Appendix G. Consultation Comments

This appendix contains the comment letters provided by the federal land managers (FLMs) as part of the formal consultation required between states and FLMs as part of the Regional Haze Rule. Minnesota's Class I areas, Voyageurs National Park and Boundary Waters Canoe Area Wilderness, are managed by the National Parks Service and U.S. Forest Service, respectively. The specific requirements for state and FLM consultation are identified in 40 CFR § 51.308(i)(2).

The MPCA provided a copy of Minnesota's draft Regional Haze SIP and supporting documents to the FLMs on May 11, 2022, to begin the official consultation period identified in 40 CFR § 51.308(i)(2). In this opportunity for consultation, the MPCA requested that the FLMs provide comments by July 11, 2022, and offered to facilitate additional meetings and discussions regarding areas of interest in the draft Regional Haze SIP if requested.

Subsequently, the MPCA met with representatives from the U.S. NPS and U.S. FS in a virtual meeting on June 30, 2022, to receive their recommendations and conclusions regarding the Regional Haze SIP for the second implementation period. Representatives from the U.S. FWS and staff from U.S. EPA Region 5 were invited as well.

The comment letters from the FLMs are included in this appendix while a summary of the formal consultation between MPCA and the FLMs, including how the MPCA addressed the FLM comments, is available in Section 4.3 of the comprehensive update to Minnesota's Regional Haze SIP for the second implementation period.

From:	Pohlman, David C.
To:	Bouchareb, Hassan (MPCA)
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Subject:	NPS Consultation Comments on Draft Minnesota Regional Haze SIP
Date:	Monday, July 11, 2022 4:17:21 PM
Attachments:	NPS-MN_RH-CalculationWorkbooks_07.2022.zip NPS-MN_RH-SIP-Feedback_07.11.2022.docx

Hello Hassan,

The National Park Service (NPS) appreciates the opportunity to review the Federal Land Manager (FLM) review draft of the Minnesota Regional Haze State Implementation Plan (SIP) for the Second Implementation Period (2018–2028). As you know, Minnesota contains one NPS-managed Class I area, Voyageurs National Park, and emissions from Minnesota also impact nearby Isle Royale National Park in Michigan.

On June 30, 2022, staff from the NPS Air Resources Division (ARD) and NPS Interior Regions 3, 4, and 5 hosted a regional haze consultation meeting with Minnesota Pollution Control Agency (MPCA) staff to discuss NPS input on the draft Minnesota Regional Haze SIP. Representatives from the U.S. Forest Service and Environmental Protection Agency (Region 5) also attended. Detailed technical feedback and supporting calculation worksheets are attached. This email and the attachments document NPS conclusions and recommendations presented at the June 30, 2022, meeting, and serve as our formal regional haze consultation, as required by 42 U.S.C. §7491(d).

MPCA used emissions relative to distance to Class I areas (Q/d) to select facilities to analyze for haze causing emission reduction opportunities, which resulted in the initial selection on 17 sources for analysis, and captured 85% of the total Q/d for Minnesota class 1 areas. We agree that this process resulted in a reasonable list of sources.

We commend MPCA for a robust source selection process, commitment to working with NPS and other FLMs throughout the consultation process, rejection of international endpoint adjustments, and the use of a $10k initial screening cost threshold for controls. We recognize reductions that have occurred and appreciate MPCA's willingness to consider further reductions. However, we also see opportunities for reductions beyond those required by the current draft SIP. It is with this in mind that we provide the following feedback detailed in our attached technical document and accompanying calculation workbooks.

Our review of the provided four-factor analyses shows that additional controls on visibility-impairing pollutants could be cost effective for American Crystal Sugar's Crookston and East Grand Forks facilities, Southern Minnesota Beet Sugar Cooperative, and Power Boiler 9 at Sappi Cloquet, LLC. In addition, we recommend that MPCA strengthen the demonstration of effective controls for Boise White Paper, showing why emissions cannot reasonably be reduced, or require a four-factor analysis for Boiler 2 and the Recovery Furnace at this facility. See the attached documents for details of these recommendations.

MPCA selected taconite facilities for analysis then determined that four-factor analyses are not required. Because of their significant emissions, we recommend that MPCA reconsider and require four-factor evaluations for these facilities. Based on an analysis of emissions relative to distance to our Class I areas, MN ranked 9th in the US, with the taconite facilities comprising more than half of those impacts. Six Minnesota taconite facilities emit over 35,000 tons annually of visibility-impairing emissions and are relatively close to Voyageurs and Isle Royale national parks. EPA's 2016 taconite Federal Implementation Plan stated: "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." As our analysis in the attached technical feedback demonstrates there are more effective controls available that may be technically feasible and cost-effective.

In order to make reasonable progress in this planning period we recommend that MPCA require the addition of technically feasible cost-effective control strategies that provide the greatest emission reductions for each of the facilities considered. Please know that we welcome the opportunity for further dialogue with you as Minnesota progresses to a final SIP revision. If you have any questions, do not hesitate to reach out to us. Also, feel free to let us know if you have any edits to this summary and especially if any corrections are needed.
Best,

David

Attachment List:
NPS-MN_RH-SIP-Feedback_07.11.2022.docx
NPS-MN_RH-CalculationWorkbooks_07.2022.zip

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National Park Service (NPS) Regional Haze SIP feedback for the Minnesota Pollution Control Agency

July 11, 2022

Contents

1 Executive Summary

The NPS commends the Minnesota Pollution Control Agency (MPCA) for a robust source selection process, commitment to working with NPS and other FLMs throughout the consultation process, rejection of international endpoint adjustments, and the use of a $10k initial screening cost threshold for controls. Overall, the Minnesota draft regional haze SIP is one of the most technically sound and complete plans that the NPS has reviewed in this planning period.

However, in some cases NPS disagrees with the conclusions reached by MPCA. NPS finds that emission control costs for American Crystal Sugar (ACS) Crookston, ACS East Grand Forks, and the Southern Minnesota Beet Sugar Cooperative have been overestimated. NPS analysis indicates that further controls may be cost effective for these facilities as well as for Power Boiler 9 at Sappi Cloquet, LLC. The NPS recommends that cost-effective emission controls that achieve the greatest level of reductions be required for these facilities. Source specific recommendations are detailed in subsequent sections of this document.

For Boise White Paper as well as all of the taconite facilities, the NPS recommends that MPCA could improve the draft SIP with more robust demonstrations of effective controls. In the absence of such compelling demonstrations, four factor analyses may identify further reasonable emission reduction opportunities in this planning period. For the taconite facilities in particular, the NPS recommends that opportunities for further controls be evaluated as discussed in EPA's 2016 Federal Implementation Plan. The NPS recommends that MPCA require all taconite facilities originally selected for four-factor analysis to conduct four-factor analyses evaluating how an integrated approach to emission control improvements could reduce visibility-impairing emissions.

Emission reductions achieved through the regional haze planning process will advance the incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

2 Overarching Feedback

2.1 Four-factor Analysis Screening - Demonstration of Effective Controls

In its July 2021 clarification memo, EPA advised that once a source is selected states must show why additional emission reductions are not necessary to make reasonable progress to use "effective controls" as rationale to forgo a four-factor analysis. Section 2.3 addressed the analytical expectations for "effectively controlled" determinations:

> *The underlying rationale for the "effective controls" flexibility is that if a source's emissions are already well controlled, it is unlikely that further cost-effective reductions are available.* ***A state relying on an "effective control" to avoid performing a four-factor analysis for a source should demonstrate why, for that source specifically, a four-factor analysis would not result in new controls and would, therefore, be a futile exercise.***

NPS finds that, for many of the sources that MPCA determined were effectively controlled, a 4-factor analysis may, in fact, have resulted in additional controls. See the comments on individual facilities for specific information.

2.2 Retrofit Factors in Cost Analyses

We recognize that determining if a retrofit factor is appropriate and, if so, what that factor should be, is not a simple process. However, in some cases, Minnesota facilities did not provide any documentation justifying retrofit factors, some of which exceed the maximum value (1.5) recommended by EPA. Site-specific retrofit factors should be based upon a thorough and well-documented analysis of the individual factors involved in a project. We recommend that the procedure outlined by William Vatavuk on pages 59-62 in his book Estimating Costs of Air Pollution Control be followed. That process involves estimating and assigning a retrofit factor to each major element of a project and from that deriving an overall retrofit factor. The EPA Control Cost Manual (CCM) also addresses "Retrofit Cost Considerations" in section 2.6.4.2. The CCM (Section 4, Chapter 2) advises that:

> *A retrofit factor of 0.8 should be used for new construction and a retrofit factor of 1 should be used for average retrofits. The equations may overestimate costs for some simple retrofits of existing plants. For retrofits that are more complicated than average, a retrofit factor of greater than 1 can be used to estimate capital costs provided the reasons for using a higher retrofit factor are appropriate and fully documented.*

And in the instructions for the SCR Cost Calculation Spreadsheet:

> *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.*

In the absence of such a proper analysis, NPS assumed a retrofit factor = 1.0.

3 Electric Generating Facilities – Four-Factor Feedback

3.1 Hibbing Public Utilities Commission

The Hibbing Public Utilities Commission (HPUC) operates a co-generation facility for the city of Hibbing that provides steam for space heating and industrial processes. The facility is capable of providing electricity as well. The combustion emission units at the facility consist of three coal-fired boilers—EQUI 1, EQUI 2, and EQUI 3—and wood-fired boiler EQUI 7. Boiler 7 includes a gas burner that was installed in 2015 to assist in stabilizing combustion to lower carbon monoxide (CO) emissions. The boiler is equipped with a selective non-catalytic reduction (SNCR) system for NO_x control and a multi-cyclone followed by an electrostatic precipitator (ESP) for particulate matter control.

HPUC no longer holds a power purchase agreement and does not plan to generate electricity in the future. According to the four-factor analysis, the facility expects to discontinue use of the wood boiler, limit coal use to 14,000 tons per season, and burn natural gas as needed to meet needed steam loads. However, the facility indicated that it does not plan to remove the wood boiler from its operating permit.

The four-factor analysis estimated the cost of adding SNCR or selective catalytic reduction (SCR) to the coal-fired boilers EQUI 1 and EQUI 2 and concluded these technologies would not be cost-effective. MPCA provided its own cost estimates of these technologies using EPA's Control Cost Manual worksheets and concluded that SNCR would be cost-effective for all three coal-fired boilers. MPCA estimated costs at $6,700-$7,500 per ton of NO_x removed. These cost estimates assumed the boilers would be combusting coal. According to the draft SIP, the facility is working on a utility plan for the next 10 years and are considering possible operational changes that could limit coal usage. The facility has not yet provided details of potential operational changes.

MPCA also used the EPA Control Cost Manual worksheets to estimate the costs of wet and dry scrubbers to the coal-fired boilers for SO_2 control and concluded that it would not be cost-effective at $21,000-$32,500 per ton of SO_2 removed. These calculations assumed an uncontrolled SO_2 emissions rate of 0.30 lb/MMBtu, but the three boilers have a permit limit of 4.0 lb/MMBtu, which is roughly 10 times higher than the actual rate. NPS recommends that MPCA consider establishing lower SO_2 emissions limits closer to the units' actual emissions rates to prevent backsliding.

The NPS agrees with MPCA's conclusion that SNCR is warranted on coal-fired Boilers 1-3. If the facility submits a new plan for these boilers that affects the cost-effectiveness estimate, the NPS recommends this information be included in the SIP. Any operational constraints relied upon in a new cost analysis should be made federally enforceable. The NPS also suggests that MPCA consider removing Boiler 7 from the permit if the facility does not intend to use it in the future.

3.2 Minnesota Power–Boswell Energy Center

The Boswell Energy Center includes two coal-fired electrical generating units, a 355-megawat unit (Unit 3) and a 585 megawatt unit (Unit 4). Unit 3 is equipped with low-NO_x burners, overfire air controls, and selective catalytic reduction (SCR) for NO_x control, a wet flue gas desulfurization (FGD) system for SO_2 and acid gas control, and a fabric filter with activated carbon injection for $PM/PM_{10}/PM_{2.5}$ and mercury control. Unit 4 is equipped with low-NO_x burners, overfire air controls, and selective non-catalytic reduction (SNCR) for NO_x control, a semi-dry FGD system for SO_2 and acid gas control, and a fabric filter with activated carbon injection for $PM/PM_{10}/PM_{2.5}$ and mercury control. Based on these controls, MPCA concluded in the draft SIP that both units are already effectively controlled and did not request the facility to complete a four-factor analysis.

Unit 3 is required to meet a NO_x emissions limit of 0.06 lb NO_x/MMBtu and Unit 4 is required to meet a limit of 0.12 lb NO_x/MMBtu. Both units are required to meet a limit of 0.20 lb SO_2/MMBtu in accordance with the mercury and air toxics standards (MATS) rule. According to EPA Clean Air Markets program emissions data from 2015 through 2021, the SO_2 emissions rate at Unit 3 was 0.01 to 0.014 lb SO_2/MMBtu, and the SO_2 emissions rate at Unit 4 was 0.023 to 0.045 lb SO_2/MMBtu. These emissions rates are much lower than the allowable rate of 0.2 lb SO_2/MMBtu. If the two units had emitted SO_2 at the maximum allowable rate, the facility would have emitted as much as 6,000 additional tons of SO_2 annually over the period. NPS recommends that MPCA consider establishing lower SO_2 emissions limits closer to the units' actual emissions rates to prevent backsliding.

3.3 Virginia Department of Public Utilities

The Virginia Department of Public Utilities (VDPU) operates a co-generation facility for the city of Virginia that provides steam for space heating. The facility is capable of providing electricity as well.

The emission units at the facility consist of a coal-fired boiler Boiler #7 (EQUI 2), a natural gas-fired boiler Boiler #10 (EQUI 4) that serves as the primary backup boiler, a wood-fired boiler Boiler #11 (EQUI 16), fuel storage and transfer systems, and ash handling systems. Boiler #11 is equipped with selective non-catalytic reduction (SNCR) for NO_x control and a multi-cyclone followed by an electrostatic precipitator for particulate matter control.

From the discussion of Boiler #11 in the four-factor analysis prepared by the facility, it is not entirely clear how the facility will use it in the future. The four-factor analysis states that although Boiler #11 is capable of burning wood, *"Boiler #11 will most likely burn only natural gas moving forward"* (p. 2). However, the analysis also says: *"Natural gas is not the primary fuel and not the focus of this analysis for Boiler #11"* (p.6). The four-factor analysis states that *"Boiler #11 (EQUI 16) will be used as needed but most likely only if there is a problem starting Boiler #10."* MPCA used the EPA Control Cost Worksheet to estimate the cost of adding SCR to the boiler and concluded it would not be cost-effective. That estimate assumed the boiler would combust wood and operate 311 days per year, which suggests it could be used as more than a backup boiler. It is thus not clear how much Boiler 11 will operate and what the primary fuel will be.

The NPS recommends that MPCA clarify what the operational parameters of the boiler will be and update the SCR cost analysis if natural gas is expected to be the primary fuel. The NPS also suggests that the SIP explain why Boiler #10 was excluded from the analysis is it is not discussed in the four-factor analysis.

4 Sugar beet Processing Facilities – Four-Factor Feedback

4.1 American Crystal Sugar – Crookston

4.1.1 Summary of NPS Recommendations for American Crystal Sugar–Crookston

NPS review of the four-factor analysis conducted for American Crystal Sugar – Crookston facility (ACSC) finds that there are technically feasible and cost-effective opportunities available to further control SO_2 and NO_x emissions from Boilers 1, 2, and 3. In fact, NPS analyses show that the cost of control is more economical than estimated by MPCA when analyses are adjusted in accordance with the EPA Control Cost Manual.

The addition of DSI on all three boilers could reduce SO_2 emissions from this facility by about 600 tons/year for less than $5,000/ton (with baghouse replacement). The addition of SCR on all three boilers could reduce NO_x emissions from this facility by about 320 tons/year for around $10,000/ton.

The NPS recommends that MPCA require the addition of DSI with milled trona and a new baghouse as well as SCR on Boilers 1, 2, and 3 at American Crystal Sugar – Crookston. By requiring implementation of identified controls MPCA will be reducing haze causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

4.1.2 Facility Characteristics

ACSC 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). ACSC is located about 270 km southwest of Voyageurs National Park, a Class I area administered by the NPS.

