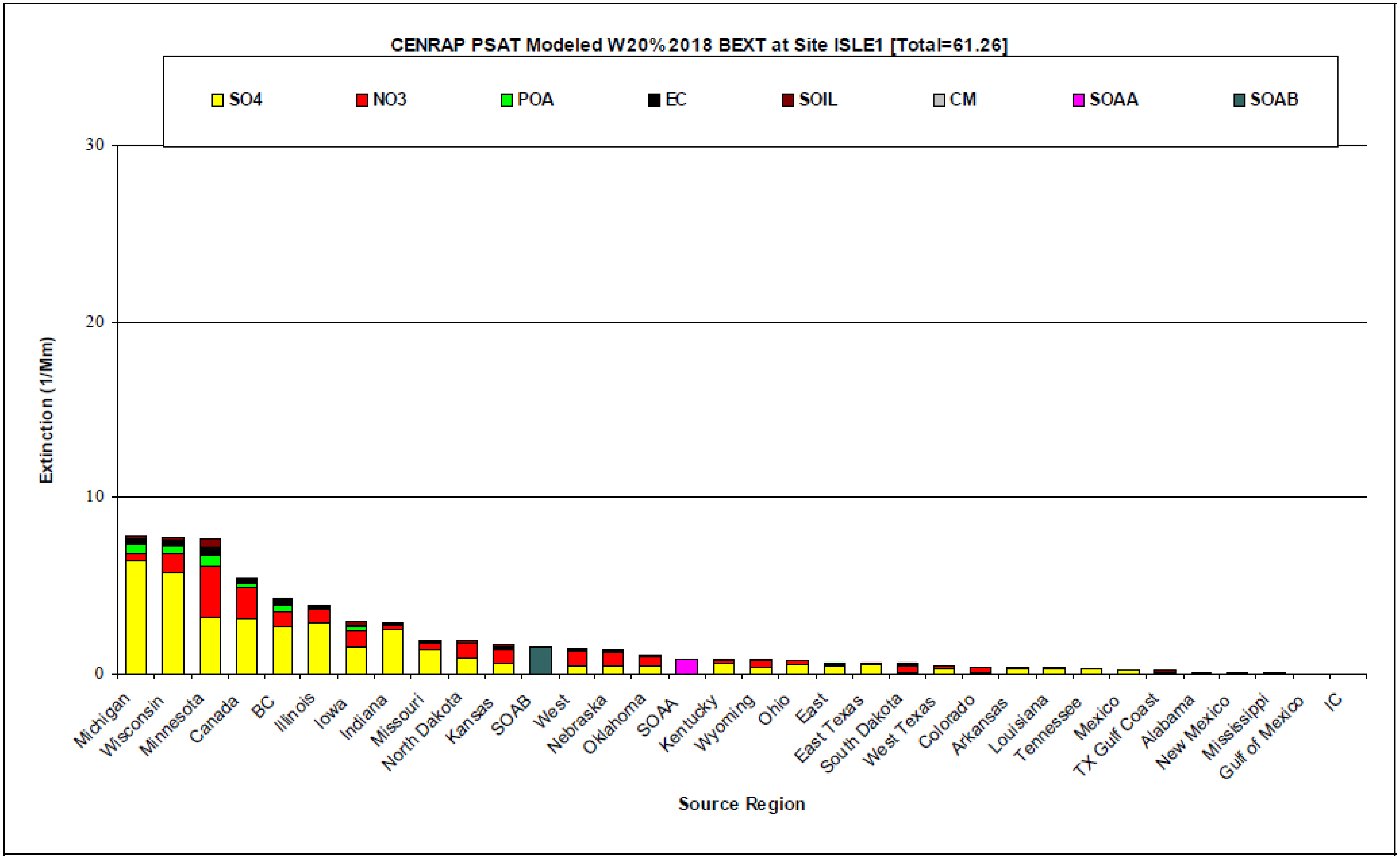


Figure 11.3. Source apportion contributions by region and pollutant to ISLE in 2018.

Figure 11 PSAT Results from CENRAP CAMx Modeling for Seney Wilderness Area

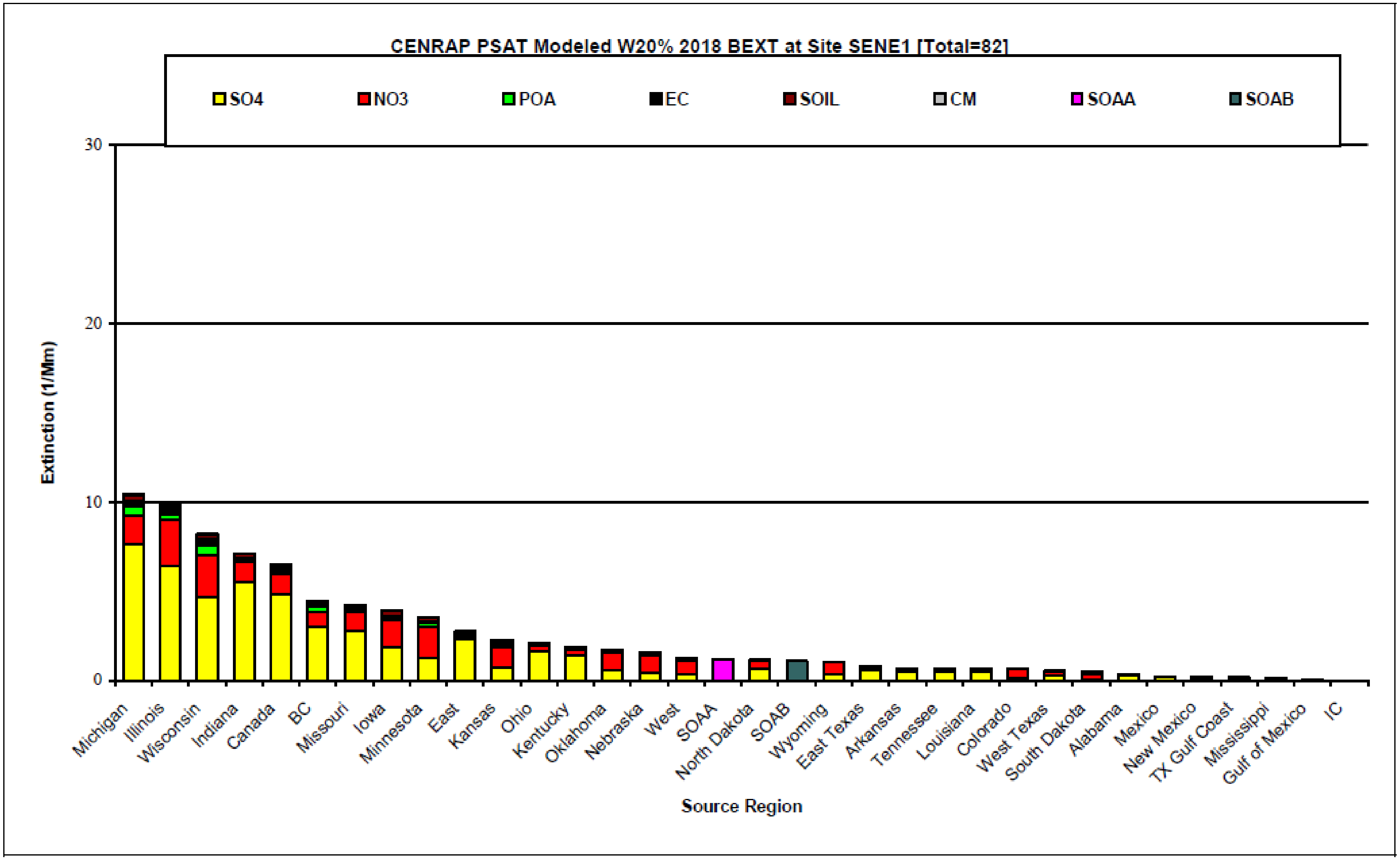


Figure 11.4. Source apportion contributions by region and pollutant to SENE in 2018.

Figure 12 PSAT Results from CENRAP CAMx Modeling for Boundary Waters Canoe Area Wilderness

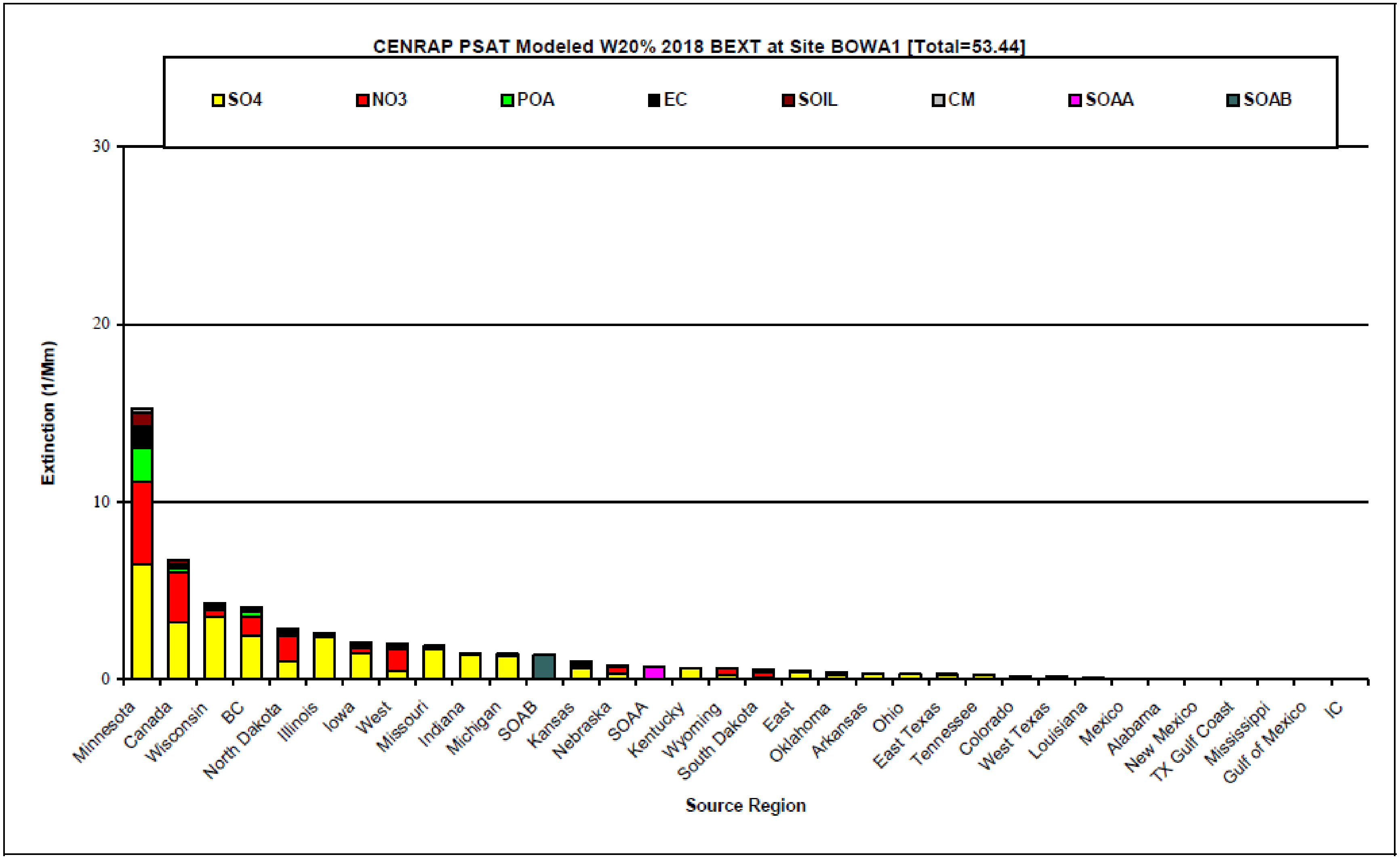


Figure 11.1. Source apportion contributions by region and pollutant to BOWA in 2018.

Figure 13 PSAT Results from CENRAP CAMx Modeling for Voyageurs National Park

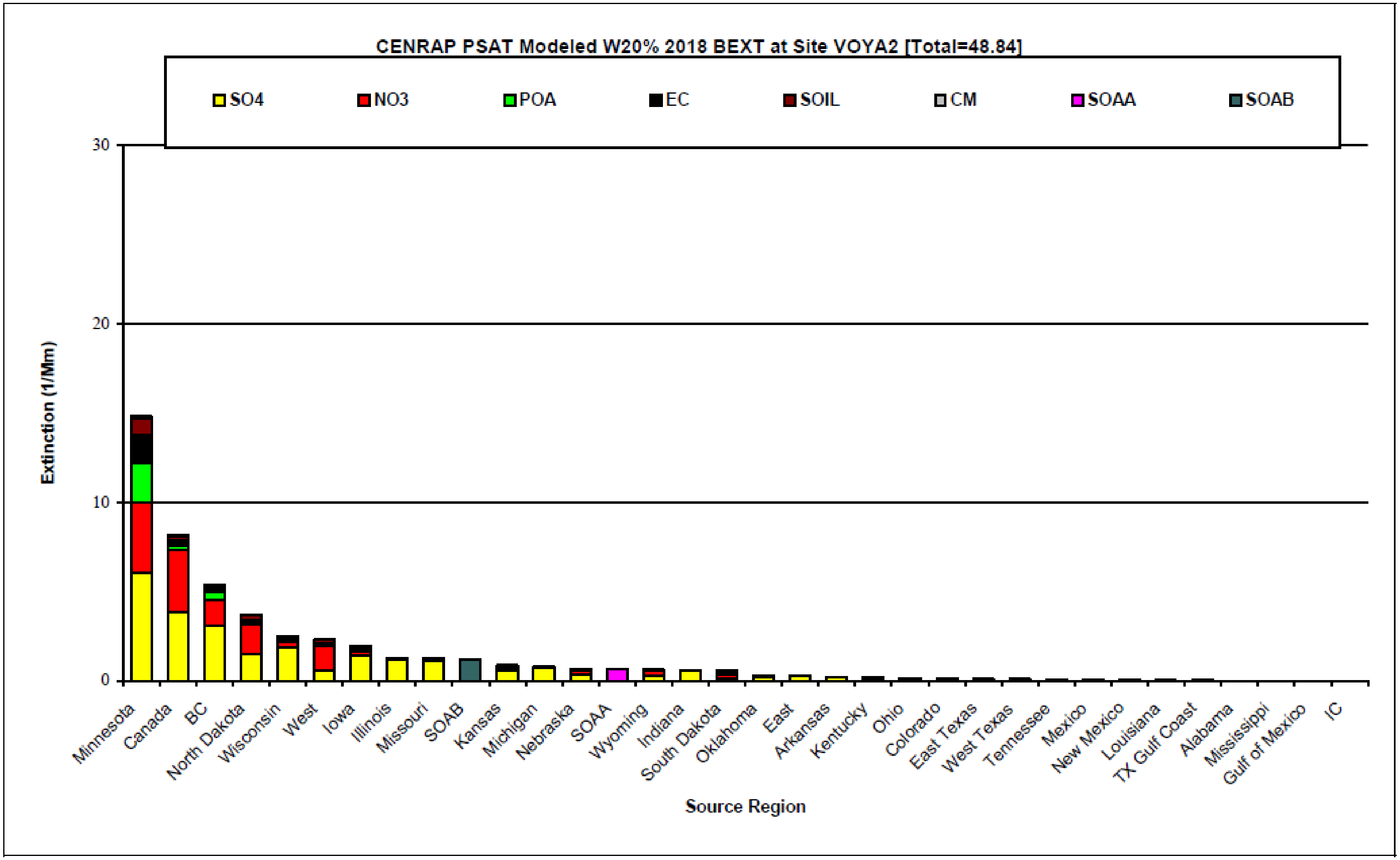


Figure 11.2. Source apportion contributions by region and pollutant to VOYA in 2018.

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_X 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 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X 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.

APPENDIX A

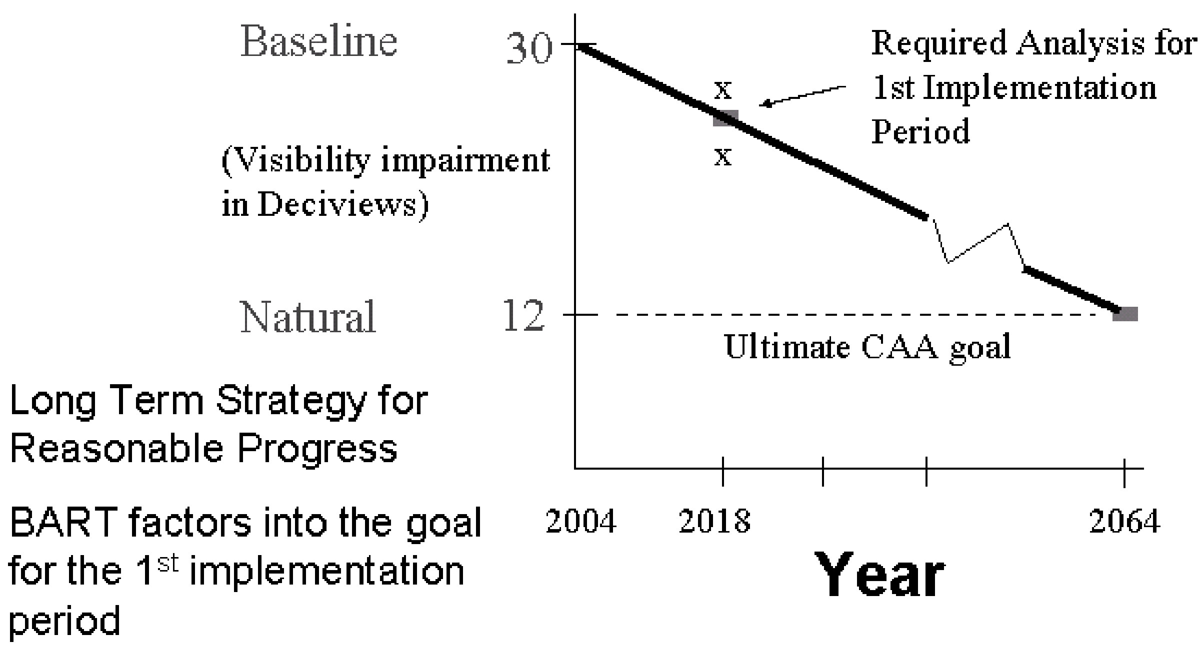
THE REGIONAL HAZE RULE GOAL OF NATURAL CONDITIONS

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[13] 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 20th century.

Figure A-1: Illustration of the Uniform Rate of Progress Goal



[13] *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, (U.S. Environmental Protection Agency, September 2003). http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf.

In its RHR SIP, North Dakota[14] 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_2 and NO_x 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.

[14] North Dakota Dep. of Health, 2010. North Dakota State Implementation Plan for Regional Haze. http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Main%20SIP%20Sections%201-12.pdf.
.

- As a result, there is a substantial reduction in SO_2 and NO_x 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[15], 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 (http://views.cira.colostate.edu/web/) 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_2 and NO_X.

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_2 and NO_x).

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.

[15] See Appendix 2-2 at http://www.tceq.state.tx.us/implementation/air/sip/bart/haze_appendices.html.

These estimates were derived from Trijonis[16] and use two different sets of natural concentrations for the eastern and western U.S. Tombach[17] 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		Error Factor	Dry Extinction Efficiency (m^2/g)
	West ($\mu g/m^3$)	East ($\mu g/m^3$)		
Ammonium sulfate [b]	0.12	0.23	2	3
Ammonium nitrate	0.10	0.10	2	3
Organic carbon mass [c]	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 $\mu g/m^3$ and 1.5 $\mu g/m^3$ 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.[18]

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.

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[16] 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.

[17] 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 http://www.wrapair.org/forums/aamrf/projects/NCB/index.html.

[18] 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[19] reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach[8] 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[8] 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[20]; Koo et al., 2010[21]), 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 20th century, fire suppression has resulted in a buildup of vegetative "fuels" and catastrophic wildfires. Recent estimates of background visual range, such as Trijonis[16], 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

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[19] 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.

[20] 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. (http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC_2006_report_FINAL.pdf).

[21] 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. Atm. Env., 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 http://www.nps.gov/thro/parkmgmt/firemanagement.htm for the Theodore Roosevelt National Park that:

"For most of the 20th 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[22] 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 background estimates. The consequences of the artificially low estimates of natural visibility conditions include the distortion of Reasonable Progress analyses and also to BART modeling results that overestimate the visibility improvement achievable from NO_X 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_2 and NO_x 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 20th 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.

[22] See explanation at http://www.msnbc.msn.com/id/48569985/ns/us_news-environment/t/forest-service-gets-more-aggressive-small-fires/.

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_2 and NO_X 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.

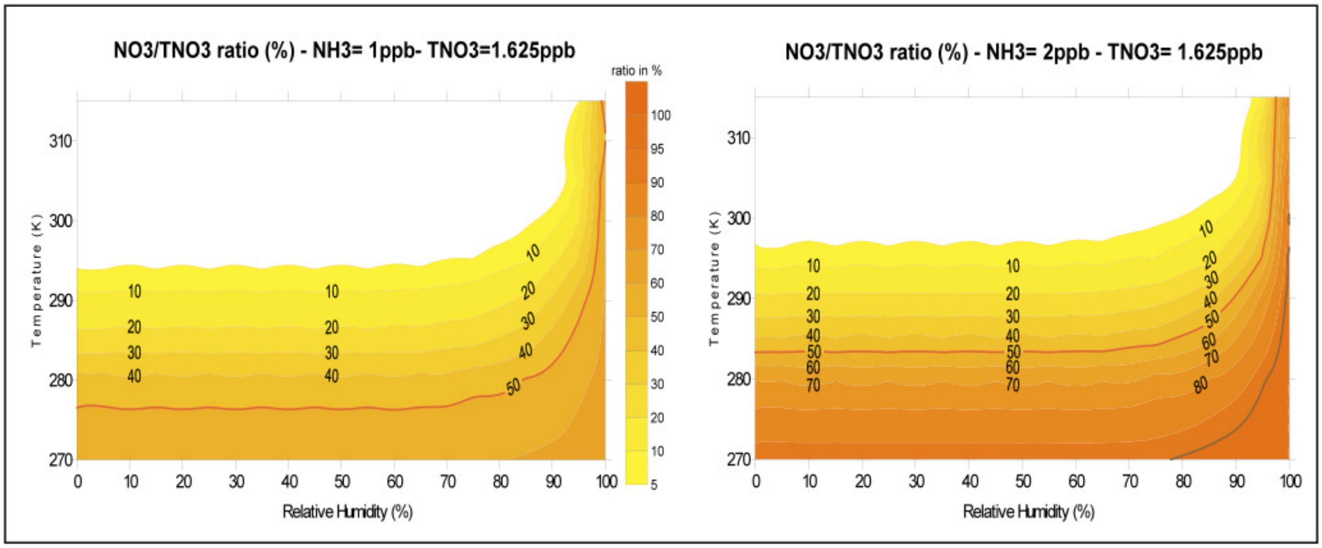
In the CALPUFF model, the oxidation of NO_X to nitric acid (HNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration. In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous HNO_3 and NO_3 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_3 to form ammonium nitrate, as shown in Figure 6[23]. 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.

[23] Scire, Joseph. CALPUFF MODELING SYSTEM. CALPUFF course presented at Chulalongkorn University, Bangkok, Thailand. May 16-20, 2005; slide 40 available at http://aqnis.pcd.go.th/tapce/plan/4CALPUFF%20slides.pdf, accessed March 2011.

Figure B-1: NO_3/HNO_3 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_X emissions relative to SO_2 emissions[24]. 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.

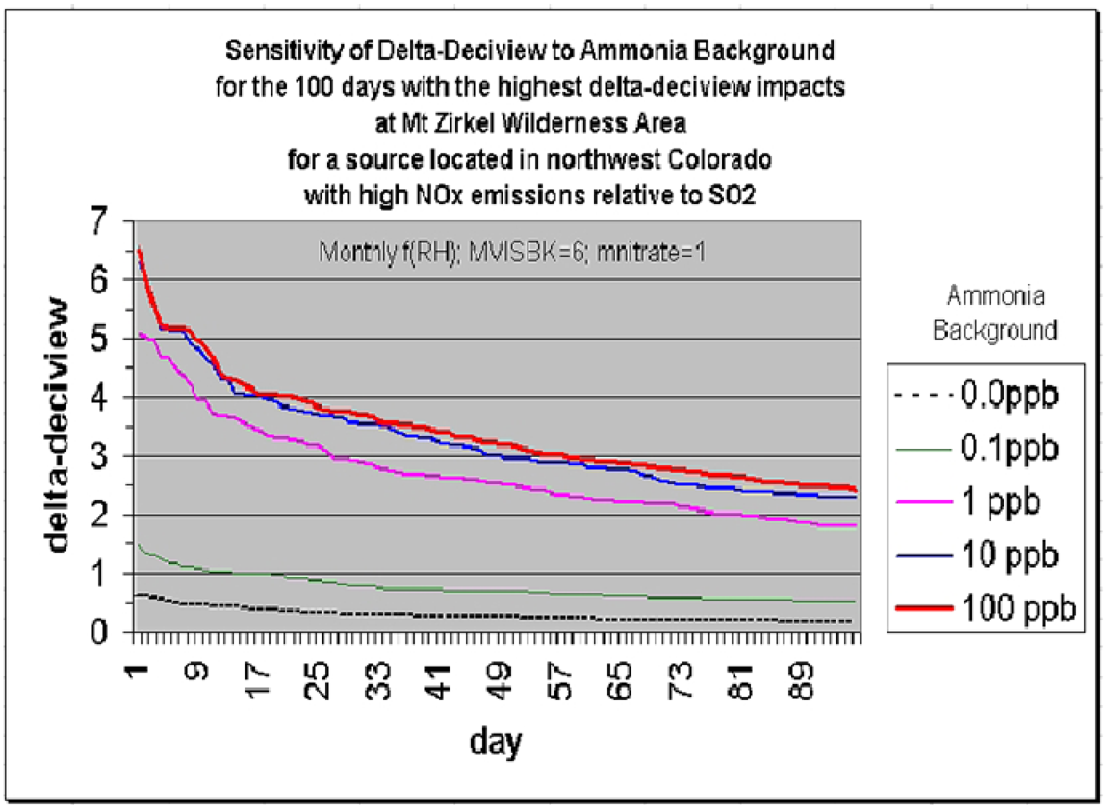
It is also noteworthy that CALPUFF version 5.8's demonstrated over-predictions of wintertime nitrate can be mitigated to some extent by using lower winter ammonia background values, although there is not extensive measurement data to determine the ambient ammonia concentrations. This outcome showing the superiority of the monthly-varying background ammonia concentrations was found by Salt River

[24] Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at http://www.colorado.gov/airquality/documents/Draft-ColoradoSupplementalBARTAnalysisCALPUFFProtocol-25June2010.pdf. (2010)

Project in case studies of the Navajo Generating Station impacts on Grand Canyon monitors, as presented[25] to EPA in 2010.

It is important to note that 14 years ago in 1998, when the IWAQM Phase 2 guidance[26] 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.



[25] 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.

[26] IWAQM Phase 2 Summary Report and Recommendations (EPA-454/R-98-019), EPA OAQPS, December 1998). http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf.

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_2 to sulfate.

On page 39121, the BART rule[27] 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[28]."

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.[29] 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[30]. 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

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[27] July 6, 2005 Federal Register publication of the Regional Haze BART rule.

[28] The next (9th) 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 10th 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.

[29] 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)

[30] 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)

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_2) by the hydroxide ion (OH^-) 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[31]. 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_X 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)[32,33], 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

[31] 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.

[32] 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.

[33] 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)

of aqueous-phase SO_2 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[34], 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_3 concentrations on model predictions of PM nitrate. Twice-weekly background NH_3 concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH_3 concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

1. MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH_3 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_3 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[35]. The results were similar to those noted above: the improved

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[34] 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)

[35] 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[36], 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 10th modeling conference in March 2012 by Scire[37], 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[29,30] 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_X emission reductions.

[36] 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)

[37] Scire, J., 2012. New Developments and Evaluations of the CALPUFF Model. http://www.epa.gov/ttn/scram/10thmodconf/presentations/3-5-CALPUFF_Improvements_Final.pdf.

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[38] 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_X emission reductions.

[38] http://pah.cert.ucr.edu/aqm/cenrap/meetings.shtml, under “MPE”, slides 9 and 10.

Figure B-3: Sensitivity Study of Nitrate Predictions at Bridger Wilderness Area for Input Ammonia Concentrations to CALPUFF (0.23, 0.5, and 1.0 ppb).

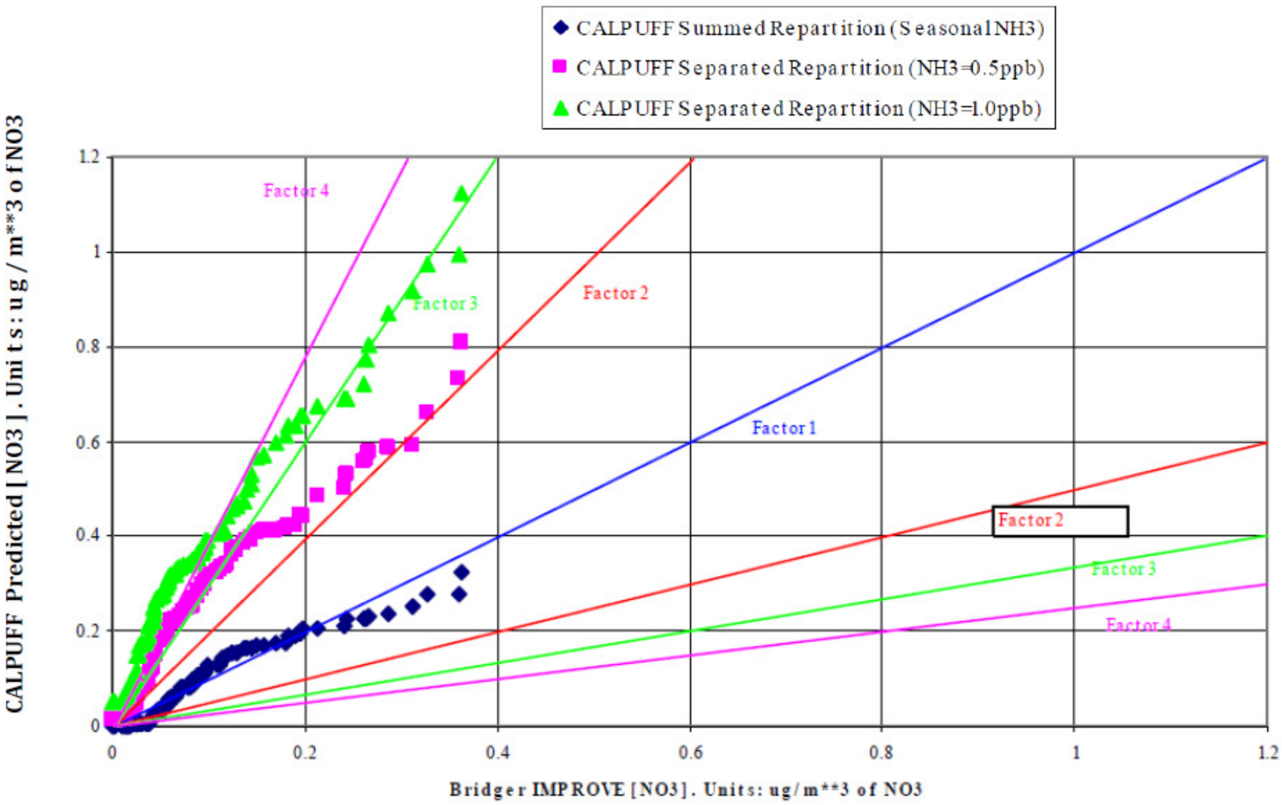


Figure B-4 CMAQ vs. Observed Haze Predictions at Voyageurs National Park

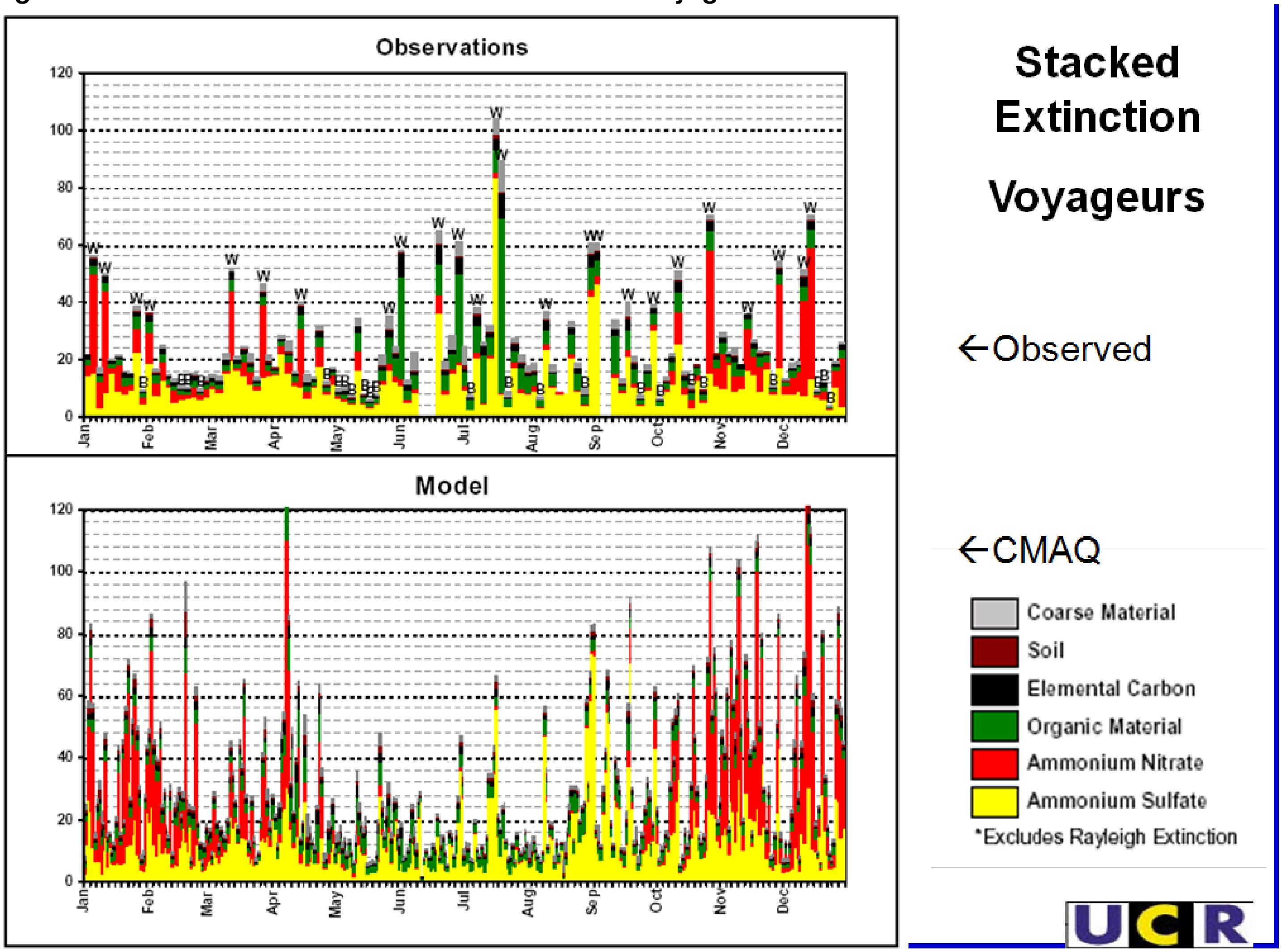
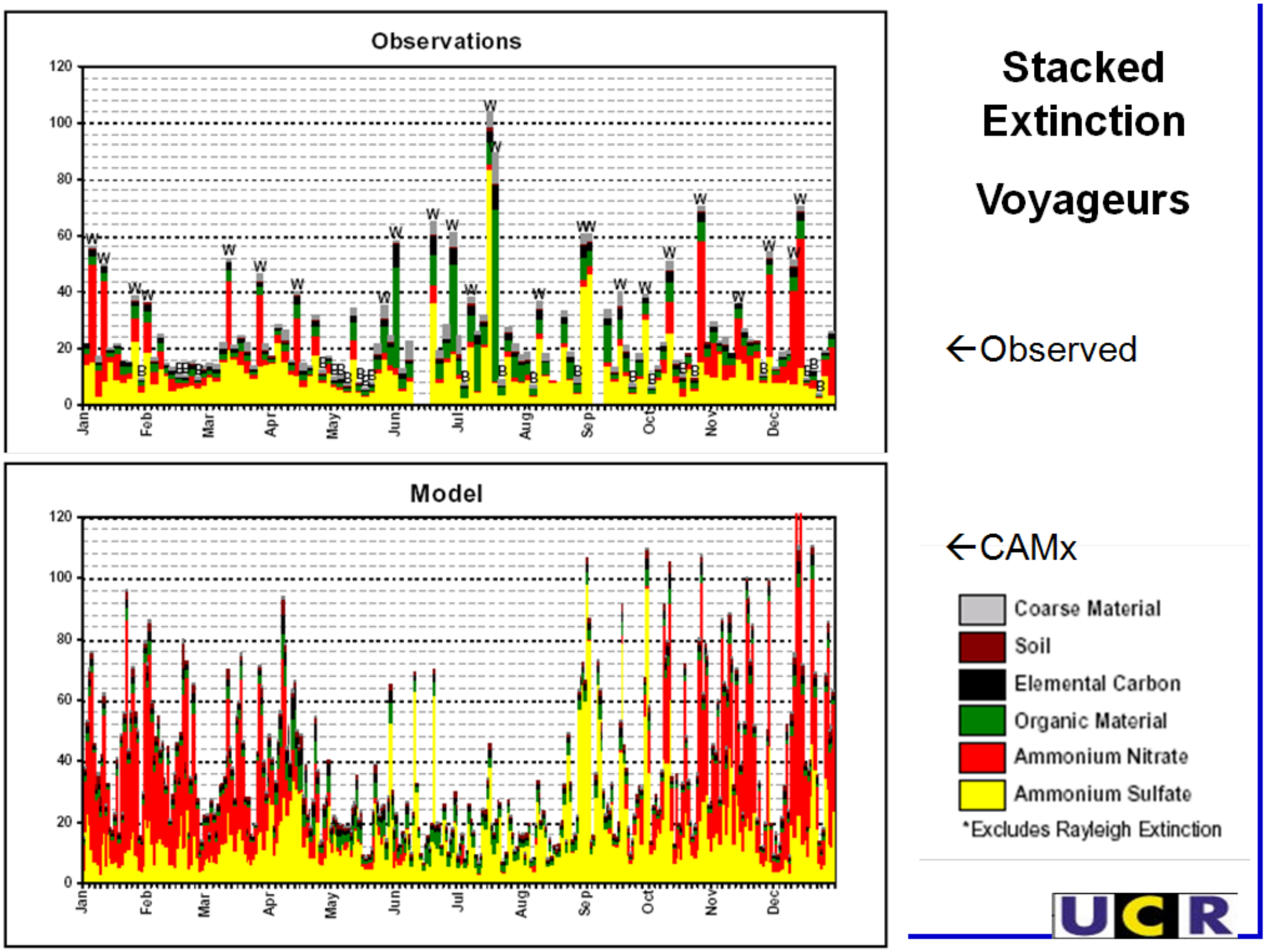


Figure B-5 CAMx vs. Observed Haze Predictions at Voyageurs National Park



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)

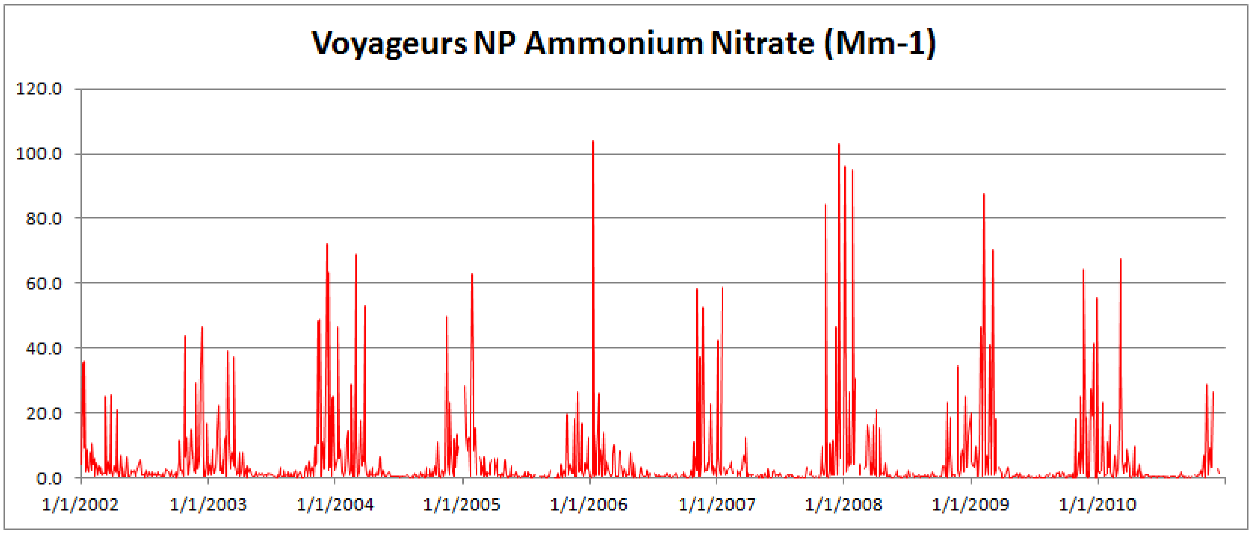


Figure C-2 Time Series of Sulfate Haze at Voyageurs National Park (2002-2010)

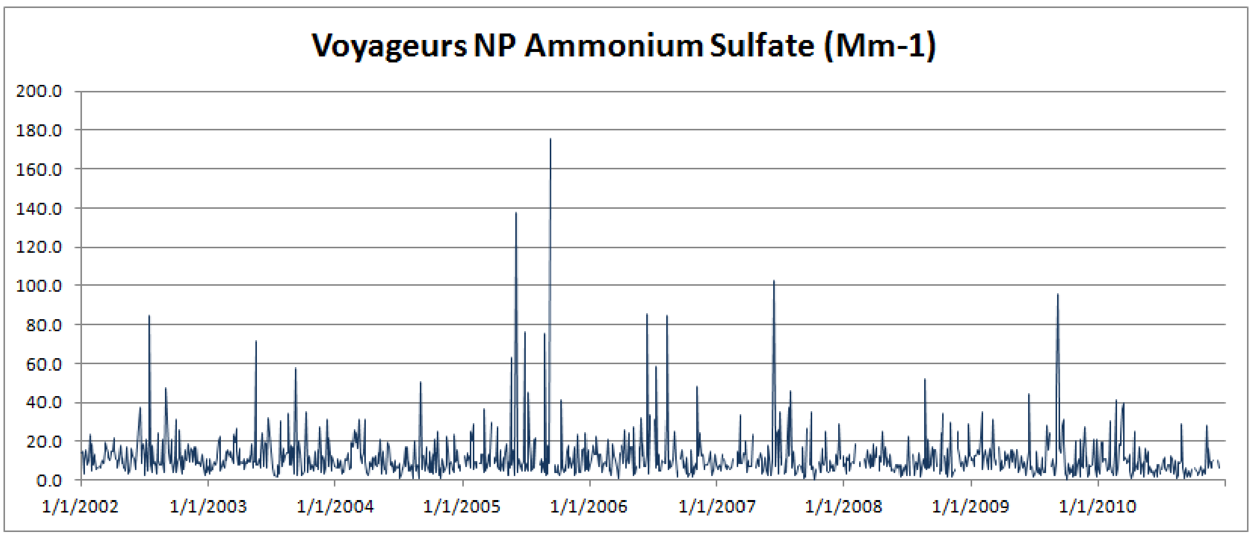


Figure C-3 Time Series of Nitrate Haze at Seney Wilderness Area (2002-2010)

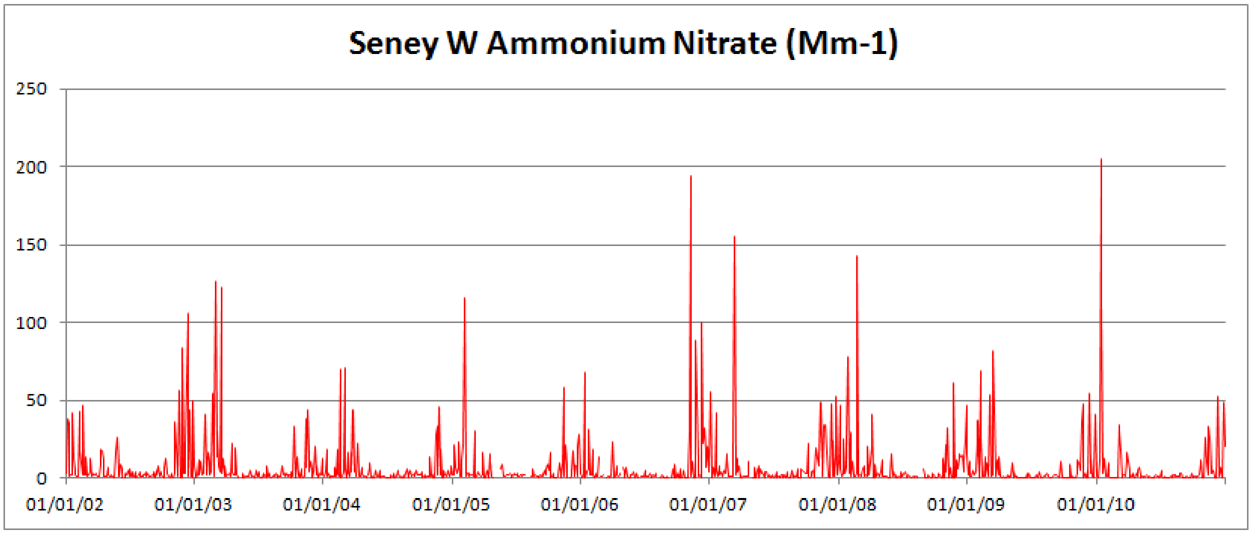


Figure C-4 Time Series of Sulfate Haze at Seney Wilderness Area (2002-2010)

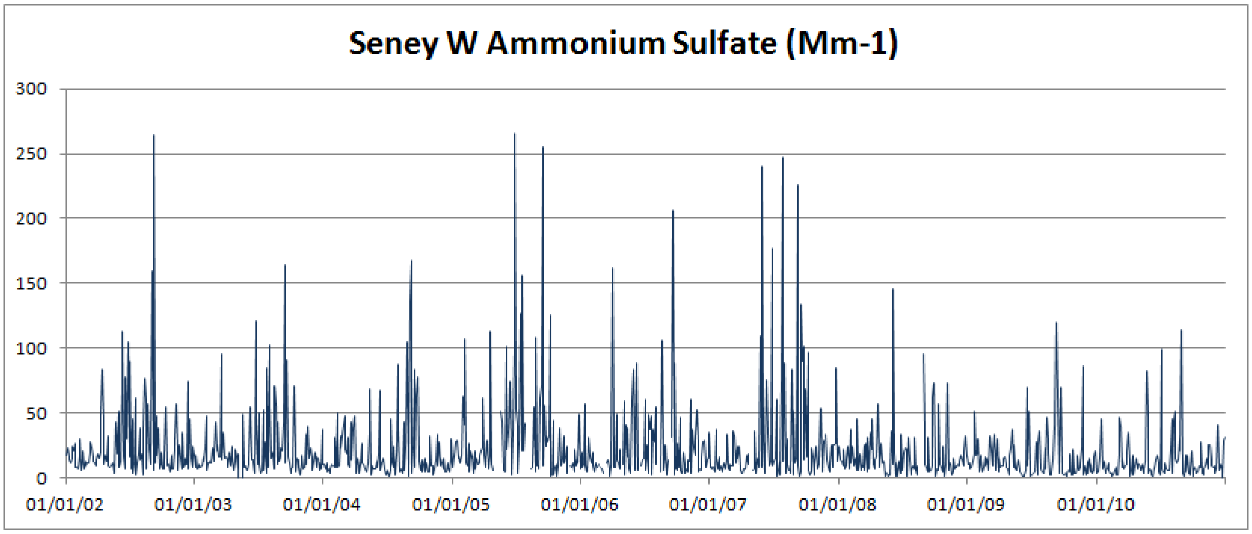


Figure C-5 Time Series of Nitrate Haze at Isle Royale National Park (2002-2010)

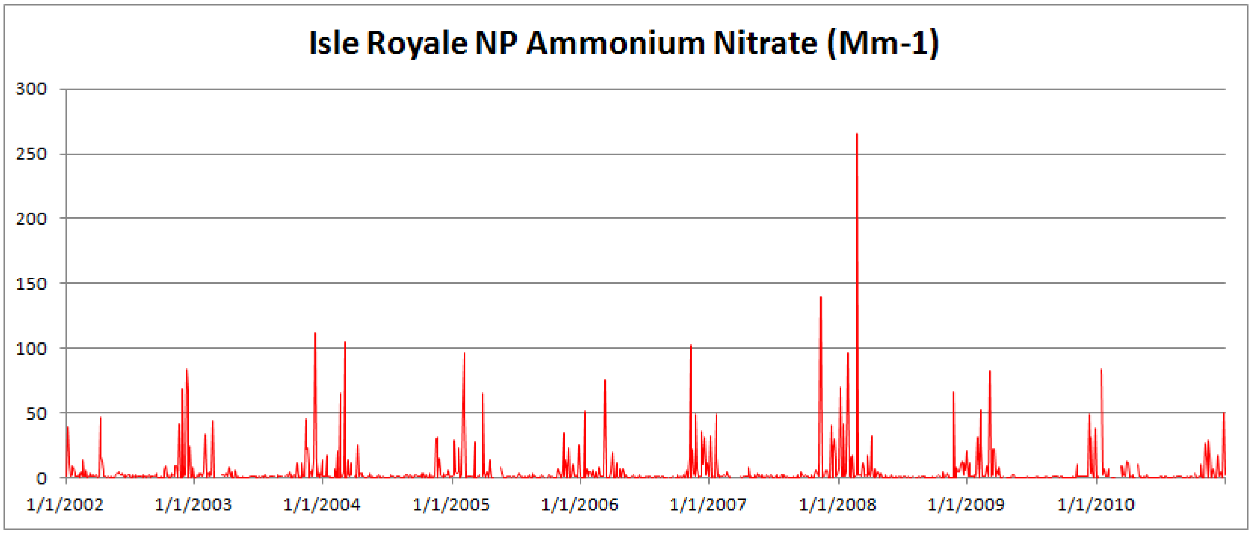
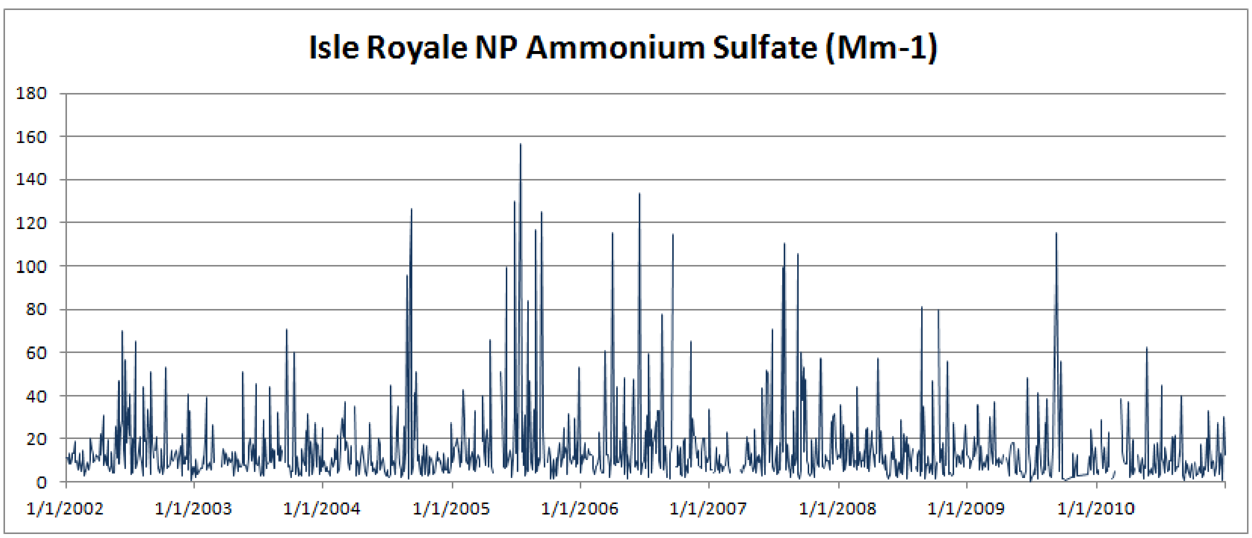


Figure C-6 Time Series of Sulfate Haze at Isle Royale National Park (2002-2010)



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 98th 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_2 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[39] 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_2 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[40] 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.

[39] 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).

[40] 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 mark.berkman@berkeleyeconomics.com.

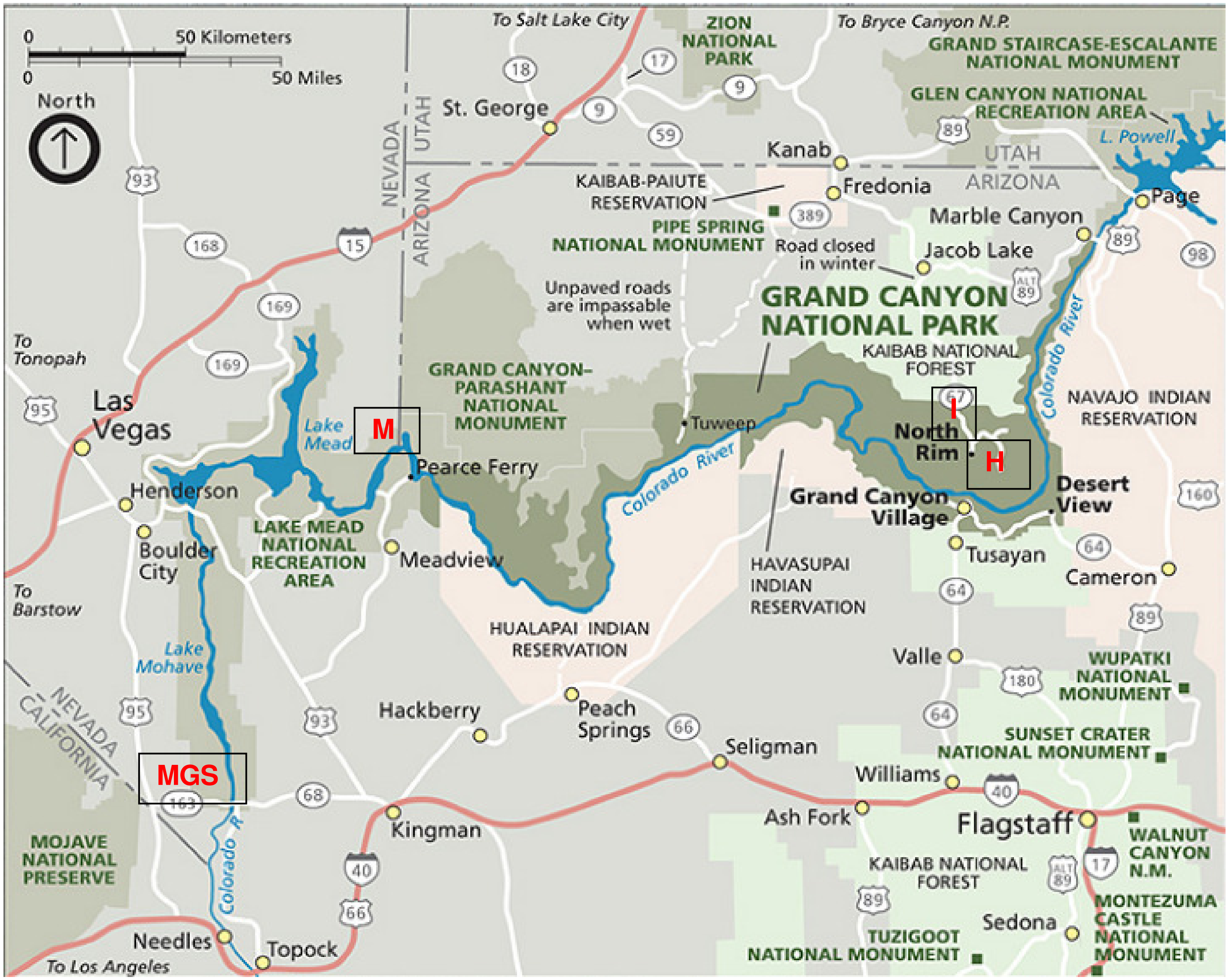
According to the authors, the Project Mohave observations were consistent with observations during temporary outages of MGS, for which there were no reports of substantial changes to visibility in the Grand Canyon.

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 98th 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_2 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.

Figure D-1 : Map Showing the Relationship of the Mohave Generating Station to the Grand Canyon National Park



http://www.nps.gov/grca/planyourvisit/upload/GRCAmap2.pdf

H: Hance Camp monitor

I: Indian Garden monitor

M: Meadview monitor

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)
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July 15, 2020

325 South Lake Avenue
Duluth, MN 55802
218.529.8200
www.barr.com

Regional Haze Four-Factor Analysis

July 15, 2020

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1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency's (MPCA's) submitted a Request for Information (RFI)[1] 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)[2]. The RFI requested that the facility evaluate potential emissions reduction measures for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) for Boiler #2 (EQUI 16 / EU430), Recovery Furnace (EQUI 9 / EU 320), and for NO_X 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[3] (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_X 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_X permit limits for Boiler #1 as presented in Table 2-2.

[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to Boise Paper LLC.

[2] 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).

[3] 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_2 and NO_X. 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 Controlled[4]	Four Factor Analysis Required[5]
Boiler #1	EQUI 15 / EU 420	NO_X	Not Applicable	Yes
Boiler #2	EQUI 16 / EU 430	NO_X, SO_2	Yes	No
Recovery Furnace	EQUI 9 / EU 320	NO_X	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.

[4] See Section 2.3 Boiler #2 and Recovery Furnace: Effective Controls

[5] 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_X 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.

- **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_2SO_4), 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_X controls but does use staged air injection to manage the generation of NO_X.

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"[6] 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."[7] 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

6 US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, Page 22.

7 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 #01700002-101 limits Boiler #1 NO_X emissions in Conditions 5.13.1-5.14.5. In addition, the emissions of NO_X from this source are also subject to the NO_X Cap Group limits as presented in Conditions 5.2.1-5.2.7. Boiler #1 does not have add-on NO_X controls but the generation of NO_X is managed by good combustion practices and NO_X 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_X emission limit is based on modeling and the NO_X Cap Group limits are based on a visibility impacts analysis. Additionally, the NOx 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."

Table 2-2 Boiler #1 (EQUI 15) Permit Limits

Pollutant	Condition	Limit	Basis of Limit
NO_X	5.14.3	Nitrogen Dioxide <= 0.20 pounds per million Btu heat input 30-day rolling average.	Title I Condition: 40 CFR 52.21(k) (modeling) & Minn. R. 7007.3000
NO_X	5.2.1	The Permittee shall limit emission of Nitrogen Oxides <= 3.67 tons per day from combustion sources (EQUI 9, EQUI 15, EQUI 16, EQUI 17, and EQUI 18).	Title I Condition: 40 CFR 52.21(o) (visibility) & Minn. R. 7007.3000
NO_X	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 52.21(o) (visibility) & Minn. R. 7007.3000

3 Boiler #1: Four-factor Analysis for NO_X

This section identifies baseline emission rates and evaluates the four statutory factors for NO_X 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."[8] 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."[9] This section addresses the selection of emission control options for NO_X 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)[10] 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_X is presented in Appendix B and a summary is provided in Table 3-1.

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[8] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 28.

[9] Ibid, Page 29.

[10] RACT/BACT/LAER Clearinghouse (RBLC) as maintained by USEPA (link to RBLC website)

Table 3-1: Natural Gas Power Boiler RBLC Summary – NO_X

RBLC ID	Technology
TN-0162 TN-0164	Selective Catalytic Reduction Low NO_X Burners Flue Gas Recirculation
TX-0811	Selective Catalytic Reduction Low NO_X Burners
TX-0731	Selective Catalytic Reduction
IN-0179 WV-00025	Ultra Low NO_X Burners Flue Gas Recirculation
PA-0306 LA-0314 OH-0363 AK-0083 VA-0325 TX-0712	Ultra Low NO_X Burners
LA-0272 AR-0121 IN-0263 MI-0423 OH-0374	Low NO_X Burners Flue Gas Recirculation
MI-0427	Low NO_X Burners with internal (within the burner) Flue Gas Recirculation
LA-0307 TX-0641 VA-0328 OH-0354 TX-0708	Low NO_X 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."[11] 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 NO_X 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_X emission control measures following EPA's Control Cost Manual as recommended in the 2019 SIP Guidance.[12] 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_X 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.

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[11] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 29.

[12] Ibid, Page 21.

Table 3-3: Boiler #1 NO_X Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Total Capital Investment ($)	Total Annualized Costs ($/year)	Control Efficiency (%)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
SCR	$7,828,245	$970,836	69%	63.1	$15,375
LNB with FGR and OFA	$11,144,531	$1,557,544	62.0%	56.2	$27,707

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_X 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
  - Increased truck and/or train traffic (reagent and catalyst deliveries)
  - Possible ammonia slip (unreacted reagent that is emitted to the atmosphere)
  - Catalyst regeneration
  - 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_X Controls and Emissions Rates

This four-factor analysis does not support the installation of additional NO_X emission control measures at Boiler #1 beyond those described in Section 2.3. As such, Boise proposes to maintain the existing NO_X 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[1] 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 four-factor analysis. For example, the guidance states that it "*may be reasonable for a state not to select an effectively controlled source*"[2] 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.*"[3]

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[4]. 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

1 USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019.
2 Ibid, Page 22.
3 Ibid, Page 23
4 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"[5] by July 31, 2020, for the emission units identified in Table 1.

Table 1: Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Recovery Furnace	EQUI 9 / EU 320	NO_X
Boiler #1	EQUI 15 / EU 420	NO_X
Boiler #2	EQUI 16 / EU 430	NO_X, SO_2

The RFI stated that the "*analysis should be prepared using the U.S. Environmental Protection Agency guidance*[6] *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.*"[7]

5 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.

6 USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

7 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.*"[8]

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[9]. 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)[10]. 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).

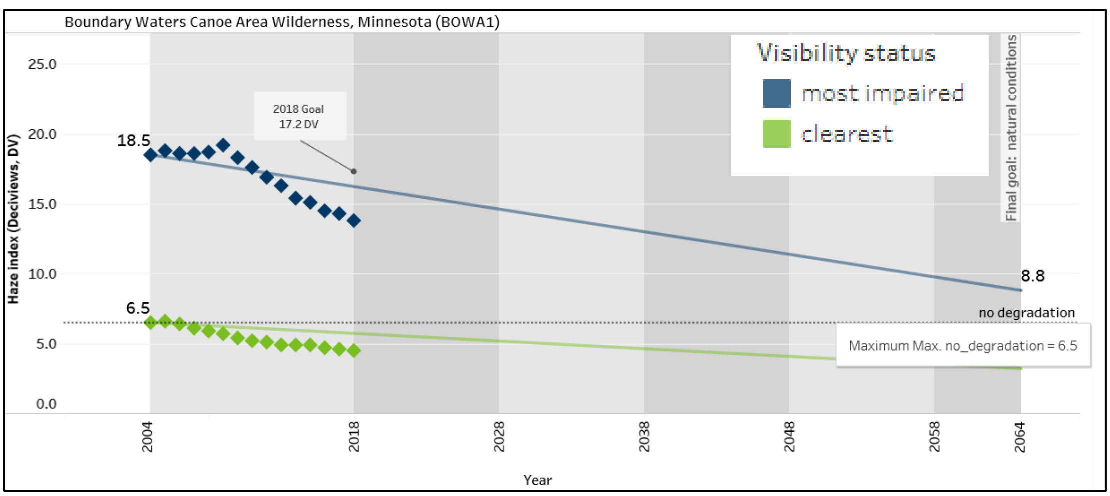

Figure 1: BWCAW Current Visibility Conditions

8 40 CFR 51.308(d)(1)(i)(B)

9 https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibility progress

10 The URP is determined based on the slope of the line from baseline conditions (2000-2004) to the natural visibility conditions in 2064

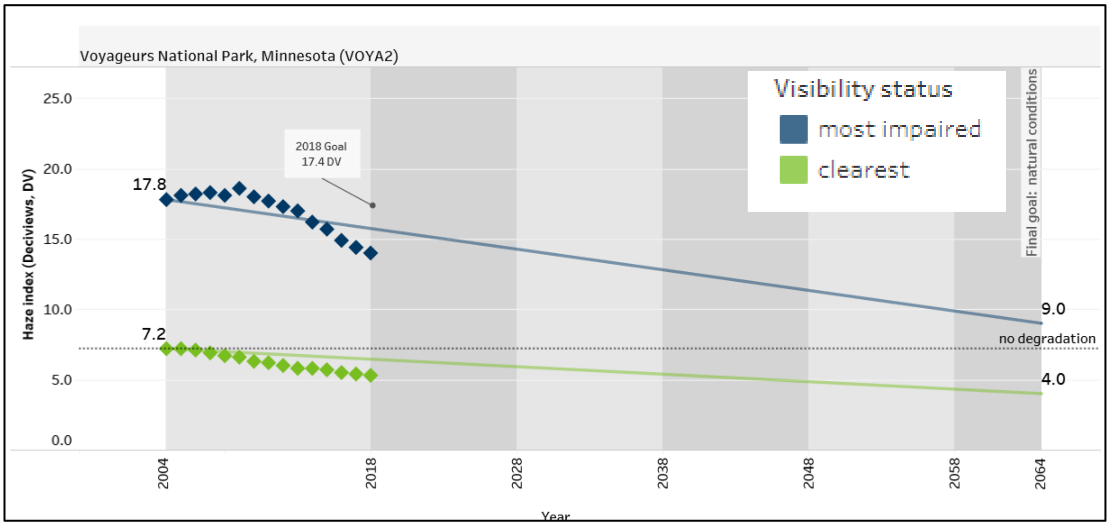

Figure 2: Voyageurs Current Visibility Conditions

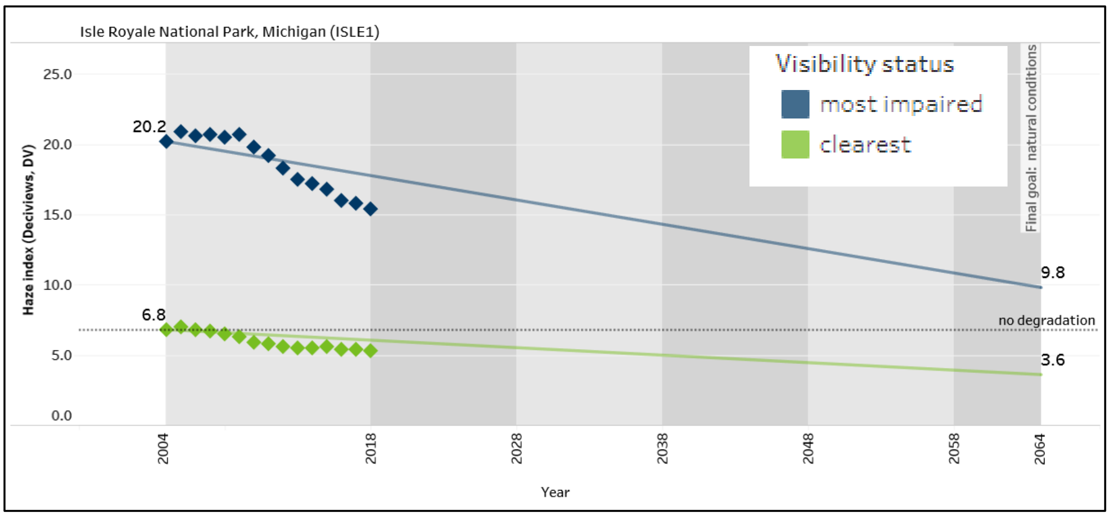

Figure 3: Isle Royale Current Visibility Conditions

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_X 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[11] 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[12]. 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.*"[13] The monitoring information will help MPCA "*explain why the decision is consistent with the requirement to make reasonable progress.*"[14]

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"[15] 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*."[16] 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.[17] 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.*"

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11 USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019
12 Ibid, Page 9.
13 Ibid.
14 Ibid, Page 23.
15 Ibid, Page 22.
16 Ibid, Page 23.
17 Ibid.

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_X BACT review since July 31, 2013, so this unit does not directly meet this scenario. However, the current NO_X limit[18] (100 lb/hr per 30-day rolling average, which is equivalent to 80 ppm at 8% oxygen (O_2)) was compared to recent determinations in EPA's RBLC database (Attachment A) and the limit is consistent with NO_X 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_X 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: [21]

- Biomass (commonly referred to as "hog fuel")
- WWTP Sludge
- Natural Gas
- Non-Condensable Gas (NCG)

The associated combustion results in NO_X and SO_2 emissions, among other emissions.

NO_X: Boiler #2's current NO_X limit[22] (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_X limits from recent BACT determinations (e.g., two determinations[23,24] with 0.3 lb/MMBtu limits).

Because the current NO_X 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

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18 Title V Operating Permit (TVOP) Condition 5.13.7
19 2019 BACT determination for Sun Bio Materials Company (AR-0161)
20 2015 BACT determination for Rocktenn CP, LLC (AL-0302)
21 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."
22 TVOP Condition 5.17.7
23 2010 BACT determination for Boise White Paper (AL-0250)
24 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_2: 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_2 emissions from the boiler are a direct result of Non-Condensable Gas (NCG) combustion. However, Boiler #2 is the secondary NCG combustion source[25] 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[26].
- Boiler #2 has an SO_2 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.[27]
- Boiler #1 and Boiler #2 have a combined SO_2 emission limit (115 tons per rolling 12-month period) which applies when burning NCG in either of the backup combustion sources.[28]
- 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_2 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)[29], was compared to recent determinations in EPA's RBLC database (Attachment C). The limit is consistent with SO_2 limits from recent BACT determinations for similar sources (e.g., 0.025 lb/MMBtu[30], 0.21 lb/MMBtu[31]).

The TVOP limits the SO_2 emissions from the backup NCG combustion sources (Boiler #1 and Boiler 2) to 115 tons per rolling 12-month period.[32] 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

25 TVOP Condition 5.3.3
26 Ibid.
27 TVOP Condition 5.17.6
28 TVOP Condition 5.3.6
29 TVOP Condition 5.17.6
30 2019 BACT determination for Sun Bio Materials Company (AR-0161)
31 2014 BACT determination for Abengoa Bioenergy Biomass of Kansas (KS-0034)
32 TVOP Condition 5.3.6

example, the maximum annual SO_2 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_2 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_2 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_2 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_2 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_2 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*."[33] 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 karahuziak@boisepaper.com with questions or to request a meeting.

Thank you for considering our request.

Sincerely,

Mike Wagner
Mill Manager

Attachments:

A. RBLC Summary: NO_X from Recovery Furnaces
B. RLBC Summary: NO_X from Hog Fuel Boilers
C. RBLC Summary: SO_2 from Hog Fuel Boilers

33 USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 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.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0266	GEORGIA PACIFIC BREWTON LLC	GEORGIA PACIFIC LLC	AL	502-0001-X044	322130	06/11/2014 ACT	Kraft Pulp & Paper mdu	No.4 Recovery & Smelt Tank	Black Liquor	1355	MMBTU/ hr	Nitrogen Oxides (NOx)	Staged air combustion	90	PPM@8%O2	3HRS AVG	BACT-PSD	221	LB/H	3HRS AVG	0		
AL-0266	GEORGIA PACIFIC BREWTON LLC	GEORGIA PACIFIC LLC	AL	502-0001-X044	322130	06/11/2014 ACT	Kraft Pulp & Paper mdu	No. 4 REC & Smelt	Natural Gas	1355	mmbtu	Nitrogen Oxides (NOx)	Gas Combustion	0.2	LB/MMBTU	3 HRS AVG	BACT-PSD	145.12	LB/H	3 HRS AVG	0		
AL-0274	BOISE WHITE PAPER, LLC	BOISE WHITE PAPER, LLC	AL	102-0001-X011	322121	02/04/2015 ACT	Paper mill	Recovery Furnace - Non-Direct Contact with Dry -	Black Liquor Solids (BLS)	2.88	million lbs. of BLS	Nitrogen Oxides (NOx)		90	PPMDV	@8% O2	BACT-PSD	105.8	LB/H	3-HR. ROLLING	0		
AL-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 (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 Furnace	Black Liqour	1355	MMBtu/hr	Nitrogen Oxides (NOx)		90	PPMV @8% O2		BACT-PSD	221.9	LB/HR	3 HR	0		
AR-0156	GREEN BAY PACKAGING - ARKANSAS KRAFT DIVISION	GREEN BAY PACKAGING - ARKANSAS KRAFT DIVISION	AR	0224-AOP-R21	322130	02/08/2019 ACT	paperboard mill	Recovery Boiler	black liquor solids	401400	T/YR	Nitrogen Oxides (NOx)		80	LB/H		OTHER CASE-BY-CASE	313.1	T/YR		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 Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Recovery Boiler	Black Liquor Solids	2900	MMBtu/hr	Nitrogen Oxides (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	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Lime Kiln	Natural Gas	225	MMBtu/hr	Nitrogen Oxides (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 Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Power Boiler	Biomass	1200	MMBtu/hr	Nitrogen Oxides (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 STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0250	BOISE WHITE PAPER	BOISE WHITE PAPER, LLC	AL	102-0001	322121	03/23/2010 ACT		COMBINATION BOILER	WOOD	435	MMBTU/H	Nitrogen Oxides (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 Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Power Boiler	Biomass	1200	MMBtu/hr	Nitrogen Oxides (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 STOKER BOILER - Transient Period (see notes)	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	102	PPM	@12% CO2, 8-HR 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 STOKER BOILER	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	80	PPM	@12% CO2, 8-HR ROLLING AVG	BACT-PSD	50.75	LB/H	8-HR ROLLING AVG	0		
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	SIERRA PACIFIC INDUSTRIES	CA	SAC 12-01	321113	04/25/2014 ACT	31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY	STOKER BOILER (NORMAL OPERATION)	BIOMASS	468	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.13	LB/MMBTU	12-MONTH ROLLING BASIS	BACT-PSD	0.15	LB/MMBTU	3-HOUR BLOCK AVERAGE	0		
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	SIERRA PACIFIC INDUSTRIES	CA	SAC 12-01	321113	04/25/2014 ACT	31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY	STOKER BOILER (STARTUP & SHUTDOWN PERIODS)	BIOMASS	468	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	70.2	LB/H	8-HR AVG (STARTUP PERIODS)	BACT-PSD	70.2	LB/H	8-HR AVG (SHUTDOWN PERIODS)	0		
CT-0156	MONTVILLE POWER LLC	NRG ENERGY	CT	107-0056	221119	04/06/2010 ACT	43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL CAPACITY FACTOR)	42 MW Biomass utility boiler	Clean wood	600	MMBTU/H	Nitrogen Oxides (NOx)	Regenerative SCR	0.06	LB/MMBTU	24 HR BLOCK	LAER	0			0		
CT-0162	PLAINFIELD RENEWABLE ENERGY, LLC	PLAINFIELD RENEWABLE ENERGY, LLC	CT	145-0049	221119	12/29/2010 ACT	37.5 MW Biomass Power Plant	Fluidized Bed Gasification	Wood	523.1	MMBtu/hr	Nitrogen Oxides (NOx)	SNCR	0.075	LB/MMBTU		LAER	45.3	PPMVD @7% O2	24 HR BLOCK	0		
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	OGETHORPE POWER CORPERATION	GA	4911-301-0016-P-01-0	221119	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 water pump emergency engines; a raw material handling & storage area; a sorbent storage silo; a boiler bed sand silo, a sand day	Boiler, Biomass Wood	Biomass wood	100	MW	Nitrogen Oxides (NOx)	Selective non-catalytic reduction system (SNCR)	0.1	LB/MMBTU	30 D ROLLING AV / CONDITION 2.9	BACT-PSD	648	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.18	0		
*KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	C-11396	325193	05/27/2014 ACT	Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and operate a biomass-to-ethanol and biomass-to-energy production facility near Hugoton, Kansas.	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction System (SCR) and an over-fire system (OFA)	0.3	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	BACT-PSD	157.5	LB/HR	1-HR AVE, 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 making facility.	Biomass Boiler 8	Biomass	814	MMBTU/H	Nitrogen Oxides (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.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*AR-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 Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	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	CT	107-0056	221119	04/06/2010 ACT	43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL CAPACITY FACTOR)	42 MW Biomass 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	CT	145-0049	221119	12/29/2010 ACT	37.5 MW Biomass Power Plant	Fluidized Bed Gasification	Wood	523.1	MMBtu/hr	Sulfur Dioxide (SO2)	Spray Dryer, Bed Injection	0.035	LB/MMBTU		OTHER CASE-BY-CASE	15.4	PPMVD @7% O2	3 HR BLOCK	0		
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	OGETHORPE POWER CORPERATION	GA	4911-301-0016-P-01-0	221119	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 water pump emergency engines; a raw material handling & storage area; a sorbent storage silo; a boiler bed sand silo, a sand day	Boiler, Biomass Wood	Biomass wood	100	MW	Sulfur Oxides (SOx)	Dust sorbent injection system	0.01	LB/MMBTU	30 D ROLLING AV / CONDITION 2.12	BACT-PSD	56	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.20	0		
*KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	C-11396	325193	05/27/2014 ACT	Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and operate a biomass-to-ethanol and biomass-to-energy production facility near Hugoton, Kansas.	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Sulfur Dioxide (SO2)	Injection of sorbent (lime) in combination with a dry flue gas desulfurization (FGD) system	0.21	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	BACT-PSD	110.25	LB/HR	MAX 1-HR, INCLUDES SS, EXCLUDES 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 FUEL BOILER	HOGGED FUEL/BARK	992.43	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	60	LB/H	HOURLY MAXIMUM	BACT-PSD	262.8	T/YR	ANNUAL MAXIMUM	0.06	LB/MMBTU	
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 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 A.2

Regional Haze Correspondence with Hassan Bouchareb

Dated May 29, 2020

-------- Original message --------
From: "Bouchareb, Hassan (MPCA)" <hassan.bouchareb@state.mn.us>
Date: 5/29/20 12:12 PM (GMT-06:00)
To: "Huziak, Kara" <KaraHuziak@BoisePaper.com>
Cc: "Rein, Patrick" <PatrickRein@boisepaper.com>
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 four-factor 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

From: Huziak, Kara <KaraHuziak@BoisePaper.com>
Sent: Thursday, May 21, 2020 3:45 PM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
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_X 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 (Air Permit Number 01700002-101 – see the BACT analysis in Section 3.3.3 of the TSD).

Permit #	Issued Date	Description
001	09/1990	The NO_X permit limit in the first Title V permit was: • Nitrogen Oxides: less than or equal to 86.9 lbs/hour using 30-day Rolling Average. This is equivalent to 80 ppm on a dry basis, corrected to 8% oxygen. • Title I Condition: 40 CFR Section 52.21 (modeling and netting); Minn. R. 7007.3000
003	10/2000	This permit was for the Efficiency Improvement Project which was permitted under PSD. The TSD describes the NO_X limit as follows: • NO_X 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_X limit on this emission unit has been increased, the NO_X emission cap for the facility has not been increased. The NO_X 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. The permit limit was listed as follows: • Nitrogen Oxides: less than or equal to 94.5 lbs/hour using 30-day Rolling Average. • Title I Condition: 40 CFR Section 52.21(j) (BACT limit); Minn. R. 7007.3000
006	11/2004	This permit amendment included an increase in the NO_X emission limit for the Recovery Furnace. The NO_X emission limit increase was based on an update to the NO_X BACT analysis because the existing permit limit was a BACT limit. The permit limit was listed as follows: • 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. • Title I Condition: 40 CFR Section 52.21(j) (BACT limit); Minn. R. 7007.3000
009	10/2008	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_X emission limit. The permit amendment also increased the NO_X emission limit which included an update to the NO_X BACT analysis because the existing permit limit was a BACT limit. As described in the TSD, "*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*" (Air Permit 07100002-009 – see page 16 of the TSD). The permit limit was listed as follows: • 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. • Title I Condition: 40 CFR Section 52.21(j) (BACT limit); Minn. R. 7007.3000
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_X 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_X 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_X emission limit.

Please let me know if you have questions or need additional assistance for your review.

Thank you,

Kara Huziak

Environmental, Air
400 2nd Street
International Falls, MN 56649

218.285.5449 Office
218.417.0624 Cell

From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Wednesday, May 20, 2020 2:12 PM
To: Huziak, Kara <KaraHuziak@BoisePaper.com>
Cc: Rein, Patrick <PatrickRein@boisepaper.com>
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_X 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_X 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_X 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

From: Huziak, Kara <KaraHuziak@BoisePaper.com>
Sent: Wednesday, May 20, 2020 9:09 AM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Cc: Rein, Patrick <PatrickRein@boisepaper.com>
Subject: RE: Regional Haze Request

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 2nd 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 <PatrickRein@boisepaper.com>
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 2nd 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_X

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 NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
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 (NOx)	Low NOx burners	0.011	LB/MMBTU	CORRECTED TO 3% 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 generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Nitrogen Oxides (NOx)	Good combustion design and practices, selective catalytic reduction (SCR), low-NOX burners with flue gas recirculation	0.013	LB/MMBTU		BACT-PSD	0			0		
TX-0576	PIPE MANUFACTURING STEEL MINI MILL	TPCO AMERICA INC	TX	PSDTX1188 AND 86860	331513	04/19/2010 ACT	converts scrap steel into seamless pipe	vacuum degasser boiler	natural gas	40	MMBTU/H	Nitrogen Oxides (NOx)	good combustion practice	0.1	LB/MMBTU		BACT-PSD	0			0		
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	65-00990 C/E	221112	02/12/2016 ACT	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Nitrogen Oxides (NOx)	Good combustion practices and ULNOx 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 lbs/yr of ethylene	boiler A and B (010 and 011)	natural gas/fuel gas	248	mm btu/hr (each)	Nitrogen Oxides (NOx)	good combustion practices; fueled by natural gas or process fuel gas; ULNB (FGR and economizer)	0.06	LB/MM BTU	THREE ONE-HOUR 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 lbs/yr of ethylene	boiler B-201	natural gas/fuel gas	229	mm btu	Nitrogen Oxides (NOx)	good combustion practices; fueled by natural gas or process fuel gas; ULNB (FGR and economizer)	0.06	LB/MM BTU	THREE ONE-HOUR 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 Boilers	Natural Gas	450	MMBtu/hr, each boiler	Nitrogen Oxides (NOx)	SCR, low-NOX burners, flue gas recirculation, good combustion design & practices	0.013	LB/MMBTU	30-DAY AVG EXCLUDING STARTUP & SHUTDOWN	BACT-PSD	0.2	LB/MMBTU	30-DAY AVG, APPLIES AT ALL TIMES	0		
OH-0354	KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	P0108853	325212	01/15/2013 ACT	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Nitrogen Oxides (NOx)	Low-NOx burners	0.12	LB/MMBTU	BURNING DISTILLATE OIL	N/A	392.83	T/YR		0.1	LB/MMBTU	BURNING NATURAL 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 Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Nitrogen Oxides (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 PRODUCTION, SUFLURIC ACID PRODUCTION, AMMONIA PRODUCTION, AND AMMONIA NITRATE PRODUCTION	START-UP BOILER	NATURAL GAS	240	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	4.32	LB/H	ROLLING 3 HOUR AVERAGE	BACT-PSD	0.018	LB/MMBTU	ROLLING 3 HOUR 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 AUXILIARY BOILERS (EU-012A, EU-012B,	NATURAL GAS	218.6	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES	20.4	LB/MMCF EACH	3 HOUR AVERAGE	BACT-PSD	1877.39	MMCF/12 MONTH 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) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EACH	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS FLUE GAS 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	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	Nitrogen Oxides (NOx)	FLUE GAS RECIRCULATION, LOW NOX BURNERS, AND GOOD COMBUSTION PRACTICES (I.E., PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING	11.92	LB/H	HOURLY MAXIMUM	BACT-PSD	21.86	T/YR	ANNUAL MAXIMUM	0.05	LB/MM BTU	ANNUAL AVERAGE
TX-0811	LINEAR ALPHA OLEFINS PLANT	INEOS OLIGOMERS USA LLC	TX	136130 AND N250	325110	11/03/2016 ACT	Manufactures linear alpha olefins (LAO) from ethylene	Industrial-Sized Furnaces, Natural Gas-fired	natural gas	217	MM BTU / H	Nitrogen Oxides (NOx)	Low-NOX burners and Selective Catalytic Reduction (SCR). Ammonia slip limited to 10 ppmv (corrected to 3% O2) on a 1-hr block average.	0.006	LB / MM BTU	HHV BASIS, ANNUAL AVERAGE	LAER	0.014	LB/MMBTU	HHV BASIS, 1-HR AVERAGE	0		
OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	P0122594	221112	10/23/2017 ACT	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners and flue gas recirculation	3.7	LB/H		BACT-PSD	9.25	T/YR	PER ROLLING 12 MONTH PERIOD	0.02	LB/MMBTU	
VA-0325	GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	52525	221112	06/17/2016 ACT	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	Nitrogen Oxides (NOx)	ultra low-NO_x burners	0.011	LB/MMBTU		N/A	0			0		
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	66-17	221112	11/17/2017 ACT	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	Nitrogen Oxides (NOx)	LNB that incorporate internal (within the burner) FGR and good combustion practices.	0.04	LB/MMBTU	30 DAY ROLLING 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 (Auxiliary Boiler)	natural gas	182	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners/Flue gas recirculation and good combustion practices.	0.04	LB/MMBTU	30 DAY ROLLING AVG TIME PERIOD	BACT-PSD	0			0		
TX-0641	PINECREST ENERGY CENTER	PINECREST ENERGY CENTER LLC	TX	PSDTX1298	221122	11/12/2013 ACT	Combinec Cycle Electric Generating Plant	Auxiliary boiler	natural gas	150	MMBTU/H	Nitrogen Oxides (NOx)	low NOx burners	16	PPMVD	INITIAL STACK TEST, 3% OXYGEN	BACT-PSD	0			0		
TX-0708	LA PALOMA ENERGY CENTER	LA PALOMA ENERGY CENTER, LLC	TX	101542 PSDTX1288	221112	02/07/2013 ACT	The proposed project is a new electric power plant, fueled by pipeline quality natural gas. The design of the plant is standard combined cycle (CC) technology.	boiler	natural gas	150	MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners, limited use	0.02	LB/MMBTU	3-HR ROLLING AVERAGE	BACT-PSD	0			0		
OH-0363	NTE OHIO, LLC		OH	P0116610	221112	11/05/2014 ACT	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	Nitrogen Oxides (NOx)	Ultra low NOx burner	1.65	LB/H		BACT-PSD	3.3	T/YR	PER ROLLING 12 MONTH PERIOD	0.011	LB/MMBTU	
TX-0712	TRINIDAD GENERATING FACILITY	SOUTHERN POWER COMPANY	TX	111393 PSDTX1368	221112	11/20/2014 ACT	Southern Power Company (SPC) is proposing to construct an electric generating facility near Trinidad, Henderson County, Texas. The Trinidad Generating Facility (TGF) will include a natural gas-fired combined cycle combustion turbine generator (CTG) equipped with	boiler	natural gas	110	MMBTU/H	Nitrogen Oxides (NOx)	ultra-low NOx burners, limited use	9	PPMVD	@15% O2	BACT-PSD	0			0		
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	WV	R14-0030	221112	11/21/2014 ACT	Nominal 549 mW(output) natural gas-fired combined cycle power plant.	Auxiliary Boiler	Natural Gas	100	mmBtu/hr	Nitrogen Oxides (NOx)	Ultra Low-NOx Burners, Flue-Gas Recirculation, & Good Combustion Practices	2	LB/H		BACT-PSD	0			0.02	LB/MMBTU	
TX-0731	CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	MAGELLAN PROCESSING LP	TX	118270 AND PSDTX1398	324110	04/10/2015 ACT	100 MBpd topping refinery	Industrial-Size Boilers/Furnaces	natural gas	0		Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR)	0.006	LB/MMBTU	12-MONTH AVG	BACT-PSD	0.01	LB/MMBTU	BLOCK 1-HR AVG	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 PRODUCTS MANUFACTURING CORPORATION (APMC) STOCKTON COGEN AND LOCATED IN STOCKTON, CALIFORNIA	AUXILIARY BOILER	NATURAL GAS	178	MMBTU/H	Nitrogen Oxides (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	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	AUXILIARY BOILER	NATURAL GAS	110	MMBTU/H	Nitrogen Oxides (NOx)		9	PPMVD	@3% O2, 3-HR AVG	BACT-PSD	0			0		
OH-0336	CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	P0106678	311422	12/14/2010 ACT	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		Nitrogen Oxides (NOx)		0.04	LB/MMBTU	BASED ON MFG. GUARANTEE	OTHER CASE-BY-CASE	63.08	T/YR	ROLLING 12 MO. FROM 3 BOILERS TOGETHER	0		

Appendix C.1

Boiler #1 Cost Calculations for NO_X Control (SCR)

Boise - International Falls, MN
#1 Boiler
NO_X SNCR Calculations

	Boiler 1		Comment
Max Firing Rate	398	MMBtu/hr	PTE Calculations for Boiler 1.
NO_X Emission Rate (Uncontrolled)	0.1310	lb/MMBtu	Air emission inventory (see "Data Inputs")
NO_X Controls Emission Rate	0.0622	lb/MMBtu	Target (see "Data Inputs")
System Capacity Factor (Actuall rate vs. max firing rate at 8760)	39.8%		Actual fuel per year / Maxium fuel per year (See "SNCR Design Parameters")
Uncontrolled Emissions	90.9	ton/year	Calculated from Above
Control Efficiency	53%		Based on target emission rate above (mid-point of pulp and paper in Table 1.2)
Controlled Emissions	43.2	ton/year	Calculated from Above
Total Capital Investment (TCI)	$4,228,677		From "Cost Estimate"
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 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? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.6

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 398.0 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual fuel consumption? 1,414,842,703 scf/year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR}) 351 days

Plant Elevation 1129 Feet above sea level

Inlet NO_x Emissions (NOx_{in}) to SNCR	0.131	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) 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_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	50	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Urea

Enter the cost data for the proposed SNCR:

Desired dollar-year	2020	
CEPCI for 2020	592.1	Enter the CEPCI value for 2020 — 541.7 2016 CEPCI
Annual Interest Rate (i)	5.5	Percent*
Fuel ($Cost_{fuel}$)	2.13	\$/MMBtu
Reagent ($Cost_{reag}$)	1.81	\$/gallon for a 50 percent solution of urea
Water ($Cost_{water}$)	0.0051	\$/gallon
Electricity ($Cost_{elect}$)	0.0676	\$/kWh*
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: 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 December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/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. 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/.	
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_B) =	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_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.40	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	3487	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	53	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	27.37	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	47.72	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04		
Atmospheric pressure at 1129 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	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 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 ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	42	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	83	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	8.7	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	3,000	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	3.6	kW/hour	
Water Usage: Water consumption (q_w) =	$(m_{sol}/\text{Density of water}) \times ((C_{stored}/C_{inj}) - 1)$ =	0	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.04	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,257,491	in 2020 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2020 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,995,337	in 2020 dollars
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 ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$1,257,491	in 2020 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 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_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$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 $Cost_{elect}$ x t_{op} =	$859	in 2020 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2020 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$277	in 2020 dollars
Additional Ash Cost =	ΔAsh 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

Table 1.2: SNCR NO_x Reduction Efficiency by Industry and Reagent Type [2, 4]

Industry and Units	% Reduction	
	Ammonia-Based	Urea-Based
Cement Kilns	12-77	25–90
Chemical Industry	NA[a]	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

[a]NA means not available.

Appendix C.2

Boiler #1 Cost Calculations for NO_X 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:
  - 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
  - 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
    - General mechanical
    - Electrical
    - 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 Firing Rate	398	MMBtu/hr	PTE Calculations for Boiler 1
NO_X Emission Rate (Uncontrolled)	0.131	lb/MMBtu	2019 Air emission inventory (see Table 2)
NO_X Controls Emission Rate	0.050	lb/MMBtu	Target
Utilization Rate	41.4%		2019 Air emission inventory (see Table 2)
Uncontrolled Emissions	90.9	ton/year	Calculated from Above
Control Efficiency	62%		Calculated from Above
Controlled Emissions	34.7	ton/year	Calculated from Above
Total Capital Investment (TCI)	$11,144,531		From Table 3 - NOx Control - LNB with FGR
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 in 2020 dollars	Calculated from Above

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
Emission Unit Number	EQUI17			EPA Default Scaled Value or Other Public Source
Stack/Vent Number	STRU25			Other Barr Project (public or not client specific)

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	67.53	$/hr	60	2016	EPA SCR Cost Manual Spreadsheet	
Maintenance Labor	67.53	$/hr				Assumed to be equivalent to operating labor
Installation Labor	67.53	$/hr				Assumed to be equivalent to operating labor
Electricity	0.08	$/kwh			2015-2019 EIA Average prices for the commerical sector	
Natural Gas	3.90	$/kscf			2015-2019 EIA Average prices for the commerical sector	
Water	0.42	$/mgal	0.20	1995	Hbbing Taconite BART 2006 Study	
Cooling Water	0.42	$/mgal	0.23	1999	Hbbing Taconite BART 2006 Study	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Control cost estimate for 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_{catalyst}$)	20,000	hours			EPA Control Cost Manual for SCR suggests 16,000 - 24,000 hours	
SCR Catalyst cost ($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	$/bag	180	2012	Taconite FIP Docket - Control cost estimate for UTAC	
Other						
Sales Tax	6.875%			2020	Tax Foundation Sales Tax as of 1/1/2019	Minnesota specific sales tax, not including local tax
Interest Rate	5.50%			2016	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)			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 estimate such as (1) Structural aspect of new equipment integrated into the existing steel. and (2) 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).)
Operating Information						
Annual Op. Hrs	8,424	Hours			2019 Operating Data	
Utilization Rate	41.4%				Assumed	
Design Capacity	398.0	MMBTU/hr			PTE Calculations for Boiler 9	
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	acfm			2014 Boiler 1 Hg Stack Test Data	
Standardized Flow Rate	132,954	scfm @ 68º F	123,889	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	117,332	dscfm @ 68º F			Calculated Value	
Fuel higher heating value (HHV)	1,020	btu/scf			Standard value	
Plant Elevation	1,100	Feet above sea level				International Falls, MN elevation
# days boiler operates	351	days			2019 AEI	
	Baseline Emissions					
Pollutant	**Lb/Hr**	**Ton/Year**			**Unit: lb/mmbtu**	
Nitrous Oxides (NOx)	21.6	90.9			0.131	2019 CEMS lb/MMBtu average. Use "utlization rate" to adjust to match ton/year from emission inventory

Boise White Paper LLC
International Falls, MN
Table 3 NO_x 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

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)		Vendor provided cost estimate	**3,500,000.00**
Purchased Equipment Total (B)	11.9%	increase to control device cost (A) to include MN Sales Tax and Freight	**3,915,625.00**
Installation - Standard Costs		Vendor provided cost 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 retrofit factor = (DC + IC) * (1 + retrofit factor)	25%	retrofit factor to account for issues not addressed by vendor such as structural steel, condition of existing equipment, asbestos, etc.	**11,144,531.25**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	111,997.69
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	1,445,546.77
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,557,544.47**

Emission Control Cost Calculation

Pollutant	Baseline Emis. T/yr	Cont. Emis. lb/hr	Cont. Emis. lb/MMBtu	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrous Oxides (NOx)	90.9	19.9	**0.05**	34.7	56.2	27,707

Notes & Assumptions

1 Total installed capital cost estimate from vendor

2 Assumed 0.5 hr/shift operatior and maintenance labor for LNB

3 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)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)		Vendor provided cost estimate	**$3,500,000.00**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation		Costs included in vendor provided estimate	$0.00
MN Sales Taxes	6.9%	of control device cost (A)	$240,625.00
Freight	5%	of control device cost (A)	$175,000.00
Purchased Equipment Total (B)	12%		**$3,915,625.00**
Installation [1]			
Foundations & supports			$0.00
Handling & erection			$0.00
Electrical			$0.00
Piping			$0.00
Insulation			$0.00
Painting			$0.00
Installation Total		Vendor provided cost estimate	**$5,000,000.00**
Installation Total			**$5,000,000.00**
Total Direct Capital Cost, DC			**$8,915,625.00**
Indirect Capital Costs			
Engineering, supervision	0%	Costs included in vendor provided estimate	$0.00
Construction & field expenses	0%	Costs included in vendor provided estimate	$0.00
Contractor fees	0%	Costs included in vendor provided estimate	$0.00
Start-up	0%	Costs included in vendor provided estimate	$0.00
Performance test	0%	Costs included in vendor provided estimate	$0.00
Model Studies	0%	Costs included in vendor provided estimate	$0.00
Contingencies	0%	Costs included in vendor provided estimate	$0.00
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)	**$0.00**
Total Capital Investment (TCI) = DC + IC			**$8,915,625.00**
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			**$0.00**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**$8,915,625.00**
Total Capital Investment (TCI) with Retrofit Factor	25%	retrofit factor to account for issues not addressed by vendor such as structural steel, condition of existing equipment, asbestos, etc.	**$11,144,531.25**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 0.5 hr/8 hr shift, 8424 hr/yr	$35,554.82
Supervisor	15%	15% of Operator Costs	$5,333.22
Maintenance (2)			
Maintenance Labor	67.53	$/Hr, 0.5 hr/8 hr shift, 8424 hr/yr	$35,554.82
Maintenance Materials	100%	of maintenance labor costs	$35,554.82
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
Total Annual Direct Operating Costs			**$111,997.69**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	$67,198.62
Administration (2% total capital costs)	2%	of total capital costs (TCI)	$222,890.63
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	$111,445.31
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	$111,445.31
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	$932,566.91
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**$1,445,546.77**
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	

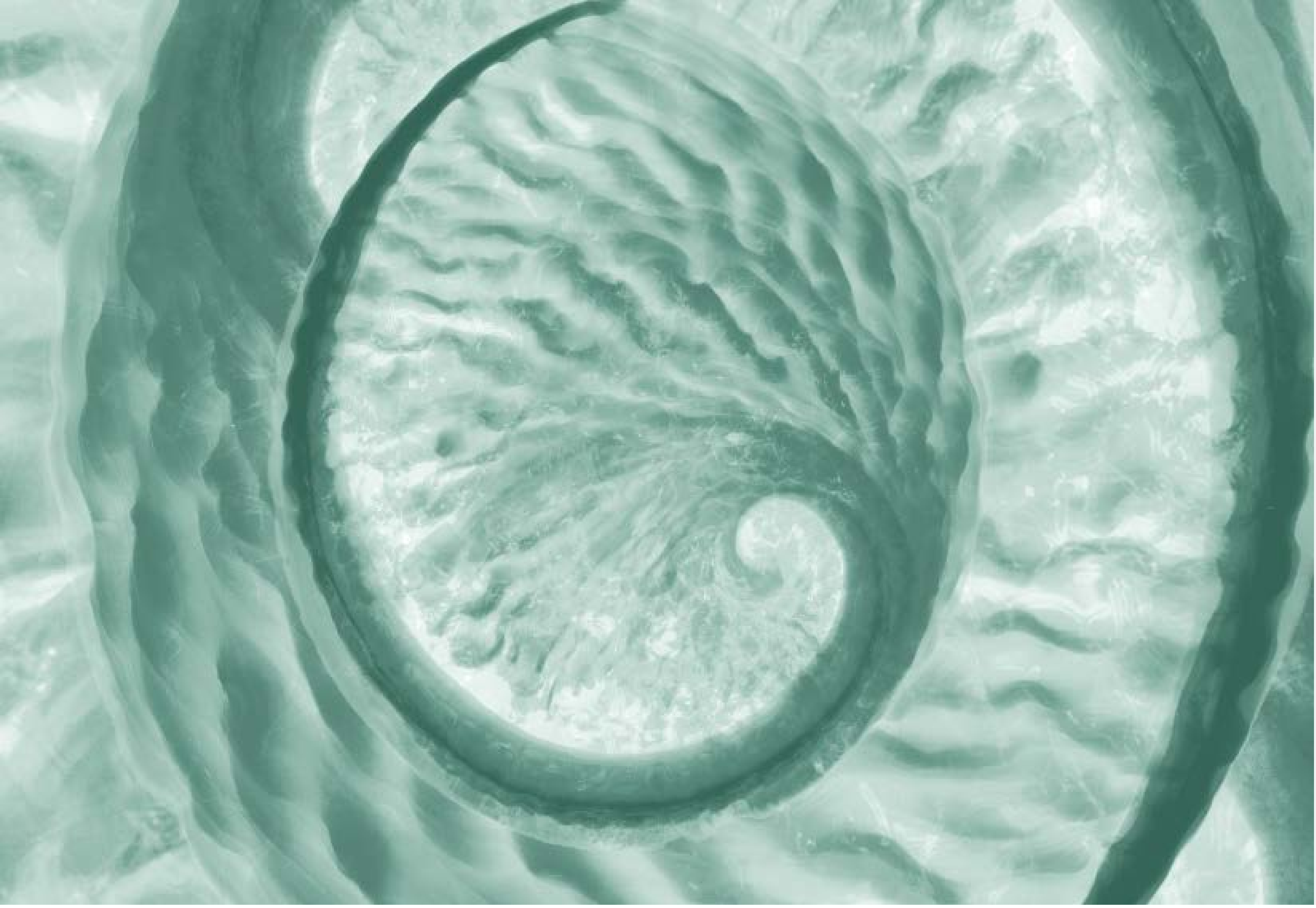
Replacement Parts & Equipment:
N/A

Replacement Parts & Equipment:
N/A

Electrical Use

Reagent Use & Other Operating Costs

Operating Cost Calculations	**Annual hours of operation:**	**8,424**
	Utilization Rate:	**41%**



Four Factor Analysis

Hibbing Public Utilities Commission

Hibbing, Minnesota

28 July 2020

Project No.: 0560921

The business of sustainability

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

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Acronyms and Abbreviations

Name	Description
°F	degrees Fahrenheit
BACT	Best Available Control Technology
CEM	continuous emission monitor
CFR	Code of Federal Regulations
CO	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	kilowatts
LAER	Lowest Achievable Emission Rate
lb	pounds
LNB	Low NO_x Burner
LSD	Lime Spray Dryer
LSFO	Limestone Forced Oxidation
MMBtu	million British thermal units
MPCA	Minnesota Pollution Control Agency
MW	megawatts
NO_x	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_2	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_x) and sulfur dioxide (SO_2) 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_x 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_2 and NO_x 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_x 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_x monitor, and CO monitor. The boiler design includes over-fire air (OFA), which will reduce the formation of NO_x but was not specifically included for NO_x control and is not listed in the air permit as control for NO_x. 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_2 and NO_x Emissions

A summary of recent continuous emission monitor information is listed in Table 1.

Table 1: Continuous Emission Monitor

Value Description	EQUI 1 and EQUI 2 SO_2 (lb/MMBtu)	EQUI 3 SO_2 (lb/MMBtu)	EQUI 7 NO_x (lb/MMBtu)
Minimum	0	0	0
Maximum	0.47 [a]	0.52 [a]	0.155 [b]
Range [c]	0.47	0.52	0.155
Average	0.10	0.17	0.0.03

Abbreviations: lb = pounds; MMBtu = million British thermal units

[a] *Permit limit for each coal-fired boiler (EQUI 1, EQUI 2, and EQUI 3) is 4.0 lbs/MMBtu when combusting coal.*

[b] *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.*

[c] *Range is the difference between the highest (maximum) and the lowest (minimum) within a set of numbers.*

The potential emissions of SO_2 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_2 from EQUI 3 are 223 lb/hr and 978 tpy.

The potential emissions of NO_x from EQUI 1 and EQUI 2 are 140 lb/hr and 612 tpy each. The potential emissions of NO_x from EQUI 3 are 160 lb/hr and 703 tpy. The potential emissions of NO_x for EQUI 7 while burning wood are 34.5 lb/hr and 151.11 tpy.

2.2 Historical SO_2 and NO_x 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_2 emissions have decreased each year from 2016 to 2019. Table 2 provides the actual annual SO_2 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_2 from the combustion reaction.

Table 2: Historical SO_2 Emissions

Year	EQUI 1 (tpy)	EQUI 2 (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

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.

Table 3: Historical NO_x Emissions

Year	EQUI 1 (tpy)	EQUI 2 (tpy)	EQUI 3 (tpy)	EQUI 7 (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

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_2 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_2 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_2 removal efficiencies of 95% (Institute of Clean Air Companies [ICAC] Acid Gas/SO_2 Controls), https://www.icac.com/page/Acid_Gas_SO2_Control.

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_2. 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_2 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_2 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_x Control Technology

In August 2010 the USEPA published "Documentation for Integrated Planning Model Base Case" that included NO_x emission control information prepared by engineering firm Sargent and Lundy (USEPA 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_x emission controls for large utility boilers.

Available control options identified are:

- Low NO_x 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_x Control Technology

The coal-fired boilers at HPUC do not employ any add on control technologies for NO_x 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_x 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_x. 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_x are in table B-2.

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_x formation.

OFA Systems – Additional NO_x 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_x reduction systems.

SCR – 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.

SNCR – 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_x 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_x 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_x 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_x 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_x 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_x 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_x emission control information prepared by engineering firm Sargent and Lundy (USEPA 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_X 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_x 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_x 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_x formation.

OFA – Additional NO_x 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_x reduction systems.

SCR – 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.

SNCR – 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 EQUI 7, 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 EQUI 7 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_x 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_x 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_x by ammonia. The SCR is designed to evenly distribute the flow of NO_x 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_x 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_x 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_x 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_2 Control Costs

The costs for SO_2 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_2,

The level of SO_2 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.

Table 4: EQUI 1 and EQUI 3 SO_2 Control Cost Estimate Summary

Parameter	EQUI 1 (17.8 MW, 178,000 kW)		EQUI 3 (21.4 MW, 214,000 kW)	
	Wet	**Spray Dry**	**Wet**	**Spray Dry**
Capital Cost (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 (14 $/kW for wet and 155 $/KW for spray dry)	$2,492,000	$27,590,000	$2,996,000	$33,170,000
Annual Cost (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 $ [a]	$265,738,372	$289,586,687	$319,483,211	$348,154,781
Emission Reduction Percent	90%	80%	90%	80%
Emission Reduction [b] (tpy)	98.01	87.12	99.25	88.22
Cost of Emission Reduction ($/ton) [c]	**$2,711,339**	**$3,323,998**[d]	**$3,218,974**	**$3,946,438**[d]

Abbreviations: MW = megawatts; O&M = operation and maintenance

[a] *The inflation rate in the United States between 2001 and today is 47.23%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, July 2020.*

[b] *Emission reduction is based on a 4-year average of actual emissions reported from 2016–2019. Emissions of 108.90 tons of SO_2 are from EQUI 1 and 110.28 tons of SO_2 are from EQUI 3.*

[c] *Cost of emission reduction is rounded to the nearest whole dollar.*

[d] *Cost of emission reduction does not include the addition of a fabric filter down stream of the spray dryer.*

3.3.1.2 NO_x Control SNCR Cost

Table 5 summarizes the cost of retrofitting EQUI 1 and EQUI 3 with an SNCR NO_x 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_x Control Cost Estimate Summary

Parameter	EQUI 1 (17.8 MW/216 MMBtu/hr)	EQUI 3 (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 $ [a]	$818,756	$889,837
Emission Reduction Percent	40%	40%
Emission Reduction [b] (tpy)	43.17	57.62
Cost of Emission Reduction [c] ($/ton)	$18,966	$15,443

[a] *The inflation rate in the United States between 1999 and today is 56.91%, (U.S. Bureau of Labor Statistics, https://www.bls.gov/data/inflation_calculator.htm, July 2020.*

[b] *Emission reduction is based on a 4-year actual average of 2016–2019 emissions of 107.93 tons of NO_x from EQUI 1 and 144.05 tons of NO_x from EQUI 3.*

[c] *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_x 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_x actual emissions contained in Table 3.

3.3.1.3 NO_x Control SCR Cost

The costs for NO_x 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_x. Table 6 summarizes the costs associated with retrofitting EQUI 1 and EQUI 3 with SCR for NO_x Control.

Table 6: EQUI 1 and EQUI 3 SCR NO_x Control Cost Estimate Summary

Parameter	EQUI 1 (216 MMBtu/hr)	EQUI 3 (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 $ [a]	$6,151,500	$7,062,833
Pre-heater for Exhaust	Cost Not Available [b]	Not Applicable
Emission Reduction Percent	85%	85%
Emission Reduction [c] (tpy)	91.74	122.44
Cost of Emission Reduction [d] ($/ton)	$67,054	$57,684

[a] *The inflation rate in the United States between 1999 and today is 56.91%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, July 2020.*

[b] *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.*

[c] *Emission reduction is based on actual average emissions from 2016–2019 of 107.93 tons of NO_x from EQUI 1 and 144.05 tons of NO_x from EQUI 3.*

[d] *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_x 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_x 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_x 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_x emissions contained in Table 3.

3.3.2 Wood-Fired Boiler EQUI 7 Additional NO_x 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 EQUI 7, 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_x 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_x 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.

Table 7: EQUI 7 SCR NO_x Control Cost Estimate Summary

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]	$2,760,831
Pre-heater for Exhaust [b]	Cost Not Available
Emission Reduction (85% total which is 53.2% above the existing SNCR system at 31.8%)	53.2%
Emission Reduction [c] (tpy)	40.72
Cost of Emission Reduction [d] ($/ton)	$67,800

a *The inflation rate in the United States between 1999 and today is 56.91%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, July 2020)*

b *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.*

c *Emission reduction is based on 2016 emissions of 87.0 tons of NO_x, which could be reduced by an additional 53.2% by retrofitting EQUI 7 with SCR for NO_x reduction.*

d *Cost of emission reduction is rounded to the nearest whole dollar.*

The cost to retrofit EQUI 7 with SCR would be about $67,800 per ton of NO_x 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_x 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.

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_x 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.

Table 8: Impacts of Potential SO_x Control Technologies

Technology	EQUI 1	EQUI 3
Electrical Energy Consumption	Yes	Yes
Transportation Impacts	Yes	Yes
Solid Waste Generation	Yes	Yes
Increased Water Consumption	Yes	Yes

Table 9: Impacts of Potential NO_x Control Technologies

Technology	EQUI 1 – SNCR or SCR	EQUI 3 – SNCR or SCR	EQUI 7 - SCR
Electrical Energy Consumption	Yes	Yes	Yes
Transportation Impacts	Yes	Yes	Yes
Solid Waste Generation	Yes	Yes	Yes
Increased Water 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_2 Control

Adding SO_2 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_2 removed for EQUI 1 and $3,323,998 per ton of SO_2 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_2 removed for EQUI 1 and over $3,946,438 per ton of SO_2 removed for EQUI 3. Both technologies, based on how the boilers are currently being operated, should be considered cost-prohibitive for visibility protection.

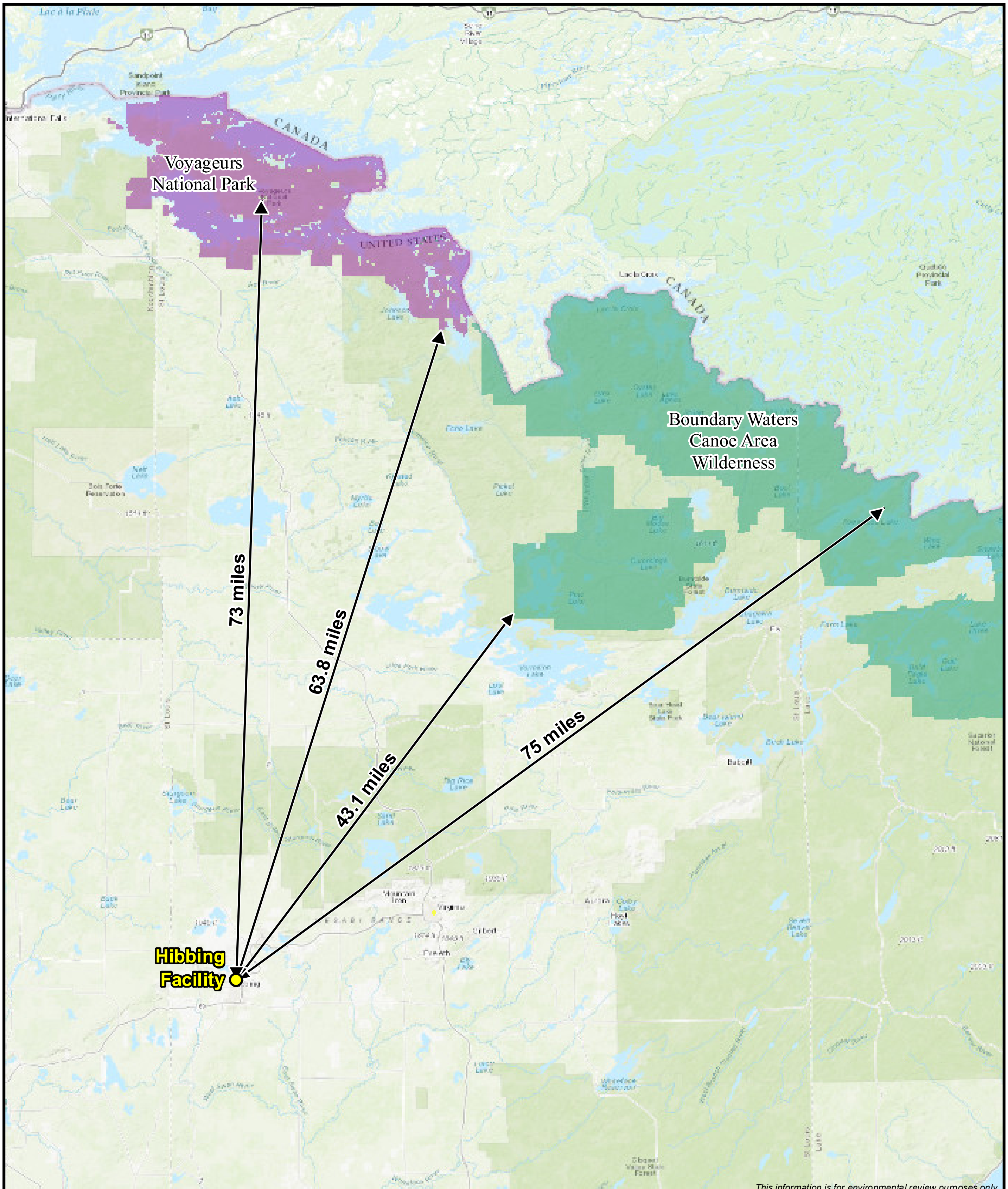
4.2 Coal-Fired Boiler – EQUI 1 and EQUI 3 NO_x Control

Reducing NO_x 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_x removed for EQUI 1 and $15,443 per ton of NO_x removed for EQUI 3. The cost of an SCR system has been calculated to be over $67,054 per ton of NO_x removed for EQUI 1 and over $57,684 per ton of NO_x 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_x Control

In the case of further reducing NO_x emissions from the EQUI 7 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_x 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



Hibbing Facility

Boundary Waters Canoe Area Wilderness

Voyageurs National Park

0 5 10 Miles

N

Hibbing Public Utilities Commission

Site Location Map

Four Factor Analysis

ERM

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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_2

RBLC ID	Company	Boiler Size (MMBtu/hr)	Pollutant	Limit	Units	Technology	Basis For Limit	Permit Issuance Date	Process Type[1]
CA-1206	APMC Stockton Cogen Stockton Cogen Company	730	SO_2	59	lb/hr	Limestone injection with 70% minimum removal efficiency	BACT	9/16/2010	11.110
NE-0037	Cargill, Inc	1500	SO_2	0.11	lb/MMBtu	Limestone injection	BACT	9/8/2006	12.110
OH-0241	Miller Brewing Company	238	SO_2	1.6	lb/MMBtu		BACT	5/27/2004	12.110
VA-0267	VPI University VPI Power Station	146.7	SO_2	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 Riegelwood Mill	249	SO_2	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 Navajo Generator Station	7725	SO_2	0		Flue gas desulfurization	BART	6/6/2012	11.110
MI-0400	Wolverine Power Supply Cooperative, Inc.	3030	SO_2	303	lb/hr	Dry flue gas desulfurization (spray dry absorber or polishing scrubber)	BACT	6/29/2011	11.110
TX-0595	Tenaska Trailblazer Partners, LLC	8307	SO_2	0.06	lb/MMBtu	Wet limestone scrubber	BACT	12/30/2010	11.110
MI-0399	Detroit Edison	7624	SO_2	0.107	lb/MMBtu	Wet flue gas desulfurization	BACT	12/21/2010	11.110
TX-0554	Coleto Creek	6670	SO_2	0.06	lb/MMBtu	Spray Dry Adsorber / Fabric Filter	BACT	5/3/2010	11.110
KY-0100	East Kentucky Power Cooperative, LLC J.K. Smith Generating Station	3000	SO_2	0.075	lb/MMBtu	Limestone Injection (circulating fluidized bed [CFB]) and flash dryer absorber with fresh lime injection	BACT	4/9/2010	11.110

EPA Website: https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en

[1] 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_x

RBLC ID	Company	Boiler Size (MMBtu/hr)	Pollutant	Limit	Units	Technology	Basis For Limit	Permit Issuance Date	Process Type[1]
CA-1206	APMC Stockton Cogen Stockton Cogen Company	730	NO_x	50	ppm	Low bed temperature staged combustion, selective non-catalytic reduction (SNCR)	BACT	9/16/2010	11.110
NE-0037	Cargill, Inc	1500	NO_x	0.08	lb/MMBtu	Combustion control, SNCR	BACT	9/8/2006	12.110
ND-0020	Red Trail Energy, LLC Richardton Plant	250	NO_x	0.1	lb/MMBtu	SNCR	BACT	8/4/2004	12.110
OH-0241	Miller Brewing Company	238	NO_x	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 Riegelwood Mill	249	NO_x	0.4	lb/MMBtu	Good combustion practices	BACT	5/10/2001	12.110
OK-0152	O G and E Muskogee Generating Station	1875.5	NO_x	0.15	lb/MMbtu	Low NO_x burners (LNB) and OFA	BART	1/30/2013	11.110
OK-0151	O G and E Muskogee Generating Station	1875.5	NO_x	0.15	lb/MMbtu	LNBs and OFA	BACT	1/17/2013	11.110
AZ-0055	Salt River Project Agricultural and Power District Navajo Generator Station	7725	NO_x	0.24	lb/MMBtu	LNBs and OFA	BACT	2/6/2012	11.110
MI-0400	Wolverine Power Supply Cooperative, Inc.	3030	NO_x	1	lb/MW-hr	SNCR	BACT	6/29/2011	11.110
TX-0595	Tenaska Trailblazer Partners, LLC	8307	NO_x	0.05	lb/MMBtu	selective catalytic reduction (SCR)	BACT	12/30/2010	11.110
MI-0399	Detroit Edison	7624	NO_x	0.08	lb/MMBtu	Staged combustion, LNBs, OFA, SCR	BACT	12/21/2010	11.110
TX-0554	Coleto Creek	6670	NO_x	0.06	lb/MMBtu	LNBs with OFA system, SCR	BACT	5/3/2010	11.110
KY-0100	East Kentucky Power Cooperative, LLC J.K. Smith Generating Station	3000	NO_x	0.07	lb/MMBtu	SNCR	BACT	4/9/2010	11.110
TX-0557	NRG Texas Power LLC Limestone Electric Generating Station	9061	NO_x	0.25	lb/MMBtu	Tuning of existing low NO_x firing system to induce deeper state combustion	BACT	2/1/2010	11.110
TX-0556	Southwestern Public Service Company Harrington Station Unit 1 Boiler	3630	NO_x	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

[1] 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 lilgnite).

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_x

RBLC ID	Company	Boiler Size (MMBtu/hr)	Pollutant	Limit	Units	Technology	Basis For Limit	Permit Issuance Date	Process Type[1]
ME-0040	Robbins Lumber, Inc.	167.3	NO_x	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_x	95	lb/hr	Good combustion practices, low NO_x burners (LNB)	BACT	5/9/2017	12.120
MI-0421	Arauco North America Grayling Particleboard	110	NO_x	95	lb/hr	Good combustion practices, LNB	BACT	8/26/2016	12.120
SC-0149	Klausner Holding USA, Inc.	120	NO_x	0.14	lb/MMBtu	SNCR	Other	1/3/2013	12.120
FL-0332	Highlands Envirofuels (HEF), LLC Highlands Biorefinery and Cogeneration Plant	458.5	NO_x	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 Sweet Sorghum-to-Ethanol Advanced Biorefinery	536	NO_x	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_x	0.06	lb/MMBtu	SCR	BACT	9/23/2019	11.120
FL-0359	US Sugar Corporation	1,077	NO_x	0.1	lb/MMBtu	SNCR (NH_3 injection)	BACT	11/29/2016	11.120
KS-0034	Abengoa Bioenergy Biomass of Kansas (ABBK)	500	NO_x	0.3	lb/MMBtu	SCR and overfire air (OFA) system	BACT	5/27/2014	11.120
CA-1225	Sierra Pacific Industries	468	NO_x	0.13	lb/MMBtu	SNCR	BACT	4/25/2014	11.120
VT-0039	North Springfield Sustainable Energy Project, LLC	464	NO_x	0.03	lb/MMBtu	Bubbling fluidized bed boiler design and SCR	BACT	4/19/2013	11.120
GA-0141	Ogethorpe Power Corporation Warren County Biomass Energy Facility	341	NO_x	0.1	lb/MMBtu	SNCR	BACT	12/17/2010	11.120
VT-0037	Beaver Wood Energy Fair Haven, LLC	482	NO_x	0.03	lb/MMBtu	Good combustion control and SCR	BACT	2/10/2012	11.120
ME-0037	Verso Bucksport, LLC	817	NO_x	0.15	lb/MMBtu	SNCR	BACT	11/29/2010	11.120
CA-1203	Sierra Pacific Industries	335.7	NO_x	80	ppm	SNCR	BACT	8/30/2010	11.120
NH-0018	Berlin Station, LLC Burgess Biopower	1,013	NO_x	0.06	lb/MMBtu	SCR with NH_3 injection[2]	LAER	7/26/2010	11.120
CT-0156	NRG Energy	600	NO_x	0.06	lb/MMBtu	Regenerative SCR	LAER	4/6/2010	11.120
AL-0250	Boise White Paper, LLC	435	NO_x	0.3	lb/MMBtu	LNB	BACT	3/23/2010	11.120
TX-0553	Lindale Renewable Energy, LLC	1,256	NO_x	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

[1]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).

[2]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_x 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 AIR CONTROL TECHNOLOGY SNCR FACT SHEET

EPA-452/F-03-031

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_X)

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_X reductions (> 60%) on utility boilers greater than 6,000 MMBtu/hr (600MW). (ICAC, 2000).

b. **Temperature:** The NO_X 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_X 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 site-specific 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 removed
Seasonal 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_X 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_X required to achieve the targeted NO_X 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_X 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_X 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_X reductions.

Disadvantages:

- The waste gas stream must be within a specified temperature range.
- Not applicable to sources with low NO_X concentrations such as gas turbines.
- Lower NO_X 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

EPA-452/F-03-032

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 gas-fired 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 $\$/m^3$ (283 $\$/ft^3$). A 350 MMBtu/hr natural gas-fired boiler operating at 85% capacity requires approximately 17 m^3 (600 ft^3). For the same sized coal-fired boiler, the required catalyst is on the order of 42 m^3 (1,500 ft^3). (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.

Table 1a: Summary of Cost Information in $/MMBtu/hr (1999 Dollars) [a, b]

Unit Type	Capital Cost ($/MMBtu)	O&M Cost [d] ($/MMBtu)	Annual Cost [d] ($/MMBtu)	Cost per Ton of Pollutant Removed ($/ton)
Industrial Coal Boiler	10,000 - 15,000	300	1,600	2,000 - 5,000
Industrial Oil, Gas, Wood [c]	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 1b: Summary of Cost Information in $/MW (1999 Dollars) [a, b]

Unit Type	Capital Cost ($/MW)	O&M Cost [d] ($/MW)	Annual Cost [d] ($/MW)	Cost per Ton of Pollutant Removed ($/ton)
Industrial Coal Boiler	1,000 - 1,500	30	160	2,000 - 5,000
Industrial Oil, Gas, Wood [c]	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

[a] (ICAC, 1997; NESCAUM, 2000; EPA, 2002)
[b] Assumes 85% capacity factor and annual control of NOx
[c] SCR installed on wood fired boiler assumes a hot side electrostatic precipitator for PM removal
[d] 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.

l) 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 (TUsee 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. 113925V-0202 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.

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
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

EPA-452/F-03-034

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_2)

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_2 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_2 removal for dry sorbent injection systems range from 150°C to 180°C (300°F to 350°F). Optimal temperatures for SO_2 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_2 scrubbers are limited to dilute SO_2 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_2 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_2 scrubbers have decreased by over 30% since the beginning of the 1990's. Current costs for SO_2 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).

Table 1a: Summary of Cost Information in $/MMBtu/hr (2001 Dollars) [a]

Scrubber Type	Unit Size (MMBtu/hr)	Capital Cost ($/MMBtu)	O&M Cost [b] ($/MMBtu)	Annual Cost ($/MMBtu)	Cost per Ton of Pollutant Removed ($/ton)
Wet	> 4,000	10,000 -25,000	200 - 800	25 - 40	200 - 500
	< 4,000	25,000 - 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 - 150,000	1,000 - 30,000	10,000 - 50,000	500 - 4,000

Table 1b: Summary of Cost Information in $/MW (2001 Dollars) [a]

Scrubber Type	Unit Size (MW)	Capital Cost ($/kW)	O&M Cost [b] ($/kW)	Annual Cost ($/kW)	Cost per Ton of Pollutant Removed ($/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

[a] (EIA, 2002; EPA, 2000; Srivastava, 2001)
[b] 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^3 of flue gas (liters of slurry/1000Nm^3 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_2 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_2 concentrations greater than 2,000 ppm
- Disposal of waste products significantly increases O&M costs

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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 M. LaTendresse

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

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1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency (MPCA) submitted a Request for Information (RFI) Letter[1] to Hibbing Taconite Company (HTC) to consider potential emissions reduction measures of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) 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)[2]:

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[3] (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_x and SO_2. HTC has BART emission controls and emission limits for NO_X and SO_2 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[4] and October 2015[5] USEPA Federal Implementation Plan (FIP) rulemaking. (see Section 5)

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[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to Hibbing Taconite Company.

[2] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[3] USEPA, Regional Haze Rule Requirements – Long Term Strategy for Regional Haze, 40 CFR 52.308(f)(2)

[4] USEPA, Federal Register, 08/15/2012, Page 49308.

[5] 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_2 and NO_X 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.[6] 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)[7], by July 31, 2020 for the emission units identified in Table 2-1.

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[6] 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.

[7] 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 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 95/EU 020	NO_X, SO_2
Natural Gas Fired Indurating Furnace Line No 2 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 96/EU 021	NO_X, SO_2
Natural Gas Fired Indurating Furnace Line No 3 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 97/EU 022	NO_X, SO_2

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[8].

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."[9] 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 and determine 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."[10]

The SIP revision must also include the "Long-term strategy for regional haze."[11] 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

[8] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[9] 40 CFR 51.308(f)(1)

[10] 40 CFR 51.308(f)(1)(vi)(A)

[11] 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[12], emission unit retirement and replacement schedules[13], and the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during the implementation period[14].

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)[15]. The reasonable progress goal is not enforceable but will be considered by USEPA in evaluating the adequacy of the SIP[16].

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*"[17] 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."[18]

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"[19] 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."[20] 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.[21]

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)

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[12] 51.308(f)(2)(iv)(A)

[13] 51.308(f)(2)(iv)(C)

[14] 51.308(f)(2)(iv)(E)

[15] 40 CFR 51.308(f)(3)

[16] 40 CFR 51.308(f)(3)(iii)

[17] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[18] Ibid, page 1.

[19] Ibid.

[20] Ibid, page 9 (emphasis added).

[21] Ibid.

- Selection of sources for analysis (Step 3), with a focus on:
    - Estimating baseline visibility impacts for source selection (Step 3b)
    - 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):[22]

$$URP = [(\text{2000-2004 visibility})_{\text{20\% most impaired}} - (\text{natural visibility})_{\text{20\% most impaired}}]/60$$

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.[23] 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….”[24]

[22] Ibid, Page 7.

[23] Ibid, Page 50.

[24] 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 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."[25]

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[26]
- the four statutory factors (to the extent they have been characterized at this point in SIP development)[27]
- potential visibility benefits (also to the extent they have been characterized at this point in SIP development)[28]
- sources already having effective emissions controls in place[29]
- emission reductions at the source due to ongoing air pollution control programs[30]
- in-state emission reductions due to ongoing air pollution control programs that will result in an improvement in visibility[31]

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[25] Ibid, Page 9.
[26] Ibid, Page 10.
[27] Ibid.
[28] Ibid.
[29] Ibid, Page 21.
[30] Ibid, Page 22.
[31] Ibid.

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."[32]

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[33]:

- 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:[34]

> "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."[35] One of the "effectively controlled" scenarios is for "BART-

[32] Ibid, Page 10.

[33] Ibid, Page 12.

[34] Ibid, Page 27.

[35] Ibid, Page 22.

eligible units that installed and began operating controls to meet BART emission limits for the first implementation period."[36] 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."[37] 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."[38]

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_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."[39]

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

[36] Ibid, Page 25.

[37] Ibid.

[38] Ibid.

[39] 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.

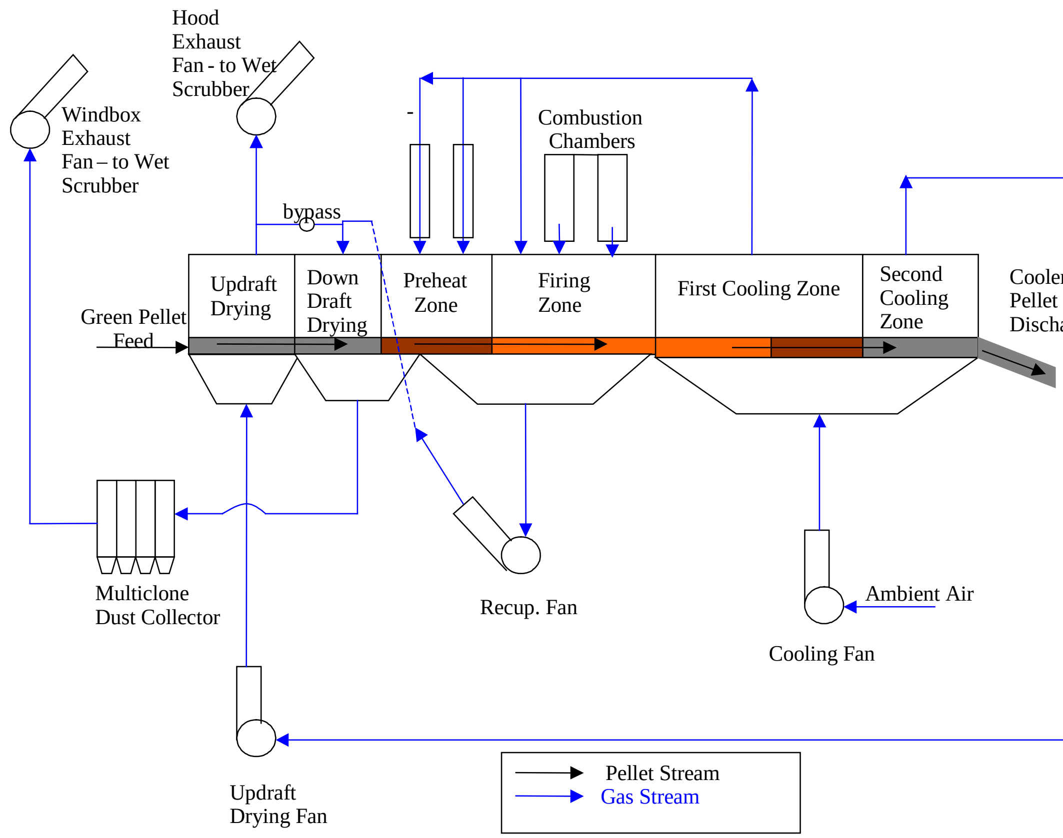

Figure 2-1 Natural Gas Fired Straight Grate Furnace Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers Diagram

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."[40] 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.[41] 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."[42]

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).[43] 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.[44] 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."[45] In

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[40] 40 CFR 51.308(f)(1)

[41] 40 CFR 51.308(f)(3)

[42] 40 CFR 51.308(d)(1)

[43] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[44] https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

[45] 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."[46]

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath[47] 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.

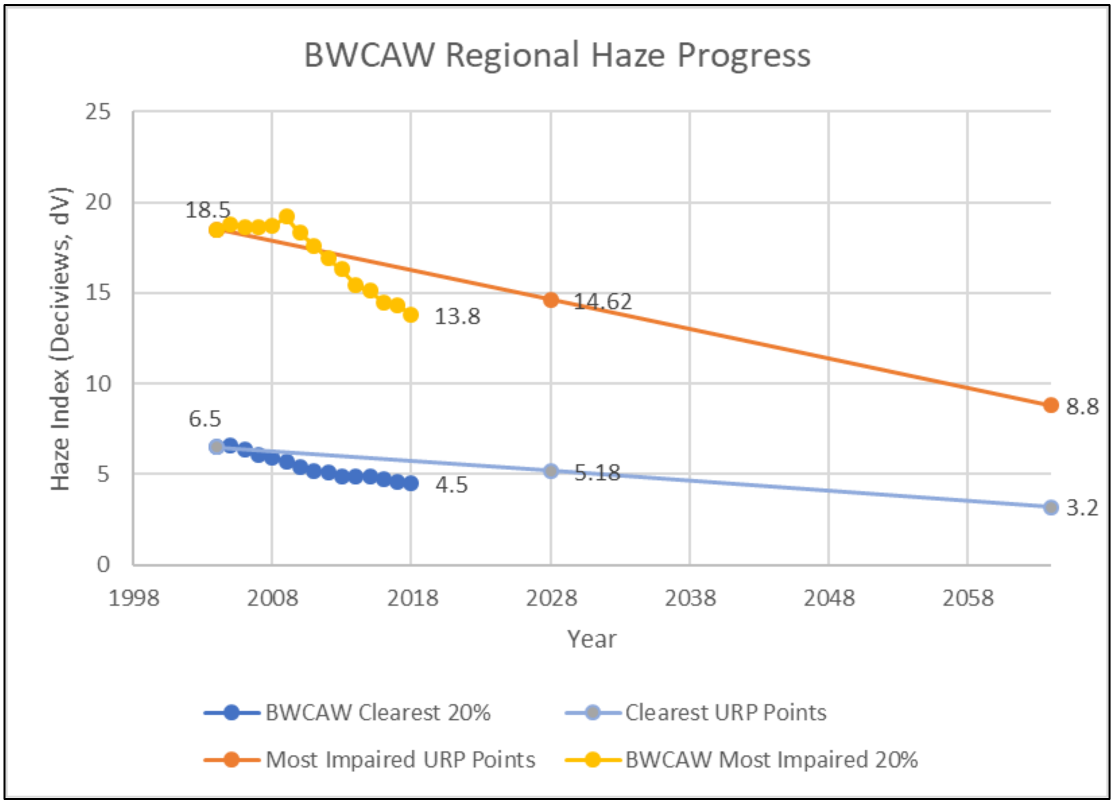

Figure 3-1 Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

[46] USEPA, Federal Register, 01/10/2017, Page 3104

[47] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

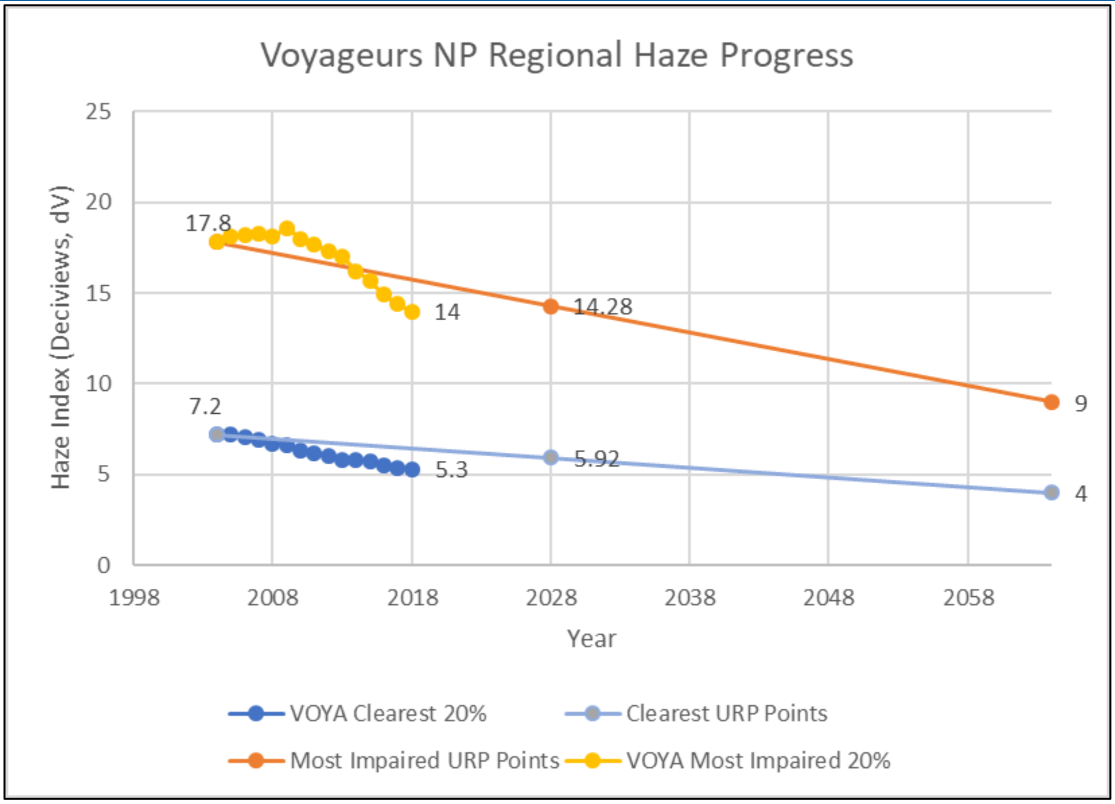

Figure 3-2 Visibility Trend versus URP – Voyageurs National Park (VOYA1)

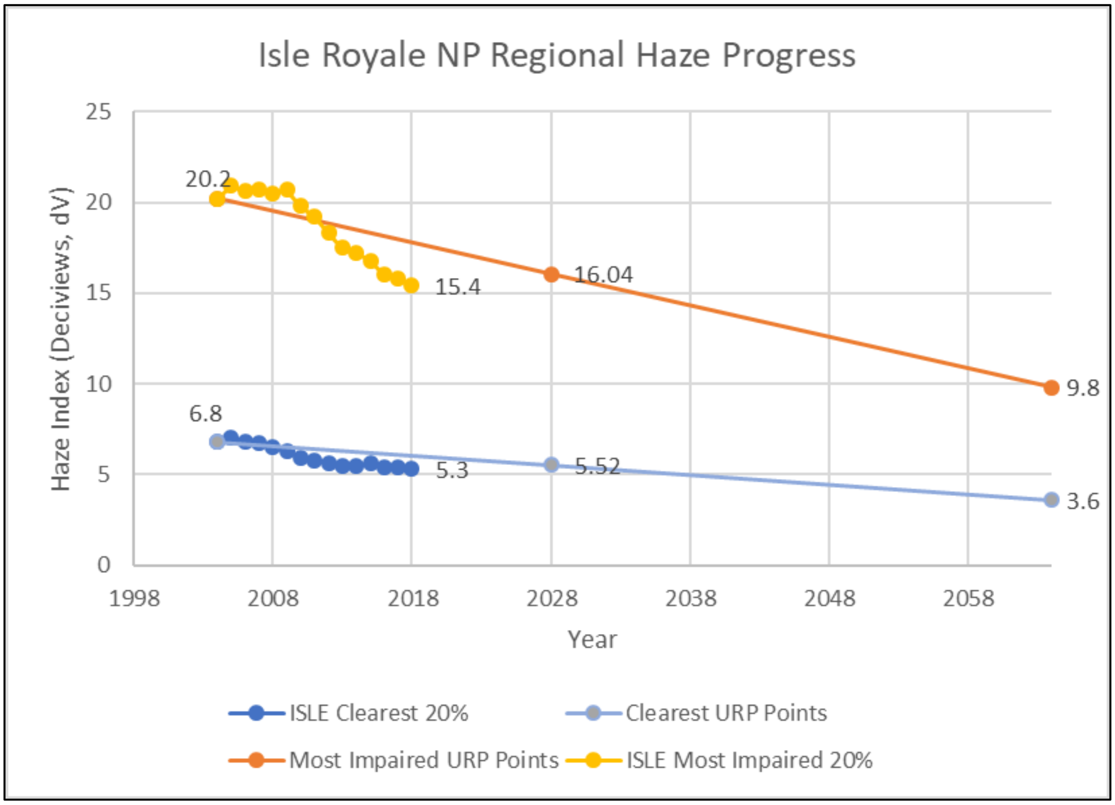

Figure 3-3 Visibility Trend versus URP – Isle Royale National Park (ISLE1)

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[48]. 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
    - 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.

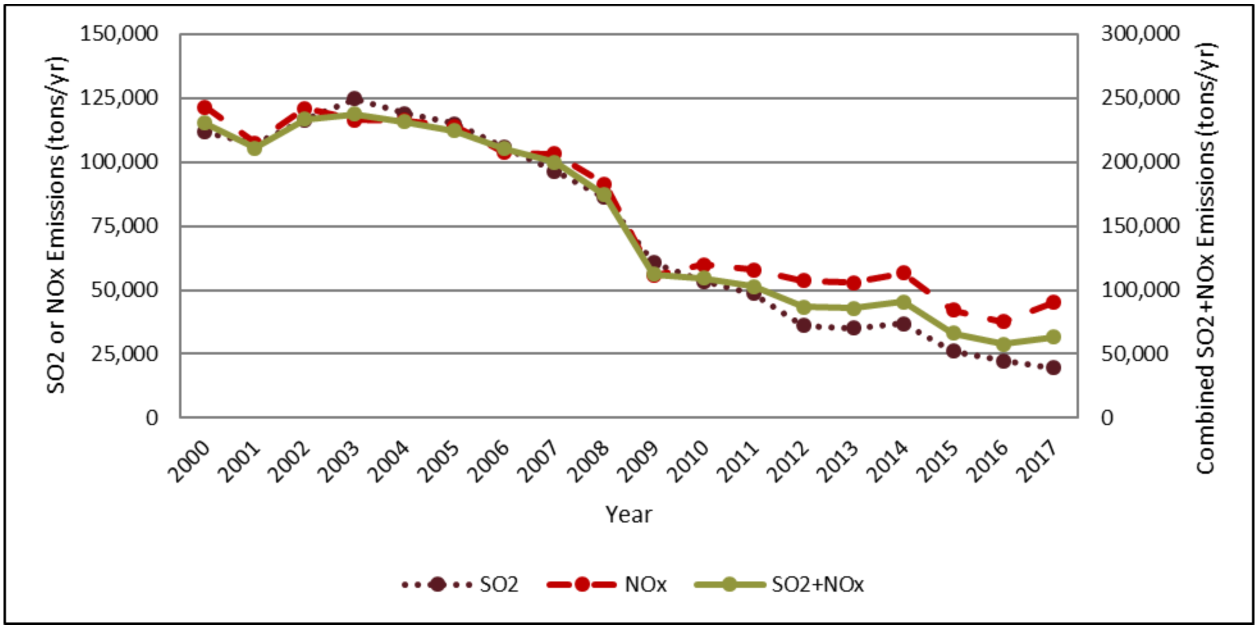

Figure 3-4 Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)

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[48] The data for NO_X and SO_2 emissions was downloaded from the MPCA point source emissions inventory (https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data). 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.

Table 3-1 Notable Minnesota Emission Reductions

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_X*
2018	Minntac Line 7: FIP emission limit compliance date for NO_X* MP Boswell: Units 1 & 2 retired from service**
2019	Hibtac Line 1: FIP emission limit compliance date for NO_X* Keetac: FIP emission limit compliance date for NO_X * Minntac Line 4 or 5: FIP emission limit compliance date for NO_X* Utac Line 1: FIP emission limit compliance date for NO_X*
2020	Hibtac Line 2: FIP emission limit compliance date for NO_X* Minntac Line 4 or 5: FIP emission limit compliance date for NO_X* Minorca: FIP emission limit compliance date for NO_X* Utac Line 2: FIP emission limit compliance date for NO_X*
2021	Minntac Line: FIP emission limit compliance date for NO_X* Hibtac Line 3: FIP emission limit compliance date for NO_X*
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***

* 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*[49]
  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*[50]
  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_X emission reductions suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces.

- *Other reasonable techniques*[51]
  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

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49 USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 13.

50 Ibid, Page 14.

51 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."[52] 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."[53]

[52] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.
[53] 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."[54] This section demonstrates that the indurating furnace Lines 1-3 meet USEPA's BART-required control equipment installation scenario for NO_X and SO_2.

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"[55] for NO_X and SO_2

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_X BART-required Controls

In the preamble to the October 2015 proposed FIP,[56] the USEPA concluded that BART for NO_X from straight-grate furnaces is low-NO_X 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[57]
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure[58]
- Selective Catalytic Reduction (SCR) controls because two vendors declined to bid on NO_x reduction testing for a taconite facility[59]

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54 USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, page 22.

55 Ibid, page 25.

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

57 Federal Register 77, No. 158 (August 15, 2012); 49321. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

58 Ibid.

59 Ibid.

- High-stoichiometric and low-stoichiometric low NO_x burners (LNB) because the technology had never been used on straight-grate furnaces at the time of the determination.[60]

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_X emissions from taconite indurating furnaces.

In accordance with the FIP, HTC implemented the BART NO_x 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_x emission limits[61] 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[62].

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[60] Federal Register 80, No. 204 (October 22, 2015); 64167. Available at: https://www.govinfo.gov/app/details/FR-2015-10-22/2015-25023

[61] 40 CFR 52.1235(b)(1)

[62] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10.

Table 5-1 NO_X Emission Limits

Unit	Unit ID	NO_X Emission Limit(1) (lb/MMBtu)	Compliance Date(2)
Natural Gas Fired Indurating Furnace Line No 1 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 95/EU 020	1.2-1.8	June 12, 2019
Natural Gas Fired Indurating Furnace Line No 2 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 96/EU 021	1.2-1.8	December 12, 2020
Natural Gas Fired Indurating Furnace Line No 3 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology 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_2 BART-required Controls

In the preamble to the August 2012 proposed FIP[63], the USEPA concluded that BART for SO_2 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[64]

In addition, USEPA eliminated Wet Walled Electrostatic Precipitator (WWESP) and secondary (polishing) wet scrubber technologies because they were not cost-effective.[65] HTC also considered and eliminated

[63] Federal Register 77, No. 158 (August 15, 2012); 49323. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

[64] Ibid, 49322.

[65] Ibid, 49323.

the addition of caustic, lime, or limestone to the scrubber water to improve SO_2 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_2 emissions from taconite indurating furnaces.

In accordance with the FIP, HTC has continued to operate the BART SO_2 control measures and is complying with the FIP SO_2 emission limits[66], 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_2. 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[67].

Table 5-2 SO_2 Emission Limits

Unit	Unit ID	SO_2 Emission Limit[(1)] (lb/hr)	Compliance Date[(2)]
Natural Gas Fired Indurating Furnace Line No 1 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 95/EU 020	279.3	April 11, 2018
Natural Gas Fired Indurating Furnace Line No 2 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 96/EU 021		
Natural Gas Fired Indurating Furnace Line No 3 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 97/EU 022		

(1) This limit was established using one year of SO_2 CEMS data, in accordance with the procedures outlined within 40 CFR 52.1235(b)(2)(v).
(2) HTC submitted the revised SO_2 limit request on April 11, 2018, in accordance with 40 CFR 52.1235(b)(2)(v).

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[66] 40 CFR 52.1235(b)(2)

[67] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 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_X and SO_2 (see Section 5). As stated in the 2019 Guidance, "it may be reasonable for a state not to select an effectively controlled source."[68] 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_X 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.**

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[68] 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")[1] 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[2], to determine the frequency that the trajectories on the "most impaired days"[3] 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).[4] 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.[5] 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[6], Draxler - 1992[7], Draxler and Hess - 1998[8]). 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.

[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[2] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[3] "Most impaired days" is the 20% most anthropogenically impaired days on an annual basis, measured in deciviews (dv), as provided on MPCA's website.

[4] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[5] https://www.arl.noaa.gov/hysplit/hysplit/

[6] http://www.kenrahn.com/DustClub/Articles/Stohl%201998%20Trajectories.pdf

[7] https://www.arl.noaa.gov/documents/reports/ARL%20TM-195.pdf

[8] 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.

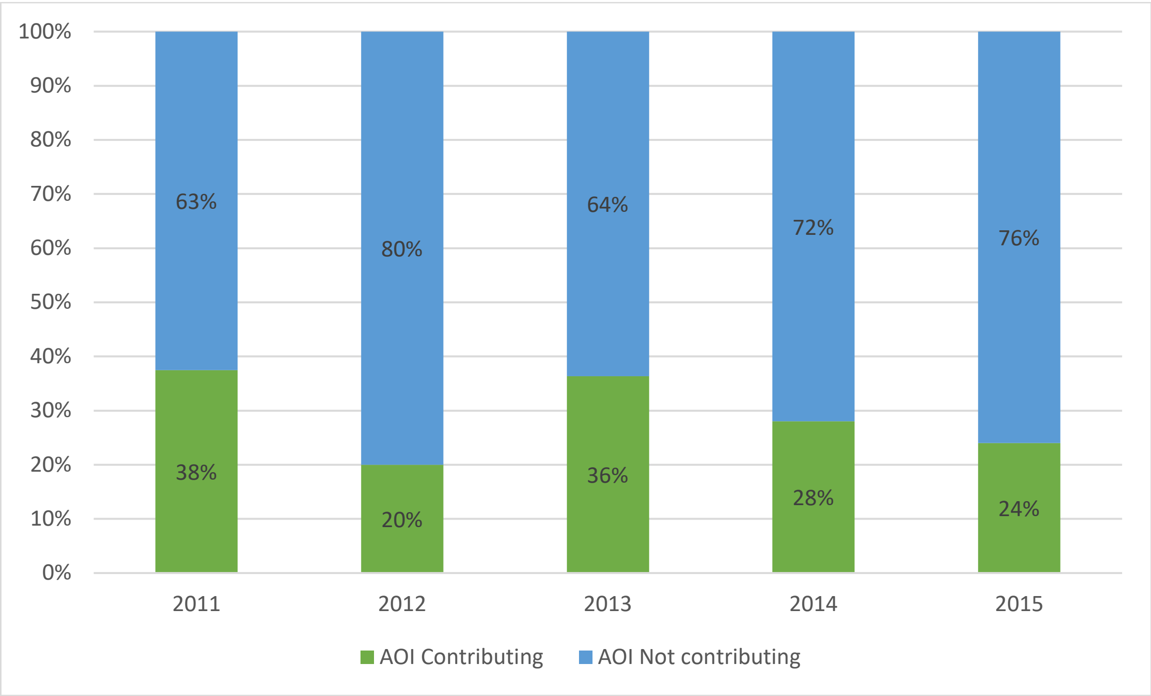

Figure A1 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at BWCA

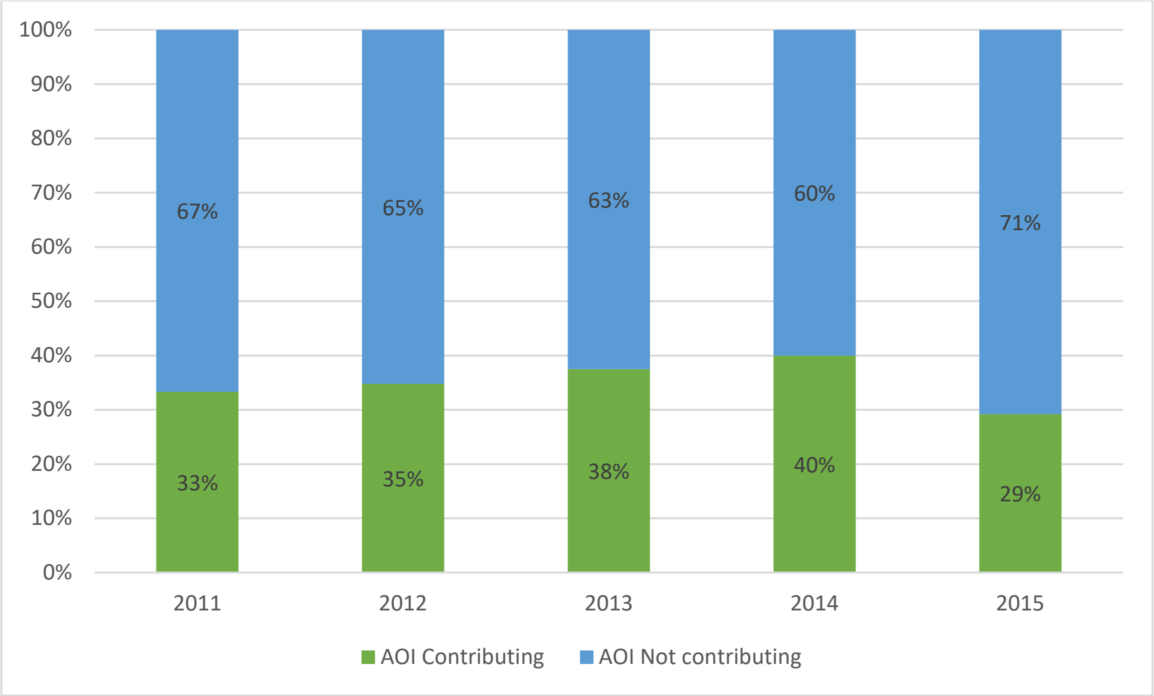

Figure A2 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at Voyageurs

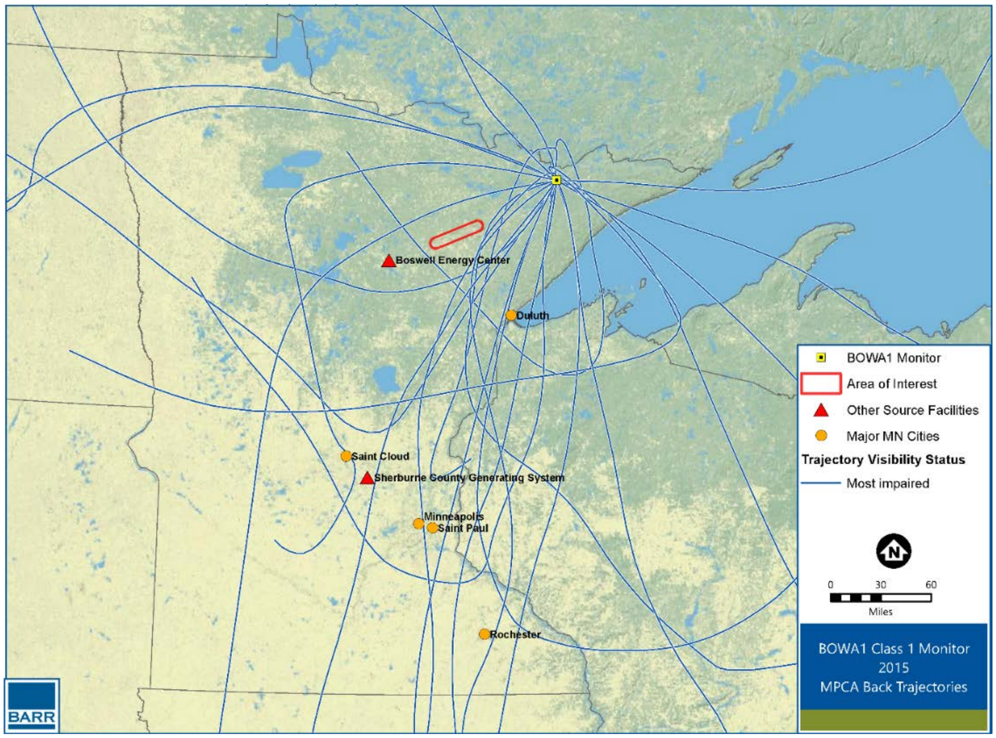

Figure A3 Reverse Trajectories and Other Sources Influencing Visibility at BWCA[9]

[9] 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, baseline source visibility impacts (or a surrogate metric for the impacts), [and] the in-place emission control measures…"*[10]

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. The first step in doing this is to estimate the impact of the source or set of sources on daily concentrations of PM species.*
>
> *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).*

[10] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 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 $PM_{2.5}$ 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."[11]

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 2nd 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_X 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_X 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_X 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 NOx 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_X 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

[11] 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_X 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_X 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_X 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_X 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_3) is a component of haze associated with NO_X 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."[12] 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."[13]

[12] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.
[13] Ibid, Page 12.

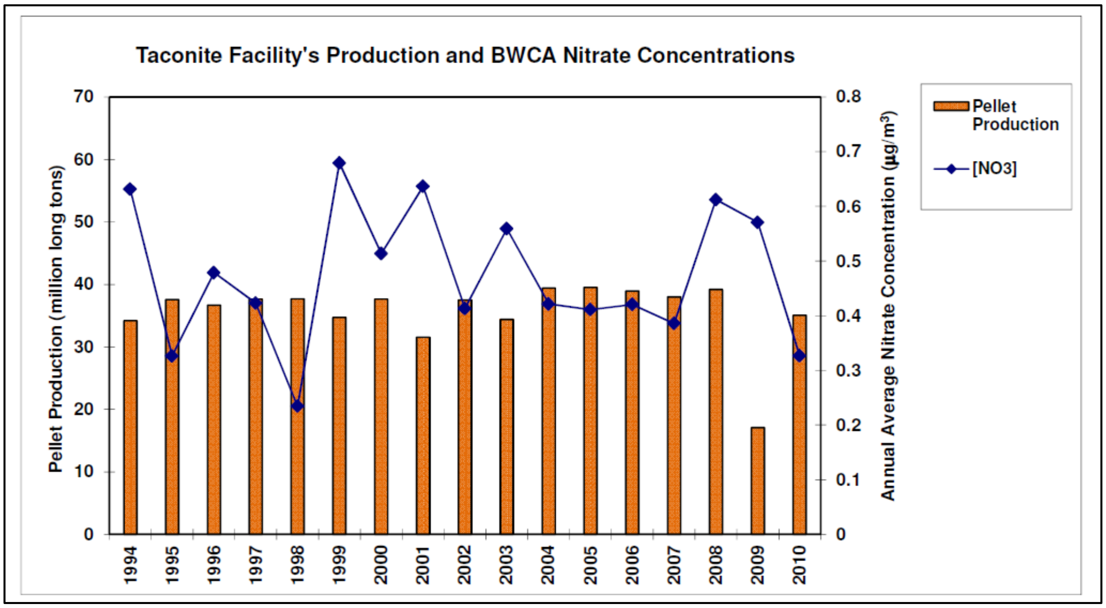

Figure A4 Minnesota Taconite Production and BWCA Nitrate Concentrations 1994-2010 [14]

[14] 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

Table A1 Results from MPCA Hysplit Trajectories for the BOWA1 Monitor

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

Table A2 Results from MPCA Hysplit Trajectories for the VOYA2 Monitor

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

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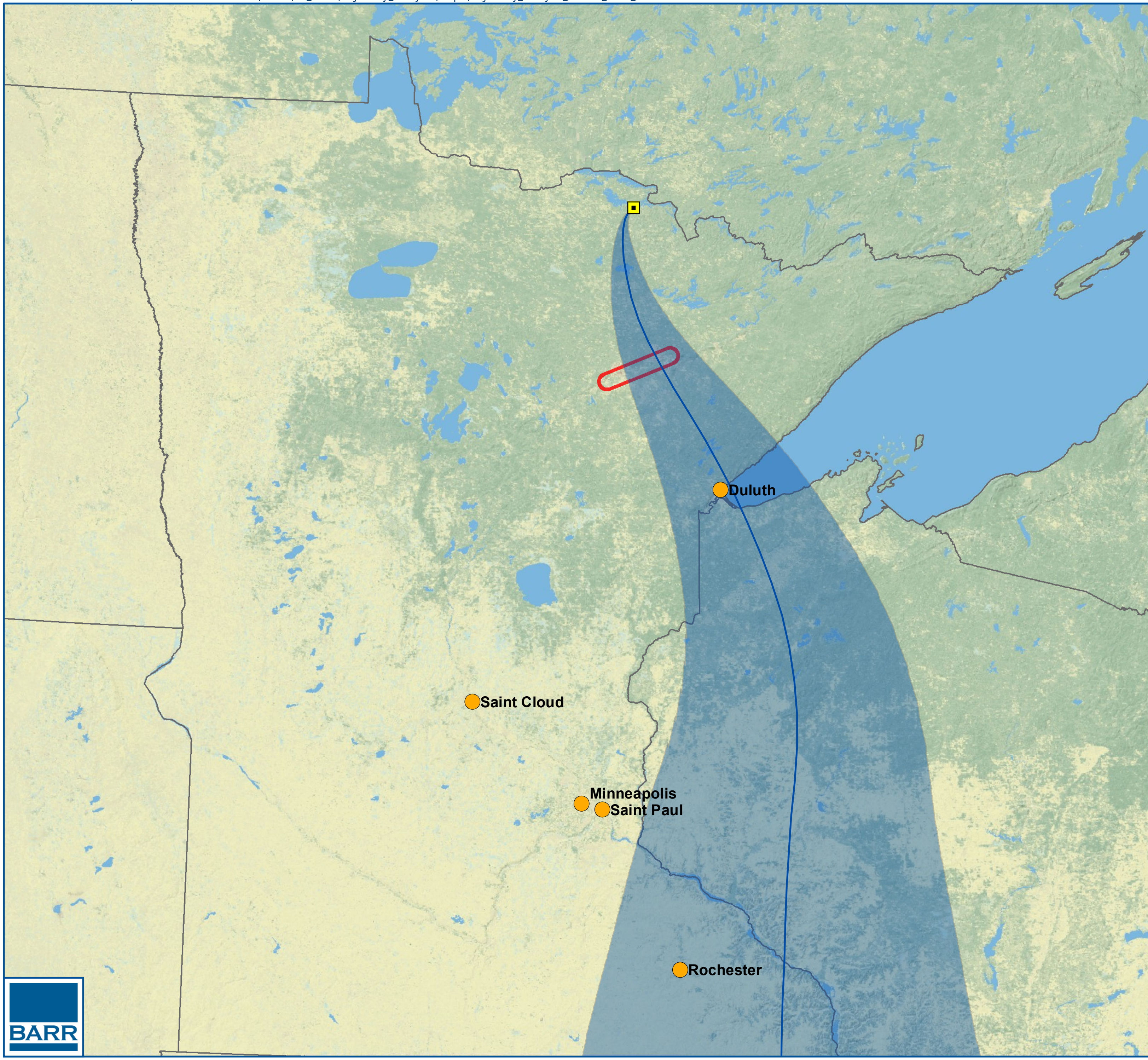

VOYA2 Class 1 Monitor
2013 SON
MPCA Back Trajectories

FIGURE 1

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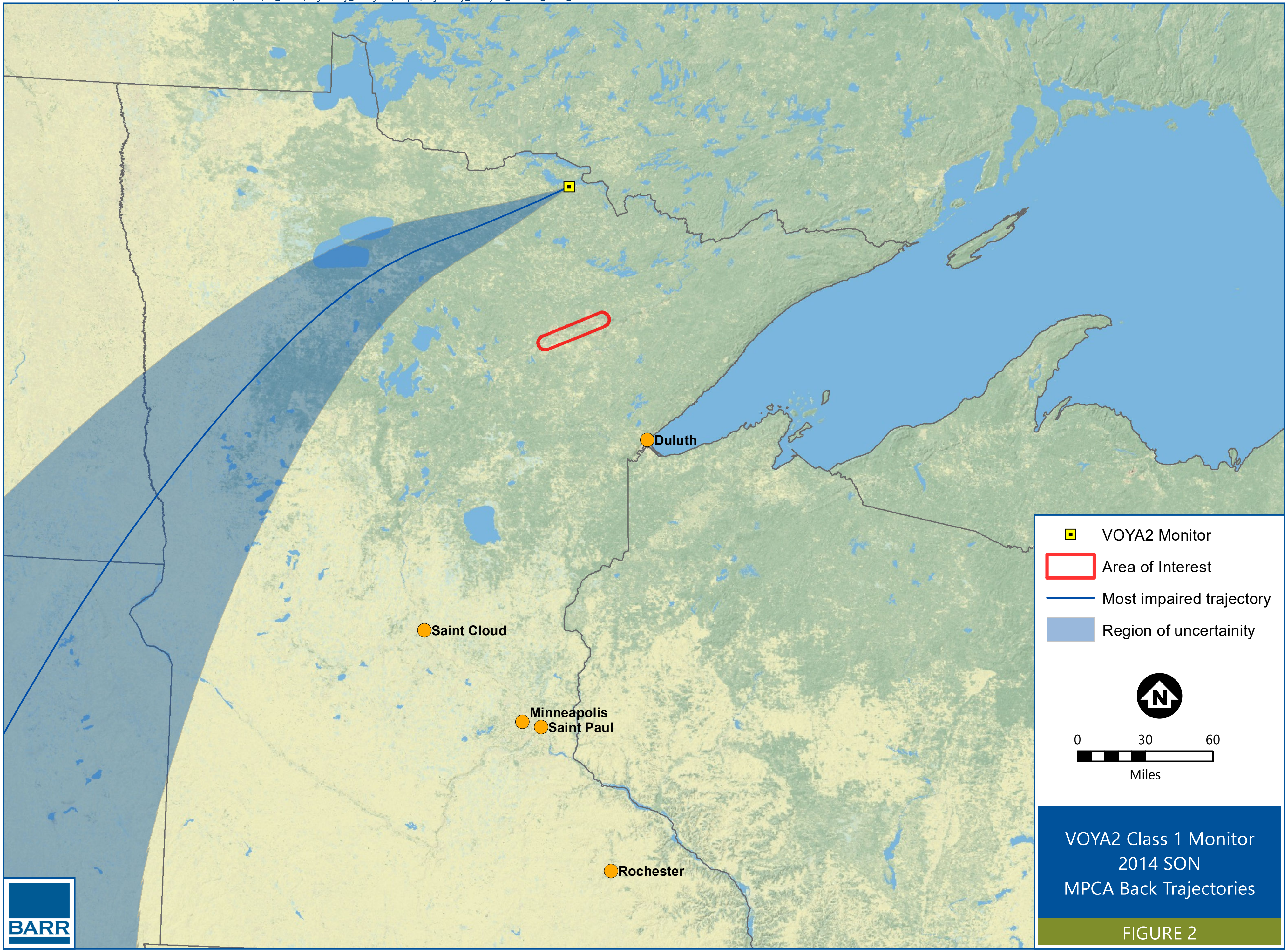

VOYA2 Class 1 Monitor
2014 SON
MPCA Back Trajectories

FIGURE 2

Attachment 2

CAM_X Modeling Report

resourceful. naturally.
engineering and environmental consultants

Technical Memorandum

From: Barr Engineering

Subject: Summary of Comprehensive Air Quality Model with Extensions (CAM_X) 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_X), 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_X, as EPA's approach over-predicted visibility impacts by factors of ten to sixty when compared with the proper CAM_X 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_X Modeling Methodology

The methodology utilized by Barr to complete the CAM_X 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_X modeling system (CAM_X 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_X 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."[1] 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

[1] 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_X 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_X (including Tilden Mining). A list of the sources that were included in the specific PSAT groups can be found in Appendix C: CAM_X 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.

Table 1: Facility Taconite Furnace Emission Summary

Facility	FIP Baseline (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**

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.

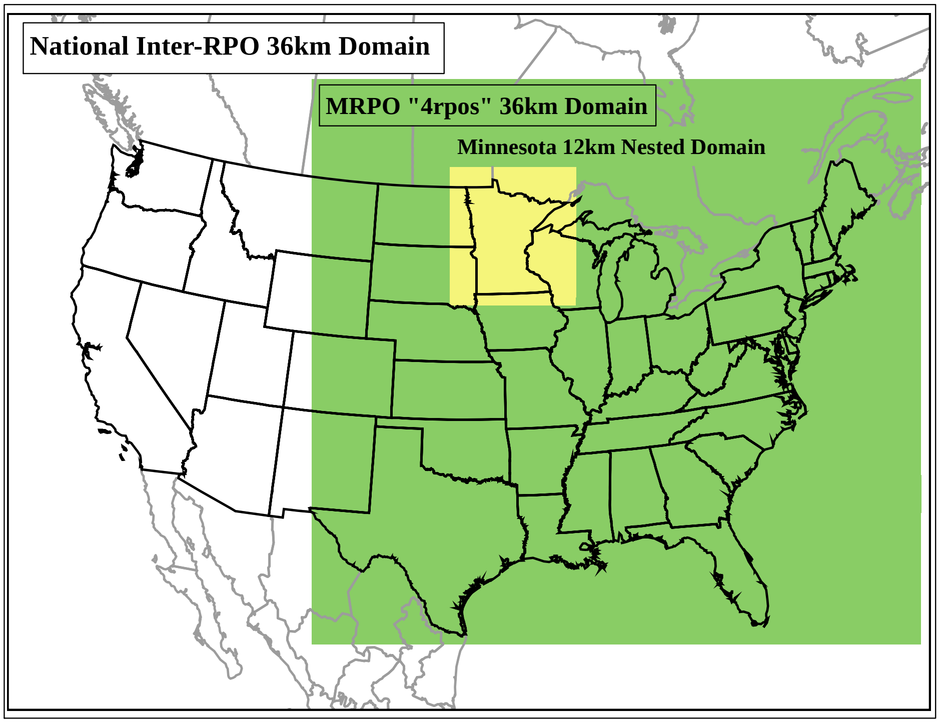

Figure 1. MPCA Modeling Domain

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_X 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_X 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_X/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_X Results

As mentioned above, the CAM_X 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_X 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_X modeling for this project on a facility by facility basis. The first three facilities contain emission reductions for only NO_X: Arcelor Mittal, Hibbing Taconite, and Northshore Mining. These results are summarized in Tables 2-4. United Taconite and Tilden Mining, which have both SO_2 and NO_X emission reductions, have result comparisons that require additional discussion.

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

0.5 dV impact 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)[2],

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

0.1 dV difference was defined by other agencies, such as the northeastern states MANE-VU Regional Planning Organization[3] as the degree of visibility improvement that is too low to justify additional emission controls. In addition, EPA's Regional Haze Rule mentions[4] 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 98th 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_X Modeled Difference).

Table 2: Arcelor Mittal Visibility Impact Comparison

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[2] 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule.

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

[4] 64 FR 35730.

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by 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 Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by 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 Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by 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_X 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 10 times the predicted 98^{th} percentile visibility improvement in all cases for the Arcelor Mittal, Hibbing Taconite, and Northshore Mining facilities. The maximum 98^{th} 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^{th} 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.

Table 5: Hibbing Taconite Line-Specific Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 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

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_2 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_X and the revised emission reduction for SO_2. Then, those resultants were averaged for each of the Class I areas to obtain the "updated" EPA all pollutant estimates.

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

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.6		1.40		110%
Voyageurs	0.8		0.85		N/A
Isle Royale	1.1		0.35		320%

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_X 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_X 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_X 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_X 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.[5]

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

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.0		1.29		N/A
Voyageurs	0.5		0.74		N/A
Isle Royale	0.6		0.28		210%

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

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	2.3		0.18		1300%
Voyageurs	1.1		0.08		1400%
Isle Royale	1.6		0.05		3200%

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[5] 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.

Table 9: United Taconite Line-Specific Nitrate Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 98% dV
Boundary Waters	Line 1		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

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.

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

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV
Boundary Waters	N/A		0.08
Voyageurs	N/A		0.03
Isle Royale	N/A*		0.17

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

Table 11: Tilden Mining Pollutant-Specific Impact Comparison

Class I Area	CAM_X Sulfate Modeled Difference 98% dV		CAM_X Nitrate Modeled Difference 98% dV
Boundary Waters	0.07		0.01
Voyageurs	0.03		0.00
Isle Royale	0.14		0.02

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_X 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.”[6] Our analysis demonstrates that the ratio approach has over-estimated impacts by a factor of ten to sixty for NO_X reductions. When accurately modeled, the NO_X reductions do not yield discernible visibility benefits. To that end, the following pictures from WinHaze Level 1 Visual Air Quality Imaging Modeler

[6] 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[7].

Isle Royale FIP Base – United Taconite

Isle Royale Final FIP – United Taconite

Boundary Waters FIP Base – Hibbing 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_X 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.

[7] Voyageurs National Park pictures are not contained within the WinHaze program

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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?

- *<u>For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.</u>*

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.

- *<u>Make the net visibility improvement determination.</u>*

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.

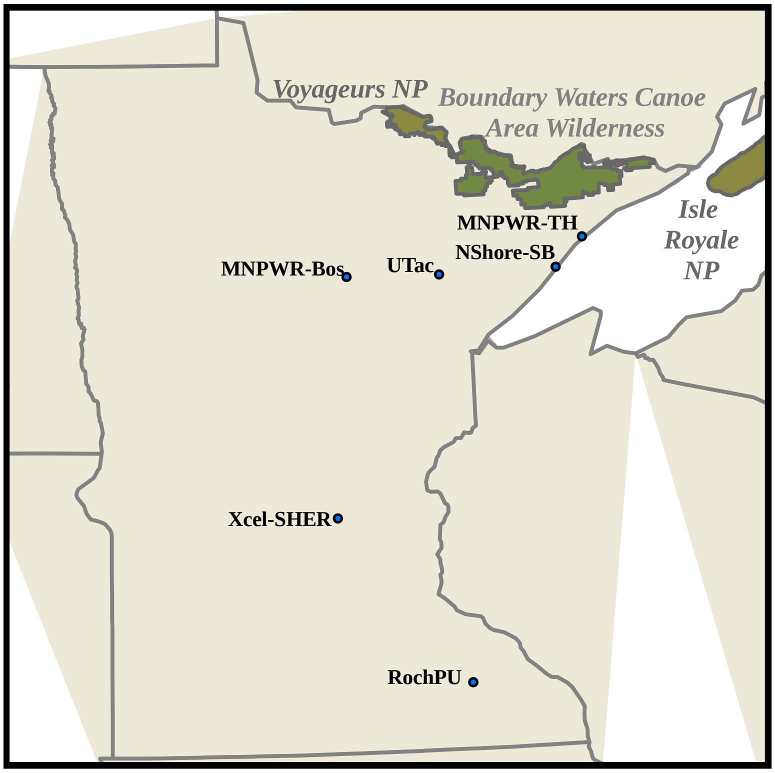
II. Summary of EPA's approach

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[1] 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).

[1] 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^{th} 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 combined the results to estimate 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_X 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_X 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 98th 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_X 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_X 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

Facility	Emission Unit		Pollutant	Emissions			Emission Reductions			Emissions	Note(s)
				Proposed FIP			Baseline - Prop FIP	Baseline - Prop FIP		Final FIP	
				Baseline	FIP		Emission Tables	Visibility Calcs			
	ModID	Description		tons/yr	tons/yr	Note(s)	tons/yr	tons/yr	Note(s)	lb/hr	
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 Combined	NOx	6,888	2,066		**4,821**	**5,259**	[3]		
			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]
	NSM	BART Units Combined	NOx	805	250		**555**	**926**	[9]		
			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]
	TMC	BART Units Combined	NOx	4,707	1,478		3,229	3,229	[18]		
			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 Combined	NOx	5,330	1,599		**3,731**	**3,208**	[26]		
			SO2	4,043	404		3,639	3,639	[26]	529	[28]
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	1,092	[29]	**2,547**	**2,859**	[31]		[32]
			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		EPA Furnace
FIP Baseline does not match reference		NOx Control %
FIP Table B emission tables do not match Table C visibility calculation tables		70%

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 Emisssions = 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)

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APPENDIX B: Barr and MPCA CAM_X Modeling Comparison of Results

March 6, 2013

Minnesota Power – Taconite Harbor (BART01)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	94	90	-4	11	9	-2	30	27	-3
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	95	90	-5	11	9	-2	30	27	-3
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-Ence	Base	BART	Differ-ence	Base	BART	Differ-Ence
Days > 0.5 dv	2002	111	60	-51	86	58	-28	48	27	-21
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-Ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	110	61	-49	86	58	-28	47	27	-20
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	77	72	-5	9	8	-1	20	15	-5
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	78	72	-6	9	8	-1	20	15	-5
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	59	44	-15	32	20	-12	8	1	-7
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	63	46	-17	34	20	-14	8	1	-7
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Difference	Base	BART	Difference	Base	BART	Difference
Days > 0.5 dv	2002	74	58	-16	53	39	-14	42	30	-12
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Difference	Base	BART	Difference	Base	BART	Difference
Days > 0.5 dv	2002	74	59	-15	53	39	-14	42	29	-13
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Difference	Base	BART	Difference	Base	BART	Difference
Days > 0.5 dv	2002	0	0	0	0	0	0	0	0	0
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Difference	Base	BART	Difference	Base	BART	Difference
Days > 0.5 dv	2002	0	0	0	0	0	0	0	0	0
98th Percentile Δ dv	2002	0.10	0.06	0.04	0.08	0.04	0.04	0.09	0.04	0.05

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APPENDIX C: CAM_X PSAT Source List

March 6, 2013

2009 MPCA Tracked, Elevated Point Sources

RANKTRAC BARTSRC_ID	RECEPTOR 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

(yellow)	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	2703100001	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

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

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APPENDIX D: Summary of CAM_X Elevated Point Source Emissions

March 6, 2013

Summary of CAMx Elevated Point Source Emissions

Facility	Emission Unit ModID	Emission Unit Description	Pollutant	Emissions Proposed FIP Baseline tons/yr	Note(s)	Emissions Final FIP FIP tons/yr	Note(s)	Emission Reductions Baseline - Final FIP 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 Combined	NOx	6,888		2,066		4,821
			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
	NSM	BART Furnaces Combined	NOx	764		229		535
			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 Combined	NOx	5,330		1,599		3,731
			SO2	4,043		1,969		2,074
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	[28]	1,092	[30]	2,547
			SO2	179	[29]	179	[31]	0

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

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)

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

March 6, 2013

From: Jeffry D. Bennett
Sent: Thursday, January 31, 2013 7:42 PM
To: 'Rosenthal.steven@Epa.gov'
Cc: 'Long, Michael E'
Subject: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: 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

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APPENDIX F: CAMx Modeling Results by Facility

March 6, 2013

Arcelor Mittal CAMx Emissions and Modeling Results

Arcelor Emissions

Unit	EPA FIP Baseline NOx Emission (TPY) [1]	Final FIP NOx Emission (TPY) [1]	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY) [2]	Final FIP SO2 Emission (TPY)[3]	SO2 Emission Difference (TPY)
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)

Arcelor CAMx Results (By Unit) [4]

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Proposed FIP Days > 0.5 dV	Proposed FIP 98% dV	Difference Days >0.5 dV [5]	Difference 98% dV [5]
Boundary Waters						
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
Voyageurs						
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:

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

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

0.1 dV difference 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 98th 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 98th 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 C Emission Difference = 2,859 TPY NOx)[6]

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

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[8]	CAMx Modeled Difference 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

[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 98th 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 Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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
Voyageurs						
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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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 Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (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)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Voyageurs						
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
Isle Royale						
2002						
Power Boiler #1	3	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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	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 Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)[12]	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)[13]	SO2 Emission Difference (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

UTAC CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[16]	CAMx Modeled Difference 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

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

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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

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_X 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).

UTAC Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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						
Line #1 – NO3	0	0.026	0	0.011	0	0.015
Line #1 – SO4	0	0.150	0	0.072	0	0.078
Line #1 – All	0	0.163	0	0.080	0	0.083

UTAC Line 2 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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 – SO4	16	0.773	6	0.436	10	0.337
Line #2 – All	17	0.786	6	0.446	11	0.340
Isle Royale						
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 Comparison of Sulfate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 2,074 TPY SO2

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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

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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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^{th} percentile NO3 impact when combining both line emission reductions is <u>0.18 dV</u>, while the maximum 98^{th} 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 Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1	0	0.141	0	0.037	0	0.104
2005						
Line #1	0	0.097	0	0.042	0	0.055
Voyageurs						
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

Tilden Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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
Voyageurs						
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

Attachment 3

2012 AECOM Report

AECOM

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.

Impacts of the taconite plants' NO_X 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 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X 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)[1] 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[2].

The United States Environmental Protection Agency (EPA) has issued a proposed rule[3] to address BART requirements for taconite plants in Minnesota and Michigan that involves emission controls for SO_2 and NO_X. This document addresses the likely visibility impact of taconite plant emissions, specifically NO_X 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[4], the distance limitation is 200-300 km because of the overprediction tendencies[5] 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.

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[1] Regional Haze Regulations; Final Rule. *Federal Register*, *64*, 35713-35774. (July 1, 1999).

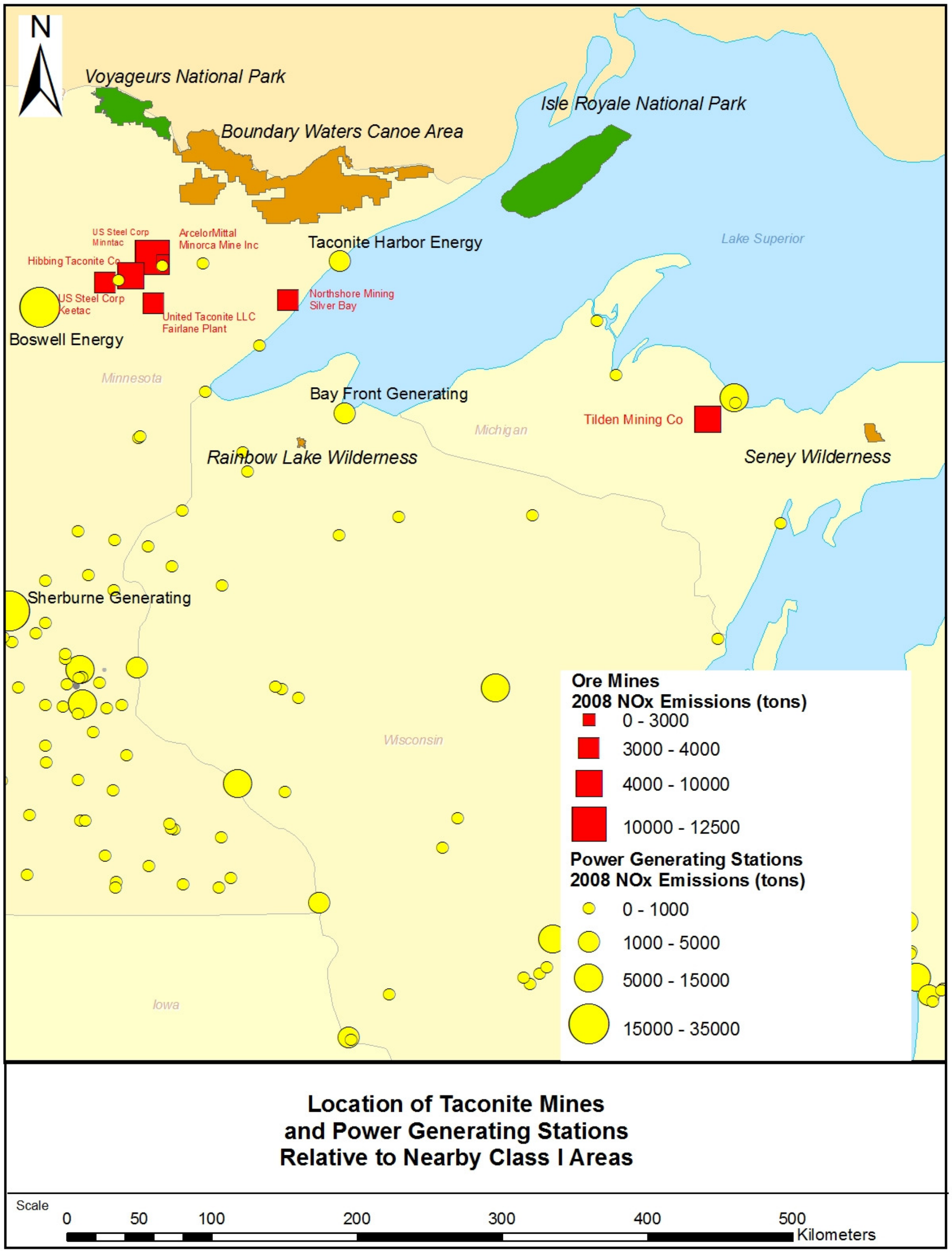
[2] Federal Register. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, Vol. 70. (July 6, 2005)

[3] 77FR49308, August 15, 2012.

[4] CALPUFF Dispersion Model, 2000. http://www.epa.gov/scram001 (under 7th Modeling Conference link to Earth Tech web site).

[5] 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_X emission controls are considered as a BART option because modeling secondary formation of ammonium nitrate is quite challenging. Accurately modeling the effects of NO_X 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_X, and the associated effectiveness of NO_X 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.

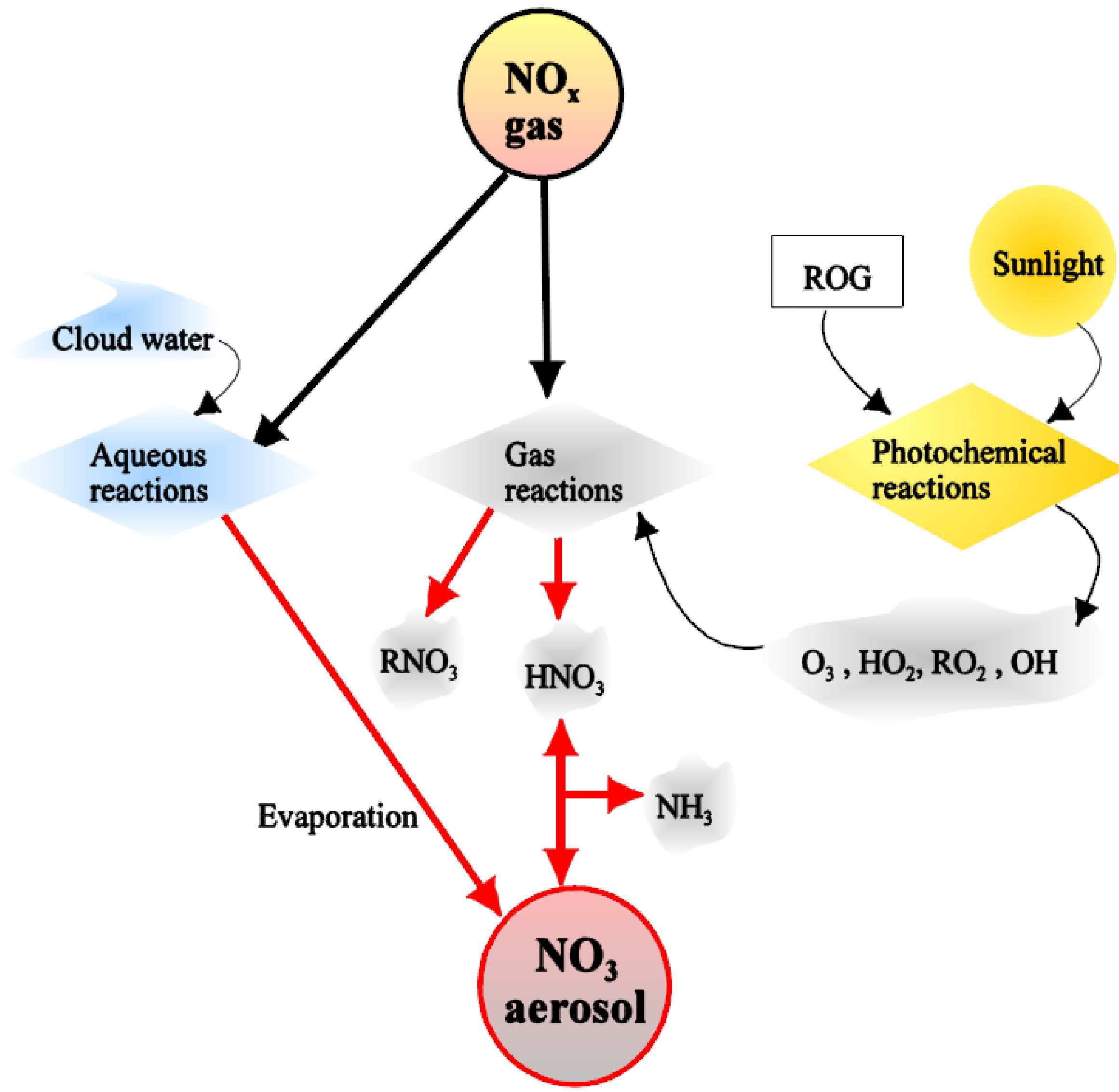
- There are examples where actual significant emission reductions have occurred, where CALPUFF modeling as conducted for BART would predict significant visibility improvements, but no perceptive changes in haze occurred.

Visibility Impact of NO_X Emissions – Unique Aspects and Seasonality

The oxidation of NO_X to total nitrate (TNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the TNO_3 is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state with HNO_3 gas that is a function

of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 2[6]. 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_x Oxidation



[6] Figure 2-32 from CALPUFF Users Guide, available at http://www.src.com/calpuff/download/CALPUFF_UsersGuide.pdf.

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:

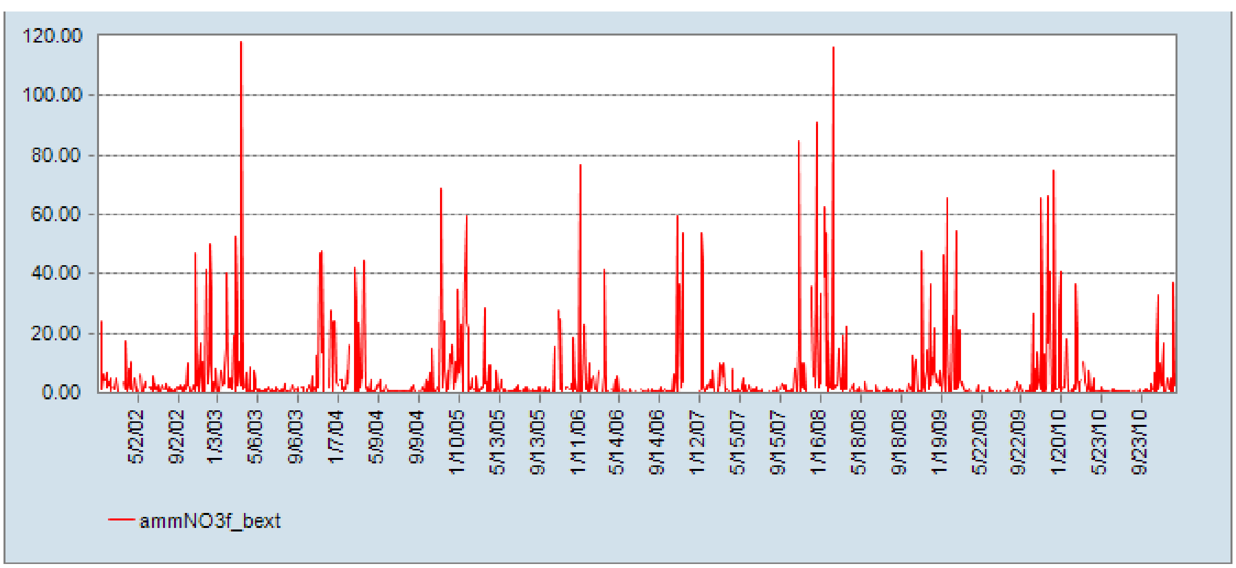
- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium 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_X 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



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 water-dominant Class I areas in Minnesota (Voyageurs and Boundary Waters) that freeze in winter. In fact, for Voyageurs National Park, the typical monthly attendance[7] 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 totally close[8] 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[9] 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[10] 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[11] of nitrate and sulfate haze in

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[7] As documented at http://www.gorp.com/parks-guide/voyageurs-national-park-outdoor-pp2-guide-cid9423.html.

[8] As noted at http://www.nps.gov/isro/planyourvisit/hours.htm.

[9] As noted at http://www.fws.gov/midwest/seney/visitor_info.html.

[10] 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.