The 2017 National Emissions Inventory (NEI) shows plantwide emissions of 740 tons of NO_x and 775 tons of SO_2.

4.1.3 SO_2 Four-factor Analysis

Control Selection & Efficiency

The NPS supports ACSC's selection of Dry Sorbent Injection (DSI), Spray Dry Absorption (SDA) or Circulating Dry Scrubber (CDS) in the category Dry FGD, and Wet Flue Gas Desulfurization (Wet FGD) for evaluation.

ACSC four-factor analyses assume that DSI can achieve 46%–51% control. The Sargent & Lundy (S&L) DSI IPM model assumes that DSI with milled trona, for example, can achieve 70% removal when followed by an ESP and 90% when followed by a baghouse (BGH). As a result, the controlled emission rates presented by ACSC for wet and dry scrubbing are too high. Scrubber emissions (and efficiencies) are driven by chemical equilibrium factors. The EPA Control Cost Manual (CCM) advises that SDA or CDS with baghouse can achieve 0.06 lb/mmbtu and that a Wet FGD scrubber can achieve 0.04 lb/mmbtu.

Even though Wet FGD may not be as cost-effective as SDA/CDS on small boilers, it may still be cost-effective relative to the MPCA cost-effectiveness threshold for consideration. Because Wet FGD achieves greater SO_2 reduction, the NPS evaluation included it.

Statutory Factor 1: Cost of Compliance

In the initial (2021) four factor analysis submittal for ACSC the consulting firm HDR showed that the cost-effectiveness of DSI to reduce SO_2 emissions was below $5,000/ton. This is quite cost-effective in spite of several factors that lead to overestimation of costs in the initial analysis. However, on February 1, 2022, consulting firm HDR submitted an "Updated Dry Sorbent Injection Costs for American Crystal Sugar Company Four Factor Analysis" to MPCA revising those findings. HDR expressed concern that the ESPs at ACSC, which have historically provided around 99.1% control of PM, might not be able to handle the additional loading presented by DSI and still maintain compliance with mercury and PM limits. According to HDR:

> *Therefore, the FFA was updated to enhance the PM control by adding a fabric filter baghouse. The addition of a baghouse will allow higher sorbent injection rates while maintaining compliance with the applicable PM emission limits. Further, the additional system residence time, higher sorbent injection rates, and associated sorbent filter cake in the baghouse, will allow an increased control efficiency of 70% for SO_2.*

NPS review finds substantial evidence to refute the HDR finding that DSI cannot be added without replacing the ESPs with baghouses. The S&L DSI documentation states, *"Trona, when captured in an ESP, typically removes 40 to 50% of* SO_2 *without an increase in particulate emissions…"*[1] The IPM DSI models include both ESPs and baghouses. The S&L DSI IPM

[1] **S&L:** Based on commercial testing, removal efficiencies with DSI are limited by the particulate capture device employed. Trona, when captured in an ESP, typically removes 40 to 50% of SO2 without an increase in particulate emissions, whereas hydrated lime may remove an even lower percentage of SO2. A baghouse used with sodium-based sorbents generally achieves a higher SO2 removal efficiency (70 to 90%) than that of an ESP. DSI technology, however, should not be applied to fuels with sulfur content greater than 2 lb SO2/MMBtu.

model assumes that DSI with milled trona, for example, can achieve 70% removal when followed by an electrostatic precipitator (ESP) and 90% when followed by a baghouse (BGH). Also, NPS review of EPA's Clean Air Markets Data (CAMD) indicates that DSI can achieve 0.10 lb/mmbtu when followed by an ESP and 0.08 lb/mmBtu when followed by a baghouse. Furthermore, EPA's Clean Air Markets data for 2021 includes several coal-fired Electric Generating Units (EGUs) with DSI and ESPs.

Table 1. Examples of coal-fired Electric Generating Units (EGUs) with DSI, CAMD 2021

State	**Facility Name**	**Unit ID**	**SO_2 (tons)**	**Calculated Avg. SO_2 Rate (lb/MMBtu)**	**Heat Input (MMBtu)**	**Unit Type**	**PM Control(s)**
MN	Boswell	4	391	0.025	31,545,340	Tangentially-fired	Baghouse
MI	J H Campbell	1	2,758	0.275	20,090,010	Tangentially-fired	Baghouse
MI	J H Campbell	2	2,094	0.300	13,961,840	Cell burner boiler	Baghouse
IN	R Gallagher	2	49	0.631	154,982	Dry bottom wall-fired	Baghouse (Retired 6/1/21)
IN	R Gallagher	4	68	0.720	189,738	Dry bottom wall-fired	Baghouse (Retired 6/1/21)
WI	J P Madgett	B1	849	0.083	20,454,088	Dry bottom turbo-fired	Baghouse | ESP
OK	Northeastern	3313	4,564	0.340	26,816,608	Tangentially-fired	Baghouse | ESP
IL	Kincaid	2	1,083	0.093	23,285,397	Cyclone boiler	Electrostatic Precipitator
IL	Kincaid	1	808	0.093	17,366,842	Cyclone boiler	Electrostatic Precipitator
IL	Waukegan	7	501	0.095	10,522,238	Tangentially-fired	Electrostatic Precipitator
IL	Powerton	62	278	0.109	5,084,619	Cyclone boiler	Electrostatic Precipitator
IL	Powerton	61	304	0.111	5,502,464	Cyclone boiler	Electrostatic Precipitator
LA	Big Cajun 2	2B1	1,203	0.342	7,032,558	Dry bottom wall-fired	Electrostatic Precipitator
OR	Boardman	1SG				Dry bottom wall-fired	Electrostatic Precipitator

In its 2022 submittal, HDR states:

> *American Crystal Sugar Company (ACSCC) obtained site-specific vendor quotes for Dry Sorbent Injection (DSI) equipment in order to verify estimated capital equipment and annual operating costs included in the original Four Factor Analysis (FFA) for the ACSCC East Grand Forks (EGF) and Crookston (CRK) facilities.*

NPS review of the HDR submittal identifies these issues:

- Use of a 5% interest rate instead of the current prime rate as recommended by the EPA Control Cost Manual (CCM).
- 20-year life for DSI
- Underestimation of DSI efficiency
- HDR proposes to "Extend three stacks to 200 ft."
- Exaggerated performance test costs

In the revised analysis HDR's cost-effectiveness of DSI increased to above $10,000/ton. Many of the costs in ACSC's Tables 4 & 5 and HDR's Table 2 are overestimated:

- ACSC used a 20-year life for DSI; the CCM recommends 30 years for SO_2 scrubbers.
- ACSC stated that Boilers 1 & 2 have rated capacities of 137 mmBtu/hr and that annual SO_2 emissions are 241 tons at 0.37 lb/mmBtu. However, at maximum capacity, Boilers 1 & 2 can emit no more than 222 tpy.

In addition, it is unclear why it would be necessary to extend three stacks to 200ft as HDR proposes. This likely represents an unjustified expense.

MPCA appears to have used much of the HDR cost estimates without addressing these issues. The NPS also questions the cost of a new fabric filter—see below. Instead, NPS analyses applied the current EPA CCM workbooks for wet and dry scrubbers, ESPs, and baghouses, as well as the current S&L model for DSI with milled trona and:

- the existing ESP at 50% control
- a baghouse at 80% SO_2 control

NPS analyses applied a retrofit factor = 1.0 assuming that the new baghouses or new SDA/CDS could be installed within the footprint of, or inside the shells of, the ESPs. NPS assumed equipment lives of 30 years for SO_2 scrubbers and 20 years for a new baghouse.

The NPS analysis used the CCM to estimate ESP operating cost savings (see ESP workbook). ESP purchased equipment costs were scaled up from the CCM example using the six-tenths power rule based upon gas flow provided by ACSC. Other costs were scaled up based upon a straight gas flow ratio. The CEPCI 2021/1987 ratio was applied to estimate total capital investment. The NPS included ACSC's $200,000 for demolition of the ESPs and estimate that saved ESP operating costs would be about $550,000/yr.

The NPS analysis used the CCM to estimate baghouse costs (see baghouse workbook). Some baghouse purchased equipment costs were scaled up from the CCM example using the six-tenths power rule based upon gas flow provided by ACSC. Other equipment costs were scaled up based upon a straight gas flow ratio. The CEPCI 2021/1998 ratio to estimate total capital investment.

Table 2. NPS SO_2 Control Cost Estimates for DSI at ACSC

ACS CRK Boilers 1, 2 & 3	**Combined DSI w Milled Trona**			
Control Technology	**w Existing ESP**	**w BGH**	**Combined New Baghouse**	**Totals**
Capacity (MW)	43.9	43.9	43.9	
Retrofit factor	1	1	1	
CEPCI	776.3	776.3	776.3	
Capital Cost	$ 10,158,253	$ 11,121,747	$ 3,699,379	$ 14,821,126
Interest rate	4.75	4.75%	4.75%	
Control Equipment Life (yr)	30	30	20	
Capital Recovery Factor	0.0632	0.0632	0.0786	
Capital Recovery Cost	$ 642,098	$ 703,000	$ 145,799	$ 848,799
Indirect Cost/Fixed O&M	$ 316,867	$ 322,537	$ 361,543	$ 684,080
Total System Capacity Factor				
Direct Cost/Variable O&M	$ 1,225,524	$ 1,577,580	$ 262,636	$ 1,840,216
Total Annual Cost	$ 2,184,489	$ 2,603,117	$ 624,178	$ 2,956,908
Uncontrolled SO_2 Emission Rate (lb/mmbtu)	0.40	0.40		0.40
Maximum Uncontrolled Tons				
Uncontrolled Tons	735	735		735
SO_2 Removal Efficiency	50	80		80
Controlled SO_2 Emission Rate (lb/mmbtu)	0.20	0.08		0.08
Tons Removed	368	588		588
Cost-Effectiveness	$ 5,944	$ 4,427		$ 5,029

NPS analyses show that the cost-effectiveness of adding DSI with milled trona to the existing system is < $6,000/ton and with baghouse replacement is $5,000/ton.

NPS calculations also applied the CCM workbooks for SDA/CDS and Wet FGD and adjusted the annual fuel input to produce the baseline annual SO_2 emissions cited by ACSC (even though boilers 1 & 2 cannot emit that much (241 tons) SO_2 based upon their capacity (137 mmBtu/hr) and their cited 0.37 lb/mmBtu emission rates).

Table 3. NPS SO_2 Control Cost Estimates for SDA/CDS with Baghouse and Wet FGD with Baghouse at ACSC

ACS CRK Boilers 1, 2 & 3	**SDA/CDS w Baghouse (each)**		**Wet FGD w Baghouse (each)**	
Control Technology	**Boilers 1 & 2**	**Boiler 3**	**Boilers 1 & 2**	**Boiler 3**
Capacity (MW)	13.7	16.5	13.7	16.5
Retrofit factor	1	1	1	1
CEPCI	776.3	776.3	776.3	776.3
Capital Cost	$ 22,861,209	$ 26,173,918	$ 42,220,270	$ 45,701,376
Interest rate	4.75%	4.75%	4.75	4.75
Control Equipment Life (yr)	30	30	30	30
Capital Recovery Factor	0.0632	0.0632	0.0632	0.0632
Capital Recovery Cost	$ 1,444,828	$ 1,654,192	$ 2,668,321	$ 2,888,327
Indirect Cost/Fixed O&M	$ 1,478,895	$ 1,688,855	$ 2,720,849	$ 2,941,481
Total System Capacity Factor	1.083	0.854	1.083	0.854
Direct Cost/Variable O&M	$ 1,535,990	$ 1,582,978	$ 2,818,345	$ 2,761,386
Total Annual Cost	$ 3,014,885	$ 3,271,833	$ 5,539,193	$ 5,702,867
Uncontrolled SO_2 Emission Rate (lb/mmbtu)	0.37	0.41	0.37	0.41
Maximum Uncontrolled Tons	222	296	222	296
Uncontrolled Tons	241	253	241	253
SO_2 Removal Efficiency	84	85	89	90
Controlled SO_2 Emission Rate (lb/mmbtu)	0.06	0.06	0.04	0.04
Tons Removed	202	216	215	228
Cost-Effectiveness	$ 14,962	$ 15,139	$ 25,824	$ 24,961

Because the results of the NPS cost analysis for SDA/CDS with Baghouse and Wet FGD with Baghouse at ACSC exceeded $10,000/ton, the NPS did not pursue these options further.

Statutory Factor 2: Time Necessary for Compliance

The NPS estimates that it would take 18 months for DSI with milled trona to be installed and operational.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

When evaluating statutory factor 3, ACSC raises several potential concerns with respect to Dry FGD or DSI including energy use, solid waste production, and potentially shortened useful life of the boiler. NPS review finds that:

- The energy impacts mentioned are most properly accounted for when analyzing statutory factor 1, Cost of Compliance.
- Solid waste production is not a unique issue to this site and has been handled effectively in numerous instances.
- Factors that could affect boiler life can be avoided if sorbent is injected downstream of the boiler.

Statutory Factor 4: Remaining Useful Life

ACS notes that the remaining useful life of the ACSC boilers is greater than 20 years. Therefore, the remaining useful life has no impact on the annualized estimated control technology costs. In addition, the CCM recommends 30-year life for scrubbers unless limited by a federally-enforceable condition.

4.1.4 NO_x Four-factor Analysis

Control Selection & Efficiency

NPS review finds that the controlled emission rates presented by ACSC for SCR (in its Table 6) are too high. SCR emissions (and efficiencies) are driven by chemical equilibrium factors. The CCM advises that SCR can achieve up to 90% control and reduce emissions down to 0.04 lb/mmbtu. In this case, achieving 0.04 lb/mmBtu would require 88% control efficiency, which is within the capability of SCR.

Statutory Factor 1: Cost of Compliance

On February 21, 2022, HDR submitted an "Updated Selective Non-Catalytic Reduction Performance Data for American Crystal Sugar Company Four Factor Analysis" to MPCA.

Some SNCR costs in ACSC's Tables 7 & 8 and HDR's Table 1 are underestimated due to the recent rise in the CEPCI, prime interest rate, and reagent cost. However, overall, ACSC's SCR costs are inflated for several reasons:

- ACSC applied undocumented retrofit factors (1.5)
- ACSC used an unsupported 5% interest rate.
- ACSC used a 20-year life for SCR versus 25 years recommended by the CCM for SCR on industrial boilers. MPCA did not provide estimates for SCR.
- ACSC stated that Boilers 1 & 2 have rated capacities of 137 mmBtu/hr and that annual NO_x emissions are 209 tons at 0.33 lb/mmBtu. However, at maximum capacity, Boilers 1 & 2 can emit no more than 198 tpy.
- ACSC has underestimated uncontrolled annual emissions; this results in underestimation of tons of NO_x removed and an overestimation of $/ton.

NPS estimates are based 10% control by SNCR and 85% control by SCR (0.05 lb/mmBtu) and are shown below.