[11] 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 4 Minnesota Taconite Production and BWCA Nitrate Concentrations

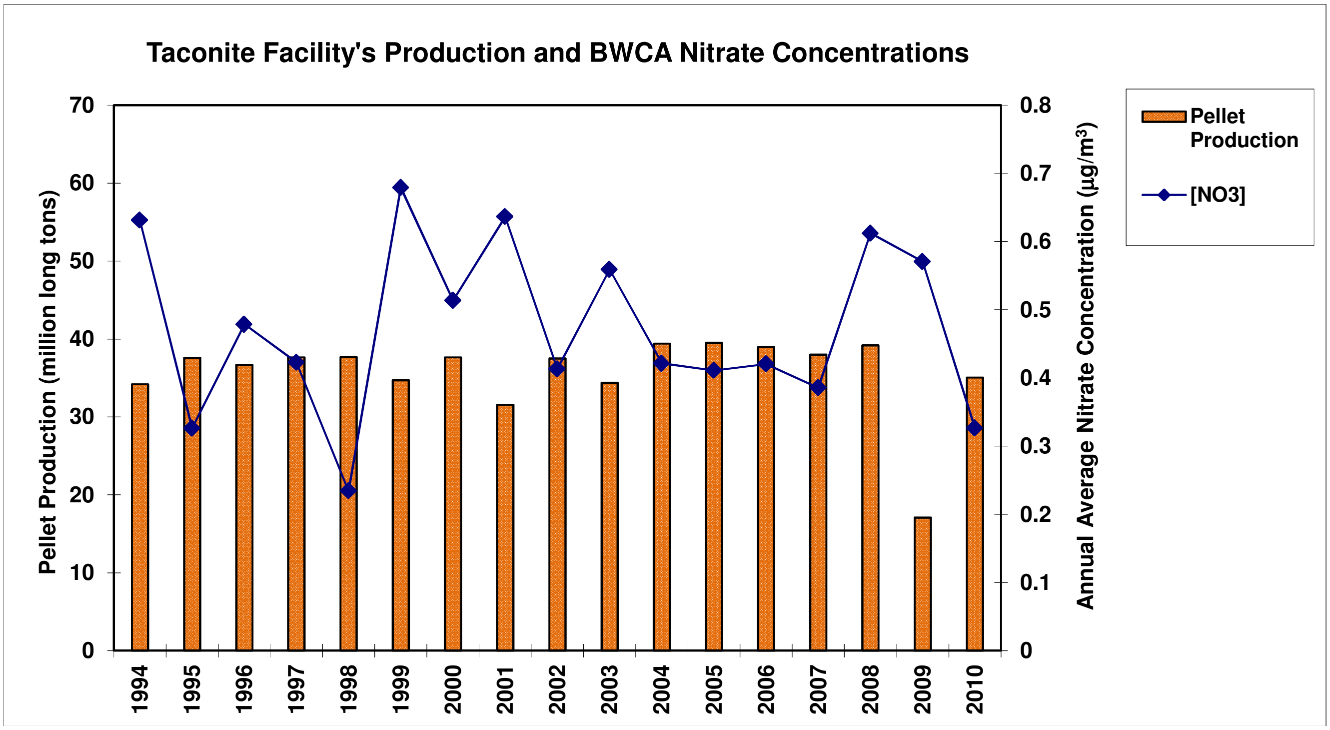


Figure 5 Time Series of Nitrate Haze at Boundary Waters Canoe Area (2002-2010)

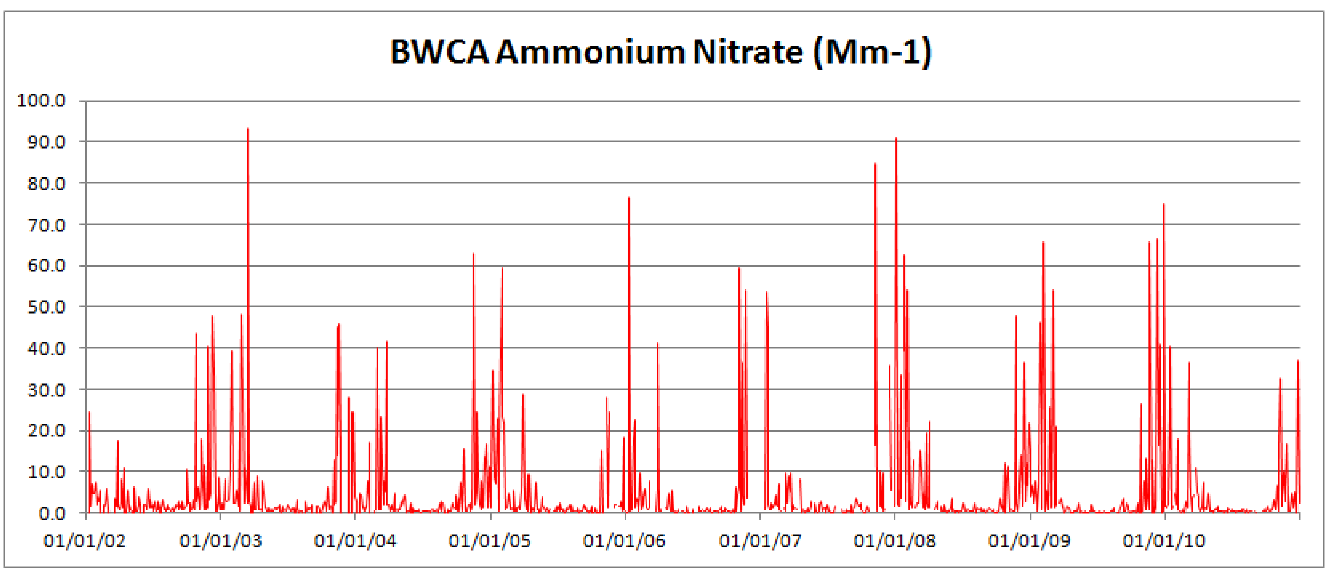
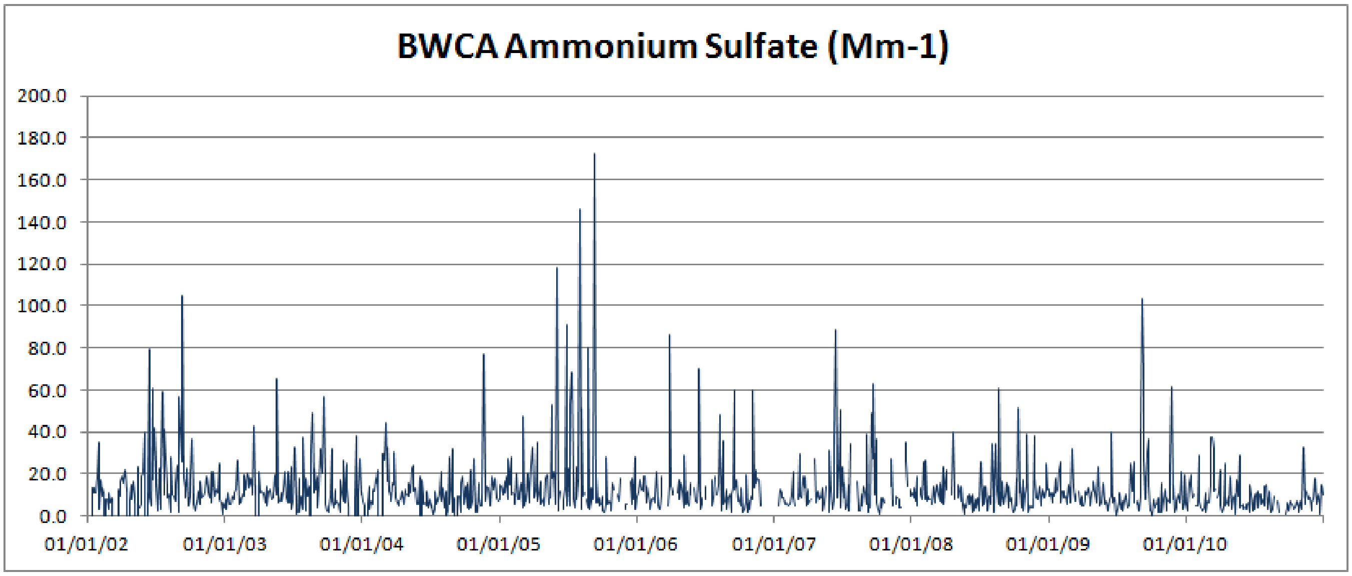


Figure 6 Time Series of Sulfate Haze at Boundary Waters Canoe Area (2002-2010)



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

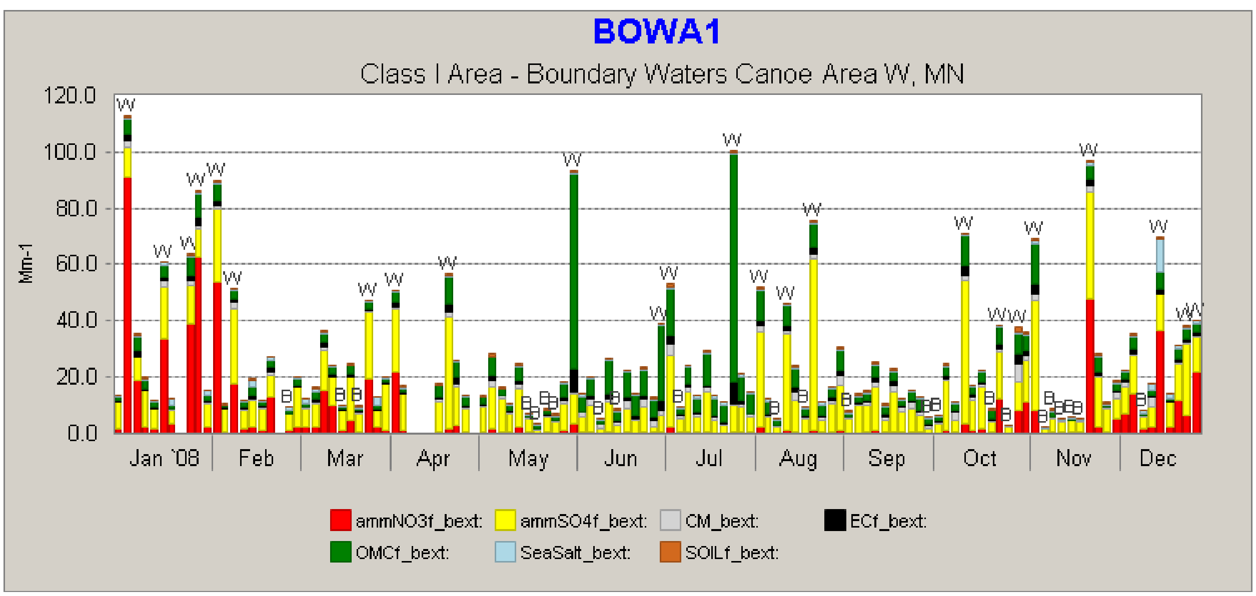


Figure 8 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2009

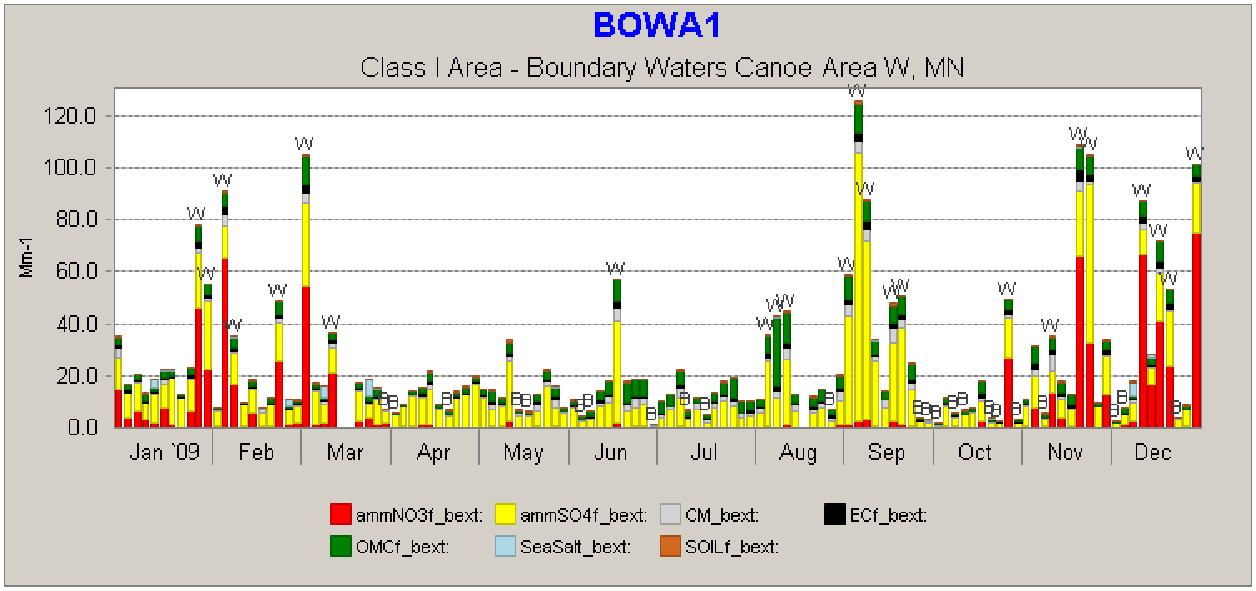
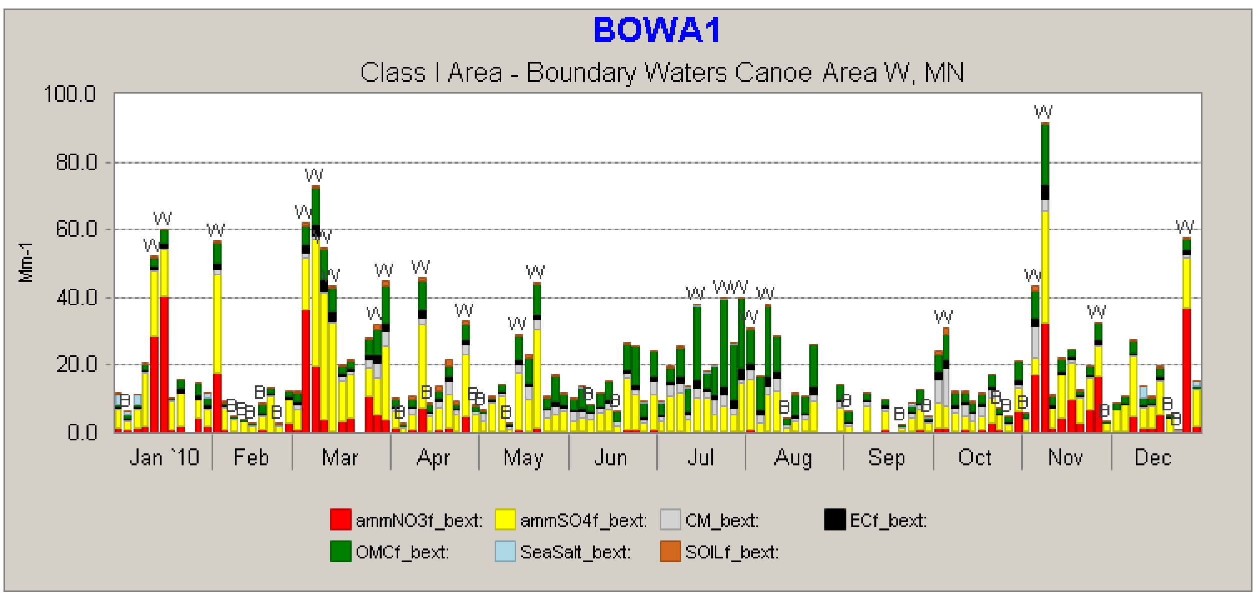


Figure 9 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2010



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.

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 98th 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

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_X 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[12] 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 9th 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 11th and 12th, 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.

[12] See, for example, the Iowa State Implementation Plan for Regional Haze report at http://www.iowadnr.gov/portals/idnr/uploads/air/insidednr/rulesandplanning/rh_sip_final.pdf, Figures 11.3 and 11.4.

Figure 10 PSAT Results from CENRAP CAMx Modeling for Isle Royale National Park

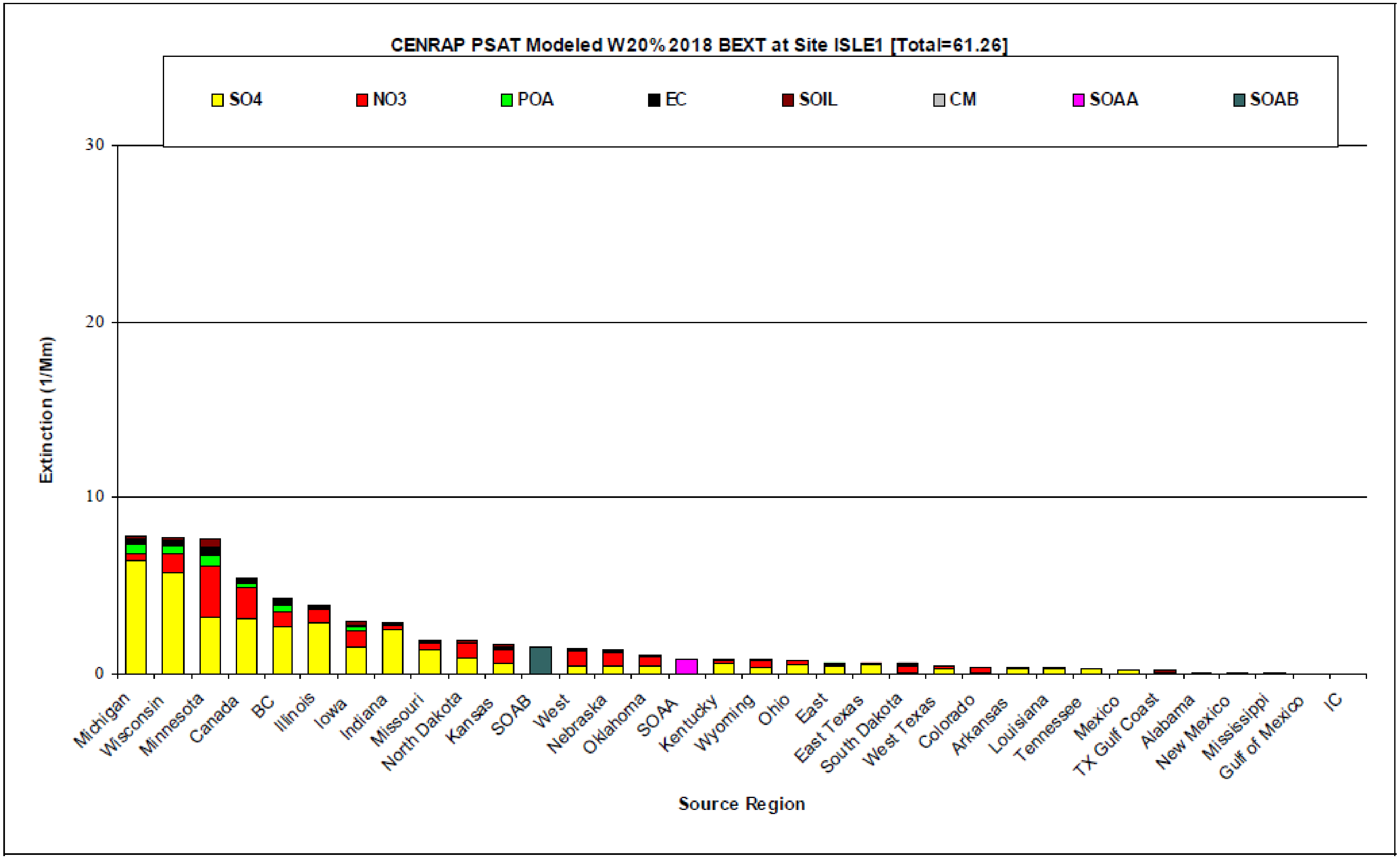


Figure 11.3. Source apportion contributions by region and pollutant to ISLE in 2018.

Figure 11 PSAT Results from CENRAP CAMx Modeling for Seney Wilderness Area

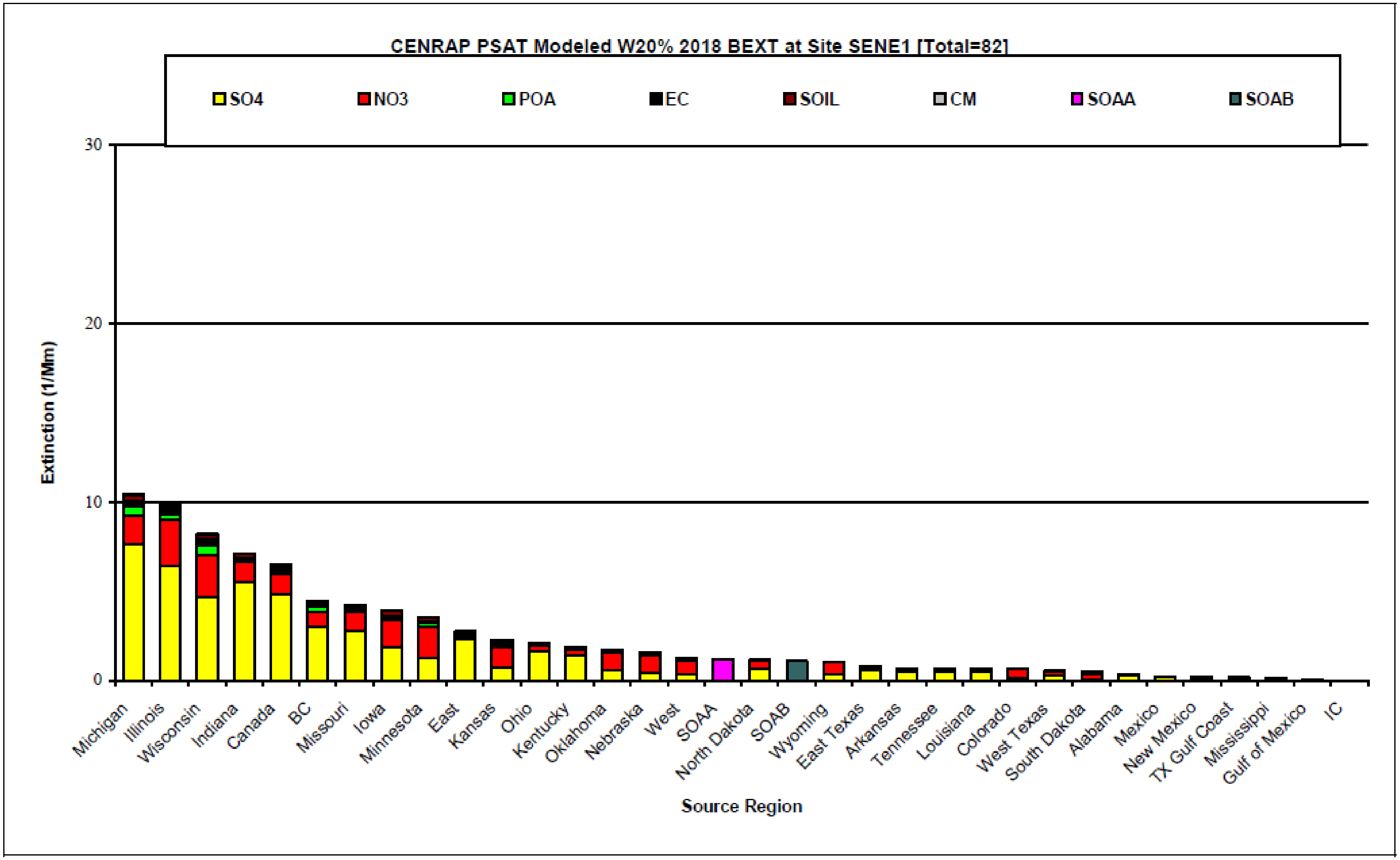


Figure 11.4. Source apportion contributions by region and pollutant to SENE in 2018.

AECOM

Figure 12 PSAT Results from CENRAP CAMx Modeling for Boundary Waters Canoe Area Wilderness

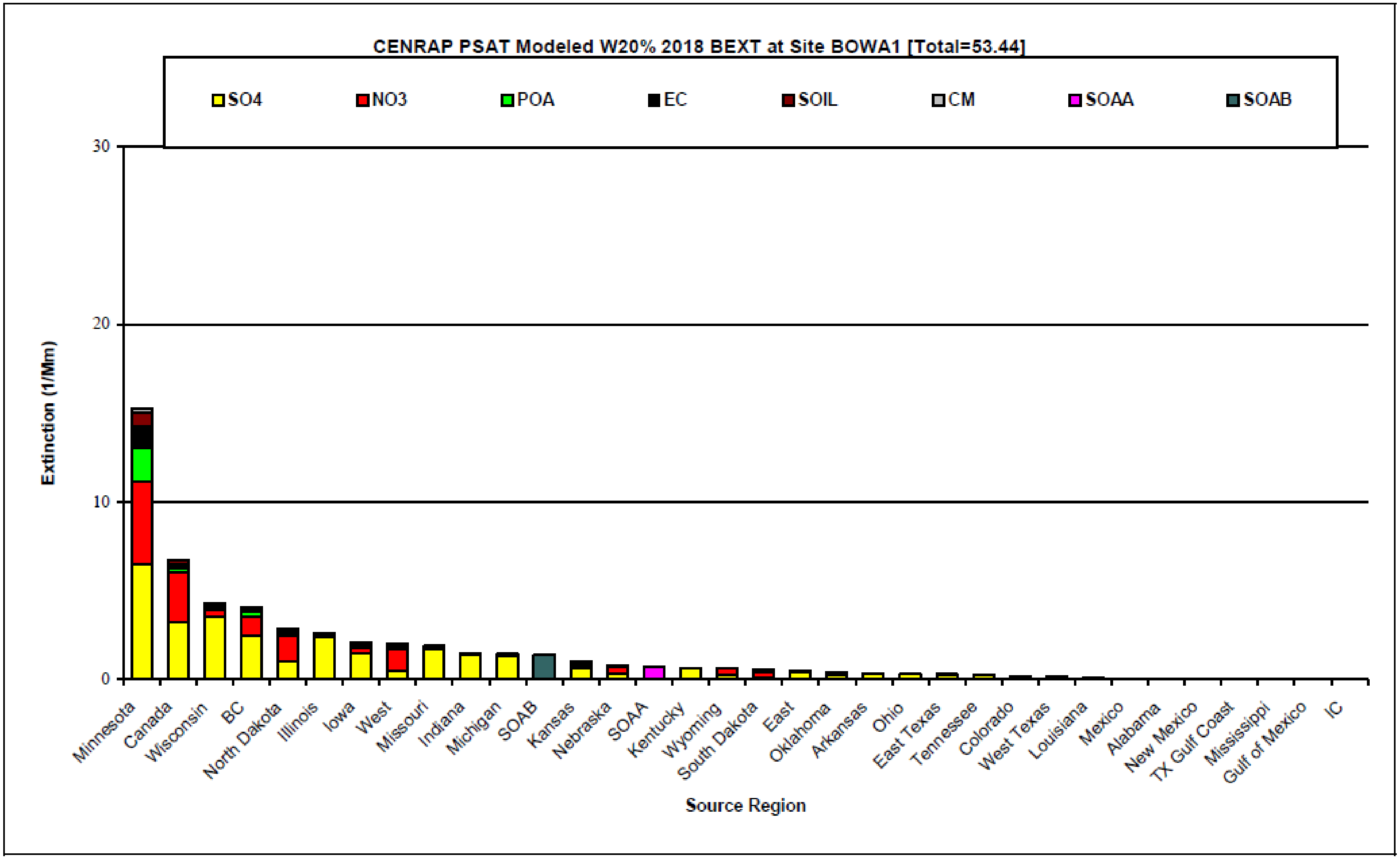


Figure 11.1. Source apportion contributions by region and pollutant to BOWA in 2018.

Figure 13 PSAT Results from CENRAP CAMx Modeling for Voyageurs National Park

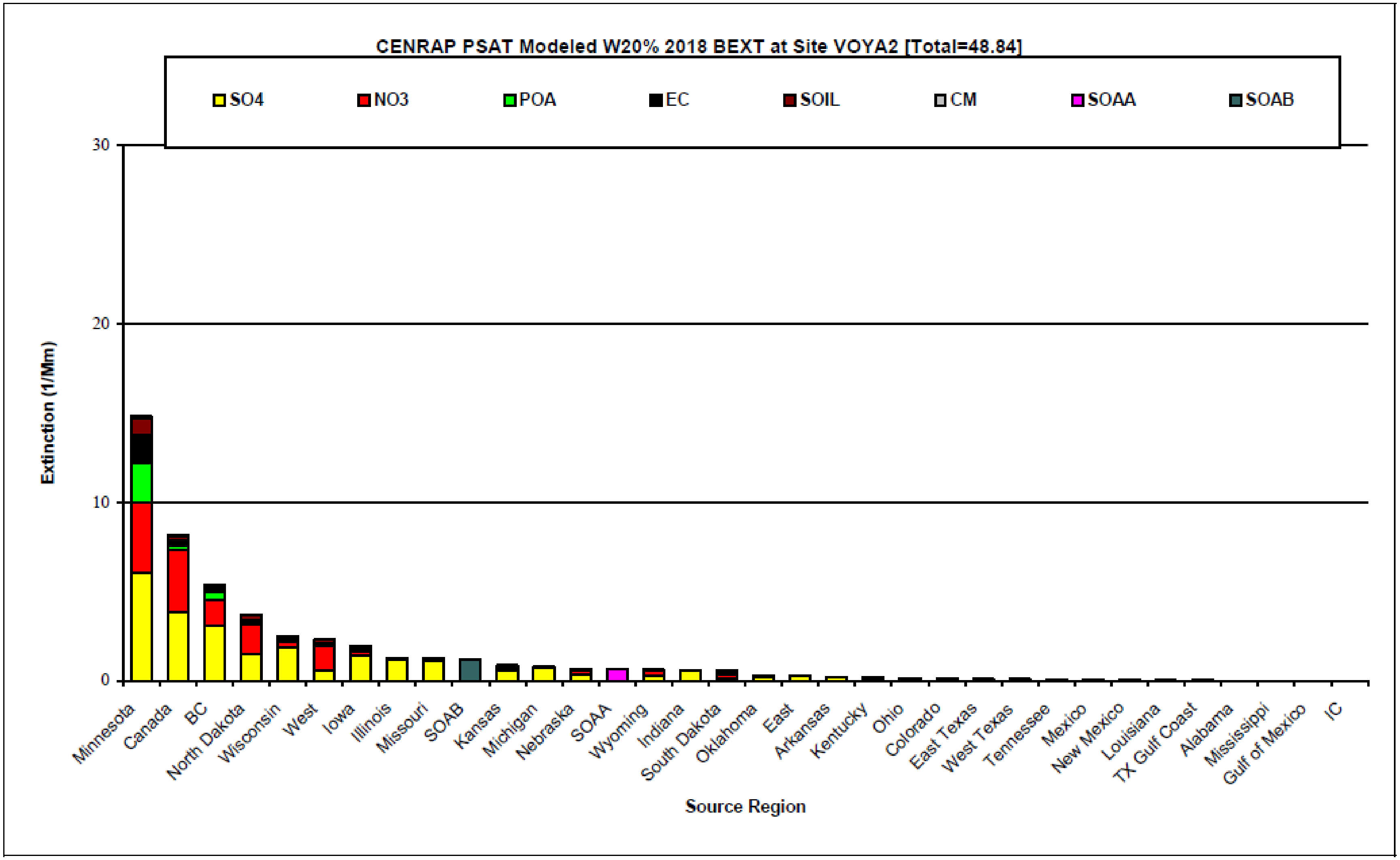


Figure 11.2. Source apportion contributions by region and pollutant to VOYA in 2018.

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_X 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 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X 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.

APPENDIX A

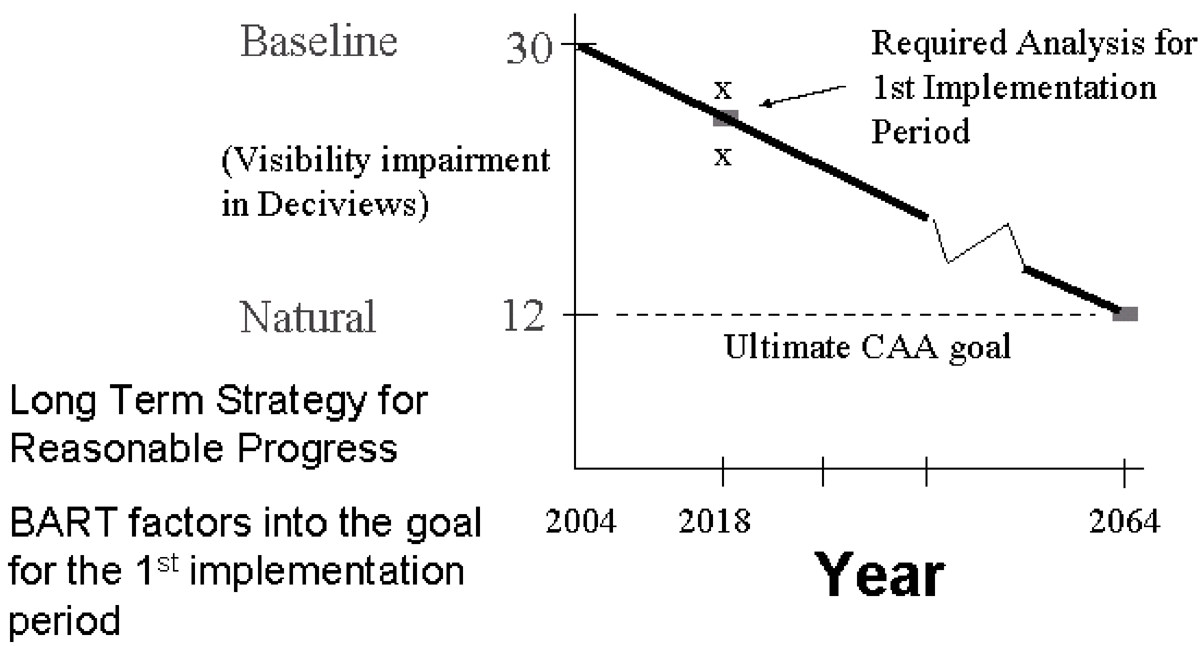
THE REGIONAL HAZE RULE GOAL OF NATURAL CONDITIONS

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[13] 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 20th century.

Figure A-1: Illustration of the Uniform Rate of Progress Goal



[13] *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, (U.S. Environmental Protection Agency, September 2003). http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf.

In its RHR SIP, North Dakota[14] 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_2 and NO_x 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.

[14] North Dakota Dep. of Health, 2010. North Dakota State Implementation Plan for Regional Haze. http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Main%20SIP%20Sections%201-12.pdf.
.

- As a result, there is a substantial reduction in SO_2 and NO_x 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[15], 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 (http://views.cira.colostate.edu/web/) 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_2 and NO_X.

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_2 and NO_x).

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.

[15] See Appendix 2-2 at http://www.tceq.state.tx.us/implementation/air/sip/bart/haze_appendices.html.

These estimates were derived from Trijonis[16] and use two different sets of natural concentrations for the eastern and western U.S. Tombach[17] 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		Error Factor	Dry Extinction Efficiency (m^2/g)
	West ($\mu g/m^3$)	East ($\mu g/m^3$)		
Ammonium sulfate [b]	0.12	0.23	2	3
Ammonium nitrate	0.10	0.10	2	3
Organic carbon mass [c]	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 $\mu g/m^3$ and 1.5 $\mu g/m^3$ 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.[18]

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.

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[16] 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.

[17] 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 http://www.wrapair.org/forums/aamrf/projects/NCB/index.html.

[18] 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[19] reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach[8] 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[8] 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[20]; Koo et al., 2010[21]), 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 20th century, fire suppression has resulted in a buildup of vegetative "fuels" and catastrophic wildfires. Recent estimates of background visual range, such as Trijonis[16], 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

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[19] 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.

[20] 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. (http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC_2006_report_FINAL.pdf).

[21] 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. Atm. Env., 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 http://www.nps.gov/thro/parkmgmt/firemanagement.htm for the Theodore Roosevelt National Park that:

"For most of the 20th 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[22] 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 background estimates. The consequences of the artificially low estimates of natural visibility conditions include the distortion of Reasonable Progress analyses and also to BART modeling results that overestimate the visibility improvement achievable from NO_X 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_2 and NO_x 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 20th 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.

[22] See explanation at http://www.msnbc.msn.com/id/48569985/ns/us_news-environment/t/forest-service-gets-more-aggressive-small-fires/.

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_2 and NO_X 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.

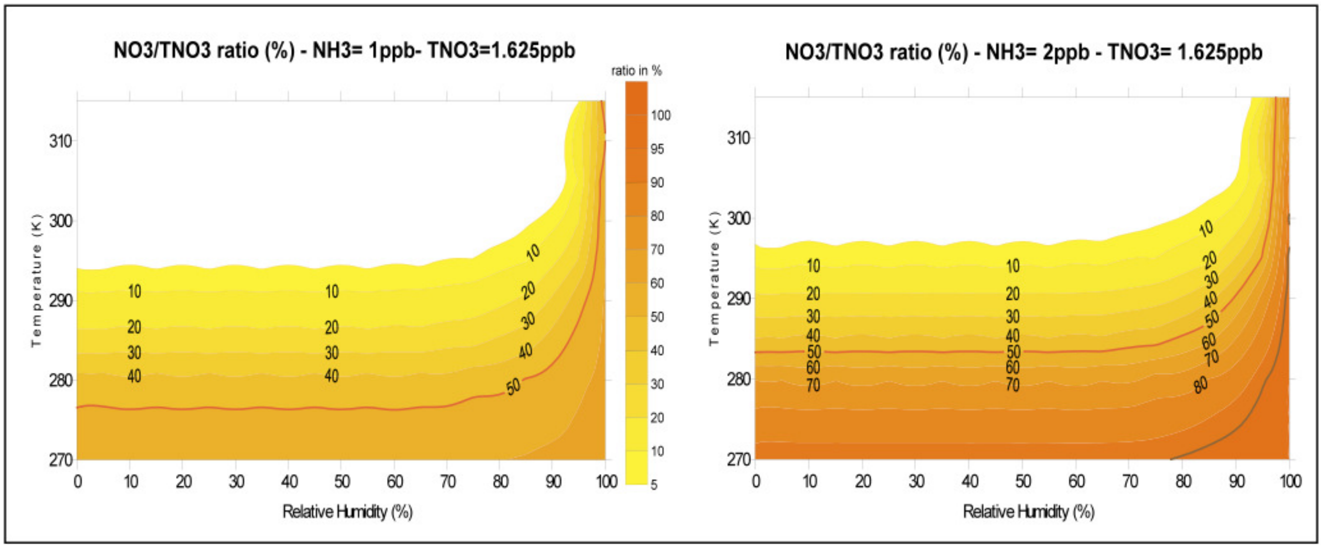
In the CALPUFF model, the oxidation of NO_X to nitric acid (HNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration. In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous HNO_3 and NO_3 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_3 to form ammonium nitrate, as shown in Figure 6[23]. 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.

[23] Scire, Joseph. CALPUFF MODELING SYSTEM. CALPUFF course presented at Chulalongkorn University, Bangkok, Thailand. May 16-20, 2005; slide 40 available at http://aqnis.pcd.go.th/tapce/plan/4CALPUFF%20slides.pdf, accessed March 2011.

Figure B-1: NO_3/HNO_3 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_X emissions relative to SO_2 emissions[24]. 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.

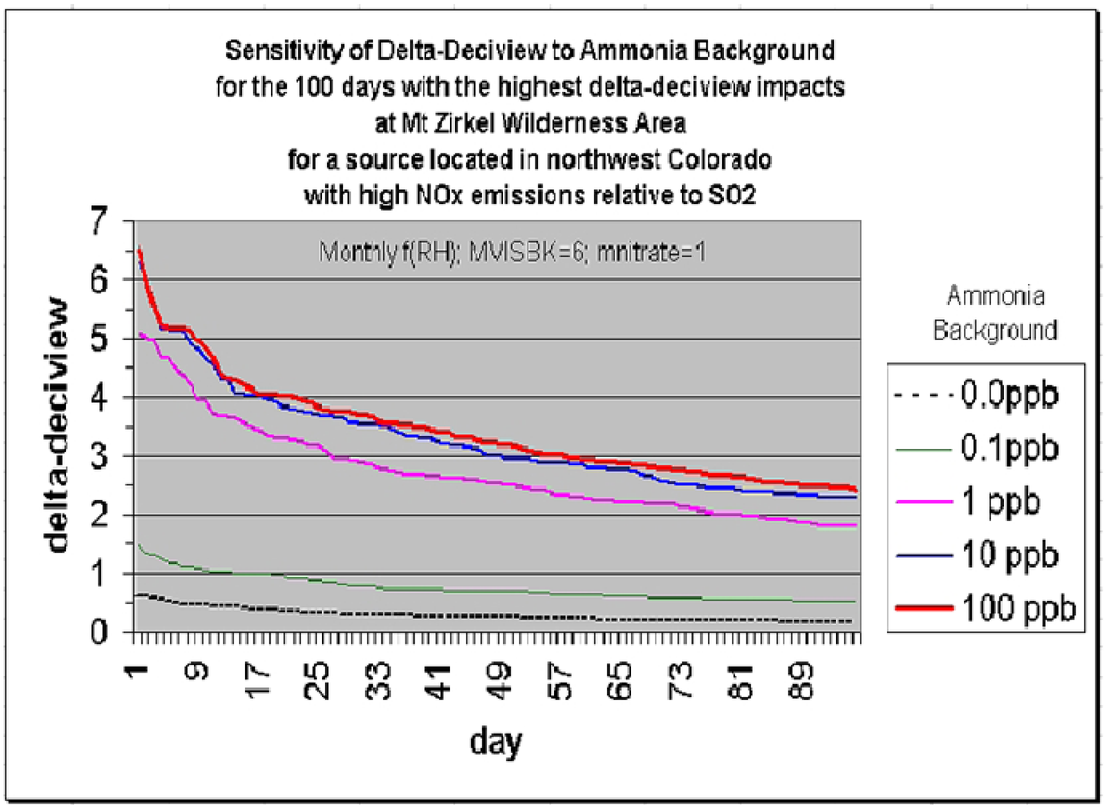
It is also noteworthy that CALPUFF version 5.8's demonstrated over-predictions of wintertime nitrate can be mitigated to some extent by using lower winter ammonia background values, although there is not extensive measurement data to determine the ambient ammonia concentrations. This outcome showing the superiority of the monthly-varying background ammonia concentrations was found by Salt River

[24] Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at http://www.colorado.gov/airquality/documents/Draft-ColoradoSupplementalBARTAnalysisCALPUFFProtocol-25June2010.pdf. (2010)

Project in case studies of the Navajo Generating Station impacts on Grand Canyon monitors, as presented[25] to EPA in 2010.

It is important to note that 14 years ago in 1998, when the IWAQM Phase 2 guidance[26] 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.



25 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.

26 IWAQM Phase 2 Summary Report and Recommendations (EPA-454/R-98-019), EPA OAQPS, December 1998). http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf.

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_2 to sulfate.

On page 39121, the BART rule[27] 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[28]."

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.[29] 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[30]. 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

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[27] July 6, 2005 Federal Register publication of the Regional Haze BART rule.

[28] The next (9th) 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 10th 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.

[29] 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)

[30] 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)

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_2) by the hydroxide ion (OH^-) 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[31]. 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_X 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)[32,33], 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

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[31] 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.

[32] 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.

[33] 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)

of aqueous-phase SO_2 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[34], 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_3 concentrations on model predictions of PM nitrate. Twice-weekly background NH_3 concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH_3 concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

1. MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH_3 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_3 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[35]. The results were similar to those noted above: the improved

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[34] 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)

[35] 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[36], 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 10th modeling conference in March 2012 by Scire[37], 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[29,30] 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_X emission reductions.

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[36] 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)

[37] Scire, J., 2012. New Developments and Evaluations of the CALPUFF Model. http://www.epa.gov/ttn/scram/10thmodconf/presentations/3-5-CALPUFF_Improvements_Final.pdf.

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[38] 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_X emission reductions.

[38] http://pah.cert.ucr.edu/aqm/cenrap/meetings.shtml, under “MPE”, slides 9 and 10.

Figure B-3: Sensitivity Study of Nitrate Predictions at Bridger Wilderness Area for Input Ammonia Concentrations to CALPUFF (0.23, 0.5, and 1.0 ppb).

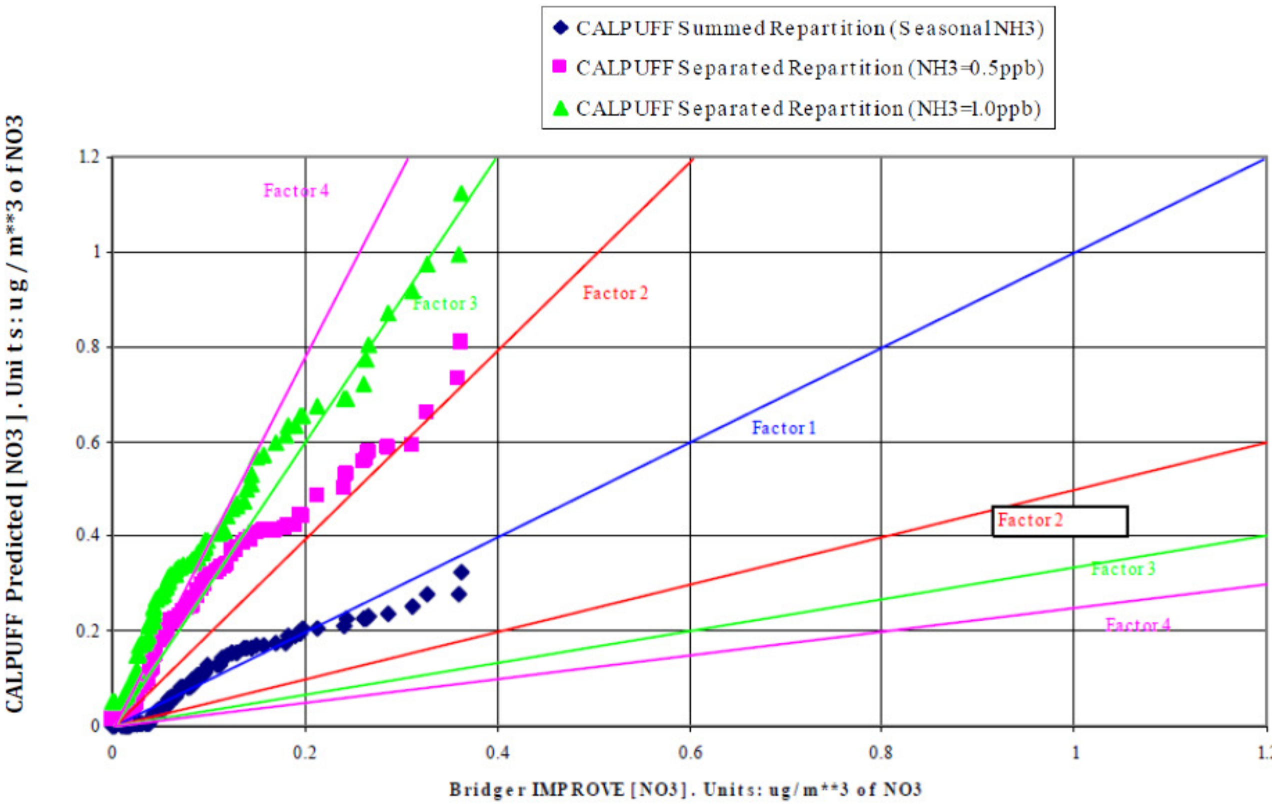


Figure B-4 CMAQ vs. Observed Haze Predictions at Voyageurs National Park

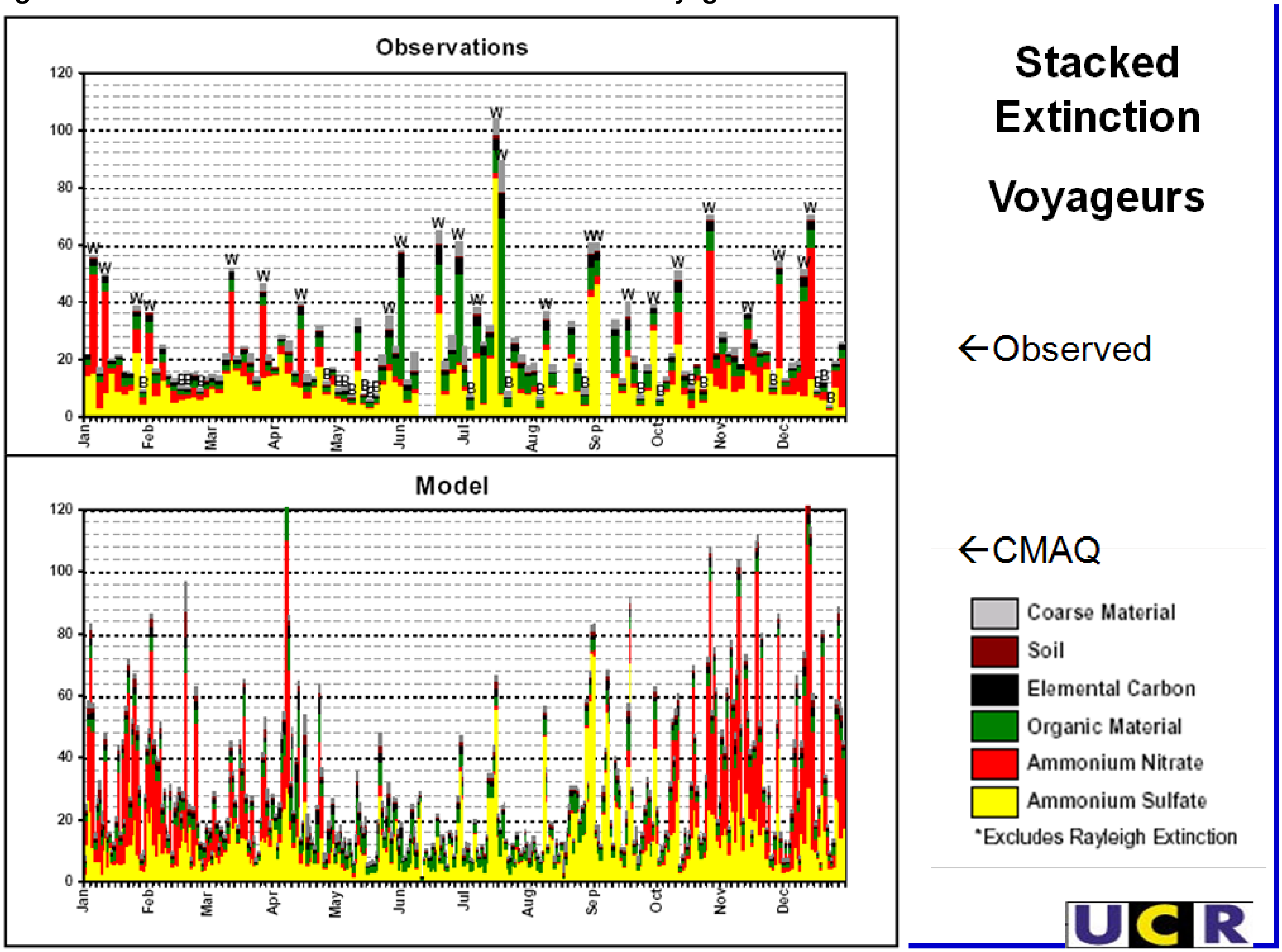
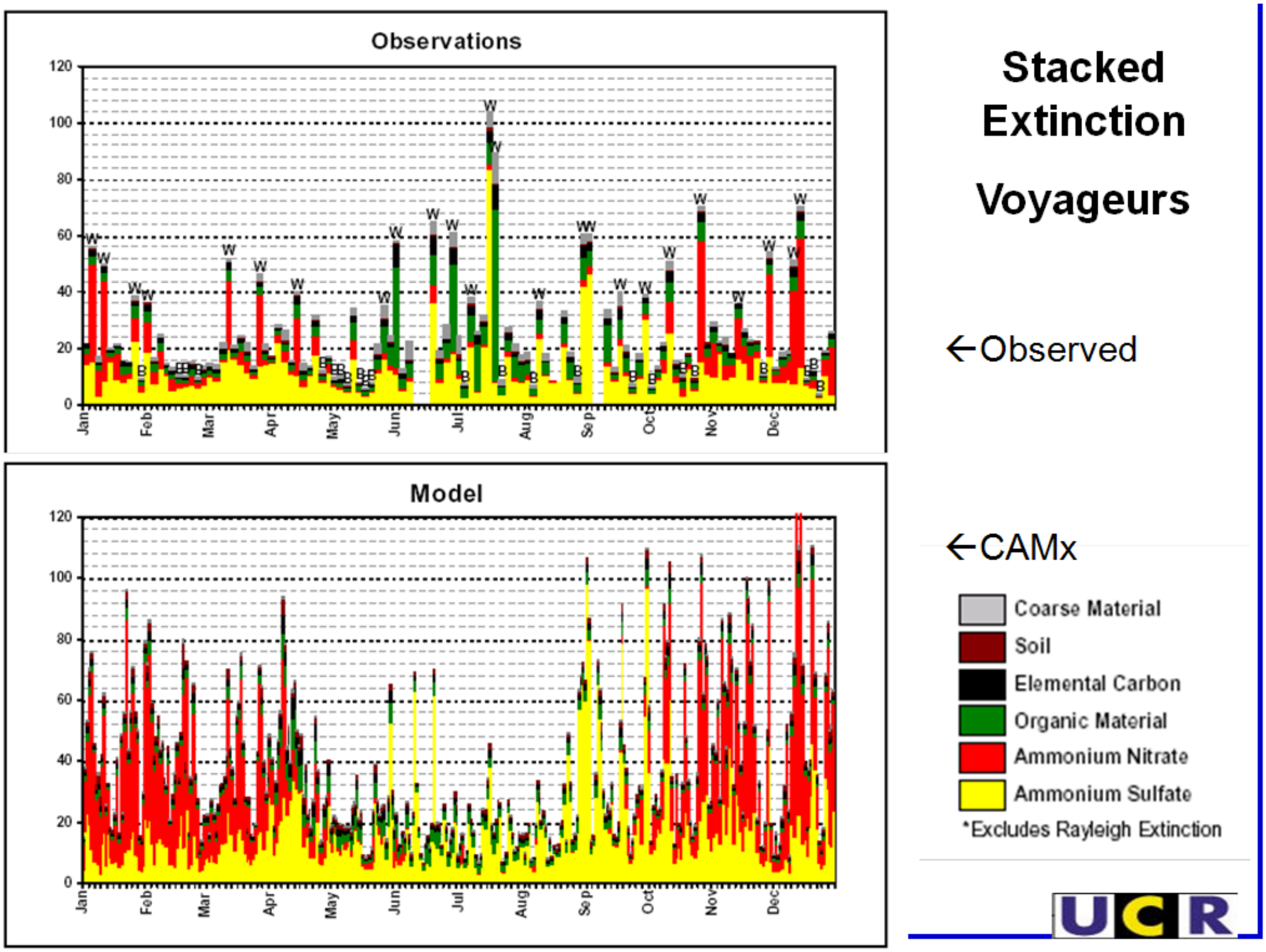


Figure B-5 CAMx vs. Observed Haze Predictions at Voyageurs National Park



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)

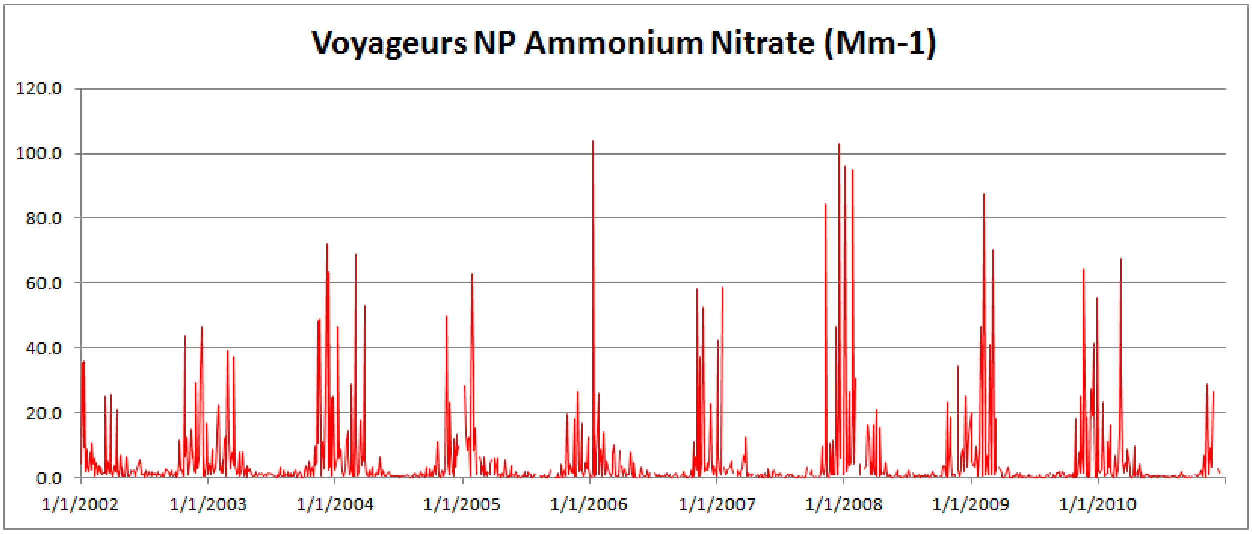


Figure C-2 Time Series of Sulfate Haze at Voyageurs National Park (2002-2010)

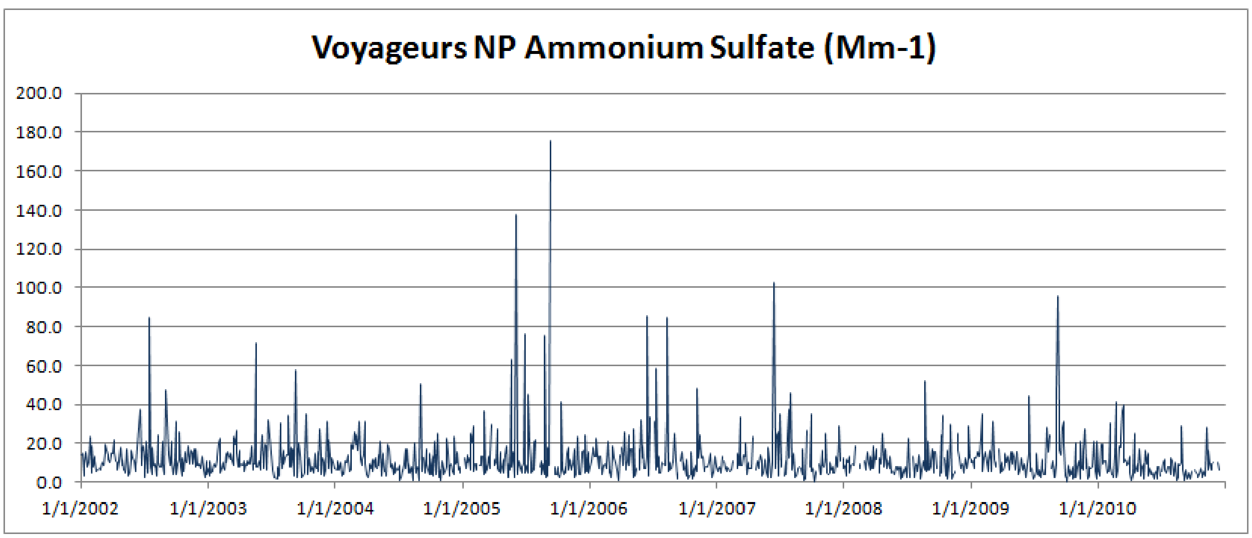


Figure C-3 Time Series of Nitrate Haze at Seney Wilderness Area (2002-2010)

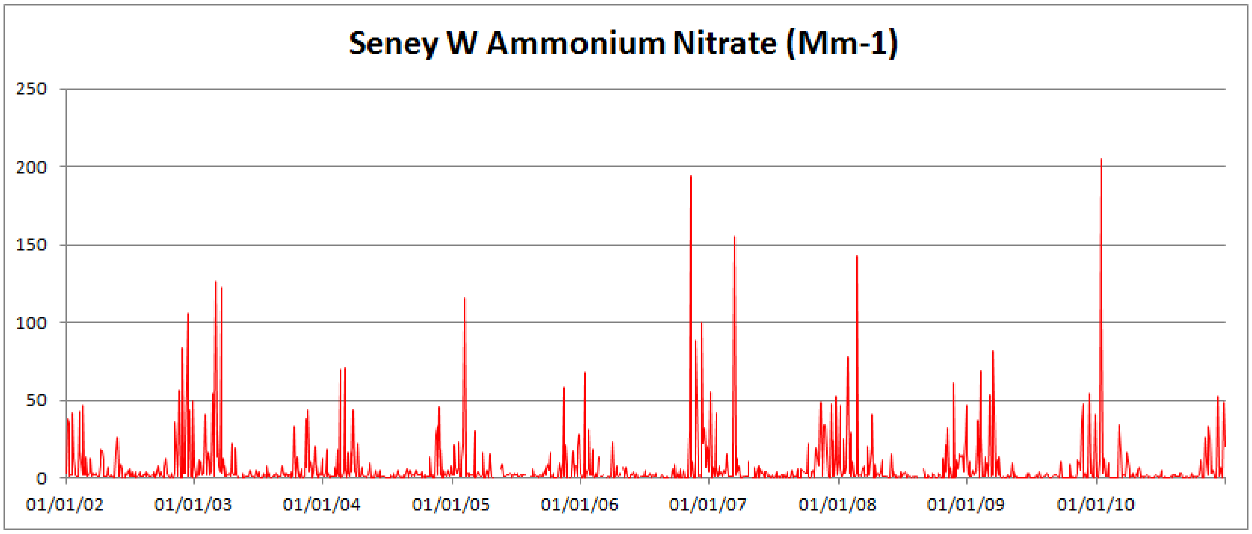


Figure C-4 Time Series of Sulfate Haze at Seney Wilderness Area (2002-2010)

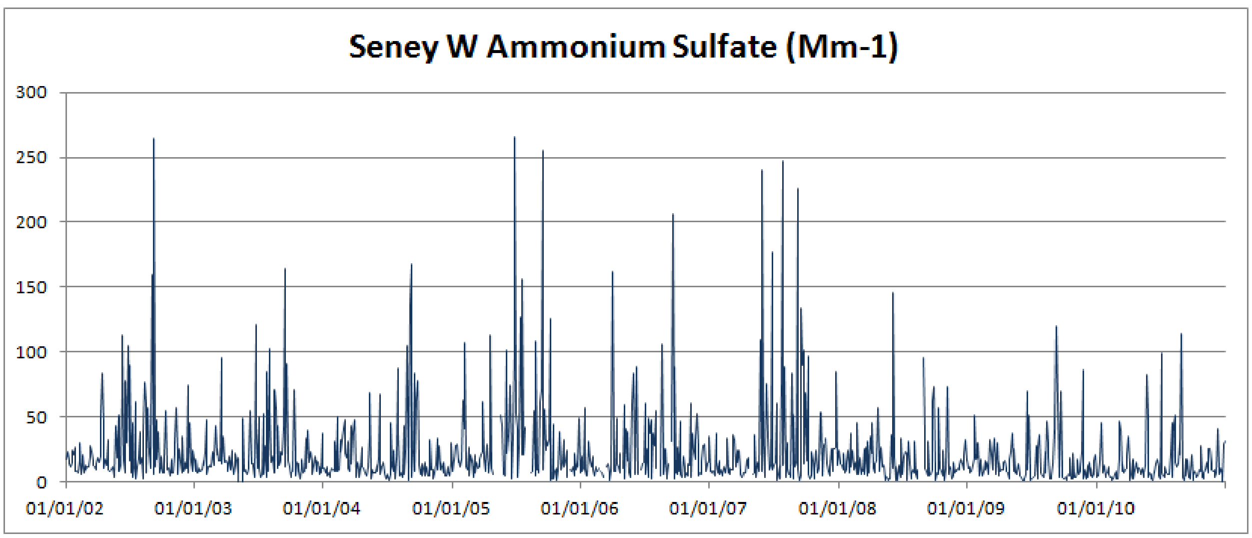


Figure C-5 Time Series of Nitrate Haze at Isle Royale National Park (2002-2010)

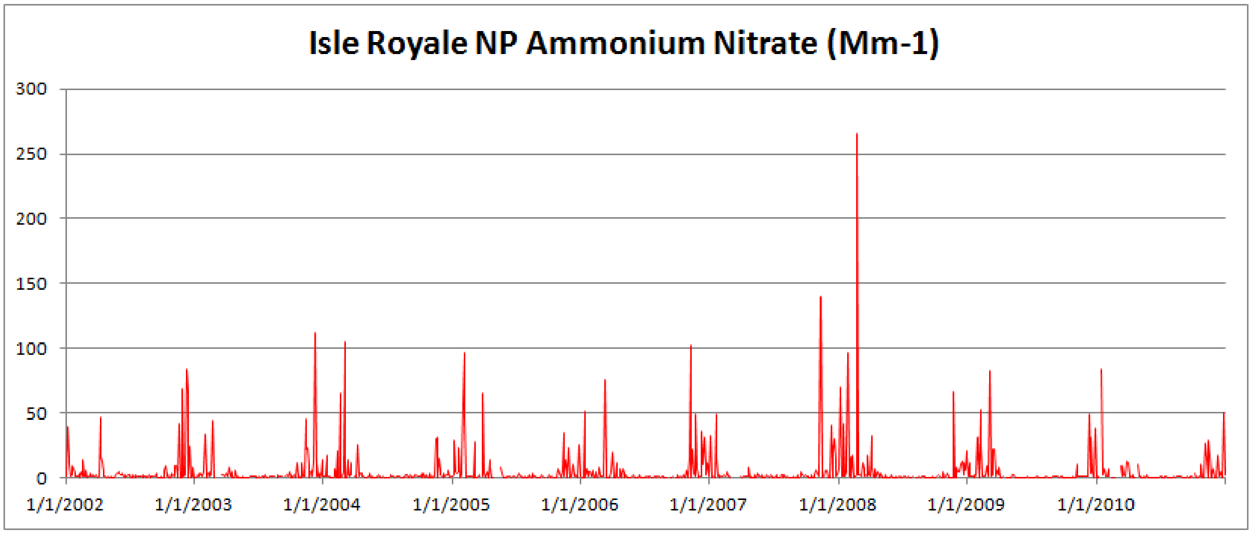
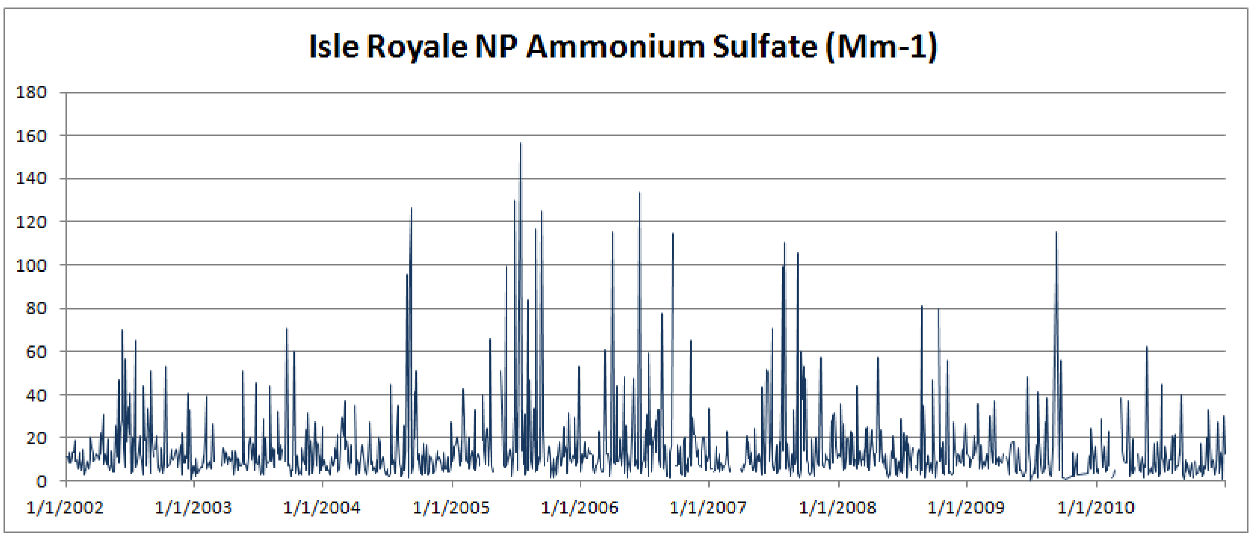


Figure C-6 Time Series of Sulfate Haze at Isle Royale National Park (2002-2010)



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 98th 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_2 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[39] 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_2 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[40] 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.

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[39] 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).

[40] 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 mark.berkman@berkeleyeconomics.com.

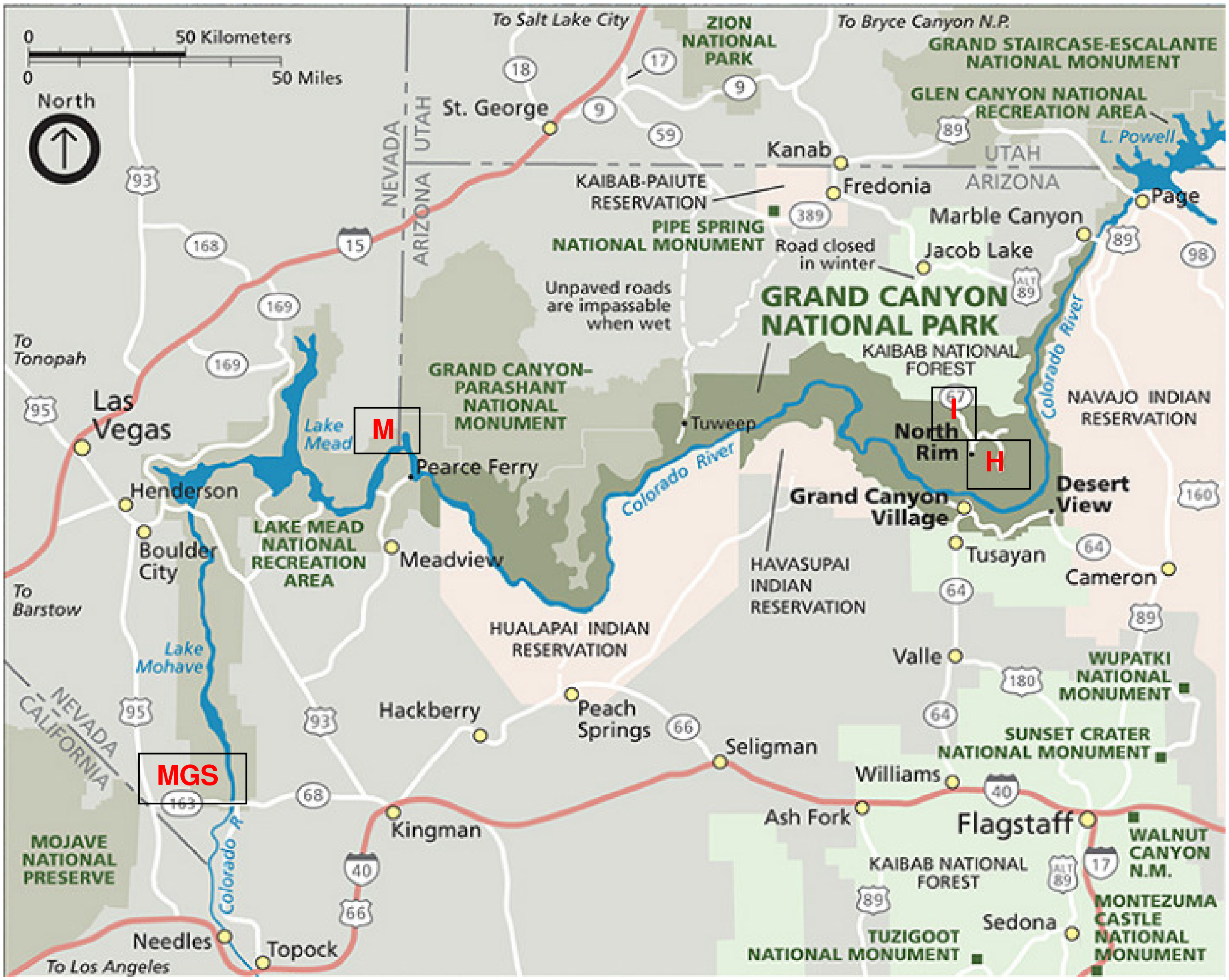
According to the authors, the Project Mohave observations were consistent with observations during temporary outages of MGS, for which there were no reports of substantial changes to visibility in the Grand Canyon.

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 98th 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_2 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.

Figure D-1 : Map Showing the Relationship of the Mohave Generating Station to the Grand Canyon National Park



http://www.nps.gov/grca/planyourvisit/upload/GRCAmap2.pdf

H: Hance Camp monitor

I: Indian Garden monitor

M: Meadview monitor

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_2
- Unit 2 – Wall-fired dry bottom (EQUI 83 / EU 002) that addresses emissions of NOx and SO_2
- Unit 3 – Wall-fired dry bottom (EQUI 100 / EU 003) that addresses emissions of NOx and SO_2
- Unit 4 – Wall-fired dry bottom (EQUI 85 / EU 004) that addresses emissions of NOx and SO_2

This letter is MP's response to the "Four Factor Analysis" request for BEC.

<u>BEC Unit 1 (EQUI 82 / EU 001) and Unit 2 (EQUI 83 / EU 002)</u>

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.

BEC Unit 3 (EQUI 100 / EU 003)

The MPCA specifies in the RFI that U.S. Environmental Protection Agency (USEPA) guidance[1] 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[2]. 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_X** – 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*."[3] 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_X burners, over-fire air, and selective catalytic reduction[4] to control NO_X 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)[5] for BEC's Title V Operating Permit (No. 06100004-008), BEC3's NO_X BART limit was later replaced with BEC3's more restrictive Consent Decree limit[6]. As such, BEC Unit 3 meets this example, and is "effectively controlled" for NO_X as defined in USEPA's guidance document.

- **SO_2** – 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

[1] USEPA, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019.
[2] Ibid, Pages 22-25.
[3] Ibid, Page 25.
[4] Controls identified as TREA 5 and TREA 8 in the facility's current Title V Operating Permit No. 06100004-008.
[5] Technical Support Document to Permit No. 06100004-008, Page 12 of 71
[6] Case No.: 0:14-cv-02911-ADM-LIB, https://www.epa.gov/sites/production/files/2014-07/documents/minnesotapower-cd.pdf

that meets the applicable alternative SO_2 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_2 is necessary to make reasonable progress.*"[7] BEC3 is an EGU equipped with wet FGD (TREA 10) and is currently complying with the alternative SO_2 emission limit of the MATS Rule. BEC3 therefore meets the example scenario of USEPA's guidance document and is considered "effectively controlled" for SO_2.

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_X and SO_2 which excludes the source from the requirement to conduct a "Four Factor Analysis":

- **NO_X** – 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[8] (RBLC) in May 2020 revealed there have been no NOx BACT or LAER determinations entered into the database for coal-fired utility

[7] USEPA, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, Page 23.
[8] https://cfpub.epa.gov/rblc/index.cfm?action=Home.Home&lang=en

boilers with a maximum firing rate of greater than 250 MMBtu/hr since July 31, 2013[9] (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_X BACT evaluations between January 1, 2010 and July 31, 2013[10]. Although, BEC4 has not undergone a BACT or LAER review for NO_X at any time, the current BEC4 NO_X limit (0.12 lb NO_X/MMBtu) is much more stringent than these most recent RBLC-listed NO_X BACT evaluations (0.24 – 0.25 lb/MMBtu) for tangentially-fired coal boilers[11].

To achieve this NOx limit, BEC4 is equipped with existing NO_X control equipment, consisting of low-NO_X burners with separated over fire air and ROTA-Mix Selective Non-Catalytic Reduction[12]. 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[13]. As such, BEC Unit 4 should be considered "effectively controlled" for NO_X, based on the USEPA's guidance document which references "*…effective controls in place … to meet another CAA requirement*"[14].

- **SO_2** – Similar to BEC3, BEC4 is an EGU equipped with semi-dry FGD (TREA 21) and utilizes the MATS Rule alternative SO_2 emission limit compliance demonstration option. BEC4 is therefore "effectively controlled" for SO_2 as defined in USEPA's guidance document [an electric generating unit (EGU) with flue gas desulfurization (FGD) and that meets the applicable alternative SO_2 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_2 is necessary to make reasonable progress.*"[15]

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[9] 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.
[10] The same search of the RBLC was conducted, except the date range was changed to 01/01/2010 to 07/31/2013.
[11] 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_X/MMBtu, respectively.
[12] Controls identified as TREA 6 and TREA 7 in the facility's current Title V Operating Permit No. 06100004-008.
[13] See BACT evaluations for Navajo Generating Station (AZ-0055), Wolverine Power (MI-0400), and Minnkota Power Cooperative (ND-0026) for examples of similar controls accepted as BACT.
[14] USEPA, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, Page 22.
[15] 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,

Melissa S. Weglarz

Melissa Weglarz
Environmental Audit & Policy Manager
Minnesota Power Environmental & Land Mgmt.
mweglarz@mnpower.com
Mobile: 218-343-0927

Enclosure: RBLC Search for NO_X 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_X

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD			
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD			
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD			
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 PRODUCTS MANUFACTURING CORPORATION (APMC) STOCKTON COGEN AND LOCATED IN STOCKTON, CALIFORNIA	CIRCULATING FLUIDIZED BED BOILER	COAL	730	MMBTU/H	Nitrogen Oxides (NOx)	LOW BED TEMPERATUR STAGED COMBUSTION; SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	50	PPM	@3% O2, 3-HR AVG	BACT-PSD	42	LB/H	3-HR AVG
MI-0399	DETROIT EDISON--MONROE	DETROIT EDISON	MI	93-09A	221112	12/21/2010 ACT	Utility--Coal fired power plant	Boiler Units 1, 2, 3 and 4	Coal	7624	MMBTU/H	Nitrogen Oxides (NOx)	Staged combustion, low-NOx burners, overfire air, and SCR.	0.08	LB/MMBTU	EACH, 12-MONTH ROLLING AVG.	BACT-PSD	222.6	T/MO	EACH, 12-MONTH ROLLING AVG.
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	Petcoke/coal	3030	MMBTU/H EACH	Nitrogen Oxides (NOx)	SNCR (Selective Non-Catalytic Reduction)	1	LB/MW-H	GROSS OUTPUT; EACH; 30 D ROLL. AVG; NSPS	BACT-PSD	281.1	LB/H	EACH; 24H ROLL.AVG.; BACT
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2) - EXCLUDING Startup & Shutdown	Petcoke/coal	3030	MMBTU/H each	Nitrogen Oxides (NOx)	SNCR (Selective Non-Catalytic Reduction)	0.07	LB/MMBTU	EACH, 30 D ROLLING AVG; BACT	BACT-PSD			
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	ND	PTC12003	221112	03/08/2012 ACT	Two lignite fired cyclone boilers.	Cyclone Boilers, Unit 1	Lignite	3200	MMBTU/H	Nitrogen Oxides (NOx)	SNCR plus separated over fire air	0.36	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	2070.2	LB/H	24 HOUR AV DURING STARTUP
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	ND	PTC12003	221112	03/08/2012 ACT	Two lignite fired cyclone boilers.	Cyclone Boilers, Unit 2	Lignite	6300	MMBTU/H	Nitrogen Oxides (NOx)	SNCR plus separated over fire air	0.35	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	3995.6	LB/H	24 HOUR AV DURING STARTUP
OK-0151	SOONER GENERATING STATION	O G AND E	OK	2010-338-C(M-1)PSD	221112	01/17/2013 ACT	The facility is an electricity generation plant (SIC Code 4911) located in an attainment area. The facility is currently operating under Permit No. 2010-338-TVR2 issued November 21, 2011.	COAL-FIRED BOILERS	COAL	550	MW	Nitrogen Oxides (NOx)	LOW-NOx BURNERS AND OVERFIRE AIR.	0.15	LB/MMBTU	30-DAY AVG	BART			
OK-0152	MUSKOGEE GENERATING STATION	O G AND E	OK	2005-271-C(M-5)PSD	221112	01/30/2013 ACT	The Muskogee Generating Station utilizes sub-bituminous coal, natural gas, and some waste products (used oil-sorb, used antifreeze, used solvents, used oil, chemical cleaning wastes, hazardous waste fuel, activated carbon, demineralizer resin, and waste water treatment sludge) to produce electricity (SIC 4911). The facility includes 3 large boiler units and auxiliary facilities for storage and processing of solid and liquid fuels and for handling ash and other wastes.	COAL-FIRED BOILER	COAL	550	MW	Nitrogen Oxides (NOx)	LOW-NOx BURNERS AND OVERFIRE AIR	0.15	LB/MMBTU	30-DAY AVG	BART			
TX-0554	COLETO CREEK UNIT 2	COLETO CREEK	TX	PSDTX1118 AND 83778	221112	05/03/2010 ACT	Coal-fired boiler	Coal-fired Boiler Unit 2	PRB coal	6670	MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners with OFA, Selective Catalytic Reduction	0.06	LB/MMBTU	ROLLING 30 DAY AVG	BACT-PSD	0.05	LB/MMBTU	ROLLING 12 MONTH AVG
TX-0556	HARRINGTON STATION UNIT 1 BOILER	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	PSDTX631M1 AMD 1388	221112	01/15/2010 ACT	The Southwestern Public Service Company (Xcel), the operator of a 3,630 MMBtu/hr coal fired electrical generating facility, is seeking authorization to install modifications to the Unit 1 Boiler at the Harrington Station Boiler Unit 1 in conjunction with a federally-mandated NOx reduction project. These modifications to this pollution control project include a separated overfire air windbox system, low-NOx burner tips and additional yaw control to the burners. These modifications will allow control of sufficient control emissions such that actual NOX emissions are expected to be reduced by an estimated 514 tons per year. However, as a result of these modifications, collateral increases in actual CO emissions are projected to be approximately 4,862 tons per year. Since this increase in CO emissions is in excess of 100 tpy, this project triggers the requirements for a PSD major modification. This project is not expected to increase other NAAQS constituents.	Unit 1 Boiler	Coal	3630	MMBTU/H	Nitrogen Oxides (NOx)	Separated overfire air windbox system; low-NOx burner tips and additional ya control to 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_X
NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2
TX-0557	LIMESTONE ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	TX	PSDTX371M4 AND 8576	221112	02/01/2010 ACT	NRG Texas Power LLC (NRG) operates two coal and petroleum coke-fired steam/electric units, otherwise known as Limestone Units 1 and 2, which were originally permitted to operate in September 1981. These units are Combustion Engineering tangentially-fired, controlled circulation radiant reheat, divided furnace boilers. In January 2000 and August 2001, these units were authorized to install and operate low-NOX combustion systems, including secondary air staging technology and low-NOX burner tips with separated over-fire air. The tilting tangential firing system consists of ten elevations of solid fuel firing equipment with two elevations of Close Coupled Overfire Air and one elevation of warm-up gas firing. The modification requested under this amendment is a tuning of the existing low-NOx firing systems to induce deeper state combustion for NOx reductions with no new construction. Although, the deeper stage combustion will reduce NOX emissions, it will also result in a significant collateral increase in CO emissions above the current actual CO emission rates with no increase in authorized emission rates.	LMS Units 1 and 2	Coal	9061	MMBtu/H	Nitrogen Oxides (NOx)	Tuning of existing low-NOx firing system to induce deeper state combustion.	0.25	LB/MMBTU	30-DAY	BACT-PSD			
*TX-0577	WHITE STALLION ENERGY CENTER	WHITE STALLION ENERGY CENTER, LLC	TX	86088, PAL26, HAP28, PSDTX1160	221112	12/16/2010 ACT	WSEC proposes to construct and operate new steam-electric utility generating facilities using four circulating fluidized bed (CFB) boilers, each with a design maximum heat input of 3,300 million British thermal units per hour (MMBtu/hr) and 300 MW net electric output. The gross electric output of the four steam electric generators is about 1,320 MW; the net electric output of the WSEC is about 1,200 MW. The proposed fuels are Illinois Basin coal and petroleum coke. Low-sulfur distillate fuel oil is proposed as the CFB startup fuel. Steam condensation is supported by four water-cooled cooling towers, each with a cooling water circulation design rate of 161,000 gallons per minute. Coal and petroleum coke fuels, and limestone for the CFB beds may be received by barge, rail, or truck, and will be transported via partially enclosed conveyors to large stockpiles for storage. These materials will be conveyed to a crusher building before being stored in silos next to the boilers. Activated carbon for mercury control, lime for sulfur dioxide (SO2) control, and sand for CFB bed stabilization will be delivered via railcar or truck and conveyed pneumatically to storage silos. The fly ash and boiler bottom ash solid wastes will be stored in silos near the boilers, loaded into trucks, and sent to an on-site landfill.	CFB BOILER	COAL & PET COKE	3300	MMBTU/H	Nitrogen Oxides (NOx)	CFB AND SNCR	0.07	LB NOX/MMBTU	30-DAY ROLLING	BACT-PSD	0.1	LB NOX/MMBTU	1-HR
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	TENASKA TRAILBLAZER PARTNERS LLC	TX	PSDTX1123 AND HAP13, 84167	221112	12/30/2010 ACT	Coal-fired electric generating facility	Coal-fired Boiler	Sub-bituminous coal	8307	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.05	LB/MMBTU	12-MONTH ROLLING	BACT-PSD	0.06	LB/MMBTU	30-DAY ROLLING

AN ALLETE COMPANY

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_X and SO_2
- Boiler No. 2 (EQUI 5 / EU 002) for NO_X and SO_2

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 mweglarz@mnpower.com or 218-343-0927 if you have questions or require additional information.

Sincerely,

Melissa S. Weglarz

Melissa Weglarz
Environmental Audit & Policy Manager
Minnesota Power Environmental & Land Mgmt.

enclosure: Regional Haze Four-Factor Analysis for NO_X and SO_2 Emissions Control
cc: Barr Engineering: Beau Thurman, Erik Boleman

Regional Haze Four-Factor Analysis for NO_X and SO_2 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_X and SO_2 Emissions Control

July 31, 2020

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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_X 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
NO_X	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_2	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[1], Minnesota Power's (MP's) Taconite Harbor Energy Center (THEC) evaluated potential emissions reduction measures for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) 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)[2]. 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[3] (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_X four-factor analysis evaluated the following NO_X emissions reduction measures:

- Low-NO_X 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_X emission performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

The SO_2 four-factor analysis evaluated the following SO_2 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_2 emission performance

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[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to Melissa Weglarz of Minnesota Power.

[2] 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).

[3] 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_X Four-Factor Analysis

List of Emission Reduction Technology	Factor 1 – Cost of Compliance ($/ton)	Factor 2 – Time Necessary for Compliance	Factor 3 - Energy and Non-Air Quality Environmental Impacts of Compliance	Factor 4 – Remaining Useful Life of the Source	Factor 5 – Visibility Improvements	Does this Analysis Support the Installation of this Emission Reduction Technology?
Low NO_X Burners (Coal Tip Replacement)	$19,010/ton NO_X controlled	2 to 3 years	None expected	Conservatively Excluded from Analysis	Not Evaluated	No
ROFA/SNCR System Enhancements	$9,530/ton NO_X controlled	2 to 3 years	Minimal concern related to construction activities and additional truck traffic for SNCR deliveries	Conservatively Excluded from Analysis	Not Evaluated	No

Table 1-2 Summary of SO_2 Four-factor Analysis

List of Emission Reduction Technology	Factor 1 – Cost of Compliance ($/ton)	Factor 2 – Time Necessary for Compliance	Factor 3 - Energy and Non-Air Quality Environmental Impacts of Compliance	Factor 4 – Remaining Useful Life of the Source	Factor 5 – Visibility Improvements	Does this Analysis Support the Installation of this Emission Reduction Technology?
Lime Injection System Enhancements	$18,780/ton SO_2 controlled	2 years	Minimal concern related to construction activities and potential increases in ash for disposal	Conservatively Excluded from 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_2 and NO_X. 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.

Table 2-1 Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Boiler No. 1	EQUI 64 / EU 001	NO_X, SO_2
Boiler No. 2	EQUI 5 / EU 002	NO_X, SO_2

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[4].

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.

[4] 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_X 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_X control efficiency of about 62% and typical emission rate of approximately 0.125 lb NO_X/MMBtu[5]. The permitted limit for both boilers is 0.160 lb NO_X/MMBtu on a 30-day rolling average basis. For SO_2 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_2 control efficiency of about 65% and typical emission rate of 0.28 lb SO_2/MMBtu[6]. The permitted limit for both boilers is 0.30 lb SO_2/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[7] (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*

[5] The 62% NO_X 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_X/MMBtu emission rate is the annual average emission rate observed at Boilers No. 1 and 2 in calendar years 2015 and 2016.

[6] The 65% SO_2 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_2/MMBtu emission rate is the annual average emission rate observed at Boilers No. 1 and 2 in calendar year 2016.

[7] 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_X and SO_2 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.

Table 3-1 THEC Boiler No. 1 (EQUI 64 / EU 001) Historical Fuel Usage

Parameter	2011	2012	2013	2014	2015
Coal Fired (short ton/year)	253,593	224,487	180,741	256,023	268,677
Fuel Oil Fired (1,000 gal/year)	30.9	31.5	55.2	19.5	34.6
Total Heat Input (MMBtu/year)	4,575,772	4,054,231	3,276,941	4,616,605	4,830,987

Table 3-2 THEC Boiler No. 2 (EQUI 5 / EU 002) Historical Fuel Usage

Parameter	2011	2012	2013	2014	2015
Coal Fired (short ton/year)	206,840	102,755	220,489	208,881	262,050
Fuel Oil Fired (1,000 gal/year)	48.7	37.2	39.1	51.1	23.6
Total Heat Input (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_X and SO_2 emission rates, the permitted limits for both Boilers No. 1 and 2 are 0.160 lb NO_X/MMBtu and 0.30 lb SO_2/MMBtu[8]. These limits only became effective relatively recently[9,10] 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_X/MMBtu[11] and 0.28 lb SO_2/MMBtu[12] for both Boilers

[8] Both the NO_X and SO_2 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).

[9] The 0.16 lb NO_X/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.

[10] 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.

[11] The quoted 0.125 lb NO_X/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_X/MMBtu limit became effective.

[12] The quoted 0.28 lb SO_2/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_2/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.

Table 3-3 Baseline Emissions for THEC Boiler No. 1 (EQUI 64 / EU 001) and No. 2 (EQUI 5 / EU 002)

Emission Unit	NO_X (ton/year)	SO_2 (ton/year)
Boiler No. 1 (EQUI 64 / EU 001)	303[1]	679[2]
Boiler No. 2 (EQUI 5 / EU 002)	303[1]	679[2]

[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] $679\ \frac{ton\ NO_X}{year} = 4{,}850{,}000 \frac{MMBtu}{yr} \times 0.280 \frac{lb\ SO_2}{MMBtu} \times \frac{ton}{2{,}000\ lb}$

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."[13] However, a "state must reasonably pick and justify the measures that is will consider."[14] The EPA provides the following examples of the types of emission control measures states may consider[15]:

- 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_2, NO_X, and/or PM[16] 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:

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[13] 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.

[14] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 29.

[15] 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.

[16] 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[17] 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_X Control Options

The RBLC search for coal-fired utility boilers for NO_X 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.

[17] RACT/BACT/LAER Clearinghouse (RBLC) as maintained by USEPA (link to RBLC website)

Table 4-1 Coal-Fired Utility Boilers RBLC Summary – NO_X

Technology	Example RBLC IDs	Applicable to THEC?
Low-NO_X Burners (LNB)	AZ-0055 OK-0151 TX-0554	Yes
Over-Fire Air Includes Separated Over-Fire Air (SOFA) and Rotating Over-Fire Air (ROFA)	AZ-0055 OK-0151 TX-0554	Yes[1]
Selective Non-Catalytic Reduction (SNCR)	CA-1206 MI-0400 TX-0577	Yes[1]
Selective Catalytic Reduction (SCR)	MI-0399 TX-0554 TX-0585	No[2]
Low Bed Temperatures	CA-1206	No[3]
Convert Boilers to Use Natural Gas as Fuel	N/A[4]	No[5]

Table Footnotes

[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_X 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_2 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.

Table 4-2 Coal-Fired Utility Boilers RBLC Summary – SO_2

Technology	Example RBLC IDs	Applicable to THEC?
Reagent (Lime, Limestone, Sodium Bicarbonate) Injection	CA-1206 KY-0100	Yes[1]
Spray Dryer	MI-0400 TX-0554	No[2]
Wet Lime Scrubbing (Wet Flue-Gas Desulfurization, FGD)	MI-0399 TX-0585	No[3]
Convert Boilers to Use Natural Gas as Fuel	N/A[4]	No[5]

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) [18] unless more refined site-specific estimate are available. Under this

[18] US EPA, "EPA Air Pollution Control Cost Manual, Sixth Edition," January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may be accessed at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution as of the date of this report.

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_X and SO_2 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_X 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_X 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_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. 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_X emissions from coal combustion[19].

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:

$$N_2 + O_2 \rightarrow 2NO \qquad (1)$$

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 NO_X formation is a function of the residence time, free oxygen, and peak reaction temperature.

Prompt NO_X is a form of thermal NO_X 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_X emissions from combustion sources are from prompt NO_X 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.

[19] 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_X Control Measures with Potential Application to THEC Boilers No. 1 and 2

Control Technology
Low-NO_X 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_X/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_X/MMBtu. For the purposes of this evaluation, MP has conservatively assumed that these enhancements would achieve the lower estimate of 0.11 lb NO_X/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_X Emission Reductions for THEC Boiler No. 1 (EQUI 64 / EU 001) and No. 2 (EQUI 5 / EU 002)

Emission Unit	Baseline NO_X (ton/year)[1]	NO_X Emissions with LNB (ton/year)	Emissions Reduction from LNB (ton/year)	NO_X Emissions with SNCR/ROFA Enhancements (ton/year)	Emissions Reduction from SNCR/ ROFA Enhancements (ton/year)
Boiler No. 1 (EQUI 64 / EU 001)	303	291[2]	12[3]	267[4]	36[3]
Boiler No. 2 (EQUI 5 / EU 002)	303	291[2]	12[3]	267[4]	36[3]

[1] See Table 3-3

[2] $291\,\frac{ton\ NO_X}{year} = 4{,}850{,}000\,\frac{MMBtu}{yr} \times 0.120\,\frac{lb\ NO_X}{MMBtu} \times \frac{ton}{2{,}000\ lb}$

[3] Difference between baseline emissions and emissions estimate with control equipment added.

[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_X 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_X 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[20].

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.

Table 5-3 NO_X Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Installed Capital Cost ($)	Annualized Capital Cost ($/yr)	Annual Operating Costs ($/yr)	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
Low-NO_X Burners (LNB, Coal Tip Replacement)	$609,375	$72,352	$155,775	$228,127	12	$19,010
Enhancements to the existing ROFA and SNCR systems	$1,218,750	$83,824	$259,221	$343,045	36	$9,530

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_X 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.

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[20] 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*[21] 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_X Controls and Emissions Rates

This analysis does not support the installation of additional NO_X 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_X emission limits and control technologies at THEC.

[21] Docket No. E015/D-19-534, Document 20198-155376-01.

6 SO_2 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_2 Control Measures Overview

SO_2 emissions occur as a result of oxidation of sulfur in the fuels combusted. Theoretically, several techniques can be used to reduce SO_2 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_2 Control Measures with Potential Application to THEC Boilers No. 1 and 2

Control Technology
Enhancements 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_2/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_2 Emission Reductions for THEC Boiler No. 1 (EQUI 64 / EU 001) and No. 2 (EQUI 5 / EU 002)

Emission Unit	Baseline NO_X (ton/year)[1]	SO_2 Emissions with Lime Injection System Enhancements (ton/year)
Boiler No. 1 (EQUI 64 / EU 001)	679	606[2]
Boiler No. 2 (EQUI 5 / EU 002)	665	606[2]

[1] See Table 3-3

[2] $606\ \frac{ton\ NO_X}{year} = 4{,}850{,}000 \frac{MMBtu}{yr} \times 0.250 \frac{lb\ NO_X}{MMBtu} \times \frac{ton}{2{,}000\ lb}$

[3] Difference between baseline emissions and emissions estimate with control equipment added.

6.2 Factor 1 – Cost of Compliance

MP has completed a screening-level cost estimate for the selected SO_2 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_2 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[22].

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_2 Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Installed Capital Cost ($)	Annualized Capital Cost ($/yr)	Annual Operating Costs ($/yr)	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
Enhancements to the existing Lime 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_2 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

[22] 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*[23] 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_2 Controls and Emissions Rates

This analysis does not support the installation of additional SO_2 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.

[23] 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_X and SO_2 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_X or SO_2 controls were identified to be cost effective (refer to Sections 5.2 and 6.2 for more information). Therefore, the facility's existing NO_X and SO_2 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_X

Minnesota Power - Taconite Harbor Energy Center
Regional Haze RFI
Appendix A-1: RBLC Search for Coal-Fired Utility Boilers for NO_X

Pollutant Name: NO_X
NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD	0			0		
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD	0			0		
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD	0			0		
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 PRODUCTS MANUFACTURING CORPORATION (APMC) STOCKTON COGEN AND LOCATED IN STOCKTON, CALIFORNIA	CIRCULATING FLUIDIZED BED BOILER	COAL	730	MMBTU/H	Nitrogen Oxides (NOx)	LOW BED TEMPERATUR STAGED COMBUSTION; SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	50	PPM	@3% O2, 3-HR AVG	BACT-PSD	42	LB/H	3-HR AVG	0		
MI-0399	DETROIT EDISON--MONROE	DETROIT EDISON	MI	93-09A	221112	12/21/2010 ACT	Utility--Coal fired power plant	Boiler Units 1, 2, 3 and 4	Coal	7624	MMBTU/H	Nitrogen Oxides (NOx)	Staged combustion, low-NOx burners, overfire air, and SCR.	0.08	LB/MMBTU	EACH, 12-MONTH ROLLING AVG.	BACT-PSD	222.6	T/MO	EACH, 12-MONTH ROLLING AVG.	0		
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	Petcoke/coal	3030	MMBTU/H EACH	Nitrogen Oxides (NOx)	SNCR (Selective Non-Catalytic Reduction)	1	LB/MW-H	GROSS OUTPUT; EACH; 30 D ROLL. AVG; NSPS	BACT-PSD	281.1	LB/H	EACH; 24H ROLL.AVG.; BACT	0		
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2) -	Petcoke/coal	3030	MMBTU/H each	Nitrogen Oxides (NOx)	SNCR (Selective Non-Catalytic Reduction)	0.07	LB/MMBTU	EACH, 30 D ROLLING AVG; BACT	BACT-PSD	0			0		
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	ND	PTC12003	221112	03/08/2012 ACT	Two lignite fired cyclone boilers.	Cyclone Boilers, Unit 1	Lignite	3200	MMBTU/H	Nitrogen Oxides (NOx)	SNCR plus separated over fire air	0.36	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	2070.2	LB/H	24 HOUR AV DURING STARTUP	0		
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	ND	PTC12003	221112	03/08/2012 ACT	Two lignite fired cyclone boilers.	Cyclone Boilers, Unit 2	Lignite	6300	MMBTU/H	Nitrogen Oxides (NOx)	SNCR plus separated over fire air	0.35	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	3995.6	LB/H	24 HOUR AV DURING STARTUP	0		
OK-0151	SOONER GENERATING STATION	O G AND E	OK	2010-338-C(M-1)PSD	221112	01/17/2013 ACT	The facility is an electricity generation plant (SIC Code 4911) located in an attainment area. The facility is currently operating under Permit No. 2010-338-TVR2 issued November 21, 2011.	COAL-FIRED BOILERS	COAL	550	MW	Nitrogen Oxides (NOx)	LOW-NOx BURNERS AND OVERFIRE AIR.	0.15	LB/MMBTU	30-DAY AVG	BART	0			0		
OK-0152	MUSKOGEE GENERATING STATION	O G AND E	OK	2005-271-C(M-5)PSD	221112	01/30/2013 ACT	The Muskogee Generating Station utilizes sub-bituminous coal, natural gas, and some waste products (used oil-sorb, used antifreeze, used solvents, used oil, chemical cleaning wastes, hazardous waste fuel, activated carbon, demineralizer resin, and	COAL-FIRED BOILER	COAL	550	MW	Nitrogen Oxides (NOx)	LOW-NOx BURNERS AND OVERFIRE AIR	0.15	LB/MMBTU	30-DAY AVG	BART	0			0		
TX-0554	COLETO CREEK UNIT 2	COLETO CREEK	TX	PSDTX1118 AND 83778	221112	05/03/2010 ACT	Coal-fired boiler	Coal-fired Boiler Unit 2	PRB coal	6670	MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners with OFA, Selective Catalytic Reduction	0.06	LB/MMBTU	ROLLING 30 DAY AVG	BACT-PSD	0.05	LB/MMBTU	ROLLING 12 MONTH AVG	0		
TX-0556	HARRINGTON STATION UNIT 1 BOILER	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	PSDTX631M1 AMD 1388	221112	01/15/2010 ACT	The Southwestern Public Service Company (Xcel), the operator of a 3,630 MMBtu/hr coal fired electrical generating facility, is seeking authorization to install modifications to the Unit 1 Boiler at the Harrington Station Boiler Unit 1 in conjunction with a federally-	Unit 1 Boiler	Coal	3630	MMBTU/H	Nitrogen Oxides (NOx)	Separated overfire air windbox system; low-NOx burner tips and additional ya control to the burners.	1452	LB/H		BACT-PSD	0			0		
TX-0557	LIMESTONE ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	TX	PSDTX371M4 AND 8576	221112	02/01/2010 ACT	NRG Texas Power LLC (NRG) operates two coal and petroleum coke-fired steam/electric units, otherwise known as Limestone Units 1 and 2, which were originally permitted to operate in September 1981. These units are Combustion Engineering tangentially-fired,	LMS Units 1 and 2	Coal	9061	MMBtu/H	Nitrogen Oxides (NOx)	Tuning of existing low-NOx firing system to induce deeper state combustion.	0.25	LB/MMBTU	30-DAY	BACT-PSD	0			0		
*TX-0577	WHITE STALLION ENERGY CENTER	WHITE STALLION ENERGY CENTER, LLC	TX	86088, PAL26, HAP28, PSDTX1160	221112	12/16/2010 ACT	WSEC proposes to construct and operate new steam-electric utility generating facilities using four circulating fluidized bed (CFB) boilers, each with a design maximum heat input of 3,300 million British thermal units per hour (MMBtu/hr) and 300 MW net electric	CFB BOILER	COAL & PET COKE	3300	MMBTU/H	Nitrogen Oxides (NOx)	CFB AND SNCR	0.07	LB NOX/MMBTU	30-DAY ROLLING	BACT-PSD	0.1	LB NOX/MMBTU	1-HR	0		
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	TENASKA TRAILBLAZER PARTNERS LLC	TX	PSDTX1123 AND HAP13, 84167	221112	12/30/2010 ACT	Coal-fired electric generating facility	Coal-fired Boiler	Sub-bituminous coal	8307	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.05	LB/MMBTU	12-MONTH ROLLING	BACT-PSD	0.06	LB/MMBTU	30-DAY ROLLING	0		

Appendix A.2

RBLC Search for Coal-Fired Utility Boilers for SO_2

Minnesota Power - Taconite Harbor Energy Center
Regional Haze RFI
Appendix A-2: RBLC Search for Coal-Fired Utility Boilers for SO_2

Pollutant Name: SO_2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	Petcoke/coal	3030	MMBTU/H EACH	Sulfur Dioxide (SO2)	Dry flue gas desulfurization (spray dry absorber or polishing scrubber).	303	LB/H	EACH; 24-H ROLL.AVG.; BACT & SIP	BACT-PSD	1.4	LB/MW-H	GROSS OUTPUT; EACH; 30D ROLL.AVG.	0		
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2) -	Petcoke/coal	3030	MMBTU/H each	Sulfur Dioxide (SO2)	Dry flue gas desulfurization (spray dry absorber or polishing scrubber).	0.06	LB/MMBTU	EACH; 30D ROLL.AVG.; BACT&SIP; EXC. SS	BACT-PSD	0.05	LB/MMBTU	EACH;12-MO ROLL.AVG.; BACT&SIP; EXC.SS	0		
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Sulfur Dioxide (SO2)	FLUE GAS DESULFURIZATION (FGD), SCRUBBER	0			BART	0			0		
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Sulfur Dioxide (SO2)	FLUE GAS DESULFURIZATION (FGD), SCRUBBER	0			BART	0			0		
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Sulfur Dioxide (SO2)	FLUE GAS DESULFURIZATION (FGD), SCRUBBER	0			BART	0			0		
*TX-0577	WHITE STALLION ENERGY CENTER	WHITE STALLION ENERGY CENTER, LLC	TX	86088, PAL26, HAP28, PSDTX1160	221112	12/16/2010 ACT	WSEC proposes to construct and operate new steam-electric utility generating facilities using four circulating fluidized bed (CFB) boilers, each with a design maximum heat input of 3,300 million British thermal units per hour (MMBtu/hr) and 300 MW net electric	CFB BOILER	COAL & PET COKE	3300	MMBTU/H	Sulfur Dioxide (SO2)	LIMESTONE BED CFB AND LIME SPRAY DRYER PERMIT DESIGN SULFUR CONTENT OF ILL BASIN COAL IS 3.9 WT% AND OF PET COKE 4.3 AVG/6.0 MAX HI WEIGHTING OF LIMITS	0.114	LB SO2/MMBTU	PET COKE 30-DAY ROLLING	BACT-PSD	0.086	LB SO2/MMBTU	PET COKE 12-MO ROLLING	0.063	LB SO2/MMBTU	COAL 30-DAY & 12-MO ROLLING
KY-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 TITLE V PROCEDURES, PERMITTEE AGREED TO TERMINATE CONSTRUCTION AUTHORITY FOR PROJECT. R4 TO THIS PERMIT REMOVES CONSTRUCTION AURTHORITY, AND THE PERMIT MAY	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2	COAL	3000	MMBTU/H	Sulfur Dioxide (SO2)	LIMESTONE INJECTION (CFB)AND A FLASH DRYER ABSORBER WITH FRESH LIME 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 PRODUCTS MANUFACTURING CORPORATION (APMC) STOCKTON COGEN AND LOCATED IN STOCKTON, CALIFORNIA	CIRCULATING FLUIDIZED BED BOILER	COAL	730	MMBTU/H	Sulfur Dioxide (SO2)	LIMESTONE INJECTION W/ A MINIMUM REMOVAL EFFICIENCY OF 70% (3-HR AVG) TO 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	TX	PSDTX1118 AND 83778	221112	05/03/2010 ACT	Coal-fired boiler	Coal-fired Boiler 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 ROLLING	0		
TX-0601	GIBBONS CREEK STEAM ELECTRIC STATION	TEXAS MUNICIPAL POWER AGENCY	TX	5699 AND PSDTX18M2	221122	10/28/2011 ACT	one 5,060 MMBtu/h boiler burning natural gas, lignite, coal, and a 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 EDISON--MONROE	DETROIT EDISON	MI	93-09A	221112	12/21/2010 ACT	Utility--Coal fired power plant	Boiler Units 1, 2, 3 and 4	Coal	7624	MMBTU/H	Sulfur Dioxide (SO2)	Wet flue gas desulfurization.	0.107	LB/MMBTU	EACH, 24-H ROLL. AVG.	BACT-PSD	815.8	LB/H	EACH, 24-H ROLL. AVG.	0		
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	TENASKA TRAILBLAZER PARTNERS LLC	TX	PSDTX1123 AND HAP13, 84167	221112	12/30/2010 ACT	Coal-fired electric generating facility	Coal-fired Boiler	Sub-bituminous 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 ROLLING	0		

Appendix B

Unit-Specific Screening Level Cost Summary for NO_X 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

EQUIPMENT DETAILS

Emission Unit Number	**Boilers No. 1 and No. 2**
Control Equipment Type	**Burner Modifications - LNB coal tip replacement only (NOx improvement)**
Details	Replace coal tip with nozzle tip that changes boiler fireball shape
Max Operating Design	900 MMBtu/hr
Expected Utilization Rate	100%
Expected Annual Hours of Operation	8,760 Hours
Annual Interest Rate	3.25% Bank Prime Rate for July 16, 2020 from https://www.federalreserve.gov/releases/h15/.
Expected Equipment Life	10 yrs

CAPITAL COSTS

Direct Capital Costs				
Purchased Equipment (A) (1)				
Purchased Equipment Costs (A)		Engineering judgement based on previous project by Minnesota Power	$	500,000
Instrumentation	10.00%	of control device cost (A)	$	50,000
Sales Taxes	6.875%	of control device cost (A)	$	34,375
Freight	5.0%	of control device cost (A)	$	25,000
Purchased Equipment Total (B)			**$**	**609,375**
Installation				
Foundations & supports	0%	Conservatively excluded from analysis	$	-
Handling & erection	0%	Conservatively excluded from analysis	$	-
Electrical	0%	Conservatively excluded from analysis	$	-
Piping	0%	Conservatively excluded from analysis	$	-
Insulation	0%	Conservatively excluded from analysis	$	-
Painting	0%	Conservatively excluded from analysis	$	-
Installation Subtotal Standard Expenses			**$**	**-**
Site Preparation, as required	0%	None required	$	-
Buildings, as required	0%	None required	$	-
Site Specific - Other	0%	None required	$	-
Total Site Specific Costs			$	-
Installation Total			**$**	**-**
Total Direct Capital Cost, DC			**$**	**609,375**
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	0%	Conservatively excluded from analysis	$	-
Model Studies	0%	Conservatively excluded from analysis	$	-
Contingencies	0%	Conservatively excluded from analysis	$	-
Total Indirect Capital Costs, IC			**$**	**-**
Total Capital Investment (TCI) = DC + IC			**$**	**609,375**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**$**	**609,375**

OPERATING COSTS

NOTE: *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.)*

Item	Unit Cost	Unit of Measure	Use Rate	Unit of Measure	Comments		
Direct Annual Operating Costs, DC							
Operating Labor							
Operator	$ 60.00	$/Hr	0.00	hr/8 hr shift	No additional labor costs	$	-
Supervisor	15%	of Op. Labor			15% of Operator Costs	$	-
Maintenance							
Maintenance 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, 8,760 hr/yr, Based on average annual maintenenance cost for labor and material	$	65,700
Maintenance Materials	100%	of Maint Labor			of maintenance labor costs	$	65,700
Utilities, Supplies, Replacements & Waste Management							
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	$	-
Total Annual Direct Operating Costs						**$**	**131,400**
Indirect Operating Costs							
Overhead					0% Conservatively excluded from analysis	$	-
Administration (2% total capital costs)					2% of total capital costs (TCI)	$	12,188
Property tax (1% total capital costs)					1% of total capital costs (TCI)	$	6,094
Insurance (1% total capital costs)					1% of total capital costs (TCI)	$	6,094
Capital Recovery					0.1187 capital recovery factor for a 10-year equipment life and 3.3% interest rate	$	72,352
Total Annual Indirect Operating Costs						**$**	**96,727**
Total Annual Cost (Direct Operating Cost + Indirect Operating Cost)						**$**	**228,127**

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

EQUIPMENT DETAILS

Emission Unit Number	**Boilers No. 1 and No. 2**	
Control Equipment Type	**Enhance SNCR/ROFA (NOx improvement)**	
Details	Add CCOFA with tilt and yaw, change SNCR injection ports and locations, add additional ROFA system controls	
Max Operating Design	900	MMBtu/hr
Expected Utilization Rate	100%	
Expected Annual Hours of Operation	8,760	Hours
Annual Interest Rate	3.25%	Bank Prime Rate for July 16, 2020 from https://www.federalreserve.gov/releases/h15/.
Expected Equipment Life	20	yrs

CAPITAL COSTS

Direct Capital Costs				
Purchased Equipment (A) (1)				
Purchased Equipment Costs (A)		Engineering judgement based on previous project by Minnesota Power	$	1,000,000
Instrumentation	10.00%	of control device cost (A)	$	100,000
Sales Taxes	6.875%	of control device cost (A)	$	68,750
Freight	5.0%	of control device cost (A)	$	50,000
Purchased Equipment Total (B)			**$**	**1,218,750**
Installation				
Foundations & supports	0%	Conservatively excluded from analysis	$	-
Handling & erection	0%	Conservatively excluded from analysis	$	-
Electrical	0%	Conservatively excluded from analysis	$	-
Piping	0%	Conservatively excluded from analysis	$	-
Insulation	0%	Conservatively excluded from analysis	$	-
Painting	0%	Conservatively excluded from analysis	$	-
Installation Subtotal Standard Expenses			**$**	**-**
Site Preparation, as required	0%	None required	$	-
Buildings, as required	0%	None required	$	-
Site Specific - Other	0%	None required	$	-
Total Site Specific Costs			$	-
Installation Total			**$**	**-**
Total Direct Capital Cost, DC			**$**	**1,218,750**
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	0%	Conservatively excluded from analysis	$	-
Model Studies	0%	Conservatively excluded from analysis	$	-
Contingencies	0%	Conservatively excluded from analysis	$	-
Total Indirect Capital Costs, IC			**$**	**-**
Total Capital Investment (TCI) = DC + IC			**$**	**1,218,750**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**$**	**1,218,750**

OPERATING COSTS

NOTE: 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.)

Item		**Unit Cost**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Comments**		
Direct Annual Operating Costs, DC								
Operating Labor								
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	$	65,700
Supervisor		15%	of Op. Labor			15% of Operator Costs	$	9,855
Maintenance								
Maintenance 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, 8,760 hr/yr	$	65,700
Maintenance Materials		100%	of Maint Labor			of maintenance labor costs	$	65,700
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	$	-
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	$	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	0	ton/yr	no impacts expected- engineering judgement	$	-
Ammonia	$	0.293	/gal	12,000	gal/yr	engineering judgement	$	3,516
Total Annual Direct Operating Costs							**$**	**210,471**
Indirect Operating Costs								
Overhead					0%	Conservatively excluded from analysis	$	-
Administration (2% total capital costs)					2%	of total capital costs (TCI)	$	24,375
Property tax (1% total capital costs)					1%	of total capital costs (TCI)	$	12,188
Insurance (1% total capital costs)					1%	of total capital costs (TCI)	$	12,188
Capital Recovery					0.0688	capital recovery factor for a 20-year equipment life and 3.3% interest rate	$	83,824
Total Annual Indirect Operating Costs							**$**	**132,574**
Total Annual Cost (Direct Operating Cost + Indirect Operating Cost)							**$**	**343,045**

Appendix C

Unit-Specific Screening Level Cost Summary for SO_2 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

EQUIPMENT DETAILS

Emission Unit Number	**Boilers No. 1 and No. 2**	
Control Equipment Type	**Enhance Lime/SBC Injection (SO2 improvement)**	
Details	CFD modeling to adjust injection port locations and resolve operational problems	
Max Operating Design	900	MMBtu/hr
Expected Utilization Rate	100%	
Expected Annual Hours of Operation	8,760	Hours
Annual Interest Rate	3.25%	Bank Prime Rate for July 16, 2020 from https://www.federalreserve.gov/releases/h15/.
Expected Equipment Life	20	yrs

CAPITAL COSTS

Direct Capital Costs				
Purchased Equipment (A) (1)				
Purchased Equipment Costs (A)		Engineering judgement based on previous project by Minnesota Power	$	3,000,000
Instrumentation	10.00%	of control device cost (A)	$	300,000
Sales Taxes	6.875%	of control device cost (A)	$	206,250
Freight	5.0%	of control device cost (A)	$	150,000
Purchased Equipment Total (B)			**$**	**3,656,250**
Installation				
Foundations & supports	0%	Conservatively excluded from analysis	$	-
Handling & erection	0%	Conservatively excluded from analysis	$	-
Electrical	0%	Conservatively excluded from analysis	$	-
Piping	0%	Conservatively excluded from analysis	$	-
Insulation	0%	Conservatively excluded from analysis	$	-
Painting	0%	Conservatively excluded from analysis	$	-
Installation Subtotal Standard Expenses			**$**	**-**
Site Preparation, as required	0%	None required	$	-
Buildings, as required	0%	None required	$	-
Site Specific - Other	0%	None required	$	-
Total Site Specific Costs			$	-
Installation Total			**$**	**-**
Total Direct Capital Cost, DC			**$**	**3,656,250**
Indirect Capital Costs				
Engineering, supervision	0%	None required	$	-
Construction & field expenses	0%	None required	$	-
Contractor fees	0%	None required	$	-
Start-up	0%	None required	$	-
Performance test	0%	None required	$	-
Model Studies	0%	None required	$	-
Contingencies	0%	None required	$	-
Total Indirect Capital Costs, IC			**$**	**-**
Total Capital Investment (TCI) = DC + IC			**$**	**3,656,250**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**$**	**3,656,250**

OPERATING COSTS

NOTE: 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.)

Item		Unit Cost	Unit of Measure	Use Rate	Unit of Measure	Comments		
Direct Annual Operating Costs, DC								
Operating Labor								
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	$	65,700
Supervisor		15%	of Op. Labor			15% of Operator Costs	$	9,855
Maintenance								
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, 8,760 hr/yr	$	131,400
Maintenance Materials		100%	of Maint Labor			of maintenance labor costs	$	131,400
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	$	-
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	$	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	$	635,100
Ammonia	$	0.293	/gal	0	gal/yr	No impacts expected- engineering judgement	$	-
Total Annual Direct Operating Costs							**$**	**973,455**
Indirect Operating Costs								
Overhead					0%	Conservatively excluded from analysis	$	-
Administration (2% total capital costs)					2%	of total capital costs (TCI)	$	73,125
Property tax (1% total capital costs)					1%	of total capital costs (TCI)	$	36,563
Insurance (1% total capital costs)					1%	of total capital costs (TCI)	$	36,563
Capital Recovery					0.0688	capital recovery factor for a 20-year equipment life and 3.3% interest rate	$	251,473
Total Annual Indirect Operating Costs							**$**	**397,723**
Total Annual Cost (Direct Operating Cost + Indirect Operating Cost)							**$**	**1,371,178**

Regional Haze Four-Factor Analysis for NO_X and SO_2 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_X and SO_2 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

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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_X Burners
MPCA	Minnesota Pollution Control Agency
NO	Nitric Oxide
NO_X	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_2	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[1], Northshore Mining Company (Northshore) evaluated potential emissions control measures for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) for Power Boilers 1 (EQUI 14/ EU001) and 2 (EQUI 15/EU002) as part of the state's Regional Haze Rule (RHR)[2] 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[3] 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_X and SO_2 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_X and SO_2, respectively.

The NO_X Four-Factor Analysis evaluated the following NO_X 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_X emission performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

[1] February 24, 2020 letter from Hassan Bouchareb of MPCA to Andrea Hayden of Northshore Mining Company.
[2] 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).
[3] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

The SO_2 Four-Factor Analysis evaluated the following SO_2 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_2 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_2 emissions are minimized by coal pre-processing. Therefore, Northshore's existing SO_2 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_2 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_X Four-Factor Analysis

List of Emission Control Measure	Factor #1 – Cost of Compliance			Factor #2 – Time Necessary for Compliance	Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance	Factor #4 – Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
	Installed Capital Cost ($)	Annualized Operating Cost ($/year)	Pollution Control Cost ($/ton)				
LNB-OFA (Power Boiler 2 only)	$11,609,362	$1,725,870	NA – See Section 3.2	5 years after SIP promulgation. See Section 5.3.	Environmental Increased carbon monoxide emissions, loss of efficiency, and likely Prevention of Significant Deterioration (PSD) permitting implications. Potential for increased steam tube damage and maintenance due to flame impingement on tubes. Increased maintenance due to scale build-up and corrosion.	20 years control equipment life	No
SNCR	$7,239,275 for Power Boiler 1 $8,917,925 for Power Boiler 2	$992,019 for Power Boiler 1 $1,435,176 for Power Boiler 2	NA – See Section 3.2	5 years after SIP promulgation. See Section 5.3.	Energy Increased energy use to overcome the increased differential pressure. Increased water use for reagent dilution. Increased fuel usage for vaporization of the water in the reagent solution. Environmental Increased ammonia emissions from ammonia slip, which contributes to regional haze. Additional ammonia reacts with sulfates causing increased visibility impairment pollutants.	20 years control equipment life	No

List of Emission Control Measure	Factor #1 – Cost of Compliance			Factor #2 – Time Necessary for Compliance	Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance	Factor #4 – Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
	Installed Capital Cost ($)	Annualized Operating Cost ($/year)	Pollution Control Cost ($/ton)				
					Ammonia emissions will increase condensable PM emissions that will have possible PSD permitting implications. Loss of fly ash re-use. Nitrogen deposition onto nearby lakes and waters of the state will contribute nutrients and to undesirable biological growth. Additional safety and regulatory concerns associated with ammonia or urea storage on site.		
SCR	$40,647,490 for Power Boiler 1 $55,724,684 for Power Boiler 2	$4,159,366 for Power Boiler 1 $5,985,367 for Power Boiler 2	NA – See Section 3.2	5 years after SIP promulgation. See Section 5.3.	Energy Increased energy use to overcome the increased differential pressure. Electricity is required for the SCR equipment, to vaporize the aqueous ammonia reagent. Environmental Increased ammonia emissions from ammonia slip.	20 years control equipment life	No

List of Emission Control Measure	Factor #1 – Cost of Compliance			Factor #2 – Time Necessary for Compliance	Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance	Factor #4 – Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
	Installed Capital Cost ($)	Annualized Operating Cost ($/year)	Pollution Control Cost ($/ton)				
					Ammonium would combine with NOx and SO_2 to form ammonia salts, which would be emitted to the atmosphere as PM_{10}. Emissions of ammonia, ammonium sulfates, and sulfuric acid mist increase plume visibility and contribute to 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. Increased oxidized mercury emissions. Nitrogen deposition onto nearby lakes and waters of the state will contribute nutrients and to undesirable biological growth. There are safety risks associated with the transportation, handling, and storage of aqueous ammonia or urea. Spent catalyst from the SCR is typically disposed of in a landfill; however, catalyst recycling or reconditioning may be available.		

Table 1-2 Summary of SO_2 Four-Factor Analysis

List of Emission Control Technology	Factor #1 – Cost of Compliance			Factor #2 – Time Necessary for Compliance	Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance	Factor #4 – Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
	Installed Capital Cost ($)	Annualized Operating Cost ($/year)	Pollution Control Cost ($/ton)				
DSI/Baghouse	$34,463,571 for Power Boiler 1 $37,737,598 for Power Boiler 2	$6,144,640 for Power Boiler 1 $6,943,044 for Power Boiler 2	NA – See Section 3.2	5 years after SIP promulgation. See Section 6.3.	Energy Increased energy use to accommodate new baghouse and additional equipment for material preparation and handling. Environmental Additional solid waste generated and disposed. Loss of fly ash re-use. Increase in wastewater generation.	20 years control equipment life	No
SDA/Baghouse	$58,737,702 for Power Boiler 1 $61,962,015 for Power Boiler 2	$12,796,563 for Power Boiler 1 $13,572,909 for Power Boiler 2	NA – See Section 3.2	5 years after SIP promulgation. See Section 6.3.	Energy Increased energy use to accommodate new baghouse and additional equipment for material preparation and handling. Environmental Additional solid waste generated and disposed. Loss of fly ash re-use. Increase in wastewater generation.	20 years control 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_2 and NO_X. 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_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 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.

Table 2-1 Identified Emission Units

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_x and SO_2
Power Boiler 1	EQUI 14 (EU 001)	NO_x and SO_2
Power Boiler 2	EQUI 15 (EU 002)	NO_x and SO_2

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.[3]

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 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_x and SO_2. 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-wall-fired 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_x burners in conjunction with overfire air on Power Boiler 1 for NO_x control. SO_2 emissions from the boilers are reduced by coal processing prior to combustion. There are no post-combustion SO_2 controls. SO_2 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)[4], 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

[4] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003. https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period

recommendations for states to consider when estimating 2028 emissions for the purpose of evaluating potential emission control measures 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).

> *Selection of emissions information when estimating visibility impacts (or surrogates) for source selection purposes*
>
> *… 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,[5] 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[6] 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 Boiler 1		Power Boiler 2	
		SO_2 (tons)	NOx (tons)	SO_2 (tons)	NOx (tons)
January	**2019**	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	**2020**	0	0	0	0
February		0	0	0	0

[5] Cliffs Natural Resources, Inc. (2016, May 24) *Cliffs Announces Agreements with Minnesota Power* [Press Release]. Retrieved from http://www.clevelandcliffs.com/English/news-center/news-releases/news-releases-details/2016/Cliffs-Announces-Agreements-with-Minnesota-Power/default.aspx

[6] Allete, Inc. (2016) *Form 10-K*. Retrieved from https://www.allete.com/Content/Documents/Investors/AnnualReports/FINALREPORTALLETE2016.pdf

Silver Bay Power Emissions				
	Power Boiler 1		Power Boiler 2	
	SO_2 (tons)	NOx (tons)	SO_2 (tons)	NOx (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_2 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_X and 50 percent to 90 percent for SO_2. 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) [7] 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

[7] US EPA, "EPA Air Pollution Control Cost Manual, Sixth Edition," January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may be accessed at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution as of the date of this report.

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_X or SO_2 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_X Four-Factor Analysis for Power Boilers

This section identifies and describes various NO_X 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_X as described in Sections 5.1 to 5.6.

5.1 NO_X Control Measures Overview

Three mechanisms by which NO_X production typically forms are thermal, fuel and prompt NO_X formation. In the case of natural gas combustion, the primary mechanism of NO_X production is 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:

$$N_2 + O_2 \rightarrow 2NO \qquad (1)$$

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_X is a form of thermal NO_X, 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_X are emitted as prompt NO_X.

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. Natural gas has minimal fuel bound nitrogen, which eliminates fuel bound NO_X 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_2, 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:

$NO + NH_3 + \frac{1}{4}O_2 \rightarrow N_2 + 3/2H_2O$ (1)

$NH_3 + \frac{1}{4}O_2 \rightarrow NO + 3/2H_2O$ (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_3 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_X control measures for the Power Boilers.

Table 5-1: Additional NO_X 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_X 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_X 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.

Table 5-2: NO_X Control Cost Summary, per Unit Basis

Emission Unit	Additional Emissions Control Measure	Installed Capital Cost ($MM)	Total Annualized Costs ($/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

Sections 5.3 through 5.5 provide a summary of the remaining three factors evaluated for the NO_X 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_X 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 NO_x 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_{10} 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_{10} 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_3 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_3 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_2 to SO_3. It is important to understand that SO_2 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_2 oxidation rates would be expected to increase. If lower levels of SO_2 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_2 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_3 and H_2SO_4 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_X Four-Factor Analysis Conclusion

Based on the analysis conducted in Sections 5.1 through 5.5, Northshore has determined that installation of additional NO_X 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_X emissions. As such, Northshore intends to continue complying with CSAPR, which EPA has been determined to be better than BART.

6 SO_2 Four-Factor Analysis for Power Boilers

This section identifies and describes various SO_2 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_2 as described in Sections 6.1 to 6.6.

6.1 SO_2 Control Measures Overview

SO_2 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_2. 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_2 is absorbed by the slurry, forming $CaSO_3$/$CaSO_4$. 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_2 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_2 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_2 emissions based on the factors presented below. Table 6-1 lists technically feasible SO_2 control measures for Power Boilers 1 and 2.

Table 6-1 Additional SO_2 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_2 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_2 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.

Table 6-2: SO_2 Control Cost Summary for Power Boilers 1 and 2, per Unit Basis

Emission Unit	Additional Emissions Control Measure	Installed Capital Cost ($MM)	Total Annualized Costs ($/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

Sections 6.3 through 6.5 provide a summary of the remaining three factors evaluated for the SO_2 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_2 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_2 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_2 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_2 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_2 Four-Factor Analysis Conclusion

Based on the analysis conducted in Sections 6.1 through 6.5, Northshore has determined that installation of additional SO_2 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_2 emissions. As such, Northshore proposes to maintain compliance with its SO_2 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_x Control Cost Summary

Control Technology	Control Eff %	Installed Capital Cost $	Annualized Operating Cost $/yr
Selective Non-Catalytic Reduction (SNCR)	25%	$7,239,275	$992,019
Selective Catalytic Reduction (SCR)	80%	$40,647,490	$4,159,366

SO_2 Control Cost Summary

Control Technology	Control Eff %	Installed Capital Cost $	Annualized Operating Cost $/yr
Dry Sorbent Injection (DSI) with Baghouse	70%	$34,463,571	$6,144,640
Spray Dry Absorber (SDA) 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

Operating Unit:	Power Boiler 1	**Study Year**	2020
Emission Unit Number	EQUI 14 / EU 001		
Stack/Vent Number	SV 001		

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	60	$/hr		2020	Site-specific data	
Maintenance Labor	60	$/hr		2020	Site-specific data	
Electricity	0.076	$/kwh			EIA 2020 Avg Price Industrial Nat Gas in MN	
Natural Gas	4.98	$/kscf		NA	5-year average based on 2014-2018 gas prices on epia.gov	
Water	0.34	$/mgal	0.20	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2	Adjusted for 3% inflation
Cooling Water	0.42	$/mgal	0.23	1999	EPA Air Pollution Control Cost Manual 6th Ed 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
Compressed Air	0.48	$/kscf	0.38	2012	EPA Air Pollution Control Cost Manual 6th Ed 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	$/ton			Vendor estimated delivered cost	
Urea 50% Solution	1.81	$/gallon	1.66	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours			EPA Control Cost Manual Chapter 7, 7th Edition default	
SCR Catalyst cost ($CC_{replace}$)	248	$/cubic foot (includes rem	227	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Cost per bag	249.27	$/bag	160	2005	Northshore Mining March 2009 submittal to MPCA	Adjusted for 3% inflation
Other						
Sales Tax	6.875%			2020	Current MN sales tax rate	
Interest Rate	5.50%				EPA Control Cost Manual Chapter 7, 7th Edition default	
Solid Waste Disposal	42.56	$/ton	25	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Adjusted for 3% inflation
Contingencies	10%	of purchased equip cost (B)			EPA Control Cost Manual Chapter 2, 7th Edition estimates contingencies from 5-15%. Assumed the mid range	
Markup on capital investment (retrofit factor)	60%				CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit factor for installations in existing facilities.	
Operating Information						
Annual Op. Hrs	5,650	Hours			2017 Site-specific operating hours	
Utilization Rate	73%				Site-specific estimate, 2017 emission 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	acfm			Site-specific estimate	
Standardized Flow Rate	140,800	scfm @ 68º F	133,505	scfm @ 32º F	Site-specific estimate	
Dry Std Flow Rate	128,300	dscfm @ 68º F			Site-specific estimate	
Fuel higher heating value (HHV)	8,826	BTU/lb			EPA Control Cost Manual Chapter 7, 7th 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 Edition default for sub-bituminous	
# days boiler operates	235	days			Site Specific Data	
Technology Control Efficiency						
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%	Trona Control Efficiency			Control efficiency is based on trona as injected reagent.	
SCR - NO_x Control Efficiency	80%				Based on engineering assessment.	
SNCR - NO_x Performance	0.26	lb/MMBtu			EPA Control Cost Manual Chapter 7, 7th Edition, SCR Figure 1.1 *(efficiency vs inlet NOx concentration approximation (25%) reduction)*	

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? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.6

* 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

What is the higher heating value (HHV) of the fuel? 8,826 Btu/lb

*HHV value of 8826 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 241,600,555 lbs/year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.41 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

*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

*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:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	235	days
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	

Plant Elevation: 764 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 Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:

50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

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
Annual Interest Rate (i)	5.50	Percent*		
Fuel ($Cost_{fuel}$)	2.13	$/MMBtu		
Reagent ($Cost_{reag}$)	1.81	$/gallon for a 50 percent solution of urea		
Water ($Cost_{water}$)	0.0051	$/gallon		
Electricity ($Cost_{elect}$)	0.0760	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	42.56	$/ton		

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/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 ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: 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 Demand. July 11, 2017. Available at: 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 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)	5.84	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)	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/.	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	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_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.30	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5650	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	25	percent
Coal Factor ($Coal_F$) =	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 =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03	
Atmospheric pressure at 764 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ 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.

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 ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	118	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	236	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	24.9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	8,400	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/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: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.96	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	6.3	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,233,111 in 2020 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2020 dollars
Balance of Plant Costs (BOP_{cost}) =	$3,335,563 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 ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,233,111 in 2020 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 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_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$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} x $Cost_{reag}$ x t_{op} =	\$255,054 in 2020 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	\$3,652 in 2020 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	\$3,281 in 2020 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	\$11,498 in 2020 dollars
Additional Ash Cost =	ΔAsh 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_x 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 Correlation								
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 costs + capital recovery cost							**3,406,329**
Total Annual Cost (Annualized Capital Cost + Operating Cost)									**4,159,366**

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)

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-3: NOx Control - Selective Catalytic Reduction

CAPITAL COSTS			
SCR Capital Costs (SCRcost)		*Refer to the SCR Cost Estimate tab*	22,537,169
Reagent Preparation Costs (RPC)		*Refer to the SCR Cost Estimate tab*	3,510,336
Air Pre-Heater Costs (APHC)		*Refer to the SCR Cost Estimate tab*	-
Balance of Plant Costs (BPC)		*Refer to the SCR Cost Estimate tab*	5,219,795
Retrofit factor	60%	*of TCI, see SCR Cost Estimate tab*	
Total Capital Investment (TCI)			**40,647,490**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Maintenance			
Annual Maintenance Cost =		*Refer to the SCR Cost Estimate tab*	203,237
Utilities, Supplies, Replacements & Waste Management			
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 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	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst - Refer to the SCR Cost Estimate Tab

Reagent Use
Refer to the SCR Cost Estimate tab

Operating Cost Calculations	**Annual hours of operation:**	**5,650**
Refer to the SCR Cost Estimate tab	**Utilization Rate:**	**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_x 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 ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), 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

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.6

* 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
What is the higher heating value (HHV) of the fuel?	8,826	Btu/lb
What is the estimated actual annual fuel consumption?	241,600,555	lbs/year
Operating Hours	5,650	323,950,000.00
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW
Plant Elevation	764	Feet above sea level

*HHV value of 8826 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if 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

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.41 percent by weight

*The sulfur content of 0.41% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ● Method 2
- ○ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	235	days
Number of days the boiler operates (t_{plant})	235	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.35	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.07	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	301,336	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

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 ($Cost_{reag}$)	1.814	$/gallon for 50% urea		
Electricity ($Cost_{elect}$)	0.0760	$/kWh		
Catalyst cost ($CC_{replace}$)	248.05	$/cubic foot (includes removal and disposal/regeneration of existing 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) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf	
Electricity Cost ($/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.	
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/.	
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/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/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_B) =	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_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.471	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5,650	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	80.0	percent
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	301,336	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	144.04	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03	
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	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)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.2303	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	2,091.98	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	314	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	361	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	19.0	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	50	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	99	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	198	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	21	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ 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 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	295.66	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$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_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$22,537,169 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564,000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564,000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$3,510,336 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 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.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$5,219,795 in 2019 dollars

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 = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$203,237	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$214,245	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$126,956	in 2019 dollars
Annual Catalyst Replacement Cost =		$208,599	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2 selected.	
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 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**

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 cost (A)	**9,921,386**
Installation - Standard Costs	74%	of purchased equip 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 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 Factor			**34,463,571**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,566,197
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	4,578,443
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**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 Capital Costs			
Purchased Equipment (A) [1]			**8,140,624**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	814,062
State Sales Taxes	6.9%	of control device cost (A)	559,668
Freight	5%	of control device cost (A)	407,031
Purchased Equipment Total (B)	22%		**9,921,386**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	396,855
Handling & erection	50%	of purchased equip cost (B)	4,960,693
Electrical	8%	of purchased equip cost (B)	793,711
Piping	1%	of purchased equip cost (B)	99,214
Insulation	7%	of purchased equip cost (B)	694,497
Painting	4%	Included in vendor estimate	396,855
Installation Subtotal Standard Expenses	74%		**7,341,825**
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			**7,341,825**
Total Direct Capital Cost, DC			**17,263,211**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	992,139
Construction & field expenses	20%	of purchased equip cost (B)	1,984,277
Contractor fees	10%	of purchased equip cost (B)	992,139
Start-up	1%	of purchased equip cost (B)	99,214
Performance test	1%	of purchased equip cost (B)	99,214
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	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 Bags, etc) for Capital Recovery Cost			**21,539,732**
Total Capital Investment (TCI) with Retrofit Factor	60%		**34,463,571**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	60.00	$/Hr	84,750
Supervisor	0.15	of Op Labor	12,713
Maintenance			
Maintenance Labor	60.00	$/Hr	42,375
Maintenance Materials	100	% of Maintenance Labor	42,375
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 218.1 kW-hr, 5650 hr/yr, 73% utilization	93,639
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization	47,841
N/A			-
Solid Waste Disposal	42.56	$/ton, 0.5 ton/hr, 5650 hr/yr, 73% utilization	84,175
Trona	285.00	$/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			-
Total Annual Direct Operating Costs			**1,566,197**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	109,328
Administration (2% total capital costs)	2%	of total capital costs (TCI)	689,271
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	344,636
Insurance (1% total capital costs)	1%	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 + Operating Cost)			**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 Bags for new baghouse
Total Rep Parts Cost	823,565	Cost adjusted 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 H2O	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	214.87	lb/hr SO2	1193.80	lb/hr Trona
Solid Waste Disposal	2,709	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	73%	Annual Operating Hours		5,650				
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	60.00	$/Hr	2.0	hr/8 hr shift	1,413	$	84,750	$/Hr, 2.0 hr/8 hr shift, 1,413 hr/yr
Supervisor	15%	of Op Labor			NA	$	12,713	% of Operator Costs
Maintenance								
Maint Labor	60.00	$/Hr	1.0	hr/8 hr shift	706	$	42,375	$/Hr, 1.0 hr/8 hr shift, 706 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$	42,375	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.076	$/kwh	218.1	kW-hr	1,232,089	$	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	$	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	$	84,175	$/ton, 0.5 ton/hr, 5650 hr/yr, 73% utilization
Trona	285.00	$/ton	1,193.8	lb/hr	2,462	$	701,646	$/ton, 1,193.8 lb/hr, 5650 hr/yr, 73% utilization
Filter Bags	249.27	$/bag	2,952	bags	N/A	$	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 001		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
			Dry 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 cost (A)	**25,990,134**
Installation - Standard Costs	74%	of purchased equip 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 equip 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, supervision, materials, replacement parts, utilities, etc.	1,031,783
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	11,764,780
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**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
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. 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)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**21,325,238**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC			
Instrumentation	10%	of control device cost (A)	2,132,524
State Sales Taxes	6.9%	of control device cost (A)	1,466,110
Freight	5%	of control device cost (A)	1,066,262
Purchased Equipment Total (B)	22%		**25,990,134**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	1,039,605
Handling & erection	50%	of purchased equip cost (B)	12,995,067
Electrical	8%	of purchased equip cost (B)	2,079,211
Piping	1%	of purchased equip cost (B)	259,901
Insulation	7%	of purchased equip cost (B)	1,819,309
Painting	4%	of purchased equip cost (B)	1,039,605
Installation Subtotal Standard Expenses	74%		**19,232,699**
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			NA
Installation Total			**19,232,699**
Total Direct Capital Cost, DC			**45,222,832**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,599,013
Construction & field expenses	20%	of purchased equip cost (B)	5,198,027
Contractor fees	10%	of purchased equip cost (B)	2,599,013
Start-up	1%	of purchased equip cost (B)	259,901
Performance test	1%	of purchased equip cost (B)	259,901
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	2,599,013
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**13,514,869**
Total Capital Investment (TCI) = DC + IC			**58,737,702**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**57,855,102**
Total Capital Investment (TCI) with Retrofit Factor	60%		**92,568,163**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	60.00	$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr	84,750
Supervisor	15%	15% of Operator Costs	12,713
Maintenance			
Maintenance Labor	60.00	$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr	42,375
Maintenance Materials	100%	of maintenance labor costs	42,375
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization	156,065
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization	47,841
N/A			-
SW Disposal	42.56	$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization	51,679
Lime	167.17	$/ton, 290.7 lb/hr, 5650 hr/yr, 73% utilization	137,302
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			-
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,031,783**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	109,328
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,851,363
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	925,682
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	925,682
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	7,952,726
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**11,764,780**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**12,796,563**

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)

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 Bags for new baghouse	
Total Rep Parts Cost	823,565	Cost adjusted for freight & sales tax	
Installation Labor	59,035	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**882,600**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**206,684**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	200,800	10.00			2,053,481	Electricity demand for new baghouse
Total					2,053,481	

Reagents and Other Operating 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 reaction byproducts		

Operating Cost Calculations

Utilization Rate	73%	Annual Operating Hours		5,650			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	60.00	$/Hr	2.0	hr/8 hr shift	1,413	$ 84,750	$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr
Supervisor	15%	of Op.			NA	$ 12,713	15% of Operator Costs
Maintenance							
Maint Labor	60.00	$/Hr	1.0	hr/8 hr shift	706	$ 42,375	$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	$ 42,375	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.076	$/kwh	363.4	kW-hr	2,053,481	$ 156,065	$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	99,384	$ 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	$ 51,679	$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization
Lime	167.17	$/ton	290.7	lb/hr	821	$ 137,302	$/ton, 290.7 lb/hr, 5650 hr/yr, 73% utilization
Filter Bags	249.27	$/bag	2,952	bags	N/A	$ 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_x Control Cost Summary

Control Technology	Control Eff %	Installed Capital Cost $	Annualized Operating Cost $/yr
Low NOx Burners + Over Fire Air (LNB+OFA) Coal-Fired	40%	$11,609,362	$1,725,870
Selective Non-Catalytic Reduction (SNCR)	25%	$8,917,925	$1,435,176
Selective Catalytic Reduction (SCR)	80%	$55,724,684	$5,985,367

SO_2 Control Cost Summary

Control Technology	Control Eff %	Installed Capital Cost $	Annualized Operating Cost $/yr
Dry Sorbent Injection (DSI) with Baghouse	70%	$37,737,598	$6,943,044
Spray Dry Absorber (SDA) 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	EQUI 15 / EU 002		
Stack/Vent Number	SV 002		

Item	Unit Cost (2020)	Units	Cost	Year	Data Source	Notes
Operating Labor	60	$/hr		2020	Site-specific data	
Maintenance Labor	60	$/hr		2020	Site-specific data	
Electricity	0.076	$/kwh			EIA 2020 Avg Price Industrial Nat Gas in MN	
Natural Gas	4.98	$/kscf		NA	5-year average based on 2014-2018 gas 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
Compressed Air	0.48	$/kscf	0.38	2012	EPA Air Pollution Control Cost Manual 6th Ed 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	$/ton			Vendor estimated delivered cost	
Urea 50% Solution	1.81	$/gallon	1.66	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours			EPA Control Cost Manual Chapter 7, 7th Edition default	
SCR Catalyst cost ($CC_{replace}$)	248	$/cubic foot	227	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Fabric Filter Bags	249.27	$/bag	160	2005	Northshore Mining March 2009 submittal to MPCA	Adjusted for 3% inflation
Other						
Sales Tax	6.875%			2020	Current MN sales tax rate	
Interest Rate	5.50%			2016	EPA Control Cost Manual Chapter 7, 7th Edition default	
Solid Waste Disposal	42.56	$/ton	25	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Adjusted for 3% inflation
Contingencies	10%	of purchased equip cost (B)			EPA Control Cost Manual Chapter 2, 7th Edition estimates contingencies from 5-15%. Assumed the mid range	
Markup on capital investment (retrofit factor)	60%				CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit 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	yrs			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	dscfm @ 68º F			Site-specific estimate	
Fuel higher heating value (HHV)	8,826	BTU/lb			EPA Control Cost Manual Chapter 7, 7th 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 Edition default for sub-bituminous	
# days boiler operates	241	days			Site Specific Data	
Technology Control Efficiency						
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%	Trona Control Efficiency			Control efficiency is based on trona as injected reagent.	
SCR - NO_x Control Efficiency	80%				Based on engineering assessment.	
LNB+OFA- NO_x Control Efficiency	40%				Northshore Mining September 2006 submittal to MPCA	
SNCR - NO_x Performance	0.44	lb/MMBtu			EPA Control Cost Manual Chapter 7, 7th Edition, SCR Figure 1.1 *(efficiency vs inlet NOx concentration approximation (25%) reduction)*	

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-3: NO_x 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 cost (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, replacement parts, utilities, etc.	277,985
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	1,447,885
Total Annual Cost (Annualized Capital Cost + Operating 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

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**2,948,468**
Purchased Equipment Costs (A)			
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	30%	of purchased equip cost (B)	1,007,270
Handling & erection	20%	of purchased equip cost (B)	671,514
Electrical	20%	of purchased equip cost (B)	671,514
Piping	10%	of purchased equip cost (B)	335,757
Insulation	10%	of purchased equip cost (B)	335,757
Painting	2.5%	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	15%	of direct costs (DC)	982,089
Owner's cost	10%	of direct costs (DC)	654,726
Construction & field expenses	5%	of direct costs (DC)	327,363
Contractor fees	15%	of direct costs (DC)	982,089
Start-up and spare parts	2%	of direct costs (DC)	130,945
Performance test	1%	Engineering estimate	50,000
Model Studies	NA	of direct costs (DC)	N/A
Contingencies	20%	of direct costs (DC) and indirect costs (IC) above	1,934,894
Total Indirect Capital Costs, IC	68%	of direct costs (DC)	**5,062,104**
Total Capital Investment (TCI) = DC + IC			**11,609,362**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Allowance for funds used during construciton	10.5%	of DC + IC	1,218,983
Total Site Specific Costs			**1,218,983**
TCI with site specifics for capital recovery cost			**12,828,344**
Total Capital Investment (TCI) with Retrofit Factor	0%	No retrofit factor needed based on site-specific analysis	**12,828,344**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Maintenance labor and materials	3%	of direct capital (DC) costs	196,418
Utilities, Supplies, Replacements & Waste Management			
Replacement power from efficiency loss	NA	0.2% OFA efficiency drop per engineering estimates	81,567
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**277,985**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	117,851
Administration (2% total capital costs)	2%	of total capital costs (TCI)	256,567
Property tax (1% total capital costs)	N/A	of total capital costs (TCI)	0
Insurance (1% total capital costs)	N/A	Already included in costs above	0
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	1,073,467
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,447,885**
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 Engineering Vendor — **Operating Hours** 5,774; **Utilization Rate:** 78%

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual 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? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.6

* 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)? 765 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,826 Btu/lb

*HHV value of 8826 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 390,363,222 lbs/year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.41 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

*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

*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:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	241	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.58	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.44	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	0.80	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation: 764 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 Control Cost Manual (as updated March 2019).

Densities of typical SNCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

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
Annual Interest Rate (i)	5.50	Percent*
Fuel ($Cost_{fuel}$)	2.13	$/MMBtu
Reagent ($Cost_{reag}$)	1.81	$/gallon for a 50 percent solution of urea
Water ($Cost_{water}$)	0.0051	$/gallon
Electricity ($Cost_{elect}$)	0.0760	$/kWh
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	42.56	$/ton

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/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 ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: 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 Demand. July 11, 2017. Available at: 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 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)	5.84	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)	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/.	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	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_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.34	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5774	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	25	percent
Coal Factor ($Coal_F$) =	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 =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03	
Atmospheric pressure at 764 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ 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.

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 ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	232	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	464	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	48.9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	16,500	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	16.7	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	223	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.88	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/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:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,632,583	in 2020 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2020 dollars
Balance of Plant Costs (BOP_{cost}) =	$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 ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,632,583	in 2020 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 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_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$4,227,360	in 2020 dollars

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} x $Cost_{reag}$ x t_{op} =	$512,408 in 2020 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$7,337 in 2020 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$6,591 in 2020 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$23,099 in 2020 dollars
Additional Ash Cost =	ΔAsh 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_x Control - Selective Catalytic Reduction

Operating Unit: **Power Boiler 2**

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 Correlation							
Total Capital Investment (TCI) with Retrofit								55,724,684
								55,724,684
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						**1,316,135**
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						**4,669,232**
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**5,985,367**

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)
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			
SCR Capital Costs (SCRcost)		*Refer to the SCR Cost Estimate tab*	32,318,901
Reagent Preparation Costs (RPC)		*Refer to the SCR Cost Estimate tab*	4,392,698
Air Pre-Heater Costs (APHC)		*Refer to the SCR Cost Estimate tab*	-
Balance of Plant Costs (BPC)		*Refer to the SCR Cost Estimate tab*	6,153,542
Retrofit factor	60%	*of TCI, see SCR Cost Estimate tab*	
Total Capital Investment (TCI)			**55,724,684**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Maintenance			
Annual Maintenance Cost =		*Refer to the SCR Cost Estimate tab*	278,623
Utilities, Supplies, Replacements & Waste Management			
Annual Electricity Cost =		*Refer to the SCR Cost Estimate tab*	191,978
Annual Catalyst Replacement Cost =		*Refer to the SCR Cost Estimate tab*	308,662
Annual Reagent Cost =		*Refer to the SCR Cost Estimate tab*	536,872
Total Annual Direct Operating Costs			**1,316,135**
Indirect Operating Costs			
Administrative Charges (AC) =		*Refer to the SCR Cost Estimate tab*	5,076
Capital Recovery Costs (CR)=	0.0837	*Refer to the SCR Cost Estimate tab*	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 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	

Replacement Catayst - Refer to the SCR Cost Estimate Tab

Reagent Use
Refer to the SCR Cost Estimate tab

Operating Cost Calculations	**Annual hours of operation:**	**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_x 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 ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), 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

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.6

* 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)? 765 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,826 Btu/lb

*HHV value of 8826 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 390,363,222 lbs/year

Operating Hours 5,774 323,950,000.00

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 764 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.41 percent by weight

*The sulfur content of 0.41% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ● Method 2
- ○ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	241	days
Number of days the boiler operates (t_{plant})	241	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.58	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.12	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	355,523	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

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 ($Cost_{reag}$)	1.814	$/gallon for 50% urea			
Electricity ($Cost_{elect}$)	0.0760	$/kWh			
Catalyst cost ($CC_{replace}$)	248.05	$/cubic foot (includes removal and disposal/regeneration of existing 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) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf	
Electricity Cost ($/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.	
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/.	
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/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/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_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_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.514	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5,774	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	80.0	percent
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	355,523	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	106.69	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03	
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	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)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.2303	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B 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 ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	370	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst}))$ + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	426	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	20.6	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (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^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	243	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	487	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	51	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ 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 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	437.48	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$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_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$32,318,901 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$4,392,698 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 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.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$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 Maintenance Cost =	0.005 x TCI =	$278,623	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$536,872	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$191,978	in 2019 dollars
Annual Catalyst Replacement Cost =		$308,662	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2 selected.	
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) 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 cost (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 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 Factor			**37,737,598**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,925,055
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	5,017,989
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**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) [1]			**8,933,488**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	893,349
State Sales Taxes	6.9%	of control device cost (A)	614,177
Freight	5%	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	50%	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			**8,056,889**
Total Direct Capital Cost, DC			**18,944,577**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,088,769
Construction & field expenses	20%	of purchased equip cost (B)	2,177,538
Contractor fees	10%	of purchased equip cost (B)	1,088,769
Start-up	1%	of purchased equip cost (B)	108,877
Performance test	1%	of purchased equip cost (B)	108,877
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	1,088,769
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**5,661,598**
Total Capital Investment (TCI) = DC + IC			**24,606,175**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for 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 Management			
Electricity	0.08	$/kwh, 252.1 kW-hr, 5774 hr/yr, 78% utilization	110,610
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization	60,382
N/A			-
Solid Waste Disposal	42.56	$/ton, 0.6 ton/hr, 5774 hr/yr, 78% utilization	115,574
Trona	285.00	$/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			250,000
N/A			-
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)	2%	of total capital costs (TCI)	754,752
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	377,376
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	377,376
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	3,157,857
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**5,017,989**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**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:	**Filter 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 adjusted for freight, sales tax, and bag disposal
Installation Labor	68,237	20 min per bag
Total Installed Cost	**1,020,177**	
Annualized Cost	**238,901**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	232,100	6.00	1,455,398	Electricity for new baghouse
Total			1,455,398	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	270.18	lb/hr SO2	1501.10	lb/hr Trona
Solid Waste Disposal	3,481	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	78%	Annual Operating Hours		5,774			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	60.00	$/Hr	2.0	hr/8 hr shift	1,444	$ 86,610	$/Hr, 2.0 hr/8 hr shift, 1,444 hr/yr
Supervisor	15%	of Op Labor			NA	$ 12,992	% of Operator Costs
Maintenance							
Maint Labor	60.00	$/Hr	1.0	hr/8 hr shift	722	$ 43,305	$/Hr, 1.0 hr/8 hr shift, 722 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 43,305	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.076	$/kwh	252.1	kW-hr	1,455,398	$ 110,610	$/kwh, 252.1 kW-hr, 5774 hr/yr, 78% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	125,438	$ 60,382	$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	42.56	$/ton	0.6	ton/hr	2,716	$ 115,574	$/ton, 0.6 ton/hr, 5774 hr/yr, 78% utilization
Trona	285.00	$/ton	1,501.1	lb/hr	3,380	$ 963,375	$/ton, 1,501.1 lb/hr, 5774 hr/yr, 78% utilization
Filter Bags	249.27	$/bag	3,412	bags	N/A	$ 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 002		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
			Dry Std Flow Rate	145,700	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**22,495,853**
Purchased Equipment Total (B)	22%	of control device cost (A)	**27,416,821**
Installation - Standard Costs	74%	of purchased equip 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 equip 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, supervision, materials, replacement parts, utilities, etc.	1,162,688
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	12,410,221
Total Annual Cost (Annualized Capital Cost + Operating 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
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. 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)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**22,495,853**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC			
Instrumentation	10%	of control device cost (A)	2,249,585
State Sales Taxes	6.9%	of control device cost (A)	1,546,590
Freight	5%	of control device cost (A)	1,124,793
Purchased Equipment Total (B)	22%		**27,416,821**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	1,096,673
Handling & erection	50%	of purchased equip cost (B)	13,708,410
Electrical	8%	of purchased equip cost (B)	2,193,346
Piping	1%	of purchased equip cost (B)	274,168
Insulation	7%	of purchased equip cost (B)	1,919,177
Painting	4%	of purchased equip cost (B)	1,096,673
Installation Subtotal Standard Expenses	74%		**20,288,447**
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			NA
Installation Total			**20,288,447**
Total Direct Capital Cost, DC			**47,705,268**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,741,682
Construction & field expenses	20%	of purchased equip cost (B)	5,483,364
Contractor fees	10%	of purchased equip cost (B)	2,741,682
Start-up	1%	of purchased equip cost (B)	274,168
Performance test	1%	of purchased equip cost (B)	274,168
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	2,741,682
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**14,256,747**
Total Capital Investment (TCI) = DC + IC			**61,962,015**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**60,941,838**
Total Capital Investment (TCI) with Retrofit Factor	60%		**97,506,941**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	60.00	$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr	86,610
Supervisor	15%	15% of Operator Costs	12,992
Maintenance			
Maintenance Labor	60.00	$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr	43,305
Maintenance Materials	100%	of maintenance labor costs	43,305
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization	184,350
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization	60,382
N/A			-
SW Disposal	42.56	$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization	66,408
Lime	167.17	$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization	176,434
Filter Bags	249.27	$/bag, 3,412 bags, 5774 hr/yr, 78% utilization	238,901
Lost Revenue - Fly Ash			250,000
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,162,688**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	111,727
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,950,139
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	975,069
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	975,069
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	8,398,217
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**12,410,221**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**13,572,909**

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		
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	3412	# of Bags for new baghouse	
Total Rep Parts Cost	951,939	Cost adjusted for freight & sales tax	
Installation Labor	68,237	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**1,020,177**	**Zero out if no replacement parts needed**	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	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	365.58	lb/hr Lime
Solid Waste Disposal	1,560	ton/yr unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	78%	Annual Operating Hours	5,774

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	60.00	$/Hr	2.0	hr/8 hr shift	1,444	$	86,610	$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr
Supervisor	15%	of Op.			NA	$	12,992	15% of Operator Costs
Maintenance								
Maint Labor	60.00	$/Hr	1.0	hr/8 hr shift	722	$	43,305	$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	$	43,305	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.076	$/kwh	420.1	kW-hr	2,425,663	$	184,350	$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	125,438	$	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	$	66,408	$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization
Lime	167.17	$/ton	365.6	lb/hr	1,055	$	176,434	$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization
Filter Bags	249.27	$/bag	3,412	bags	N/A	$	238,901	$/bag, 3,412 bags, 5774 hr/yr, 78% utilization

Appendix C

Submittals to MPCA Regarding Indurating Furnaces 11 and 12

CLIFFS

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_X and SO_2 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 NO_x and SO_2.

Table 1: Identified Emission Units

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

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_x and SO_2. 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)[1].

In Section II.B.3.f of the 2019 RH SIP Guidance[2], 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."*[3]

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*"[4] to make reasonable progress towards reducing visibility impairments at Class I areas.

Section II.B.4.h. of the 2019 RH SIP Guidance[5] 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"

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[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019
[2] Ibid, page 11.
[3] Ibid, page 22.
[4] Ibid, page 23.
[5] Ibid, page 28.

for the associated pollutants.[6] The USEPA notes, "*it may be unlikely that there will be further available reasonable controls for such sources.*"[7] 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.*"[8] 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_2 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 high-energy 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_2 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_2/hr for both furnaces combined were established in the final Federal Implementation Plan (FIP) dated February 6, 2013[9]. The BART limits from the FIP are shown in Table 2.

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[6] Ibid, page 25.
[7] Ibid.
[8] Ibid.
[9] Federal Register/ Vol. 78. No. 25, February 6, 2013, EPA-R05-OAR-2010-0037 beginning on page 8706.

Table 2 BART NOx and SO_2 Emission Limits

Unit	Unit ID	NOx Limit (lb/MMBtu)	SO_2 Limit (lb/hr)
Indurating Furnace 11	EQUI 126 & EQUI 127/ EU100 & EU104	1.2-1.5	39
Indurating Furnace 12	EQUI 128 & EQUI 129 / EU110 & EU1114		

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_2 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_2 to one to two parts per million in the exhaust. The USEPA concluded in the 2013 FIP.[10] that because Northshore is burning natural gas and fuel oil, additional SO_2 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_2 control measures and is complying with the FIP SO_2 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_2.

The indurating furnaces meet the USEPA's scenario for effectively controlled units because:

[10] 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_2
- In 2013, EPA promulgated a FIP that included, among other things, BART requirements to effectively control NOx and SO_2 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,

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.[1] 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][2]. 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,

[1] Approval and Promulgation of Implementation Plans; States of Minnesota and Michigan; Regional Haze Federal Implementation Plan. 77 Fed. Reg. 49308. (proposed August 15, 2012).
[2] https://www.pca.state.mn.us/sites/default/files/bart-facility-northshore.pdf

- 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[3]

NO_X Control Measure	Technically Feasible for Straight-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 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.[4] 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

[3] Ibid., 49315.

[4] 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).

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_2 BART Analysis

Both furnaces are controlled by wet-walled electrostatic precipitators (WWESP) using caustic reagent. The following SO_2 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_2 Emission Control Measures Technical Feasibility Conclusions[5]

SO_2 Control Measure	Technically Feasible for Straight-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 cost-effectiveness. “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_2 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_2 removed.”[6] 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.

[5] 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.
[6] Ibid.

In the final Taconite FIP, EPA established an aggregate SO_2 limit of 39.0 lbs/hr on a 30-day rolling average for the furnaces when natural gas is used as fuel[7]. The BART limit is based on the WWESPs already installed on the furnaces.

SO_2 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_2 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,

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

[7] 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

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

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_2 Emissions Control

Sappi Cloquet LLC submits the attached Four-Factor Analysis for NOx and SO_2 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_2 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 Emissions Control Measure	Factor 1 – Cost of 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 Hassan.Bouchareb@state.mn.us .

Please contact Alycia McWilliams at 218-879-0637 if you have any questions or comments concerning this report.

sappi

Yours sincerely

Tom Radovich
Managing Director
Cloquet Operations

sappi/999

Regional Haze Four-Factor Analysis for NO_X and SO_2 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_X and SO_2 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

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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[1] regarding the Regional Haze Rule (RHR)[2] and the state's requirement to make reasonable progress on visibility improvement at nearby Class I areas.[3] As required by the RFI, the report presents the emissions reduction evaluation for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) from Power Boiler #9 (EQUI 4 / EU 004) and for NO_X 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[4] (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_X and SO_2, respectively. These analyses demonstrate that the installation of additional control equipment NO_X and SO_2 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

[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to Sappi

[2] 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).

[3] 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

[4] 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"[5] 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."[6] 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."[7] 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 1-1: Projected 2028 NO_X Emissions (tons per year)

Year	Source	Pollutant	Annual Emissions
2019 Actual Emissions And 2028 Projected Emissions	Power Boiler #9	NO_X	347 tons/year
	Power Boiler #9	SO_2	22 tons/year
	Recovery Boiler #10	NO_X	680 tons/year

[5] Ibid, Page 22.

[6] Ibid, Page 23.

[7] Ibid, page 29.

Table 1-2: Summary of NO_X Four-factor Analysis

Emission Reduction Technology	Factor 1 – Cost of Compliance	Factor 2 – Time Necessary for Compliance	Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance	Factor 4 – Remaining Useful Life of the Source	Factor 5 – Visibility Improvements	Does this Analysis Support the Installation of this Emission Reduction Technology?
SCR	$9,493/ton	3 years after SIP approval	• Catalyst plugging could lead to decreased control efficiency, decreased catalyst life, and additional boiler downtime • Increased truck and/or train traffic (reagent and catalyst deliveries) • Possible ammonia slip (unreacted reagent that is emitted to the atmosphere) • Increased natural gas burning to reheat flue gas to achieve SCR inlet temperatures • Catalyst regeneration • Catalyst disposal • Electricity consumption (fans and pumps)	No shutdown or rebuild of Power Boiler #9 is anticipated	Unlikely	No
SNCR	$7,191/ton	3 years after SIP approval	• Increased truck and/or train traffic (reagent deliveries) • Possible ammonia slip (unreacted reagent that is emitted to the atmosphere) • Nitrous oxide (N2O) generation (a greenhouse gas) • Electricity consumption (fans and pumps)	No shutdown or rebuild of Power Boiler #9 is anticipated	Unlikely	No

Table 1-3: Summary of SO_2 Four-factor Analysis

List of Emission Reduction Technology	Factor 1 – Cost of Compliance	Factor 2 – Time Necessary for Compliance	Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance	Factor 4 – Remaining Useful Life of the Source	Factor 5 – Visibility Improvements	Does this Analysis Support the Installation of this Emission Reduction Technology?
Spray dryer	$1,589,900	3 years after SIP approval	• Increased waste generation and disposal due to additional material collected in the particulate emissions control system • Increased truck and/or train traffic (reagent deliveries and waste hauling) • Water consumption for slurry • Electricity consumption (fans and pumps) • Wastewater generation and disposal	No shutdown or rebuild of Power Boiler #9 is anticipated	Unlikely	No
Dry sorbent injection	$5,672,396	3 years after SIP approval	• Increased waste generation and disposal due to additional material collected in the particulate emissions control system • Increased truck and/or train traffic (reagent deliveries and waste hauling) • Electricity consumption (fans and pumps)	No shutdown or rebuild of Power Boiler #9 is 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_2 and NO_X. 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_X and SO_2 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.

Table 2-1: Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Recovery Boiler #10	EQUI 53 / EU 005	NO_X
Power Boiler #9	EQUI 4 / EU 004	NO_X, SO_2

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_2SO_4), 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_X and SO_2 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_X 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.

Table 2-2: Power Boiler #9 – NO_X and SO_2 Permit Limits

Pollutant	Condition	Limit	Basis of Limit
NO_X	5.9.8	Nitrogen Dioxide <= 151.10 pounds per hour 30-day rolling average.	Prevention of Significant Deterioration (PSD) modeling
NO_X	5.9.9	Nitrogen Dioxide <= 0.20 to 0.70 pounds per million Btu heat input 3-hour rolling average. [Based on fuel mix]	New Source Performance Standards (NSPS) Subpart D
NO_X	5.9.10	Nitrogen Oxides <= 200.0 pounds per hour.	PSD modeling
SO_2	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_2	5.9.12	Sulfur Dioxide <= 0.80 pounds per million Btu heat input 3-hour rolling average while burning fuel oil or fuel oil and wood. While burning coal, wood, or coal and wood, SO_2 must be less than or equal to 1.2 lb/mmBtu. These limits also apply if natural gas is being burned in combination with these fuels. [Formula for other fuel mixes] All emission limits shall be determined on a 3-hour rolling average basis. NCG is not considered a fuel, and the contribution from burning NCGs is to be disregarded when determining compliance with this limit.	NSPS Subpart D

The NO_X 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_X controls but does use quaternary air injection to manage the generation of NO_X.

Table 2-3: Recovery Boiler #10 – NO_X Permit Limits

Pollutant	Condition	Limit	Basis of Limit
NO_X	5.17.11	Nitrogen Dioxide <= 100 parts per million 30-day rolling average by volume (dry) corrected to 8% oxygen.	BACT limit
NO_X	5.17.12	Nitrogen Dioxide <= 226.5 pounds per hour 30-day rolling average.	MPCA limit
NO_X	5.17.13	Nitrogen Dioxide <= 241.0 pounds per hour 30-day rolling average.	PSD modeling
NO_X	5.17.14	Nitrogen Oxides <= 241.0 pounds per hour 1-hour average.	BACT limit
NO_X	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 Subpart Db

3 Power Boiler #9: Four-factor Analysis

3.1 NO_X 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."[8] 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."[9] This section addresses the selection of emission control options for NO_X 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)[10] 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 (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.

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[8] Ibid, page 28.

[9] Ibid, Page 29.

[10] RACT/BACT/LAER Clearinghouse (RBLC) as maintained by USEPA (link to RBLC website)

Table 3-1: Biomass Power Boiler RBLC Summary – NO_X

RBLC ID	Technology
CT-0156	Regenerative SCR (RSCR)
AR-0161 KS-0034	Selective Catalytic Reduction (SCR)
CA-1203 CA-1225 GA-0141 ME-0037	Selective Non-Catalytic Reduction (SNCR)
AL-0250	Low NO_X 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_X burners were not considered in the four factor analysis because:

- Low NO_X 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_X emissions. This technology is not feasible for the stoker grate hog fuel boiler at Sappi.

- Low NO_X 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_X burners for natural gas and/or distillate oil would have a minor impact on NO_X 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."[11] 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_X 2028 emissions, but Sappi proposes to revise the projected emissions as shown in Table 3-2.

Table 3-2: Projected 2028 NO_X Emissions (tons per year)

Year	Power Boiler #9
2019 Actual Emissions And 2028 Projected Emissions	347 tons/year

3.1.3 Factor 1 – Cost of Compliance

Sappi has completed compliance cost estimates for the selected NO_X emission control measures following EPA's Control Cost Manual as recommended in the 2019 SIP Guidance.[12] 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_X 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.

Table 3-3: Power Boiler #9 NO_X Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Total Capital Investment ($)	Total Annualized Costs ($/year)	Control Efficiency (%)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/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

[11] Ibid, page 29.

[12] Ibid, Page 21.

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_X 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_X control measures are summarized below.

- SCR
    - Catalyst plugging could lead to decreased control efficiency, decreased catalyst life, and additional boiler downtime
    - Increased truck and/or train traffic (reagent and catalyst deliveries)
    - Possible ammonia slip (unreacted reagent that is emitted to the atmosphere)
    - Increased natural gas burning to reheat flue gas to achieve SCR inlet temperatures
    - Catalyst regeneration
    - Catalyst disposal
    - Electricity consumption (fans and pumps)

- SNCR
    - Increased truck and/or train traffic (reagent deliveries)
    - Possible ammonia slip (unreacted reagent that is emitted to the atmosphere)
    - Nitrous oxide (N_2O) 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_X Controls and Emissions Rates

This analysis does not support the installation of additional NO_X 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_2 Four-factor Analysis – Power Boiler #9

This section identifies baseline emission rates and evaluates the four statutory factors for SO_2 emissions from Power Boiler #9.

3.2.1 Emission Control Options

The selection of SO_2 emission control options followed the same methodology as described in Section 3.1.1.

The RBLC search for biomass power boilers for SO_2 is presented in Appendix C and a summary is provided in Table 3-4.

Table 3-4: Biomass Power Boiler RBLC Summary – SO_2

RBLC ID	Technology
CT-0162	Spray Dryer
AR-0161 GA-0141 KS-0034	Dry Sorbent Injection
CT-0156 LA-0249 ME-0037	Low Sulfur Fuels

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_2 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_2 emissions in 2028 will equal 2019 actual emissions. LADCO estimated 54.18 tpy for 2028 SO_2 emissions, but Sappi proposes to revise the projected emissions as shown in Table 3-5.

Table 3-5: Projected 2028 SO_2 Emissions (tons per year)

Year	Power Boiler #9
2019 Actual Emissions And 2028 Projected Emissions	22 tons/year

3.2.3 Factor 1 – Cost of Compliance

Sappi has completed compliance cost estimates for the selected SO_2 emission control measures following EPA's Control Cost Manual as recommended in the 2019 SIP Guidance.[13] 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_2 emission control measures are provided in Appendix C.

[13] 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.

Table 3-6: Power Boiler #9 SO_2 Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Total Capital Investment ($)	Total Annualized Costs ($/year)	Control Efficiency (%)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
Spray dryer absorption	$144,535,337	$24,484,747	70%	15.4	$1,589,900
Dry sorbent injection	$41,178,526	$5,672,396	50%	11.0	$5,672,396

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_2 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_2 control measures are summarized below:

- Spray Dryer
    - Increased waste generation and disposal due to additional material collected in the particulate emissions control system
    - Increased truck and/or train traffic (reagent deliveries and waste hauling)
    - Water consumption for slurry
    - Electricity consumption (fans and pumps)

- Dry Sorbent injection
    - Increased waste generation and disposal due to additional material collected in the particulate emissions control system
    - Increased truck and/or train traffic (reagent deliveries and waste hauling)
    - 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_2 Controls and Emissions Rates

This analysis does not support the installation of additional SO_2 emission control measures at Power Boiler #9 beyond those described in Section 2.3. As such, Sappi proposes to maintain the existing SO_2 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"[14] 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."[15] 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.[16] EPA notes that the BACT control equipment review methodologies are "similar to, if not more stringent than, the four statutory factors for reasonable progress."[17]

Recovery Boiler #10 underwent a BACT review for NO_x, 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_X permit limits presented in Table 2-3.

[14] Ibid, Page 22.

[15] Ibid, Page 23.

[16] Ibid, Page 23.

[17] Ibid, Page 23.

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."[18] This is used to establish progress goals to be achieved by the end of the implementation period in 2028.[19] 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.[20] In addition, the 2019 SIP Guidance says that a state can consider visibility impacts in Class I areas when evaluating possible emission control measures.[21] 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).[22] 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.[23] Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms)

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[18] 40 CFR 51.308(f)(1)

[19] 40 CFR 51.308(f)(3)

[20] Ibid, Page 13.

[21] Ibid, Page 34.

[22] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[23] https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."[24]

Figure 5.1 through Figure 5.3 show the rolling 5-year average visibility impairment compared with the URP glidepath[25] 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.

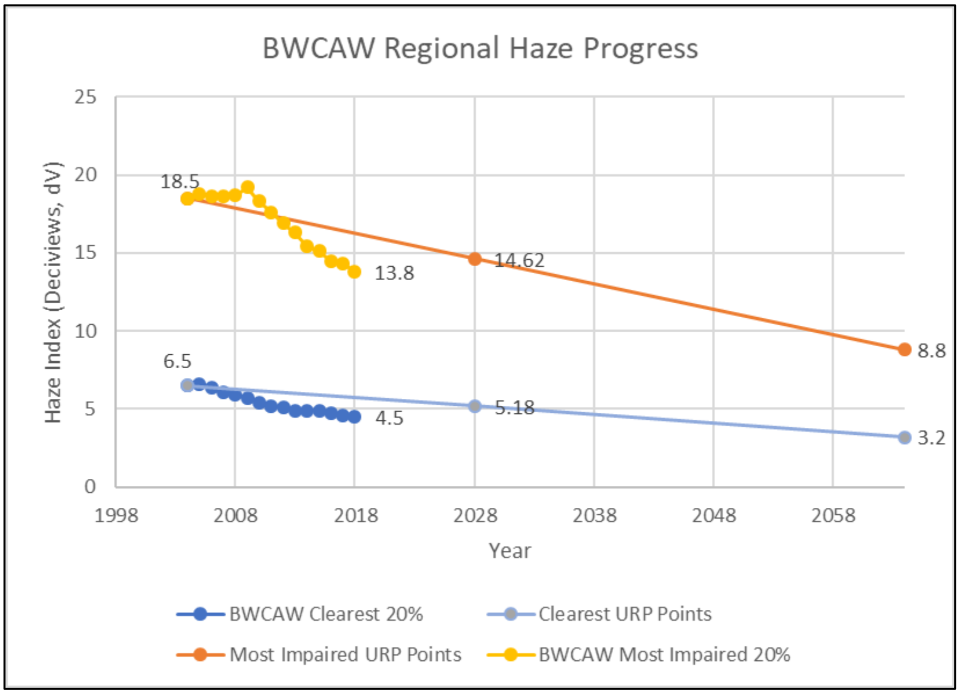

Figure 5.1: Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

[24] USEPA, Federal Register, 05/04/2016, Page 26948

[25] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

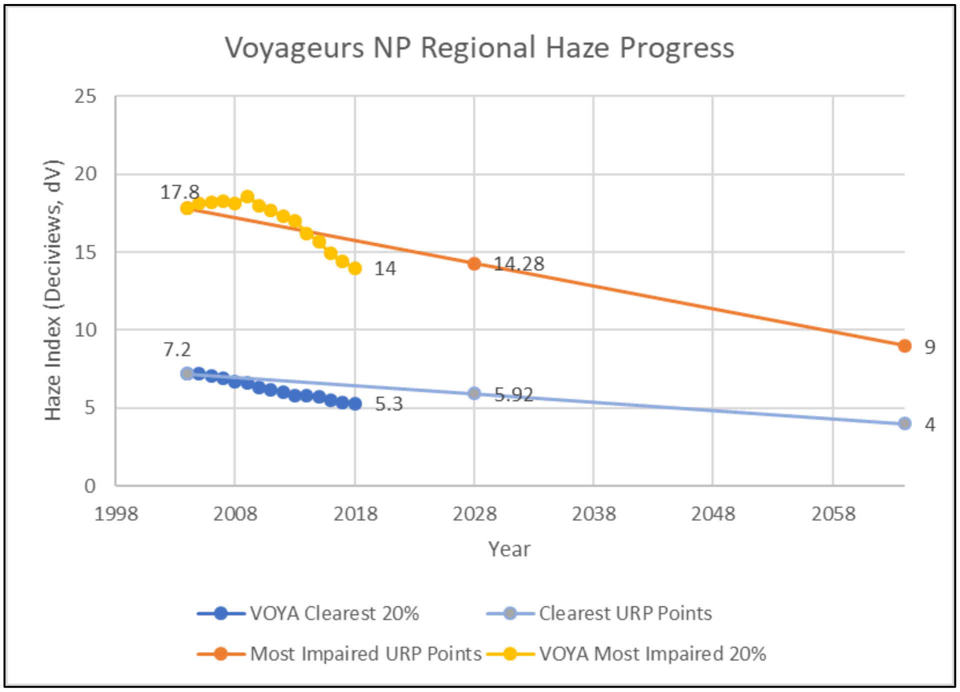

Figure 5.2: Visibility Trend versus URP – Voyageurs National Park (VOYA1)

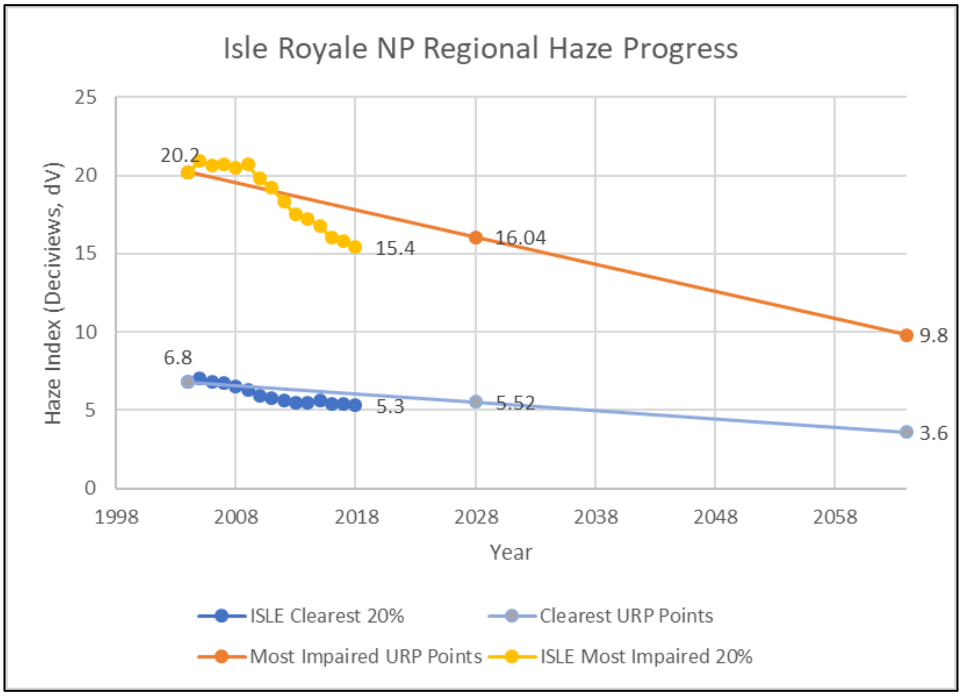

Figure 5.3: Visibility Trend versus URP – Isle Royale National Park (ISLE1)

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)

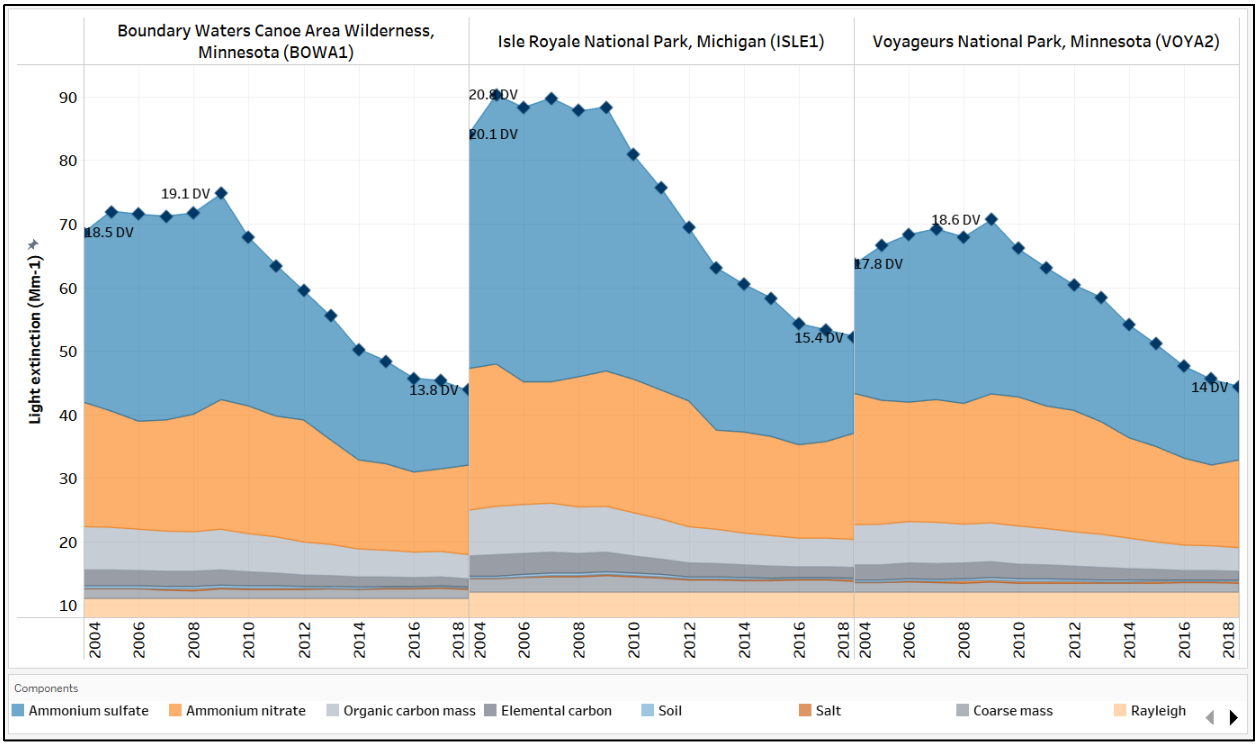

Figure 5.4: Visibility Components Trend for each Class 1 Monitor from 2004-2018[26]

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

[26] 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_X 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.[27] 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.[28] In addition, the 2019 Guidance says that a state can consider visibility impacts in Class I areas when evaluating possible emission control measures.[29] 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[30] 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.[31] 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

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[27] Ibid, Page 9.

[28] Ibid, Page 12.

[29] Ibid, Page 34.

[30] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[31] https://www.arl.noaa.gov/hysplit/hysplit/

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.

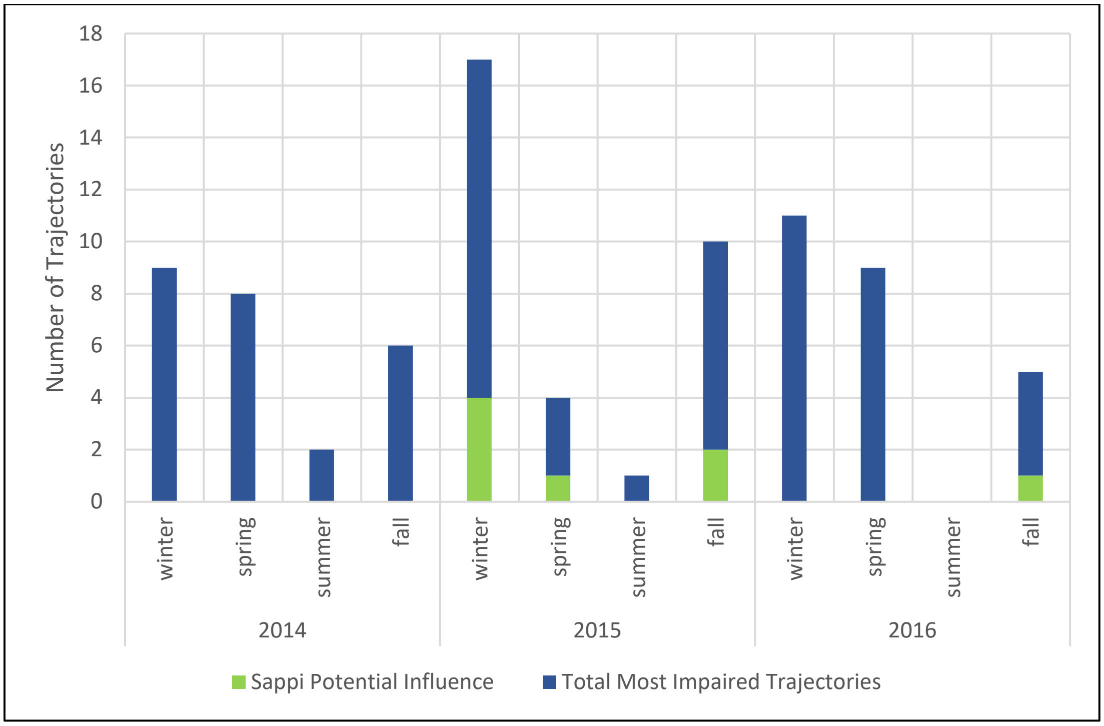

Figure 5.5: Total Number of Most Impaired Trajectories and Number that Cross Near Sappi for 2014-2016

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_X

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 NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0250	BOISE WHITE PAPER	BOISE WHITE PAPER, LLC	AL	102-0001	322121	03/23/2010 ACT		COMBINATION BOILER	WOOD	435	MMBTU/H	Nitrogen Oxides (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 Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base	Power Boiler	Biomass	1200	MMBtu/hr	Nitrogen Oxides (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 STOKER BOILER - Transient Period (see notes)	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	102	PPM	@12% CO2, 8-HR 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 STOKER BOILER	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	80	PPM	@12% CO2, 8-HR ROLLING AVG	BACT-PSD	50.75	LB/H	8-HR ROLLING AVG	0		
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	SIERRA PACIFIC INDUSTRIES	CA	SAC 12-01	321113	04/25/2014 ACT	31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY	STOKER BOILER (NORMAL OPERATION)	BIOMASS	468	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.13	LB/MMBTU	12-MONTH ROLLING BASIS	BACT-PSD	0.15	LB/MMBTU	3-HOUR BLOCK AVERAGE	0		
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	SIERRA PACIFIC INDUSTRIES	CA	SAC 12-01	321113	04/25/2014 ACT	31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY	STOKER BOILER (STARTUP & SHUTDOWN PERIODS)	BIOMASS	468	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	70.2	LB/H	8-HR AVG (STARTUP PERIODS)	BACT-PSD	70.2	LB/H	8-HR AVG (SHUTDOWN PERIODS)	0		
CT-0156	MONTVILLE POWER LLC	NRG ENERGY	CT	107-0056	221119	04/06/2010 ACT	43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL CAPACITY FACTOR)	42 MW Biomass utility boiler	Clean wood	600	MMBTU/H	Nitrogen Oxides (NOx)	Regenerative SCR	0.06	LB/MMBTU	24 HR BLOCK	LAER	0			0		
CT-0162	PLAINFIELD RENEWABLE ENERGY, LLC	PLAINFIELD RENEWABLE ENERGY, LLC	CT	145-0049	221119	12/29/2010 ACT	37.5 MW Biomass Power Plant	Fluidized Bed Gasification	Wood	523.1	MMBtu/hr	Nitrogen Oxides (NOx)	SNCR	0.075	LB/MMBTU		LAER	45.3	PPMVD @7% O2	24 HR BLOCK	0		
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	OGETHORPE POWER CORPERATION	GA	4911-301-0016-P-01-0	221119	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 water pump emergency engines; a raw material handling & storage area; a sorbent storage silo; a boiler bed sand silo, a sand	Boiler, Biomass Wood	Biomass wood	100	MW	Nitrogen Oxides (NOx)	Selective non-catalytic reduction system (SNCR)	0.1	LB/MMBTU	30 D ROLLING AV / CONDITION 2.9	BACT-PSD	648	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.18	0		
*KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	C-11396	325193	05/27/2014 ACT	Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and operate a biomass-to-ethanol and biomass-to-energy production facility near Hugoton, Kansas.	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction System (SCR) and an over-fire system (OFA)	0.3	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	BACT-PSD	157.5	LB/HR	1-HR AVE, 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 making facility.	Biomass Boiler 8	Biomass	814	MMBTU/H	Nitrogen Oxides (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_X

Sappi Cloquet LLC

Boiler #9

Appendix B - NO_X SNCR Calculations

	Boiler 9		Comment
Max Firing Rate	430	MMBtu/hr	PTE Calculations for Boiler 9
NO_X Emission Rate (Uncontrolled)	0.292	lb/MMBtu	2019 Emission Inventory
System Capacity Factor (Actual rate vs. max firing rate at 8760)	63.1%		2019 actual fuel per year / Maximum fuel per year (See "SCR Design Parameters")
Uncontrolled Emissions	347.0	ton/year	Calculated from Above
Control Efficiency	25.0%		From "Data Inputs"
NO_X Controls Emission Rate	0.219	lb/MMBtu	Calculated from Above
Controlled Emissions	260.3	ton/year	Calculated from Above
Total Capital Investment (TCI)	$5,021,391		From "Cost Estimate"
Total Annual Cost (TAC) =	$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? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.33

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 430.0 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 4,597 Btu/lb

What is the estimated actual annual fuel consumption? 536,062,322 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite

Enter the sulfur content (%S) = 0.05 percent by weight

or

Select the appropriate SO_2 emission rate: < 3lb/MMBtu

Ash content (%Ash): 2.8 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	352	days	Plant Elevation	1083	Feet above sea level
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.292	lb/MMBtu	25.0% Control Efficiency		
Outlet NO_x Emissions (NOx_{out}) from SNCR	0.219	lb/MMBtu			
Estimated Normalized Stoichiometric Ratio (NSR)	3.02				

Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

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 ($Cost_{fuel}$)	1.74	$/MMBtu*			
Reagent ($Cost_{reag}$)	0.29	$/gallon for a 29 percent solution of ammonia			
Water ($Cost_{water}$)	0.0042	$/gallon*			
Electricity ($Cost_{elect}$)	0.0676	$/kWh*			
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*			

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 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.	
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: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.82	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at 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_B) =	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_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.631	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5527	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	25	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	31.39	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	86.75	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04	
Atmospheric pressure at 1083 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	141	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	485	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	64.8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	21,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	17.9	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	110	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.14	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/HHV =	6.9	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:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$3,862,609	in 2020 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2020 dollars
Balance of Plant Costs (BOP_{cost}) =	$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 ($SNCR_{cost}$)		
SNCR Capital Costs ($SNCR_{cost}$) =	$3,862,609	in 2020 dollars (Jansen report 2012 equipment scaled to 2020 $)

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 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_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$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} x $Cost_{reag}$ x t_{op} =	$104,863 in 2020 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$6,670 in 2020 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$2,544 in 2020 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$10,951 in 2020 dollars
Additional Ash Cost =	ΔAsh 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_2

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 NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*AR-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 Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production 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	CT	107-0056	221119	04/06/2010 ACT	43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL CAPACITY FACTOR)	42 MW Biomass 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	CT	145-0049	221119	12/29/2010 ACT	37.5 MW Biomass Power Plant	Fluidized Bed Gasification	Wood	523.1	MMBtu/hr	Sulfur Dioxide (SO2)	Spray Dryer, Bed Injection	0.035	LB/MMBTU		OTHER CASE-BY-CASE	15.4	PPMVD @7% O2	3 HR BLOCK	0		
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	OGETHORPE POWER CORPERATION	GA	4911-301-0016-P-01-0	221119	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 water pump emergency engines; a raw material handling & storage area; a sorbent storage silo; a boiler bed sand silo, a sand	Boiler, Biomass Wood	Biomass wood	100	MW	Sulfur Oxides (SOx)	Dust sorbent injection system	0.01	LB/MMBTU	30 D ROLLING AV / CONDITION 2.12	BACT-PSD	56	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.20	0		
*KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	C-11396	325193	05/27/2014 ACT	Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and operate a biomass-to-ethanol and biomass-to-energy production facility near Hugoton, Kansas.	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Sulfur Dioxide (SO2)	Injection of sorbent (lime) in combination with a dry flue gas desulfurization (FGD) system	0.21	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	BACT-PSD	110.25	LB/HR	MAX 1-HR, INCLUDES SS, EXCLUDES 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 FUEL BOILER	HOGGED FUEL/BARK	992.43	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	60	LB/H	HOURLY MAXIMUM	BACT-PSD	262.8	T/YR	ANNUAL MAXIMUM	0.06	LB/MMBTU	
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 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_2

Sappi Cloquet LLC

Appendix D, Table 1 - Unit Summary

Unit	**Boiler 9**	
Maximum Hourly Heat Input Rate	430	MMBtu/hr
Exhaust Flow Rate	271,905	acfm
Exhaust Temperature	413	º 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 Absorption**	**Dry Sorbent Injection**
Expected Equipment Life (years)		20	20
SO_2 Control Efficiency		70%	50%
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)	[3]	-	$5,263,766
Total Annual Cost ($/year)	[4]	$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

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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	º 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 (*permitted limit)	7.2	lb/hr
Annual Emissions	22.0	tons/yr
Volumetric Flow Rate SO2 (VFR_{SO2})	0.7	scfm SO2
Concentration SO2 (C_{SO2})	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 Lb/Hr	Annual Ton/Yr	Cont Eff %	Cont Emis Ton/Yr	Reduction Ton/Yr	Cont Cost $/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

$$TAC = (Op_{hrs})\{[(1.62x10^{-3})(F_d)]+[(6.84x10^{-7})(C_{SO2})(F_d)]+[(3.72x10^{-5})(F_a)]+21.157)\}+\{[7.2X10^{-2}+CRF]xTCI\}$$

3

Chemical Engineerig Magazine Plant Cost Index		
Historical Date/Cost Index	2008	575.4
Current Date/Cost Index	2019	591.1
Inflation Adjustment		1.03

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Appendix D, Table 3 - Dry Sorbent Injection

Operating Unit: **Boiler 9**

						Alt Op Para #1	**Alt Op Para #2**
Emission Unit Number			Stack/Vent Number				
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 Engineerig 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 program estimate			$10,690,976.67	**$16,350,417.36**
Purchased Equipment Total (B)	15%	of control device cost (A)							**$18,802,979.97**
Installation - Standard Costs	74%	of purchased 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 purchased 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, supervision, materials, replacement parts, utilities, etc.							$408,629.74
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost							$5,263,766.17
Total Annual Cost (Annualized Capital Cost + Operating Cost)									**$5,672,395.91**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual Ton/Yr**	**Calculation Method**	**Cont Eff %**	**Performance Basis**	**Conc. Units**	**Cont Emis Ton/Yr**	**Reduction Ton/Yr**	**Cont Cost $/Ton Rem**
Sulfur Dioxide (SO2)	7.18	22.00	% Removal	0.50			11.00	11.00	$515,700

Notes & Assumptions

1. 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
2. Calculations per EPA Air Pollution Control Cost Manual 6th 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

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Appendix D, Table 3 - Dry Sorbent Injection

CAPITAL COSTS

Direct Capital Costs			
Purchased Equipment (A) [1]			**$16,350,417.36**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
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)	$817,520.87
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	7%	of purchased equip cost (B)	$1,316,208.60
Painting	4%	of purchased equip cost (B)	$752,119.20
Installation Subtotal Standard Expenses	74%		**$13,914,205.17**
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/A
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)	-
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**
Total Capital Investment (TCI) = DC + IC			**$41,178,526.13**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**$41,178,526.13**

OPERATING COSTS

Direct Annual Operating Costs, DC			
Operating Labor			
Operator	34.36	$/Hr	$188,125.38
Supervisor	0.15	of Op Labor	$28,218.81
Maintenance			
Maintenance Labor	28.45	$/Hr	$93,453.65
Maintenance Materials	100	% of Maintenance Labor	$93,453.65
Utilities, Supplies, Replacements & Waste Management			
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	198.00	bags	$1,988.06
Total Annual Direct Operating Costs			**$408,629.74**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	$241,950.89
Administration (2% total capital costs)	2%	of total capital costs (TCI)	$823,570.52
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	$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		Sum indirect oper costs + capital recovery cost	**$5,263,766.17**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**$5,672,395.91**

See summary page for notes and assumptions

Sappi Cloquet LLC

Appendix D, Table 3 - Dry Sorbent Injection

Capital Recovery Factors

Primary Installation		
Interest Rate	5.25%	
Equipment Life	20	years
CRF	0.0820	

Replacement Parts & Equipment: **Filter bags & cages**

Equipment Life	5	years	
CRF	0.2326		
Rep part cost per unit	33.71	$/bag	
Amount Required	198	cages	
Total Rep Parts Cost	7,008	Cost adjusted for freight & sales tax	
Installation Labor	1,540	10 min per bag, Labor + Overhead (64%)	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**8,548**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**1,988**		

Summary of "Other" site specific Costs

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 area ft^2			0.0	EPA Cont Cost Manual 6th ed Section 6 Chapter 1 Eq 1.14
Total					492.1	

Reagent Use & Other Operating Costs

Lime Use	7.18	lb/hr SO2	0.96	lb Lime/lb SO2	6.91 lb/hr Lime
Water Makeup Rate/WW Disch =		gpm			

Baghouse Filter Cost See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs

Gross BH Filter Area	2,655 ft				
Cages	10 ft long	5 in dia	13.42 area/cage ft^2	198 Cages	11.04 $/cage
Bags	1.69	$/ft2 of fabric			22.68 $/bag
Total					33.71

Operating Cost Calculations

Utilization Rate 1% Annual Operating Hours 8,760

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*		Annual Cost	Comments
Operating Labor								
Op Labor	34.36	$/Hr	5.0	hr/8 hr shift	5,475	$	188,125	$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr
Supervisor	15%	of Op Labor			NA	$	28,219	% of Operator Costs
Maintenance								
Maint Labor	28.45	$/Hr	3.0	hr/8 hr shift	3,285	$	93,454	$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$	93,454	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.080	$/kW-h	492.1	kW-hr	30,178	$	2,408	$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization
Natural Gas	3.770	$/kscf	N/A					
Water	0.340	$/kgal	0	gpm	0	$	-	$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization
Cooling Water	0.419	$/kgal	N/A					
Compressed Air	0.479	$/kscf	2	scfm/kacfm	2,001	$	958	$/kscf, 2 scfm/kacfm, 8760 hr/yr, 0.7% utilization
Wastewater Disposal Neutralization	2.554	$/kgal	0	gpm	0	$	-	$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization
Wastewater Disposal Biotreatment	6.469	$/kgal	N/A					
Solid Waste Disposal	19.002	$/ton	0.0	ton/hr	0	$	4	$/ton, 0 ton/hr, 8760 hr/yr, 0.7% utilization
Hazardous Waste Disposal	425.608	$/ton	N/A					
Lime	95.00	$/ton	6.9	lb/hr	0	$	20	$/ton, 7 lb/hr, 8760 hr/yr, 0.7% utilization
Filter Bags	57.39	$/bag	198.0	bags	N/A	$	1,988	$/bag, 198 bags, 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_x and SO_2 Emissions Control

July 31, 2020

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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
O&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_2	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[1], Southern Minnesota Beet Sugar Cooperative (SMBSC) evaluated potential emission control measures for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) for Boiler No. 1 as part of the State's Regional Haze Rule (RHR)[2] 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[3] 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_x and SO_2 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_x and SO_2, respectively.

The NO_x four-factor analysis evaluated the following NO_x emissions control measures:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Low NO_x Burners (LNB)
- Low NO_x 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_x emission control measures are reasonable for installing on SMBSC's Boiler 1.

The SO_2 four-factor analysis evaluated the following SO_2 emissions reduction technologies:

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[1] February 14, 2020 letter from Hassan Bouchareb of MPCA to Derwood Brady of Southern Minnesota Beet Sugar Cooperative

[2] 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).

[3] 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_2 cost thresholds (refer to Sections 4.2 and 6.1.1 for more information). Therefore, none of the potential SO_2 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_x Four-Factor Analysis

List of Emission Control Measures	Factor 1 – Cost of Compliance	Factor 2 – Time Necessary for Compliance	Factor 3 - Energy and Non-Air Quality Environmental Impacts of Compliance	Factor 4 – Remaining Useful Life of the Source
Selective Catalytic Reduction with Reheat	$7,000/ton	2-3 years	Additional electricity and natural gas consumption for reheat	20 years
Low NO_x Burners	$5,100/ton	2-3 years	Reduced Thermal Efficiency	20 years
Low NO_x Burners with Over Fire Air	$3,600/ton	2-3 years	Reduced Thermal Efficiency	20 years
Selective Non-Catalytic Reduction	$3,800/ton	2-3 years	Additional electricity to operate equipment Additional fuel to evaporate water in the injected reagent Additional waste generated due to increased fuel consumption	20 years

Table 1-2: Summary of SO_2 Four-factor Analysis

List of Emission Control Measures	Factor 1 – Cost of Compliance	Factor 2 – Time Necessary for Compliance	Factor 3 - Energy and Non-Air Quality Environmental Impacts of Compliance	Factor 4 – Remaining Useful Life of the Source
Spray Dry Absorber with baghouse	$16,600/ton	2-3 years	Additional electricity use to operate equipment Solid waste disposal for spent sorbent and baghouse bags	20 years
Dry Sorbent Injection	$12,700/ton	2-3 years	Additional electricity use to operate equipment Solid waste disposal for spent 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_2 and NO_x. 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 four-factor analysis) by July 31, 2020 for the emission units identified in Table 1 as part of the State's regional haze reasonable progress.

Table 2-1: Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Boiler No. 1	EQUI17	NO_x & SO_2

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.[3]

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 sub-bituminous 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_x, SO_2, and O2.

Figure 2-1 shows a schematic representation of Boiler 1.

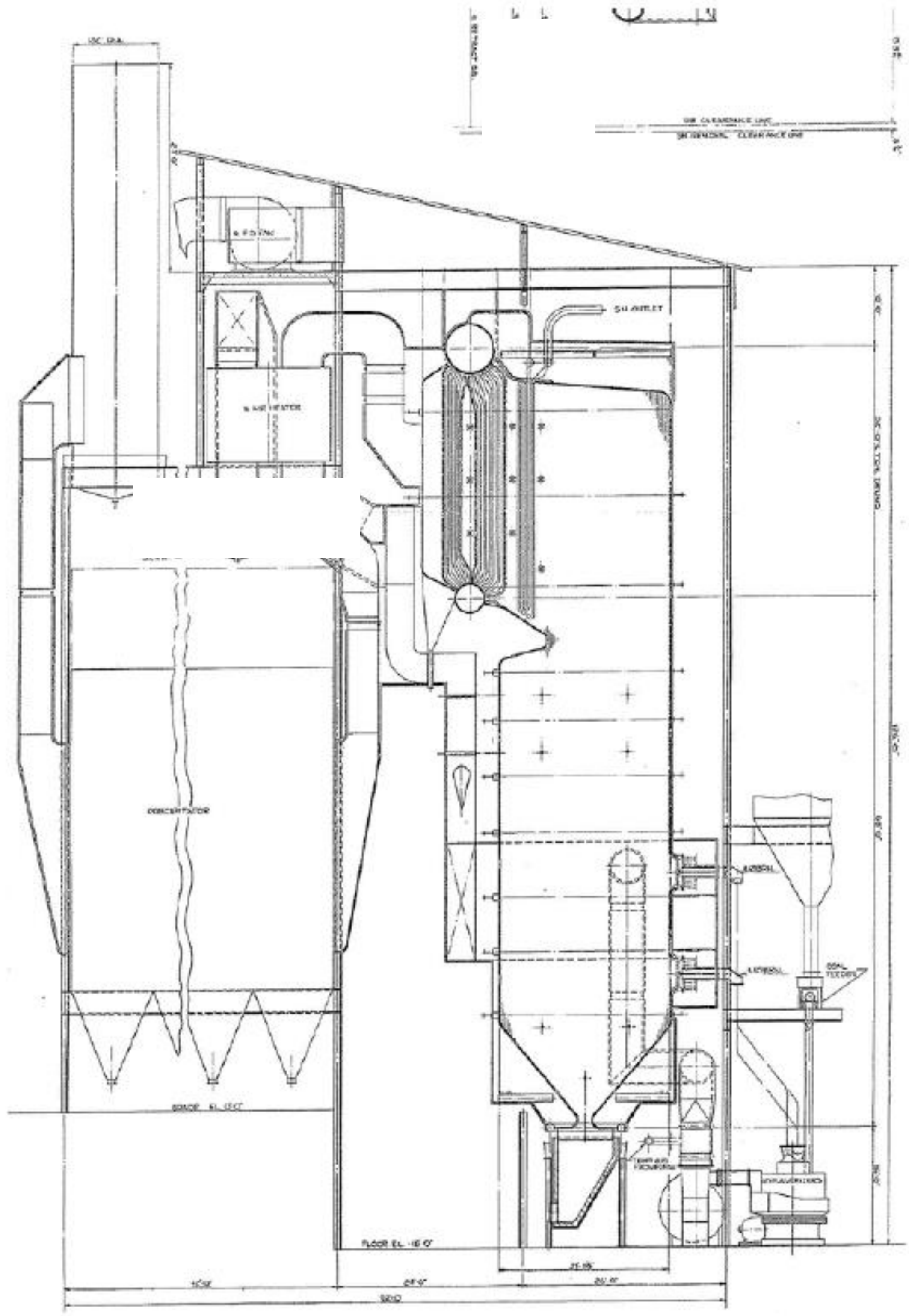

Figure 2-1: Boiler 1 Schematic

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.