Table 4. NPS/MPCA NO_x Control Cost Estimate Comparison for SNCR and SCR at ACSC Boilers 1 & 2

ACS CRK Boilers 1 & 2	**SNCR**		**SCR**	
Control Technology	**ARD**	**MPCA**	**ARD**	**MPCA**
Capacity (mmBtu/hr)	137	137	137	137
Retrofit factor	1.0	1.5	1.0	1.5
CEPCI	776.3	607.5	776.3	607.5
Capital Cost	$ 3,222,724	$ 3,782,954	$ 12,794,943	$ 14,757,119
Interest rate	4.75	3.25	4.75	3.50
Control Equipment Life (yr)	20	20	25	20
Capital Recovery Cost	$ 253,306	$ 260,267	$ 885,410	$ 1,038,901
Indirect Cost	$ 254,756	$ 261,970	$ 888,086	$ 1,041,695
Total System Capacity Factor	0.581	0.581	0.581	0.581
Direct Cost	$ 73,496	$ 71,316	$ 152,113	$ 157,727
Total Annual Cost	$ 328,252	$ 333,285	$ 1,040,199	$ 1,199,421
Uncontrolled NO_x Emission Rate (lb/mmbtu)	0.33	0.33	0.33	0.33
Maximum Uncontrolled Tons	198	198	198	198
Uncontrolled Tons	115	115	115	115
NO_x Removal Efficiency	25	25	88	79
Controlled NO_x Emission Rate (lb/mmbtu)	0.25	0.25	0.04	0.07
Tons removed	29	29	101	91
Cost-Effectiveness	$ 11,416	$ 11,591	$ 10,292	$ 13,236

Table 5.NPS/MPCA NO_x Control Cost Estimate Comparison for SNCR and SCR at ACSC Boiler 3

ACS CRK Boiler 3	**SNCR**		**SCR**	
Control Technology	**ARD**	**MPCA**	**ARD**	**MPCA**
Capacity (mmBtu/hr)	165	165	165	165
Retrofit factor	1.0	1.5	1.0	1.5
CEPCI	776.3	607.5	776.3	607.5
Capital Cost	$ 3,275,005	$ 3,844,323	$ 14,456,576	$ 16,766,382
Interest rate	4.75	3.25	4.75	3.50
Control Equipment Life (yr)	20	20	25	20
Capital Recovery Cost	$ 257,415	$ 264,489	$ 1,000,395	$ 1,180,353
Indirect Cost	$ 258,889	$ 266,219	$ 1,003,170	$ 1,183,267
Total System Capacity Factor	0.581	0.581	0.581	0.581
Direct Cost	$ 78,503	$ 74,683	$ 167,027	$ 175,778
Total Annual Cost	$ 337,392	$ 340,902	$ 1,170,198	$ 1,359,046
Uncontrolled NO_x Emission Rate (lb/mmbtu)	0.32	0.32	0.32	0.32
Maximum Uncontrolled Tons	231	231	231	231
Uncontrolled Tons	134	134	134	134
NO_x Removal Efficiency	10	10	88	81
Controlled SO_2 Emission Rate (lb/mmbtu)	0.288	0.288	0.04	0.06
Tons removed	13	13	118	109
Cost-Effectiveness	$ 25,118	$ 25,379	$ 9,956	$ 12,453

As the above tables demonstrate, the NPS estimates cost-effectiveness values are about $10,000/ton for SCR on Boilers 1, 2 & 3. The addition of SCR on all three boilers could reduce NO_x emissions from this facility by about 320 tpy.

Statutory Factor 2: Time Necessary for Compliance

The time necessary for compliance for SCR is typically four to five years after SIP approval.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

When evaluating statutory factor 3, ACSC raises several potential concerns with respect to SNCR and SCR including energy use, ammonia storage, potential ammonia slip, and potential impacts to mercury controls. NPS review finds that:

- The energy impacts mentioned are most properly accounted for when analyzing statutory factor 1, Cost of Compliance.

- Ammonia storage and potential slip issues are not unique to this site and should be addressed by proper operation and maintenance.
- With respect to potential implications for mercury controls, the SNCR ammonia slip issue is not unique to this application. SCR is known to promote ionization/oxidation of elemental mercury to a form that can be captured by downstream control equipment. It is possible that addition of SCR upstream of the SO_2 and PM controls could result in reduced mercury emissions and/or PAC consumption/costs.

Statutory Factor 4: Remaining Useful Life

ACS notes that the remaining useful life of the ACSC boilers is greater than 20 years. Therefore, the remaining useful life has no impact on the annualized estimated control technology costs. In addition, the CCM recommends 30-year life for SCR on industrial boilers unless limited by a federally-enforceable condition.

4.1.5 NPS Conclusions and Recommendations for American Crystal Sugar – Crookston

NPS review finds that ACSC and MPCA have overestimated the Cost of Compliance due to:

- Use of an unsupported high (5%) interest rate.
- Use of equipment life (20 years) for some controls that is too short.
- Application of unsupported retrofit factors.
- Underestimation of control efficiencies.

With respect to statutory factor one, the Cost of Compliance, after making the adjustments described above NPS analysis finds that:

1. The addition of DSI (with trona) is cost-effective for SO_2 emission reductions with or without addition of a new baghouse, and
2. The addition of SCR is a cost-effective option for reducing NO_x emissions from this facility.

The NPS recommends that MPCA evaluate statutory factor two, *Time Necessary for Compliance*, for addition of DSI and SCR for all three boilers. Review of statutory factors three and four finds no unusual *Energy and Non-Air Quality Environmental Impacts* related to DSI or SCR and *Remaining Useful Life* is not an issue.

In conclusion, based on the four factors, the NPS recommends that MPCA require the addition of DSI with trona and a new baghouse as well as SCR to all three boilers analyzed at American Crystal Sugar – Crookston.

The addition of DSI on all three boilers could reduce SO_2 emissions from this facility by over 600 tons/year for less than $5,000/ton (with baghouse replacement). The addition of SCR on all three boilers could reduce NO_x emissions from this facility by about 320 tons/year for around $10,000/ton.

4.2 American Crystal Sugar–East Grand Forks

4.2.1 Summary of NPS Recommendations for American Crystal Sugar–East Grand Forks

NPS review of the four-factor analysis conducted for American Crystal Sugar – East Grand Forks facility (EGF) finds that there are technically feasible and cost-effective opportunities available to further control SO_2 and NO_x emissions from Boilers 1 and 2. In fact, NPS analyses show that the cost of control is more economical than estimated by MPCA when analyses are adjusted in accordance with the EPA Control Cost Manual.

The addition of DSI with trona and a new baghouse on both boilers could reduce SO_2 emissions from this facility by over 600 tons/year for about $4,900/ton. The addition of SCR on both boilers could reduce NO_x emissions from this facility by about 600 tons/year for less than $7,000/ton.

The NPS recommends that MPCA require the addition of DSI with trona and a new baghouse as well as SCR on both boilers analyzed at American Crystal Sugar – East Grand Forks. By requiring implementation of identified controls MPCA will be reducing haze causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

4.2.2 Facility Characteristics

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 (ESPs) to control particulate matter (PM) 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). Based on Spring Creek Mine quality specifications, the typical mean sulfur content is 0.38 percent, and the typical mean ash content is 4.12 percent. The facility is located about 315 km southwest of Voyageurs National Park, a Class I area administered by the NPS.

The 2017 National Emissions Inventory (NEI) shows plantwide emissions of 676 tons of NO_x and 1,301 tons of SO_2.

4.2.3 SO_2 Four-factor Analysis

Control Selection & Efficiency

The NPS supports EGF's selection of Dry Sorbent Injection (DSI), Spray Dry Absorption (SDA) or Circulating Dry Scrubber (CDS) in the category Dry FGD, and Wet Flue Gas Desulfurization (Wet FGD) for evaluation.

ACS four-factor analyses assume that DSI can achieve 46%–51% control. The S&L DSI IPM model assumes that DSI with milled trona, for example, can achieve 70% removal when followed by an ESP and 90% when followed by a baghouse (BGH). Review of EPA's Clean Air Markets Data (CAMD) indicates that DSI can achieve 0.10 lb/mmbtu when followed by an ESP and 0.08 lb/mmBtu when followed by a baghouse.

As a result of low efficiency assumptions, the controlled emission rates presented by ACS for wet and dry scrubbing are too high. Scrubber emissions (and efficiencies) are driven by chemical equilibrium factors. The EPA Control Cost Manual (CCM) advises that SDA or CDS with baghouse can achieve 0.06 lb/mmbtu and that a Wet FGD scrubber can achieve 0.04 lb/mmbtu.

Even though Wet FGD may not be as cost-effective as SDA/CDS on small boilers, it may still be cost-effective relative to the MPCA cost-effectiveness threshold for consideration. Because Wet FGD achieves greater SO_2 reduction, the NPS evaluation included it.

Statutory Factor 1: Cost of Compliance

In the initial (2021) four factor analysis submittal for EGF the consulting firm HDR showed that the cost-effectiveness of DSI to reduce SO_2 emissions was below $5,000/ton. This is quite cost-effective in spite of several factors that lead to overestimation of costs in the initial analysis. However, on February 1, 2022, consulting firm HDR submitted an "Updated Dry Sorbent Injection Costs for American Crystal Sugar Company Four Factor Analysis" to MPCA revising those findings. HDR expressed concern that the ESPs at EGF, which have historically provided around 99.1% control of PM, might not be able to handle the additional loading presented by DSI and still maintain compliance with mercury and PM limits. According to HDR:

> *Therefore, the FFA was updated to enhance the PM control by adding a fabric filter baghouse. The addition of a baghouse will allow higher sorbent injection rates while maintaining compliance with the applicable PM emission limits. Further, the additional system residence time, higher sorbent injection rates, and associated sorbent filter cake in the baghouse, will allow an increased control efficiency of 70% for* SO_2.

NPS review finds substantial evidence to refute the HDR finding that DSI cannot be added without replacing the ESPs with baghouses. The S&L DSI documentation states, *"Trona, when captured in an ESP, typically removes 40 to 50% of* SO_2 *without an increase in particulate emissions…"*[2] The IPM DSI models include both ESPs and baghouses. The S&L DSI IPM model assumes that DSI with milled trona, for example, can achieve 70% removal when followed by an electrostatic precipitator (ESP) and 90% when followed by a baghouse (BGH). Also, NPS review of EPA's Clean Air Markets Data (CAMD) indicates that DSI can achieve 0.10 lb/mmbtu when followed by an ESP and 0.08 lb/mmBtu when followed by a baghouse. Furthermore, EPA's Clean Air Markets data for 2021 includes several coal-fired Electric Generating Units (EGUs) with DSI and ESPs. (See Table 1 above).

In its 2022 submittal, HDR states:

> *American Crystal Sugar Company (ACSCC) obtained site-specific vendor quotes for Dry Sorbent Injection (DSI) equipment in order to verify estimated capital equipment and*

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[2] **S&L:** Based on commercial testing, removal efficiencies with DSI are limited by the particulate capture device employed. Trona, when captured in an ESP, typically removes 40 to 50% of SO2 without an increase in particulate emissions, whereas hydrated lime may remove an even lower percentage of SO2. A baghouse used with sodium-based sorbents generally achieves a higher SO2 removal efficiency (70 to 90%) than that of an ESP. DSI technology, however, should not be applied to fuels with sulfur content greater than 2 lb SO2/MMBtu.

annual operating costs included in the original Four Factor Analysis (FFA) for the ACSCC East Grand Forks (EGF) and Crookston (CRK) facilities.

NPS review of the HDR submittal identifies these issues:

- Use of a 5% interest rate instead of the current prime interest rate as recommended by the CCM.
- 20-year life for DSI, the CCM recommends 30 years for SO_2 scrubbers.
- Underestimation of DSI efficiency
- HDR proposes to “Extend two stacks to 200 ft.”
- Exaggerated performance test costs

In the revised analysis HDR’s cost-effectiveness of DSI increased to above $10,000/ton. Many of the costs in ACSC Table 3 and HDR’s Table 1 are overestimated.

In addition, it is unclear why it would be necessary to extending two stacks to 200ft as HDR proposes. This likely represents an unjustified expense.

MPCA appears to have used much of the HDR cost estimates without addressing these issues. The NPS also questions the cost of a new fabric filter—see below. Instead, NPS analyses applied the current EPA CCM workbooks for wet and dry scrubbers, ESPs, and baghouses, as well as the current S&L model for DSI with milled trona and:

- the existing ESP at 50% control
- a baghouse at 80% SO_2 control

NPS analyses applied a retrofit factor = 1.0 assuming that the new baghouses or new SDA/CDS could be installed within the footprint of, or inside the shells of, the ESPs. NPS assumed equipment lives of 30 years for SO_2 scrubbers and 20 years for a new baghouse.

The NPS analysis used the CCM to estimate ESP operating cost savings (see ESP workbook). ESP purchased equipment costs were scaled up from the CCM example using the six-tenths power rule based upon gas flow provided by ACSC. Other costs were scaled up based upon a straight gas flow ratio. The CEPCI 2021/1987 ratio was applied to estimate total capital investment. The NPS included ACSC’s $200,000 for demolition of the ESPs and estimate that saved ESP operating costs would be about $550,000/yr.

The NPS analysis used the CCM to estimate baghouse costs (see baghouse workbook). Some baghouse purchased equipment costs were scaled up from the CCM example using the six-tenths power rule based upon gas flow provided by ACSC. Other equipment costs were scaled up based upon a straight gas flow ratio. The CEPCI 2021/1998 ratio to estimate total capital investment.

Table 6. NPS SO_2 Control Cost Estimates for DSI at EGF

ACS EGF Boilers 1 & 2	**DSI w Milled Trona w Existing ESP**	**Combined DSI w Milled Trona**			**SDA/CDS w New BGH (each)**
Control Technology		**Combined DSI w BGH**	**Combined New Baghouse**	**Totals**	
Capacity (MW)	71.2	71.2			35.6
Retrofit factor	1	1	1		1
CEPCI	776.3	776.3	776.3		776.3
Capital Cost	$ 11,128,987	$ 12,181,094	$ 6,441,038	$ 18,622,132	$ 45,535,539
Interest rate (%)	4.75	4.75	4.75		4.75
Control Equipment Life (yr)	30	30	20		30
Capital Recovery Factor	0.0632	0.0632	0.0786		0.0632
Capital Recovery Cost	$ 703,457	$ 769,960	$ 505,947	$ 1,275,907	$ 2,877,846
Indirect Cost/Fixed O&M	$ 322,579	$ 328,771	$ 752,052	$ 1,080,823	$ 2,915,994
Direct Cost/Variable O&M	$ 1,237,341	$ 1,488,773	$ 381,728	$ 1,870,501	$ 2,657,615
Total Annual Cost	$ 2,263,377	$ 2,587,504	$ 1,133,780	$ 3,080,643	$ 5,573,609
Uncontrolled SO_2 Emission Rate (lb/mmbtu)	0.45	0.45		0.45	0.45
Maximum Uncontrolled Tons					702
Uncontrolled Tons	904	904		904	452
SO_2 Removal Efficiency	40	70		70	87
Controlled SO_2 Emission Rate (lb/mmbtu)	0.27	0.14		0.14	0.06
Tons Removed	362	633		633	392
Cost-Effectiveness	$ 6,259	$ 4,089		$ 4,868	$ 14,220

NPS analyses show that the cost-effectiveness of adding DSI with milled trona and the existing ESP had a cost-effectiveness value around $6,300/ton, with a new baghouse < $4,900/ton and SDA/CDS for > $14,000/ton.

Statutory Factor 2: Time Necessary for Compliance

The NPS estimates that it would take 18 months for DSI with milled trona to be installed and operational.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

When evaluating statutory factor 3, ACS raises several potential concerns with respect to Dry FGD or DSI including energy use, solid waste production, and potentially shortened useful life of the boiler. NPS review finds that:

- The energy impacts mentioned are most properly accounted for when analyzing statutory factor 1, Cost of Compliance.
- Solid waste production is not a unique issue to this site and has been handled effectively in numerous instances.
- Factors that could affect boiler life can be avoided if sorbent is injected downstream of the boiler.

Statutory Factor 4: Remaining Useful Life

ACS notes that 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. In addition, the CCM recommends 30-year life for scrubbers unless limited by a federally enforceable condition.

4.2.4 NO_x Four-factor Analysis

Control Selection & Efficiency

NPS review finds that the controlled emission rates presented by ACSC for SCR (in its Table 4 are too high. SCR emissions (and efficiencies) are driven by chemical equilibrium factors. The CCM advises that SCR can achieve up to 90% control and reduce emissions down to 0.04 lb/mmbtu. In this case, achieving 0.04 lb/mmBtu would require 88% control efficiency, which is within the capability of SCR.

Statutory Factor 1: Cost of Compliance

On February 21, 2022, HDR submitted an "Updated Selective Non-Catalytic Reduction Performance Data for American Crystal Sugar Company Four Factor Analysis" to MPCA.

Some SNCR costs in ACS's Table 5 and HDR's Table 1 are underestimated due to the recent rise in the CEPCI, prime interest rate, and reagent cost. However, overall, ACS's SNCR costs for EGF are inflated for several reasons:

- No justification is provided for the retrofit factor = 1.5.
- SCR life is underestimated. The CCM recommends 20 – 25 years: while ACSC used 20 years, it also estimates that the SCR would only operate 265 days per year.[3] Such limited operation should allow SCR to operate for at least 25 years.
- ACSC applied a 5% interest rate instead of the current prime as recommended by the CCM.