Table 3-2: 2016 and 2028 EPA Modeling Emissions Inventory for SMBSC Sources (TPY)

Units	2016 SO_2	2028 SO_2	2016 NO_x	2028 NO_x
Boiler 1	805	786	930	907

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) [4] 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.

[4] US EPA, "EPA Air Pollution Control Cost Manual, Sixth Edition," January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may be accessed at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution as of the date of this report.

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_2 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.[5] This 1999 value is scaled to today's dollars using the Chemical Engineering Plant Cost Index (CEPCI).[6] 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_2. The average cost effectiveness threshold for NO_x is based on the EPA's Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS[7] which provides a cost effectiveness

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[5] 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.

[6] More information on CEPCI may be found at this link: https://www.chemengonline.com/pci-home. The CEPCI is accessible by subscription through "Chemical Engineering" magazine. The CEPCI scaling factors for this analysis compare 1999 values to January 2020 values.

[7] The EPA's Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS[7] may be found online at this link: https://www.epa.gov/sites/production/files/2017-05/documents/final_assessment_of_non-egu_nox_emission_controls_cost_of_controls_and_time_for_compliance_final_tsd.pdf

value of $2,400 per ton for NO_x control on a coal-fired boiler. This 2011 value scaled to today's dollars using CEPCI, is $3,100 per ton of NO_x.

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_x 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_x 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_x production is 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:

$$N_2 + O_2 \rightarrow 2NO \qquad (1)$$

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_x is a form of thermal NO_x 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_x are emitted as prompt NO_x.

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_x emissions from coal-fired boilers, as listed in Table 5-1.

Table 5-1: Additional NO_x Emission Control Measures with Potential Application at Coal-Fired Boilers

Emission Control Measures
Low- NO_x Burners (LNB)
Low- NO_x 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_x Burners (LNB)

LNB technology utilizes advanced burner design to reduce NO_x 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_x 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_x 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_x 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_x Burners with Overfire Air (LNB+OFA)

Low NO_x 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_x as well as providing oxygen to complete the combustion reaction.

A Low NO_x 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_x control measure in which ammonia (NH_3) or urea (CH_4N_2O) 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 EPA Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001)

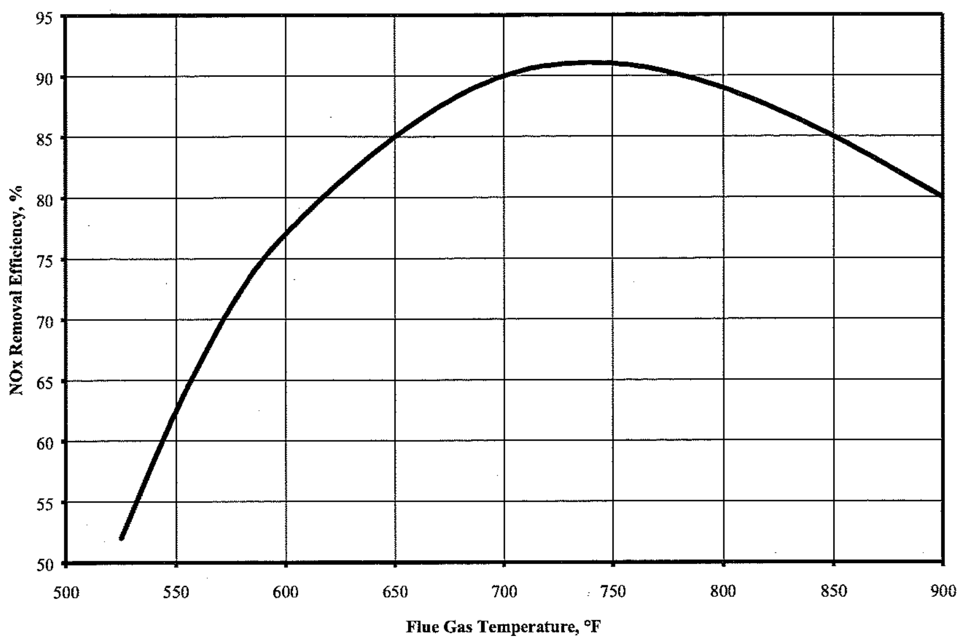

Figure 5-1: NO_X Removal using SCR vs. Flue Gas Temperature

SMBSC's Boiler 1 flue gas temperature is approximately 370°F under current operating conditions. For the SCR to effectively control NO_x 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_x emissions are controlled. At temperatures above 2,000°F, reaction (2) will dominate and the ammonia will decompose and increase NO_x 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_x 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_x 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.[8] 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.[9] 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_x 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.

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[8] 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.

[9] U.S. Environmental Protection Agency. EPA Air Pollution Control Cost Manual, Sixth Edition, Section 1, Chapter 2.6.4.2 Retrofit Cost Considerations. 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

Table 5-2: NO_x Control Cost Summary

Additional Emissions Control Measure	Installed Capital Cost with Retrofit Factor ($)	Indirect Costs ($/yr)	Direct Operating Costs ($/yr)	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
Low NO_x Burners	$3,090,000	$442,000	$100,000	$542,000	106	$5,100
Low NO_x Burners with Overfire Air	$5,340,000	$721,000	$100,000	$821,000	231	$3,600
Selective Catalytic Reduction	$39,000,000	$3,400,000	$2,280,000	$5,690,000	813	$7,000
Selective Non-Catalytic 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_x 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_X 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_x 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_2 Four-factor Analysis

This section identifies and describes various SO_2 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_2 as summarized in Sections 6.1 to 6.5.

6.1 SO_2 Control Measures Overview

Sulfur emissions from coal combustion consist primarily of SO_2, with a much lower quantity of SO_3 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_2 during the combustion process and that 1% of the uncontrolled SO_2 will oxidize to SO_3. Technically feasible SO_2 control options for SMBSC's Boiler 1 are summarized in Table 6-1.

Table 6-1: Additional SO_2 Control Measures with Potential Application at Coal-Fired Boilers

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_2 emissions. The lime neutralizes the absorbed SO_2 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_2.

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_2 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.[10] 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.[11] 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_2 emission control measures are provided in Appendix A.

The resulting cost effectiveness calculations are summarized in Table 6-2.

Table 6-2: SO_2 Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Installed Capital Cost with Retrofit Factor ($)	Indirect Costs ($/yr)	Direct Operating Costs ($/yr)	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
Spray Dry Absorber	$82,900,000	$10,600,000	$1,090,000	$11,700,000	707	$16,600
Dry Sorbent Injection	$36,000,000	$4,820,000	$2,170,000	$6,990,000	550	$12,700

The cost effectiveness values for all the SO_2 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_2 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_2 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_2 emission control measures are reasonable for installing on SMBSC's Boiler 1.

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[10] 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.

[11] U.S. Environmental Protection Agency. EPA Air Pollution Control Cost Manual, Sixth Edition, Section 1, Chapter 2.6.4.2 Retrofit Cost Considerations. 2017. https://www.epa.gov/sites/production/files/2017-12/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_2 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_2 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."[12] This is used to establish progress goals to be achieved by the end of the implementation period in 2028.[13] 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.[14] In addition, the 2019 SIP Guidance says that a state can consider visibility impacts in Class I areas when evaluating possible emission control measures.[15] 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_2 and NO_x inventory summary information for Boiler 1.

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[12] 40 CFR 51.308(f)(1)

[13] 40 CFR 51.308(f)(3)

[14] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003. Page 13.

[15] Ibid, Page 34.

Table 7-1 2016 and 2028 EPA Modeling Emissions Inventory for SMBSC Sources (TPY)

Units	2016 SO_2	2028 SO_2	2016 NO_x	2028 NO_x
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).[16] 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.[17] 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."[18]

Figure 7-1 through Figure 7-3 show the rolling 5-year average visibility impairment compared with the URP glidepath[19] 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.

[16] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[17] https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

[18] USEPA, Federal Register, 05/04/2016, Page 26948

[19] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

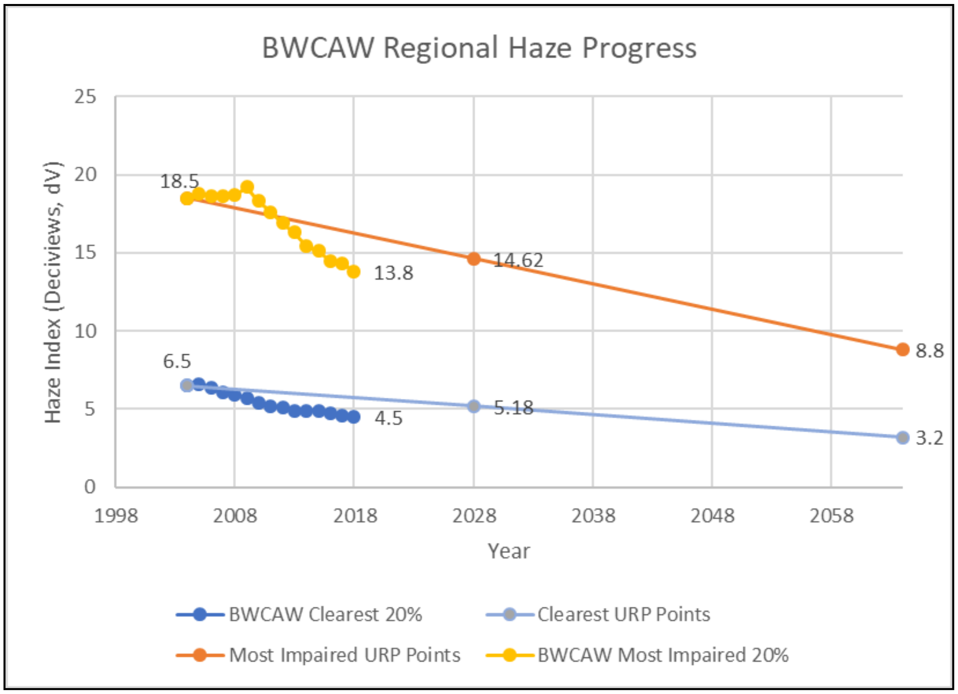


Figure 7-1: Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

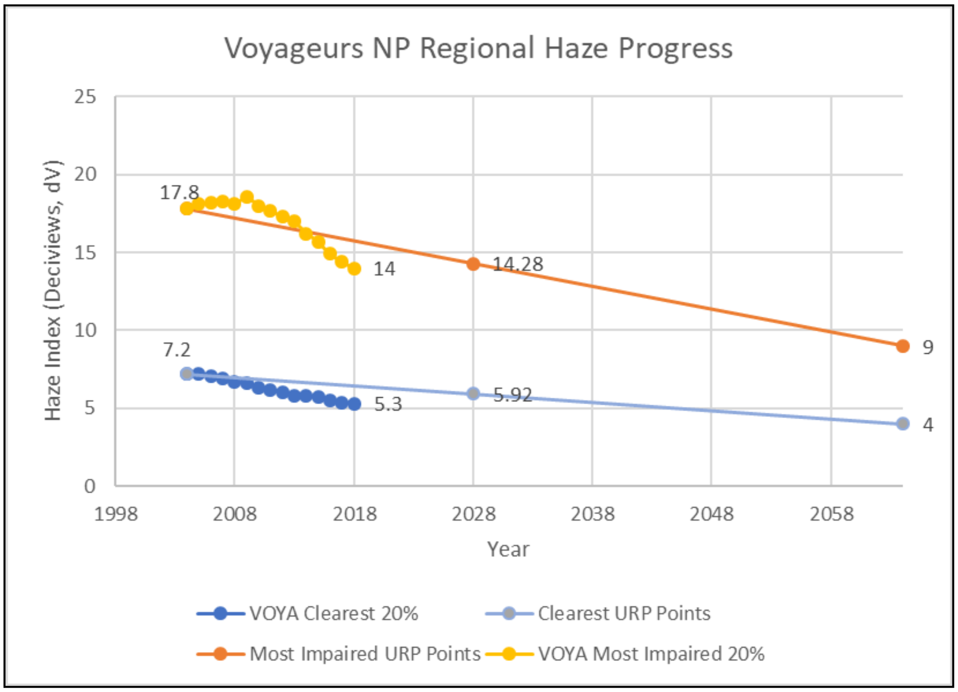


Figure 7-2: Visibility Trend versus URP – Voyageurs National Park (VOYA1)

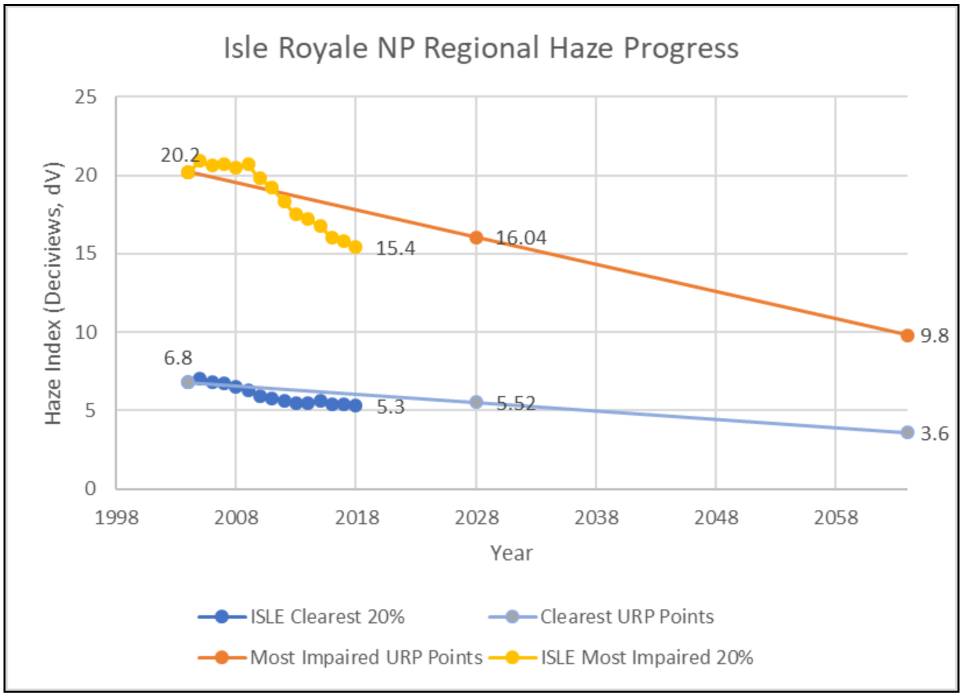


Figure 7-3: Visibility Trend versus URP – Isle Royale National Park (ISLE1)

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)

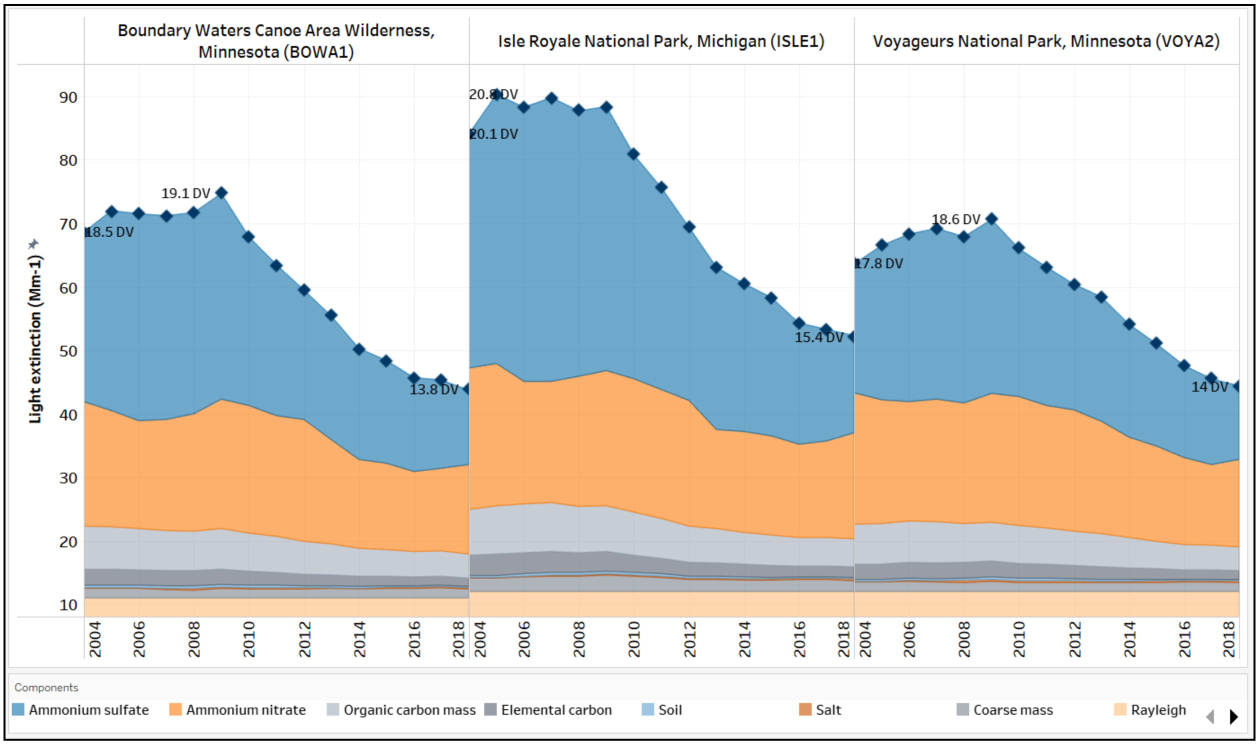


Figure 7-4: Visibility Components Trend for each Class 1 Monitor from 2004-2018[20]

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_x 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.[21] Because the IMPROVE monitoring network data demonstrates sustained progress towards visibility goals and the 5-year average visibility impairment on

[20] MPCA – Regional Haze Tableau Public. https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[21] 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.[22] In addition, the 2019 Guidance says that a state can consider visibility impacts in Class I areas when evaluating possible emission control measures.[23]

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.

[22] Ibid, Page 12.

[23] Ibid, Page 34.

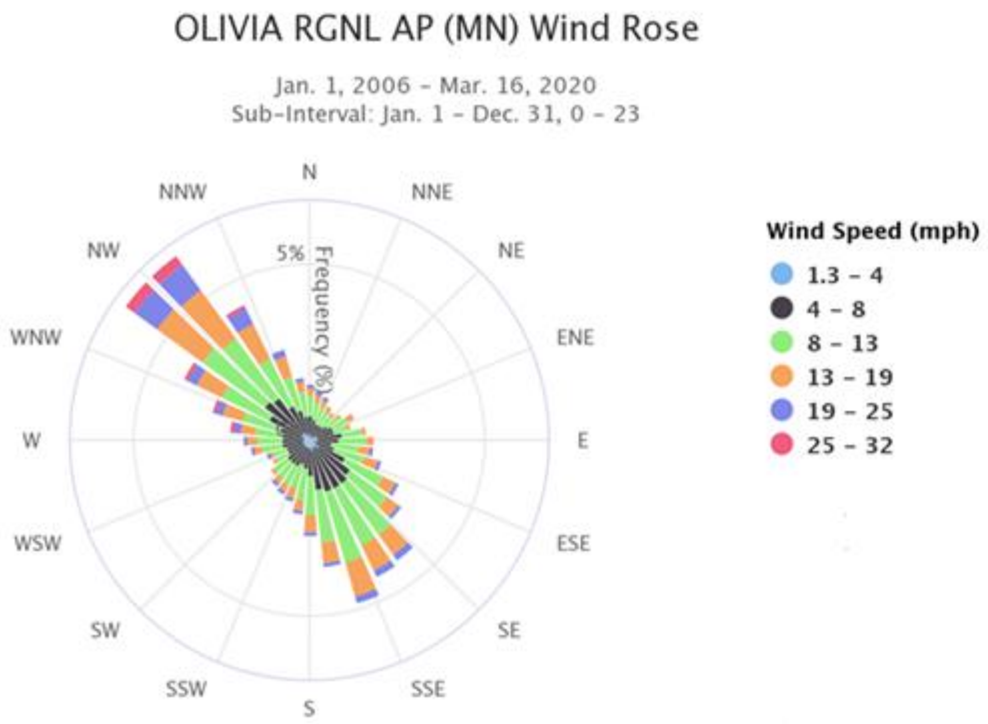


Figure 7-5: Olivia Wind Rose

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[24] 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[25]). 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.

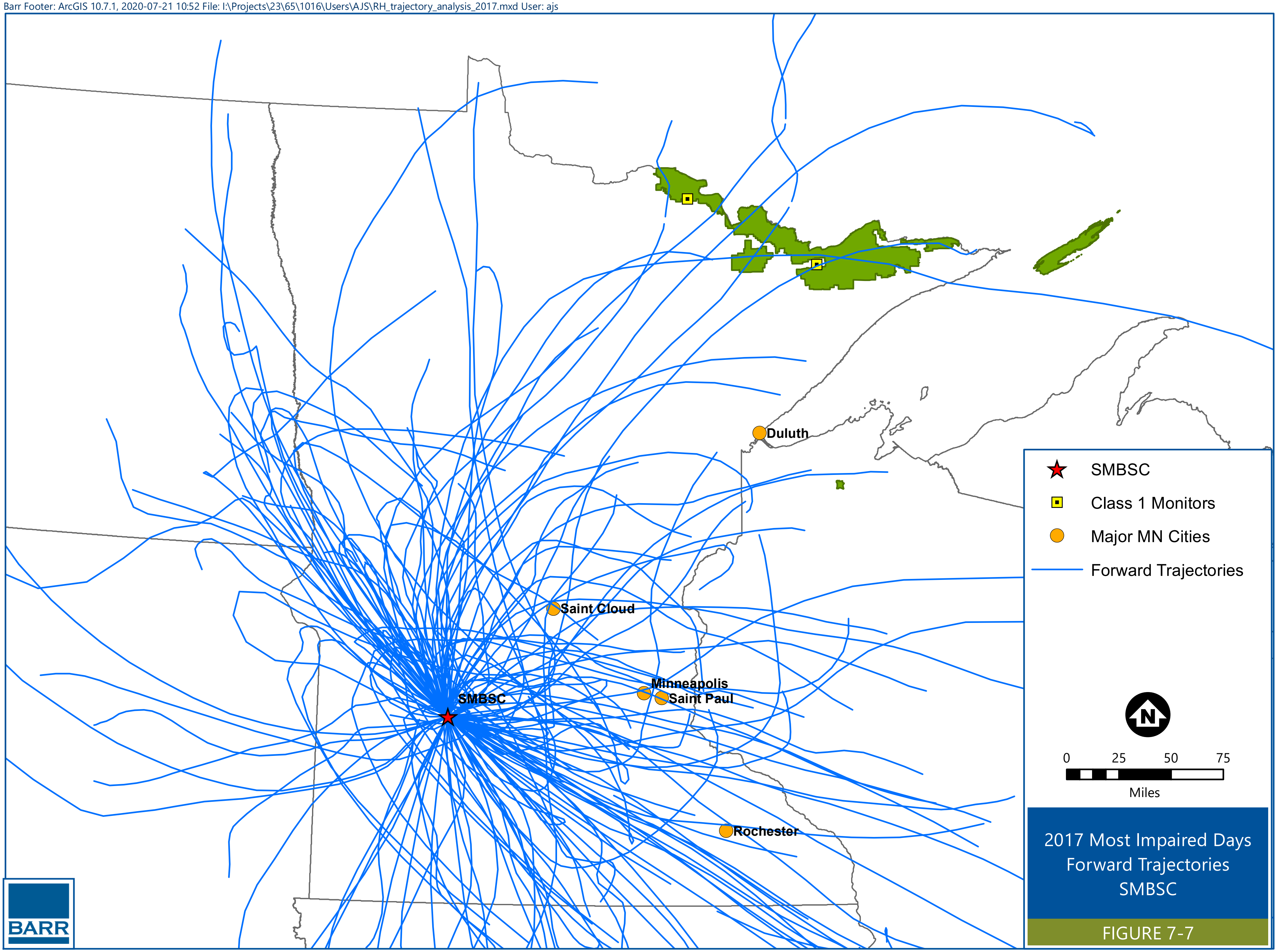
[24] Forward trajectories were modeled using staggered start times throughout the days of monitored impairment. Trajectories crossing the Class I areas in 2017 are attributable to two modeled days of multiple trajectories, rather than several days of impairment.

[25] MPCA 2017 statewide air emissions inventory. https://www.pca.state.mn.us/air/statewide-and-county-air-emissions

Figure 7-6: Voyageurs Trajectories for Most Impaired Days 2014-2016

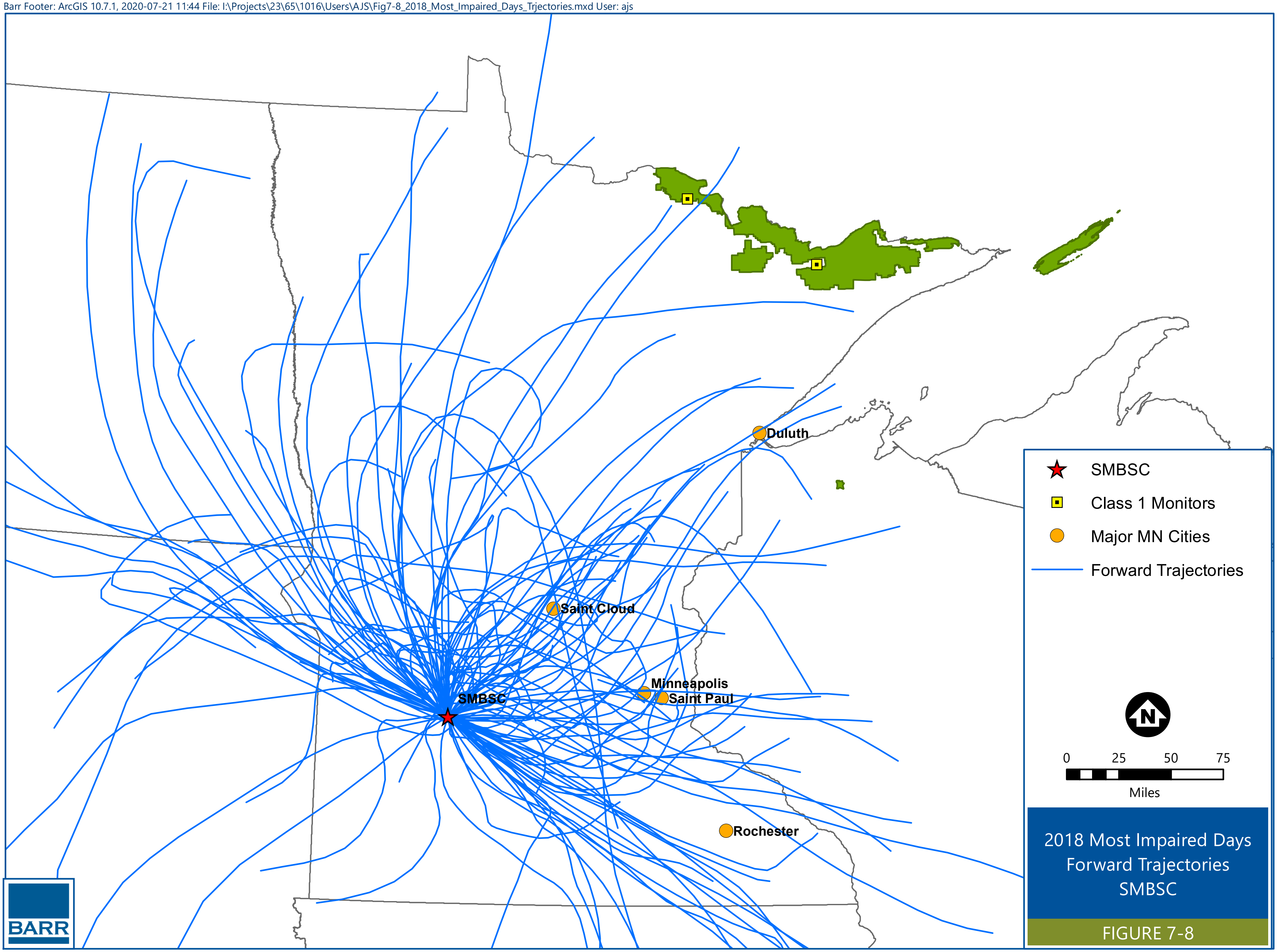
7.3 Visibility Review Summary

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.



2017 Most Impaired Days
Forward Trajectories
SMBSC

FIGURE 7-7



2018 Most Impaired Days
Forward Trajectories
SMBSC

FIGURE 7-8

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_x Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $[2]	Annualized Operating Cost $/yr[2]	Pollution Control Cost $/ton[2]
Selective Catalytic Reduction with Reheat (SCR)	90%	94.5	812.5	$38,983,220	$5,686,381	$6,999
Low NOx Burners (LNB) Coal-Fired[1]	12%	801.0	105.9	$2,057,668	$542,043	$5,117
Low NOx Burners + Over Fire Air (LNB+OFA) Coal-Fired[1]	25%	676.4	230.5	$3,560,926	$820,926	$3,561
Selective Non-Catalytic Reduction (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_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)	90%	78.6	707.2	$56,147,603	$11,708,110	$16,556
Dry Sorbent Injection (DSI) with Baghouse (including trona injection 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		

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.08	$/kwh			2015-2019 EIA Average prices for the commerical sector	
Natural Gas	3.90	$/kscf			2015-2019 EIA Average prices for the commerical sector	
Water	5.13	$/mgal	4.17	2013	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.	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Urea 50% Solution	1.81	$/gallon	1.66	2017	EPA SCR Control Cost Manual Spreadsheet	
Fuel Cost	2.13		1.89	2016	EPA SNCR Control Cost Manual Spreadsheet	
Estimated operating life of the catalyst ($H_{catalyst}$)	20,000	hours			EPA Control Cost Manual for SCR suggests 16,000 - 24,000 hours	
SCR Catalyst cost ($CC_{replace}$)	255	$/cubic foot	227	2016	EPA SCR 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	Taconite FIP Docket	
Other						
Sales Tax	6.875%			2020	Minnesota sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	50%				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	acfm			2014 Boiler 1 Hg Stack Test Data	
Standardized Flow Rate	132,954	scfm @ 68º F	123,889	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	117,332	dscfm @ 68º F			Calculated Value	
Fuel higher heating value (HHV)	9,152	BTU/lb			SMBSC Site Specific Data	Average of 2015-2019 Operating Data
Plant Elevation	1,100	Feet above sea level				Renville, MN elevation
Sulfur Content (%)	0.28	%			SMBSC Site Specific Data	Average of 2015-2019 Operating Data
# days boiler operates	314	days			SMBSC Site Specific Data	Average of 2015-2019 Operating Data
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	240.7	906.9	286	286.1	0.48	Baseline ton/year is based on 2028 NOx modeling emission inventory. Lb/MMBtu is based on 2015-2019 CEMS average
Sulfur Dioxides (SO2)	208.5	785.8	178	178.0		Baseline ton/year is based on 2028 SO2 modeling emission inventory.
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%	Trona Ore Control Efficiency			Control efficiency is based on trona as injected reagent.	
SCR - NO_x Control Efficiency	90%				Common design basis for SCR units per EPA Control Cost Manual	
LNB - NO_x Performance	0.45	lb/MMBtu			Vendor estimated burner performance	
LNB+OFA- NO_x Performance	0.38	lb/MMBtu			Vendor estimated burner performance	
SNCR - NO_x Performance	0.30	lb/MMBtu			EPA Control Cost Manual SCR spreadshet default outlet NOx emission rate	

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 3: NO_x Control - Selective Catalytic Reduction with Reheat

Operating Unit: **Boiler 1**

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 @ 68º F
			Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Total Capital Investment (TCI)		SCR Only	37,031,999
		SCR + Reheat	**38,983,220**
Operating Costs			
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	SCR + Reheat	**2,280,595**
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	SCR + Reheat	**3,398,577**
Total Annual Cost (Annualized Capital Cost + Operating Cost		SCR + Reheat	**5,686,381**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Cont Emis T/yr	Reduction T/yr	Cont Cost $/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			
SCR Capital Costs (SCRcost)		*Refer to the SCR Summary tab*	20,134,912
Reagent Preparation Costs (RPC)		*Refer to the SCR Summary tab*	3,581,809
Air Pre-Heater Costs (APHC)		*Refer to the SCR Summary tab*	-
Balance of Plant Costs (BPC)		*Refer to the SCR Summary tab*	4,769,432
Retrofit factor	50%	*of TCI, see SCR Summary tab*	
Total Capital Investment (TCI)			**37,031,999**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Maintenance			
Annual Maintenance Cost =		*Refer to the SCR Summary tab*	185,160
Utilities, Supplies, Replacements & Waste Management			
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 + Operating 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	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst - Refer to the SCR Summary Tab

Reagent Use
Refer to the SCR Summary tab

Operating Cost Calculations	**Annual hours of operation:**	**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_x Control - Flue Gas Reheat for SCR (Thermal Oxidizer)

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25		**Chemical Engineering**	
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)			635,318
Purchased Equipment Total (B)	22%	of control device cost (A)	**774,294**
Installation - Standard Costs	30%	of purchased equip cost (B)	232,288
Installation - Site Specific Costs			NA
Installation Total			232,288
Total Direct Capital Cost, DC			1,006,582
Total Indirect Capital Costs, IC	38%	of purchased equip cost (B)	294,232
Total Capital Investment (TCI) = DC + IC			**1,300,814**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,319,647
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	301,441
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,621,087**

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

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			
Direct Capital Costs			
Purchased Equipment (A) (1)			**635,318**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	63,532
MN Sales Taxes	6.9%	of control device cost (A)	43,678
Freight	5%	of control device cost (A)	31,766
Purchased Equipment Total (B)	22%		**774,294**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	61,944
Handling & erection	14%	of purchased equip cost (B)	108,401
Electrical	4%	of purchased equip cost (B)	30,972
Piping	2%	of purchased equip cost (B)	15,486
Insulation	1%	of purchased equip cost (B)	7,743
Painting	1%	of purchased equip cost (B)	7,743
Installation Subtotal Standard Expenses	30%		**232,288**
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			**232,288**
Total Direct Capital Cost, DC			**1,006,582**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	77,429
Construction & field expenses	5%	of purchased equip cost (B)	38,715
Contractor fees	10%	of purchased equip cost (B)	77,429
Start-up	2%	of purchased equip cost (B)	15,486
Performance test	1%	of purchased equip cost (B)	7,743
Model Studies		of purchased equip cost (B)	0
Contingencies	10%	of purchased equip cost (B)	77,429
Total Indirect Capital Costs, IC	38%	of purchased equip cost (B)	**294,232**
Total Capital Investment (TCI) = DC + IC			**1,300,814**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**1,300,814**
Total Capital Investment (TCI) with Retrofit Factor	50%		**1,951,221**
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			
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 Management			
Electricity	0.08	$/kwh, 774 kW-hr, 7536 hr/yr, 100% utilization	464,503
Natural Gas	3.90	$/mscf, 428 scfm, 7536 hr/yr, 100% utilization	754,952
Total Annual Direct Operating Costs			**1,319,647**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	60,115
Administration (2% total capital costs)	2%	of total capital costs (TCI)	39,024
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	19,512
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	19,512
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	163,277
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**301,441**
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 Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:	**Catalyst**	
Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	0	$/ft^3
Amount Required	39	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

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

Electrical Use							
	Flow acfm		Δ P 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
Oxidizer Type	**thermal**	(catalytic or thermal)				774.3	

Reagent Use & Other Operating Costs Oxidizers - NA

Operating Cost Calculations			**Annual hours of operation:**			**7,536**	
			Utilization Rate:			**100%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual 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 Maintenance Labor			NA	31,807	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
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	754,952	$/mscf, 428 scfm, 7536 hr/yr, 100% utilization

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

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

T_{wi}	370	Deg F - Temperature of waste gas into heat recovery
T_{fi}	650	Deg F - Temperature of Flue gas into heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	70%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	566	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	454	Deg F - Temperature of flue gas out of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.2684	Btu/lb - Deg F Heat Capacity of waste gas (air)
ρ_{wg}	0.0739	lb/scf - Density of waste gas (air) at 77 Deg F
ρ_{af}	0.0408	lb/scf - Density of auxiliary fuel (methane) at 77 Deg F
Q_{wg}	132,954	scfm - Flow of waste gas
Q_{af}	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	
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 Capacity - Basis Typical Composition

		100 scfm	359 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_x 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 ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), 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?

What type of fuel does the unit burn?

Is the SCR for a new boiler or retrofit of an existing boiler?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	472	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	9,152	Btu/lb
What is the estimated actual annual fuel consumption?	323,950,000	lbs/year
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 1,100 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned:

Enter the sulfur content (%S) = 0.28 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- Method 1
- Method 2 (selected)
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	314	days
Number of days the boiler operates (t_{plant})	314	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.48	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.05	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	209,000	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	20,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used

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 ($Cost_{reag}$)	1.814	$/gallon for 50% urea	
Electricity ($Cost_{elect}$)	0.0796	$/kWh	
Catalyst cost ($CC_{replace}$)	255.49	$/cubic foot (includes removal and disposal/regeneration of existing 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 the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf	Refer to the *Utility Chem$ Data* tab
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	Refer to the *Utility Chem$ 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 ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	Refer to the *Utility Chem$ 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_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.716	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7,536	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	89.6	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	203.13	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	812.46	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.12	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	209,000	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	96.78	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/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]$^{5.256}$ 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.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	2,159.47	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	218	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	250	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	15.8	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	54	feet

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	139	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	278	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	29	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ 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 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	270.15	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$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
Balance of Plant Costs (BPC) =	$4,769,432	in 2020 dollars
Total Capital Investment (TCI) =	$37,031,999	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.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$20,134,912 in 2020 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$3,581,809 in 2020 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 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 (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$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 Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$185,160 in 2020 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$400,990 in 2020 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$162,055 in 2020 dollars
Annual Catalyst Replacement Cost =		$212,743 in 2020 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2 selected.
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) 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_x Control - Low NOx Burners (LNB) Coal-Fired

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25	
Desgin Capacity	472	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º 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 @ 68º F
			Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**727,000**
Purchased Equipment Total (B)	22%	of control device cost (A)	**886,031**
Installation - Standard Costs	0%	of purchased equip 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 cost (B)	460,736
Total Capital Investment (TCI) = DC + IC			**2,057,668**
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	441,851
Total Annual Cost (Annualized Capital Cost + Operating Cost			**542,043**

Emission Control Cost Calculation

Pollutant	Baseline Emis. T/yr	Cont. Emis. lb/hr	Cont. Emis. lb/MMBtu	Cont Emis T/yr	Reduction T/yr	Cont Cost $/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_2)		-			-	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)	0
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**
Total Capital Investment (TCI) = DC + IC			**2,057,668**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	
Total Site Specific Costs			**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**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 Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**100,192**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	60,115
Administration (2% total capital costs)	2%	of total capital costs (TCI)	61,730
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	30,865
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	30,865
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	258,276
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**441,851**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**542,043**

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		
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:** **7,536** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual 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 Maintenance Labor			NA	31,807	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
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
Water	5.13	$/kgal	0.0	gpm	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_x Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25	
Desgin Capacity	472	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º 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 @ 68º F
			Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**1,265,871**
Purchased Equipment Total (B)	22%	of control device cost (A)	**1,542,780**
Installation - Standard Costs	0%	of purchased equip cost (B)	1,215,900
Installation - Site Specific Costs			0
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	720,734
Total Annual Cost (Annualized Capital Cost + Operating Cost			**820,926**

Emission Control Cost Calculation

Pollutant	Baseline Emis. T/yr	Cont. Emis. lb/hr	Cont. Emis. lb/MMBtu	Cont Emis T/yr	Reduction T/yr	Cont Cost $/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_2)		-			-	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/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			
Direct Capital Costs			
Purchased Equipment (A) (1)			**1,265,871**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	126,587
MN Sales Taxes	6.9%	of control device cost (A)	87,029
Freight	5%	of control device cost (A)	63,294
Purchased Equipment Total (B)	22%		**1,542,780**
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)	0
Installation Subtotal Standard Expenses	0%		**1,215,900**
Installation Total			**1,215,900**
Total Direct Capital Cost, DC			**2,758,680**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	154,278
Construction & field expenses	20%	of purchased equip cost (B)	308,556
Contractor fees	10%	of purchased equip cost (B)	154,278
Start-up	1%	of purchased equip cost (B)	15,428
Performance test	1%	of purchased equip cost (B)	15,428
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	10%	of purchased equip cost (B)	154,278
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**802,246**
Total Capital Investment (TCI) = DC + IC			**3,560,926**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	
Total Site Specific Costs			**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**3,560,926**
Total Capital Investment (TCI) with Retrofit Factor	50%		**5,341,389**
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 Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**100,192**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	60,115
Administration (2% total capital costs)	2%	of total capital costs (TCI)	106,828
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	53,414
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	53,414
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	446,964
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**720,734**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**820,926**

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		
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:** **7,536** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual 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 Maintenance Labor			NA	31,807	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
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
Water	5.13	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7536 hr/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 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? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	472.4	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	9,152	Btu/lb
What is the estimated actual annual fuel consumption?	323,950,000	lbs/year
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.28 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

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.

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	314	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.48	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.30	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.30	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

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 Control Cost Manual (as updated March 2019).

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

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 ($Cost_{fuel}$)	2.13	$/MMBtu			
Reagent ($Cost_{reag}$)	1.81	$/gallon for a 50 percent solution of urea			
Water ($Cost_{water}$)	0.0051	$/gallon			
Electricity ($Cost_{elect}$)	0.0796	$/kWh			
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	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) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	Refer to the *Utility Chem$ Data* tab
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	Refer to the *Utility Chem$ 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
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	Refer to the *Utility Chem$ Data* tab
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	Refer to the *Utility Chem$ 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 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
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 Information Administration (EIA) from data reported on EIA Form EIA-923, Power 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. 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
Interest 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_B) =	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_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.62	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	7536	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	38	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	85.03	lb/hour
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	340.10	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04	
Atmospheric pressure at 1100 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ 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.

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 ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x NSR x $MW_R)/(MW_{NOx}$ x SR) = (whre SR = 1 for NH_3; 2 for Urea)	192	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	384	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	40.4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	13,600	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	13.8	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{sol}$/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	184	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	1.55	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	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:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,040,438 in 2020 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2020 dollars
Balance of Plant Costs (BOP_{cost}) =	$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 ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,040,438 in 2020 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 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_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$3,274,167 in 2020 dollars

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_{sol} x $Cost_{reag}$ x t_{op} =	$552,860 in 2020 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$8,291 in 2020 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$7,111 in 2020 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$24,922 in 2020 dollars
Additional Ash Cost =	ΔAsh 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)

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25	
Design Capacity	472	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º F
Utilization Rate	100%		Temperature	370	Deg F
Annual Operating Hours	7,536	Hours	Moisture Content	11.8%	
Annual Interest Rate	5.5%		Actual Flow Rate	209,000	acfm
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)			**20,384,880**
Purchased Equipment Total (B	22%	of control device cost (A	**24,844,072**
Installation - Standard Costs	74%	of purchased equip cost (B)	18,384,613
Installation - Site Specific Costs			NA
Installation Total			18,384,613
Total Direct Capital Cost, DC			43,228,685
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	12,918,917
Total Capital Investment (TCI) = DC + IC			**56,147,603**
Adjusted TCI for Replacment Parts			**55,294,650**
TCI with Retrofit Factor			**82,941,976**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, et	1,086,037
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	10,622,073
Total Annual Cost (Annualized Capital Cost + Operating Cost			**11,708,110**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		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 scfm from Northshore Mining Powerhouse #2 2006 BART submittal including anciliary equipment
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 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 7: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A)[1]		**20,384,880**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentatior	10% of control device cost (A	2,038,488
State Sales Taxes	6.9% of control device cost (A)	1,401,460
Freight	5% of control device cost (A	1,019,244
Purchased Equipment Total (B)	22%	**24,844,072**
Installation		
Foundations & supports	4% of purchased equip cost (B)	993,763
Handling & erection	50% of purchased equip cost (B)	12,422,036
Electrical	8% of purchased equip cost (B	1,987,526
Piping	1% of purchased equip cost (B)	248,441
Insulation	7% of purchased equip cost (B	1,739,085
Painting	4% of purchased equip cost (B)	993,763
Installation Subtotal Standard Expenses	74%	**18,384,613**
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		NA
Installation Total		**18,384,613**
Total Direct Capital Cost, DC		**43,228,685**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B	2,484,407
Construction & field expenses	20% of purchased equip cost (B)	4,968,814
Contractor fees	10% of purchased equip cost (B	2,484,407
Start-up	1% of purchased equip cost (B)	248,441
Performance test	1% of purchased equip cost (B)	248,441
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	2,484,407
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**12,918,917**
Total Capital Investment (TCI) = DC + IC		**56,147,603**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos		**55,294,650**
Total Capital Investment (TCI) with Retrofit Factor	50%	**82,941,976**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 7536 hr/yr	127,228
Supervisor	15% 15% of Operator Costs	19,084
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 7536 hr/yr	63,614
Maintenance Materials	100% of maintenance labor costs	63,614
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.08 $/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization	226,923
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization	90,981
N/A		-
SW Disposal	63.34 $/ton, 0.2 ton/hr, 7536 hr/yr, 100% utilization	99,558
Lime	183.68 $/ton, 282.2 lb/hr, 7536 hr/yr, 100% utilization	195,295
Filter Bags	228.02 $/bag, 3,072 bags, 7536 hr/yr, 100% utilization	199,741
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,086,037**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	164,123
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,658,840
Property tax (1% total capital costs)	1% of total capital costs (TCI)	829,420
Insurance (1% total capital costs)	1% of total capital costs (TCI)	829,420
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	7,140,270
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cos	**10,622,073**
Total Annual Cost (Annualized Capital Cost + Operating Cost		**11,708,110**

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 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		
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.
Annualized Cost	**199,741**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	209,000	10.00			2,850,793	Incremental electricity increase over with baghouse replacin scrubber including ducting
Total					2,850,793	

Reagents and Other Operating Costs

Lime Use Rate	1.30 lb-mole CaO/lb-mole SO:	282.17 lb/hr Lime	
Solid Waste Disposal	1,572	ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate 100% Annual Operating Hours 7,536

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	1,884	$ 127,228	$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr
Supervisor	15%	of Op.			NA	$ 19,084	15% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	942	$ 63,614	$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	$ 63,614	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.080	$/kwh	378.3	kW-hr	2,850,793	$ 226,923	$/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	189,003	$ 90,981	$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 7536 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.21	ton/hr	1,572	$ 99,558	$/ton, 0.2 ton/hr, 7536 hr/yr, 100% utilization
Lime	183.68	$/ton	282.2	lb/hr	1,063	$ 195,295	$/ton, 282.2 lb/hr, 7536 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	3,072	bags	N/A	$ 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 @ 68º 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 cost (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, replacement parts, utilities, etc	2,166,769
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	4,818,246
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,985,015**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual Ton/Yr	Cont Eff %	Cont Emis Ton/Yr	Reduction Ton/Yr	Cont Cost $/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
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 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			
Direct Capital Costs			
Purchased Equipment (A) [1]			**9,026,849**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	902,685
State Sales Taxes	6.9%	of control device cost (A)	620,596
Freight	5%	of control device cost (A)	451,342
Purchased Equipment Total (B)	22%		**11,001,473**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	440,059
Handling & erection	50%	of purchased equip cost (B)	5,500,736
Electrical	8%	of purchased equip cost (B)	880,118
Piping	1%	of purchased equip cost (B)	110,015
Insulation	7%	of purchased equip cost (B)	770,103
Painting	4%	Included in vendor estimate	440,059
Installation Subtotal Standard Expenses	74%		**8,141,090**
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			**8,141,090**
Total Direct Capital Cost, DC			**19,142,562**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,100,147
Construction & field expenses	20%	of purchased equip cost (B)	2,200,295
Contractor fees	10%	of purchased equip cost (B)	1,100,147
Start-up	1%	of purchased equip cost (B)	110,015
Performance test	1%	of purchased equip cost (B)	110,015
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	1,100,147
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**5,720,766**
Total Capital Investment (TCI) = DC + IC			**24,863,328**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**24,010,376**
Total Capital Investment (TCI) with Retrofit Factor	50%		**36,015,563**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	127,228
Supervisor	0.15	of Op Labor	19,084
Maintenance			
Maintenance Labor	67.53	$/Hr	63,614
Maintenance Materials	100	% of Maintenance Labor	63,614
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization	136,154
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization	90,981
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.5 ton/hr, 7536 hr/yr, 100% utilization	222,137
Trona	285.00	$/ton, 1,158.6 lb/hr, 7536 hr/yr, 100% utilization	1,244,217
Filter Bags	228.02	$/bag, 3,072 bags, 7536 hr/yr, 100% utilization	199,741
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**2,166,769**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	164,123
Administration (2% total capital costs)	2%	of total capital costs (TCI)	720,311
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	360,156
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	360,156
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	3,013,758
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**4,818,246**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,985,015**

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	1,710,476	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			1,710,476	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	208.54	lb/hr SO2	1158.62	lb/hr Trona
Solid Waste Disposal	3,507	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		7,536			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	1,884	$ 127,228	$/Hr, 2.0 hr/8 hr shift, 1,884 hr/yr
Supervisor	15%	of Op Labor			NA	$ 19,084	% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	942	$ 63,614	$/Hr, 1.0 hr/8 hr shift, 942 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 63,614	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.080	$/kwh	227.0	kW-hr	1,710,476	$ 136,154	$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	189,003	$ 90,981	$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	63.34	$/ton	0.5	ton/hr	3,507	$ 222,137	$/ton, 0.5 ton/hr, 7536 hr/yr, 100% utilization
Trona	285.00	$/ton	1,158.6	lb/hr	4,366	$ 1,244,217	$/ton, 1,158.6 lb/hr, 7536 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	3,072	bags	N/A	$ 199,741	$/bag, 3,072 bags, 7536 hr/yr, 100% utilization

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 candice.maxwell@clevelandcliffs.com if you have questions about this submittal or require additional information.

Sincerely,

Candice 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_X and SO_2 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_X and SO_2 Emissions Control

July 31, 2020

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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_X Burners
LoTOx	Low Temperature Oxidation
MPCA	Minnesota Pollution Control Agency
NA	Not Applicable
NO	Nitric Oxide
NO_X	Nitrogen Oxides
NSCR	Non-Selective Catalytic Reduction
NSM	Northshore Mining Company
O_2	Oxygen
O&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_2	Sulfur Dioxide
SO_3	Sulfur trioxide
TMDL	Total Maximum Daily Load

tpy	tons per year
TSD	Technical Support Document
ULNB	Ultra Low-NO_X 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,[1] United Taconite LLC Fairlane Plant (UTAC) evaluated potential emission control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) 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).[2] 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[3] 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_X and Table 1-2 for SO_2.

The NO_X 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),[4] 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_X emission controls (refer to Sections 4.2 and 5.2 for more information).

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[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to Candice Maxwell of UTAC.

[2] 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).

[3] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

[4] 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_2 Four-Factor Analysis evaluated the following SO_2 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_X control technology described above, none of these SO_2 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_2 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_2 emission controls (refer to Sections 4.2 and 6.2 for more information). Therefore, the facility's existing SO_2 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_X Four-Factor Analysis

List of Emission Control Measure	Factor #1 – Cost of Compliance: Installed Capital Cost ($)	Factor #1 – Cost of Compliance: Annualized Operating Cost ($/year)	Factor #1 – Cost of Compliance: Pollution Control Cost ($/ton)	Factor #2 – Time Necessary for Compliance	Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance	Factor #4 – Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
SCR with Reheat	Line 1 - $43,637,895 Line 2 - $72,550,865	$21,350,897 $41,336,088	$32,228 $44,115	5 years after SIP promulgation. See Section 5.3.	<u>Energy</u> • Increased energy use to overcome the increased differential pressure; • Increased indirect emissions at power plant to accommodate the increased energy use. • Substantial increase in natural gas usage to reheat the exhaust stream; and • Additional electricity is required for the SCR equipment, to vaporize the aqueous ammonia reagent, and for additional fan power. <u>Environmental</u> • Unreacted ammonia (a PM_{10} precursor) would be emitted to the atmosphere (ammonia slip); • Ammonia would combine with NO_X and SO_2 to form ammonium salts, which would be emitted to the atmosphere as PM_{10}; • Sulfuric acid mist emissions will increase due to the	20-year control equipment life	No

List of Emission Control Measure	Installed Capital Cost ($)	Annualized Operating Cost ($/year)	Pollution Control Cost ($/ton)	Factor #2 – Time Necessary for Compliance	Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance	Factor #4 – Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
	Factor #1 – Cost of Compliance						
					oxidation of SO_2 to SO_3 by the SCR catalyst; • Emissions of ammonia, ammonium sulfates, and sulfuric acid mist increase plume visibility and contribute to regional haze; • Increased oxidized mercury emissions. • There are safety risks associated with the transportation, handling, and storage of aqueous ammonia; and • Spent catalyst from the SCR is typically disposed of in a landfill; however, catalyst recycling or reconditioning may be available.		

Table 1-2 Summary of SO_2 Four-Factor Analysis

List of Emission Control Technology	Factor #1 – Cost of Compliance: Installed Capital Cost ($)	Factor #1 – Cost of Compliance: Annualized Operating Cost ($/year)	Factor #1 – Cost of Compliance: Pollution Control Cost ($/ton)	Factor #2 – Time Necessary for Compliance	Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance	Factor #4 – Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
Line 1 DSI, SDA and GSA with new PM Control	Not applicable – See Section 6.1.	NA	NA	NA	NA	NA	NA
Line 2 DSI with new PM Control	$50,466,157	$10,090,749	$93,300	5 years after SIP promulgation. See Section 6.3.	Energy Increased energy use to accommodate differential pressure. Increased indirect emissions at power plant to accommodate the increased energy use. Environmental Additional solid waste generation and disposal. Lost production due to loss of recycled dust that contains valuable iron units.	20-year control equipment life	No

	Factor #1 – Cost of Compliance						
List of Emission Control Technology	**Installed Capital Cost ($)**	**Annualized Operating Cost ($/year)**	**Pollution Control Cost ($/ton)**	**Factor #2 – Time Necessary for Compliance**	**Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance**	**Factor #4 – Remaining Useful Life of the Source**	**Does this Analysis Support the Installation of this Emission Control Measure?**
Line 2 SDA with new PM Control	$120,947,748	$19,573,967	$180,891	5 years after SIP promulgation. See Section 6.3.	Energy Increased energy use to accommodate differential pressure. Increased indirect emissions at power plant to accommodate the increased energy use. Environmental Additional solid waste generated and disposed.	20-year control equipment life	No
Line 2 GSA with new PM Control	$113,793,152	$18,757,651	$173,347	5 years after SIP promulgation. See Section 6.3.	Increased energy use to accommodate differential pressure. Increased indirect emissions at power plant to accommodate the increased energy use. Environmental Additional solid waste generation and disposal.	20-year control 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_X and SO_2. 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.

Table 2-1 Identified Emission Units

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.[5]

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.

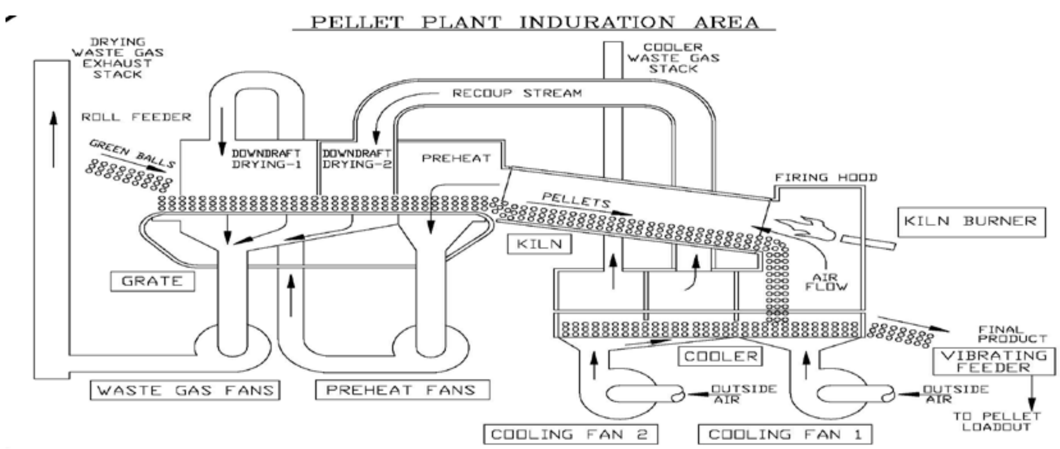

Figure 2-1 Typical Grate-Kiln Indurating Furnace Configuration

[5] 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_X and SO_2 control strategies for the indurating furnaces. MPCA subsequently developed its SIP with certain NO_X and SO_2 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.[6] The 2016 FIP imposed NO_X emission limits on UTAC'S furnaces of 2.8-3.0 lb NO_X/MMBtu when only natural gas is combusted and 1.5-2.5 lb NO_X/MMBtu for all other fuels, on a 720-hour rolling average basis. For SO_2, the 2016 FIP imposed an emission limit of 529 lb SO_2/hr, based on a 30-day rolling average, for both furnaces combined.

In addition, UTAC proposed NO_X emission limits in its 2010 Title V Major Amendment that represented a 2,415 ton per year NO_X 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*

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[6] 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_X 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 lb NOx/MMBtu 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.

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 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_X/MMBtu for natural gas only and a limit of 1.5-2.5 lb NO_X/MMBtu for all other fuels, on a 720-hour rolling average basis. For SO_2, the FIP required an aggregate Line 1 and Line 2 Indurating Furnaces emission limit of 529 lb SO_2/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), [7] 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_X and SO_2 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).[8] 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_X controlled in the 2019 SIP.[9] 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_2 were found in the 2014 Texas and Oklahoma RH FIP, citing a cost-effectiveness threshold for SO_2 of $4,000 to $5,000 per ton of SO_2 controlled.[10] 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

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[7] US EPA, "EPA Air Pollution Control Cost Manual, Sixth Edition," January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may be accessed at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution as of the date of this report.

[8] 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.

[9] U.S. EPA PADEP SIP, June 10, 2019. https://www.federalregister.gov/documents/2019/05/09/2019-09478/approval-and-promulgation-of-air-quality-implementation-plans-pennsylvania-regulatory-amendments

[10] U.S. EPA TX and OK FIP, December 16, 2014. https://www.govinfo.gov/content/pkg/FR-2014-12-16/pdf/2014-28930.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_X and SO_2 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.[11] 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.[12] 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_X 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

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[11] 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.

[12] U.S. Environmental Protection Agency. EPA Air Pollution Control Cost Manual, Sixth Edition, Section 1, Chapter 2.6.4.2 Retrofit Cost Considerations. 2017. https://www.epa.gov/sites/production/files/2017-12/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_2, 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_X or SO_2 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 long-lead 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_X Four-Factor Analysis

This section identifies and describes various NO_X 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_X as described in Sections 5.1 to 5.6.

5.1 NO_X Control Measures Overview

Three mechanisms by which NO_X production typically forms are thermal, fuel and prompt NO_X formation. In the case of natural gas combustion, the primary mechanism of NO_X production is 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:

$$N_2 + O_2 \rightarrow 2NO \qquad (1)$$

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.

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. Natural gas has minimal fuel bound nitrogen which eliminates fuel bound NO_X as a major concern.

Prompt NO_X is a form of thermal NO_X 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_X are emitted as prompt NO_X.

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_X 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,[13] 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_X as opposed to installing another SCR with reheat in the future.*

Past NO_X 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,[14] 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_X 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_X 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_3 in the reactor, the ability to inject ammonia at

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[13] Federal Register 81, no. 70 (April 12, 2016); 21675. Available at: https://www.govinfo.gov/app/details/FR-2016-04-12/2016-07818

[14] 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_3 in the reactor, the emissions of unreacted ammonia from the reactor, and formation of byproducts from the reaction such as ammonia salts and PM_{10}. These effects are often interconnected because SO_3 and unreacted ammonia can react within, and downstream of the SCR reactor. The same catalyst that promotes the reactions between ammonia and NO_X also promotes the oxidation of SO_2 to SO_3. Typically, a conversion of one to two percent of SO_2 to SO_3 could be expected. It is important to understand that SO_2 oxidation is dependent on other SCR design parameters. When high levels of catalyst activity are needed to target high NO_X reduction efficiencies and low levels of ammonia slip, or to counteract significant catalyst deactivation rates, SO_2 oxidation rates would be expected to increase. If lower levels of SO_2 oxidation are targeted, NO_X reduction, ammonia slip, or both must be compromised.[15] The potential increase of PM_{10} and $PM_{2.5}$ 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_X 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_2 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_3 and sulfuric acid mist formed in such equipment can promote the formation of a visible plume, or a blue plume.[16] 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_3, 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.

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[15] Cichanowicz, J. E. 1999. What You Should Know Before Specifying SCR. Power Magazine. May/June 1999. pp. 80-81.

[16] Moretti, A. L., Triscori, R. J., and Ritzenthaler, D. P. (2006). A System Approach to SO_3 Mitigation. Presented at the "EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium," August 28–31.

NO_X Variability and Ammonia Slip

Unlike a typical utility boiler operating at a steady load, taconite indurating furnaces typically experience significant variability in NO_X concentrations in the exhaust stream. As previously noted, thermal NO_X formation in an indurating furnace is the dominant mechanism for the formation of NO_X emissions. The rate of NO_X 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_X concentrations. The NO_X formation–peak temperature relationship is a primary factor why the variability of NOx concentrations experienced in an indurating furnace is greater than in coal-fired boilers.

The NO_X variability is dependent on the individual indurating furnace design and operations. The differences in the magnitude of the NO_X variability and the average NO_X 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_X loadings and would have to be controlled to ensure the ammonia and NO_X molar ratio remains consistent during the short-term NO_X 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_X molar ratios would reduce the overall NO_X control efficiency of an SCR system on an indurating furnace. As noted by Solnhofen cement manufacturing facility management, the NO_X 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.[17]

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_2 control reagents. Constituents in the indurating furnace exhaust gas

[17] The Experience of SCR at Solnhofen and its Applicability to US Cement Plants, June 6, 2006. http://files.dep.state.pa.us/air/AirQuality/AQPortalFiles/Pollutants/transport/Comments/Lehigh_Attachment_Solnhofen.pdf

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_X 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_X 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_2 to sulfuric acid; creating more catalyst blinding compounds.

5.2 Factor #1 – Cost of Compliance

UTAC has completed cost estimates for the selected NO_X 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.[18]
- A 2 part per million (ppm) ammonia slip to minimize collateral visibility emissions of ammonia and $PM_{2.5}$
- A control efficiency of 50 percent based on Portland Cement Association report.[19] 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.

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[18] Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for use in Portland Cement Industry

[19] The Experience of SCR at Solnhofen and its Applicability to US Cement Plants, June 6, 2006. http://files.dep.state.pa.us/air/AirQuality/AQPortalFiles/Pollutants/transport/Comments/Lehigh_Attachment_Solnhofen.pdf

See Section 5.1.1 above for detailed discussion for the true cost of compliance. The cost summary spreadsheets for the NO_X 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,[20] 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.

Table 5-1: NO_X Control Cost Summary, per Unit Basis

Additional Emission Control Measure	Installed Capital Cost ($MM)	Annual Operating Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost-effectiveness ($/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_X 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.

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[20] US EPA, "EPA Air Pollution Control Cost Manual, Sixth Edition," January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may be accessed at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution as of the date of this report, 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 above-identified NO_X 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_X reductions. The associated increase in PM_{10} 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_{10}, SO_3, 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_X and SO_2 to create PM_{10} 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_X, 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_X 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_2 Four-Factor Analysis

This section identifies and describes various SO_2 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_2 as described in Sections 6.1 to 6.6.

6.1 SO_2 Control Measures Overview

The SO_2 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_2 concentration that can be reasonably achieved by add-on control technologies is 5 ppm. The 2028 baseline emission rate of 15.7 lb SO_2/hr for Line 1 equates to 4.9 ppm SO_2. The calculation of the equivalent SO_2 concentrations is provided in the cost summary spreadsheets for the SO_2 emission control measures in Appendices A and B. With a 2028 baseline SO_2 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_2 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_2 control technologies for the Line 2 Indurating Furnace.

Table 6-1 Additional SO_2 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_2 control technology, new PM control equipment will be required to achieve the SO_2 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 100ºF to 150ºF and is saturated with water. For comparison, a utility boiler exhaust operates at 350ºF 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_2 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_2 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_2 emission control measures. Cost summary spreadsheets for the SO_2 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,[20] 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.

Table 6-2: SO_2 Control Cost Summary, Line 2 Indurating Furnace

Additional Emission Control Measure	Installed Capital Cost ($MM)	Annual Operating Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost-effectiveness ($/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

For Line 2 Indurating Furnace, the cost-effectiveness values for all of the SO_2 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_2 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_2 control measures are summarized below.

6.4.1 Energy Impacts

The SO_2 control technologies with new PM control would require additional electricity requirements. Similar to the NO_X add-on controls, operation of add-on SO_2 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_2 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_x Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control 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	**Study Year**	2020
Emission Unit Number	EU 040		
Stack/Vent Number	SV 046		

Item	Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	72.12	$/hr		2020	Site-specific labor cost	
Maintenance Labor	72.12	$/hr		2020	Site-specific labor cost	
Electricity	0.068	$/kwh	68.44	2020	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	
Compressed Air	0.48	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Adjusted for 3% inflation
Taconite Pellets	29.1	$/LT		2020	Based on Q1 2020 sales margin in earnings report	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Hydrated lime cost from 2012 Dry Flugas Desulfurization Study for UTAC Lines 1 and 2	Adjusted for 3% inflation
Urea 50% Solution	1.81	$/gallon	1.66	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Trona	285.00	$/ton		2020	Vendor estimated delivered cost	
Estimated operating life of the SCR catalyst ($H_{catalyst}$)	8,000	hours			EPA Control Cost Manual Chapter 7, 7th Edition	
Catalyst cost ($CC_{replace}$)	248.05	$/cubic foot (inc	227	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Cost per bag	116.70	$/bag	110	2018	Vendor estimated bag cost from the 2018 Best Available Mercury Reduction Technology (BAMRT) Analysis	Adjusted for 3% inflation
Other						
Sales Tax	6.875%	percent			Current MN sales tax rate	
Interest Rate	5.50%	percent			EPA Control Cost Manual Chapter 7, 7th Edition default	
Solid Waste Disposal	44.35	$/ton	41.8	2018	2018 site specific cost	Adjusted for 3% inflation
Contingency	10%	percent			EPA Control Cost Manual Chapter 2, 7th Edition estimates contingencies from 5-15%. Assumed the mid range	
Markup on capital cost (Retrofit Factor)	60%	percent			CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit factor for installations in existing facilities.	
Operating Information						
Annual Op. Hrs	8376	Hours			Site-specific estimate	
Utilization Rate	100%	percent			Site-specific estimate	
Single Furnace Pellet Production Rate	250	Lton/hr			Furnace capacity	
Desgin Capacity	190	MMBTU/hr			Furnace capacity	
Equipment Life	20	yrs			Assumed	
Temperature- After Scrubber	140	Deg F			Stack test data	
Temperature- Before Scrubber	250	Deg F			Site-specific estimate	
Moisture Content-After Scrubber	13.7%				Stack test data	
Moisture Content-Before Scrubber	6.3%		1000	lb H2O/min	Site-specific estimate	
Existing Pollution Contols PM Inlet Concentraiton	2.17	gr/dscf dust load		2018	Site-specific estimate	
Existing Pollution Contols PM Control Efficiency	94%	percent			2020 TVOP reissuance application PM control efficiency	Efficiency is used to calculate the increased baghouse dust loading for DSI because the captured dust cannot be recycled to process with the spent/unreacted reagent. This does not apply to the GSA/SDA because there is an ESP upstream of the absorber.
Actual Flow Rate-After Scrubber	420,000	acfm			Site-specific estimate	
Actual Flow Rate-Before Scrubber	460,000	acfm			Site-specific estimate	
Standardized Flow Rate-After Scrubber	369,600	scfm @ 68º F	344,400	scfm @ 32º F	Calculated from stack temperature and flow data in acfm listed above	
Standardized Flow Rate-Before Scrubber	342,085	scfm @ 68º F	318,761	scfm @ 32º F	Calculated from stack temperature and flow data in acfm listed above	
Dry Std Flow Rate-After Scrubber	318,965	dscfm @ 68º F			Calculated from stack temperature and flow data in acfm listed above	
Dry Std Flow Rate-Before Scrubber	320,696	dscfm @ 68º F			Calculated from stack temperature and flow data in acfm listed above	
Fuel higher heating value (HHV)	1,033	BTU/scf			EPA Control Cost Manual Chapter 7, 7th Edition default	
Plant Elevation	1,500	Feet above sea level			Site elevation	
Method 19 Design Factor (SCR)	8,710	dscf/MMBtu			Natural gas F-Factor	
Technology Control Efficiencies						
SCR	50%	percent			Control efficiency provided by Solnhofer Portland Cement Works GmbH & Co. KG. Reference "The Experience of SCR at Solhhofen and its Applicability to US Cement Plants, June 6, 2006. According to Portland Cement Association, the EPA 7th Edition SCR control cost data severally underestimates the costs of installation and operation of SCR control technology designed for utility boilers and transfer to Portland Cement kilns. Assumed similar control efficiency to a cement kiln.	
GSA	-2%	percent			Calculated control efficiency to determine reduction over baseline emissions to 5 ppm outlet per vendor specifications	
SDA	-2%	percent			Calculated control efficiency to determine reduction over baseline emissions to 5 ppm outlet per vendor specifications	
DSI	-2%	percent			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.	
Existing scrubber SO2 Control Efficiency	25%	percent			Site-specific estimate	
	Baseline Emissions					
Pollutant	**lb/hr**	**tpy**	**ppmv**			
Nitrous Oxides (NOx)	348	1,325	151		Baseline tpy is site-specific estimate. Lb/hr represents average when furnace was operating at >50% capacity	
Sulfur Dioxide (SO2)	15.7	59.7	4.9		Baseline tpy is site-specific estimate. Lb/hr represents average when furnace was operating at >50% capacity	
Outlet SO2 controls target			5.0			
Sulfur Dioxide (SO2) Uncontrolled with Scrubbers Removed	20.9	79.6	7		SO2 emission rate without the existing scrubbers	

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[5]	344,400	scfm @ 32º F
Expected Utilization Rate	100%		Exhaust Temperature[5]	140	Deg F
Expected Annual Hours of Operation	8,376	Hours	Exhaust Moisture Content[5]	13.7%	
Annual Interest Rate	5.5%		Actual Flow Rate[5]	420,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate[5]	369,600	scfm @ 68º F
Pellet Throughput	250	LTon/hr	Dry Std Flow Rate[5]	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, supervision, materials, replacement parts, utilities, etc.	SCR + Reheat	**17,578,490**
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	SCR + Reheat	**3,772,408**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		SCR + Reheat	**21,350,897**

Emission Control Cost Calculation

Pollutant	**Emissions Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/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	60%	of TCI, see *Cost Estimate* tab	
Lost Production for Tie-In			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**
Total Annual Cost (Annualized Capital Cost + Operating 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	

Replacement Catayst - Refer to the *Cost Estimate Tab*

Annualized Cost	**$**	**763,512**

Equivalent Duty	2,197
Uncontrolled Nox lb/mmBtu	0.158
SCR Capital Cost	

Electrical Use

Reagent Use & Other Operating Costs
Refer to the *Cost Estimate* tab

Design Basis		**Max Emis lb/MMBtu**		**Control Eff (%)**
				50%
Nitrous Oxides (NOx)		0.158	Adjusted lb/MMBtu	
Actual	100,726	dscf/MMBtu		
Method 19 Factor	8,710	dscf/MMBtu	**NG F-FACTOR**	
Adjusted Duty	2,197	MMBtu/hr		

Operating Cost Calculations	**Annual hours of operation:**	**8,376**
	Utilization Rate:	**100%**

Refer to the *Cost Estimate* tab

Cleveland Cliffs: United Taconite Line 1
Appendix A - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

Operating Unit: **Line 1**

Emission Unit Number	EU 040		Stack/Vent Number	SV 046		**Chemical Engineering**		
	190	MMBtu/hr	Standardized Flow Rate[3]	344,400	scfm @ 32º F	**Chemical Plant Cost Index**		
Expected Utilization Rate	100%		Exhaust Temperature[3]	140	Deg F	1998/1999	390	
Expected Annual Hours of Operation	8,376	Hours	Exhaust Moisture Content[3]	13.7%		2019	607.5	
Annual Interest Rate	5.5%		Actual Flow Rate[3]	420,000	acfm	Inflation Adj	1.56	
Expected Equipment Life	20	yrs	Standardized Flow Rate[3]	369,600	scfm @ 68º F			
Pellet Throughput	250	LTon/hr	Dry Std Flow Rate[3]	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 device cost (A)	**401,678**
Installation - Standard Costs	30%	of purchased 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 equip cost (B)	152,637
Total Capital Investment (TCI) with Retrofit			**1,079,709**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	15,587,817
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	204,894
Total Annual Cost (Annualized Capital Cost + Operating 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.

Cleveland Cliffs: United Taconite Line 1
Appendix A - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**329,582**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	32,958
MN Sales Taxes	6.9%	of control device cost (A)	22,659
Freight	5%	of control device cost (A)	16,479
Purchased Equipment Total (B)	22%		**401,678**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	32,134
Handling & erection	14%	of purchased equip cost (B)	56,235
Electrical	4%	of purchased equip cost (B)	16,067
Piping	2%	of purchased equip cost (B)	8,034
Insulation	1%	of purchased equip cost (B)	4,017
Painting	1%	of purchased equip cost (B)	4,017
Installation Subtotal Standard Expenses	30%		**120,503**
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			**120,503**
Total Direct Capital Cost, DC			**522,181**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	40,168
Construction & field expenses	5%	of purchased equip cost (B)	20,084
Contractor fees	10%	of purchased equip cost (B)	40,168
Start-up	2%	of purchased equip cost (B)	8,034
Performance test	1%	of purchased equip cost (B)	4,017
Model Studies		of purchased equip cost (B)	0
Contingencies	10%	of purchased equip cost (B)	40,168
Total Indirect Capital Costs, IC	38%	of purchased equip cost (B)	**152,637**
Total Capital Investment (TCI) = DC + IC			**674,818**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**674,818**
Total Capital Investment (TCI) with Retrofit Factor	60%	1.6 Retrofit Factor	**1,079,709**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	72.12	\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr	37,755
Supervisor	15%	15% of Operator Costs	5,663
Maintenance			
Maintenance Labor	72.12	\$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr	37,755
Maintenance Materials	100%	of maintenance labor costs	37,755
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
Natural Gas	4.98	\$/kscf, 6,181 scfm, 8376 hr/yr, 100% utilization	15,468,890
Total Annual Direct Operating Costs			**15,587,817**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	71,357
Administration (2% total capital costs)	2%	of total capital costs (TCI)	21,594
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	10,797
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	10,797
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	90,349
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**204,894**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**15,792,712**

Cleveland Cliffs: United Taconite Line 1
Appendix A - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

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

Replacement Catalyst:	**Catalyst**	
Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	0	$/ft^3
Amount Required	39	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

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

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Thermal	420,000		19	0.6		1,556.1	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Blower, Catalytic	420,000		23	0.6		1,883.7	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Oxidizer Type	**thermal**	(catalytic or thermal)				0.0	Reheat is by duct burner, pressure drop does not apply

Reagent Use & Other Operating Costs Oxidizers - NA

Operating Cost Calculations			**Annual hours of operation:**			**8,376**	
			Utilization Rate:			**100%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual 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 Maintenance Labor			NA	37,755	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.068	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8376 hr/yr, 100% utilization
Natural Gas	4.98	$/kscf	6,181	scfm	3,106,203	15,468,890	$/kscf, 6,181 scfm, 8376 hr/yr, 100% utilization

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

Cleveland Cliffs: United Taconite Line 1
Appendix A - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

Flue Gas Re-Heat Equipment Cost Estimate Basis Thermal Oxidizer with 70% Heat Recovery

Auxiliary Fuel Use Equation 3.19

T_{wi}	140	Deg F - Temperature of waste gas into heat recovery
T_{fi}	800	Deg F - Temperature of Flue gas into heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	0%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	140	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	800	Deg F - Temperature of flue gas out of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.2684	Btu/lb - Deg F Heat Capacity of waste gas (air)
ρ_{wg}	0.0739	lb/scf - Density of waste gas (air) at 77 Deg F
ρ_{af}	0.0408	lb/scf - Density of auxiliary fuel (methane) at 77 Deg F
Q_{wg}	369,600	scfm - Flow of waste gas
Q_{af}	6,181	scfm - Flow of auxiliary fuel

Cost Calculations 375,781 scfm Flue Gas — Cost in 1989 $'s $211,583
Current Cost Using CHE Plant Cost Index $329,582

Heat Rec %	A	B	
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 Capacity - Basis Typical Composition

	100 scfm	359 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_x 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 ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), 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

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 the level of difficulty. Enter 1 for projects of average retrofit 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)?	2,197	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,033	Btu/scf
What is the estimated actual annual fuel consumption?	17,816,081,913	scf/Year
Operating hours	8,376	
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

If the NPHR is not known, use the default NPHR value:

ASSUME DEFAULT

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	1,500	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	349	days
Number of days the boiler operates (t_{plant})	349	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.16	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.08	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	2	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	882254	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	8,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	800	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

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
Annual Interest Rate (i)	5.5	Percent*
Reagent ($Cost_{reag}$)	1.814	\$/gallon for 50% urea
Electricity ($Cost_{elect}$)	0.0684	\$/kWh
Catalyst cost ($CC_{replace}$)	248.05	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	72.12	\$/hour (including benefits)
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005	1.325
Administrative Charges Factor (ACF) =	0.03	

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-	
Electricity Cost ($/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/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/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_B) =	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_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.956	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8376	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	50.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	174.00	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	662.50	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.63		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	882,254	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	143.31	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/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]$^{5.256}$ 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 https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	1.0000	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	6,156.14	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	919	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	1,057	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	32.5	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	43	feet

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	119	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	238	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	25	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ 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 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	1129.81	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/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 TCI =	$197,727	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$381,769	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$647,665	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$763,512	in 2019 dollars
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_x Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Selective Catalytic Reduction with Reheat (SCR)	50%	937.0	937.0	$72,550,865	$41,336,088	$44,115

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Dry Sorbent Injection (DSI) 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 (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	EU 042		
Stack/Vent Number	SV 048 & 049		

Item	Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	72.12	$/hr		2020	Site-specific labor cost	
Maintenance Labor	72.12	$/hr		2020	Site-specific labor cost	
Electricity	0.068	$/kwh	68.44	2020	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	
Compressed Air	0.48	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Adjusted for 3% inflation
Taconite Pellets	29.1	$/LT		2020	Based on Q1 2020 sales margin in earnings report	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Hydrated lime cost from 2012 Dry Flugas Desulfurization Study for UTAC Lines 1 and 2	Adjusted for 3% inflation
Urea 50% Solution	1.81	$/gallon	1.66	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Trona	285.00	$/ton		2020	Vendor estimated delivered cost	
Estimated operating life of the catalyst ($H_{catalyst}$)	8,000	hours			EPA Control Cost Manual Chapter 7, 7th Edition	
Catalyst cost ($CC_{replace}$)	248.05	$/cubic foot (inclu	227	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Cost per bag	116.70	$/bag	110	2018	Vendor estimated bag cost from the 2018 Best Available Mercury Reduction Technology (BAMRT) Analysis	Adjusted for 3% inflation
Other						
Sales Tax	6.875%	percent			Current MN sales tax rate	
Interest Rate	5.50%	percent			EPA Control Cost Manual Chapter 7, 7th Edition default	
Solid Waste Disposal	44.35	$/ton	41.8	2018	2018 site specific cost	Adjusted for 3% inflation
Contingency	10%	percent			EPA Control Cost Manual Chapter 2, 7th Edition estimates contingencies from 5-15%. Assumed the mid range	
Markup on capital cost (Retrofit Factor)	60%	percent			CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit factor for installations in existing facilities. However, the retrofit factor does not apply to the GSA/SDA because the costs were based on a site-specific estimate.	
Operating Information						
Annual Op. Hrs	8376	Hours			Site-specific estimate	
Utilization Rate	100%				Site-specific estimate	
Single Furnace Pellet Production Rate	600	Lton/hr			Furnace capacity	
Desgin Capacity	400	MMBTU/hr			Furnace capacity	
Equipment Life	20	yrs			Assumed	
Temperature- After Scrubber	136	Deg F			Stack test data	
Temperature- Before Scrubber	300	Deg F			Site-specific estimate	
Moisture Content-After Scrubber	13.1%				Stack test data	
Moisture Content-Before Scrubber	6.3%		2300	lb h2o/min	Site-specific estimate	
Existing Pollution Contols PM Inlet Concentraiton	2.17	gr/dscf dust load		2018	Site-specific estimate	
Existing Pollution Contols PM Control Efficiency	94%	percent			2020 TVOP reissuance application PM control efficiency	Efficiency is used to calculate the increased baghouse dust loading for DSI because the captured dust cannot be recycled to process with the spent/unreacted reagent. This does not apply to the GSA/SDA because there is an ESP upstream of the absorber.
Actual Flow Rate-After Scrubber	840,000	acfm			Site-specific estimate	
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 acfm listed above	
Standardized Flow Rate-Before Scrubber	778,251	scfm @ 68º F	725,189	scfm @ 32º F	Calculated from stack temperature and flow data in acfm listed above	
Dry Std Flow Rate-After Scrubber	646,676	dscfm @ 68º F			Calculated from stack temperature and flow data in acfm listed above	
Dry Std Flow Rate-Before Scrubber	729,057	dscfm @ 68º F			Calculated from stack temperature and flow data in acfm listed above	
Fuel higher heating value (HHV)	1,033	BTU/scf			EPA Control Cost Manual Chapter 7, 7th Edition default	
Plant Elevation	1,500	Feet above sea level			Site elevation	
Method 19 Design Factor (SCR)	8,710	dscf/MMBtu			Natural gas F-Factor	
Technology Control Efficiency						
SCR	50%	%			Control efficiency for a cement kiln referenced in the EPA Control Cost Manual Chapter 7, 7th Edition. Efficiencies may be as high as 90%, but SCR has not been demonstrated in practice on taconite indurating furnaces.	
GSA	50%	%			Calculated control efficiency to determine reduction over baseline emissions to 5 ppm outlet per vendor specifications	
SDA	50%	%			Calculated control efficiency to determine reduction over baseline emissions to 5 ppm outlet per vendor specifications	
DSI	50%	%			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.	
Existing scrubber SO2 Control Efficiency	25%	%			Site-specific estimate	
	Max Emis	**Baseline Emissions**				
Pollutant	**Lb/Hr**	**tpy**	**ppmv**			
Nitrous Oxides (NOx)	488.0	1,874.0	93		Baseline tpy is site-specific estimate. Lb/hr represents average during baseline period when furnace was operating at >50% capacity	
Sulfur Dioxide (SO2)	73.1	215.4	10		Baseline tpy is site-specific estimate. Lb/hr represents average during baseline period when furnace was operating at >50% capacity	
Outlet SO2 controls target			5			
Sulfur Dioxide (SO2) Uncontrolled with Scrubbers I	97.5	287.2	13		SO2 emission rate without the existing scrubbers	

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 3: NO_x 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[5]	693,423	scfm @ 32º F
Expected Utilization Rate	100%		Exhaust Temperature[5]	136	Deg F
Expected Annual Hours of Operation	8,376	Hours	Exhaust Moisture Content[5]	13.1%	
Annual Interest Rate	5.5%		Actual Flow Rate[5]	840,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate[5]	744,161	scfm @ 68º F
Pellet Throughput	600	LTon/hr	Dry Std Flow Rate[5]	646,676	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Total Capital Investment (TCI) with Retrofit							SCR Only	71,277,677
							SCR + Reheat	**72,550,865**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					SCR + Reheat	**35,153,534**
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					SCR + Reheat	**6,182,554**
Total Annual Cost (Annualized Capital Cost + Operating Cost)							SCR + Reheat	**41,336,088**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/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	60%	of TCI, see *Cost Estimate* tab	
Lost Production for Tie-In			5,866,560
Total Capital Investment Retrofit Installed			**71,277,677**

OPERATING COSTS

Direct Annual Operating Costs, DC			
Maintenance			
Annual Maintenance Cost =		Refer to the *Cost Estimate* tab	322,208
Utilities, Supplies, Replacements & Waste Management			
Annual Electricity Cost =		Refer to the *Cost Estimate* tab	1,313,090
Annual Catalyst Replacement Cost =		Refer to the *Cost Estimate* tab	1,523,872
Annual Reagent Cost =		Refer to the *Cost Estimate* tab	559,897
Total Annual Direct Operating Costs			**3,719,067**
Indirect Operating Costs			
Administrative Charges (AC) =		Refer to the *Cost Estimate* tab	6,887
Capital Recovery Costs (CR)=	0.0837	Refer to the *Cost Estimate* tab	5,965,942
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**5,972,828**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,691,896**

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 - Refer to the *Cost Estimate Tab*

Annualized Cost	$	**1,523,872**

Equivalent Duty	4,455
Uncontrolled Nox lb/mmBtu	0.115
SCR Capital Cost	

Electrical Use

Reagent Use & Other Operating Costs
Refer to the *Cost Estimate* tab

Design Basis		**Max Emis lb/MMBtu**		**Control Eff (%)**
Nitrous Oxides (NOx)		0.115	Adjusted lb/MMBtu	50%
Actual	97,001	dscf/MMBtu		
Method 19 Factor	8,710	dscf/MMBtu	**NG F-FACTOR**	
Adjusted Duty	4,455	MMBtu/hr		

Operating Cost Calculations		
	Annual hours of operation:	**8,376**
	Utilization Rate:	**100%**

Refer to the *Cost Estimate* tab

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

Operating Unit: **Line 2**

Emission Unit Number	EU 042		Stack/Vent Number	SV 048 & 049		**Chemical Engineering**	
	400	MMBtu/hr	Standardized Flow Rate[3]	693,423	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utilization Rate	100%		Exhaust Temperature[3]	136	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,376	Hours	Exhaust Moisture Content[3]	13.1%		2019	607.5
Annual Interest Rate	5.5%		Actual Flow Rate[3]	840,000	acfm	Inflation Adj	1.56
Expected Equipment Life	20	yrs	Standardized Flow Rate[3]	744,161	scfm @ 68º F		
Pellet Throughput	600	LTon/hr	Dry Std Flow Rate[3]	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 device cost (A)	**473,656**
Installation - Standard Costs	30%	of purchased 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 equip cost (B)	179,989
Total Capital Investment (TCI) with Retrofit			**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		Sum indirect oper costs + capital recovery cost	209,726
Total Annual Cost (Annualized Capital Cost + Operating 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.

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) (1)		**388,641**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC		
Instrumentation	10% of control device cost (A)	38,864
MN Sales Taxes	6.9% of control device cost (A)	26,719
Freight	5% of control device cost (A)	19,432
Purchased Equipment Total (B)	22%	**473,656**
Installation		
Foundations & supports	8% of purchased equip cost (B)	37,893
Handling & erection	14% of purchased equip cost (B)	66,312
Electrical	4% of purchased equip cost (B)	18,946
Piping	2% of purchased equip cost (B)	9,473
Insulation	1% of purchased equip cost (B)	4,737
Painting	1% of purchased equip cost (B)	4,737
Installation Subtotal Standard Expenses	30%	**142,097**
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		**142,097**
Total Direct Capital Cost, DC		**615,753**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	47,366
Construction & field expenses	5% of purchased equip cost (B)	23,683
Contractor fees	10% of purchased equip cost (B)	47,366
Start-up	2% of purchased equip cost (B)	9,473
Performance test	1% of purchased equip cost (B)	4,737
Model Studies	of purchased equip cost (B)	0
Contingencies	10% of purchased equip cost (B)	47,366
Total Indirect Capital Costs, IC	38% of purchased equip cost (B)	**179,989**
Total Capital Investment (TCI) = DC + IC		**795,743**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**795,743**
Total Capital Investment (TCI) with Retrofit Factor	60% 1.6 Retrofit Factor	**1,273,188**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	72.12 $/Hr, 0.5 hr/8 hr shift, 8376 hr/yr	37,755
Supervisor	15% 15% of Operator Costs	5,663
Maintenance		
Maintenance Labor	72.12 $/Hr, 0.5 hr/8 hr shift, 8376 hr/yr	37,755
Maintenance Materials	100% of maintenance labor costs	37,755
Utilities, Supplies, Replacements & Waste Management		
NA	NA	-
Natural Gas	4.98 $/kscf, 12,512 scfm, 8376 hr/yr, 100% utilization	31,315,539
Total Annual Direct Operating Costs		**31,434,467**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	71,357
Administration (2% total capital costs)	2% of total capital costs (TCI)	15,915
Property tax (1% total capital costs)	1% of total capital costs (TCI)	7,957
Insurance (1% total capital costs)	1% of total capital costs (TCI)	7,957
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	106,540
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**209,726**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**31,644,192**

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

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

Replacement Catalyst:	**Catalyst**	
Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	0	$/ft^3
Amount Required	39	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

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

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Thermal	840,000		19	0.6		3,112.2	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Blower, Catalytic	840,000		23	0.6		3,767.4	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Oxidizer Type	**thermal**	(catalytic or thermal)				0.0	Reheat is by duct burner, pressure drop does not apply

Reagent Use & Other Operating Costs Oxidizers - NA

Operating Cost Calculations — **Annual hours of operation: 8,376** — **Utilization Rate: 100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual 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 Maintenance Labor			NA	37,755	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
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	31,315,539	$/kscf, 12,512 scfm, 8376 hr/yr, 100% utilization

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

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

Flue Gas Re-Heat Equipment Cost Estimate Basis Thermal Oxidizer with 70% Heat Recovery

Auxiliary Fuel Use Equation 3.19

T_{wi}	136	Deg F - Temperature of waste gas into heat recovery
T_{fi}	800	Deg F - Temperature of Flue gas into heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	0%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	136	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	800	Deg F - Temperature of flue gas out of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.2684	Btu/lb - Deg F Heat Capacity of waste gas (air)
p_{wg}	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_{wg}	744,161	scfm - Flow of waste gas
Q_{af}	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	
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 Capacity - Basis Typical Composition

		100 scfm	359 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_x 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 ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), 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

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 the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.6

* NOTE: You must document why a retrofit factor of 1.6 is appropriate for the proposed project.

Do not rename this tab - EPA CCM spreadsheet has hidden

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	4,455	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,033	Btu/scf
What is the estimated actual annual fuel consumption?	36,120,700,808	scf/Year
Operating Hours	8,376	
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

If the NPHR is not known, use the default NPHR value:

ASSUME DEFAULT

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 1,500 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ● Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	349	days
Number of days the boiler operates (t_{plant})	349	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.11	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.057	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	2	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	1776357	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	8,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	800	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

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
Annual Interest Rate (i)	5.5	Percent*
Reagent ($Cost_{reag}$)	1.814	$/gallon for 50% urea
Electricity ($Cost_{elect}$)	0.0684	$/kWh
Catalyst cost ($CC_{replace}$)	248.05	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	72.12	$/hour (including benefits)
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005	1.325
Administrative Charges Factor (ACF) =	0.03	

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-	
Electricity Cost ($/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/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/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_B) =	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_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.956	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8376	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	50.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	255.19	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	937.00	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.63		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	1,776,357	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	144.57	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/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]$^{5.256}$ 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 https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	1.0000	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	12,286.86	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	1,850	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	2,128	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	46.1	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	43	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	175	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	350	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	37	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ 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 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	2290.59	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

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)

Annual Maintenance Cost =	0.005 x TCI =	$322,208	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$559,897	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$1,313,090	in 2019 dollars
Annual Catalyst Replacement Cost =		$1,523,872	in 2019 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$		
Direct Annual Cost =		$3,719,067	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) =	$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

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**9,551,151**
Purchased Equipment Total (B)	12%	of control device cost (A)	**10,685,351**
Installation - Standard Costs	70%	of purchased 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 equip cost (B)	5,556,382
Total Capital Investment (TCI) = DC + IC			**33,741,308**
Total Capital Investment (TCI) with Retrofit Factor			**50,466,157**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	4,657,379
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	6,740,531
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**10,090,749**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual Ton/Yr	Calculation Method	Cont Eff %	Performance Basis	Conc. Units	Cont Emis Ton/Yr	Reduction Ton/Yr	Cont Cost $/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

1 Purchased equipment cost from vendor quotes for baghouse and anciliary equipment, adjusted for inflation using the Chemical Engineering Plant Cost Index (CEPCI).
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Used 0.6 power law factor to adjust prices based on acfm from vendor bids if applicable
4 Trona DSI applications typically achieve a 70% SO2 reduction, but the uncontrolled concentrations are too low to achieve this level of control
5 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

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**9,551,151**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	0%	Included in vendor estimate	-
State Sales Taxes	6.9%	of control device cost (A)	656,642
Freight	5%	of control device cost (A)	477,558
Purchased Equipment Total (B)	12%		**10,685,351**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	427,414
Handling & erection	50%	of purchased equip cost (B)	5,342,675
Electrical	8%	of purchased equip cost (B)	854,828
Piping	1%	of purchased equip cost (B)	106,854
Insulation	7%	of purchased equip cost (B)	747,975
Painting	0%	Included in vendor estimate	-
Installation Subtotal Standard Expenses	70%		**7,479,745**
Site specific - Site Prep	N/A	Site Specific	94,293
Site specific - Ductwork	N/A	Site Specific	3,198,081
Site specific - Buildings	N/A	Site Specific	2,159,470
0	N/A	Site Specific	0
Lost Production for Tie-In	N/A	Site Specific	5,866,560
Total Site Specific Costs			11,318,403
Installation Total			**18,798,149**
Total Direct Capital Cost, DC			**29,483,499**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,068,535
Construction & field expenses	20%	of purchased equip cost (B)	2,137,070
Contractor fees	10%	of purchased equip cost (B)	1,068,535
Start-up	1%	of purchased equip cost (B)	106,854
Performance test	1%	of purchased equip cost (B)	106,854
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	1,068,535
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**5,556,382**
Total Capital Investment (TCI) = DC + IC			**35,039,882**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**33,741,308**
Total Capital Investment (TCI) with Retrofit Factor	60%	1.6 Retrofit Factor	**50,466,157**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	72.12	$/Hr	151,019
Supervisor	0.15	of Op Labor	22,653
Maintenance			
Maintenance Labor	72.12	$/Hr	75,510
Maintenance Materials	100	% of Maintenance Labor	75,510
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh	1,062,948
Solid Waste Disposal	44.35	$/ton	2,436,978
Trona	285.00	$/ton	578,973
Taconite Product Loss	29	$/LTon	253,788
Total Annual Direct Operating Costs			**4,657,379**
Savings from Shutdown of Existing Emission Controls			**$ (1,307,161)**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	194,815
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,009,323
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	504,662
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	504,662
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	4,222,974
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**6,740,531**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**10,090,749**

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		
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	117	$/bag
Amount Required	8399	Bags
Total Rep Parts Cost	1,096,651	Cost adjusted for freight & sales tax
Installation Labor	201,923	20 min per bag
Total Installed Cost	**1,298,573**	
Annualized Cost	**304,095**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	1,120,210	7.18	12,199,907	Incremental electricity increase over with baghouse replacing scrubber including ducting
Air Compressor			3,331,191	Based on Compressor HP
Total			15,531,098	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	73.13	lb/hr SO2	485.07	lb/hr Trona
Solid Waste Disposal	53,322	ton/yr existing scrubber inlet process dust loading		
Solid Waste Disposal	1,632	ton/yr DSI unreacted sorbent and reaction byproducts		
Taconite Product Loss	8721	ton/yr lost iron production from scrubber replacement by baghouse		

Operating Cost Calculations

Utilization Rate 100% Annual Operating Hours 8,376

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	72.12	$/Hr	2.0	hr/8 hr shift	2,094	$	151,019	$/Hr, 2.0 hr/8 hr shift, 2,094 hr/yr
Supervisor	15%	of Op Labor			NA	$	22,653	% of Operator Costs
Maintenance								
Maint Labor	72.12	$/Hr	1.0	hr/8 hr shift	1,047	$	75,510	$/Hr, 1.0 hr/8 hr shift, 1,047 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$	75,510	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.068	$/kwh	1854.2	kW-hr	15,531,098	$	1,062,948	$/kwh, 1,854 kW-hr, 8376 hr/yr, 100% utilization
Solid Waste Disposal	44.35	$/ton	6.56	ton/hr	54,954	$	2,436,978	$/ton, 7 ton/hr, 8376 hr/yr, 100% utilization
Trona	285.00	$/ton	485.1	lb/hr	2,031	$	578,973	$/ton, 485 lb/hr, 8376 hr/yr, 100% utilization
Taconite Pellets	29.100	$/LTon	1.0	LT/hr	8,721	$	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

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			26,325,693
Purchased Equipment Total (B)	10%	of control device cost (A)	**28,958,262**
Installation - Standard Costs	74%	of purchased equip 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 cost (B)	12,162,470
Total Capital Investment (TCI) with Site-specific Costs			**120,947,748**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	5,410,769
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	15,470,358
Savings from Shutdown of Existing Emission Controls			(1,307,161)
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**19,573,967**

Emission Control Cost Calculation

Pollutant	Max Emis lb/hr	Annual T/Yr (Actual Emissions)	Cont Eff %	Exit Conc.	Conc. Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Sulfur Dioxide (SO_2):	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
4 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)			**26,325,693**
Instrumentation	10%	of control device cost (A)	2,632,569
MN Sales Taxes	0%	of control device cost (A)	0
Freight	0%	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	50%	of purchased equip cost (B)	14,479,131
Electrical	8%	of purchased equip cost (B)	2,316,661
Piping	1%	of purchased equip cost (B)	289,583
Insulation	7%	of purchased equip cost (B)	2,027,078
Painting	4%	of purchased equip cost (B)	1,158,330
Installation Subtotal Standard Expenses	74%		**21,429,114**
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	10%	of purchased equip cost (B)	2,895,826
Start-up	1%	of purchased equip cost (B)	289,583
Performance test	1%	of purchased equip cost (B)	289,583
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)	**12,162,470**
Total Capital Investment (TCI) = DC + IC			**62,549,846**
TCI Adj for Baghouse Filter Replacement			**61,918,209**
Retrofit multiplier	0%	of TCI	**0**
Site Specific Installed Equipment Costs			
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	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	285,510
Utilities, Supplies, Replacements & Waste Management			
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	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			
Overhead	60%	of total labor and material costs	511,622
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,418,955
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,209,477
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,209,477
Capital Recovery	0.0837	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)			**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		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	20	years
CRF	0.0000	
Rep part cost per unit	0	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment: Filter 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 adjusted 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 replacement parts needed**	
Annualized Cost	**234,119**		

Electrical Use							
	Flow acfm		**Δ P in H2O**	**Efficiency**	**Hp**	**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**	**Hp**	**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[1] **ft^2/kacfm**	**Plate Area ft^2**	**kW/ft^2**			
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 Operating Costs				
Hydrated Lime Use	51.43	lb/hr SO2 no scrubber	91.88	lb/hr lime, lime addition
NSR	1.30		114.63	lb CaSO3/hr
Waste Lime			21.20	lb/hr waste lime
Total Waste			135.84	lb/hr waste

An NSR of 1.3 means that 30% more lime is injected than is needed to capture SO2.