NPS estimates applied a higher CEPCI (776.3 vs. 607.5 used by ACSC), the resulting estimated Capital Recovery Cost is more than $700,000/year (30%) lower than the ACS EGF estimate for SNCR.

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[3] **ACSC:** The beet sugar production process is a seasonal, or campaign-based, production process that typically runs from mid-August to June of each year. During the campaign, the boilers operate continuously, 24 hours per day 7 days per week. The boilers are shut down during summer months at the end of the processing campaign. A typical campaign runs for approximately 265 days (6,000 to 6,500 hours per year).

Overall, ACS's SCR costs for EGF are also inflated because:

- Some of ACS's annual costs are overestimated (as discussed above). The NPS assumed much higher reagent costs to reflect current prices.
- Emission reductions are underestimated because ACS assumed that SCR could only achieve 80% control efficiency.

We estimate that SCR on each of the two boilers at EGF could reduce NO_x emissions by 300 tons/yr (each) at an annual cost of $2 million (each) for cost-effectiveness of about $6,800/ton. Our estimates shown below.

Table 7. NPS/MPCA NO_x Control Cost Estimate Comparison for SNCR and SCR at EGF Boilers 1 & 2

ACS EGF Boilers 1 & 2 (each)				
Control Technology	**SNCR**		**SCR**	
Estimates by	**NPS**	**MPCA**	**NPS**	**MPCA**
Capacity (mmBtu/hr)	356	356	356	356
Retrofit factor	1	1.5	1	1.5
CEPCI	776.3	607.5	776.3	607.5
Capital Cost	$ 4,615,236	$ 5,417,537	$ 25,006,287	$ 28,837,241
Interest rate (%)	4.75	3.5	4.75	3.5
Control Equipment Life (yr)	20	20	25	20
Capital Recovery Cost	$ 362,758	$ 381,395	$ 1,730,435	$ 2,030,142
Indirect Cost/Fixed O&M	$ 364,834	$ 383,833	$ 1,733,843	$ 2,033,780
Total System Capacity Factor	0.635	0.635	0.635	0.635
Direct Cost/Variable O&M	$ 144,196	$ 156,231	$ 307,011	$ 359,977
Total Annual Cost	$ 509,031	$ 540,063	$ 2,040,855	$ 2,393,757
Uncontrolled NO_x Emission Rate (lb/mmbtu)	0.34	0.306	0.34	0.34
Maximum Uncontrolled Tons	532	532	532	532
Uncontrolled Tons	338	338	338	338
NO_x Removal Efficiency (%)	10	10	88	80
Controlled NO_x Emission Rate (lb/mmbtu)	0.306	0.306	0.04	0.07
Tons Removed	35	35	299	269
Cost-Effectiveness	$ 14,482	$ 15,365	$ 6,837	$ 8,905

As the above table demonstrates, the NPS estimates cost-effectiveness values for SCR at less than $7,000/ton.

Statutory Factor 2: Time Necessary for Compliance

The time necessary for compliance for SCR is typically four to five years after SIP approval.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

When evaluating statutory factor 3, ACS EGF raises several potential concerns with respect to SNCR and SCR including energy use, ammonia storage, potential ammonia slip, and potential impacts to mercury controls. NPS review finds that:

- The energy impacts mentioned are most properly accounted for when analyzing statutory factor 1, Cost of Compliance.
- Ammonia storage and potential slip issues are not unique to this site and should be addressed by proper operation and maintenance.
- With respect to potential implications for mercury controls, the SNCR ammonia slip issue is not unique to this application. SCR is known to promote ionization/oxidation of elemental mercury to a form that can be captured by downstream control equipment. It is possible that addition of SCR upstream of the SO_2 and PM controls could result in reduced mercury emissions and/or PAC consumption/costs.

Statutory Factor 4: Remaining Useful Life

ACS notes that 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. In addition, the CCM recommends 30-year life for SCR on industrial boilers unless limited by a federally-enforceable condition.

4.2.5 NPS Conclusions and Recommendations for American Crystal Sugar – East Grand Forks

NPS review finds that ACSC and MPCA have overestimated the Cost of Compliance due to:

- Use of an unsupported high (5%) interest rate.
- Use of equipment life (20 years) for some controls that is too short.
- Application of unsupported retrofit factors.
- Underestimation of control efficiencies.

With respect to statutory factor one, the Cost of Compliance, after making the adjustments described above NPS analysis finds that:

1. The addition of DSI (with trona) is cost-effective for SO_2 emission reductions with or without addition of a new baghouse, and
2. The addition of SCR is a cost-effective option for reducing NO_x emissions from this facility.

The NPS recommends that MPCA evaluate statutory factor two, the Time Necessary for Compliance, for addition of DSI and SCR for both boilers. Review of statutory factors three and four finds no unusual Energy and Non-Air Quality Environmental Impacts related to DSI or SCR and Remaining Useful Life is not an issue.

In conclusion, based on the four factors, the NPS recommends that MPCA require the addition of DSI with trona and a new baghouse as well as SCR to both boilers analyzed at American Crystal Sugar – East Grand Forks. The addition of DSI on both boilers could reduce SO_2 emissions from this facility by over 600 tons/year for about $4,800/ton. The addition of SCR on both boilers could reduce NO_x emissions from this facility by about 600 tons/year for less than $7,000/ton.

4.3 Southern Minnesota Beet Sugar Cooperative

4.3.1 Summary of NPS Recommendations for Southern Minnesota Beet Sugar Cooperative

NPS review of the four-factor analysis conducted for Southern Minnesota Beet Sugar Cooperative (SMBSC) finds that there are technically feasible and cost-effective opportunities available to further control SO_2 and NO_x emissions from Boiler 1. NPS analyses show that the cost of control is more economical than estimated by MPCA when analyses are adjusted in accordance with the EPA Control Cost Manual (CCM).

The NPS recommends that MPCA require the addition of cost-effective control strategies that provide the greatest emission reductions. The SDA/CDS option could remove 840 tons/year of SO_2 at an annual cost of $6 million for a cost-effectiveness value of less than $7,100/ton. NPS estimates indicate that addition of SCR could reduce annual NO_x by over 800 tons/year at an annual cost of $5–$7 million resulting in a cost-effective strategy of $6,000–$8,000/ton of NO_x removed.

The NPS recommends that MPCA require the addition of SDA/CDS and SCR at SMBSC. By requiring implementation of identified controls MPCA will be reducing haze causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

4.3.2 Facility Characteristics

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 is a Babcock and Wilcox 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 for particulate emissions. The flue gas from the electrostatic precipitator is routed to a single stack. The boiler is monitored by a continuous opacity monitor and continuous emissions monitors for NO_x, SO_2, and O2.

The facility is located near Renville, MN, about 435 km south-southwest of Voyageurs National Park, a Class I area administered by the NPS.

The 2017 NEI emissions inventory indicates that emissions in 2017 increased over the reported 2016 emissions in the draft SIP and were significantly higher than those projected for 2028. The NPS recommends using recent actual emissions in four factor analyses unless the projected lower emissions are secured by a permit limit. NPS analyses used the reported 2016 emissions for SMBSC Boiler 1.

Table 8. SIP Table 3-2: 2016 and 2028 EPA Modeling Emissions Inventory for SMBSCC Sources (TPY)

Units	**2016** SO_2	**2028** SO_2	**2016** NO_x	**2028** NO_x
Boiler 1	805	786	930	907

Table 9. 2017 National Emissions Inventory (NEI) data and NPS Q/d for SMBSC

Year	**Inventory**	**Facility Name**	NO_x	SO_2	**Q**	**Distance to NPS Class I Area**	**Q/d**	**NPS Class I Area**
2017NEI_Aug2019_PT	NEI	Southern Minnesota Beet Sugar Coop	1,004	820	1,824	436	4.2	VOYA

4.3.3 Overarching Cost Issues

In response to earlier informal four-factor feedback SBMSC said (**SMBSC July 23, 2021):**

> *FLMs stated that reagent, utility, and labor costs were inflated with no basis. The basis for these parameters and the year of the estimate is listed in Appendix A of the FFA, which are reasonable representations of costs SMBSC may occur. Values were scaled up to 2020 dollars from the applicable source year assuming 3% inflation each year.*

The NPS maintains that SMBSC (and, in many cases, MPCA) increased all of these costs above their default values and, in many cases, by a greater ratio than the Chemical Engineering Plant Cost Index (CEPCI) 2020/2016 cost ratio of 1.10. The 2020 CEPCI used by Barr consulting (607.5) is too high—it was 596.2.) The CCM only applies an inflation factor to Capital Costs. Instead, Operating Costs should be based upon site-specific costs or CCM defaults. None of these costs is specific to this facility. Escalation costs of reagent, electricity, and labor into the future is not allowed by EPA's overnight costing method. In the absence of site-specific costs, NPS analyses use the CCM and IPM default values.

NPS review finds that the cost of the following consumables is now:

- Natural gas = $6.51/kscf (June 11, Henry Hub price)
- Urea (approximately) $1000/ton

EPA and the EPA Control Cost Manual (CCM) recommend use of the current prime interest rate (currently 4.75%) in the absence of a site-specific interest rate.

4.3.4 SO_2 Four-factor Analysis

Control Selection & Efficiency

Basis for the Exclusion of Wet Flue Gas Desulfurization from the FFA

In response to earlier input SMBSC (July 23, 2021) explained that a wet flue gas desulfurization scrubber was not considered for the FFA because captured SO_2 would increase sulfate and potentially mercury wastewater loading. Further SMBSC raised concerns about a new wastewater stream requiring additional wastewater treatment and consuming significant amounts of energy.

The NPS analyses estimated that Wet FGD would cost almost $13,000/ton (see attached Wet FGD workbook).

SDA and DSI SO_2 Control Efficiency Basis

In response to earlier input SMBSC (July 23, 2021) objected to the recommendation to use control efficiencies recommended by the updated CCM chapter, which was released following the initial four-factor analysis submission.

However, like most air pollution issues, regional haze is a dynamic process that changes as new information is obtained. The NPS continues to recommend that MPCA and SMBSC consider new information appropriately as part of the FLM and public review and input processes.

SMBSC also stated:

> *Further, the control efficiencies are appropriate estimates. For example, the CCM states that SDA removal efficiencies range between 85-95%. Higher control efficiencies may be possible, but SMBSC will design the SDA equipment based on what has been demonstrated consistently in practice (i.e., 90%). Further, SMBSC burns subbituminous coal, which has the lowest available sulfur content. This may inhibit the SDA's ability to achieve higher control efficiencies with a lower SO_2 inlet loading compared to other coal boilers. SMBSC estimated a 70% control efficiency for DSI, which may even be too high. Even the updated CCM estimates that DSI can achieve a 50-70% SO_2 reduction.*
>
> *SMBSC will adjust the SO_2 control efficiency based on responses from equipment vendors if applicable.*

According to Barr, the SMSBC consultant: *The dry sorbent injection system requires the installation of a baghouse to accommodate the additional particulate matter from the injected sorbent and reaction byproducts.*

NPS reviewers hold that DSI can be added without replacing the ESP with a baghouse. The S&L DSI documentation states, *"Trona, when captured in an ESP, typically removes 40 to 50% of* SO_2 *without an increase in particulate emissions…"* NPS analyses assumed that DSI could be added without replacing the ESP and achieve 40% control. In the absence of a vendor estimate

NPS analyses conservatively assumed 80% control for DSI with milled trona and a new baghouse. The IPM model estimates up to 90% control for this strategy.

Control Equipment Life

The NPS continues to recommend that SMBSC and MPCA follow CCM recommendations with respect to control equipment life for use in cost calculations.

Spray Dry Absorbers (SDA)

The 30-year life estimate that SMSBC objects to for SDA is not a "best case scenario" as they suggest. For example, the CCM states: *Manufacturers reportedly design scrubbers to be as durable as boilers, which are generally designed to operate for more than 60 years.*

NPS analyses relied on the CCM recommendation of a 30-year equipment life. This is likely conservative considering that the system operates on a seasonal (314 day/yr) basis. Nevertheless, even assuming a 20-year DSI life, this control is still quite cost-effective.

Dry Sorbent Injection (DSI) and Baghouses

SMSBC suggests that DSI relies on a baghouse as a "major critical component" and that baghouses have a typical equipment life of 20 years therefore making this the appropriate lifetime for a DSI system. However, a baghouse is not integral to, or required for, a DSI system, so its life should not be equated to that of DSI. NPS analyses assume that the 30-year SO_2 scrubber life would also apply to a relatively simple DSI system, and 20 years to a new baghouse.

Statutory Factor 1: Cost of Compliance

The vendor estimate relied on by SMBSC is not included in the SIP and the NPS cannot comment upon its usefulness. The cost methodology for estimates provided by SMBSC is of unknown origin. It appears that all values associated with operating costs are general (not specific to this site) and may be inflated. The NPS recommends that, SMBSC use established methods and present documentation to support a robust analysis.

MPCA and SMBSC could improve this analysis by explaining the rational for requiring replacement of the existing electrostatic precipitator (ESP) with a new baghouse. This may be an unnecessary expense because the IPM DSI models include both ESPs and baghouses. Further, EPA's Clean Air Markets data for 2021 includes several coal-fired Electric Generating Units (EGUs) with DSI and ESPs.

Table 10. Examples of coal-fired Electric Generating Units (EGUs) with DSI, CAMD 2021

State	Facility Name	Unit ID	SO_2 (tons)	Calculated Avg. SO_2 Rate (lb/MMBtu)	Heat Input (MMBtu)	Unit Type	PM Control(s)
MN	Boswell	4	391	0.025	31,545,340	Tangentially-fired	Baghouse
MI	J H Campbell	1	2,758	0.275	20,090,010	Tangentially-fired	Baghouse
MI	J H Campbell	2	2,094	0.300	13,961,840	Cell burner boiler	Baghouse
IN	R Gallagher	2	49	0.631	154,982	Dry bottom wall-fired	Baghouse (Retired 6/1/21)
IN	R Gallagher	4	68	0.720	189,738	Dry bottom wall-fired	Baghouse (Retired 6/1/21)
WI	J P Madgett	B1	849	0.083	20,454,088	Dry bottom turbo-fired	Baghouse ESP
OK	Northeastern	3313	4,564	0.340	26,816,608	Tangentially-fired	Baghouse ESP
IL	Kincaid	2	1,083	0.093	23,285,397	Cyclone boiler	Electrostatic Precipitator
IL	Kincaid	1	808	0.093	17,366,842	Cyclone boiler	Electrostatic Precipitator
IL	Waukegan	7	501	0.095	10,522,238	Tangentially-fired	Electrostatic Precipitator
IL	Powerton	62	278	0.109	5,084,619	Cyclone boiler	Electrostatic Precipitator
IL	Powerton	61	304	0.111	5,502,464	Cyclone boiler	Electrostatic Precipitator
LA	Big Cajun 2	2B1	1,203	0.342	7,032,558	Dry bottom wall-fired	Electrostatic Precipitator
OR	Boardman	1SG				Dry bottom wall-fired	Electrostatic Precipitator

NPS analysis used the CCM to estimate ESP operating cost savings (see ESP workbook) if the ESP is replaced. ESP purchased equipment costs were scaled up from the CCM example using the six-tenths power rule based upon gas flow provided by SMBSC. Other costs were scaled up based upon a simple gas flow ratio. The CEPCI 2021/1987 ratio was applied to estimate total capital investment. Demolition of the ESP would be about $200,000 (based on estimates for ACS) and that estimated savings on ESP operating costs would be over $700,000/yr.

The CCM was used to estimate baghouse costs (see baghouse workbook). Some baghouse purchased equipment costs were scaled up from the CCM example using the six-tenths power rule based upon gas flow provided by SMBSC. Other equipment costs were scaled up based upon a simple gas flow ratio. The CEPCI 2021/1998 ratio was applied to estimate total capital investment.

For DSI, NPS analyses used the S&L IPM models and evaluated scenarios in which hydrated lime or milled trona was used in conjunction with the existing ESP or a new baghouse. The NPS also evaluated SDA/CDS (which includes the cost of a new baghouse) and Wet FGD using the CCM workbook.

NPS review finds that SMBSC and MPCA appear to have used an obsolete method to estimate costs of adding a Spray Dry Absorber (SDA). The current CCM SDA/CDS model includes a new baghouse in its cost estimates. Finally, if the existing ESP is removed, thorough estimation requires deducting its operating costs from those of its replacement and adding demolition costs.

NPS analyses assumed that a new baghouse could be installed inside of the shell of the existing ESP or within its footprint and would not incur an extra retrofit penalty. Likewise, a SDA/CDS system could be installed within the footprint of the existing ESP with no additional retrofit penalty. $200,000 was added to the capital cost of replacing the ESP with a baghouse to account for demolition costs and annual ESP operating costs were subtracted. NPS calculations used equipment lives of 30 years for SO_2 scrubbers and 20 years for a new baghouse.

Table 11. NPS SO_2 Control Cost Estimates for SMBSC Boiler 1

SMBS Boiler 1	**DSI w ESP**	**DSI w BGH**	**DSI w ESP**	**DSI w BGH**	**SDA/CDS**	**WFGD**
Control Technology	**Hydrated Lime**	**Hydrated Lime**	**Milled Trona**	**Milled Trona**		
Capacity (MW)	47.24	47.24	47.24	47.24	47.24	47.24
Retrofit factor	1.0	1.0	1.0	1.0	1.0	1.5
CEPCI	776.3	776.3	776.3	776.3	776.3	776.3
Capital Cost	$ 8,990,341	$ 7,666,357	$ 10,320,196	$ 17,468,408	$ 56,441,860	$ 115,758,707
Interest rate (%)	4.75	4.75	4.75	4.75%	4.75	4.75
Control Equipment Life (yr)	30		30		30	30
Capital Recovery Factor	0.0632		0.0632		0.0632	0.0632
Capital Recovery Cost	$ 568,275	$ 484,586	$ 652,334	$ 1,184,466	$ 3,567,126	$ 7,315,950
Indirect Cost/Fixed O&M	$ 309,994	$ 302,203	$ 317,820	$ 1,017,179	$ 3,607,237	$ 7,381,715
Total System Capacity Factor					0.882	0.882
Direct Cost/Variable O&M	$ 841,273	$ 682,335	$ 907,504	$ 1,725,163	$ 2,350,483	$ 4,075,058
Total Annual Cost	$ 1,719,542	$ 1,469,124	$ 1,877,658	$ 2,635,664	$ 5,957,720	$ 11,456,773
Uncontrolled SO_2 Emission Rate (lb/mmbtu)	0.52	0.52	0.52	0.52	0.52	0.52
Maximum Uncontrolled Tons/yr	1,076	1,076	1,076	1076	1076	1076
Uncontrolled Tons	805	805	805	805	949	949
SO_2 Removal Efficiency (%)	30	50	40	80	88	92
Controlled SO_2 Emission Rate (lb/mmbtu)	0.36	0.26	0.31	0.10	0.06	0.04
Tons Removed	242	403	322	644	840	876
Cost-Effectiveness	$ 7,120	$ 3,650	$ 5,831	$ 4,093	$ 7,097	$ 13,079

NPS SO_2 control cost estimates (see workbooks for details) indicate that milled trona with a new baghouse and SDA/CDS are the best options. The SDA/CDS option could remove 840 tpy of SO_2 at an annual cost of $6 million for a cost-effectiveness value of less than $7,100/ton.

The NPS also evaluated MPCA's estimates of the cost-effectiveness of these scenarios by adjusting the MPCA interest rate and equipment lives to be consistent with the CCM. Again, no retrofit penalties were assumed for the reasons cited above.

Table 12. NPS Evaluation of MPCA cost-effectiveness scenarios for SMBSC SO_2 control options

Control Technology	MPCA SMBS Boiler 1		ARD Revisions to MPCA SMBS Boiler 1	
	DSI w Trona & BGH	SDA	DSI w Trona & BGH	SDA
Capacity (MW)	472	472	472	472
Retrofit factor	1.5	1.5	1	1
Capital Cost	$ 37,755,277	$ 54,520,933	$ 24,187,473	$ 34,270,795
Interest rate (%)	3.50%	3.50%	4.50%	4.50%
Control Equipment Life (yr)	20	20	30	30
Capital Recovery Factor	0.0704	0.0704	0.0614	0.0614
Capital Recovery Cost	2,656,502	$ 3,938,759	$ 1,456,465	$ 2,209,468
Indirect Cost/Fixed O&M	4,415,695	$ 6,265,971	$ 2,637,228	$ 3,706,564
Direct Cost/Variable O&M	1,870,007	$ 958,329	$ 1,818,887	$ 893,526
Total Annual Cost	$ 6,285,702	$ 7,224,301	$ 4,456,115	$ 4,600,090
Uncontrolled SO_2 Emission Rate (lb/mmbtu)	0.52	0.52	0.52	0.52
Uncontrolled Tons	795	795	795	795
SO_2 Removal Efficiency (%)	70%	90%	70%	90%
Controlled SO_2 Emission Rate (lb/mmbtu)	0.15	0.05	0.15	0.05
Tons Removed	557	716	557	716
Cost-Effectiveness	$ 11,295	$ 10,097	$ 8,007	$ 6,429

MPCA's higher Indirect costs for DSI and SDA are partially due to due to its application of a retrofit factor = 1.5 (versus = 1.0), and shorter equipment life. NPS estimates indicate that, DSI (with trona and a new baghouse) and SDA/CDS are both cost-effective.

Statutory Factor 2: Time Necessary for Compliance

Time necessary for compliance is estimated to be 18 months for DSI with milled trona and 4 – 5 years for SDA.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

SMBSC consultant Barr cites potential increased energy usage and solid waste generation concerns. In most circumstances, energy usage is most appropriately accounted for in the Cost of Compliance analysis. The solid waste generation concerns are not unique to this site.

Statutory Factor 4: Remaining Useful Life

The CCM recommends a 30-year life for scrubbers unless limited by a federally-enforceable condition.

4.3.5 NO_x Four-factor Analysis

Control Efficiency

MPCA assumed 49% efficiency by SNCR with an estimated Normalized Stoichiometric Ratio (NSR) = 1.57. NPS application of CCM Equation 1.17 yielded NSR = 0.94. As a result NPS analyses project a 30% NO_x reduction (from CCM Figure 1.1c) down to 0.30 lb/mmBtu with much less reagent.

Statutory Factor 1: Cost of Compliance

Basis for the selected retrofit factor

In the draft SIP SMBSC cost calculations for SNCR and SCR, Barr included a 1.5 retrofit factor. The CCM requires specific justification and documentation to support use of factors greater than 1.0. The EPA CCM default retrofit factor = 1.0 already includes a 20%–25% markup for many of the issues cited as rationale for the higher rate. After observing Google earth photos of the facility, and in consideration of the issues described in SMBSC's July 23, 2021 submittal, NPS review finds that it appears that a higher retrofit factor may be justified for SCR installed on the roof (NPS assumed 1.5 for this calculation). However, this should not be necessary for SNCR (or SCR installed following the ESP) unless supported by a vendor. For this reason, NPS analyses used the default retrofit factor = 1.0 for those other options.

Basis and Cost for SCR Reheat

SMBSC (and MPCA) has included costs to reheat the flue gas entering the SCR in addition to applying a 1.5 retrofit factor due to the difficulty of locating the SCR above the boiler exhaust. The SIP could be improved by a demonstration of why both of these costs (retrofit factor =1.5 and reheat costs) are necessary.

Due to the high cost of natural gas, NPS analyses included a 70%-efficient heat exchanger in the reheat system and applied CCM methods to estimate operating parameters and costs. In estimating the capital and operating costs of SCR, the NPS included the duct burner heat input to size the SCR to handle the additional load.

SCR Catalyst and Equipment Life Basis

In response to earlier input SMBSC replied (July 23, 2021):

> *FLMs stated that the catalyst and equipment life are underestimated compared to EPA CCM defaults. Section 4, Chapter 2 of the EPA CCM discusses catalyst and SCR life. SMBSC assumed the mid-range for the typical catalyst life guarantees (16,000 – 24,000 hours). While these numbers represent high dust scenarios, SMBSC will not assume that SCR catalyst will maintain proper performance without a guarantee from a vendor. This would require a detailed SCR evaluation, which is not warranted because the technology is not cost effective.*

SMBSC selected “Method 2” to estimate catalyst replacement cost; this tends to produce higher cost estimates than “Method 1.” 20,000 hours is an acceptable mid-range value for catalyst life for a high-dust configuration. However, SCR located following the ESP should have a longer catalyst life—NPS estimates 24,000 hours.

SMBSC also replied (July 23, 2021):

> *In addition, the CCM states that the expected SCR equipment life for industrial boilers is 20-25 years. SMBSC assumed 20 years for the SCR life because it is a reasonable approximation of what could be expected for an equipment life for purposes of the FFA and is within the default range provided by the CCM.*

According to the CCM, *“For other sources, the equipment life can be between 20 and 30 years.”* The CCM workbook assumes use of the 25-year mid-range value, which the NPS accepts as appropriate for a seasonal facility that only operates 314 days per year.

NPS Estimated Cost of Compliance for SNCR

Table 13. NPS estimated SNCR costs for SMSBC compared to MPCA estimates

SMBSC Boiler 1		
Control Technology	**SNCR**	
	NPS	**MPCA**
Capacity (mmBtu/hr)	472.4	472.4
Retrofit factor	1.0	1.5
CEPCI	776.3	607.5
Capital Cost	$ 5,871,808	$ 7,159,267
Interest rate (%)	4.75	3.5
Control Equipment Life (yr)	20	20
Capital Recovery Cost	$ 461,524	$ 504,012
Indirect Cost/Fixed O&M	$ 464,166	$ 507,234
Total System Capacity Factor	0.7611	0.7449
Direct Cost/Variable O&M	$ 645,264.59	$ 806,837.79
Total Annual Cost	$ 1,109,430.99	$ 1,314,071.85
Uncontrolled NO_x Emissions (Tons/yr)	929	909
Uncontrolled NO_x Emission Rate (lb/mmbtu)	0.59	0.59
NO_x Removal Efficiency (%)	30	49
Controlled NO_x Emission Rate (lb/mmbtu)	0.42	0.30
Tons Removed	274	447
Cost-Effectiveness	$ 4,042	$ 2,942

Significant Issues regarding SNCR Cost-Effectiveness:

- A retrofit factor greater than the CCM default value of 1.0 (which represents a 20% increase over a "greenfield" application) is likely unjustified considering the relative simplicity of typical SNCR systems. The CCM advises that:
  - o 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. According to the CCM, "You must document why a retrofit factor of "__" is appropriate for the proposed project"

- Updated NPS calculations apply more recent values for CEPCI and interest rate.
- It is likely that MPCA has overestimated SNCR control efficiency and the resulting Direct Operating Costs and Tons Removed. NPS recommends application of the relationship shown in CCM Figure 1.1c.

NPS analyses estimate that addition of SNCR could reduce annual NO_x by almost 300 tons at an annual cost of about $1.1 million resulting in a very cost-effective strategy of about $4,000/ton of NO_x removed.

NPS Estimated Cost of Compliance for SCR

The table below shows the SCR costs estimated by MPCA and ARD (NPS).

The column labeled "SCR" does not include reheat. The column labeled "Reheat" shows the costs of adding a 211 mmBtu/hr burner. The next column to the right shows costs associated with the SCR enlarged to treat the combined gas streams from the boiler and the burner. The next column to the right shows the combined costs of the reheat burner and the enlarged SCR. The cost-effectiveness of this combination is $7,396/ton.

The column headed "ARD/MPCA" shows NPS revisions to the MPCA calculations for the SCR w Reheat combination, while the "MPCA" column shows the actual MPCA calculations.

Table 14. NPS estimated SCR costs for SMSBC compared to MPCA estimates

SMBS Boiler 1	**SCR**	**Reheat**	**SCR+Reheat**			
Control Technology	**NPS**	**NPS**	**NPS**		**ARD/MPCA**	**MPCA**
Capacity (mmBtu/hr)	472.4	231	704		704	472.4
Retrofit factor	1.5	1	1		1	1.5
CEPCI	776.3	776.3	776.3		776.3	607.5
Capital Cost	$ 47,658,491	$ 1,887,062	$ 43,046,809	$ 44,933,871	$ 44,709,067	$ 39,367,890
Interest rate (%)	4.75	4.75	4.75		4.75	3.50
Control Equipment Life (yr)	25	25	25		25	20
Capital Recovery Cost	$ 3,297,968	$ 130,557	$ 2,978,839	$ 3,109,396	$ 3,460,963	$ 2,771,423
Indirect Cost/Fixed O&M	$ 3,303,088	$ 253,293	$ 2,983,683	$ 3,236,976	$ 2,111,312	$ 2,933,155
Total System Capacity Factor	0.761					0.745
Catalyst Life (hr)	20,000		24,000		24,000	20,000
Catalyst Replacement Cost Method	2		2		2	2
Catalyst Replacement Cost	$ 189,384		$ 282,052		$ 282,052	$ 191,915
Direct Cost/Variable O&M	$ 1,121,222	$ 1,344,912	$ 1,530,195	$ 2,875,107	$ 3,328,035	$ 2,071,903
Total Annual Cost	$ 4,424,310	$ 1,598,205	$ 4,513,878	$ 6,112,082	$ 5,307,676	$ 4,979,779
Maximum Uncontrolled (Tons/yr)	1220	101	1322			1220
Uncontrolled NO_x Emissions (Tons/yr)	929	77		1006		909
Uncontrolled NO_x Emission Rate (lb/mmbtu)	0.59	0.10			0.59	0.59
NO_x Removal Efficiency (%)	90	90	90		90	92
Controlled NO_x Emission Rate (lb/mmbtu)	0.06		0.06		0.06	0.05
Tons Remaining	94	8		102		77
Tons Removed	834	69		826	835	832
Cost-Effectiveness	$ 5,303			$ 7,396	$ 6,354	$ 5,986

Significant Issues regarding SCR Cost-Effectiveness:

- A retrofit factor greater than the CCM default value of 1.0 (which represents a 20% increase over a "greenfield" application) was not justified for SCR with reheat. The CCM advises that:
  - 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. According to the CCM, "You must document why a retrofit factor of "__" is appropriate for the proposed project"
- Updated NPS calculations apply more recent values for CEPCI and interest rate.

The NPS estimates that addition of SCR could reduce annual NO_x by over 800 tons at an annual cost of $5–$7 million resulting in a cost-effective strategy of $7,000–$8,000/ton of NO_x removed.

Statutory Factor 2: Time Necessary for Compliance

SCR operation typically requires four to five years after SIP approval, while SNCR may take up to two years.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

When evaluating statutory factor 3, SMBSC raises several potential concerns with respect to SNCR and SCR including fuel consumption and energy use. The energy impacts mentioned are most properly accounted for when analyzing statutory factor 1, Cost of Compliance.

Statutory Factor 4: Remaining Useful Life

The CCM recommends 25-year life for SCR and 20 years for SNCR on industrial boilers unless limited by a federally-enforceable condition.

4.3.6 NPS Conclusions and Recommendations Southern Minnesota Beet Sugar Cooperative

NPS review finds that SMBSC and MPCA have overestimated the Cost of Compliance due to:

- Use of equipment life (20 years) for some controls that is too short.
- Application of unsupported retrofit factors.
- Underestimation of control efficiencies.

With respect to statutory factor one, the Cost of Compliance, after making the adjustments described above NPS analysis finds that for this facility:

1. The addition of DSI (with trona) is cost-effective for SO_2 emission reductions with or without addition of a new baghouse.
2. The addition of SDA/CDS is also cost-effective and would provide a superior level of SO_2 emission control.
3. The addition of SNCR is a cost-effective option for reducing NO_x emissions.
4. The addition of SCR is also cost-effective and would provide a superior level of NO_x emission control.

The NPS recommends that MPCA evaluate statutory factor two, the Time Necessary for Compliance, addition of SDA/CDS and SCR. Review of statutory factors three and four finds no unusual Energy and Non-Air Quality Environmental Impacts related to DSI, SDA/CDS, SNCR, or SCR and Remaining Useful Life is not an issue.