Operating Cost Calculations — **Annual hours of operation: 8,376** — **Utilization Rate: 100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor BH + ESP	72.12	$/Hr	5.0	hr/8 hr shift	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 Maintenance Labor			NA	75,510	100% of Maintenance Labor
ESP Maint Mtls and Lbr	5	% of ESP purchase cost				210,000	5% of ESP Purchase Cost
Utilities, Supplies, Replacements & Waste Management							
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 is in same units of measurement as the unit cost factor

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

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			22,356,887
Purchased Equipment Total (B)	10%	of control device cost (A)	**24,592,575**
Installation - Standard Costs	74%	of purchased equip cost (B)	18,198,506
Installation - Site Specific Costs			61,304,825
Installation Total			18,198,506
Total Direct Capital Cost, DC			42,791,081
Total Indirect Capital Costs, IC	42%	of purchased equip cost (B)	10,328,882
Total Capital Investment (TCI) with Site-specific costs			**113,793,152**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	5,453,619
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	14,611,193
Savings from Shutdown of Existing Emission Controls			(1,307,161)
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**18,757,651**

Emission Control Cost Calculation

Pollutant	**Max Emis lb/hr**	**Actual Emissions Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Sulfur Dioxide (SO_2):	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
4 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 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			
Engineering, supervision	10%	of purchased equip cost (B)	2,459,258
Construction & field expenses	20%	of purchased equip cost (B)	4,918,515
Contractor fees	10%	of purchased equip cost (B)	2,459,258
Start-up	1%	of purchased equip cost (B)	245,926
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			
Civil/Structural			1,664,454
Mechanical Equipment			38,450,302
Electrical and Control			4,839,425
Freight			1,404,916
Total Indirect Costs + Contingencies			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			
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	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 Management			
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	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			**5,453,619**
Savings from Shutdown of Existing Emission Controls			**(1,307,161)**
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	0.0837	for a 20- year equipment life and a 5.5% interest rate	9,522,135
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**14,611,193**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**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)

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

Replacement Catalyst:		
Equipment Life	20	years
CRF	0.0000	
Rep part cost per unit	0	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment: Filter 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 adjusted 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 replacement parts needed**	
Annualized Cost	**234,119**		

Electrical Use							
	Flow acfm		Δ P in H2O	**Efficiency**	**Hp**	**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**	**Hp**	**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[1]	**Plate Area**				
		ft^2/kacfm	**ft^2**	**kW/ft^2**			
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 Operating Costs				
Hydrated Lime Use	51.43	lb/hr SO2 no scrubber	91.88	lb/hr lime, lime addition
NSR	1.30		114.63	lb CaSO3/hr
Waste Lime			21.20	lb/hr waste lime
Total Waste			135.84	lb/hr waste

An NSR of 1.3 means that 30% more lime is injected than is needed to capture SO2.

Operating Cost Calculations — **Annual hours of operation:** **8,376** — **Utilization Rate:** **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor BH + ESP	72.12	$/Hr	5.0	hr/8 hr shift	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 Maintenance 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, Replacements & Waste Management							
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 is 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

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1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency (MPCA) submitted a Request for Information (RFI) Letter[1] to United States Steel Corporation, Minnesota Ore Operations – Keetac (Keetac) to consider potential emissions reduction measures of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) 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)[2]:

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[3] (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_x and SO_2. Keetac has BART emission controls and emission limits for NO_X and SO_2 in accordance with 40 CFR 52.1235(b)(1) and 52.1235(b)(2), respectively.

[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to United States Steel Corporation, Minnesota Ore Operations – Keetac.

[2] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[3] 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[4] and October 2015[5] 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.

[4] USEPA, Federal Register, 08/15/2012, Page 49308.

[5] 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_2 and NO_X 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.[6] 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_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 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)[7], by July 31, 2020 for the emission units identified in Table 2-1.

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[6] 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.

[7] 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 Gas, Phase II	(EQUI 97/EU 030)	NO_X, SO_2

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[8].

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."[9] 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 and determine 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."[10]

The SIP revision must also include the "Long-term strategy for regional haze."[11] 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[12], emission unit retirement and replacement

[8] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[9] 40 CFR 51.308(f)(1)

[10] 40 CFR 51.308(f)(1)(vi)(A)

[11] 40 CFR 51.308(f)(2)

[12] 51.308(f)(2)(iv)(A)

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

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)[15]. The reasonable progress goal is not enforceable but will be considered by USEPA in evaluating the adequacy of the SIP[16].

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*"[17] 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."[18]

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"[19] 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."[20] 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.[21]

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)

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[13] 51.308(f)(2)(iv)(C)

[14] 51.308(f)(2)(iv)(E)

[15] 40 CFR 51.308(f)(3)

[16] 40 CFR 51.308(f)(3)(iii)

[17] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[18] Ibid, page 1.

[19] Ibid.

[20] Ibid, page 9 (emphasis added).

[21] Ibid.

- 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):[22]

$$URP = [(\text{2000-2004 visibility})_{\text{20\% most impaired}} - (\text{natural visibility})_{\text{20\% most impaired}}]/60$$

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.[23] 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…."[24]

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

[22] Ibid, Page 7.

[23] Ibid, Page 50.

[24] 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, 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 periods. 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."[25]

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[26]
- the four statutory factors (to the extent they have been characterized at this point in SIP development)[27]
- potential visibility benefits (also to the extent they have been characterized at this point in SIP development)[28]
- sources already having effective emissions controls in place[29]
- emission reductions at the source due to ongoing air pollution control programs[30]
- in-state emission reductions due to ongoing air pollution control programs that will result in an improvement in visibility[31]

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."[32]

[25] Ibid, Page 9.

[26] Ibid, Page 10.

[27] Ibid.

[28] Ibid.

[29] Ibid, Page 21.

[30] Ibid, Page 22.

[31] Ibid.

[32] 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[33]:

- 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:[34]

> "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."[35] 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."[36] 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

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[33] Ibid, Page 12.

[34] Ibid, Page 27.

[35] Ibid, Page 22.

[36] Ibid, Page 25.

analysis of control measures."[37] 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."[38]

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."[39]

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.

[37] Ibid.

[38] Ibid.

[39] Ibid.

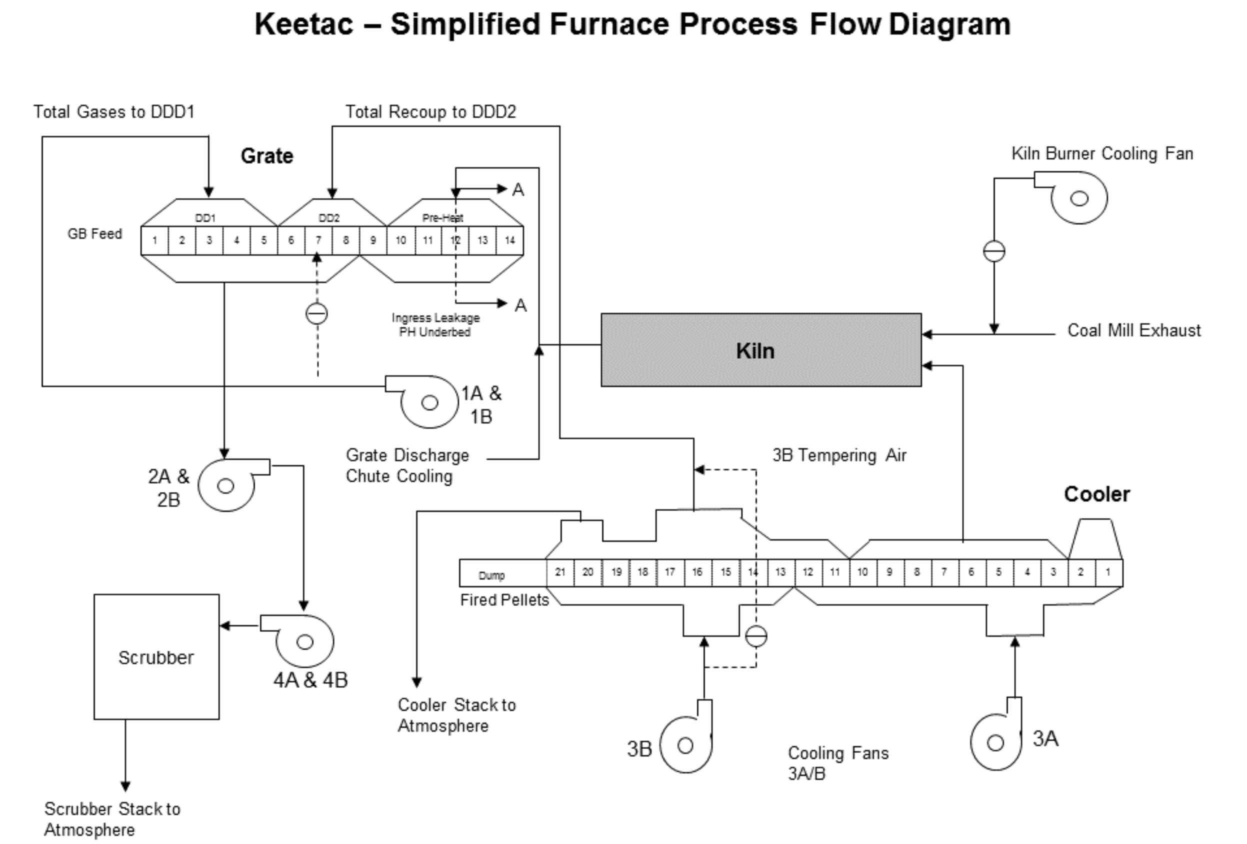

Figure 2-1 Grate Kiln – Indurator Waste Gas, Phase II (EQUI 97/EU 030) Diagram

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."[40] 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.[41] 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."[42]

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).[43] 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.[44] 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."[45] In

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[40] 40 CFR 51.308(f)(1)

[41] 40 CFR 51.308(f)(3)

[42] 40 CFR 51.308(d)(1)

[43] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[44] https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

[45] 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."[46]

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath[47] 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.

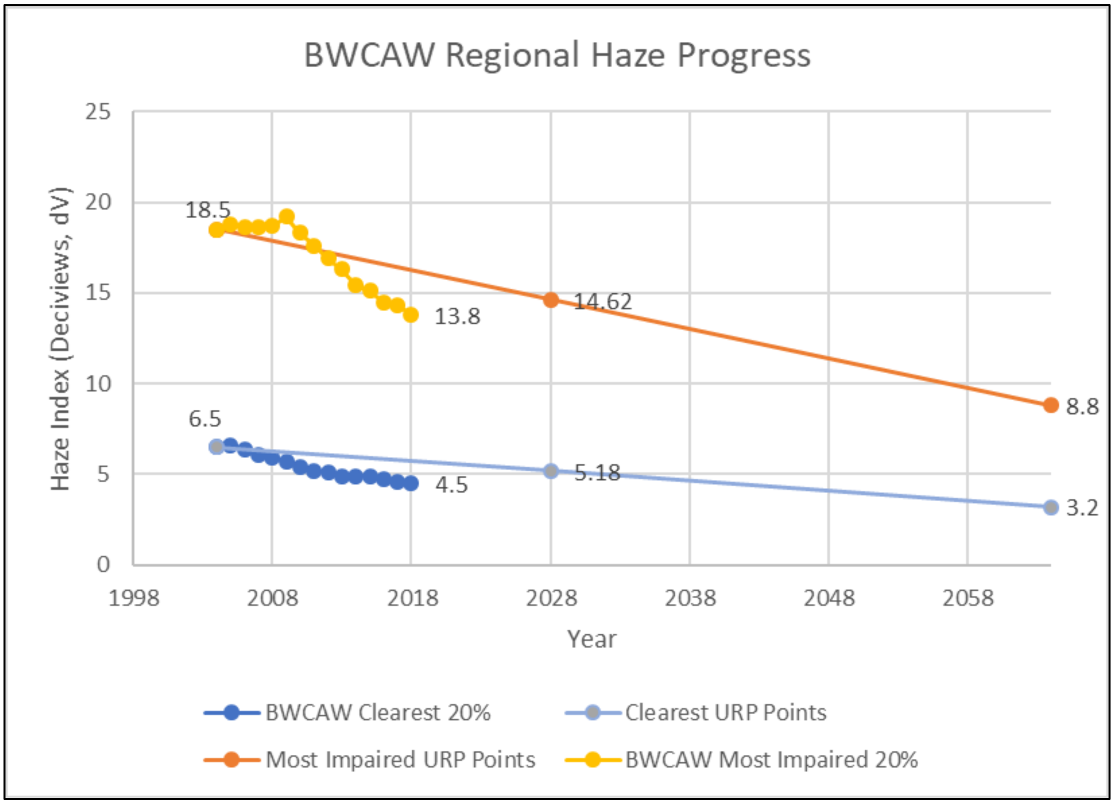

Figure 3-1 Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

[46] USEPA, Federal Register, 01/10/2017, Page 3104

[47]https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

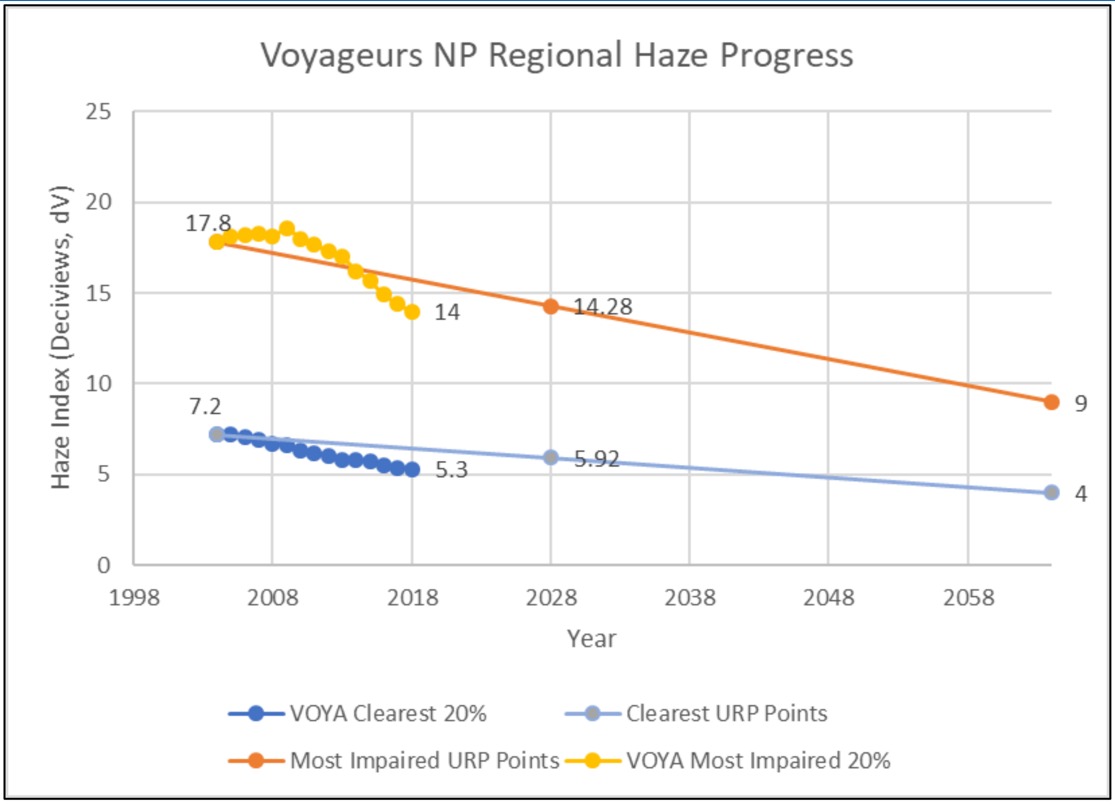

Figure 3-2 Visibility Trend versus URP – Voyageurs National Park (VOYA1)

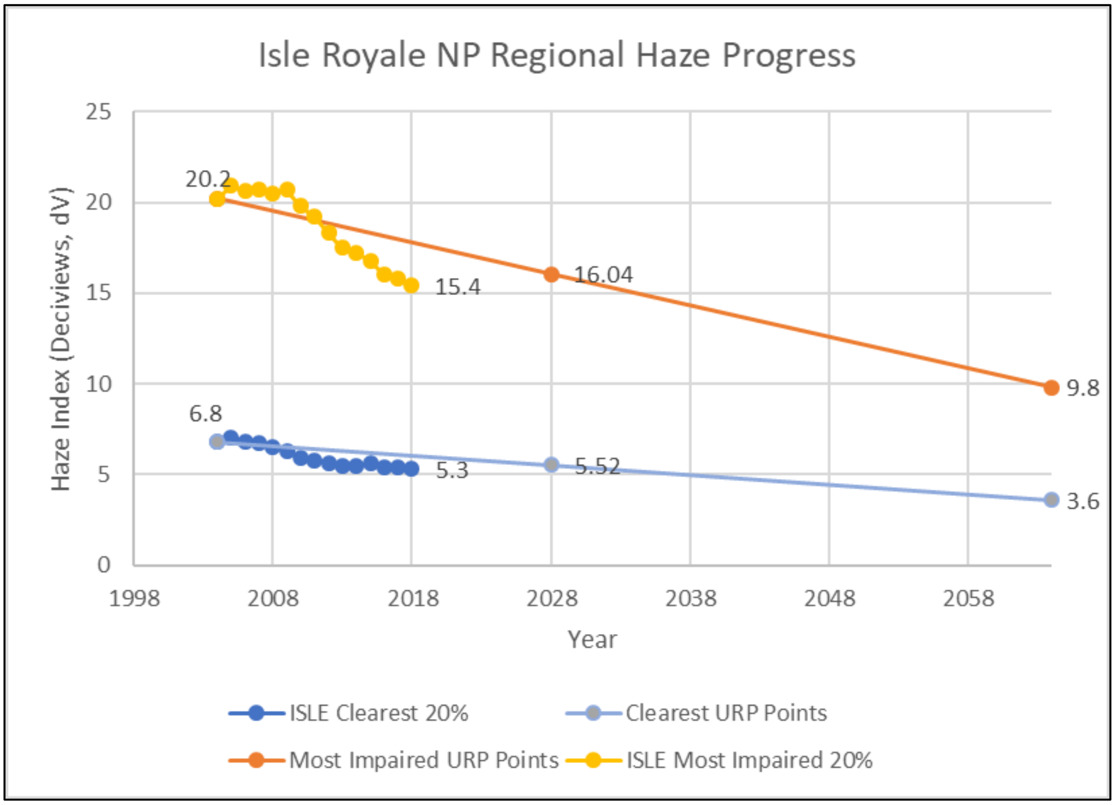

Figure 3-3 Visibility Trend versus URP – Isle Royale National Park (ISLE1)

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[48]. 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
  - 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.

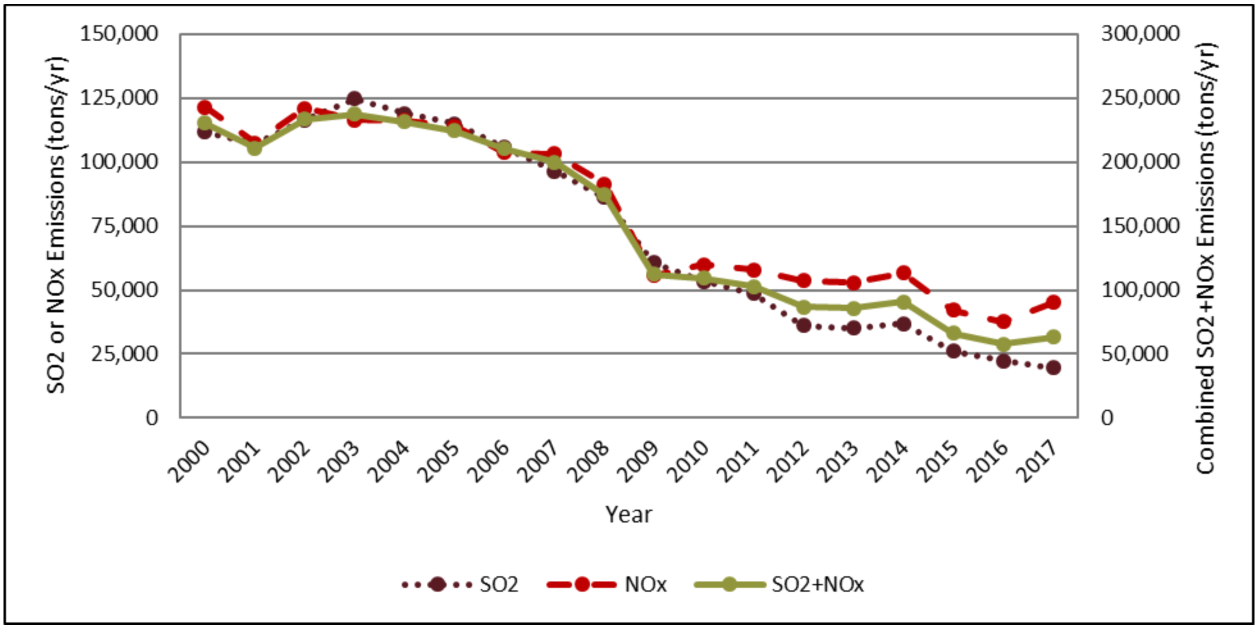

Figure 3-4 Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)

48 The data for NO_X and SO_2 emissions was downloaded from the MPCA point source emissions inventory (https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data). 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.

Table 3-1 Notable Minnesota Emission Reductions

Year	Additional Emissions Reductions Expected/Projected
2015	MP Laskin: converted from coal to natural gas(1)
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) MP Boswell: Units 1 & 2 retired from service(1)
2019	Hibtac Line 1: FIP emission limit compliance date for NO_X(2) Keetac: FIP emission limit compliance date for NO_X(2) Minntac Line 4 or 5: FIP emission limit compliance date for NO_X(2) 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) Minntac Line 4 or 5: FIP emission limit compliance date for NO_X(2) Minorca: FIP emission limit compliance date for NO_X(2) Utac Line 2: FIP emission limit compliance date for NO_X(2)
2021	Minntac Line: FIP emission limit compliance date for NO_X(2) Hibtac Line 3: FIP emission limit compliance date for NO_X(2)
2023	Xcel: Sherco Unit 2 Retirement(3)
2026	Xcel: Sherco Unit 1 Retirement(3)
2028	Xcel: Allen S. King Plant Retirement(3)
2030	Xcel: Sherco Unit 3 Retirement, Xcel target to emit 80% less carbon by 2030(3)
2050	Xcel: Energy targeting carbon free generation by 2050(3)

(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*[49]
  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*[50]
  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_X emission reductions suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces.

- *Other reasonable techniques*[51]
  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

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[49] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 13.

[50] Ibid, Page 14.

[51] 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."[52] 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."[53]

[52] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.
[53] 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."[54] This section demonstrates that the grate-kiln meets USEPA's BART-required control equipment installation scenario for NO_X and SO_2.

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 NO_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 grate kiln[56]

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_X BART-required Controls

In the August 2012 proposed rule FR notice preamble,[57] the USEPA concluded that BART for NO_X from grate-kiln furnaces is low-NO_X 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

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54 USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, page 22.

55 Ibid, page 25.

56 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.

57 Federal Register 77, No. 158 (August 15, 2012); 49311. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

- Selective Catalytic Reduction (SCR) controls because of two SCR vendors declining to bid on NO_x reduction testing at the U.S. Steel Minntac facility.[58]

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_X 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. [59] 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_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 grate-kiln from the requirement to submit a four-factor analysis[60].

Table 5-1 NO_X Emission Limits

Unit	Unit ID	NO_X Emission Limit[(1)] (lb/MMBtu)	Compliance Date([2])
Grate Kiln – Indurator Waste Gas, Phase 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_2 BART-required Controls

In the preamble to the August 2012 proposed FIP[61], the USEPA concluded that BART for SO_2 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

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58 Ibid, 49323.

59 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.

60 USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10.

61 Federal Register 77, No. 158 (August 15, 2012); 49325. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

- 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[62]

In addition, USEPA eliminated Wet Walled Electrostatic Precipitator (WWESP) and secondary (polishing) wet scrubber technologies because they were not cost-effective.[63]

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_2 emissions from taconite indurating furnaces.

In accordance with the FIP, Keetac has continued to operate the BART SO_2 control measures and is complying with the FIP SO_2 emission limit[64], 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_2. 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[65].

Table 5-2 SO_2 Emission Limits

Unit	Unit ID	SO_2 Emission Limit (lb/hr)	Compliance Date
Grate Kiln – Indurator Waste Gas, Phase II	(EQUI 97/EU 030)	225	June 8, 2013

[62] Ibid, 49324.

[63] Ibid.

[64] 40 CFR 52.1235(b)(2)

[65] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 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_X and SO_2 (see Section 5). As stated in the 2019 Guidance, "it may be reasonable for a state not to select an effectively controlled source."[66] 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
    - o 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_X 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.

[66] 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")[1] 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[2], to determine the frequency that the trajectories on the "most impaired days"[3] 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).[4] 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.[5] 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[6], Draxler - 1992[7], Draxler and Hess - 1998[8]). 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.

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[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[2] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[3] "Most impaired days" is the 20% most anthropogenically impaired days on an annual basis, measured in deciviews (dv), as provided on MPCA's website.

[4] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[5] https://www.arl.noaa.gov/hysplit/hysplit/

[6] http://www.kenrahn.com/DustClub/Articles/Stohl%201998%20Trajectories.pdf

[7] https://www.arl.noaa.gov/documents/reports/ARL%20TM-195.pdf

[8] 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.

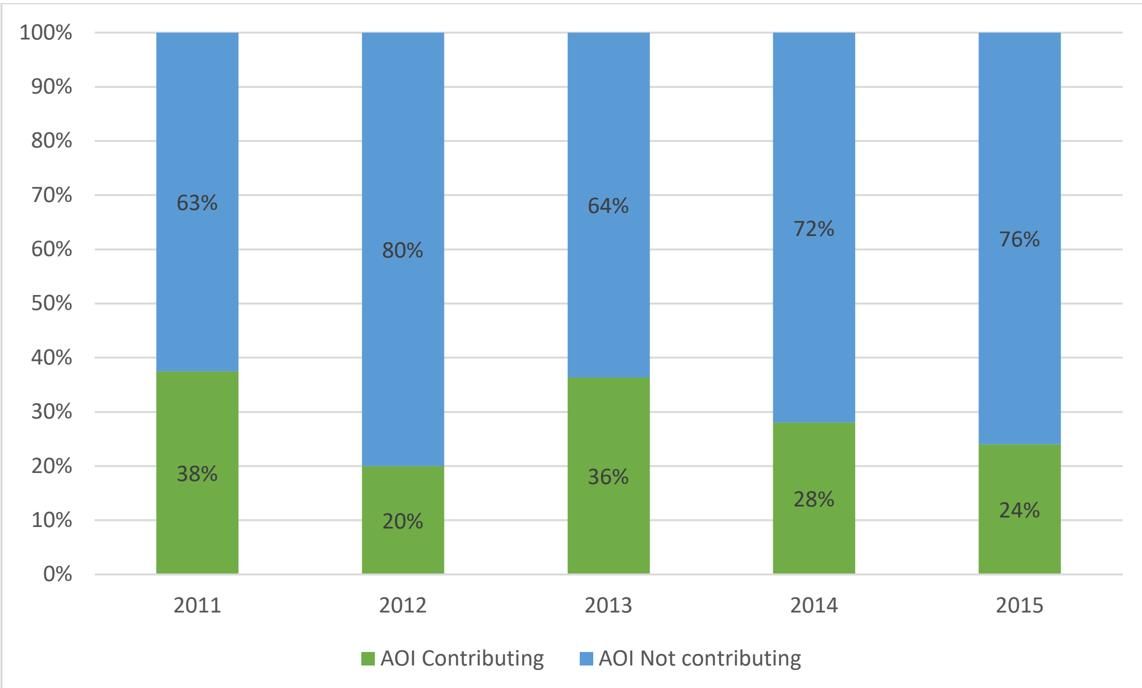

Figure A1 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at BWCA

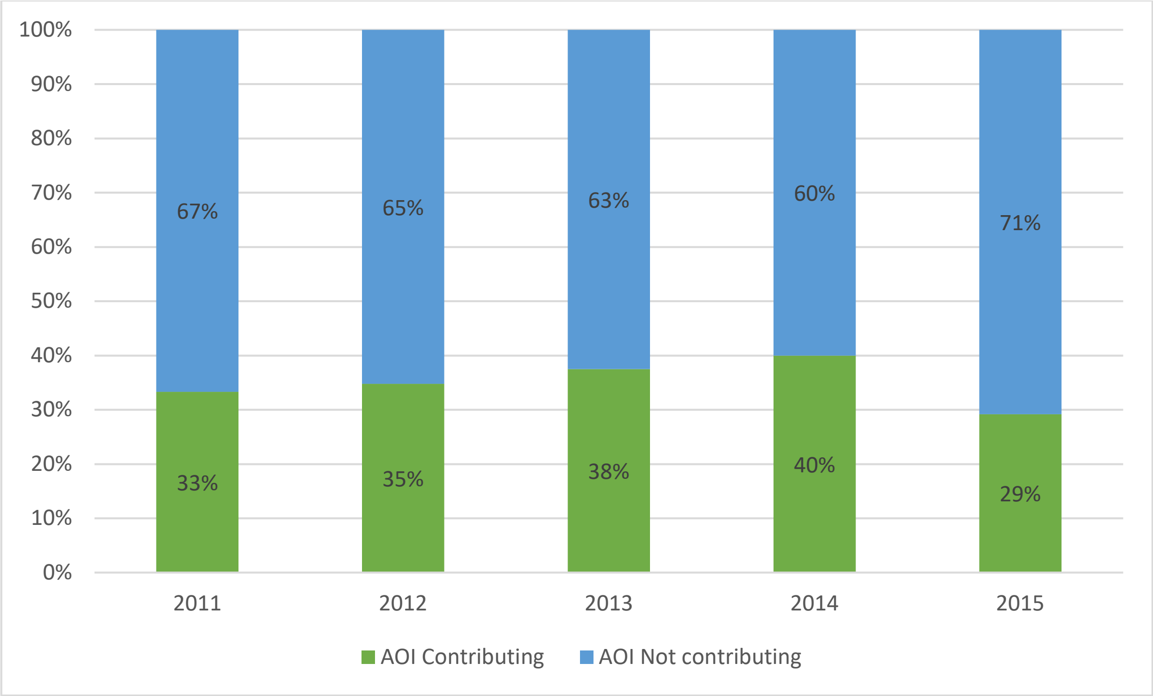

Figure A2 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at Voyageurs

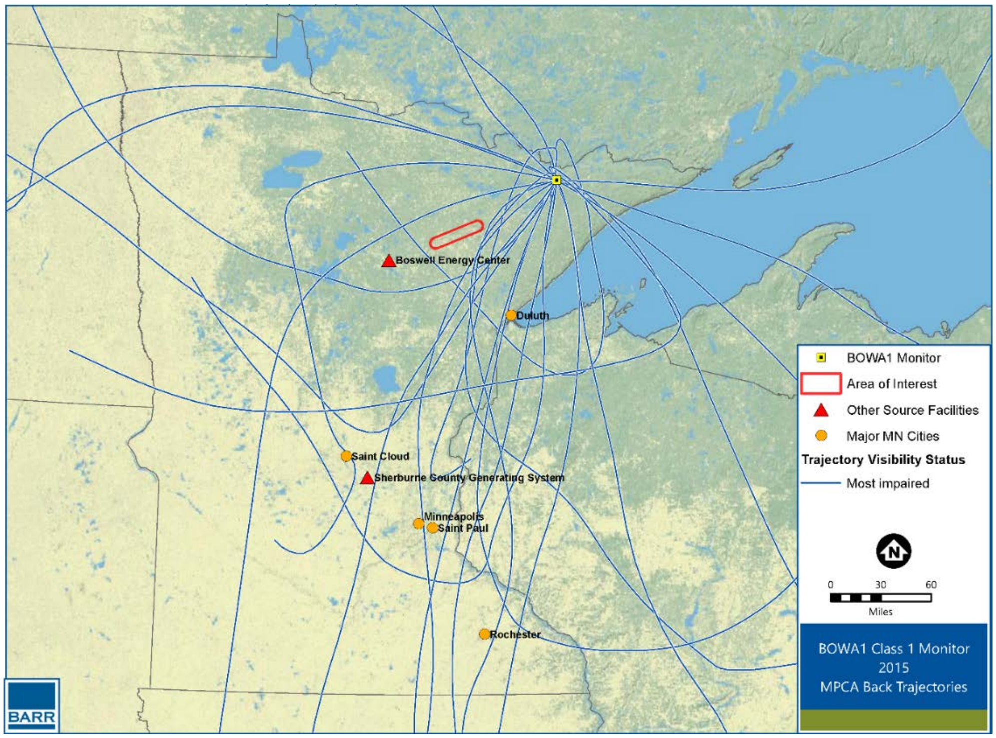

Figure A3 Reverse Trajectories and Other Sources Influencing Visibility at BWCA[9]

[9] 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 visibility impacts (or a surrogate metric for the impacts)</u>, [and] the in-place emission control measures…"*[10]

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. <u>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</u>. 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 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).*

[10] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 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 $PM_{2.5}$ 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."[11]

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 2nd 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_X 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_X 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_X 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 NOx 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_X 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

[11] 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_X 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_X 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_X 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_X 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_3) is a component of haze associated with NO_X 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."[12] 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."[13]

[12] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.
[13] Ibid, Page 12.

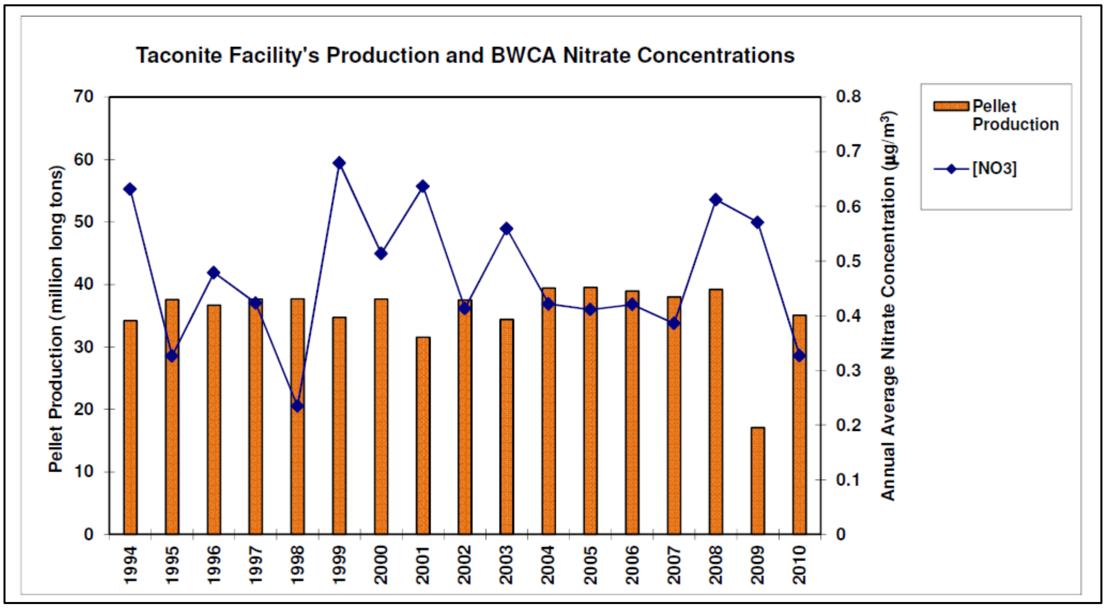

Figure A4 Minnesota Taconite Production and BWCA Nitrate Concentrations 1994-2010 [14]

[14] 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

Table A1 Results from MPCA Hysplit Trajectories for the BOWA1 Monitor

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

Table A2 Results from MPCA Hysplit Trajectories for the VOYA2 Monitor

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

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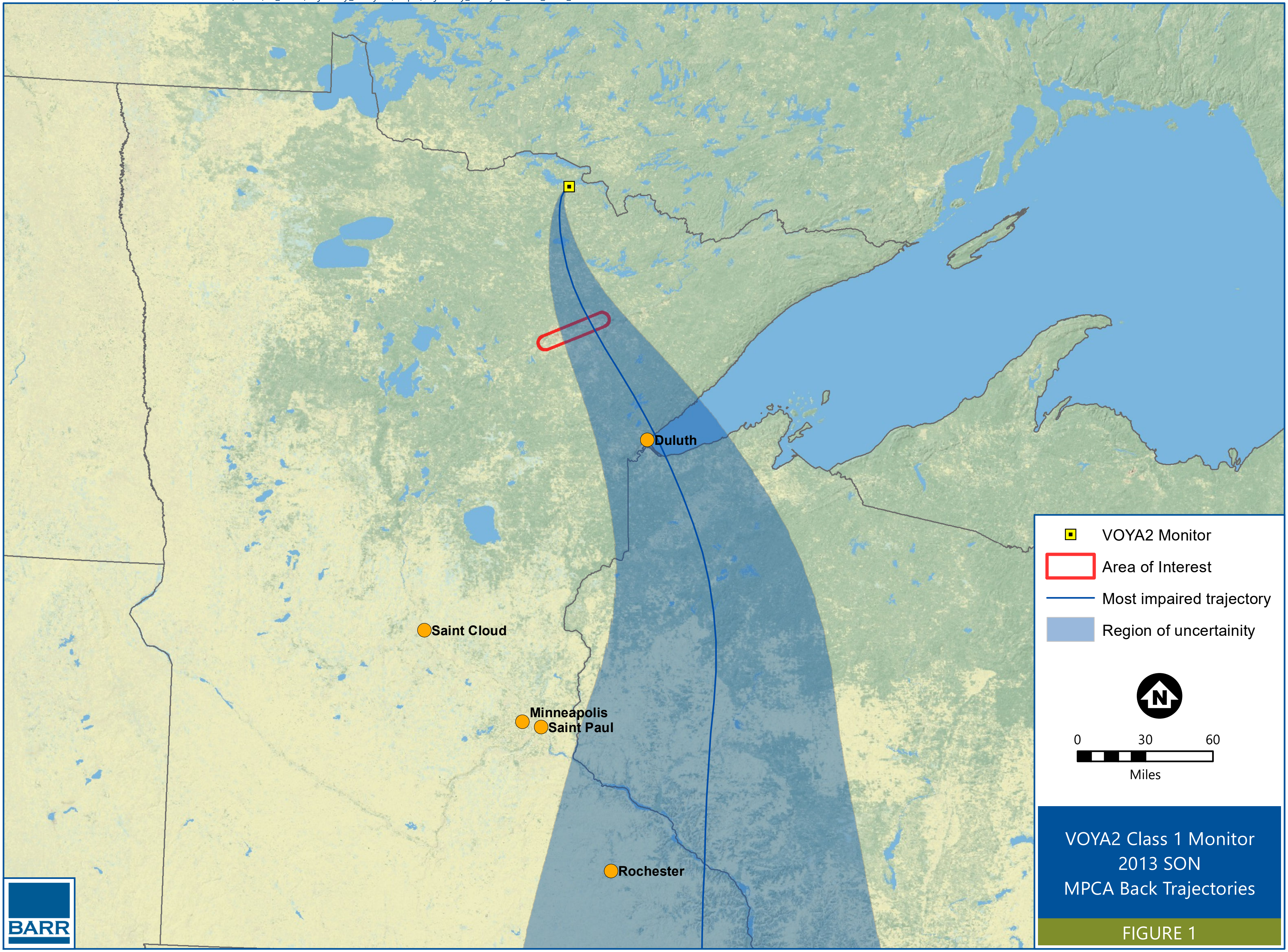

VOYA2 Class 1 Monitor
2013 SON
MPCA Back Trajectories

FIGURE 1

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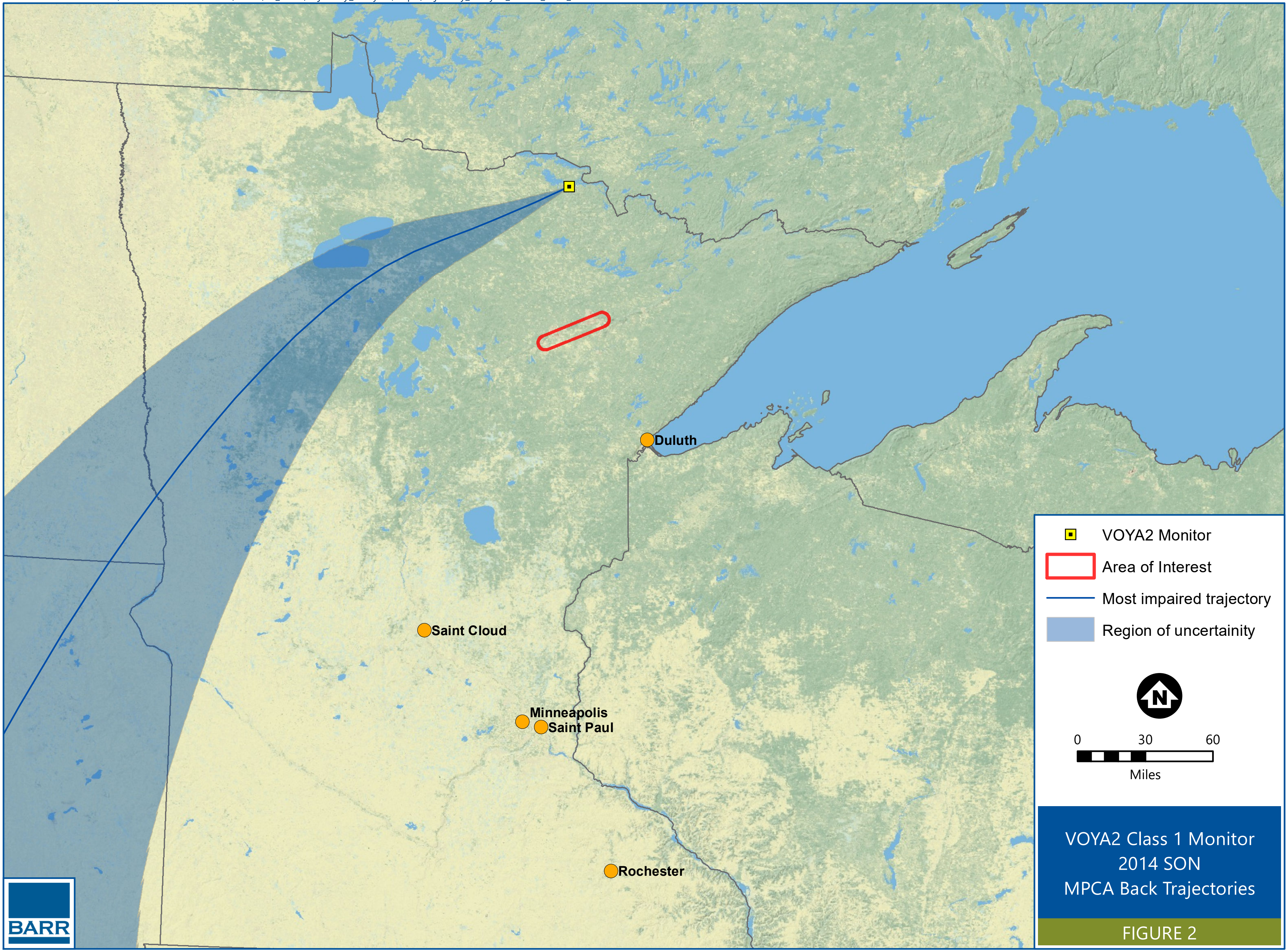

VOYA2 Class 1 Monitor
2014 SON
MPCA Back Trajectories

FIGURE 2

Attachment 2

CAM_X Modeling Report

Technical Memorandum

From: Barr Engineering

Subject: Summary of Comprehensive Air Quality Model with Extensions (CAM_X) 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_X), 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_X, as EPA's approach over-predicted visibility impacts by factors of ten to sixty when compared with the proper CAM_X 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_X Modeling Methodology

The methodology utilized by Barr to complete the CAM_X 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_X modeling system (CAM_X 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_X 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.”[1] 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

[1] 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_X 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_X (including Tilden Mining). A list of the sources that were included in the specific PSAT groups can be found in Appendix C: CAM_X 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.

Table 1: Facility Taconite Furnace Emission Summary

Facility	FIP Baseline (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**

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.

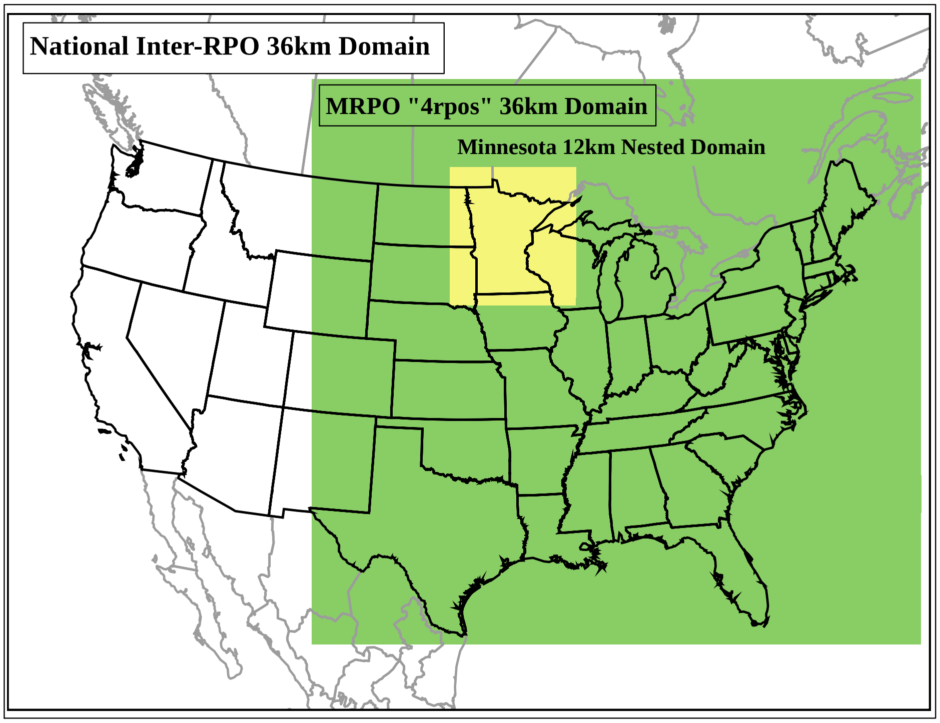

Figure 1. MPCA Modeling Domain

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_X 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_X 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_X/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_X Results

As mentioned above, the CAM_X 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_X 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_X modeling for this project on a facility by facility basis. The first three facilities contain emission reductions for only NO_X: Arcelor Mittal, Hibbing Taconite, and Northshore Mining. These results are summarized in Tables 2-4. United Taconite and Tilden Mining, which have both SO_2 and NO_X emission reductions, have result comparisons that require additional discussion.

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

0.5 dV impact 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)[2],

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

0.1 dV difference was defined by other agencies, such as the northeastern states MANE-VU Regional Planning Organization[3] as the degree of visibility improvement that is too low to justify additional emission controls. In addition, EPA's Regional Haze Rule mentions[4] 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 98th 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_X Modeled Difference).

Table 2: Arcelor Mittal Visibility Impact Comparison

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[2] 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule.

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

[4] 64 FR 35730.

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by 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 Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by 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 Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by 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_X 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 98th percentile visibility improvement in all cases for the Arcelor Mittal, Hibbing Taconite, and Northshore Mining facilities. The maximum 98th 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 98th 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.

Table 5: Hibbing Taconite Line-Specific Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 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

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_2 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_X and the revised emission reduction for SO_2. Then, those resultants were averaged for each of the Class I areas to obtain the "updated" EPA all pollutant estimates.

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

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.6		1.40		110%
Voyageurs	0.8		0.85		N/A
Isle Royale	1.1		0.35		320%

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_X 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_X 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_X 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_X 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.[5]

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

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.0		1.29		N/A
Voyageurs	0.5		0.74		N/A
Isle Royale	0.6		0.28		210%

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

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	2.3		0.18		1300%
Voyageurs	1.1		0.08		1400%
Isle Royale	1.6		0.05		3200%

[5] 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.

Table 9: United Taconite Line-Specific Nitrate Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 98% dV
Boundary Waters	Line 1		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

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.

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

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV
Boundary Waters	N/A		0.08
Voyageurs	N/A		0.03
Isle Royale	N/A*		0.17

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

Table 11: Tilden Mining Pollutant-Specific Impact Comparison

Class I Area	CAM_X Sulfate Modeled Difference 98% dV		CAM_X Nitrate Modeled Difference 98% dV
Boundary Waters	0.07		0.01
Voyageurs	0.03		0.00
Isle Royale	0.14		0.02

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_X 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."[6] Our analysis demonstrates that the ratio approach has over-estimated impacts by a factor of ten to sixty for NO_X reductions. When accurately modeled, the NO_X reductions do not yield discernible visibility benefits. To that end, the following pictures from WinHaze Level 1 Visual Air Quality Imaging Modeler

[6] 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[7].

Isle Royale FIP Base – United Taconite

Isle Royale Final FIP – United Taconite

Boundary Waters FIP Base – Hibbing 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_X 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.

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[7] Voyageurs National Park pictures are not contained within the WinHaze program

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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?

- *<u>For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.</u>*

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.

- *<u>Make the net visibility improvement determination.</u>*

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[1] 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).

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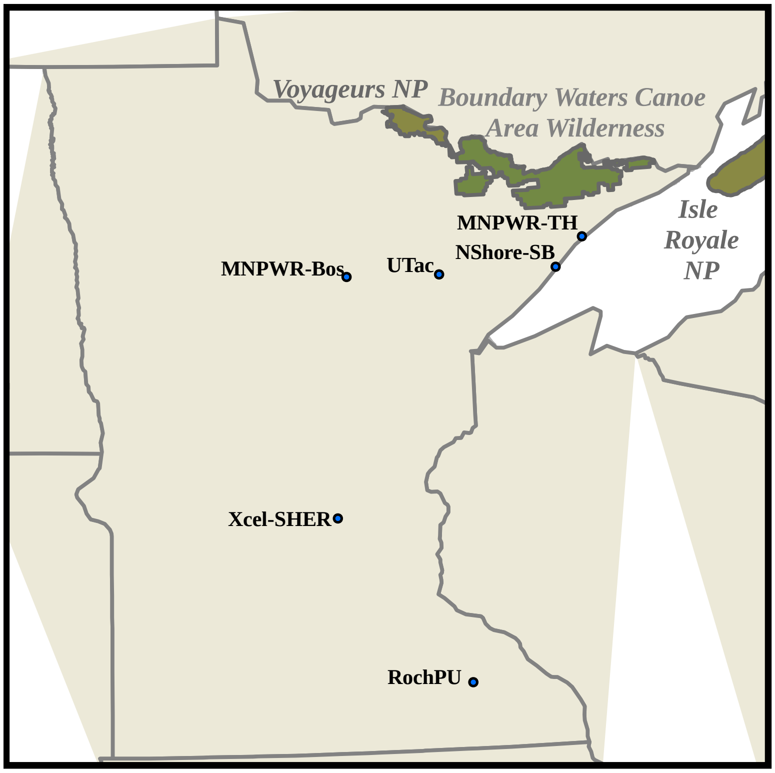
[1] Elevated point emissions include only sources with plume rise above 50m.

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 98th 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 combined the results to estimate 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_X 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_X 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 98th 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_X 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_X 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			Emission Reductions			Emissions	
				Proposed FIP			Baseline - Prop FIP	Baseline - Prop FIP		Final FIP	
Facility	Emission Unit		Pollutant	Baseline	FIP		Emission Tables	Visibility Calcs			
	ModID	Description		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 Combined	NOx	6,888	2,066		**4,821**	**5,259**	[3]		
			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]
	NSM	BART Units Combined	NOx	805	250		**555**	**926**	[9]		
			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]
	TMC	BART Units Combined	NOx	4,707	1,478		3,229	3,229	[18]		
			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 Combined	NOx	5,330	1,599		**3,731**	**3,208**	[26]		
			SO2	4,043	404		3,639	3,639	[26]	529	[28]
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	1,092	[29]	**2,547**	**2,859**	[31]		[32]
			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		EPA Furnace
FIP Baseline does not match reference		NOx Control %
FIP Table B emission tables do not match Table C visibility calculation tables		70%

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 Emisssions = 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)

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APPENDIX B: Barr and MPCA CAM_X Modeling Comparison of Results

March 6, 2013

Minnesota Power – Taconite Harbor (BART01)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	94	90	-4	11	9	-2	30	27	-3
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	95	90	-5	11	9	-2	30	27	-3
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-Ence	Base	BART	Differ-ence	Base	BART	Differ-Ence
Days > 0.5 dv	2002	111	60	-51	86	58	-28	48	27	-21
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-Ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	110	61	-49	86	58	-28	47	27	-20
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	77	72	-5	9	8	-1	20	15	-5
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	78	72	-6	9	8	-1	20	15	-5
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	59	44	-15	32	20	-12	8	1	-7
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	63	46	-17	34	20	-14	8	1	-7
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	74	58	-16	53	39	-14	42	30	-12
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	74	59	-15	53	39	-14	42	29	-13
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	0	0	0	0	0	0	0	0	0
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	0	0	0	0	0	0	0	0	0
98th Percentile Δ dv	2002	0.10	0.06	0.04	0.08	0.04	0.04	0.09	0.04	0.05

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APPENDIX C: CAM_X PSAT Source List

March 6, 2013

2009 MPCA Tracked, Elevated Point Sources

RANKTRAC BARTSRC_ID	RECEPTOR 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

(highlighted) 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	2703100001	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

(green)	Included in Barr Output Evaluation
[3]	Barr tracked furnace stacks and other noted stacks on a unit-basis while all other stacks were included in the "All Other" stacks

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APPENDIX D: Summary of CAM_X Elevated Point Source Emissions

March 6, 2013

Summary of CAMx Elevated Point Source Emissions

Facility	Emission Unit ModID	Emission Unit Description	Pollutant	Emissions Proposed FIP: Baseline tons/yr	Note(s)	Emissions Final FIP: FIP tons/yr	Note(s)	Emission Reductions Baseline - Final FIP: 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 Combined	NOx	6,888		2,066		4,821
			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
	NSM	BART Furnaces Combined	NOx	764		229		535
			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 Combined	NOx	5,330		1,599		3,731
			SO2	4,043		1,969		2,074
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	[28]	1,092	[30]	2,547
			SO2	179	[29]	179	[31]	0

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

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)

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

March 6, 2013

From: Jeffry D. Bennett
Sent: Thursday, January 31, 2013 7:42 PM
To: 'Rosenthal.steven@Epa.gov'
Cc: 'Long, Michael E'
Subject: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: 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

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APPENDIX F: CAMx Modeling Results by Facility

March 6, 2013

Arcelor Mittal CAMx Emissions and Modeling Results

Arcelor Emissions

Unit	EPA FIP Baseline NOx Emission (TPY) [1]	Final FIP NOx Emission (TPY) [1]	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY) [2]	Final FIP SO2 Emission (TPY)[3]	SO2 Emission Difference (TPY)
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)

Arcelor CAMx Results (By Unit) [4]

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Proposed FIP Days > 0.5 dV	Proposed FIP 98% dV	Difference Days >0.5 dV [5]	Difference 98% dV [5]
Boundary Waters						
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
Voyageurs						
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:

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

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

0.1 dV difference 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 98th 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 98th 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 C Emission Difference = 2,859 TPY NOx)[6]

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

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[8]	CAMx Modeled Difference 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

[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 98th 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 Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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
Voyageurs						
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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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 Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (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)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Voyageurs						
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
Isle Royale						
2002						
Power Boiler #1	3	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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	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 Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)[12]	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)[13]	SO2 Emission Difference (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

UTAC CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[16]	CAMx Modeled Difference 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

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

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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

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_X 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).

UTAC Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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						
Line #1 – NO3	0	0.026	0	0.011	0	0.015
Line #1 – SO4	0	0.150	0	0.072	0	0.078
Line #1 – All	0	0.163	0	0.080	0	0.083

UTAC Line 2 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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 – SO4	16	0.773	6	0.436	10	0.337
Line #2 – All	17	0.786	6	0.446	11	0.340
Isle Royale						
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 Comparison of Sulfate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 2,074 TPY SO_2

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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

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

Final FIP Emission Difference = 3,731 TPY NO_x

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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 98th percentile NO_3 impact when combining both line emission reductions is 0.18 dV, while the maximum 98th percentile SO_4 impact for both lines is 1.29 dV. Based on these results, it is evident that the SO_4 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 NO_x emission reductions do not provide substantive visibility improvement.

Tilden Mining CAMx Emissions and Modeling Results

Tilden Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1	0	0.141	0	0.037	0	0.104
2005						
Line #1	0	0.097	0	0.042	0	0.055
Voyageurs						
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

Tilden Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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
Voyageurs						
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

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.

Impacts of the taconite plants' NO_X 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 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X 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)[1] 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[2].

The United States Environmental Protection Agency (EPA) has issued a proposed rule[3] to address BART requirements for taconite plants in Minnesota and Michigan that involves emission controls for SO_2 and NO_X. This document addresses the likely visibility impact of taconite plant emissions, specifically NO_X 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[4], the distance limitation is 200-300 km because of the overprediction tendencies[5] 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.

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[1] Regional Haze Regulations; Final Rule. *Federal Register*, *64*, 35713-35774. (July 1, 1999).

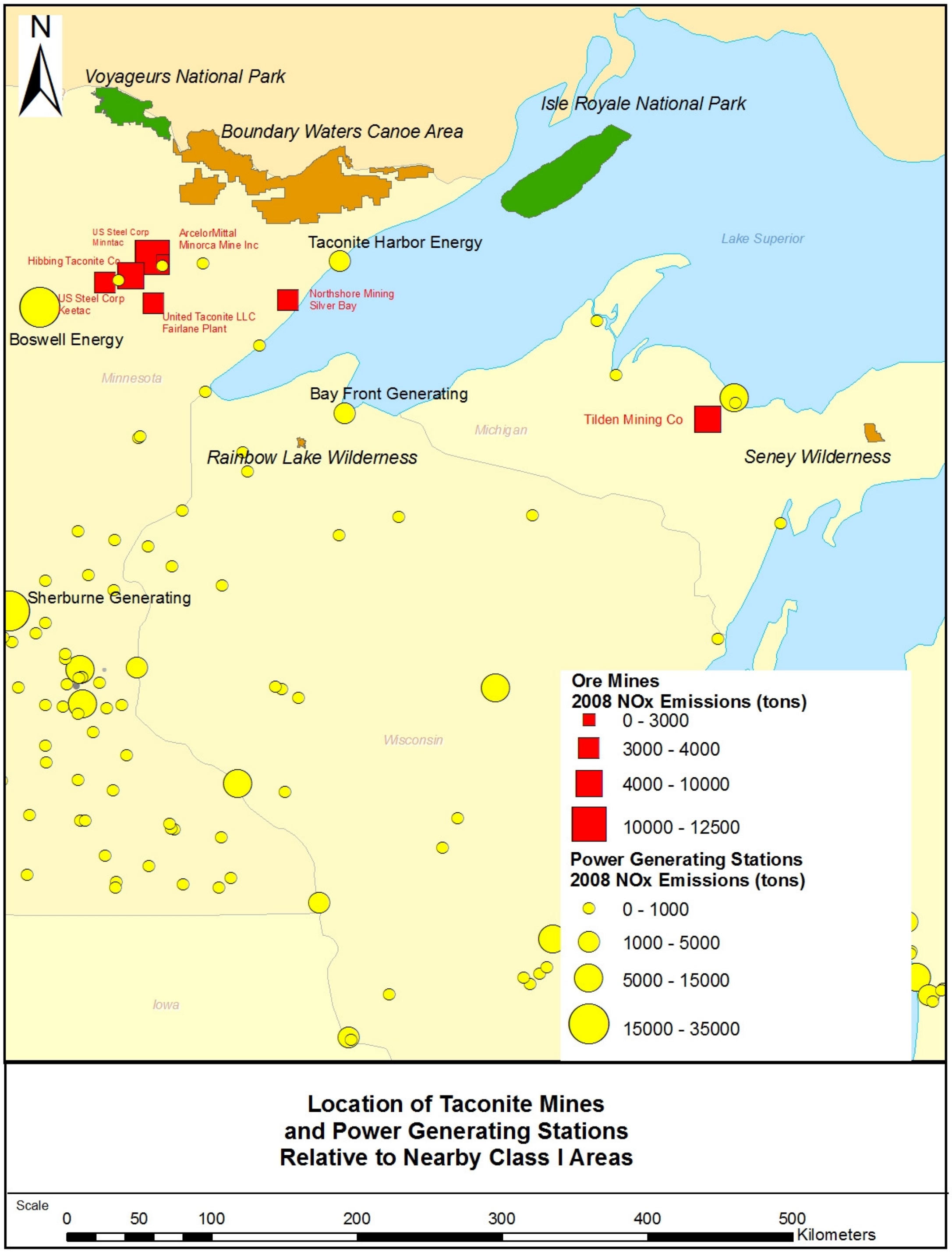
[2] Federal Register. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, Vol. 70. (July 6, 2005)

[3] 77FR49308, August 15, 2012.

[4] CALPUFF Dispersion Model, 2000. http://www.epa.gov/scram001 (under 7th Modeling Conference link to Earth Tech web site).

[5] 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_X emission controls are considered as a BART option because modeling secondary formation of ammonium nitrate is quite challenging. Accurately modeling the effects of NO_X 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_X, and the associated effectiveness of NO_X 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.

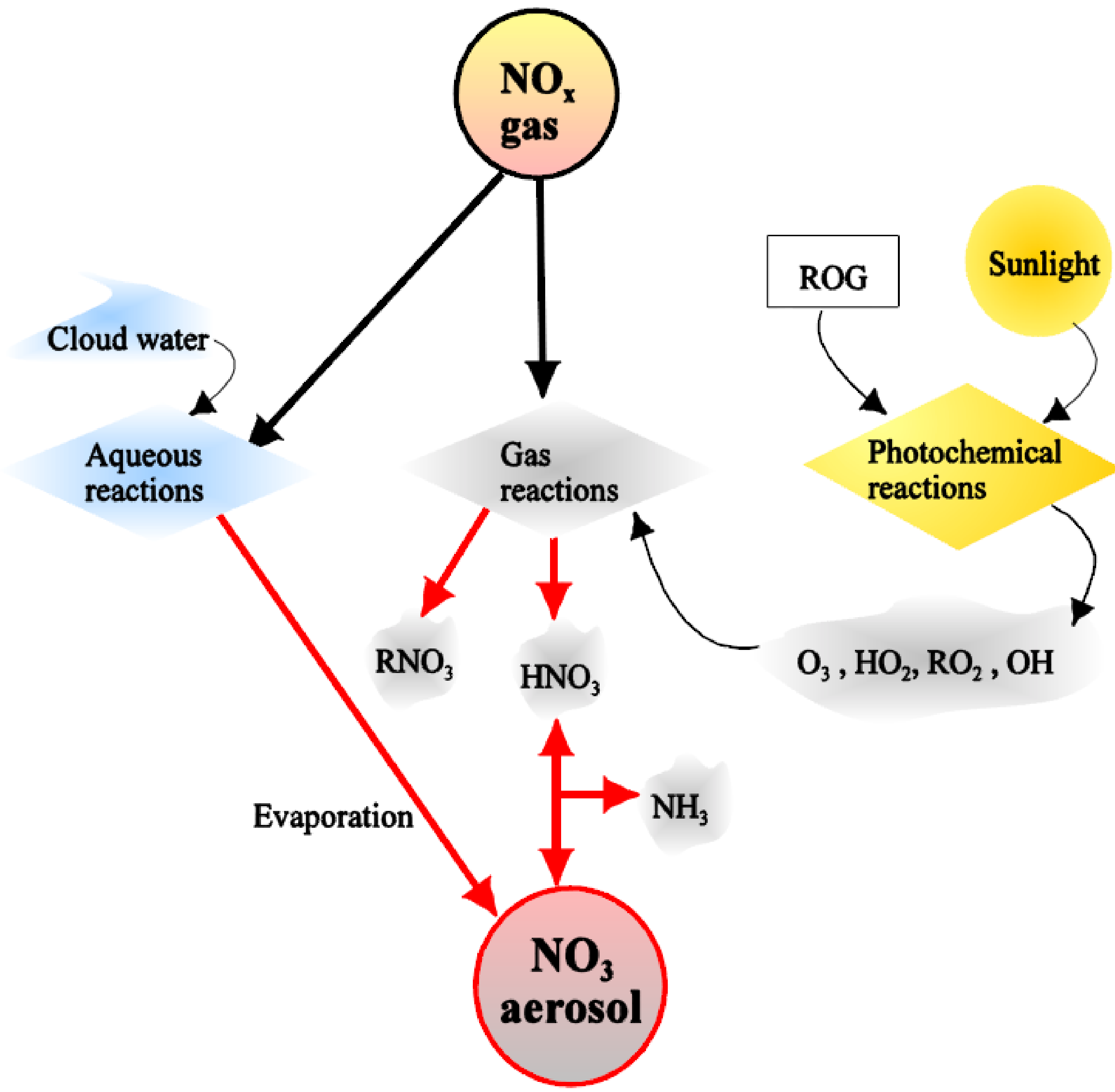
- There are examples where actual significant emission reductions have occurred, where CALPUFF modeling as conducted for BART would predict significant visibility improvements, but no perceptive changes in haze occurred.

Visibility Impact of NO_X Emissions – Unique Aspects and Seasonality

The oxidation of NO_X to total nitrate (TNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the TNO_3 is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state with HNO_3 gas that is a function

of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 2[6]. 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_x Oxidation



[6] Figure 2-32 from CALPUFF Users Guide, available at http://www.src.com/calpuff/download/CALPUFF_UsersGuide.pdf.

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:

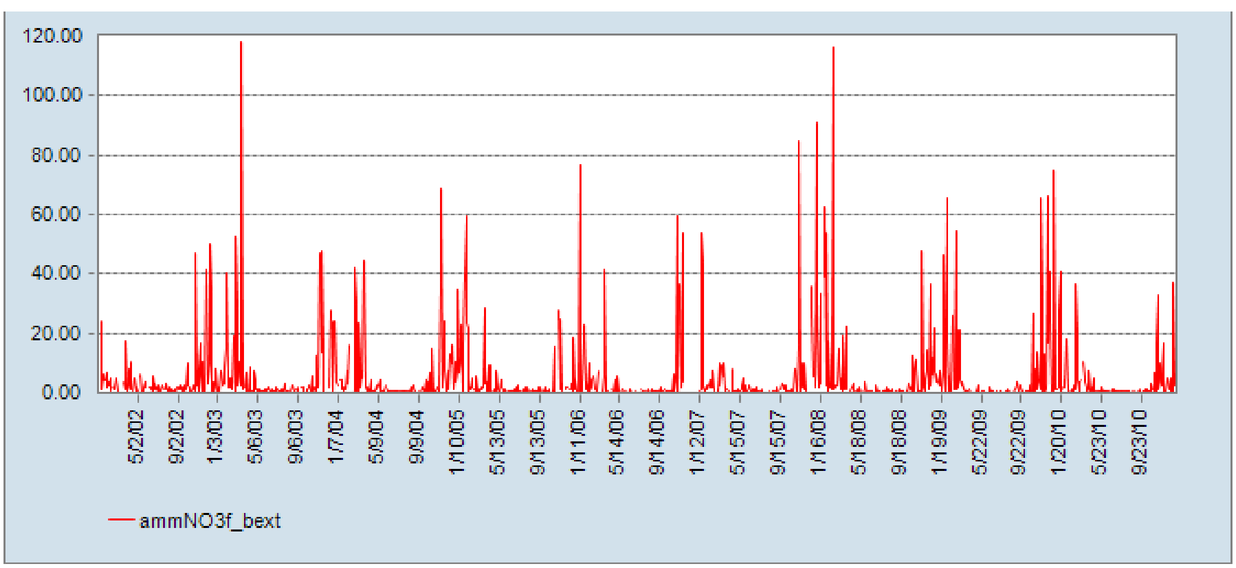
- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium 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_X 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



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 water-dominant Class I areas in Minnesota (Voyageurs and Boundary Waters) that freeze in winter. In fact, for Voyageurs National Park, the typical monthly attendance[7] 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 totally close[8] 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[9] 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[10] 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[11] of nitrate and sulfate haze in

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[7] As documented at http://www.gorp.com/parks-guide/voyageurs-national-park-outdoor-pp2-guide-cid9423.html.

[8] As noted at http://www.nps.gov/isro/planyourvisit/hours.htm.

[9] As noted at http://www.fws.gov/midwest/seney/visitor_info.html.

[10] 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.

[11] 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 4 Minnesota Taconite Production and BWCA Nitrate Concentrations

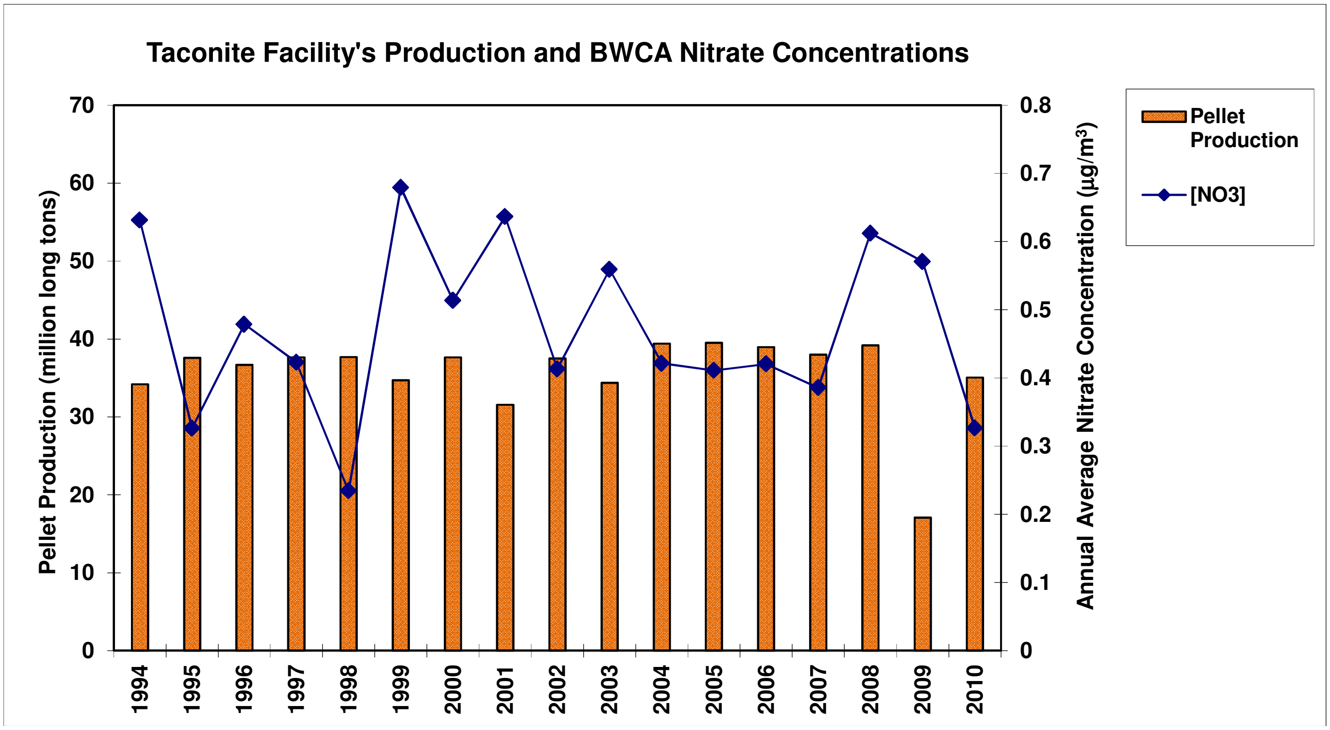


Figure 5 Time Series of Nitrate Haze at Boundary Waters Canoe Area (2002-2010)

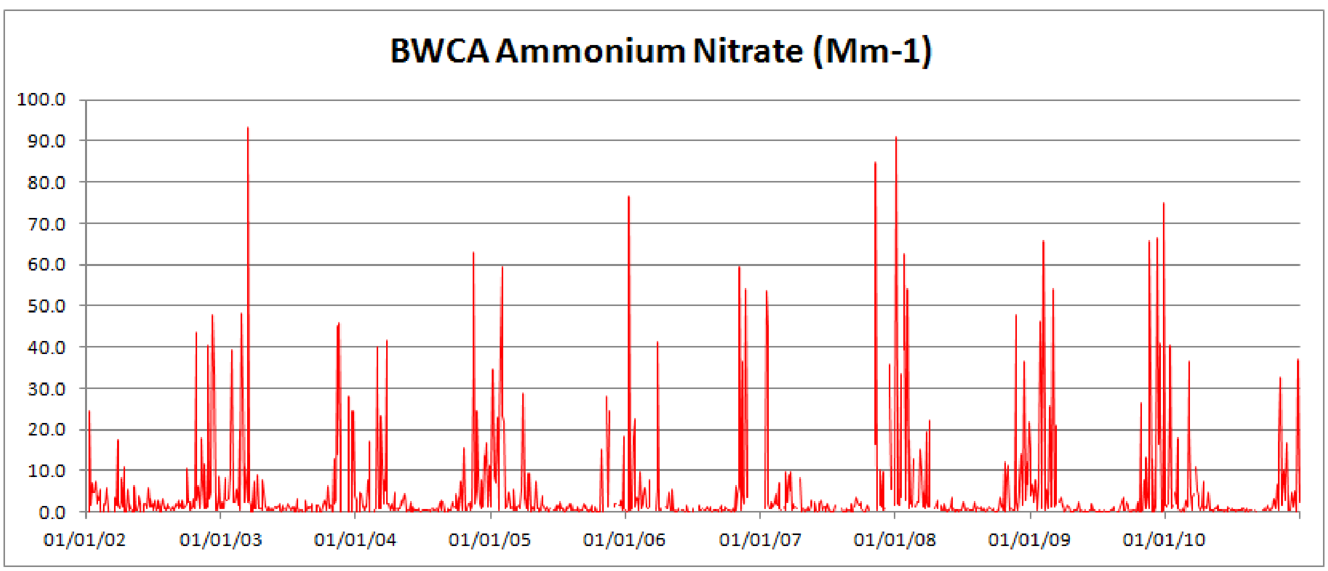
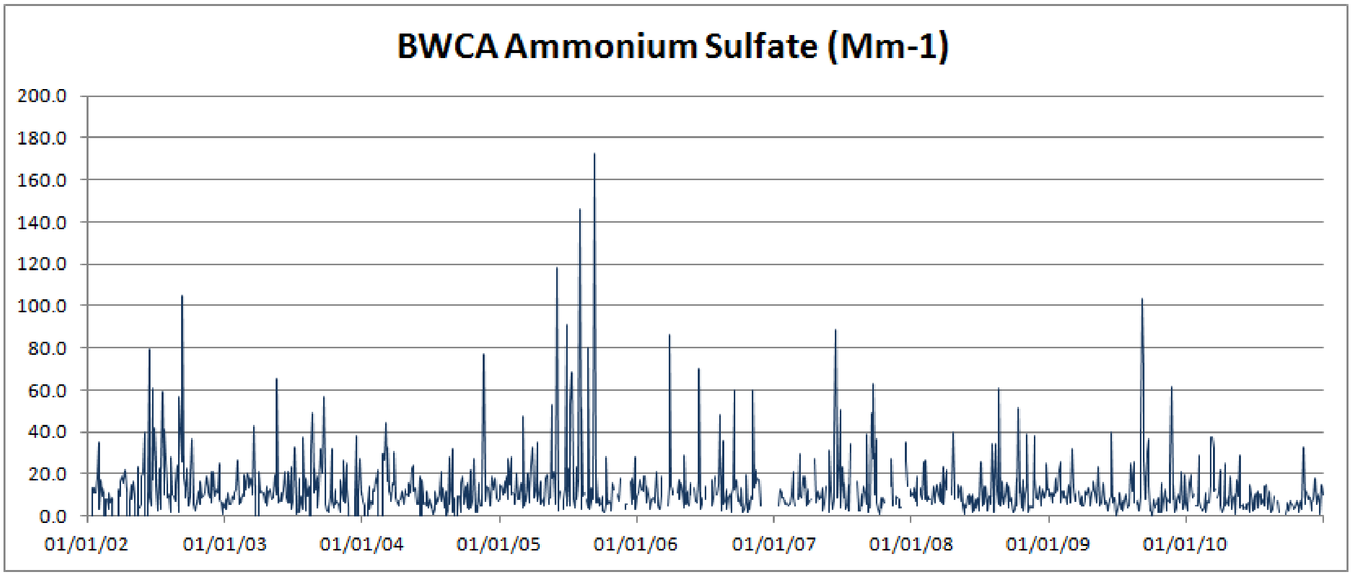


Figure 6 Time Series of Sulfate Haze at Boundary Waters Canoe Area (2002-2010)



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

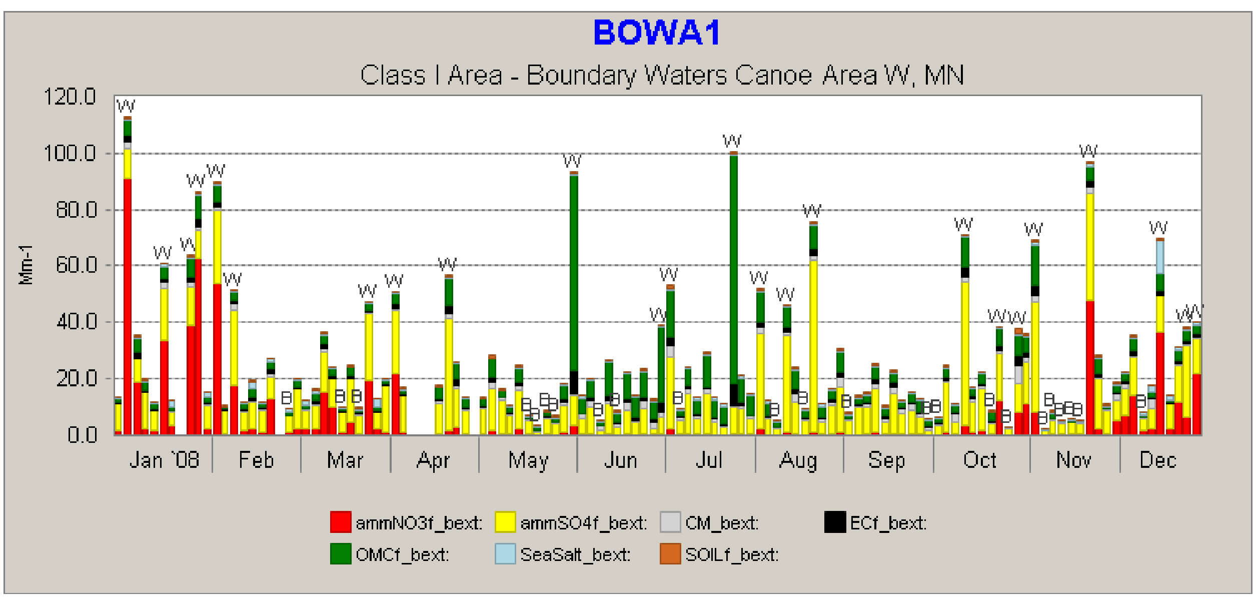


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Figure 8 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2009

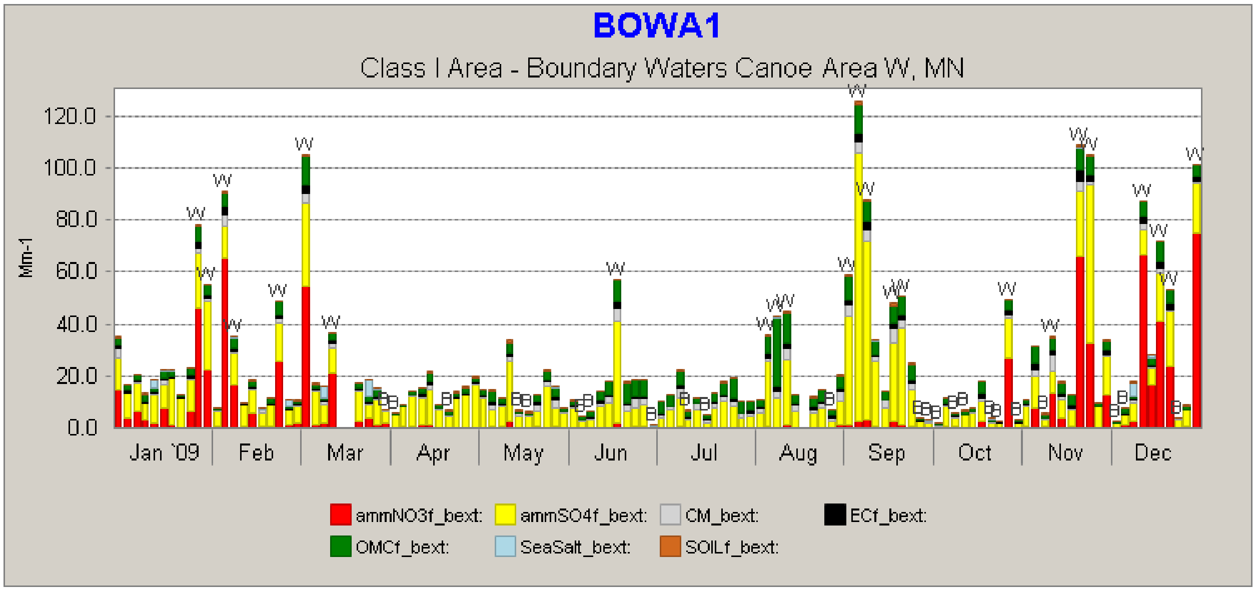
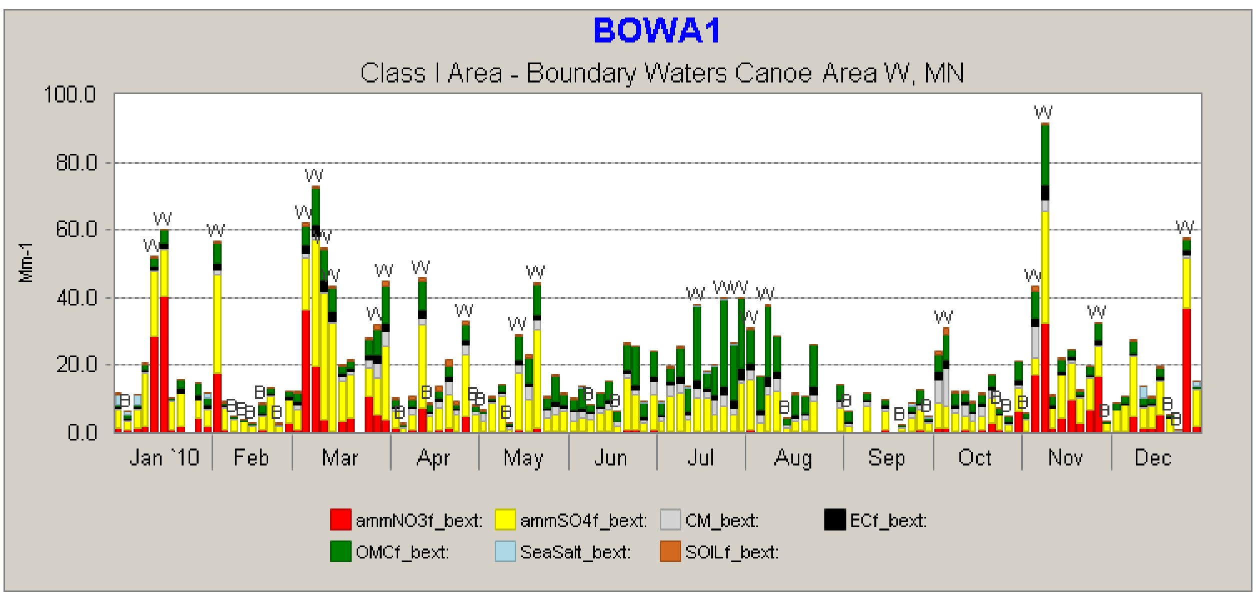


Figure 9 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2010



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.

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 anywhere 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 98th 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

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_X 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[12] 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 9th 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 11th and 12th, 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.

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[12] See, for example, the Iowa State Implementation Plan for Regional Haze report at http://www.iowadnr.gov/portals/idnr/uploads/air/insidednr/rulesandplanning/rh_sip_final.pdf, Figures 11.3 and 11.4.

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Figure 10 PSAT Results from CENRAP CAMx Modeling for Isle Royale National Park

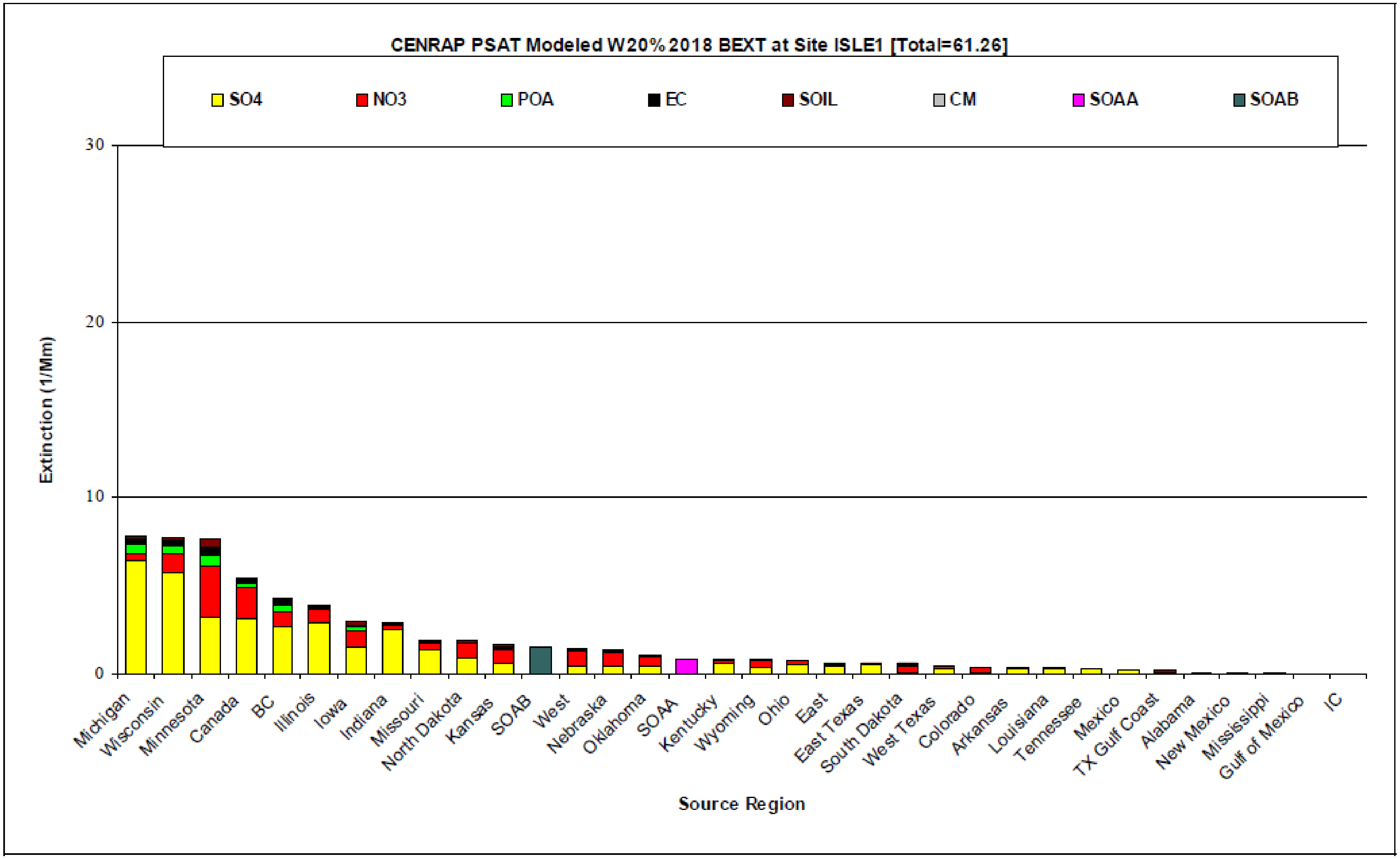


Figure 11.3. Source apportion contributions by region and pollutant to ISLE in 2018.

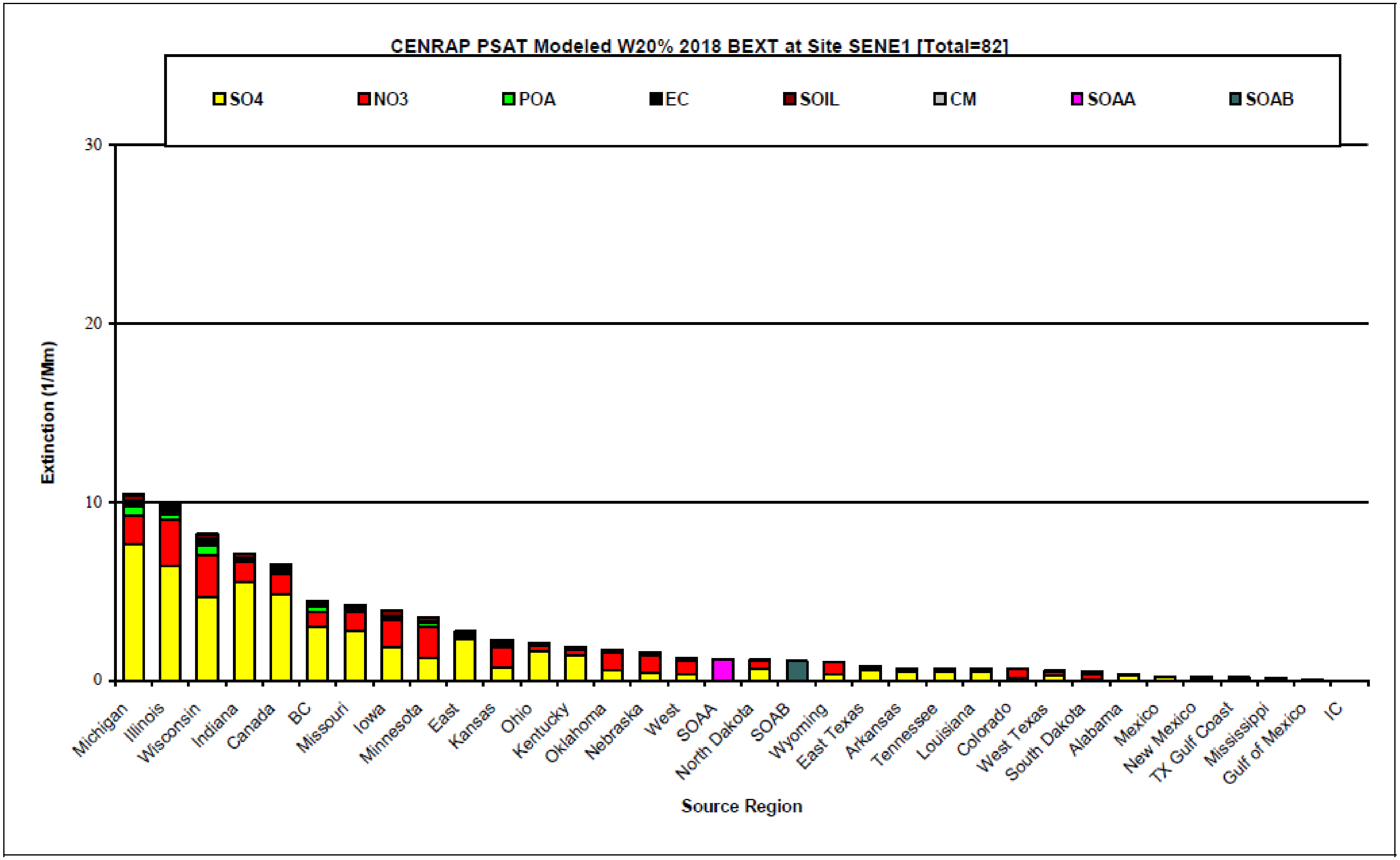


Figure 11.4. Source apportion contributions by region and pollutant to SENE in 2018.

Figure 12 PSAT Results from CENRAP CAMx Modeling for Boundary Waters Canoe Area Wilderness

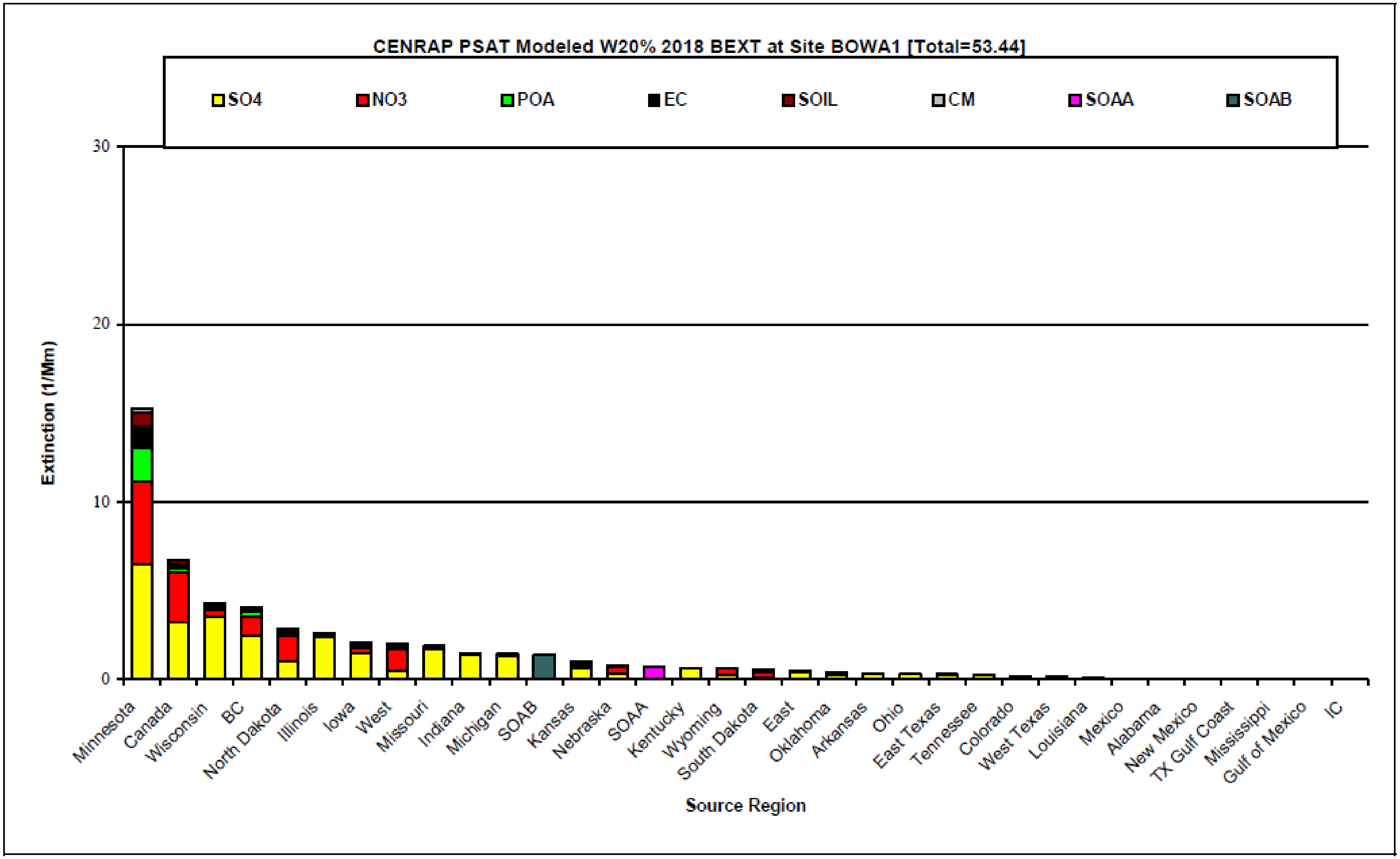


Figure 11.1. Source apportion contributions by region and pollutant to BOWA in 2018.

Figure 13 PSAT Results from CENRAP CAMx Modeling for Voyageurs National Park

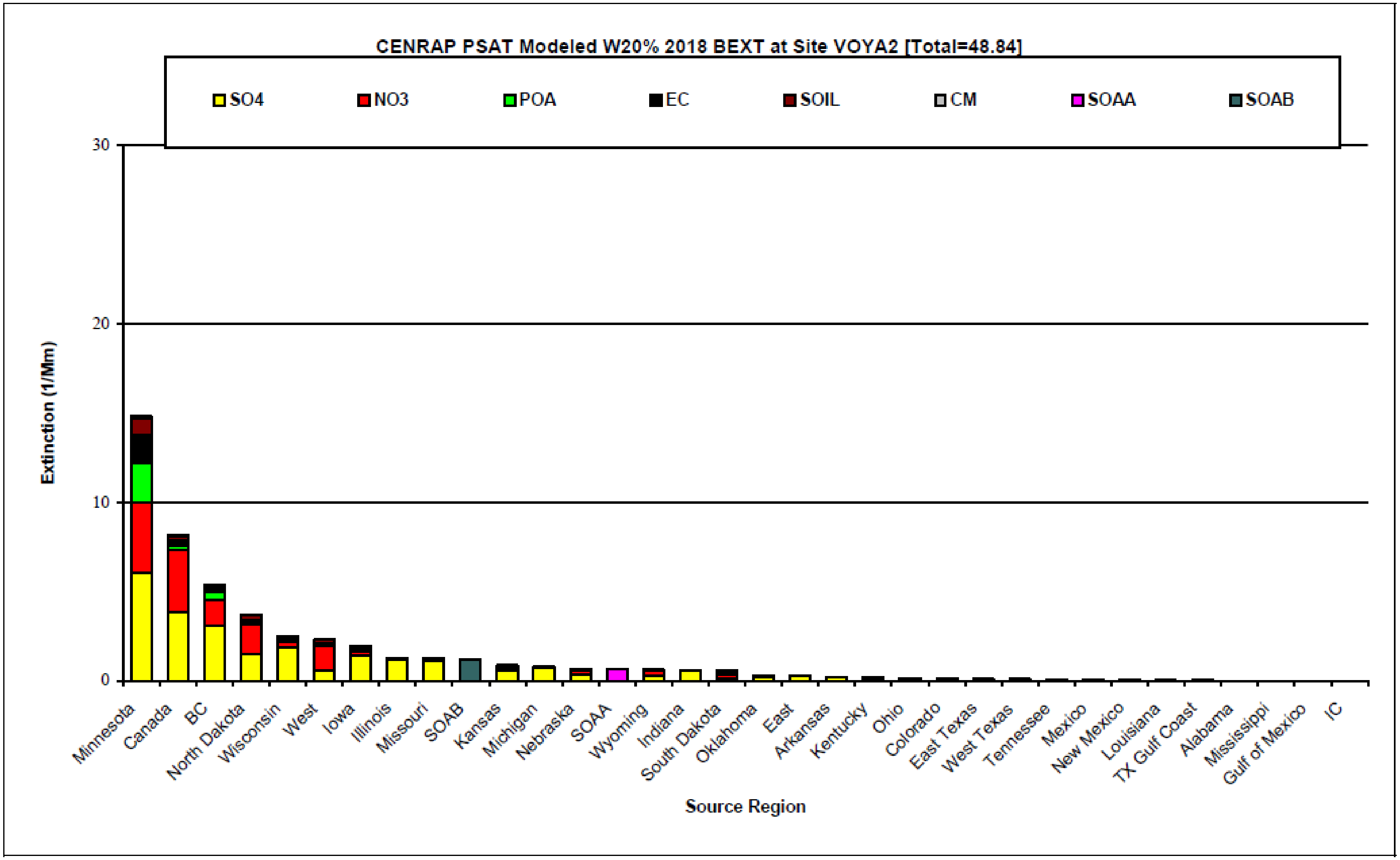


Figure 11.2. Source apportion contributions by region and pollutant to VOYA in 2018.