In conclusion, based on the four factors, the NPS recommends that MPCA require the addition of cost-effective control strategies that provide the greatest emission reductions. The SDA/CDS option could remove 840 tons/year of SO_2 at an annual cost of $6 million for a cost-effectiveness value of less than $7,100/ton. NPS estimates indicate that addition of SCR could reduce annual NO_x by over 800 tons/year at an annual cost of $5–$7 million resulting in a cost-effective strategy of $6,000–$8,000/ton of NO_x removed.

5 Paper Manufacturing – Four-Factor Feedback

5.1 Boise White Paper

5.1.1 Summary of NPS Recommendations for Boise White Paper

NPS review of the four-factor analysis conducted for Boise White Paper (Boise) finds that, as a result of screening Boiler 2 and the Recovery Furnace, almost 1,050 annual tons of SO_2 and NO_x were not evaluated at this facility.

The NPS recommends that MPCA improve the demonstration of effective controls for these units, showing why these emissions cannot reasonably be reduced, or require a four-factor evaluation of emission control opportunities.

For Boiler 1, the NPS recommends that MPCA adjust the permitted NO_x emissions rate to more closely reflect the emission rate evaluated. If the currently permitted limit is considered, SCR may be cost effective.

5.1.2 Facility Characteristics

Boise White Paper (Boise) is wholly owned by Packaging Corporation of America (PCA) and is located in International Falls, 17 km west of Voyageurs National Park, a Class I area administered by the National Park Service. The facility is an integrated kraft pulp and paper mill that produces commodity and specialty paper. The three emission units included in MPCA's request for information are:

- Boiler 1
- Boiler 2
- Recovery Furnace

MPCA screened Boiler 2 and the Recovery Furnace from four-factor analysis based on a 2013 BACT analysis and the presence of a more stringent NO_x emissions limits than found in a review of permit limits for similar sources.

In its July 2021 clarification memo, EPA advised that states must show why additional emission reductions are not necessary to make reasonable progress. Section 2.3 addressed the analytical expectations for "effectively controlled" determinations:

> *The underlying rationale for the "effective controls" flexibility is that if a source's emissions are already well controlled, it is unlikely that further cost-effective reductions are available.* ***A state relying on an "effective control" to avoid performing a four-factor analysis for a source should demonstrate why, for that source specifically, a four-factor analysis would not result in new controls and would, therefore, be a futile exercise.***

MPCA's draft SIP Table 14 shows that Boise emitted 803 tons of in NO_x 2016. Of this total, only 73 tons of NO_x from Boiler #1 are accounted for. Based upon permitted limits, it appears that Boiler #2 has potential NO_x emissions of 439 tons/yr and that the Recovery Furnace has potential NO_x emissions of 482 tons/yr. In total, as a result of screening Boiler 2 and the Recovery Furnace almost 1,050 annual tons of SO_2 and NO_x were not evaluated at this facility.

NPS ARD has reviewed three other hogged fuel boilers similar to Boiler #2 at paper mills, including the Sappi mill in Cloquet, MN where SNCR and SCR were evaluated by the state for NO_x reductions. Two of those boilers (PCA in Wallula, WA and Nippon Dynawave in Longview, WA) have NO_x emission rates that are lower than the permitted rate for Boiler 2 at Boise White. Further, while the recovery furnace uses staged air combustion to manage the generation of NO_x, it is not clear if that includes quaternary air.[4] If not, the NPS recommends that MPCA investigate its addition.

The NPS recommends that MPCA improve the demonstration of effective controls for screened units, showing why emissions cannot reasonably be reduced, or require a four-factor evaluation of emission control opportunities.

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[4] SUN BIO MATERIAL (U.S.) COMPANY, PSD PERMIT APPLICATION, November 2018: The most widely used combustion modification approach in recovery boilers is commonly referred to as "quaternary air/staged combustion." This technology involves four stages of combustion air supplied at successively higher points in the body of the furnace. Quaternary Air/Staged Combustion minimizes NOx emissions by maintaining the minimum combustion temperature possible at each successive stage in the furnace to combust the black liquor solids while maintaining high sulfur reduction efficiencies, good bed stability, and uniform velocities after the furnace to minimize high temperatures and fouling. Primary air is used for bed stability, efficient carbon burnout, and high sulfur reduction efficiencies. Secondary (low and high) air ensures even air distribution over the char bed for pyrolysis and volatiles burning. NCG gas can be mixed with high secondary air, which provides air to the start-up burners. Tertiary air is the over-fire air over black liquor sprays and provides air to load-carrying burners. Finally, quaternary air is the air staging register at the upper furnace for NOx reduction. Moreover, the "Quaternary Air/Staged Combustion" technology employed on all modern recovery boiler systems already minimizes NO_X emissions while maintaining high reduction efficiencies, good bed stability, and uniform velocities.

5.1.3 NO_x Four-factor Analysis

Control Selection & Efficiency

Three types of NO_x emission controls were evaluated for Boise Boiler 1:

- LNB/OFA + FGR
- SCR
- SNCR

The SNCR analysis is not included in MPCA SIP Table 28 but was included in NPS review.

Statutory Factor 1: Cost of Compliance

MPCA presented the analyses shown in its Table 28 below.

Table 15. Minnesota draft SIP Table 28. NO_x control information (MPCA revision)

Facility	Emission Unit	Control Measure	Emission Reduction (tpy)	Capital Costs ($)	Annual Costs ($)	Cost Effectiveness ($/ton)
Boise White Paper	Boiler 1	LNB/OFA + FGR	58	$11,144,531	$1,557,544	$26,649
		SCR	66	$8,031,851	$905,022	$13,783

In addition, MPCA provided an analysis of SNCR using methods developed by EPA in its Control Cost Manual (CCM) and determined that SNCR could reduce NO_x emissions by 38 tons/yr at an annual cost of about $250,000 for a cost-effectiveness value of just over $6,600/ton of NO_x removed. The NPS revised the MPCA calculations for both SNCR and SCR as follows:

- Based upon CCM Figure 1.1c, SNCR is estimated to reduce NO_x emissions by 19% (instead of 40%) from a baseline emission rate of 0.131 lb/mmBtu.
- SCR is assumed to be able to achieve 0.02 lb/mmBtu for this gas-fired boiler. MPCA assumed that SCR would reduce emissions by 70% down to 0.04 lb/mmBtu.
- An SCR catalyst life = 24,000 hours for this gas-fired boiler was used, instead of 20,000 hours used by MPCA.
- A Chemical Engineering Plant Cost Index (CEPCI) for 2021 = 776.3 was applied instead of the 2019 CEPCI = 607.5.
- The June 21, 2022 prime interest rate = 4.75% was used instead of 3.5%.

NPS analysis determined that SNCR could reduce NO_x emissions by 18 tons/yr at an annual cost of about $325,000 for a cost-effectiveness value of almost $18,000/ton of NO_x removed.

For SCR, along with the revisions listed above NPS applied an 85% control assumption (down to 0.02 lb/mmBtu), and determined that SCR could reduce NO_x emissions by 80 tons/yr at an annual cost of $1,008,000 for a cost-effectiveness value of about $12,600/ton of NO_x removed. However, when application of SCR at 90% control versus the permitted emission rate = 0.20 lb/mmBtu was reevaluated, we found that SCR could reduce NO_x emissions by 130 tons/yr at an annual cost of $1,031,000 for a cost-effectiveness value of about $8,000/ton of NO_x removed.

Statutory Factor 2: Time Necessary for Compliance

Installation of SCR typically requires four-to-five years.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

Energy usage is most appropriately accounted for in the Cost of Compliance analysis. The other non-air quality environmental impacts cited are not unique to this site.

Statutory Factor 4: Remaining Useful Life

MPCA used a 20-year life for SNCR and for SCR. The CCM recommends 20 – 25 years for SCR; NPS analyses assumed 25 years for this gas-fired boiler.

5.1.4 NPS Conclusions and Recommendations Boise White Paper

MPCA's Table 14 shows that Boise emitted 803 tons of NO_x in 2016. Of this total, only 73 tons of NO_x are attributed to Boiler #1, the unit selected for four-factor evaluation. Based upon permitted limits, it appears that Boiler #2 has potential NO_x emissions of 439 tons/yr and that the Recovery Furnace has potential NO_x emissions of 482 tons/yr. Potential emissions from each of these units is more than six times greater than the emissions that were evaluated.

By screening Boiler #2 and the Recovery Furnace from four-factor evaluation SIP, MPCA has evaluated less than 10% of this facility's NO_x emissions.

The NPS recommends that MPCA could improve the draft SIP by providing a more robust demonstration that Boiler #2 and the Recovery Furnace are effectively controlled or by requiring a four-factor evaluation of NO_x control opportunities from these emission units.

For Boiler #1 the NPS recommends that MPCA adjust the permitted NO_x emissions rate to reflect the emission rate evaluated. Otherwise, if the currently permitted limit is considered, SCR may be cost effective.

5.2 Sappi Cloquet LLC

5.2.1 Summary of NPS Recommendations for Sappi Cloquet LLC

NPS review of the four-factor analysis conducted for Sappi Cloquet LLC supports MPCA findings that:

- Recovery Boiler #10 is effectively controlled and can be screened from four-factor evaluation.
- Projected 2028 emissions of SO_2 from Power Boiler #9 are too low to warrant four-factor evaluation of DSI or SDA emission controls from that unit.

With respect to the NO_x evaluation on Power Boiler #9, NPS review finds that MPCA has reasonably estimated the statutory factor one, Cost of Compliance, and demonstrated that:

- Addition of SNCR is cost-effective, and
- Addition of SCR is also cost-effective and represents greater emission control.

The NPS recommends that MPCA require the addition of cost-effective control strategies that provide the greatest emission reductions. NPS estimates indicate that addition of SCR to Boiler 9 could reduce annual NO_x by 300 tons/year at an annual cost of about $2.5 million resulting in a cost-effective strategy of about $8,800/ton of NO_x removed. By requiring implementation of identified controls MPCA will be reducing haze causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

5.2.2 Facility Characteristics

Sappi Cloquet LLC is a kraft pulp and paper mill that manufactures kraft paper pulp, dissolving wood pulp, and fine coated paper. The facility is located near Cloquet, MN, about 175 km south of Voyageurs National Park, a Class I area administered by the NPS.

The two emission units included in MPCA's request for information are:

- Power Boiler #9
- Recovery Boiler #10

NPS supports MPCA findings that:

- Recovery Boiler #10 is effectively controlled and can be screened from four-factor evaluation.
- Projected 2028 emissions of SO_2 from Power Boiler #9 are too low to warrant four-factor evaluation of DSI or SDA emission controls from that unit.

5.2.3 NO_x Four-factor Analysis

Control Selection & Efficiency

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 and SNCR. The NPS supports this determination of appropriate NO_x controls for consideration.

Statutory Factor 1: Cost of Compliance

The table below shows the SNCR and SCR costs estimated by MPCA and the NPS for Sappi Cloquet LLC. All cost-effectiveness values are below $9,000/ton.

Table 16. NPS estimated NO_x control costs for Sappi Cloquet power boiler 9 compared to MPCA estimates

Sappi Power Boiler 9				
Control Technology	**SNCR**		**SCR**	
	NPS	**MPCA**	**NPS**	**MPCA**
Capacity (mmBtu/hr)	430	430	430	430
Retrofit factor	1	1	1	1.33
CEPCI	776.3	607.5	776.3	607.5
Capital Cost	$ 6,068,270	$ 6,068,270	$ 28,945,602	$ 29,945,905
Interest rate (%)	4.75	3.50	4.75	3.50
Control Equipment Life (yr)	20	20	25	25
Capital Recovery Cost	$ 476,966	$ 427,206	$ 2,003,036	$ 1,817,716
Indirect Cost/Fixed O&M	$ 479,697	$ 429,937	$ 2,007,307	$ 1,822,048
Total System Capacity Factor	0.631	0.631	0.631	0.631
Catalyst Life (hr)			20,000	20,000
Catalyst Replacement Cost Method			1	1
Catalyst Replacement Cost			$ 198,567	$ 194,561
Direct Cost/Variable O&M	$ 168,063	$ 312,950	$ 515,955	$ 514,973
Total Annual Cost	$ 647,759	$ 742,887	$ 2,523,262	$ 2,337,020
Maximum Uncontrolled (Tons/yr)	550	550	550	550
Uncontrolled NO_x Emissions (Tons/yr)	347	347	347	347
Uncontrolled NO_x Emission Rate (lb/mmbtu)	0.29	0.29	0.29	0.29
NO_x Removal Efficiency (%)	21	25	83	80
Controlled NO_x Emission Rate (lb/mmbtu)	0.23	0.22	0.05	0.06
Tons Removed	74	87	288	278
Cost-Effectiveness	$ 8,790	$ 8,562	$ 8,774	$ 8,418

Significant Issues regarding Cost-Effectiveness:

- A retrofit factor greater than the CCM default value of 1.0 (which represents a 25% increase over a “greenfield” application) was not justified. The CCM advises that:
    - 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. According to the CCM, “You must document why a retrofit factor of “__" is appropriate for the proposed project." The MPCA retrofit factor represents a 66% increase versus a “greenfield” estimate.
- Although both MPCA and NPS used the current versions of EPA’s Control Cost Manual (CCM) workbooks for SNCR and SCR, the NPS applied the current (4.75%) prime interest rate and 2021 Chemical Engineering Plant Cost Index (CEPCI = 776.3).
- The CCM default for catalyst life is 20,000 – 24,000 hours; NPS used the MPCA 20,000 hour estimate.
- It is likely that MPCA has overestimated SNCR control efficiency and the resulting Direct Operating Costs and Tons Removed. NPS recommends application of the relationship shown in CCM Figure 1.1c.
- It is likely that MPCA has underestimated SCR control efficiency and the resulting Direct Operating Costs and Tons Removed. The CCM advises that SCR can achieve emissions as low as 0.04 lb/mmbtu (and up to 90% control). NPS analyses used 0.05 lb/mmbtu (83% control) to be conservative.

The NPS estimates that addition of SNCR could reduce annual NO_x by over 70 tons at an annual cost of about $0.65 million resulting in a cost-effective strategy of about $8,800/ton of NO_x removed.

We estimate that addition of SCR could reduce annual NO_x by almost 300 tons at an annual cost of about $2.5 million resulting in a cost-effective strategy of about $8,800/ton of NO_x removed.

Statutory Factor 2: Time Necessary for Compliance

SCR operation typically requires four to five years after SIP approval, while SNCR may take up to two years.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

Energy usage is most appropriately accounted for in the Cost of Compliance analysis. The other non-air quality environmental impacts cited are not unique to this site.

Statutory Factor 4: Remaining Useful Life

The CCM recommends 20–25-year life for SCR and 20 years for SNCR on industrial boilers unless limited by a federally-enforceable condition.

5.2.4 NPS Conclusions and Recommendations Sappi Cloquet LLC

NPS supports MPCA findings that:

- Recovery Boiler #10 is effectively controlled and can be screened from four-factor evaluation.
- Projected 2028 emissions of SO_2 from Power Boiler #9 are too low to warrant four-factor evaluation of DSI or SDA emission controls from that unit.

For NO_x evaluation on Power Boiler #9, NPS review finds that MPCA has reasonably estimated the statutory factor one, *Cost of Compliance*, and demonstrated that:

- Addition of SNCR is cost-effective, and
- Addition of SCR is also cost-effective and represents greater emission control.

The NPS recommends that MPCA evaluate statutory factor two, the *Time Necessary for Compliance*, for addition of SNCR and SCR for Power Boiler #9. Review of statutory factors three and four finds no unusual *Energy and Non-Air Quality Environmental Impacts* related to SNCR or SCR and *Remaining Useful Life* is not an issue.

In conclusion, based on the four factors, the NPS recommends that MPCA require the addition of cost-effective control strategies that provide the greatest emission reductions. NPS estimates indicate that addition of SCR to Boiler 9 could reduce annual NO_x by almost 300 tons/year at an annual cost of about $2.5 million resulting in a cost-effective strategy of about $8,800/ton of NO_x removed.

6 Taconite – Four-Factor Feedback

6.1 Overarching Taconite

At the MN taconite facilities, iron ore from mines along the Mesaba Iron Range is separated from taconite (a low-grade iron ore) using magnetism. The taconite powder with the iron in it is called concentrate which is rolled with clay inside large rotating cylinders. The cylinders cause the powder to roll into marble-sized balls that are then dried and heated until they are white hot. The balls become hard as they cool and become taconite pellets which are shipped to steel mills to be melted down into steel.[5]

On February 6, 2013, U.S. EPA promulgated a Taconite Regional Haze FIP that included BART limits for taconite furnaces subject to BART in Minnesota with an effective date of March 8, 2013.[6] On April 12, 2016, U.S. EPA finalized the revisions to the 2013 FIP and the final rule (2016 FIP) was effective on May 12, 2016.[7] EPA's 2016 FIP contained this:

[5] Taconite | Minnesota DNR (state.mn.us)
[6] See 78 Fed. Reg. 8706 (February 6, 2013).
[7] See 81 Fed. Reg. 21672 (April 12, 2016).

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.

MPCA initially selected six taconite plants for four-factor analyses; their 2017 emissions (from the National Emissions Inventory—NEI) are shown below. (All emissions except Hg are in ton/yr; Hg is in lb/yr.) These facilities are located between 85 and 150 km south of Voyageurs National Park and within 300 km of Isle Royale National Park, both Class I areas administered by the National Park Service (NPS).

Table 17. Recent annual emissions from Minnesota Taconite facilities, NEI 2017

Facility Name	**Hg, lb/yr**	**NO_x, tpy**	**PM10-PRI, tpy**	**PM25-PRI, tpy**	**SO_2, tpy**	**NO_x+ PM10+ SO_2, tpy**	**Distance to NPS Class I Area, km**	**(NO_x+ PM10+ SO_2)/d**
Hibbing Taconite Co	149	3,981	1,567	400	824	6,372	100	64
ArcelorMittal Minorca Mine Inc	75	3,063	567	173	136	3,766	85	44
United Taconite LLC - Fairlane Plant	190	3,743	595	412	275	4,613	108	43
Northshore Mining Co–Silver Bay	22	2,169	461	327	1,539	4,169	147	28
US Steel Corp–Minntac	173	6,481	2,788	2,084	1,207	10,476	85	123
US Steel Corp–Keetac	90	5,009	533	411	533	6,075	109	56
Totals	700	24,446	6,511	3,807	4,514	35,471		358

Based on emissions relative to distance to NPS managed Class I areas, MN ranks #9 in the US, with the taconite facilities comprising more than half of those impacts. (The taconite plants alone would rank #22 as a "state."

MPCA subsequently decided that no four-factor analyses were required for any of these facilities. The paragraph below (United Taconite—Fairlane) is an example of MPCA's rationale from the draft SIP:

These circumstances are specific, or similar to, examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis. Regarding NO_x emissions, the emission units installed and began operating controls to meet BART emission limits for the first implementation period. Regarding SO_2 emissions, while the existing controls for the emission units were determined to be BART, meaning no add-on controls were required, both emission units are subject to an hourly SO_2 emission rate limit and fuel sulfur content requirements established in the

> *Taconite FIP. Given the level of control required for these emissions units, the MPCA determined that it was unlikely that there are further available reasonable controls for these emission units and removed them from further analysis for this implementation period.*

NPS review and analysis demonstrates that controls that are more effective than the current controls are technically feasible, cost-effective, and may be considered reasonable.

MPCA may also be relying upon two other issues related to the taconite companies:

- Analyses conducted by U.S. EPA that determined what emission reductions were BART for the indurating furnaces at taconite facilities in Minnesota, as discussed earlier in Section 2.3.5 regarding sources that are effectively controlled are referenced and relied on. The BART analyses conducted by U.S. EPA were included in the Taconite Regional Haze FIPs promulgated in 2013 and 2016.

- According to MPCA, U.S. EPA and the Minnesota taconite facilities have been in continued settlement discussions since the promulgation of these FIPs, as discussed in SIP Section 1.3, most recently resulting in revisions to the FIP requirements for U.S. Steel–Minntac in 2020. While the MPCA is not included in the settlement discussions between U.S. EPA and the Minnesota taconite facilities, the MPCA expects that U.S. EPA's current analysis is both sound and does not require an update for this implementation period given that U.S. EPA continues to evaluate the specific requirements of the FIP, including the associated BART emission limits.

EPA's previous BART determinations are no longer current (some of the facilities may have changed fuel mixtures and/or pellet characteristics) and warrant revisiting, especially with respect to EPA's 2016 comments regarding SCR with reheat.

The ongoing negotiations among EPA and the Minnesota taconite facilities do not exempt the taconite facilities from review in this planning period. In its 11/01/2021 letter to Wyoming, EPA stated:

> *Wyoming states that it did not conduct a four-factor analysis for the Wyodak facility due to ongoing first planning period litigation. First planning period litigation is not a basis to forego a four-factor analysis for Wyodak for the second regional haze implementation period. Wyoming must perform a four-factor analysis or provide a reasonable explanation for excluding Wyodak consistent with the Regional Haze Rule, EPA's Guidance, and the Clarifications Memo.*

6.2 United Taconite LLC–Fairlane Plant

6.2.1 Summary of NPS Recommendations for United Taconite LLC–Fairlane Plant

NPS review of the four-factor analysis conducted for Cleveland Cliffs' United Taconite—Fairlane Plant (UTAC) finds that NO_x, SO_2, and PM emissions from UTAC's Lines #1 & #2 are not effectively-controlled.

Further, NPS review finds that:

- Application of tail-end SCR (installed after the existing wet scrubbers) at UTAC could reduce NO_x emissions by almost 3,000 tons/yr for $7,000–$10,000/ton.
- On their own, opportunities to reduce SO_2 emissions with a modern scrubber and fabric filter or ESP are well above the threshold for consideration even when adjusted for conformance with CCM methods.

However, an integrated approach that precedes tail-end SCR with dry scrubbing and a fabric filter would minimize catalyst fouling (improving the technical feasibility of SCR) while drastically reducing PM emissions as well as reducing SO_2 emissions. This would be a far superior approach from an emissions reduction and cost effectiveness perspective with the potential to reduce haze causing emissions by thousands of tons per year in a cost-effective manner (Table 20).

The NPS recommends that MPCA require all taconite facilities originally selected for four-factor analysis to conduct four-factor analyses evaluating how an integrated approach to emission control improvements could reduce visibility-impairing emissions. Given both the scale and proximity of haze causing emissions from taconite facilities this may be the single best strategy available to MPCA for reducing haze causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

6.2.2 Facility Characteristics

UTAC is located 108 km southwest of Voyageurs National Park. Of the six taconite facilities identified by MPCA for four-factor analysis, only Cleveland Cliffs submitted one for its UTAC plant. In that submittal, the company included this disclaimer:

> *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),*[8] *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*

[8] EPA April 12, 2016 Federal Register: 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.

that the SCR with reheat control technology is included in the analysis; UTAC does not concur that SCR with reheat is considered technically feasible.[9]

The NPS observes that for the purposes of four factor analysis, a technology need not have been demonstrated on a specific industry to be "technically feasible"—it must only be available (which SCR is) and applicable (which SCR may be).

According to MPCA, lines 1 and 2 at UTAC were BART-eligible emission units and BART emission limits on NO_x and SO_2 were established by U.S. EPA in the Regional Haze Taconite FIP promulgated during the first Regional Haze Implementation Period. Lines 3, 4, and 5 can burn coal, petroleum coke, natural gas and distillate oil. These emission units utilize existing wet scrubbers for SO_2 control.

Emission units are subject to a NO_x emissions limit (1.5-3.0 lb NO_x/MMBtu for each line, fuel dependent, as a 30-day rolling average) established in the Taconite FIP dated April 12, 2016. These emission units required add-on controls, low NO_x burners, to meet the NO_x limits.

Based upon data submitted by UTAC, annual average NO_x emission rates were 1,325 tons @ 1.83 lb/mmBtu for Line 1 and 1,874 tons @ 1.22 lb/mmBtu for Line 2. Additionally, these emission units are subject to an SO_2 emissions limit (529 lb SO_2/hr, averaged across both lines as a 30-day rolling average and a 1.50 percent sulfur content limit for any coal burned as a monthly block average) established in the Taconite FIP dated April 12, 2016. In the 2016 Taconite FIP, U.S. EPA determined that additional SO_2 controls were not economically reasonable and were not necessary for BART.

UTAC reports that the existing wet scrubbers are 25% effective at reducing SO_2. Based upon data submitted by UTAC, annual average SO_2 emission rates were 59.7 tons @ 0.08 lb/mmBtu for Line 1 and 215.4 tons at 0.18 lb/mmBtu for Line 2. The existing wet scrubbers are also 94% effective at reducing PM. (These NPS calculated values are based upon Appendix B of UTAC's four factor estimate that Line 1 PM emissions are almost 1,500 tons/year and Line 2 PM emissions exceed 3,400 tons/year. MPCA reports that Line 2 emitted 94 tons of $PM_{2.5}$ in 2017.)

Considering that modern particulate controls can remove 99.9% of emissions and modern SO_2 scrubbers can achieve up to 99% control, it is reasonable to conclude that more-effective controls for these pollutants may be feasible.

6.2.3 NO_x Four-factor Analysis

SCR – Post-Scrubber with Conventional Duct Burner Reheat

UTAC states that: According to EPA's 2016 Final FIP, 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:

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[9] **Regional Haze Four-Factor Analysis for NOX and SO2 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

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.

This information was specific to a different facility that burned different fuels over nine years ago and may very well be outdated or inapplicable. The NPS recommends contacting a SCR vendor regarding application to current UTAC operations.

UTAC also raises concerns regarding the application of SCR on taconite furnaces due to the differences from utility boilers with respect to gas composition, dust loading, and chemistry. Specifically, UTAC states that:

The most serious issues yet to be resolved with SCR on furnaces include the formation of SO3 in the reactor, the ability to inject ammonia at 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

NPS review finds that the SO_2 concentrations in the gas stream exiting the existing 25%-efficient wet scrubbers is an order of magnitude lower than encountered by SCR on a typical coal-fired boiler. SCR in a tail-end configuration would also be exposed to much lower concentration of particulate and the reheated gas stream exiting the SCR would be well above the acid dew-point.

NO_x Variability and Ammonia Slip

With respect to concerns raised by UTEC regarding NO_x variability and ammonia slip, the NPS notes that the reference cited is from 2006 and uses a high dust configuration SCR. As such it may not be relevant. Modern process controls and a much cleaner tail-end SCR location should be capable of better performance. The EPA Control Cost Manual (CCM) provides this more up-to-date information:

In the cement industry, pilot tests in the 1970s and 1990s showed that SCR could be a feasible control technology for cement kilns. Building on that experience, SCRs were first installed in Europe in 2001. Today, SCR has been successfully implemented at seven European cement plants in Solnhofer, Germany (operated from 2001 until 2006), Bergamo, Italy (2006), Sarchi, Italy (2007), Mergelstetten, Germany (2010), Rohrdorf, Germany (2011), Mannersdorf, Austria (2012), and Rezatto, Italy (2015). As of 2015, there is only one cement plant in the U.S. that has installed an SCR. This SCR began

> *operation in 2013 and is installed after an electrostatic precipitator. The control efficiency for the system is reported to be about 80 percent, which is consistent with SCR applications on European kilns. SCRs have not seen widespread use in the U.S. cement industry mainly due to industry concerns regarding potential problems caused by high-dust levels and catalyst deactivation by high sulfur trioxide (SO3) concentrations from pyritic sulfur found in the raw materials used by U.S. cement plants. The SO3 could react with calcium oxide in the flue gas to form calcium sulfate and with ammonia to form ammonium bisulfate. The calcium sulfate could deactivate the catalyst, while the ammonium bisulfate could cause catalyst plugging. There have been concerns expressed about the potential for catalyst poisoning by sodium, potassium, and arsenic trioxide. Finally, other concerns expressed are that dioxins and furans may form in the SCR due to combustion gases remaining at temperatures between 450 degrees Fahrenheit (°F) and 750°F. These and other concerns regarding the implementation of SCR to the cement industry are discussed in detail in "Alternative Control Techniques Document Update – NO_x Emissions from New Cement Kilns". Due to the small number of SCRs installed at cement plants, information on capital and operating costs for SCRs at cement plants is limited. The installation and operating costs for the SCR installed at the U.S. plant in 2013 are not publicly available at this time. In general, we expect the capital and operating costs would be higher than for low-dust applications due to the need to install catalyst cleaning equipment for SCR systems installed in high-dust configurations and for heating the flue gas in low-dust, tail-end configurations.*

Mercury Oxidation

UTAC raises mercury oxidation as a potential concern saying:

> *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.*

NPS review finds that UTAC emitted 190 pounds of mercury in 2017, which ranked 49th highest in the US (2017 NEI). A co-benefit of SCR is its ability to oxidize elemental mercury to a form that is more-easily captured in follow-on controls. The NPS recommends that UTAC focus on the potential opportunity to reduce all forms of mercury emissions. Continued dispersion of mercury emissions over a wide area is a significant and ongoing concern for current controls.

Indurating Furnace Exhaust Dust

UTAC expressed concerns that constituents in the indurating furnace exhaust gas stream could adversely affect the SCR catalyst and increase adverse pollutant introduction to the exhaust stream. However, tail end SCR, being evaluated in this case, is exposed to much lower concentrations of particulates and SO_2 than conventional SCR on a coal-fired boiler, for example.

The NPS appreciates that UTAC evaluated three SO_2 control scenarios that included enhanced particulate controls.

The advantages of tail-end SCR are described by the CCM:

> *An SCR reactor located downstream of the air heater, particulate control devices, and flue gas desulfurization (FGD) system ("low-dust" or "tail-end" configuration) is essentially dust- and sulfur-free but its temperature is generally below the acceptable range.*
>
> *A tail-end system may have higher capital and operating costs than the other SCR systems because of the additional equipment and operational costs associated with flue gas reheating and heat recovery. However, these costs are in part offset by reductions in catalyst costs. Tail-end units require less catalyst because they can use catalysts with smaller pitch and higher surface area per unit volume. Tail-end SCR typically require only 2 layers of catalyst, although some use four half-layers of catalyst to allow for greater flexibility for catalyst replacement. In addition, because there is less fly ash, catalyst poisons, and SO_2 in the flue gas for tail-end units, the catalyst lifetime is significantly increased, and less expensive catalyst may be used. Some sources have reported catalyst lifetimes for tail-end SCRs to be over 100,000 hours. The tail-end SCRs may also have longer lifetimes due to the lower operating temperatures and lower levels of dust and SO3.*

Addition of SCR with reheat in a tail-end configuration at UTAC would mitigate the concerns about catalyst fouling, poisoning, and degradation. Consequently, NPS analyses assumed tail-end SCR life of 25 years and catalyst life of 24,000 hours (the upper ends of the ranges recommended by the CCM for SCR on industrial boilers). Considering the almost 5,000 tons of particulate emitted by UTAC annually, the NPS recommends an integrated approach (as evaluated by UTAC and discussed in the SO_2 control section below) to reducing particulate, SO_2 and NO_x.

Statutory Factor 1: Cost of Compliance

NPS review finds that UTAC has overestimated the capital costs by overestimating the system heat input. Instead, NPS calculations included a 70%-efficient heat exchanger to reduce natural gas reheat requirements. Not only did this reduce operating costs dramatically, but the reduced system heat input also resulted in the much lower SCR capital costs.

UTAC also overestimated capital recovery costs (and thus, operating costs) by overestimating the interest rate and underestimating equipment life. (The CCM recommends use of the current

(June 2022 = 4.75%) prime interest rate and 20–25 years for industrial boiler application.) NPS analyses used the upper end of the CCM equipment life estimate (25 years) due to the relatively “clean” tail-end location.