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_X 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 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X 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.

APPENDIX A

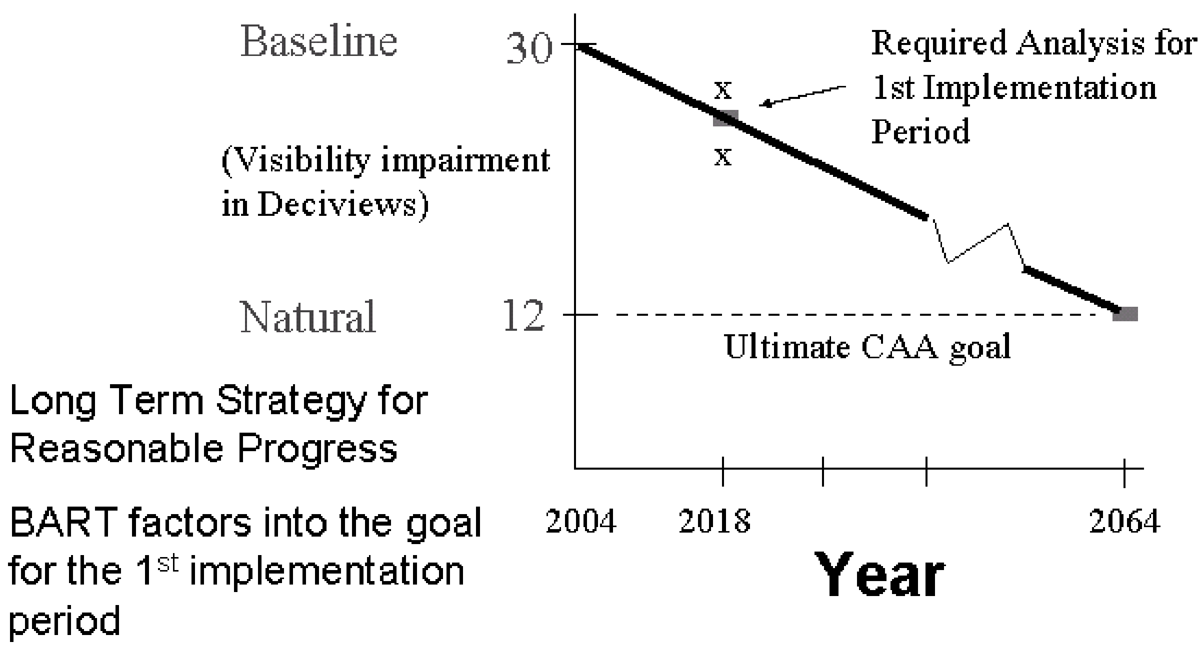
THE REGIONAL HAZE RULE GOAL OF NATURAL CONDITIONS

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[13] 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 20th century.

Figure A-1: Illustration of the Uniform Rate of Progress Goal



[13] *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, (U.S. Environmental Protection Agency, September 2003). http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf.

In its RHR SIP, North Dakota[14] 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_2 and NO_x 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.

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[14] North Dakota Dep. of Health, 2010. North Dakota State Implementation Plan for Regional Haze. http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Main%20SIP%20Sections%201-12.pdf.
.

- As a result, there is a substantial reduction in SO_2 and NO_x 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[15], 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 (http://views.cira.colostate.edu/web/) 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_2 and NO_X.

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_2 and NO_x).

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.

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[15] See Appendix 2-2 at http://www.tceq.state.tx.us/implementation/air/sip/bart/haze_appendices.html.

These estimates were derived from Trijonis[16] and use two different sets of natural concentrations for the eastern and western U.S. Tombach[17] 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		Error Factor	Dry Extinction Efficiency (m^2/g)
	West ($\mu g/m^3$)	East ($\mu g/m^3$)		
Ammonium sulfate [b]	0.12	0.23	2	3
Ammonium nitrate	0.10	0.10	2	3
Organic carbon mass [c]	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 $\mu g/m^3$ and 1.5 $\mu g/m^3$ 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.[18]

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.

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[16] 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.

[17] 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 http://www.wrapair.org/forums/aamrf/projects/NCB/index.html.

[18] 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[19] reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach[8] 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[8] 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[20]; Koo et al., 2010[21]), 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 20th century, fire suppression has resulted in a buildup of vegetative "fuels" and catastrophic wildfires. Recent estimates of background visual range, such as Trijonis[16], 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

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[19] 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.

[20] 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. (http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC_2006_report_FINAL.pdf).

[21] 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. Atm. Env., 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 http://www.nps.gov/thro/parkmgmt/firemanagement.htm for the Theodore Roosevelt National Park that:

"For most of the 20th 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[22] 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 background estimates. The consequences of the artificially low estimates of natural visibility conditions include the distortion of Reasonable Progress analyses and also to BART modeling results that overestimate the visibility improvement achievable from NO_X 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_2 and NO_x 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 20th 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.

[22] See explanation at http://www.msnbc.msn.com/id/48569985/ns/us_news-environment/t/forest-service-gets-more-aggressive-small-fires/.

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_2 and NO_X 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.

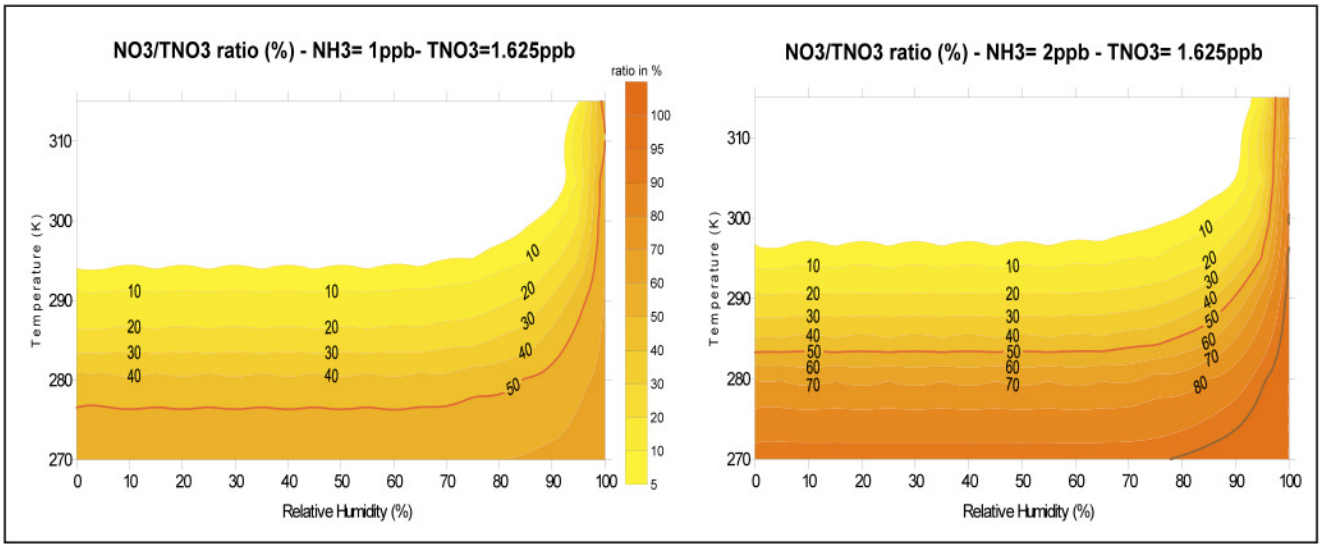
In the CALPUFF model, the oxidation of NO_X to nitric acid (HNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration. In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous HNO_3 and NO_3 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_3 to form ammonium nitrate, as shown in Figure 6[23]. 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.

[23] Scire, Joseph. CALPUFF MODELING SYSTEM. CALPUFF course presented at Chulalongkorn University, Bangkok, Thailand. May 16-20, 2005; slide 40 available at http://aqnis.pcd.go.th/tapce/plan/4CALPUFF%20slides.pdf, accessed March 2011.

Figure B-1: NO_3/HNO_3 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_X emissions relative to SO_2 emissions[24]. 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.

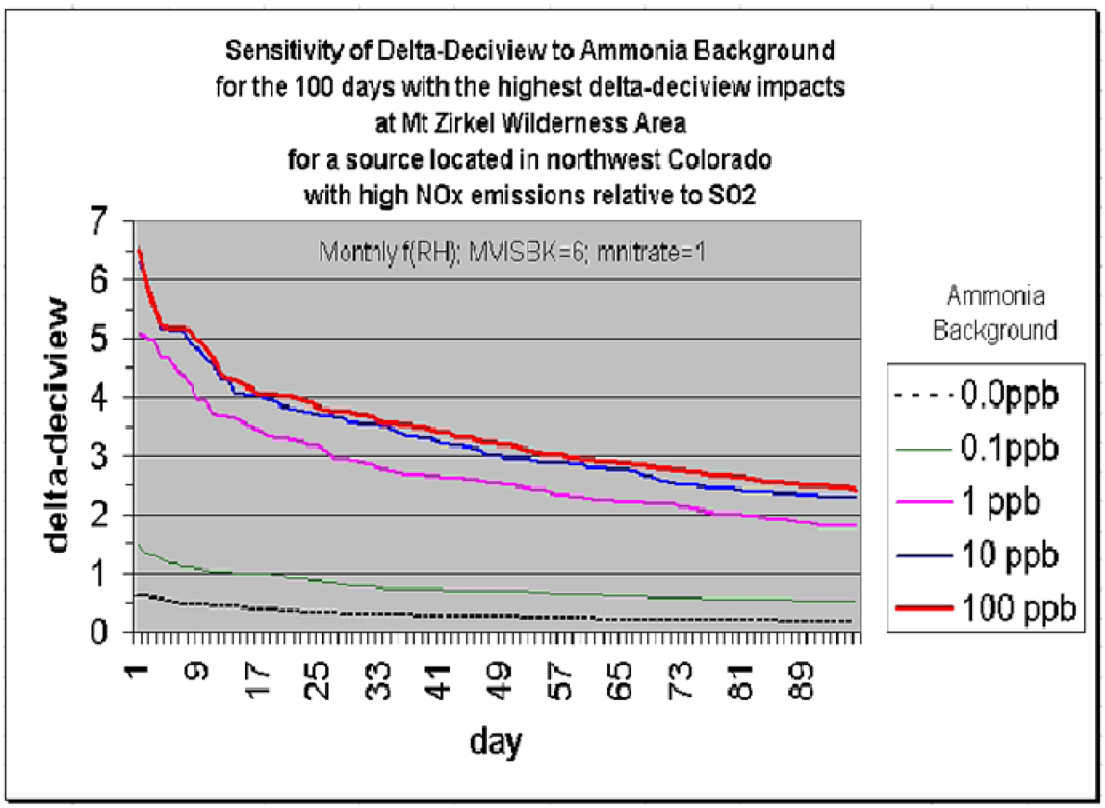
It is also noteworthy that CALPUFF version 5.8's demonstrated over-predictions of wintertime nitrate can be mitigated to some extent by using lower winter ammonia background values, although there is not extensive measurement data to determine the ambient ammonia concentrations. This outcome showing the superiority of the monthly-varying background ammonia concentrations was found by Salt River

[24] Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at http://www.colorado.gov/airquality/documents/Draft-ColoradoSupplementalBARTAnalysisCALPUFFProtocol-25June2010.pdf. (2010)

Project in case studies of the Navajo Generating Station impacts on Grand Canyon monitors, as presented[25] to EPA in 2010.

It is important to note that 14 years ago in 1998, when the IWAQM Phase 2 guidance[26] 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.



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[25] 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.

[26] IWAQM Phase 2 Summary Report and Recommendations (EPA-454/R-98-019), EPA OAQPS, December 1998). http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf.

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_2 to sulfate.

On page 39121, the BART rule[27] 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[28]."

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.[29] 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[30]. 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

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[27] July 6, 2005 Federal Register publication of the Regional Haze BART rule.

[28] The next (9th) 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 10th 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.

[29] 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)

[30] 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)

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_2) by the hydroxide ion (OH^-) 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[31]. 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_X 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)[32,33], 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

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[31] 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.

[32] 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.

[33] 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)

of aqueous-phase SO_2 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[34], 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_3 concentrations on model predictions of PM nitrate. Twice-weekly background NH_3 concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH_3 concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

1. MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH_3 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_3 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[35]. The results were similar to those noted above: the improved

[34] 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)

[35] 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[36], 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 10th modeling conference in March 2012 by Scire[37], 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[29,30] 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_X emission reductions.

[36] 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)

[37] Scire, J., 2012. New Developments and Evaluations of the CALPUFF Model. http://www.epa.gov/ttn/scram/10thmodconf/presentations/3-5-CALPUFF_Improvements_Final.pdf.

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[38] 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_X emission reductions.

[38] http://pah.cert.ucr.edu/aqm/cenrap/meetings.shtml, under “MPE”, slides 9 and 10.

Figure B-3: Sensitivity Study of Nitrate Predictions at Bridger Wilderness Area for Input Ammonia Concentrations to CALPUFF (0.23, 0.5, and 1.0 ppb).

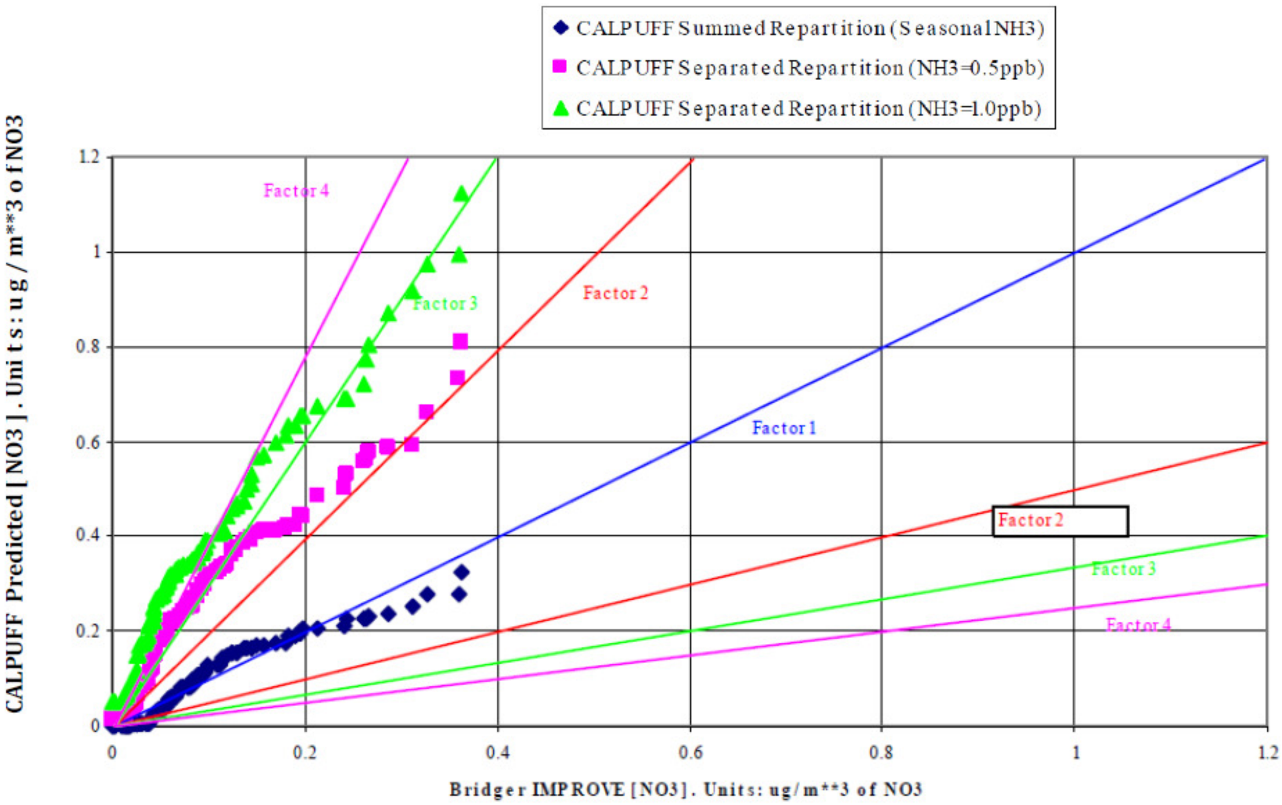


Figure B-4 CMAQ vs. Observed Haze Predictions at Voyageurs National Park

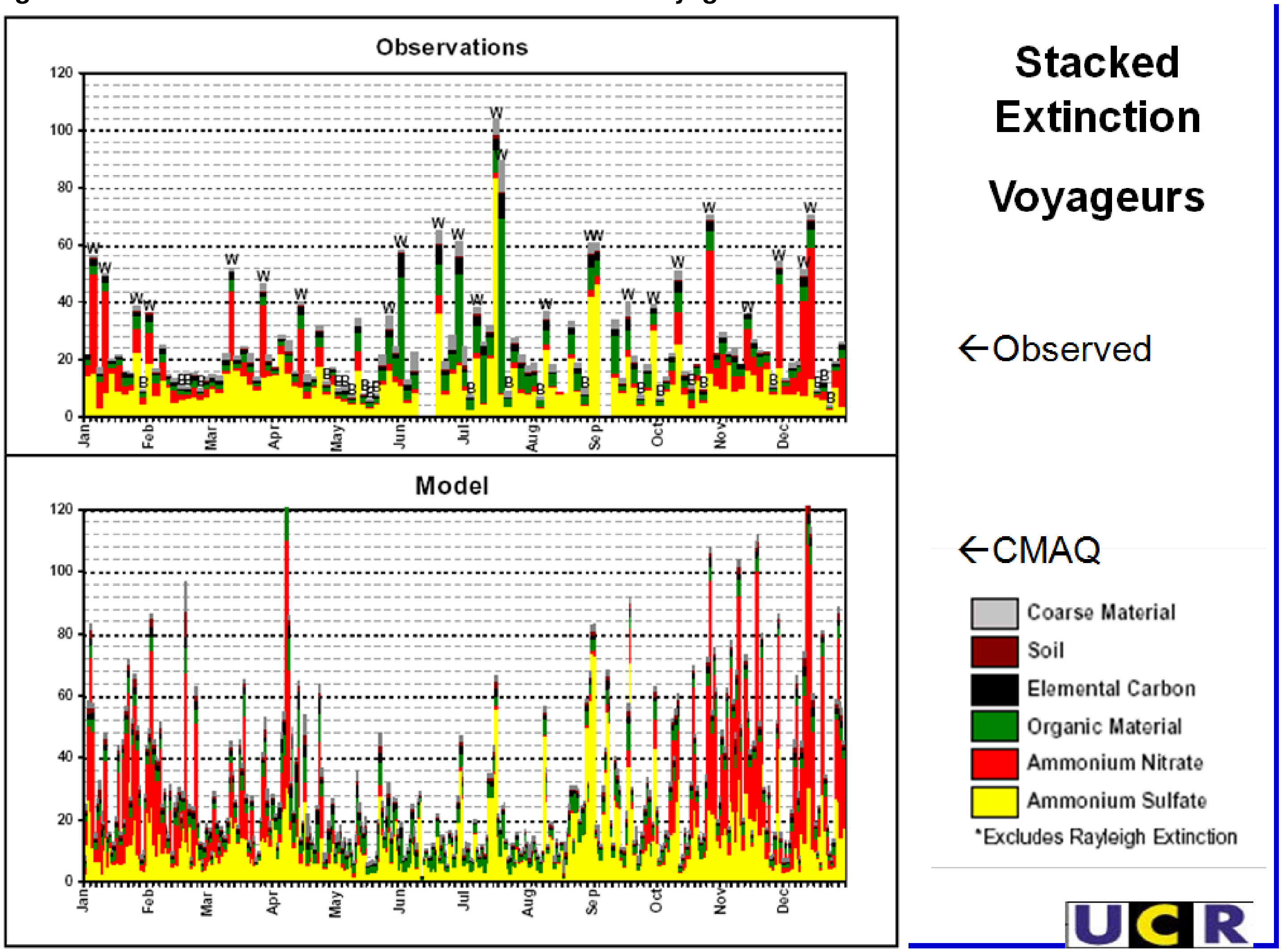
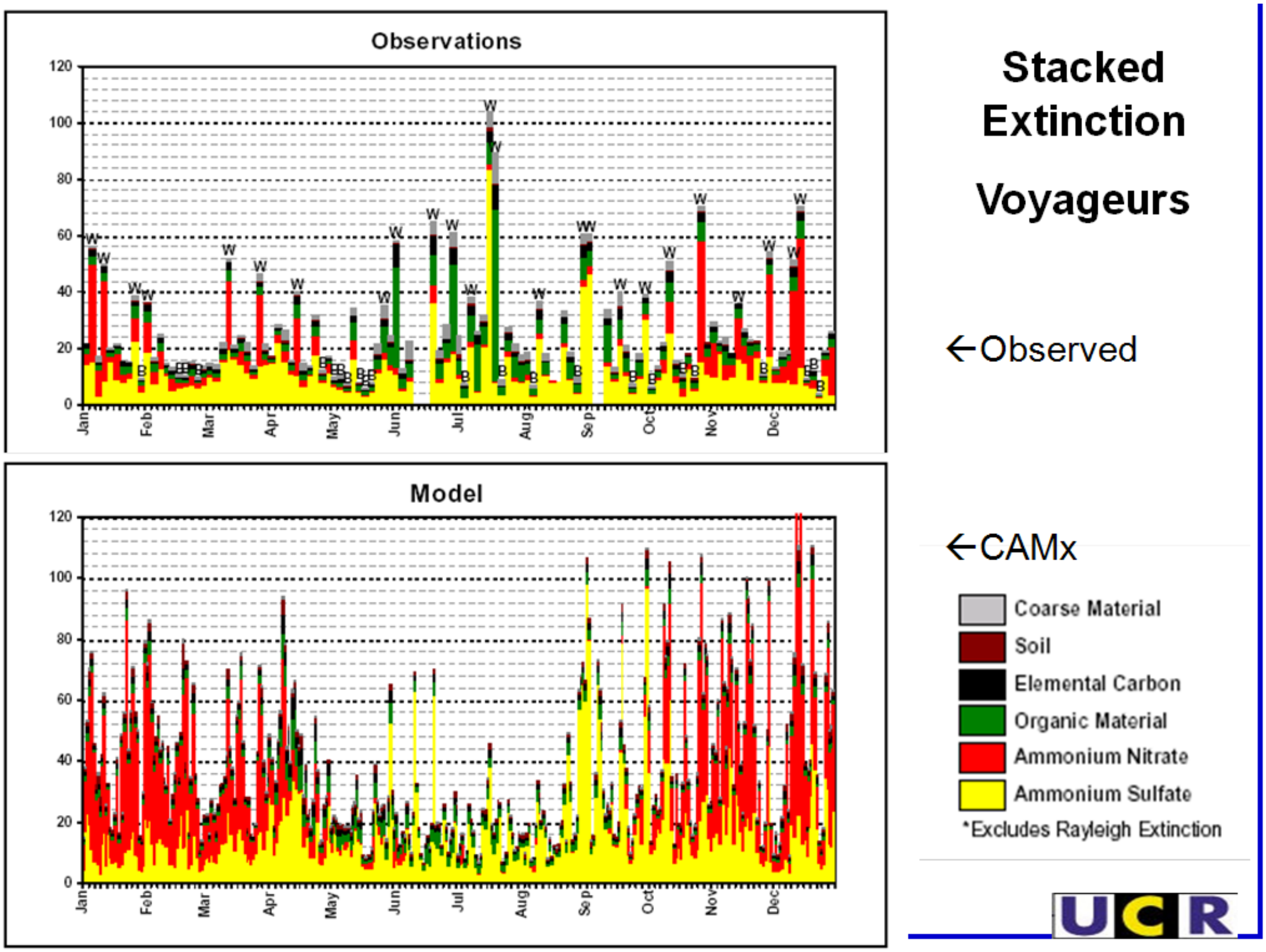


Figure B-5 CAMx vs. Observed Haze Predictions at Voyageurs National Park



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)

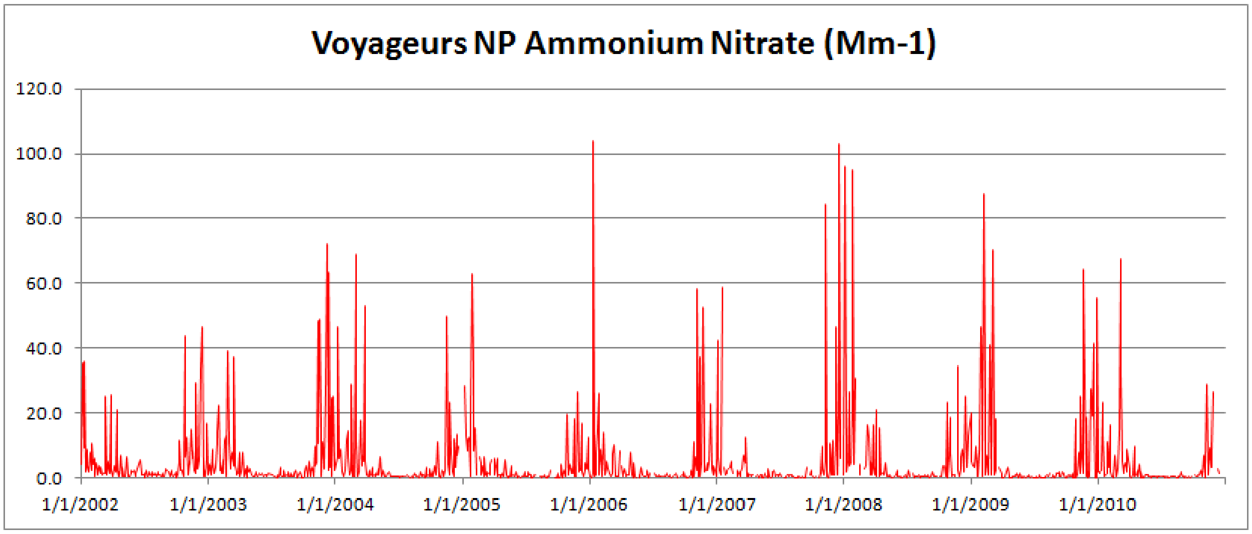


Figure C-2 Time Series of Sulfate Haze at Voyageurs National Park (2002-2010)

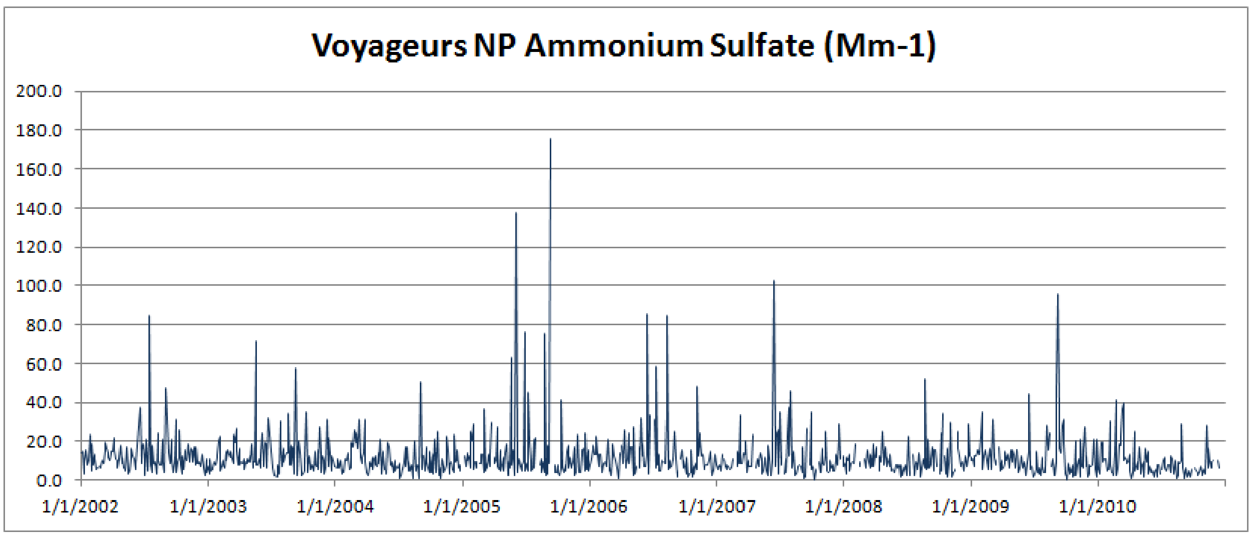


Figure C-3 Time Series of Nitrate Haze at Seney Wilderness Area (2002-2010)

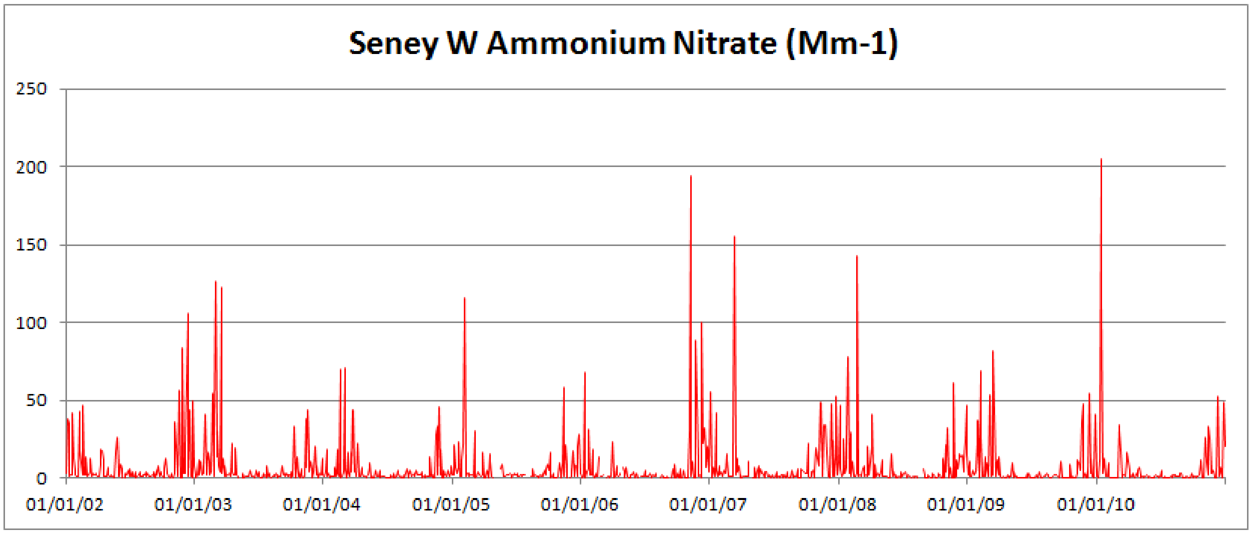


Figure C-4 Time Series of Sulfate Haze at Seney Wilderness Area (2002-2010)

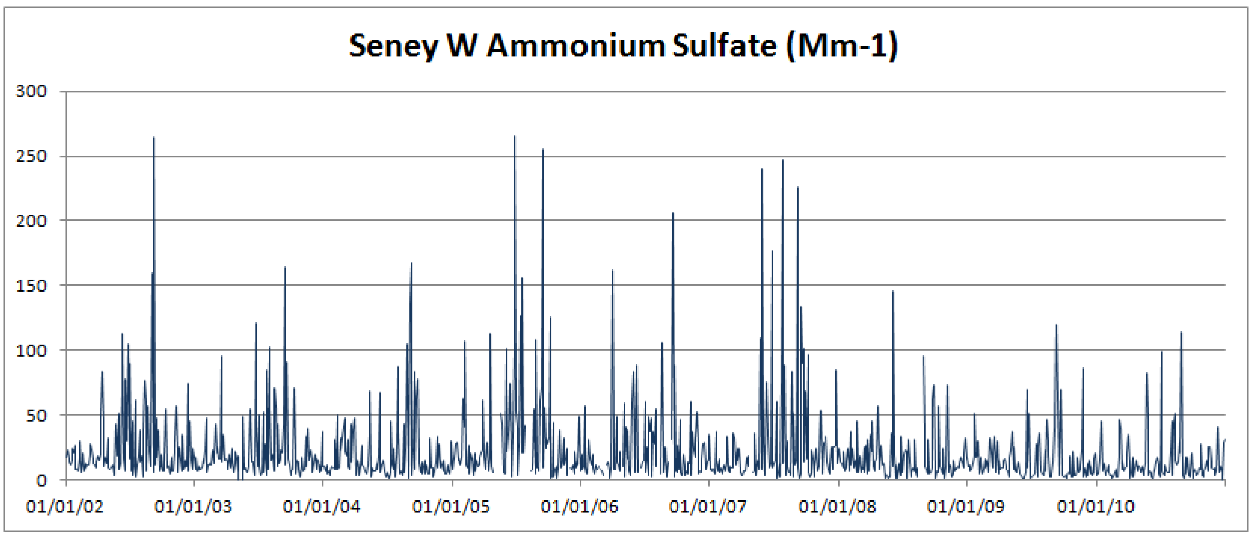


Figure C-5 Time Series of Nitrate Haze at Isle Royale National Park (2002-2010)

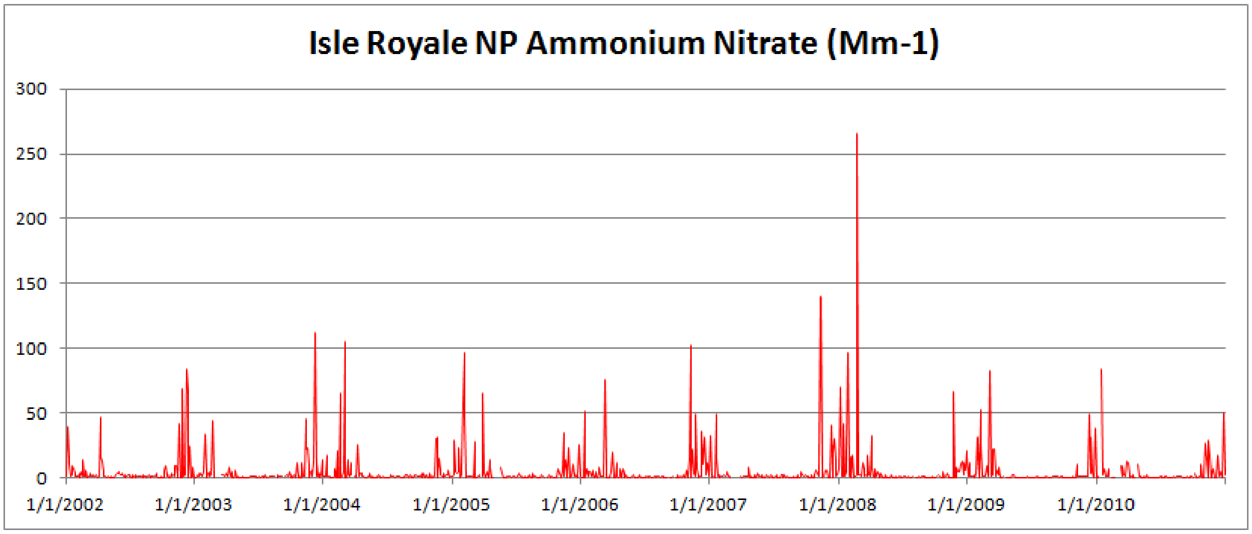
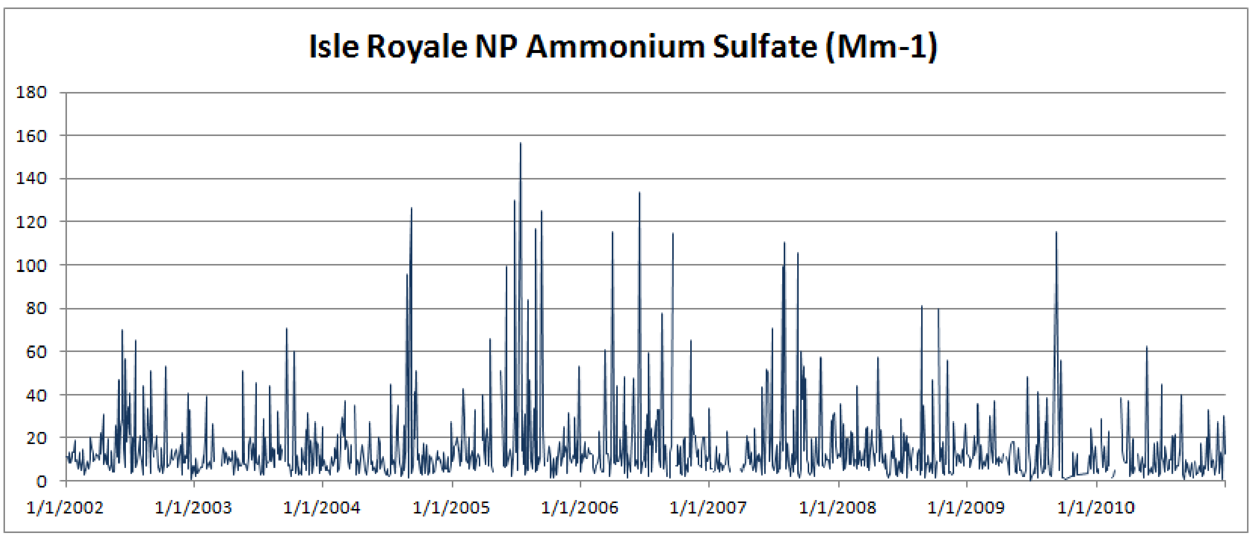


Figure C-6 Time Series of Sulfate Haze at Isle Royale National Park (2002-2010)



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 98th 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_2 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[39] 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_2 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[40] 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.

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[39] 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).

[40] 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 mark.berkman@berkeleyeconomics.com.

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.

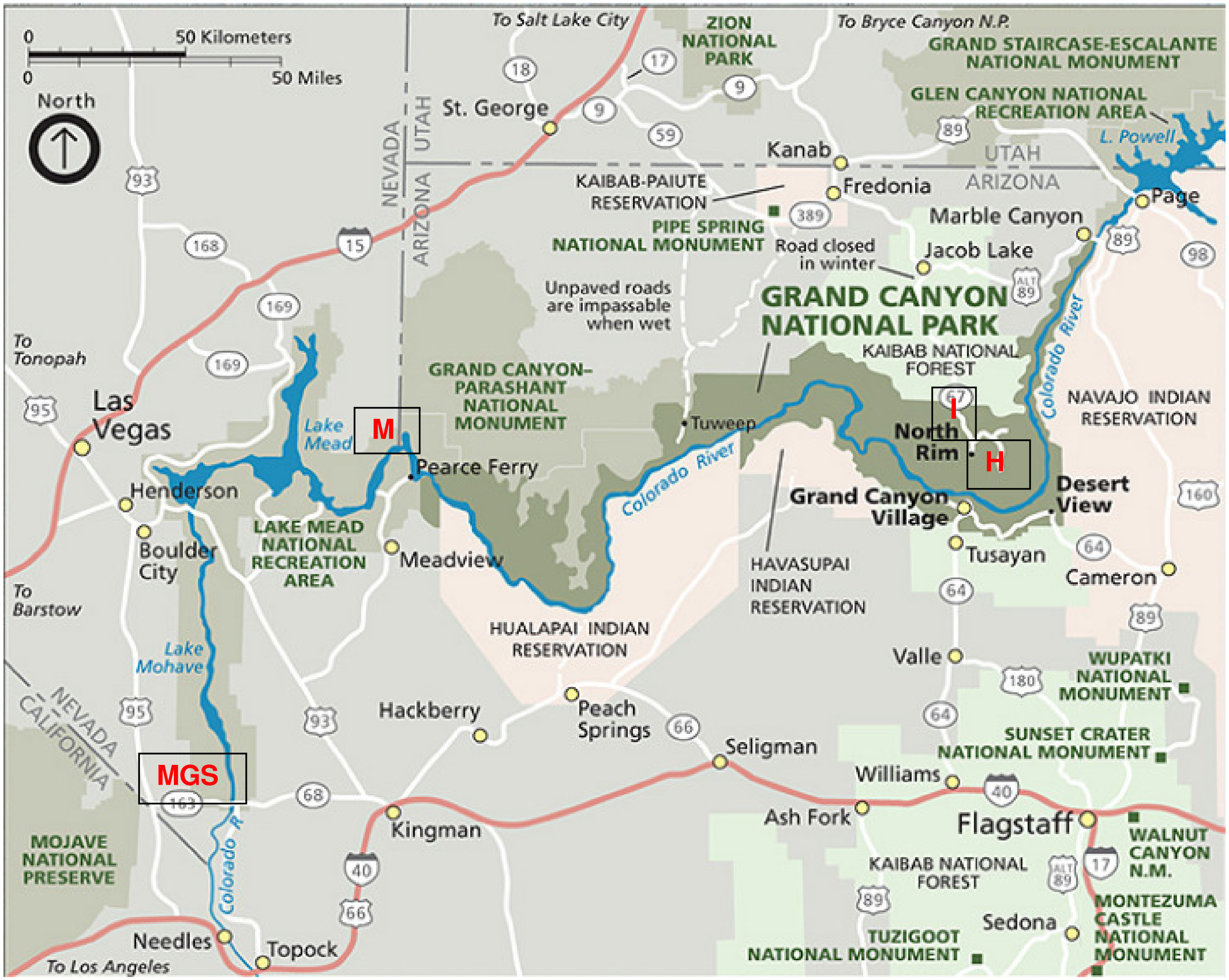
Best Available Retrofit Technology (BART) studies evaluated a possible conversion of MGS to natural gas firing in 2008. These studies used the CALPUFF dispersion model in a manner prescribed by EPA to determine the change in visibility between the baseline emissions associated with coal firing to the 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 98th 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_2 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



http://www.nps.gov/grca/planyourvisit/upload/GRCAmap2.pdf

H: Hance Camp monitor

I: Indian Garden monitor

M: Meadview monitor

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

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1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency (MPCA) submitted a Request for Information (RFI) Letter[1] to United States Steel Corporation, Minnesota Ore Operations - Minntac (Minntac) to consider potential emissions reduction measures of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) 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)[2]:

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[3] (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_x and SO_2. Minntac has BART emission controls and emission limits for NO_X and SO_2 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[4] and October 2015[5] USEPA Federal Implementation Plan (FIP) rulemaking. (see Section 5)

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[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to United States Steel Corporation – Minnesota Ore Operations - Minntac.

[2] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[3] USEPA, Regional Haze Rule Requirements – Long Term Strategy for Regional Haze, 40 CFR 52.308(f)(2)

[4] USEPA, Federal Register, 08/15/2012, Page 49308.

[5] 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_2 and NO_X 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.[6] 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)[7], by July 31, 2020 for the emission units identified in Table 2-1.

[6] 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.

[7] 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_X, SO_2
Line 4 Rotary Kiln	(EQUI 279/EU 261)	NO_X, SO_2
Line 5 Rotary Kiln	(EQUI 280/EU 282)	NO_X, SO_2
Line 6 Rotary Kiln	(EQUI 3/EU 315)	NO_X, SO_2
Line 7 Rotary Kiln	(EQUI 179/EU 334)	NO_X, SO_2

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[8].

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." [9] 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 and determine 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."[10]

The SIP revision must also include the "Long-term strategy for regional haze."[11] 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[12], emission unit retirement and replacement

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[8] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[9] 40 CFR 51.308(f)(1)

[10] 40 CFR 51.308(f)(1)(vi)(A)

[11] 40 CFR 51.308(f)(2)

[12] 51.308(f)(2)(iv)(A)

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

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)[15]. The reasonable progress goal is not enforceable but will be considered by USEPA in evaluating the adequacy of the SIP[16].

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*"[17] 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."[18]

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"[19] 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."[20] 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.[21]

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)

[13] 51.308(f)(2)(iv)(C)

[14] 51.308(f)(2)(iv)(E)

[15] 40 CFR 51.308(f)(3)

[16] 40 CFR 51.308(f)(3)(iii)

[17] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[18] Ibid, page 1.

[19] Ibid.

[20] Ibid, page 9 (emphasis added).

[21] Ibid.

- 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):[22]

$$URP = [(\text{2000-2004 visibility})_{\text{20\% most impaired}} - (\text{natural visibility})_{\text{20\% most impaired}}]/60$$

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.[23] 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…."[24]

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

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[22] Ibid, Page 7.

[23] Ibid, Page 50.

[24] 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, 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 periods. 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."[25]

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[26]
- the four statutory factors (to the extent they have been characterized at this point in SIP development)[27]
- potential visibility benefits (also to the extent they have been characterized at this point in SIP development)[28]
- sources already having effective emissions controls in place[29]
- emission reductions at the source due to ongoing air pollution control programs[30]
- in-state emission reductions due to ongoing air pollution control programs that will result in an improvement in visibility[31]

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."[32]

[25] Ibid, Page 9.
[26] Ibid, Page 10.
[27] Ibid.
[28] Ibid.
[29] Ibid, Page 21.
[30] Ibid, Page 22.
[31] Ibid.
[32] 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[33]:

- 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:[34]

> "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."[35] 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."[36] 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

[33] Ibid, Page 12.

[34] Ibid, Page 27.

[35] Ibid, Page 22.

[36] Ibid, Page 25.

analysis of control measures."[37] 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."[38]

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."[39]

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.

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[37] Ibid.

[38] Ibid.

[39] Ibid.

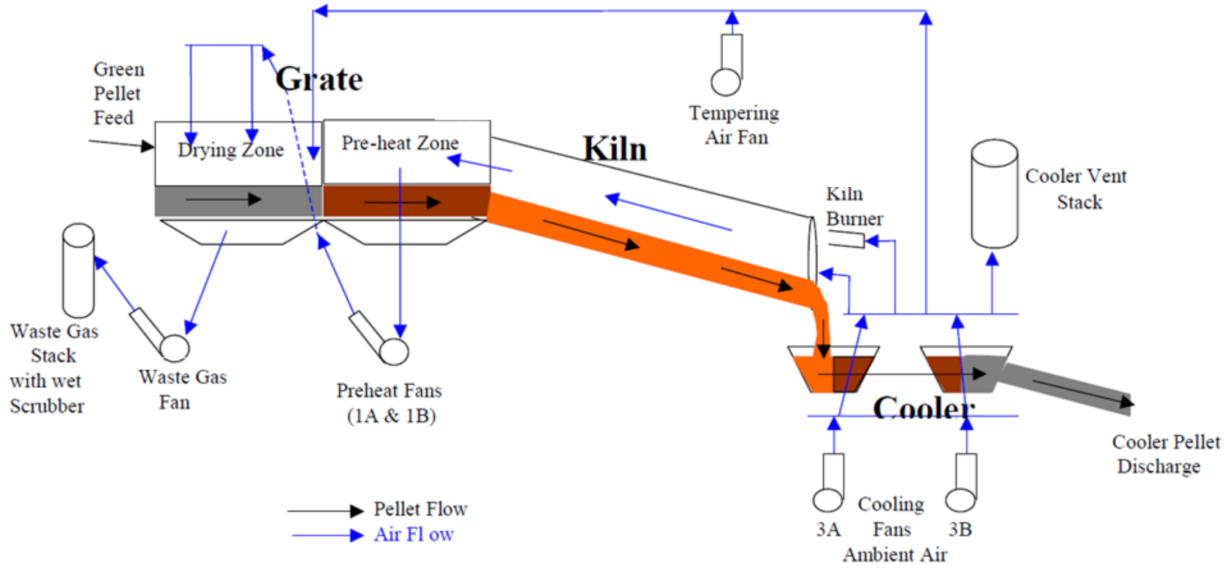

Figure 2-1 Grate-Kiln Furnace Diagram

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."[40] 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.[41] 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."[42]

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).[43] 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.[44] 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."[45] In

[40] 40 CFR 51.308(f)(1)

[41] 40 CFR 51.308(f)(3)

[42] 40 CFR 51.308(d)(1)

[43] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[44] https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

[45] 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."[46]

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath[47] 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.

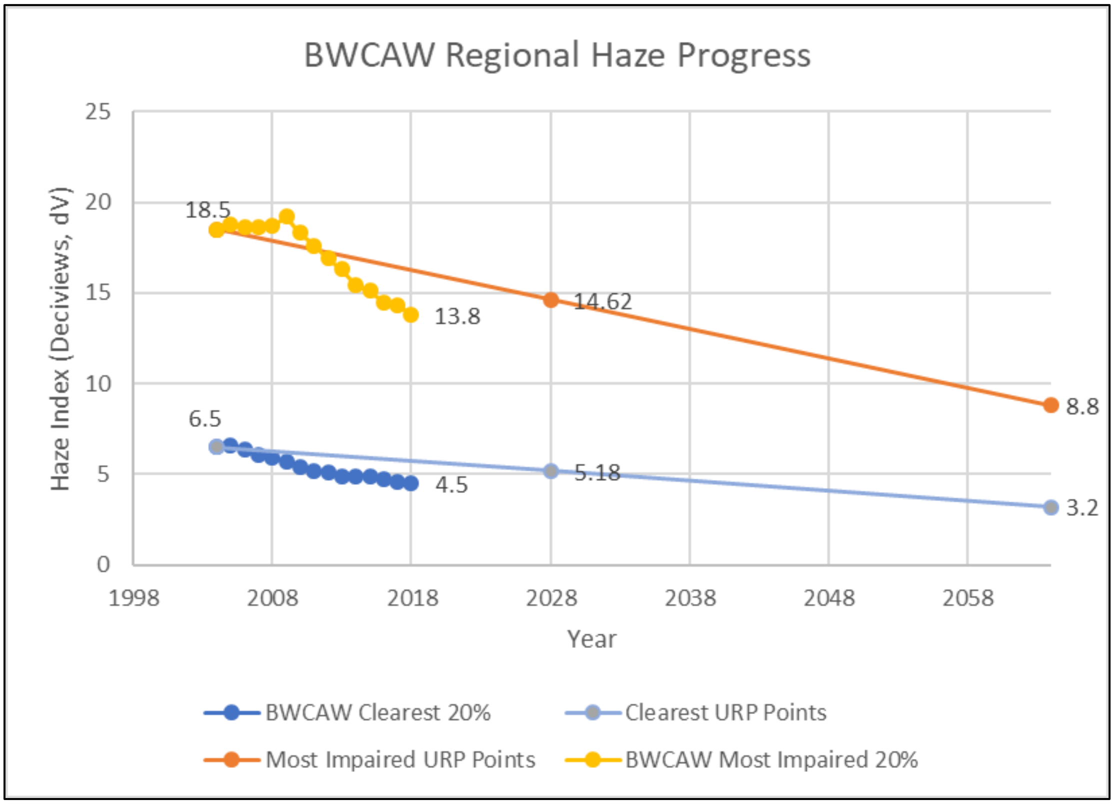

Figure 3-1 Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

[46] USEPA, Federal Register, 01/10/2017, Page 3104

[47] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

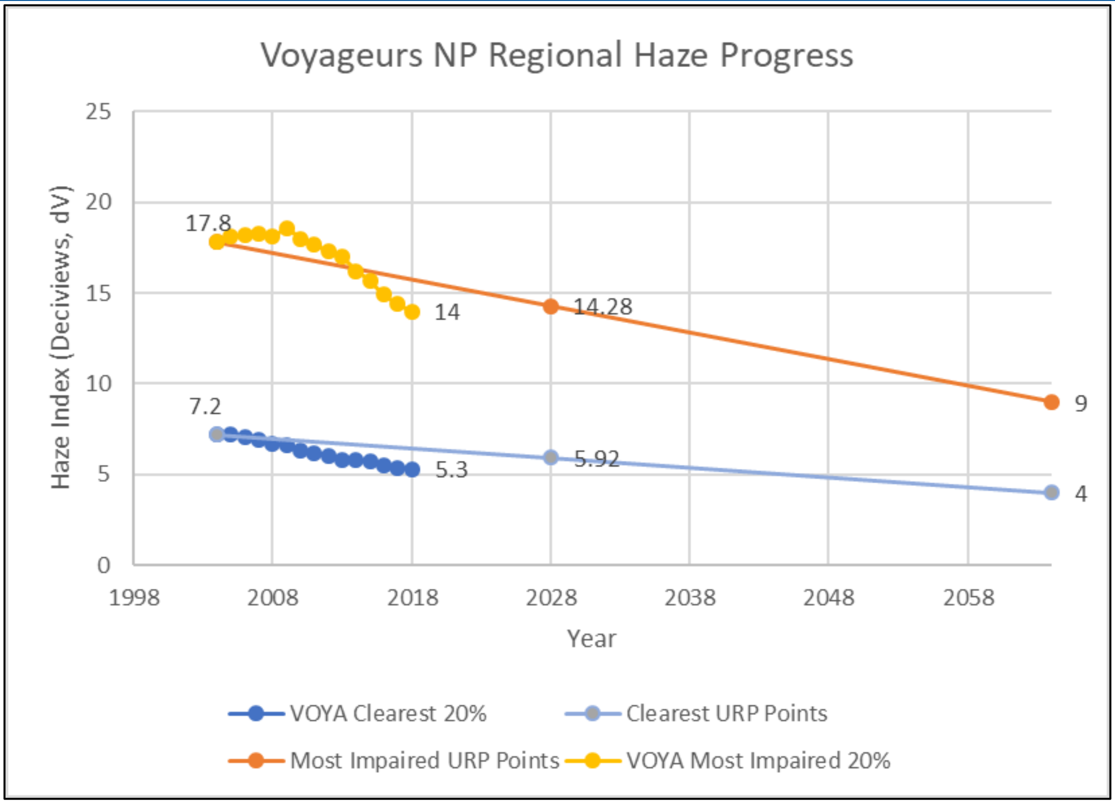

Figure 3-2 Visibility Trend versus URP – Voyageurs National Park (VOYA1)

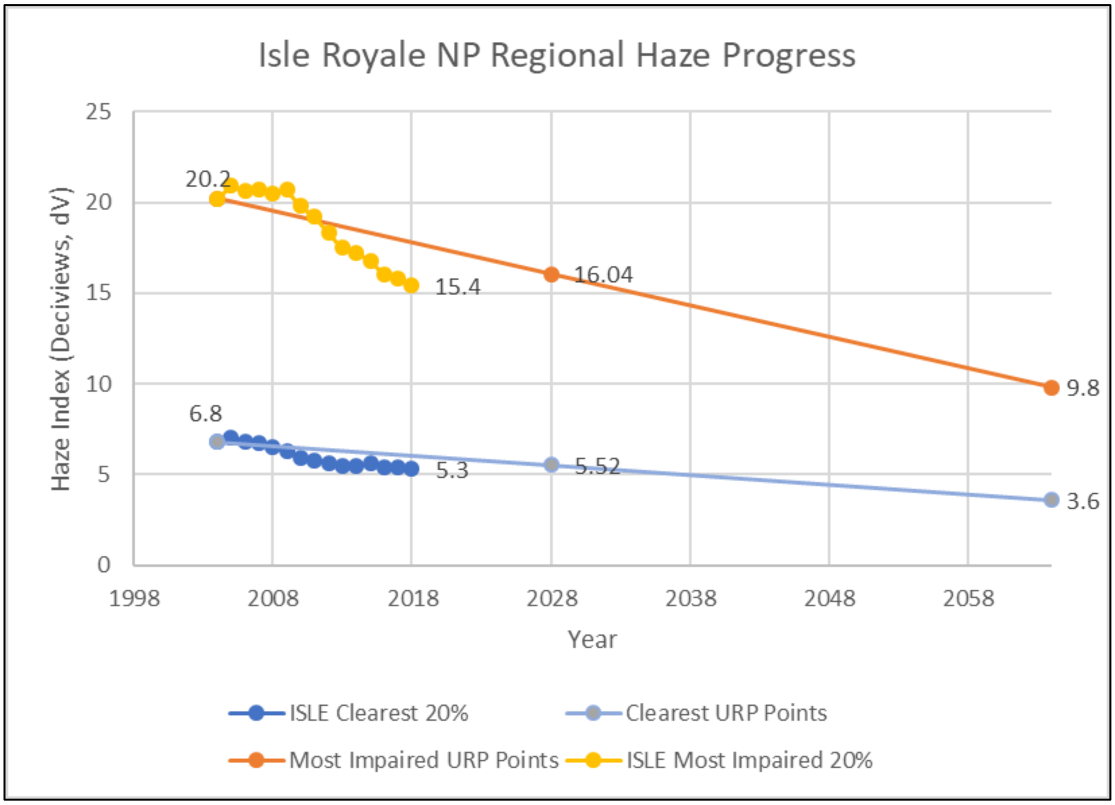

Figure 3-3 Visibility Trend versus URP – Isle Royale National Park (ISLE1)

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[48]. 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)
  - o 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.

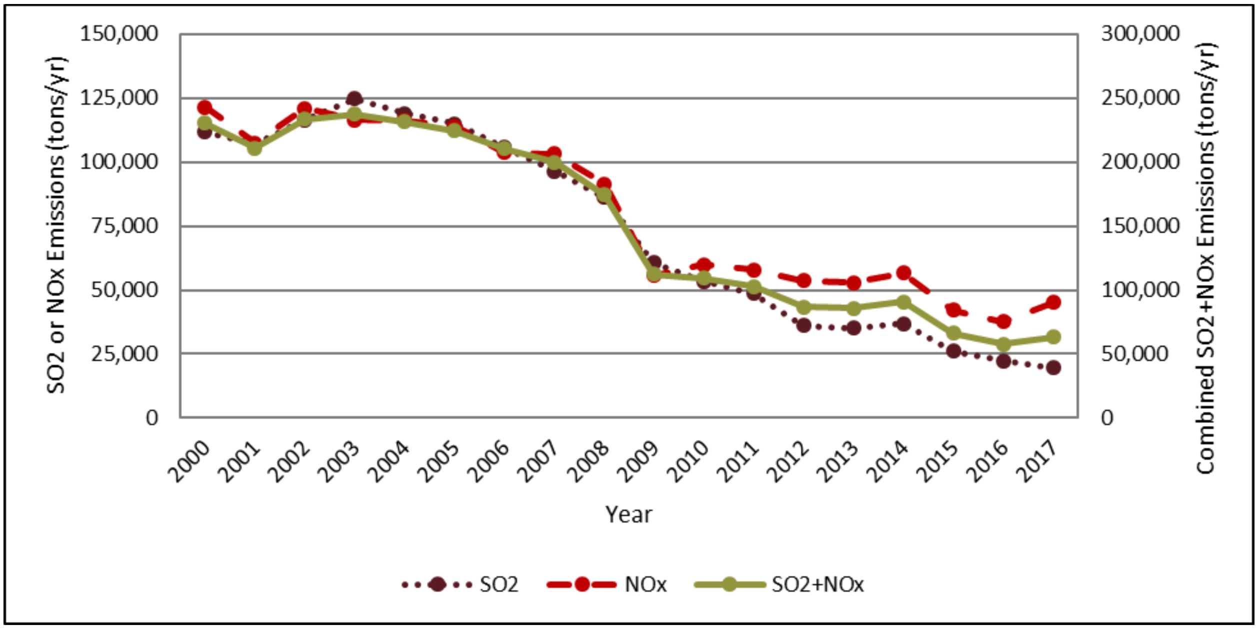

Figure 3-4 Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)

[48] The data for NO_X and SO_2 emissions was downloaded from the MPCA point source emissions inventory (https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data). 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.

Table 3-1 Notable Minnesota Emission Reductions

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_X*
2018	Minntac Line 7: FIP emission limit compliance date for NO_X* MP Boswell: Units 1 & 2 retired from service**
2019	Hibtac Line 1: FIP emission limit compliance date for NO_X* Keetac: FIP emission limit compliance date for NO_X * Minntac Line 4 or 5: FIP emission limit compliance date for NO_X* Utac Line 1: FIP emission limit compliance date for NO_X*
2020	Hibtac Line 2: FIP emission limit compliance date for NO_X* Minntac Line 4 or 5: FIP emission limit compliance date for NO_X* Minorca: FIP emission limit compliance date for NO_X* Utac Line 2: FIP emission limit compliance date for NO_X*
2021	Minntac Line: FIP emission limit compliance date for NO_X* Hibtac Line 3: FIP emission limit compliance date for NO_X*
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***

* 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*[49]
  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*[50]
  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_X emission reductions suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces.

- *Other reasonable techniques*[51]
  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

[49] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 13.

[50] Ibid, Page 14.

[51] 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."[52] 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."[53]

[52] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.
[53] 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."[54] This section demonstrates that the rotary kilns meet USEPA's BART-required control equipment installation scenario for NO_X and SO_2.

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_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[56]

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_X BART-required Controls

In the August 2012 proposed rule FR notice preamble,[57] the USEPA concluded that BART for NO_X from grate-kiln furnaces is low-NO_X 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; [58]

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[54] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, page 22.

[55] Ibid, page 25.

[56] 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.

[57] Federal Register 77, No. 158 (August 15, 2012); 49311. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789.

[58] Ibid, 49312.

- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure;[59]
- Alternate Fuels due to the uncertainty of environmental and economic benefits[60]; and
- Selective Catalytic Reduction (SCR) controls because of two SCR vendors declining to bid on NO_x reduction testing at the U.S. Steel Minntac facility.[61]

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_X 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.[62]

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[63] 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[64].

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[59] Ibid.

[60] Ibid, 49313.

[61] Ibid.

[62] 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.

[63] 40 CFR 52.1235(b)(1)

[64] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10.

Table 5-1 NO_X Emission Limits

Unit	Unit ID	NO_X Emission Limit (lb/MMBtu)	Compliance Date[1,2]
Line 3 Rotary Kiln	(EQUI 146/EU 225)	1.6	September 1, 2019
Line 4 Rotary Kiln	(EQUI 279/EU 261)		
Line 5 Rotary Kiln	(EQUI 280/EU 282)		
Line 6 Rotary Kiln	(EQUI 3/EU 315)		
Line 7 Rotary Kiln	(EQUI 179/EU 334)		

(1) Compliance date from September 2019 Settlement Agreement. https://s3.amazonaws.com/public-inspection.federalregister.gov/2019-19668.pdf

(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_2 BART-required Controls

In the preamble to the August 2012 proposed FIP[65], the USEPA concluded that BART for SO_2 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[66]
- 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;[67]
- Coal drying/processing because this requires excess heat source or low-pressure steam, which was not available at Minntac[68]
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure[69]
- 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

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[65] Federal Register 77, No. 158 (August 15, 2012); 49314. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

[66] Ibid, 49313

[67] Ibid.

[68] Ibid.

[69] Ibid, 49314.

quality and/or would cause an increased blowdown and make-up water rate, which is not available[70]

In addition, USEPA eliminated Wet Walled Electrostatic Precipitator (WWESP) and secondary (polishing) wet scrubber technologies because they were not cost-effective.[71]

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_2 emissions from taconite indurating furnaces.

In accordance with the FIP, Minntac has continued to operate the BART SO_2 control measures and is complying with the FIP SO_2 emission limits[72], 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_2. 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[73].

Table 5-2 SO_2 Emission Limits

Unit	Unit ID	SO_2 Emission Limit (flux pellets)(1) (lb/hr)	SO_2 Emission Limit (mix)(2) (lb/hr)	SO_2 Emission Limit (acid pellets)(3) (lb/hr)	Compliance Date
Line 3 Rotary Kiln	(EQUI 146/EU 225)	498	630	800	June 8, 2013
Line 4 Rotary Kiln	(EQUI 279/EU 261)				
Line 5 Rotary Kiln	(EQUI 280/EU 282)				
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.

[70] Ibid.

[71] Ibid.

[72] 40 CFR 52.1235(b)(2)

[73] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 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_X and SO_2 (see Section 5). As stated in the 2019 Guidance, "it may be reasonable for a state not to select an effectively controlled source."[74] 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
    - o 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_X 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.

[74] 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")[1] 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[2], to determine the frequency that the trajectories on the "most impaired days"[3] 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).[4] 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.[5] 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[6], Draxler - 1992[7], Draxler and Hess - 1998[8]). 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.

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[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[2] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[3] "Most impaired days" is the 20% most anthropogenically impaired days on an annual basis, measured in deciviews (dv), as provided on MPCA's website.

[4] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[5] https://www.arl.noaa.gov/hysplit/hysplit/

[6] http://www.kenrahn.com/DustClub/Articles/Stohl%201998%20Trajectories.pdf

[7] https://www.arl.noaa.gov/documents/reports/ARL%20TM-195.pdf

[8] 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.

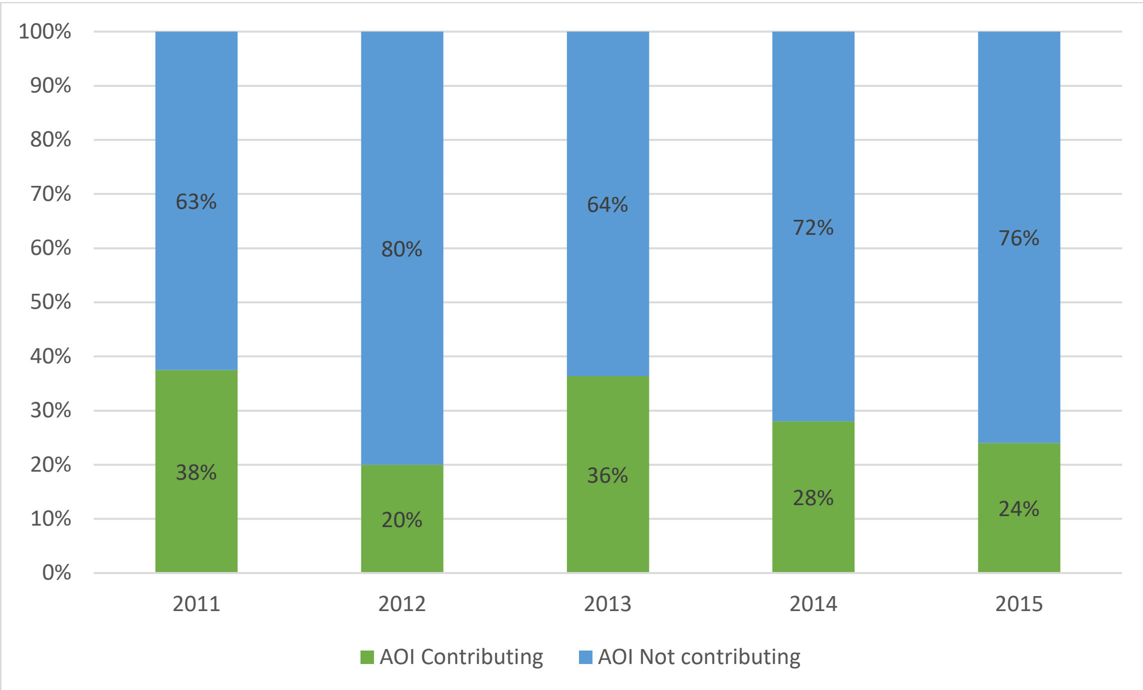

Figure A1 Proportion of “most impaired days” Iron Range AOI was Contributing or Not Contributing to Visibility at BWCA

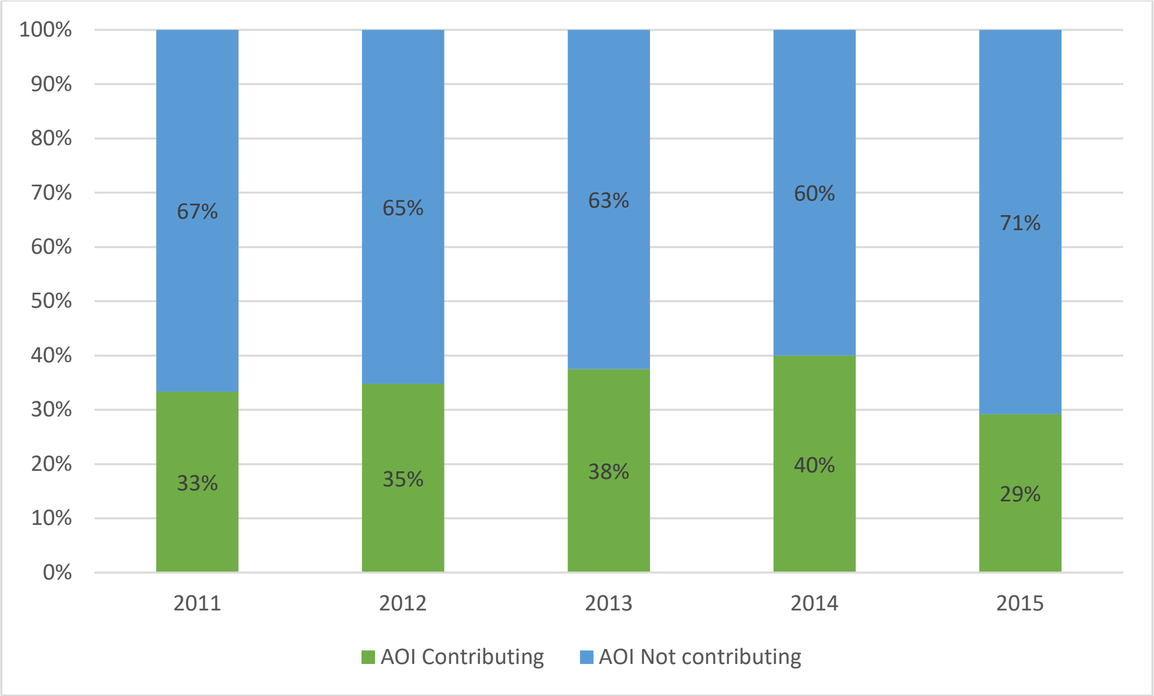

Figure A2 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at Voyageurs

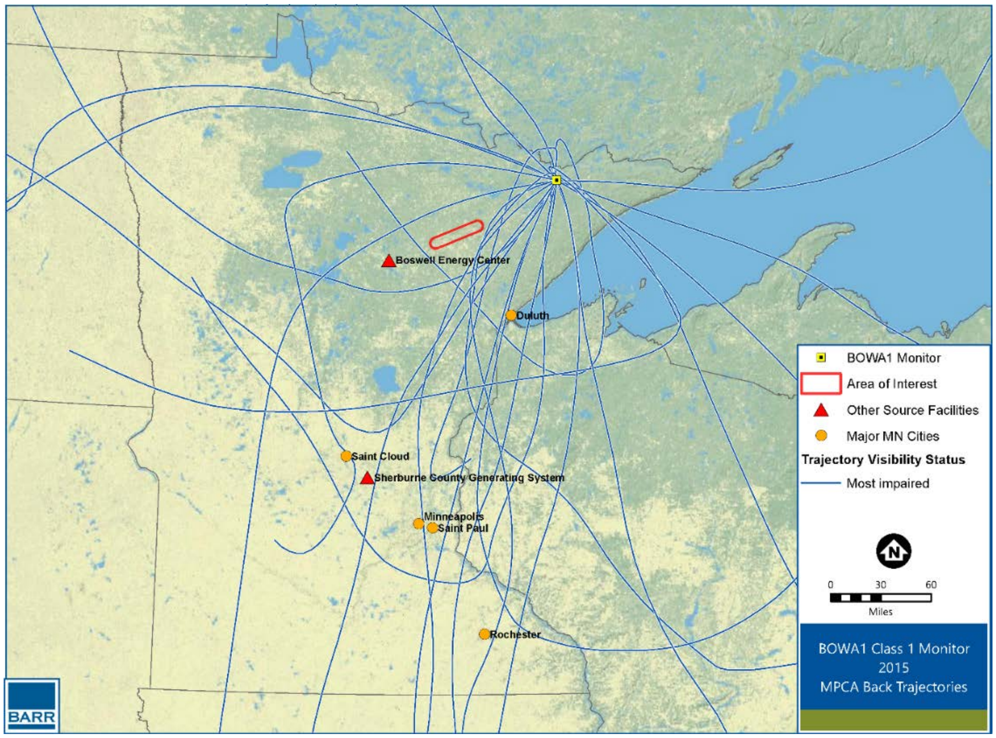

Figure A3 Reverse Trajectories and Other Sources Influencing Visibility at BWCA[9]

[9] 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, baseline source visibility impacts (or a surrogate metric for the impacts), [and] the in-place emission control measures…"*[10]

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. The first step in doing this is to estimate the impact of the source or set of sources on daily concentrations of PM species.*
>
> *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).*

[10] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 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 $PM_{2.5}$ 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."[11]

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 2nd 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_X 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_X 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_X 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 NOx 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_X 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

[11] 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_X 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_X 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_X 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_X 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_3) is a component of haze associated with NO_X 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."[12] 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."[13]

[12] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.
[13] Ibid, Page 12.

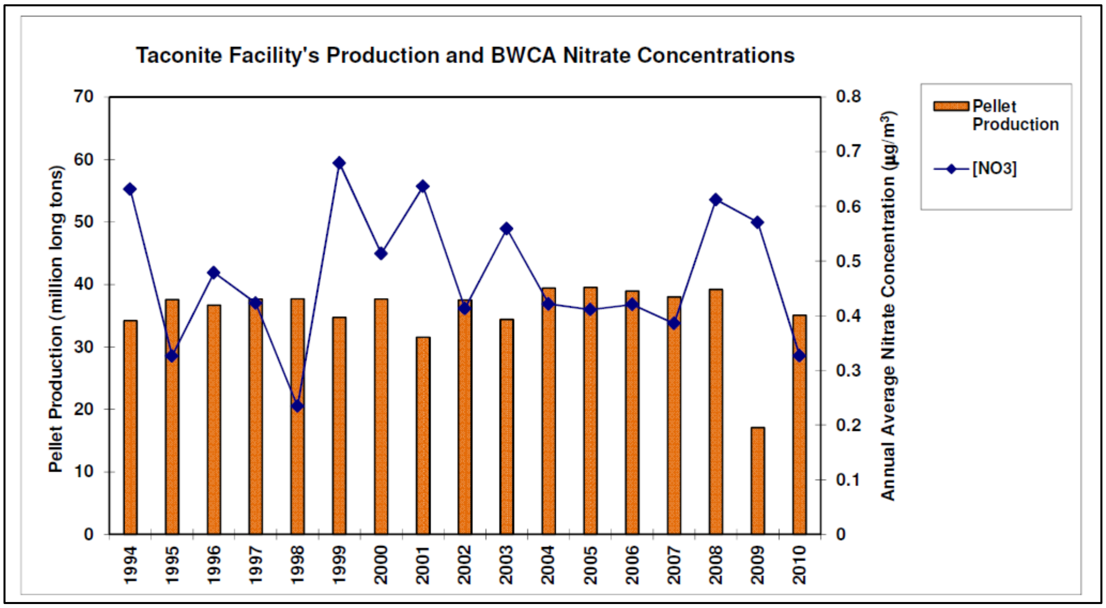

Figure A4 Minnesota Taconite Production and BWCA Nitrate Concentrations 1994-2010 [14]

[14] 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

Table A1 Results from MPCA Hysplit Trajectories for the BOWA1 Monitor

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

Table A2 Results from MPCA Hysplit Trajectories for the VOYA2 Monitor

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

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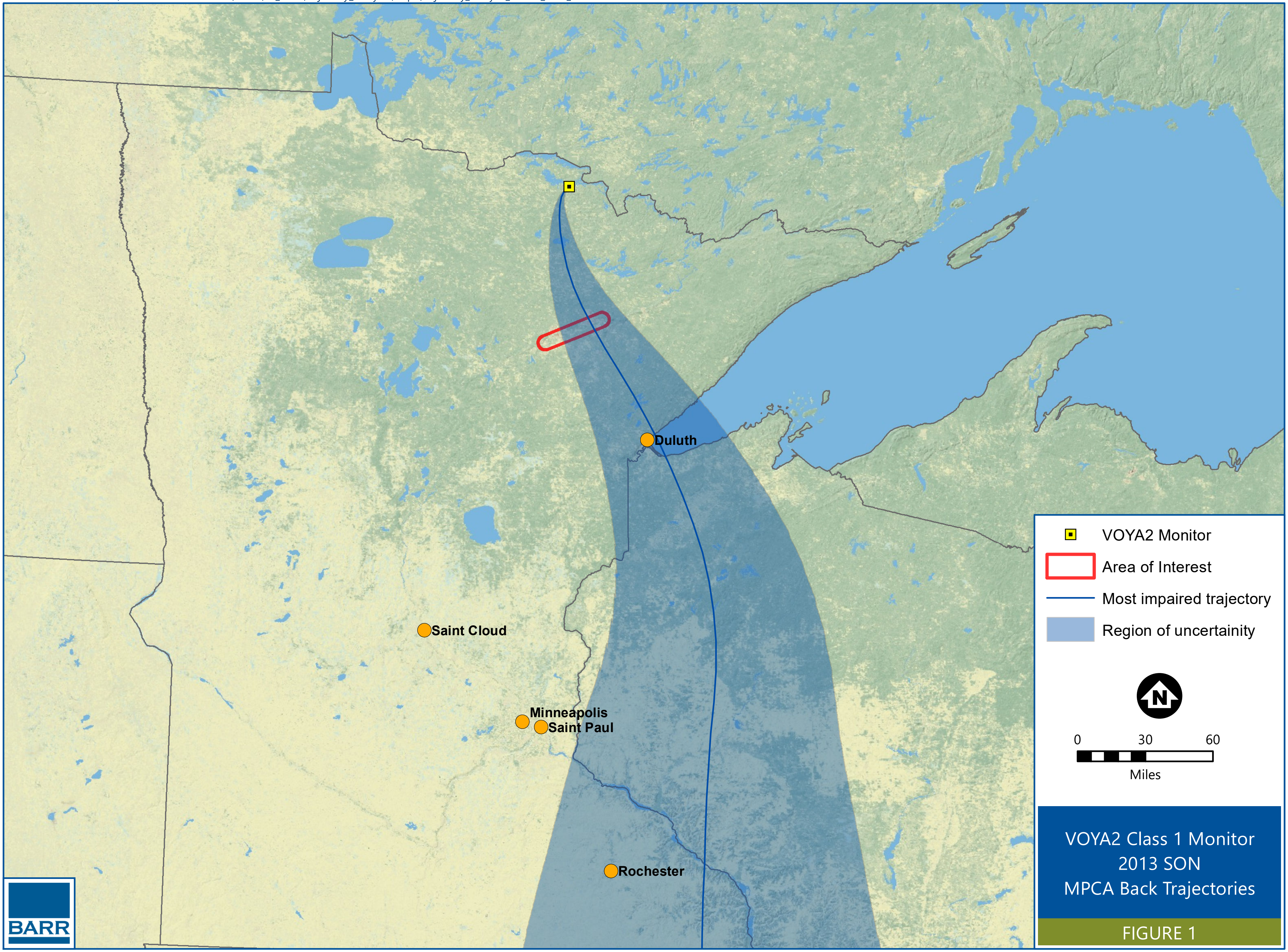
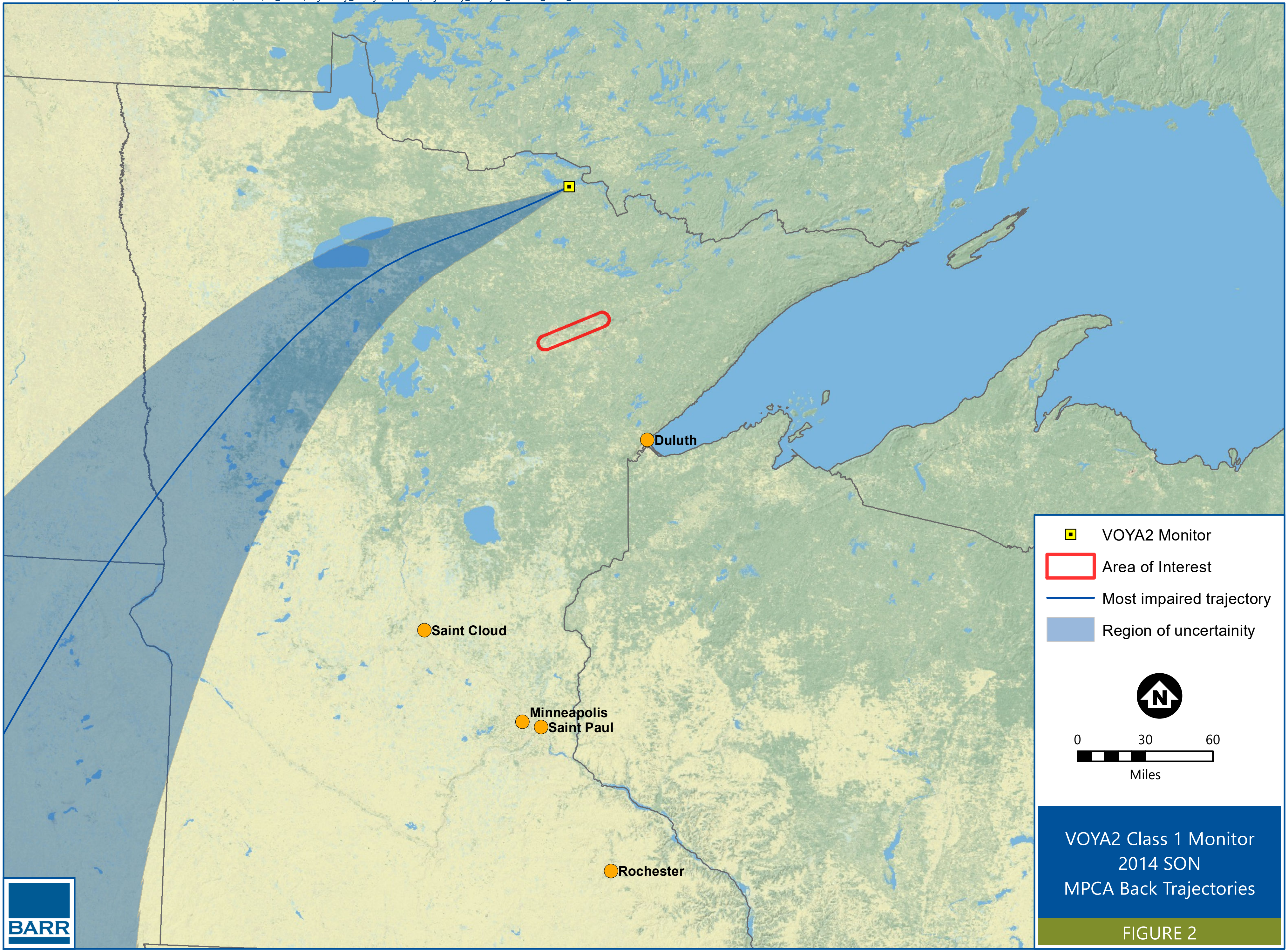


VOYA2 Class 1 Monitor
2013 SON
MPCA Back Trajectories

FIGURE 1



VOYA2 Class 1 Monitor
2014 SON
MPCA Back Trajectories

FIGURE 2

Attachment 2

CAM_X Modeling Report

resourceful. naturally.
engineering and environmental consultants

BARR

Technical Memorandum

From: Barr Engineering

Subject: Summary of Comprehensive Air Quality Model with Extensions (CAM_X) 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_X), 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_X, as EPA's approach over-predicted visibility impacts by factors of ten to sixty when compared with the proper CAM_X 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_X Modeling Methodology

The methodology utilized by Barr to complete the CAM_X 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_X modeling system (CAM_X 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_X 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."[1] 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

[1] 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_X 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_X (including Tilden Mining). A list of the sources that were included in the specific PSAT groups can be found in Appendix C: CAM_X 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.

Table 1: Facility Taconite Furnace Emission Summary

Facility	FIP Baseline (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**

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.

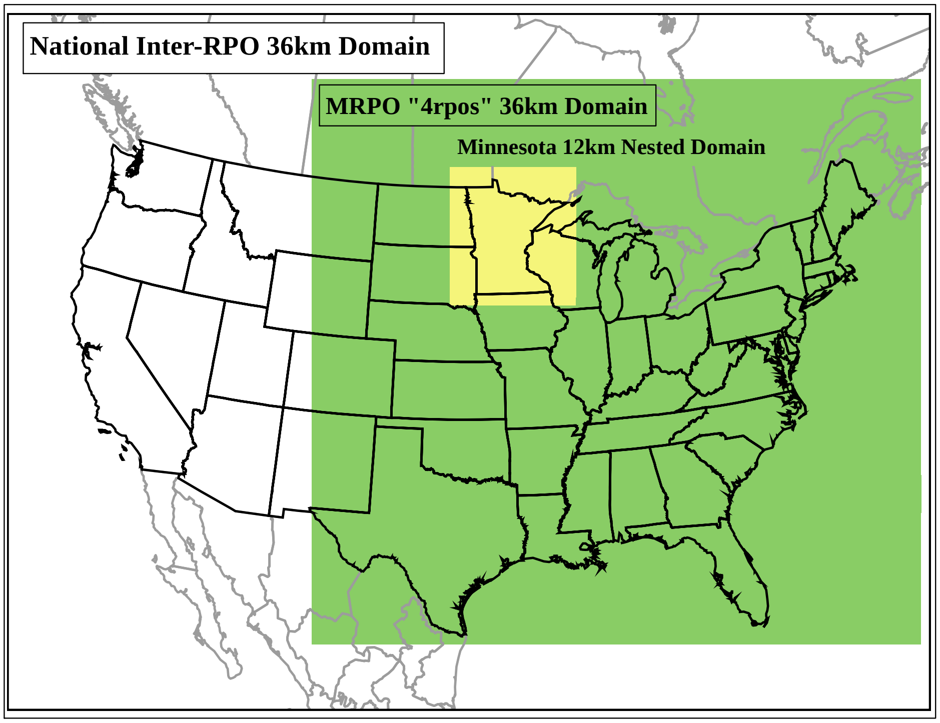


Figure 1. MPCA Modeling Domain

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_X 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_X 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_X/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_X Results

As mentioned above, the CAM_X 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_X 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_X modeling for this project on a facility by facility basis. The first three facilities contain emission reductions for only NO_X: Arcelor Mittal, Hibbing Taconite, and Northshore Mining. These results are summarized in Tables 2-4. United Taconite and Tilden Mining, which have both SO_2 and NO_X emission reductions, have result comparisons that require additional discussion.

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

0.5 dV impact 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)[2],

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

0.1 dV difference was defined by other agencies, such as the northeastern states MANE-VU Regional Planning Organization[3] as the degree of visibility improvement that is too low to justify additional emission controls. In addition, EPA's Regional Haze Rule mentions[4] 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 98th 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_X Modeled Difference).

Table 2: Arcelor Mittal Visibility Impact Comparison

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[2] 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule.

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

[4] 64 FR 35730.

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by 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 Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by 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 Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by 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_X 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 10 times the predicted 98^{th} percentile visibility improvement in all cases for the Arcelor Mittal, Hibbing Taconite, and Northshore Mining facilities. The maximum 98^{th} 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^{th} 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.

Table 5: Hibbing Taconite Line-Specific Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 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

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_2 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_X and the revised emission reduction for SO_2. Then, those resultants were averaged for each of the Class I areas to obtain the "updated" EPA all pollutant estimates.

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

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.6		1.40		110%
Voyageurs	0.8		0.85		N/A
Isle Royale	1.1		0.35		320%

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_X 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_X 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_X 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_X 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.[5]

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

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.0		1.29		N/A
Voyageurs	0.5		0.74		N/A
Isle Royale	0.6		0.28		210%

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

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	2.3		0.18		1300%
Voyageurs	1.1		0.08		1400%
Isle Royale	1.6		0.05		3200%

[5] 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.

Table 9: United Taconite Line-Specific Nitrate Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 98% dV
Boundary Waters	Line 1		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

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.

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

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV
Boundary Waters	N/A		0.08
Voyageurs	N/A		0.03
Isle Royale	N/A*		0.17

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

Table 11: Tilden Mining Pollutant-Specific Impact Comparison

Class I Area	CAM_X Sulfate Modeled Difference 98% dV		CAM_X Nitrate Modeled Difference 98% dV
Boundary Waters	0.07		0.01
Voyageurs	0.03		0.00
Isle Royale	0.14		0.02

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_X 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."[6] Our analysis demonstrates that the ratio approach has over-estimated impacts by a factor of ten to sixty for NO_X reductions. When accurately modeled, the NO_X reductions do not yield discernible visibility benefits. To that end, the following pictures from WinHaze Level 1 Visual Air Quality Imaging Modeler

[6] 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[7].

Isle Royale FIP Base – United Taconite

Isle Royale Final FIP – United Taconite

Boundary Waters FIP Base – Hibbing 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_X 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.

[7] Voyageurs National Park pictures are not contained within the WinHaze program

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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?

- <u>*For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.*</u>

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.

- <u>*Make the net visibility improvement determination.*</u>

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:

- o *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).*
- o *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.

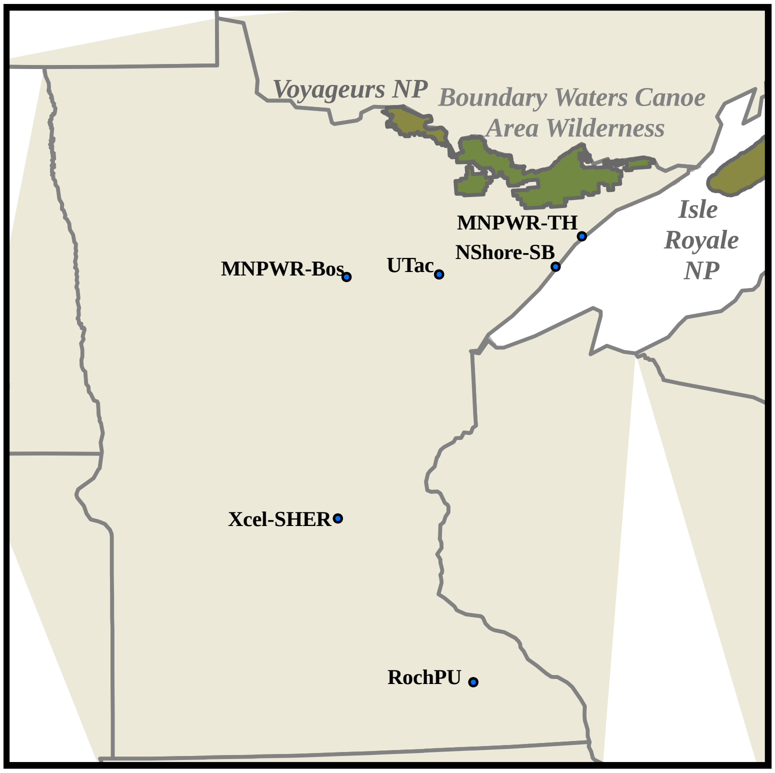
II. Summary of EPA's approach

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[1] 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).

[1] 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 98th 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 combined the results to estimate 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_X 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_X 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 98th 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_X 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_X 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			Emission Reductions			Emissions	
				Proposed FIP			Baseline - Prop FIP	Baseline - Prop FIP		Final FIP	
	Emission Unit			Baseline	FIP		Emission Tables	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 Combined	NOx	6,888	2,066		**4,821**	**5,259**	[3]		
			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]
	NSM	BART Units Combined	NOx	805	250		**555**	**926**	[9]		
			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]
	TMC	BART Units Combined	NOx	4,707	1,478		3,229	3,229	[18]		
			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 Combined	NOx	5,330	1,599		**3,731**	**3,208**	[26]		
			SO2	4,043	404		3,639	3,639	[26]	529	[28]
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	1,092	[29]	**2,547**	**2,859**	[31]		[32]
			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

EPA Furnace
NOx Control %
70%

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 Emisssions = 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)

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APPENDIX B: Barr and MPCA CAM_X Modeling Comparison of Results

March 6, 2013

Minnesota Power – Taconite Harbor (BART01)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	94	90	-4	11	9	-2	30	27	-3
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	95	90	-5	11	9	-2	30	27	-3
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-Ence	Base	BART	Differ-ence	Base	BART	Differ-Ence
Days > 0.5 dv	2002	111	60	-51	86	58	-28	48	27	-21
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-Ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	110	61	-49	86	58	-28	47	27	-20
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Differ-ence**	**Base**	**BART**	**Differ-ence**	**Base**	**BART**	**Differ-ence**
Days > 0.5 dv	**2002**	77	72	-5	9	8	-1	20	15	-5
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Differ-ence**	**Base**	**BART**	**Differ-ence**	**Base**	**BART**	**Differ-ence**
Days > 0.5 dv	**2002**	78	72	-6	9	8	-1	20	15	-5
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Differ-ence**	**Base**	**BART**	**Differ-ence**	**Base**	**BART**	**Differ-ence**
Days > 0.5 dv	**2002**	59	44	-15	32	20	-12	8	1	-7
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Differ-ence**	**Base**	**BART**	**Differ-ence**	**Base**	**BART**	**Differ-ence**
Days > 0.5 dv	**2002**	63	46	-17	34	20	-14	8	1	-7
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	74	58	-16	53	39	-14	42	30	-12
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	74	59	-15	53	39	-14	42	29	-13
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	0	0	0	0	0	0	0	0	0
98th Percentile Δ 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 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Differ-ence	Base	BART	Differ-ence	Base	BART	Differ-ence
Days > 0.5 dv	2002	0	0	0	0	0	0	0	0	0
98th Percentile Δ dv	2002	0.10	0.06	0.04	0.08	0.04	0.04	0.09	0.04	0.05

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APPENDIX C: CAM_X PSAT Source List

March 6, 2013

2009 MPCA Tracked, Elevated Point Sources

RANKTRAC BARTSRC_ID	RECEPTOR 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

(highlighted) 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	2703100001	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

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

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APPENDIX D: Summary of CAM_X Elevated Point Source Emissions

March 6, 2013

Summary of CAMx Elevated Point Source Emissions

Facility	Emission Unit ModID	Emission Unit Description	Pollutant	Emissions Proposed FIP Baseline tons/yr	Note(s)	Emissions Final FIP FIP tons/yr	Note(s)	Emission Reductions Baseline - Final FIP 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 Combined	NOx	6,888		2,066		4,821
			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
	NSM	BART Furnaces Combined	NOx	764		229		535
			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 Combined	NOx	5,330		1,599		3,731
			SO2	4,043		1,969		2,074
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	[28]	1,092	[30]	2,547
			SO2	179	[29]	179	[31]	0

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

(yellow)	Facility Furnace Unit Summary or Overall Summary
(green)	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)

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

March 6, 2013

From: Jeffry D. Bennett
Sent: Thursday, January 31, 2013 7:42 PM
To: 'Rosenthal.steven@Epa.gov'
Cc: 'Long, Michael E'
Subject: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: 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

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APPENDIX F: CAMx Modeling Results by Facility

March 6, 2013

Arcelor Mittal CAMx Emissions and Modeling Results

Arcelor Emissions

Unit	EPA FIP Baseline NOx Emission (TPY) [1]	Final FIP NOx Emission (TPY) [1]	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY) [2]	Final FIP SO2 Emission (TPY)[3]	SO2 Emission Difference (TPY)
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)

Arcelor CAMx Results (By Unit) [4]

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Proposed FIP Days > 0.5 dV	Proposed FIP 98% dV	Difference Days >0.5 dV [5]	Difference 98% dV [5]
Boundary Waters						
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
Voyageurs						
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:

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

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

0.1 dV difference 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 98th 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 98th 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 C Emission Difference = 2,859 TPY NOx)[6]

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

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[8]	CAMx Modeled Difference 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

[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 98th 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 Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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
Voyageurs						
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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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 Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (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)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Voyageurs						
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
Isle Royale						
2002						
Power Boiler #1	3	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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	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 Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)[12]	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)[13]	SO2 Emission Difference (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

UTAC CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
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 Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[16]	CAMx Modeled Difference 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

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

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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

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_X 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).

UTAC Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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						
Line #1 – NO3	0	0.026	0	0.011	0	0.015
Line #1 – SO4	0	0.150	0	0.072	0	0.078
Line #1 – All	0	0.163	0	0.080	0	0.083

UTAC Line 2 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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 – SO4	16	0.773	6	0.436	10	0.337
Line #2 – All	17	0.786	6	0.446	11	0.340
Isle Royale						
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 Comparison of Sulfate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 2,074 TPY SO_2

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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

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

Final FIP Emission Difference = 3,731 TPY NO_x

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 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^{th} percentile NO_3 impact when combining both line emission reductions is <u>0.18 dV</u>, while the maximum 98^{th} percentile SO_4 impact for both lines is <u>1.29 dV</u>. Based on these results, it is evident that the SO_4 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 NO_x emission reductions do not provide substantive visibility improvement.

Tilden Mining CAMx Emissions and Modeling Results

Tilden Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (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 Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1	0	0.141	0	0.037	0	0.104
2005						
Line #1	0	0.097	0	0.042	0	0.055
Voyageurs						
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

Tilden Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
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
Voyageurs						
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

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.

Impacts of the taconite plants' NO_X 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 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X 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)[1] 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[2].

The United States Environmental Protection Agency (EPA) has issued a proposed rule[3] to address BART requirements for taconite plants in Minnesota and Michigan that involves emission controls for SO_2 and NO_X. This document addresses the likely visibility impact of taconite plant emissions, specifically NO_X 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[4], the distance limitation is 200-300 km because of the overprediction tendencies[5] 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.

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[1] Regional Haze Regulations; Final Rule. *Federal Register*, *64*, 35713-35774. (July 1, 1999).

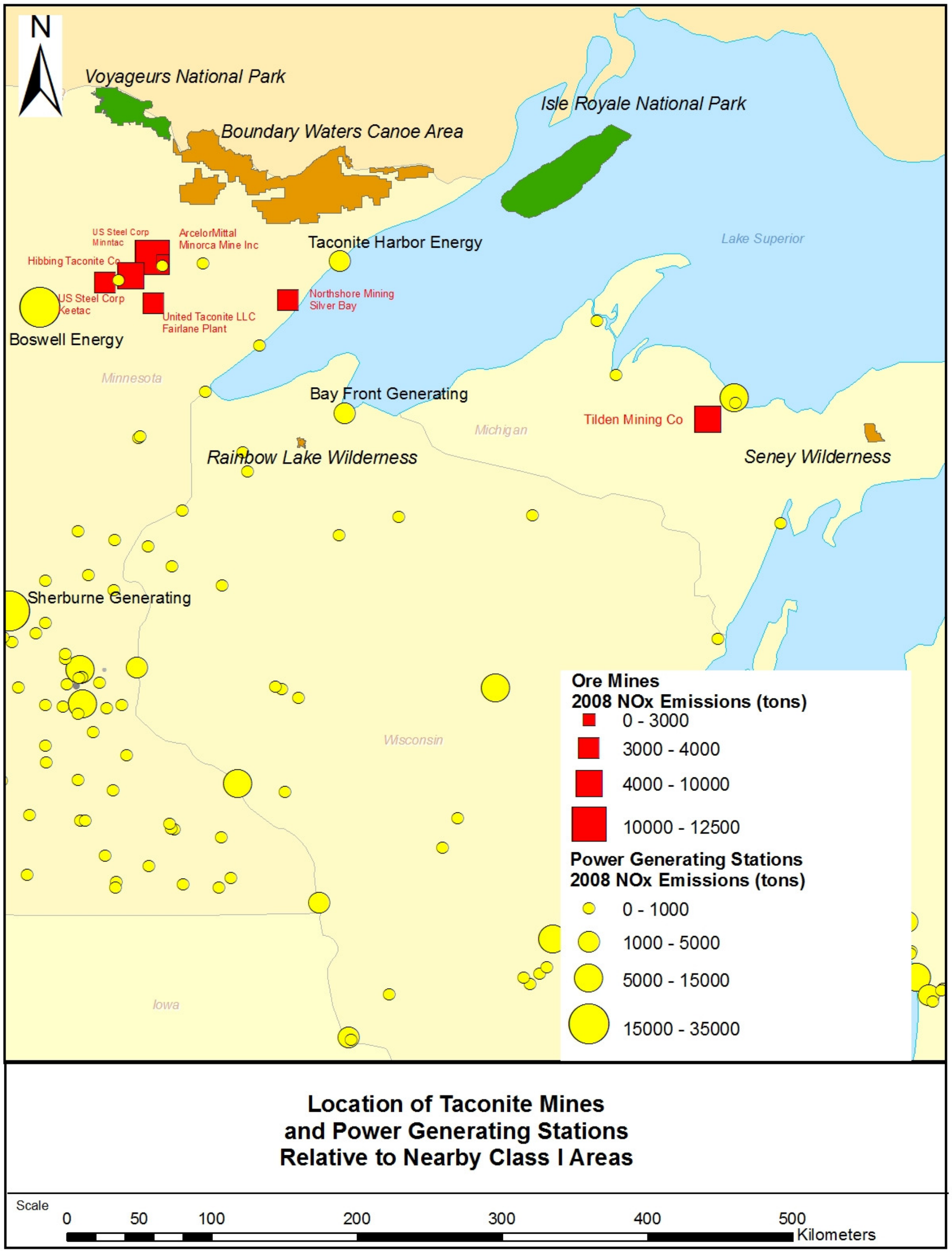
[2] Federal Register. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, Vol. 70. (July 6, 2005)

[3] 77FR49308, August 15, 2012.

[4] CALPUFF Dispersion Model, 2000. http://www.epa.gov/scram001 (under 7th Modeling Conference link to Earth Tech web site).

[5] 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_X emission controls are considered as a BART option because modeling secondary formation of ammonium nitrate is quite challenging. Accurately modeling the effects of NO_X 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_X, and the associated effectiveness of NO_X 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.

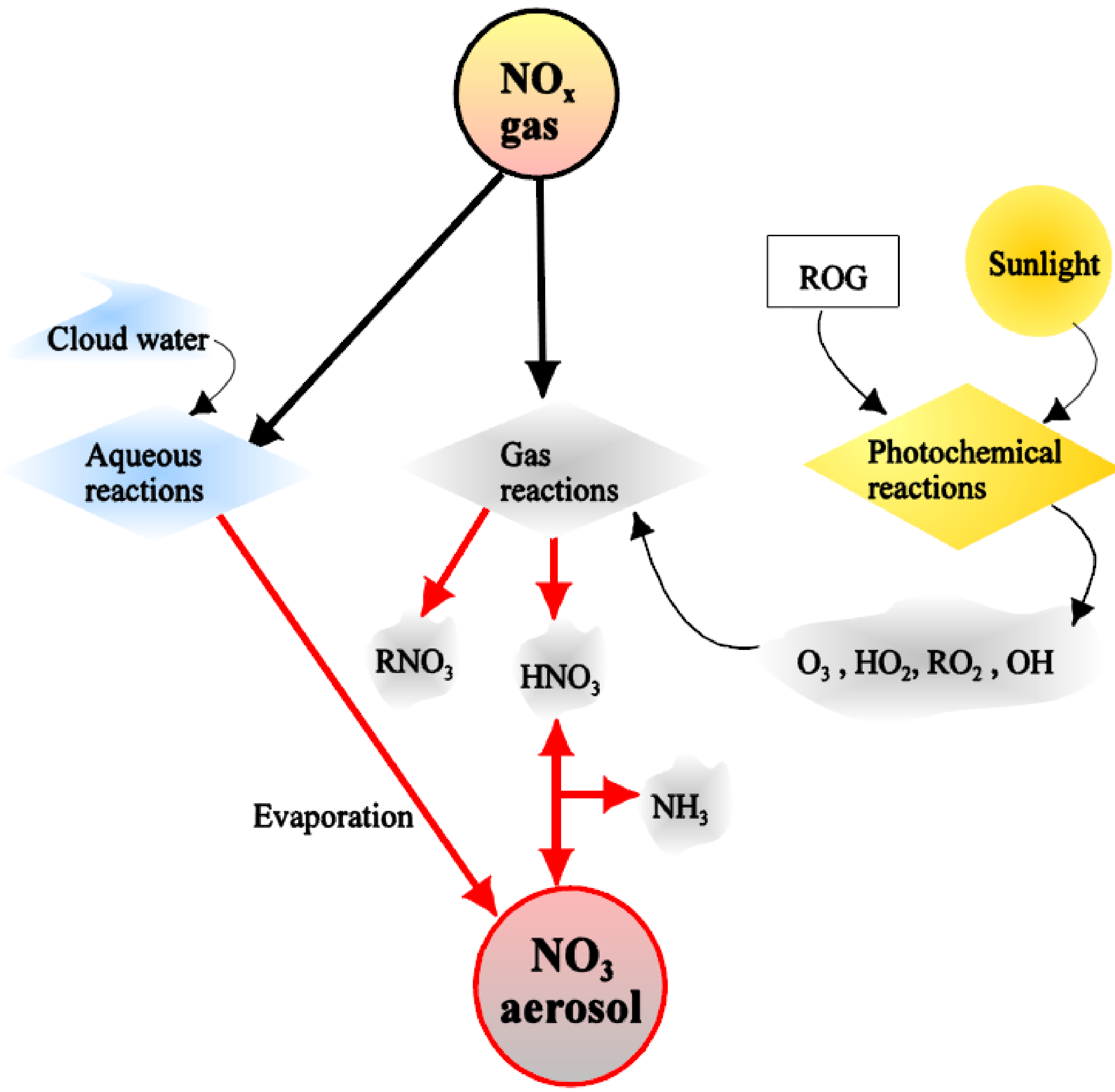
- There are examples where actual significant emission reductions have occurred, where CALPUFF modeling as conducted for BART would predict significant visibility improvements, but no perceptive changes in haze occurred.

Visibility Impact of NO_X Emissions – Unique Aspects and Seasonality

The oxidation of NO_X to total nitrate (TNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the TNO_3 is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state with HNO_3 gas that is a function

of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 2[6]. 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_x Oxidation



[6] Figure 2-32 from CALPUFF Users Guide, available at http://www.src.com/calpuff/download/CALPUFF_UsersGuide.pdf.

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:

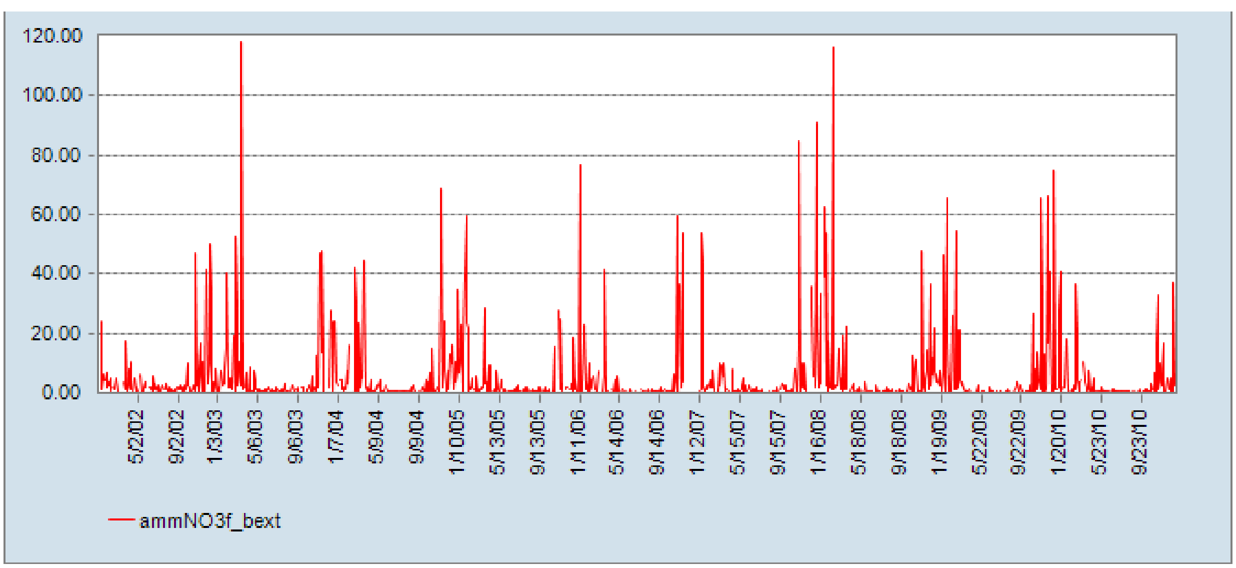
- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium 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_X 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



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 water-dominant Class I areas in Minnesota (Voyageurs and Boundary Waters) that freeze in winter. In fact, for Voyageurs National Park, the typical monthly attendance[7] 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 totally close[8] 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[9] 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[10] 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[11] of nitrate and sulfate haze in

[7] As documented at http://www.gorp.com/parks-guide/voyageurs-national-park-outdoor-pp2-guide-cid9423.html.

[8] As noted at http://www.nps.gov/isro/planyourvisit/hours.htm.

[9] As noted at http://www.fws.gov/midwest/seney/visitor_info.html.

[10] 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.

[11] 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 4 Minnesota Taconite Production and BWCA Nitrate Concentrations

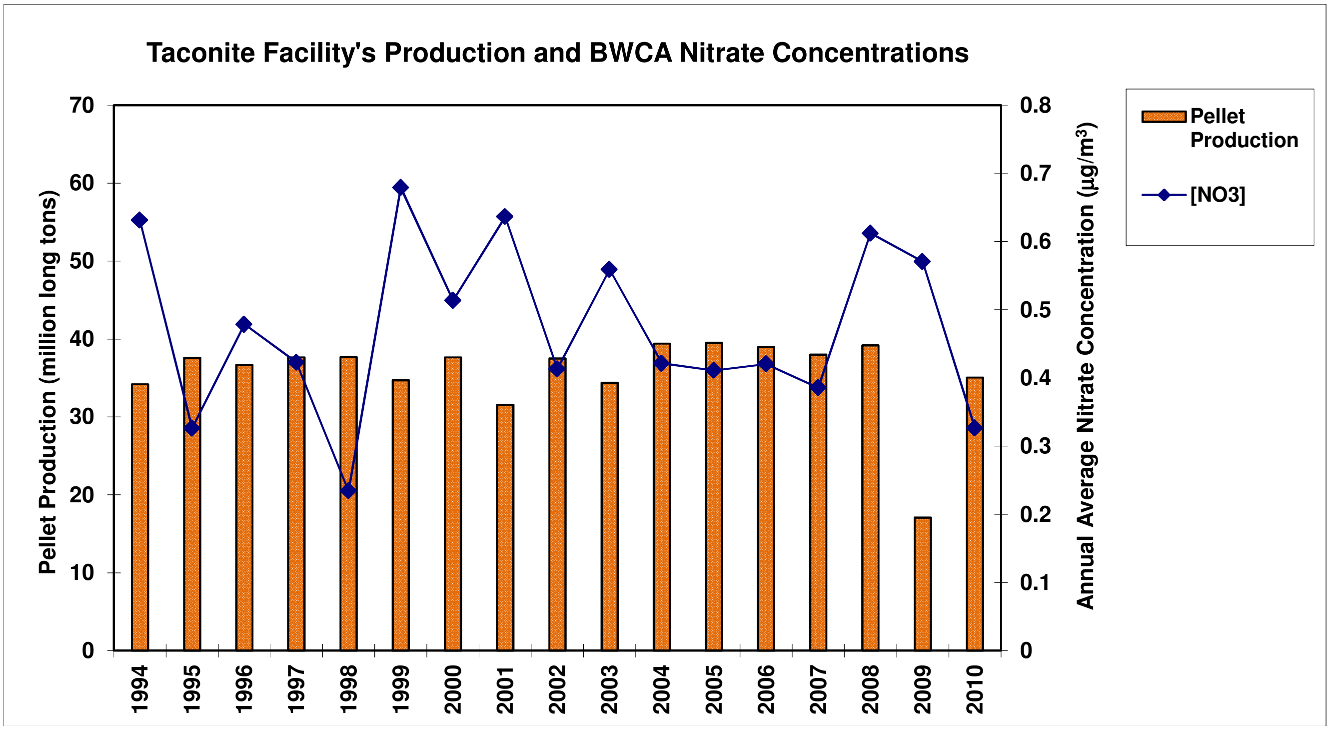


Figure 5 Time Series of Nitrate Haze at Boundary Waters Canoe Area (2002-2010)

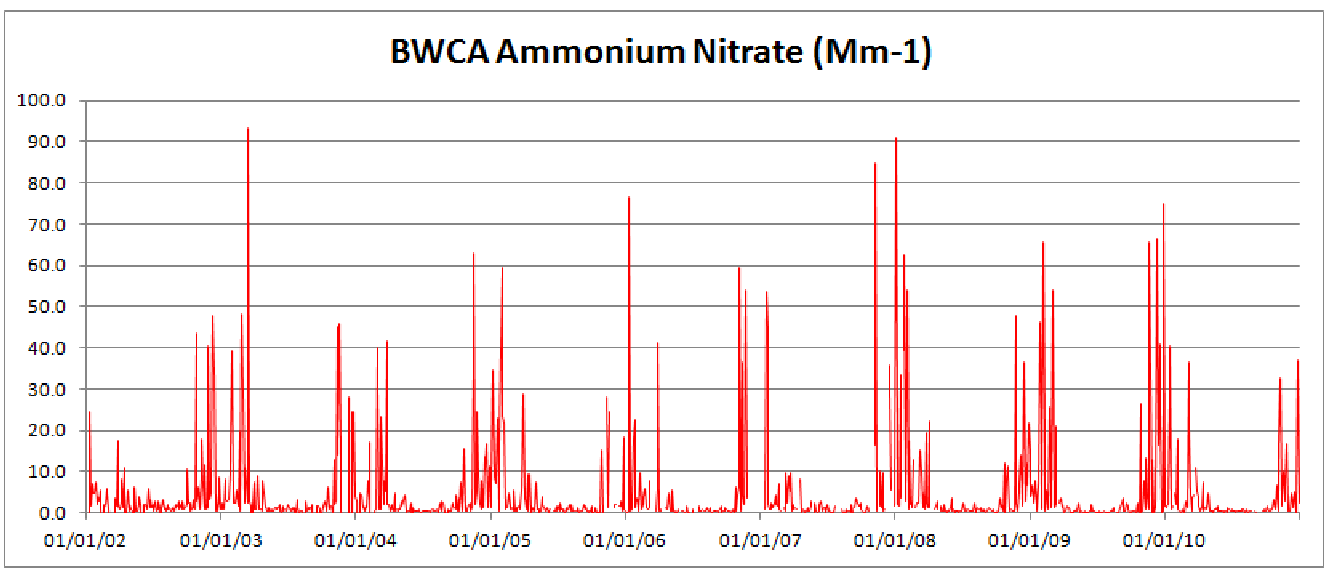
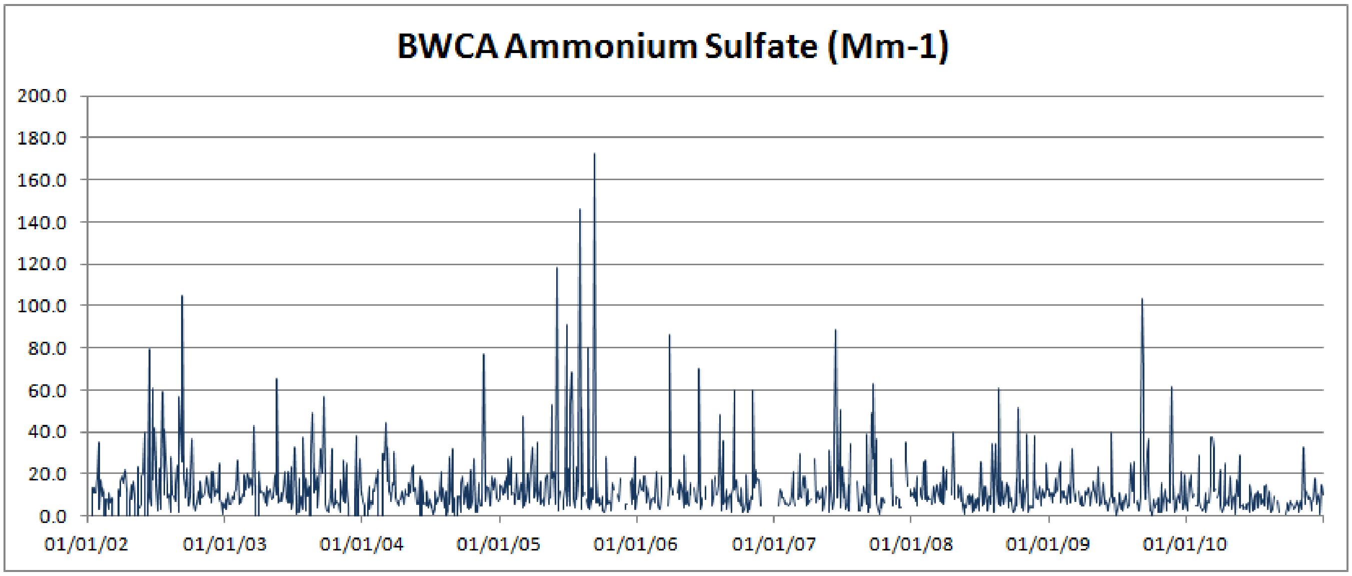


Figure 6 Time Series of Sulfate Haze at Boundary Waters Canoe Area (2002-2010)



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

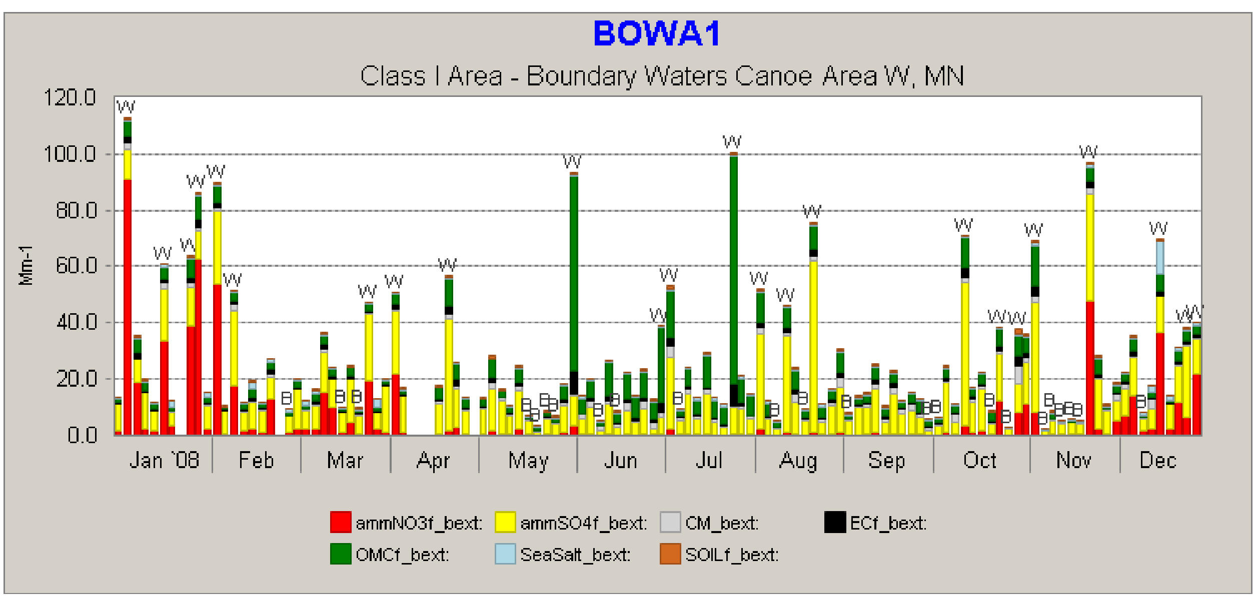


Figure 8 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2009

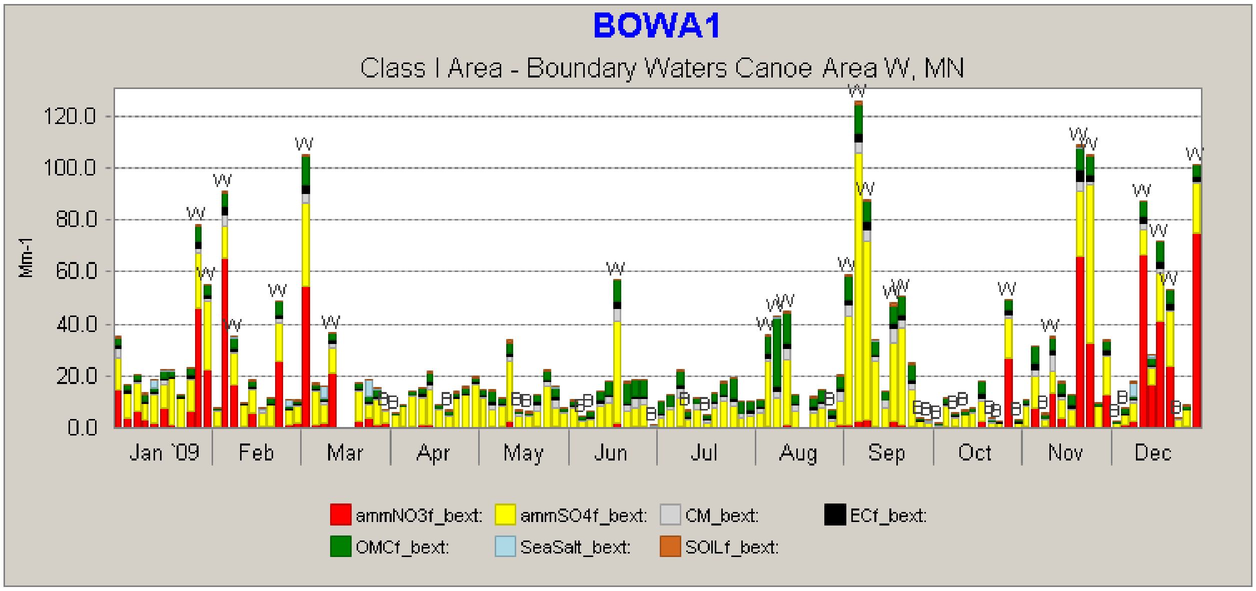
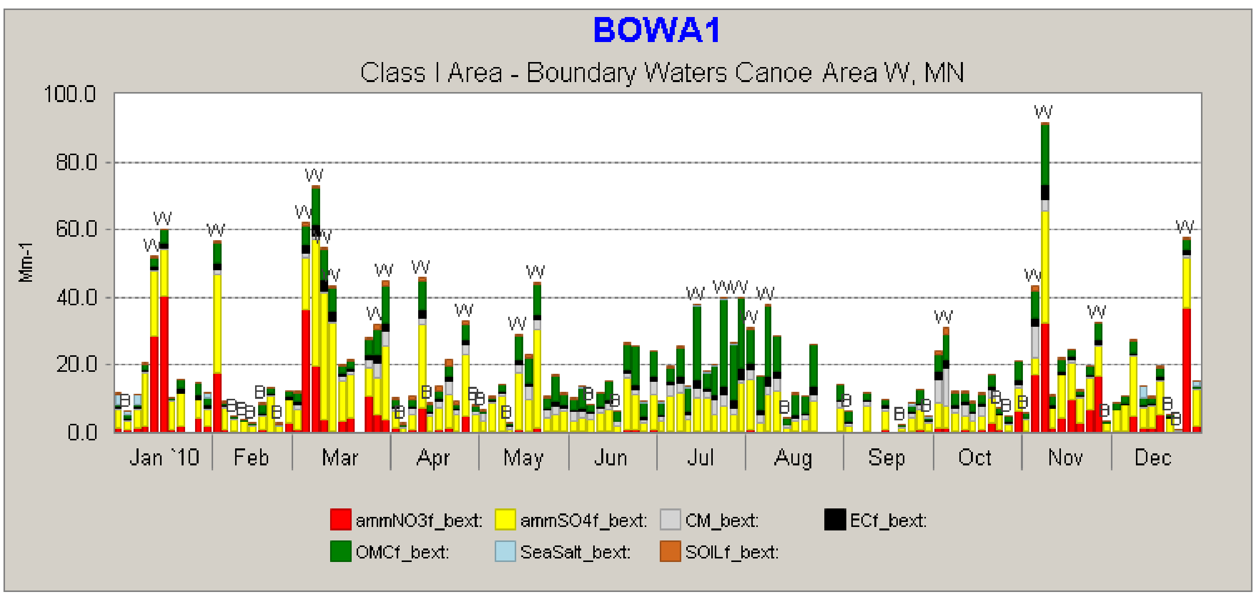


Figure 9 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2010



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.

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 anywhere 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^{th} 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

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_X 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[12] 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 9th 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 11th and 12th, 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.

[12] See, for example, the Iowa State Implementation Plan for Regional Haze report at http://www.iowadnr.gov/portals/idnr/uploads/air/insidednr/rulesandplanning/rh_sip_final.pdf, Figures 11.3 and 11.4.

Figure 10 PSAT Results from CENRAP CAMx Modeling for Isle Royale National Park

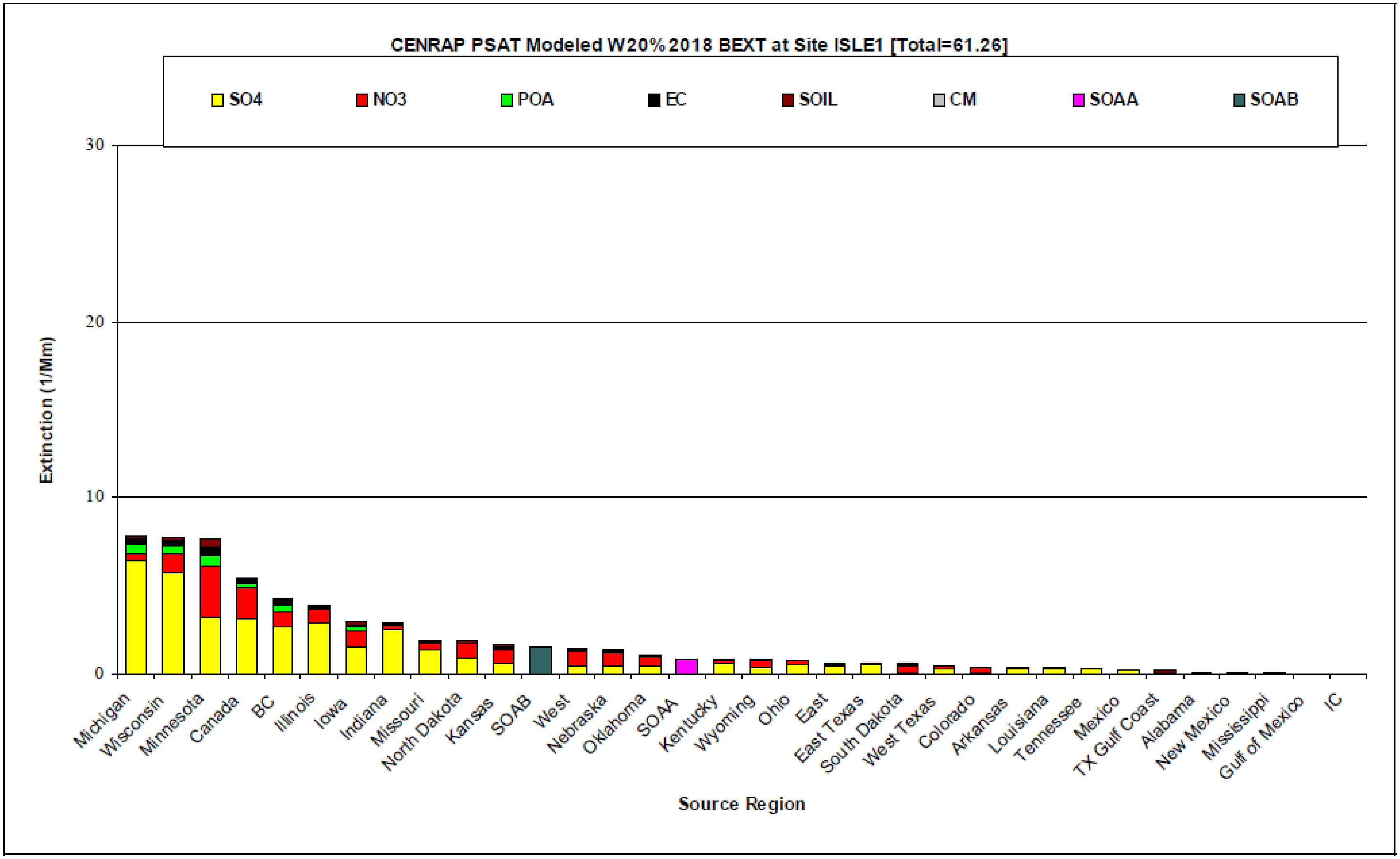


Figure 11.3. Source apportion contributions by region and pollutant to ISLE in 2018.

Figure 11 PSAT Results from CENRAP CAMx Modeling for Seney Wilderness Area

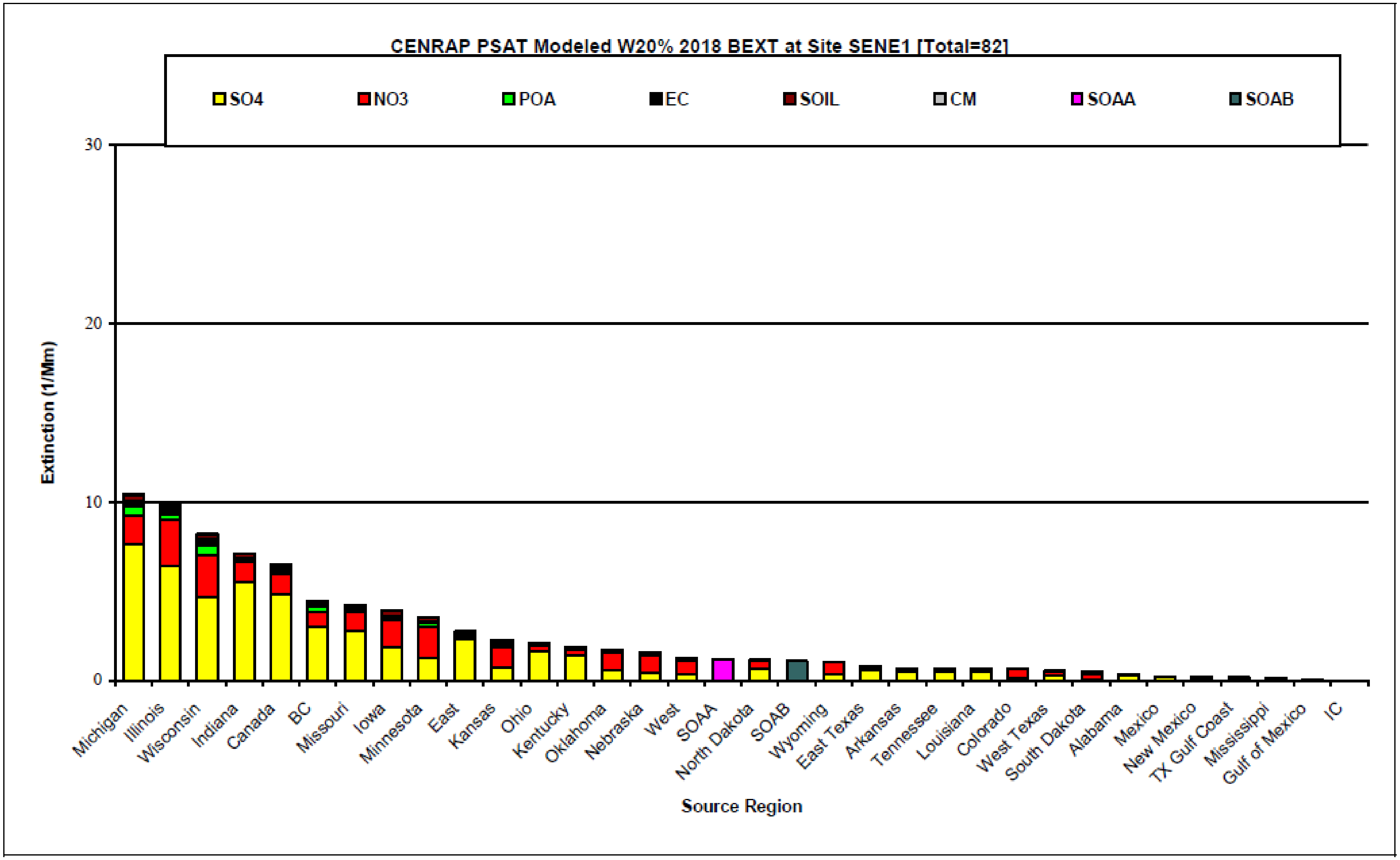


Figure 11.4. Source apportion contributions by region and pollutant to SENE in 2018.

Figure 12 PSAT Results from CENRAP CAMx Modeling for Boundary Waters Canoe Area Wilderness

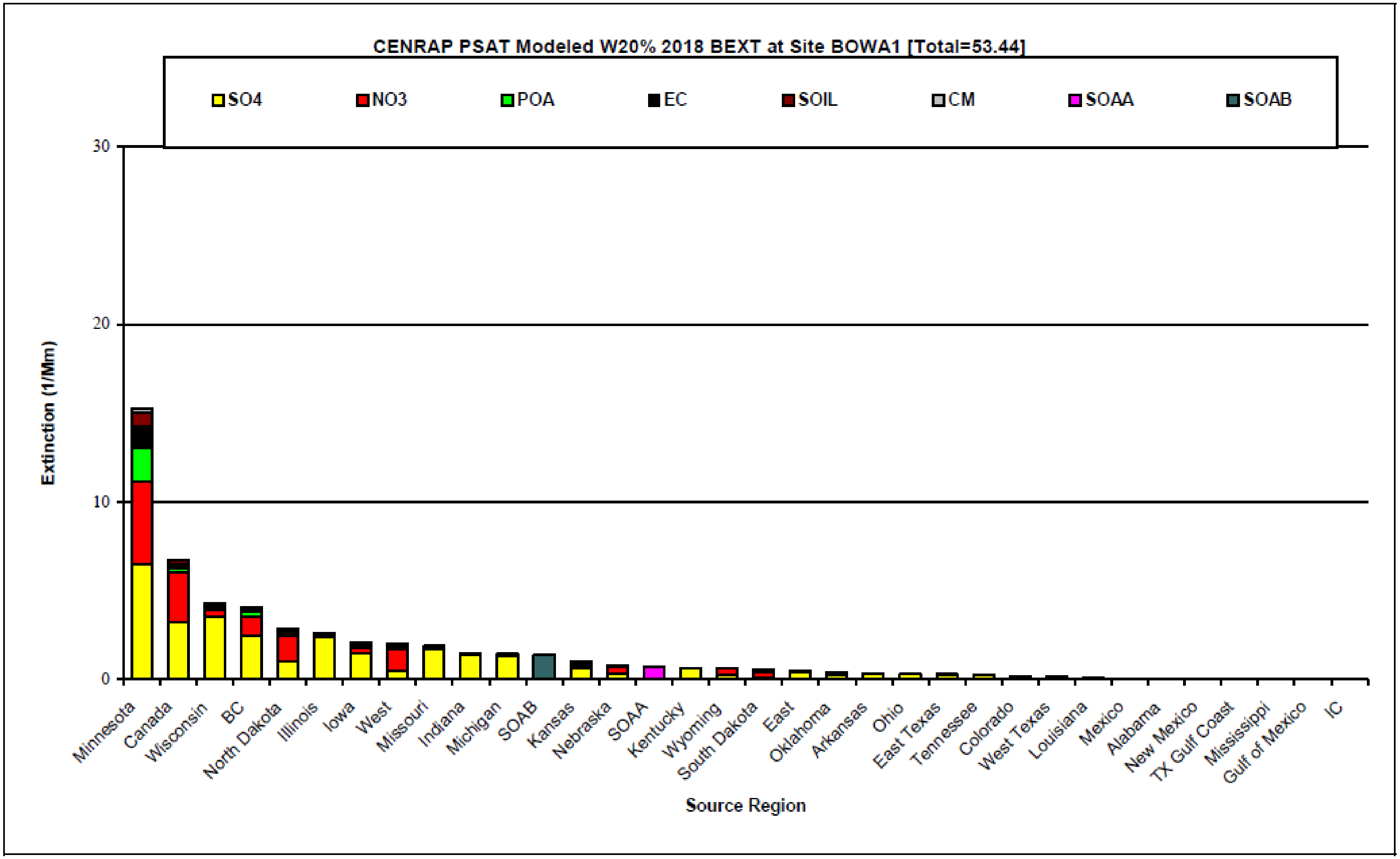


Figure 11.1. Source apportion contributions by region and pollutant to BOWA in 2018.

Figure 13 PSAT Results from CENRAP CAMx Modeling for Voyageurs National Park

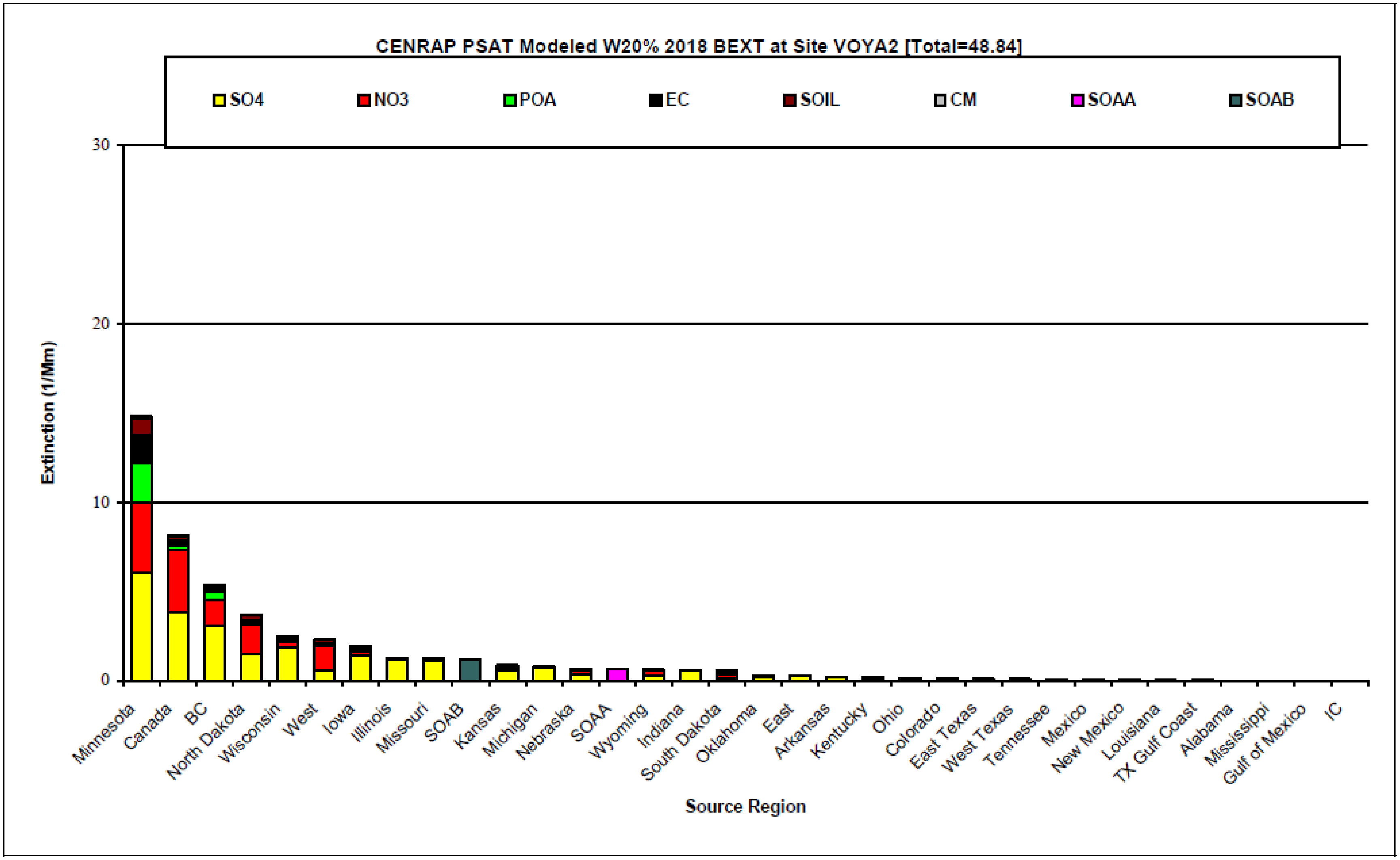


Figure 11.2. Source apportion contributions by region and pollutant to VOYA in 2018.

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_X 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 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X 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.

APPENDIX A

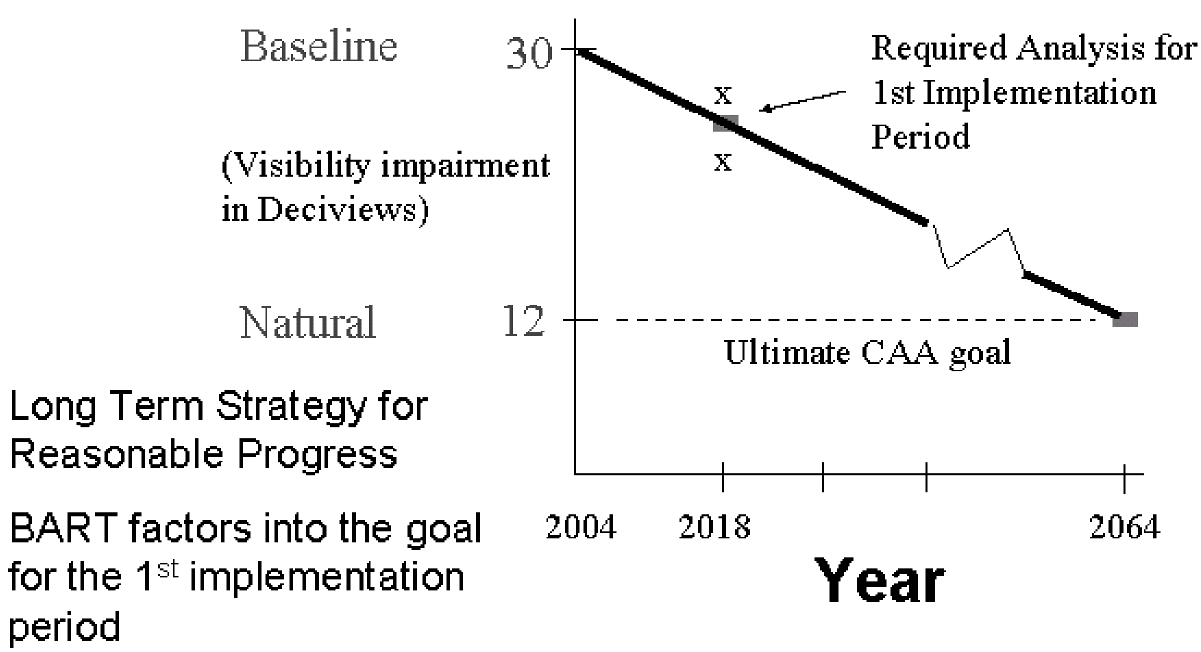
THE REGIONAL HAZE RULE GOAL OF NATURAL CONDITIONS

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[13] 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 20th century.

Figure A-1: Illustration of the Uniform Rate of Progress Goal



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[13] *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, (U.S. Environmental Protection Agency, September 2003). http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf.

In its RHR SIP, North Dakota[14] 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_2 and NO_x 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.

[14] North Dakota Dep. of Health, 2010. North Dakota State Implementation Plan for Regional Haze. http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Main%20SIP%20Sections%201-12.pdf.
.

- As a result, there is a substantial reduction in SO_2 and NO_x 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[15], 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 (http://views.cira.colostate.edu/web/) 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_2 and NO_X.

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_2 and NO_x).

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.

[15] See Appendix 2-2 at http://www.tceq.state.tx.us/implementation/air/sip/bart/haze_appendices.html.

These estimates were derived from Trijonis[16] and use two different sets of natural concentrations for the eastern and western U.S. Tombach[17] 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		Error Factor	Dry Extinction Efficiency (m^2/g)
	West ($\mu g/m^3$)	East ($\mu g/m^3$)		
Ammonium sulfate [b]	0.12	0.23	2	3
Ammonium nitrate	0.10	0.10	2	3
Organic carbon mass [c]	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 $\mu g/m^3$ and 1.5 $\mu g/m^3$ 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.[18]

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.

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[16] 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.

[17] 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 http://www.wrapair.org/forums/aamrf/projects/NCB/index.html.

[18] 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[19] reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach[8] 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[8] 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[20]; Koo et al., 2010[21]), 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 20th century, fire suppression has resulted in a buildup of vegetative "fuels" and catastrophic wildfires. Recent estimates of background visual range, such as Trijonis[16], 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

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[19] 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.

[20] 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. (http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC_2006_report_FINAL.pdf).

[21] 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. Atm. Env., 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 http://www.nps.gov/thro/parkmgmt/firemanagement.htm for the Theodore Roosevelt National Park that:

"For most of the 20th 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[22] 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 background estimates. The consequences of the artificially low estimates of natural visibility conditions include the distortion of Reasonable Progress analyses and also to BART modeling results that overestimate the visibility improvement achievable from NO_X 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_2 and NO_x 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 20th 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.

[22] See explanation at http://www.msnbc.msn.com/id/48569985/ns/us_news-environment/t/forest-service-gets-more-aggressive-small-fires/.

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_2 and NO_X 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.

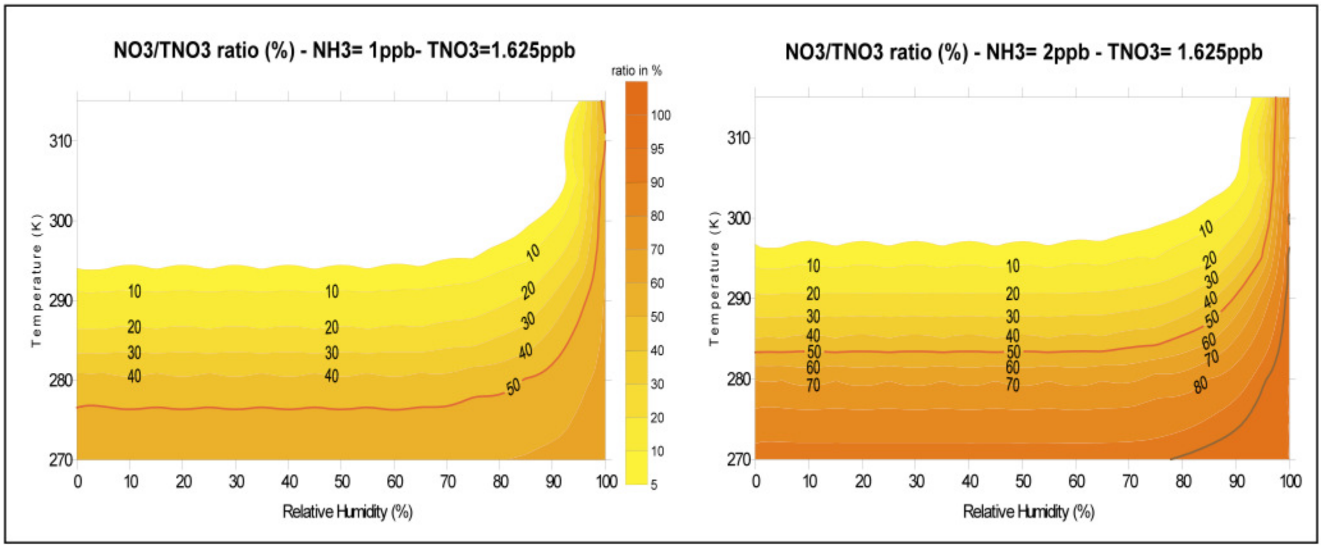
In the CALPUFF model, the oxidation of NO_X to nitric acid (HNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration. In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous HNO_3 and NO_3 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_3 to form ammonium nitrate, as shown in Figure 6[23]. 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.

[23] Scire, Joseph. CALPUFF MODELING SYSTEM. CALPUFF course presented at Chulalongkorn University, Bangkok, Thailand. May 16-20, 2005; slide 40 available at http://aqnis.pcd.go.th/tapce/plan/4CALPUFF%20slides.pdf, accessed March 2011.

Figure B-1: NO_3/HNO_3 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_X emissions relative to SO_2 emissions[24]. 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.

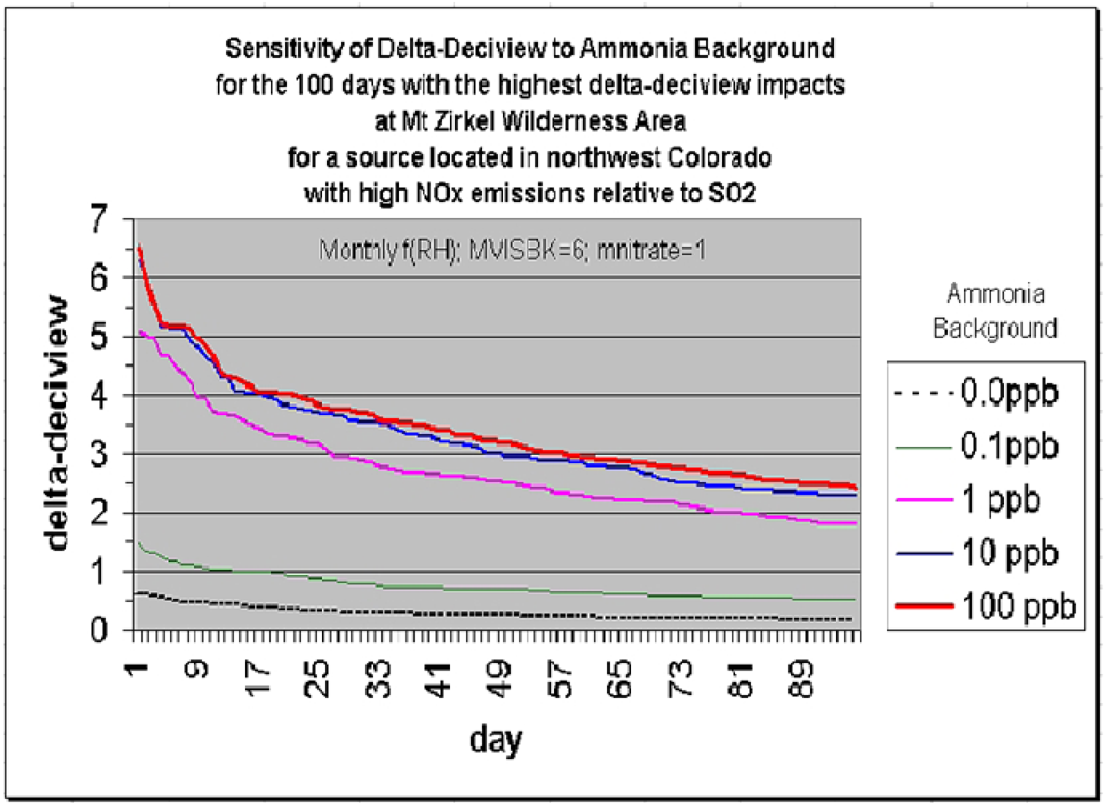
It is also noteworthy that CALPUFF version 5.8's demonstrated over-predictions of wintertime nitrate can be mitigated to some extent by using lower winter ammonia background values, although there is not extensive measurement data to determine the ambient ammonia concentrations. This outcome showing the superiority of the monthly-varying background ammonia concentrations was found by Salt River

[24] Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at http://www.colorado.gov/airquality/documents/Draft-ColoradoSupplementalBARTAnalysisCALPUFFProtocol-25June2010.pdf. (2010)

Project in case studies of the Navajo Generating Station impacts on Grand Canyon monitors, as presented[25] to EPA in 2010.

It is important to note that 14 years ago in 1998, when the IWAQM Phase 2 guidance[26] 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.



[25] 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.

[26] IWAQM Phase 2 Summary Report and Recommendations (EPA-454/R-98-019), EPA OAQPS, December 1998). http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf.

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_2 to sulfate.

On page 39121, the BART rule[27] 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[28]."

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.[29] 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[30]. 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

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[27] July 6, 2005 Federal Register publication of the Regional Haze BART rule.

[28] The next (9th) 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 10th 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.

[29] 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)

[30] 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)

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_2) by the hydroxide ion (OH^-) 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[31]. 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_X 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)[32,33], 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

[31] 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.

[32] 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.

[33] 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)

of aqueous-phase SO_2 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[34], 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_3 concentrations on model predictions of PM nitrate. Twice-weekly background NH_3 concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH_3 concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

1. MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH_3 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_3 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[35]. The results were similar to those noted above: the improved

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[34] 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)

[35] 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[36], 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 10th modeling conference in March 2012 by Scire[37], 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[29,30] 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_X emission reductions.

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[36] 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)

[37] Scire, J., 2012. New Developments and Evaluations of the CALPUFF Model. http://www.epa.gov/ttn/scram/10thmodconf/presentations/3-5-CALPUFF_Improvements_Final.pdf.

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[38] 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_X emission reductions.

[38] http://pah.cert.ucr.edu/aqm/cenrap/meetings.shtml, under “MPE”, slides 9 and 10.

Figure B-3: Sensitivity Study of Nitrate Predictions at Bridger Wilderness Area for Input Ammonia Concentrations to CALPUFF (0.23, 0.5, and 1.0 ppb).

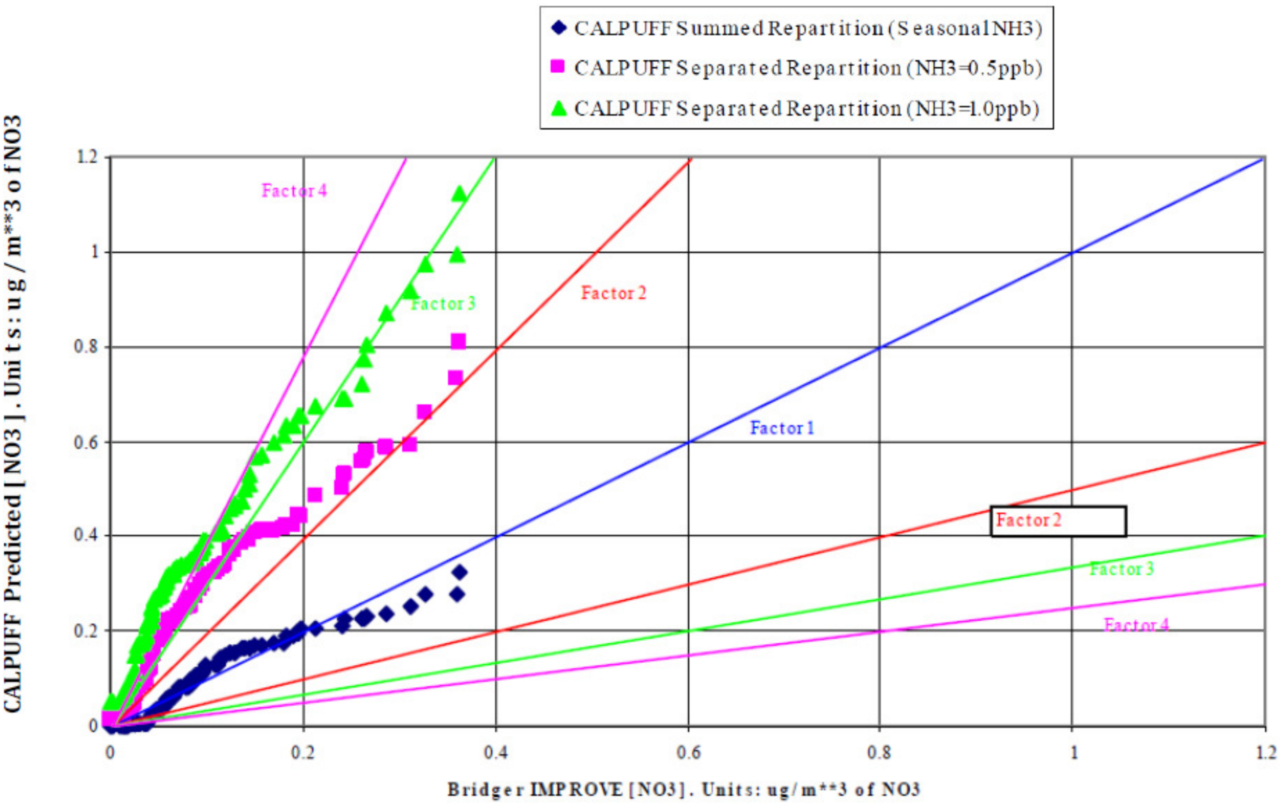


Figure B-4 CMAQ vs. Observed Haze Predictions at Voyageurs National Park

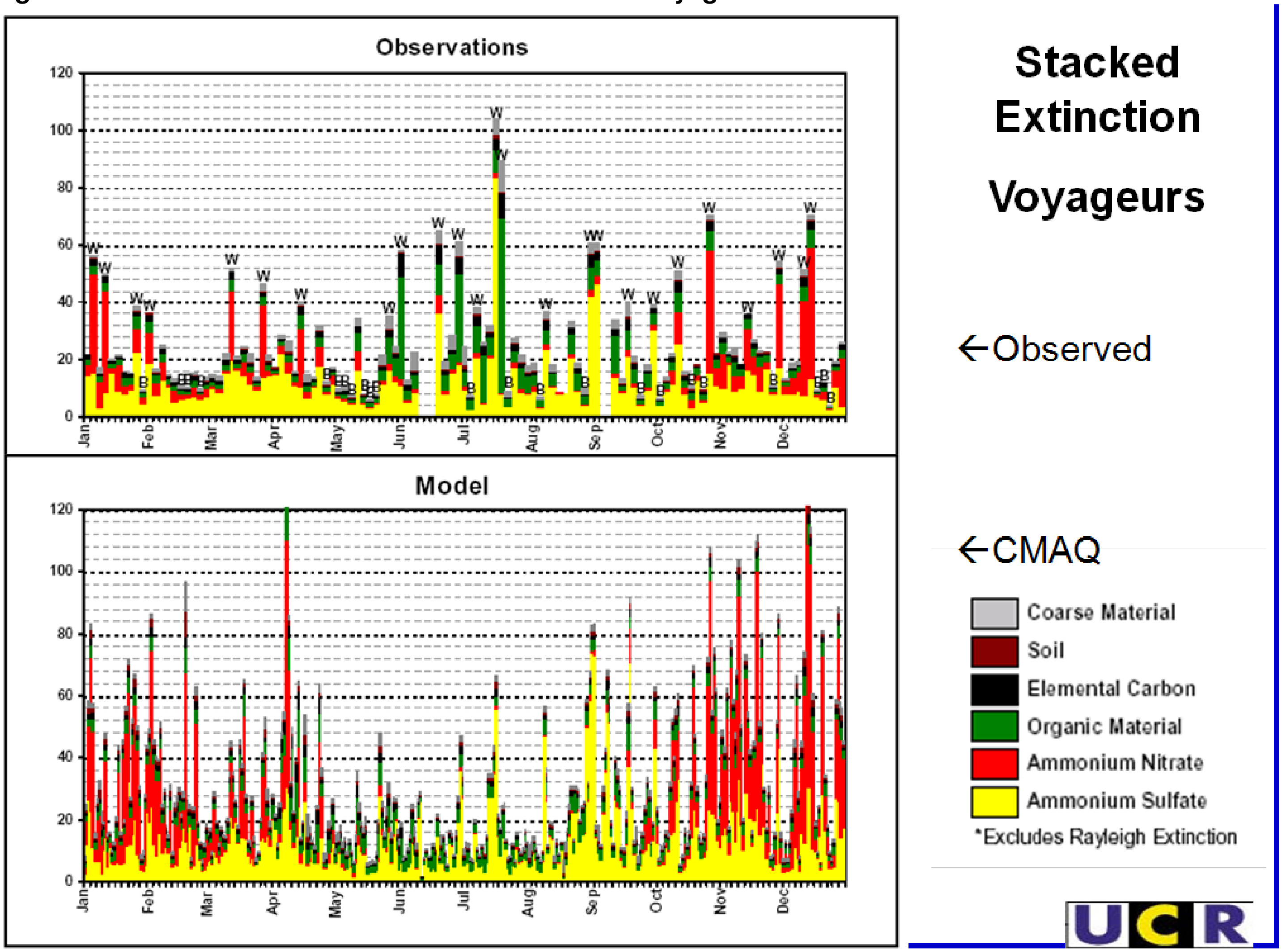
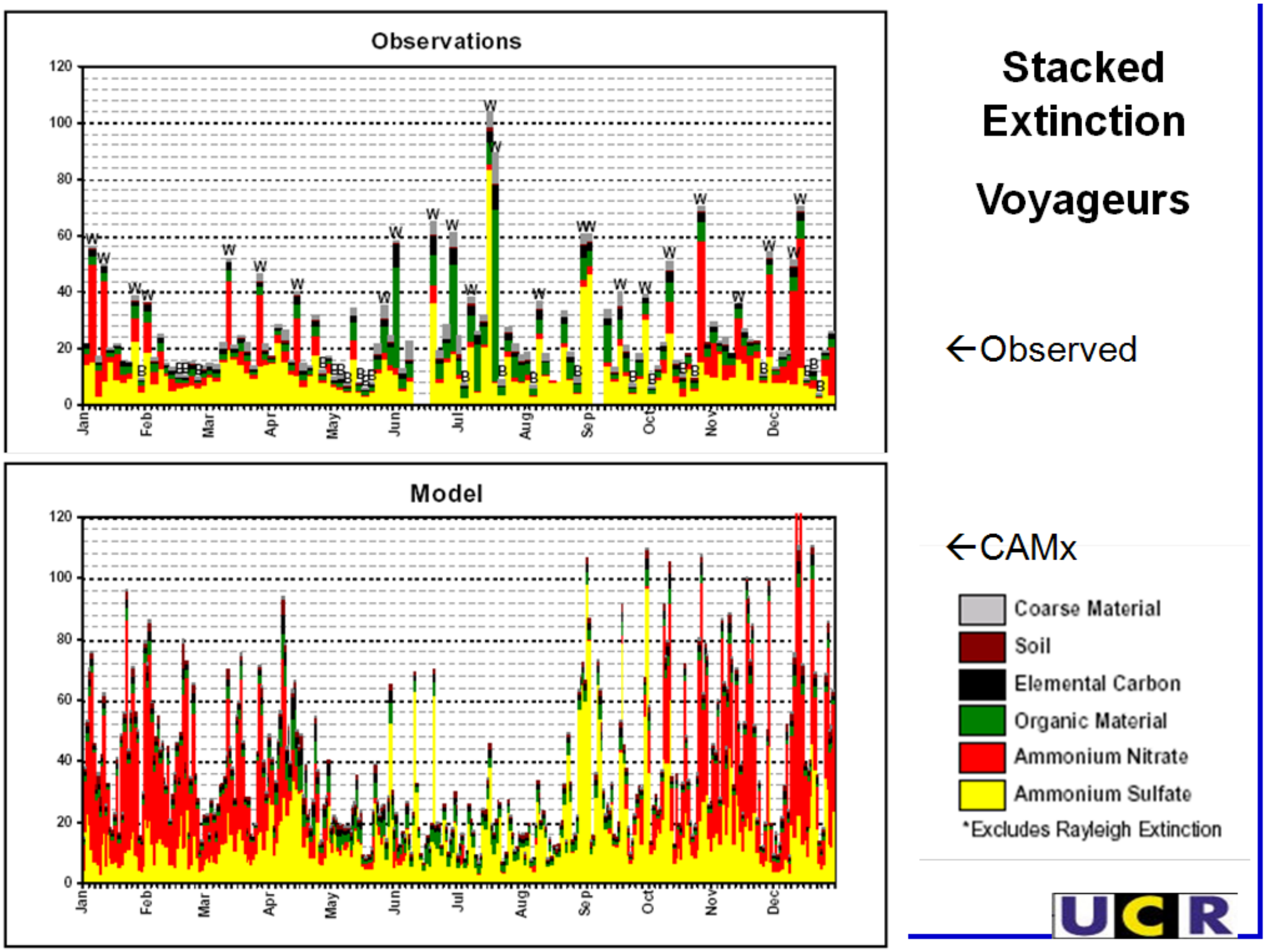


Figure B-5 CAMx vs. Observed Haze Predictions at Voyageurs National Park



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)

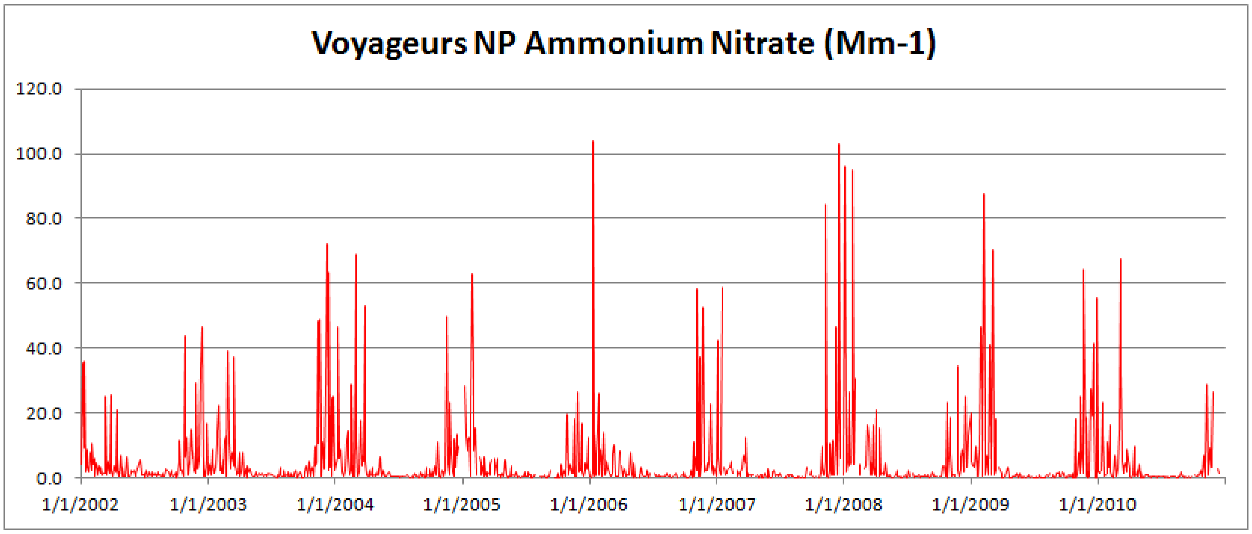


Figure C-2 Time Series of Sulfate Haze at Voyageurs National Park (2002-2010)

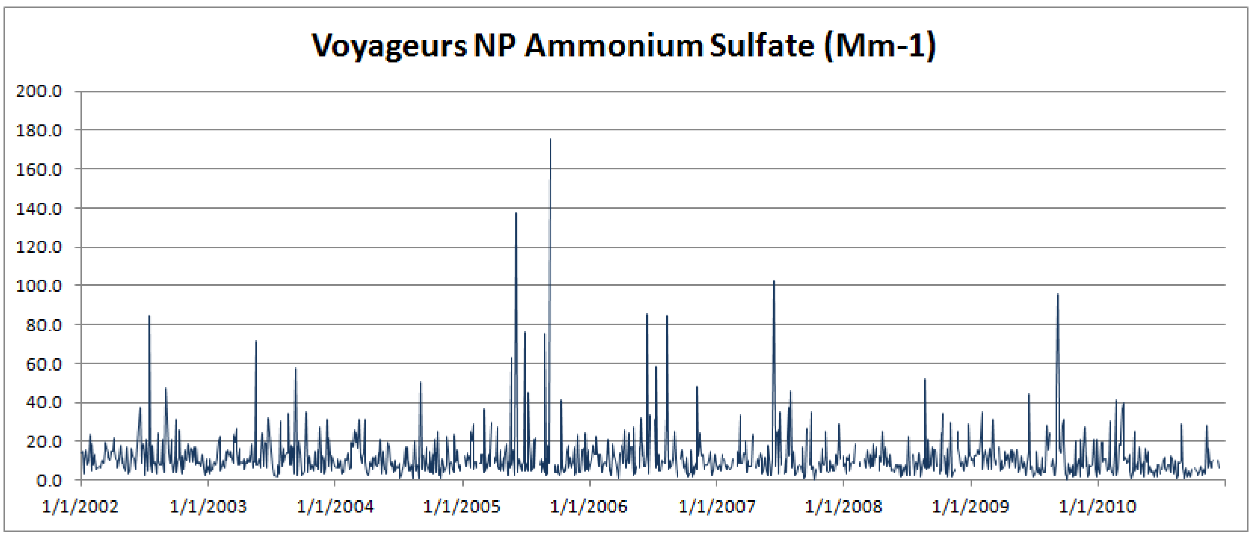


Figure C-3 Time Series of Nitrate Haze at Seney Wilderness Area (2002-2010)

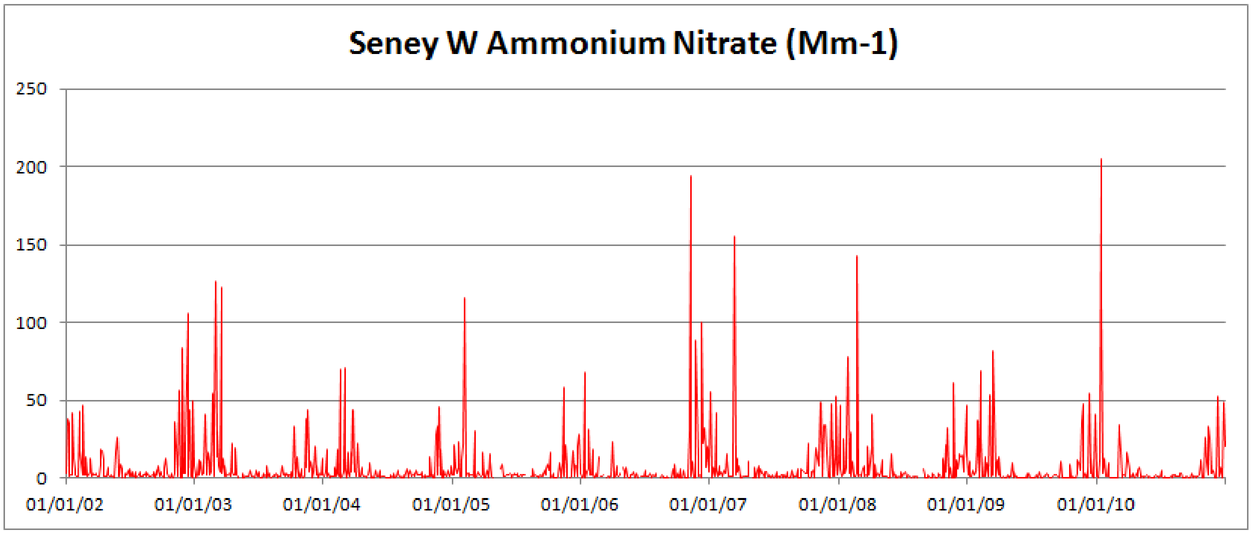


Figure C-4 Time Series of Sulfate Haze at Seney Wilderness Area (2002-2010)

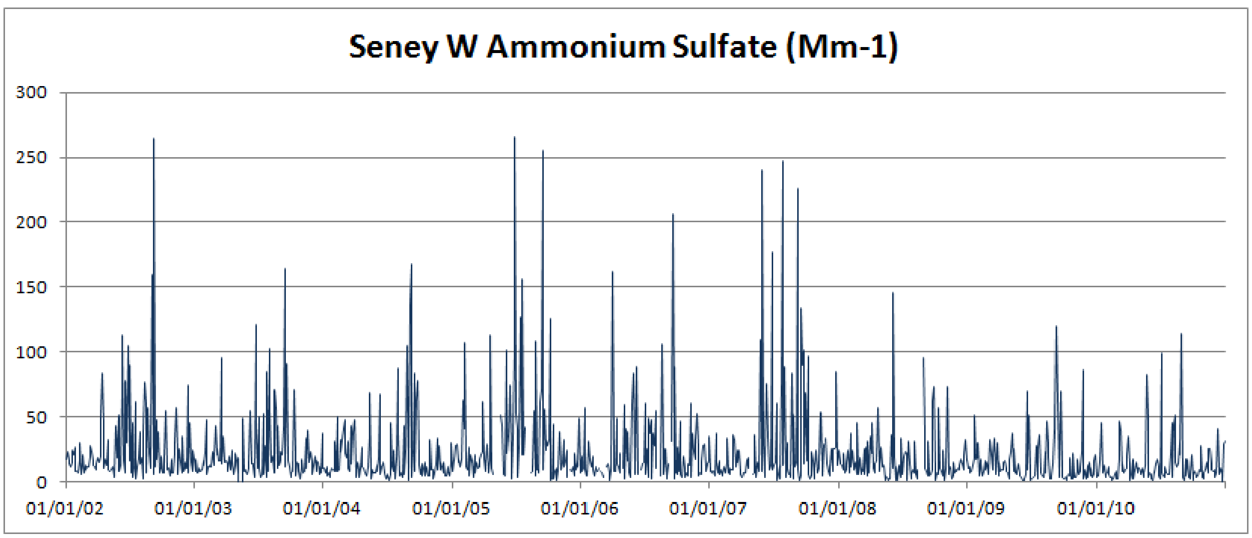


Figure C-5 Time Series of Nitrate Haze at Isle Royale National Park (2002-2010)

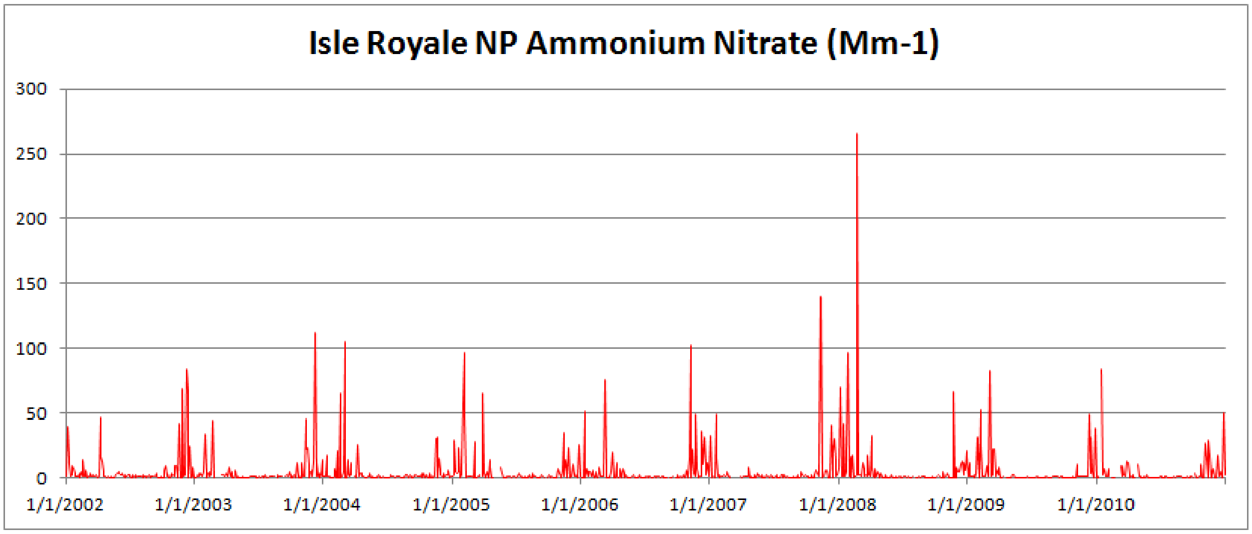
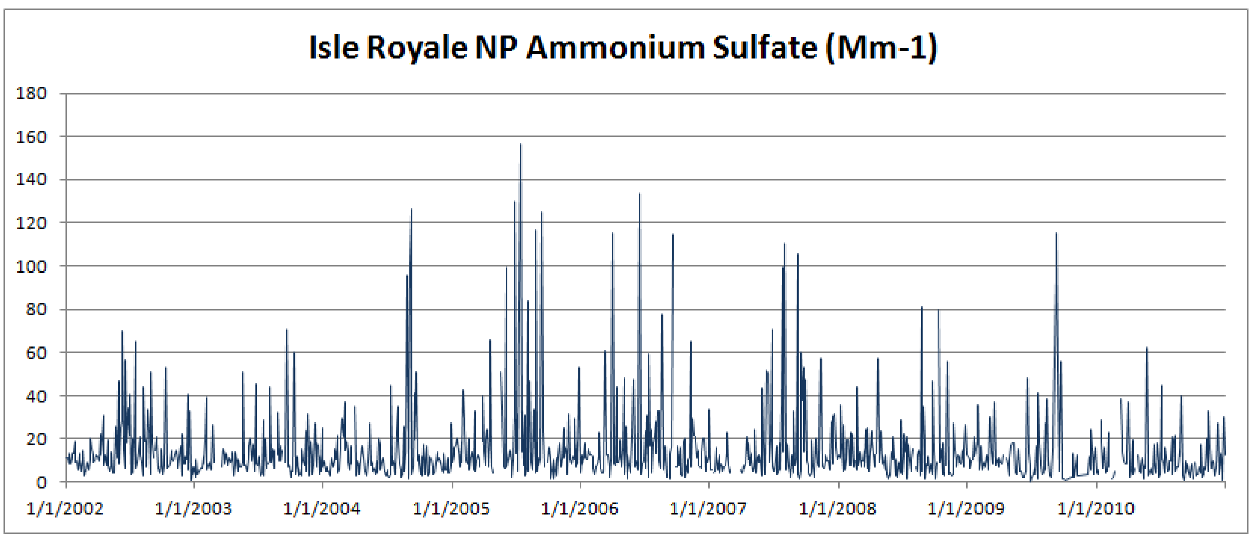


Figure C-6 Time Series of Sulfate Haze at Isle Royale National Park (2002-2010)



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 98th 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_2 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[39] 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_2 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[40] 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.

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[39] 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).

[40] 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 mark.berkman@berkeleyeconomics.com.

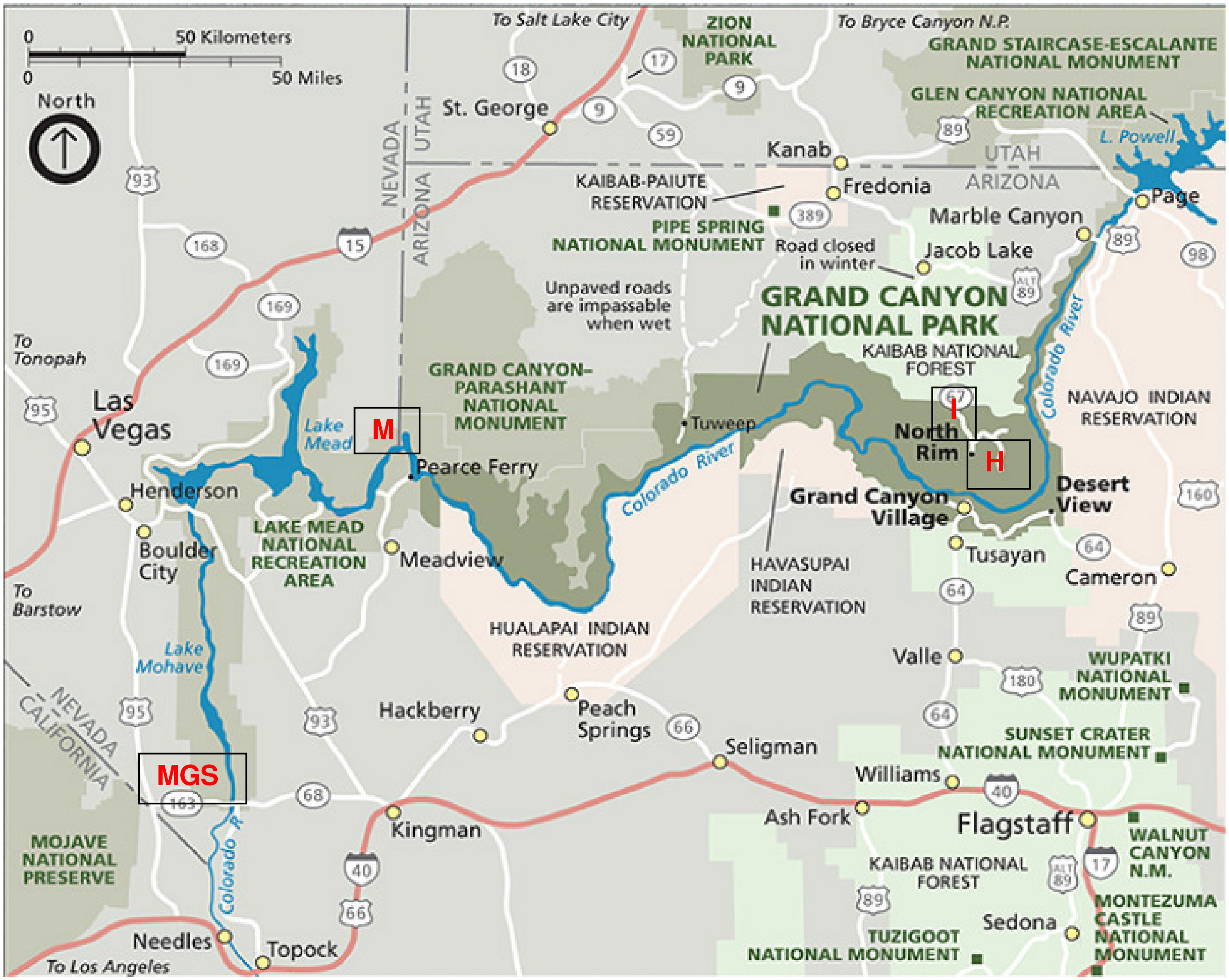
According to the authors, the Project Mohave observations were consistent with observations during temporary outages of MGS, for which there were no reports of substantial changes to visibility in the Grand Canyon.

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^{th} 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_2 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.

Figure D-1 : Map Showing the Relationship of the Mohave Generating Station to the Grand Canyon National Park

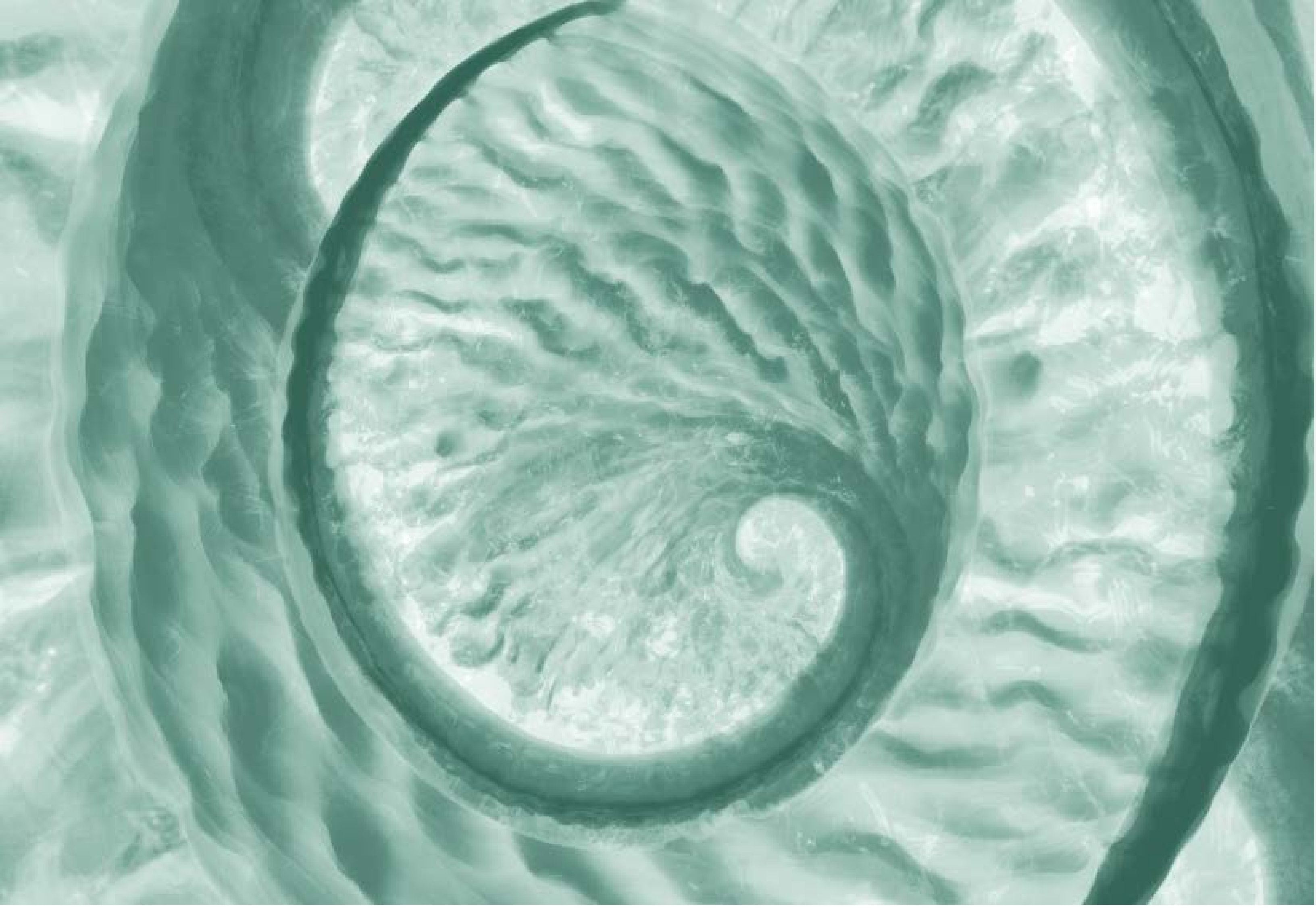


http://www.nps.gov/grca/planyourvisit/upload/GRCAmap2.pdf

H: Hance Camp monitor

I: Indian Garden monitor

M: Meadview monitor



Four Factor Analysis

City of Virginia Department of Public Utilities

Virginia, Minnesota

14 July 2020

Project No.: 0542312

The business of sustainability

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

List of Tables

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:

1. Cost of compliance.
2. Time necessary for compliance.
3. Energy and non-air quality environmental impacts of compliance.
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 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_2) 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_x. The listing of SO_2 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_x 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_x 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 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_x and SO_2 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_x 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_2 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_x control and a multi-cyclone followed by an electrostatic precipitator for particulate matter control. The boiler is also equipped with an opacity monitor, NO_x 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_x monitor reading information is listed in Table 1.

Table 1: Continuous NO_x Emission Monitor for Boiler #11

Value Description	NO_x (ppm)	NO_x (lb/MMBtu)
Minimum	39.4	0.094
Maximum	80.2	0.175[1]
Range[2]	40.8	0.081
Average	54.1	0.121

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_x for Boiler #11 while burning wood are 34.5 pounds and hour and 120 tons per year. The NO_x 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_x hourly emission rate is 27.11 pounds and the potential annual emission rate is 119 tons.

The potential and actual emission rates for NO_x while burning natural gas are based on USEPA AP-42 Emission Factors. The actual emission rates for NO_x are based on the CEM. The potential NO_x emission rate is based on a permit limit.

2.2 Historical Nitrogen Oxide Emissions Boiler #11

The actual annual NO_x 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_x emission rates from 2016 to 2019 for Boiler #11.

Table 2: Historical NO_x Emissions for Boiler #11

Year	NO_x (tpy)
2016	89.9
2017	82.84
2018	42.03
2019	38.05

3. FOUR-FACTOR ANALYSIS

The following is the four-factor analysis. The following subsections present information on the cost of supplemental NO_x 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_x 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_x 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_X 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_x control would be the same.

Available control options identified are:

- Low NO_x 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_x 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.

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_x 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_x 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_x formation.

<u>Over Fire Air Systems</u> - Additional NO_x 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_x reduction systems.

<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.

<u>SCR</u> – 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 tune-ups focus on boiler efficiency, which is related to air emissions.

3.1.4 SNCR

Boiler #11 has a SNCR system for NO_x 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_x 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_x by ammonia. The SCR is designed to evenly distribute the flow of NO_x 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_x 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_x 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_x 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_x reduction technology reviewed for cost since Boiler #11 already uses SNCR and the boiler design includes OFA. Low NO_x burners 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 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^3$). 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.

Table 3: Boiler #11 SCR NO_x Control Cost Estimate Summary

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 $[a]	$2,707,803
Pre-heater for exhaust[b]	Cost not available
Emission reduction (85% total which is 53.2% above the existing SNCR system at 31.8%)	53.2%
Emission reduction[c] (tpy)	42.07
Cost of emission reduction ($/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_x which could be reduced by another 53.2% potentially by retrofitting Boiler #11 with SCR for NO_x reduction.

The cost to retro fit Boiler #11 with SCR would be $64,364 per ton of NO_x 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_x 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

Table 4: Impacts of Potential NO_x Add-on Control Technologies for Boiler #11

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.

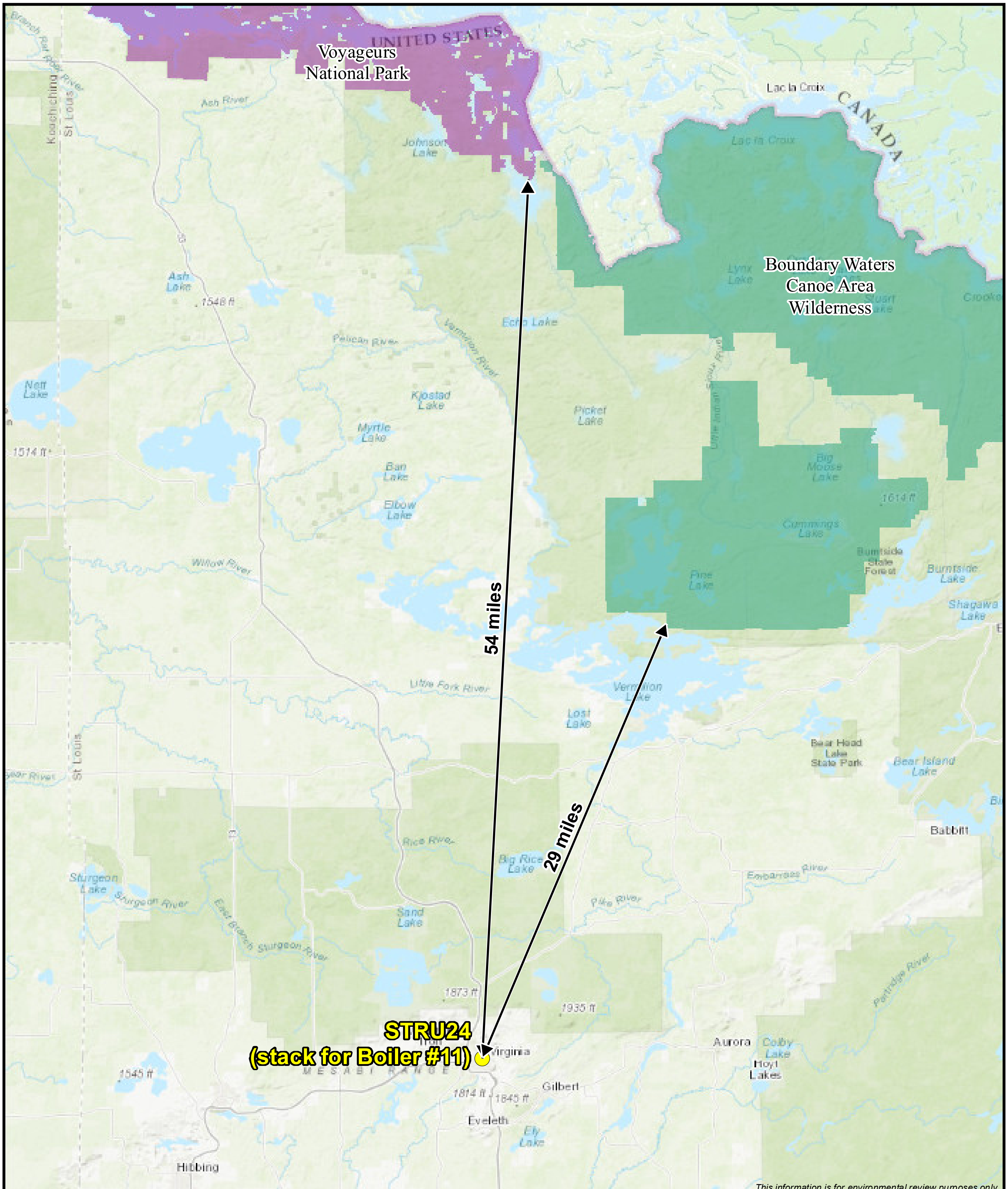
4. SUMMARY

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_x 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_x 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



● STRU Stack
Boundary Waters Canoe Area Wilderness
Voyageurs National Park

0 2.5 5 Miles

Virginia Department of Public Utilities
Site Location Map
Four Factor Analysis

ERM

M:\Clients\V-X\VPU\Virginia_ArcGIS\2020\03\Basemap\Site_Location_Map.mxd | REVISED: 06/29/2020 | SCALE: 1:525,000

DRAWN BY: JSS

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 (MMBtu/hr)	Pollutant	Limit	Units	Technology	Basis For Limit	Permit Issuance Date	Process Type[1]
ME-0040	Robbins Lumber, Inc.	167.3	NO_x	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_x	95	lb/hr	Good combustion practices, low NO_x burners (LNB)	BACT	5/9/2017	12.120
MI-0421	Arauco North America Grayling Particleboard	110	NO_x	95	lb/hr	Good combustion practices, LNB	BACT	8/26/2016	12.120
SC-0149	Klausner Holding USA, Inc.	120	NO_x	0.14	lb/MMBtu	SNCR	Other	1/3/2013	12.120
FL-0332	Highlands Envirofuels (HEF), LLC Highlands Biorefinery and Cogeneration Plant	458.5	NO_x	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 Sweet Sorghum-to-Ethanol Advanced Biorefinery	536	NO_x	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_x	0.06	lb/MMBtu	SCR	BACT	9/23/2019	11.120
FL-0359	US Sugar Corporation	1,077	NO_x	0.1	lb/MMBtu	SNCR (NH_3 injection)	BACT	11/29/2016	11.120
KS-0034	Abengoa Bioenergy Biomass of Kansas (ABBK)	500	NO_x	0.3	lb/MMBtu	SCR and Over-fire system (OFA)	BACT	5/27/2014	11.120
CA-1225	Sierra Pacific Industries	468	NO_x	0.13	lb/MMBtu	SNCR	BACT	4/25/2014	11.120
VT-0039	North Springfield Sustainable Energy Project, LLC	464	NO_x	0.03	lb/MMBtu	Bubbling fluidized bed boiler design and SCR	BACT	4/19/2013	11.120
GA-0141	Ogethorpe Power Corporation Warren County Biomass Energy Facility	341	NO_x	0.1	lb/MMBtu	SNCR	BACT	12/17/2010	11.120
VT-0037	Beaver Wood Energy Fair Haven, LLC	482	NO_x	0.03	lb/MMBtu	Good combustion control and SCR	BACT	2/10/2012	11.120
ME-0037	Verso Bucksport, LLC	817	NO_x	0.15	lb/MMBtu	SNCR	BACT	11/29/2010	11.120
CA-1203	Sierra Pacific Industries	335.7	NO_x	80	ppm	SNCR	BACT	8/30/2010	11.120
NH-0018	Berlin Station, LLC Burgess Biopower	1,013	NO_x	0.06	lb/MMBtu	SCR with NH_3 injection[2]	LAER	7/26/2010	11.120
CT-0156	NRG Energy	600	NO_x	0.06	lb/MMBtu	Regenerative SCR	LAER	4/6/2010	11.120
AL-0250	Boise White Paper, LLC	435	NO_x	0.3	lb/MMBtu	LNB	BACT	3/23/2010	11.120
TX-0553	Lindale Renewable Energy, LLC	1,256	NO_x	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

[1]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) -

[2]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_x 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.

l) 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 (TUsee 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.

FOSTER FW WHEELER

General
The following description should be read in conjunction with drawing No. 113925V-0202 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.

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
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

EPA-452/F-03-032

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 gas-fired 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 $\$/m^3$ (283 $\$/ft^3$). A 350 MMBtu/hr natural gas-fired boiler operating at 85% capacity requires approximately 17 m^3 (600 ft^3). For the same sized coal-fired boiler, the required catalyst is on the order of 42 m^3 (1,500 ft^3). (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.

Table 1a: Summary of Cost Information in $/MMBtu/hr (1999 Dollars) [a, b]

Unit Type	Capital Cost ($/MMBtu)	O&M Cost [d] ($/MMBtu)	Annual Cost [d] ($/MMBtu)	Cost per Ton of Pollutant Removed ($/ton)
Industrial Coal Boiler	10,000 - 15,000	300	1,600	2,000 - 5,000
Industrial Oil, Gas, Wood [c]	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 1b: Summary of Cost Information in $/MW (1999 Dollars) [a, b]

Unit Type	Capital Cost ($/MW)	O&M Cost [d] ($/MW)	Annual Cost [d] ($/MW)	Cost per Ton of Pollutant Removed ($/ton)
Industrial Coal Boiler	1,000 - 1,500	30	160	2,000 - 5,000
Industrial Oil, Gas, Wood [c]	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

[a] (ICAC, 1997; NESCAUM, 2000; EPA, 2002)
[b] Assumes 85% capacity factor and annual control of NOx
[c] SCR installed on wood fired boiler assumes a hot side electrostatic precipitator for PM removal
[d] 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.

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222 South 9th Street
Suite 2900
Minneapolis, MN

T: 612.347.6789

www.erm.com

Xcel Energy®

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_2) and oxides of nitrogen (NO_x), 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 co-owned 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_2 limit for Unit 3 of 0.29 pounds SO_2/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_2 emission rate from the effective date through June 30, 2020 is 0.22 pounds SO_2/MBtu, well below the permitted SO_2 emission rate limit. Outside the RAVI settlement, Unit 3 has a NO_x emission rate permit limit of 0.50 pounds NO_x/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_2 emissions are 0.12 pounds NO_x/MBtu, approximately 25% of the units permitted NO_x limit.

As requested, it has been verified that emissions of sulfur dioxide and oxides of nitrogen for Unit 3 are projected to be significantly 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