The NPS evaluated the addition of SCR with reheat by making the following adjustments to the workbooks provided by UTAC:

- Natural Gas = \$6.69/scf (June 23, 2022 Henry Hub) (UTAC used \$4.98/scf)
- Urea 50% Solution = \$2.37/gal (we assumed urea = \$1000/ton) (UTAC used \$1.81/gal)
- Estimated operating life of the catalyst ($H_{catalyst}$) = 24,000 hr (We used the upper end of the CCM catalyst life estimate (24,000 hours) due to the relative “clean” tail-end location.) (UTAC assumed 8,000 hours which is less than the 20,000-hour lower end of the CCM range.)
- Catalyst cost ($CC_{replace}$) = \$227/cf (CCM default) (UTAC used \$248.05 based on inflating the CCM value. Instead, UTAC should use an actual, site-specific current value.)
- Interest Rate = 4.75% (current prime) (UTAC applied a 5.5% interest rate)
- Markup on capital cost (Retrofit Factor) = 0% due to lack of justification/documentation (UTAC applied a 1.6 retrofit factor which exceeds the maximum value (1.5) A retrofit factor greater than the CCM default value of 1.0 (which represents a 25% increase over a “greenfield” application) was not justified. The CCM advises that:
    - 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. According to the CCM, “You must document why a retrofit factor of “__" is appropriate for the proposed project": UTAC has not done so.
- Equipment Life = 25 years (CCM for tail-end application) We used the upper end of the CCM equipment life estimate (25 years) due to the relative “clean” tail-end location. (UTAC used 20 years, the lower end of the CCM range.)
- SCR Control Efficiency = 90% due to clean, tail-end location with gas stream heated to CCM 650^{o}F default. (UTAC used 50% based upon a 2006 report on SCR applied to cement kilns in a high-dust configuration.)
- The Chemical Engineering Plant Cost Index (CEPCI) for 2021 was 776.3 (UTAC applied the 2019 value = 607.5)

NPS analyses based SCR “Data Inputs” on the following:

- What is the maximum heat input rate (QB)?
    - In addition to the heat input (190 mmBtu/hr for Line 1 and 400 mmBtu/hr for Line 2) from the induration furnace burners, the heat input from the duct burners that would be added to reheat the gas stream exiting the existing wet scrubbers (at 140^{o}F for Line 1 and 136^{o}F for Line 2) was included. NPS applied the Auxiliary Fuel Use Equation 2.21 from CCM 7th Ed November 2017 - Chapter 2 Incinerators and Oxidizers and

estimated the additional duct burner heat input required to raise the SCR inlet temperature to 650°F (the CCM default value). Addition of a 70% efficient heat exchanger to reduce natural gas use was assumed. An additional 1,771 scfm gas is estimated as necessary to reheat Line 1 and 3,587 scfm for Line 2. The induration furnace + reheat total heat input rate is estimated to = 400 mmBtu/hr for Line 1 and 622 mmBtu/hr for Line 2. These heat input rates are critical parameters in estimating the capital costs of the SCR systems.

  - UTAC did not include a heat exchanger.
  - UTAC also assumed that the SCR inlet temperature should be raised to 800°F instead of the 650°F CCM default or 730°F optimum temperature; these assumptions raised natural gas use and costs unnecessarily.
  - UTAC's assumptions resulted in a more than three-fold increase in natural gas use compared to our estimates.
  - The resulting higher natural gas requirement led to UTAC estimates for heat input rate = 2,197 mmBtu/hr for Line 1 and 4,555 mmBtu/hr for Line 2. SCR capital costs for natural gas-fired industrial applications are directly proportional to the heat input rate. As a result of UTAC's overestimates for this parameter, its capital costs are overestimated by an additional 5–7 times.
- Inlet NO_x Emissions (NO_{xin}) to SCR:
  - NPS assumed that the duct burner would emit NO_x @ 0.1 lb/mmBtu based upon Alternative Control Techniques Document—NO Emissions from Stationary Gas Turbines, U. S. EPA 1/1/1993. The duct burner NO_x emissions were added to the induration furnace NO_x emissions and divided by sums of their heat inputs to estimate the uncontrolled NO_x emission rate = 1.20 lb/mmBtu for Line 1 and 0.91 lb/mmBtu for Line 2.
  - UTAC estimated uncontrolled NO_x emission rate = 0.16 lb/mmBtu for Line 1 and 0.11 lb/mmBtu for Line 2.
- What is the estimated actual annual fuel consumption?
  - NPS adjusted the heat input to yield the uncontrolled NO_x emissions estimated as described above.
  - UTAC appears to have used a similar method to estimate the same annual uncontrolled NO_x emissions.

Reheat costs were estimated as follows:

- CCM Table 2.10: Capital Cost Factors for Thermal and Catalytic oxidizers with Eqn. 2.34
- CCM Table 2.12: Annual Costs for Thermal and Catalytic oxidizers assumed a 19.0" H_2O pressure drop across the heat exchanger per CCM Table 2.13. This added $0.8 million and $1.8 million in annual electricity costs to Lines 1 and 2, respectively.

The table below shows the cost elements of adding SCR with reheat to each line.

Table 18. NPS estimated SCR + Reheat costs for UTAC Line 1 & 2 compared to UTAC estimates

SCR + Reheat	UTAC Line 1		UTAC Line 2	
	NPS	UTAC	NPS	UTAC
Capacity (mmBtu/hr)	300	2,197	622	4,455
Retrofit factor	1	1.6	1	1.6
CEPCI	776.3	607.5	776.3	607.5
Capital Cost	$ 11,090,596	$ 43,637,895	$ 16,814,162	$ 72,550,865
Interest rate (%)	4.75	5.50	4.75	5.5
Control Equipment Life (yr)	25	20	25	20
Capital Recovery Cost	$ 790,262	$ 3,652,470	$ 1,190,691	$ 5,500,301
Reheat Indirect Annual Cost	$ 191,475	$ 90,349	228,086	$ 106,540
Indirect Cost/Fixed O&M	$ 955,922	$ 3,772,408	$ 1,381,633	$ 6,182,554
Total System Capacity Factor	0.869	0.956	0.788	0.956
Reheat Direct Annual Cost	$ 6,042,497	$ 15,468,890	$ 13,435,906	$ 31,434,467
Catalyst Life (hr)	24,000	8,000	24,000	8,000
Catalyst Replacement Cost	$ 60,184	$ 763,512	$ 115,638	$ 1,523,872
Direct Cost/Variable O&M	$ 7,046,581	$ 17,578,490	$ 14,939,577	$ 35,153,534
Total Annual Cost	$ 8,002,503	$ 21,350,897	$ 16,321,210	$ 41,336,088
Uncontrolled NO_x Emissions (Tons/yr)	1325	1325	1874	1874
Uncontrolled NO_x Emission Rate (lb/mmbtu)	1.83	0.16	1.22	0.11
NO_x Removal Efficiency (%)	90	50	90	50
Controlled NO_x Emission Rate (lb/mmbtu)	0.12	0.08	0.09	0.06
Tons Remaining	137	663	193	937
Tons Removed	1,188	663	1681	937
Cost-Effectiveness	$ 6,736	$ 32,228	$ 9,712	$ 44,115

A major factor in the difference between NPS estimates and those provided by UTAC is the addition of a 70% efficient heat exchanger to reduce natural gas consumption. This relatively small additional capital investment (Reheat Indirect Annual Cost) dramatically reduces natural gas consumption (Reheat Direct Annual Cost) and the capital cost of the SCR. The lower capital recovery cost and the lower operating costs result in much lower annual operating costs. Coupled with higher SCR control efficiency, the result is cost-effectiveness of $7,000–$10,000/ton.

Statutory Factor 2: Time Necessary for Compliance

According to UTAC 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.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

Energy usage is most appropriately accounted for in the Cost of Compliance analysis. The other non-air quality environmental impacts cited are not unique to this site.

Statutory Factor 4: Remaining Useful Life

The CCM recommends a useful life of 20–25 years for SCR on industrial boilers.

6.2.4 SO_2 Four-factor Analysis

Control Selection & Efficiency

EPA's February 2013 BART determinations are now out-of-date and should be revisited for PM and SO_2 in addition to NO_x. UTAQ included analyses of strategies to reduce SO_2 emissions from Line 2:

Dry Sorbent Injection (DSI) – With New PM Control

While DSI has not been demonstrated at an operating taconite indurating furnace, DSI could conceptually be utilized if UTAC were to replace its existing PM controls (wet scrubbers) with controls that are compatible with DSI (e.g., baghouse or electrostatic precipitator (ESP)). Indurating furnace waste gas streams are high in water content and are exhausted at or near dew points. Gases leaving the indurating furnace are currently treated for removal of particulate matter using a wet scrubber. The exhaust temperature is typically in the range of 100°F to 150°F and is saturated with water. For comparison, a utility boiler exhaust operates at 350°F or higher and is not saturated with water. The indurating furnace waste gas conditions following the existing wet scrubber would plug both the filters and the dust removal system. Therefore, the proposed control train would need to replace the existing wet scrubber with DSI and new PM control. With the removal of the existing wet scrubber and addition of new PM control after the DSI, the DSI control technology is assumed to be potentially technically feasible for Line 2 Indurating Furnace.

The DSI evaluation conclusions vary in past SO_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.

Spray Dry Absorption (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.

Gas Suspension Absorption (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.

Statutory Factor 1: Cost of Compliance

According to UTSC: 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, 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 UTAC Table 6-2.

Table 19. UTAC 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

NPS review finds several areas in which the UTAC cost analyses deviates from CCM recommended methods:

- 5.5% interest rate instead of 4.75% (June 24, 2022 prime)
- 20-year life instead of 30 years recommended by the CCM
- 50% SO_2 control efficiency instead of 95% for SDA (CCM) or GSA

Statutory Factor 2: Time Necessary for Compliance

According to UTAC: 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.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

Energy usage and costs associated with solid waste handling and disposal are most appropriately accounted for in the Cost of Compliance analysis.

Statutory Factor 4: Remaining Useful Life

The CCM recommends 30 years for scrubber life.

6.2.5 PM Four Factor Analysis

Particulate emission reductions were not considered.

UTAC states that the existing wet scrubbers are 94% effective at reducing PM. NPS calculations based upon Appendix B of UTAC’s four factor estimate that Line 1 PM emissions are almost 1,500 tpy and Line 2 PM emissions exceed 3,400 tpy. (MPCA indicates that Line 2 emitted 94 tons of $PM_{2.5}$ in 2017.)

According to the CCM, modern fabric filter baghouses and ESPs can remove at least 99.9% of particulate matter. Compared to the existing PM controls, a new baghouse or ESP could reduce annual PM emissions from Line 1 by 1,472 tons and Line 2 by 3,347 tons. Considering UTAC's costs for the GSA system at face value, the cost-effectiveness of reducing PM and (108 tons/year) SO_2 (combined) is less than $5,500/ton. It would be even more cost effective if the GSA calculations were adjusted to meet CCM guidelines. When combined with tail-end SCR, PM, SO_2 and NO_x emissions could be reduced by almost 2,700 tons from Line 1. Likewise, an integrated approach to Line 2 emissions could yield combined emission reductions of 5,200 tons/yr at a cost of $33 million/yr for a cost-effectiveness value of $6,400/ton.

6.2.6 NPS Conclusions and Recommendations United Taconite LLC–Fairlane Plant

NPS review finds that NO_x, SO_2, and PM emissions from UTAC's Lines #1 & #2 are not effectively-controlled. For example, tail-end SCR could reduce NO_x emissions by almost 3,000 tons/yr for $7,000–$10,000/ton.

UTAC also evaluated replacing the existing wet scrubber on Line 2 with a modern SO_2 scrubber and fabric filter or ESP. Although tail-end SCR with reheat may be technically-feasible when installed after the existing wet scrubbers, an integrated approach that precedes it with dry scrubbing and a fabric filter would minimize catalyst fouling (improving the technical feasibility of SCR) while drastically reducing PM emissions as well as reducing SO_2 emissions. The table below illustrates how such an integrated approach could reduce visibility-impairing emissions by thousands of tons per year in a cost-effective manner.

Table 20. NPS control cost estimates for an integrated approach to UTAC emissions

	Line 1	**Line 2**
Total Annual Cost (GSA+ESP+FF+SCR)	?	$ 33,073,605
Tons NO_x Removed	1,188	1,681
Tons PM removed	1,472	3,347
Tons SO_2 Removed	16	145
Total Tons Removed	2,677	5,172
Cost-Effectiveness ($/ton)	?	$ 6,395

**UTAC's annual cost estimate for GSA with new PM controls is likely inflated but was taken at face value for this table.*

The NPS recommends that MPCA explore this opportunity to substantively address the haze causing emissions from UTAC and other Taconite facilities in Minnesota through the regional haze process.

USDA United States Department of Agriculture | Forest Service | Superior National Forest Supervisor's Office | 8901 Grand Avenue Place
Duluth, MN 55808
218-626-4300

File Code: 2580
Date: July 11, 2022

Craig McDonnell
Assistant Commissioner for Air and Climate Policy
Minnesota Pollution Control Agency
520 Lafayette Road N
ST. Paul, MN 55155-4194

Dear Mr. McDonnell:

On May 11, 2022, the State of Minnesota submitted a draft Regional Haze State Implementation Plan describing your proposal to continue improving air quality by reducing regional haze impacts at mandatory Class I areas across our region. We appreciate the opportunity to work closely with your state through the initial evaluation, development, and now subsequent review of this plan. Cooperative efforts such as these ensure that together we will continue to make progress toward the Clean Air Act's goal of natural visibility conditions at our Class I areas. We are especially grateful for your sustained, continuous efforts to communicate with us and solicit our input over the past four years.
This letter acknowledges that the U.S. Department of Agriculture, U.S. Forest Service, has received and conducted a substantive review of your proposed Regional Haze State Implementation Plan. This review satisfies your requirements under the federal regulations 40 C.F.R. § 51.308(i)(2). Please note, however, that only the U.S. Environmental Protection Agency (EPA) can make a final determination about the document's completeness, and therefore, only the EPA has the ability to approve the document.
We have attached comments to this letter based on our review. While we have some technical issues we will bring to your attention, we want to recognize the overall high quality of your draft plan. We look forward to your response required by 40 C.F.R. § 51.308(i)(3). For further information, please contact Trent Wickman at trent.wickman@usda.gov or (218) 341-8646.

Again, we appreciate the opportunity to work closely with the State of Minnesota. The Forest Service compliments you on your hard work and dedication to significant improvement in our nation's air quality values and visibility.

Sincerely,

Constance Cummins

CONSTANCE CUMMINS
Forest Supervisor

cc: Hassan Bouchareb, Melanie Peters, Don Shepherd, Dave Pohlman, Tim Allen, Alisa Liu

Minnesota Regional Haze Plan - Technical Comments

Overall, the plan is very comprehensive and well organized. It is logically sequenced and very well explained. We specifically appreciate the attention to detail in the adjustments made to the emission inventory for some sources that had atypical emissions in 2016. We recognize the significant emission reductions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) that have been made, and those still to come in the near future, due to economic and regulatory drivers.

Air Quality Setting

The plan does a very good job of characterizing the sources of visibility impairment in the Boundary Waters Canoe Area Wilderness (BWCAW).

Ammonium sulfates and nitrates accounted for roughly 68% of the total visibility impairment in the initial baseline year (2004) and 59% in the initial projection year (2018) in the BWCAW. The main states whose emissions contribute to visibility impairment in the BWCAW and Voyageurs National Park (Voyagers) are Minnesota, North Dakota, Iowa, Nebraska, Wisconsin and Missouri.

Most air pollutant emissions have been trending down over the last 20 years as a result of emission controls/reductions for NOx and SO_2 emissions from power plants, industrial facilities, and motor vehicles. The plan includes air emissions data through 2020 that indicates Minnesota has reduced emissions of NOx by 71% and SO_2 by 89% since 2002. This has directly led to measured improvements in visibility impairment attributed to reductions in ammonium sulfate, and to a lesser extent ammonium nitrate at the BWCAW.

Based on knowledge gained from the first implementation period, along with that learned from current visibility trends, for the next implementation period you conclude:

- Minnesota will continue to be the largest contributor to visibility impairment at the BWCAW and Voyageurs.
- NOx controls will be needed, with observed data trends increasingly showing ammonium nitrate dominating most impaired visibility days.
- The BWCAW and Voyageurs may not benefit as much from control measures in States located to the East and Southeast due to prevailing winds from the West and Northwest during periods of high ammonium nitrate production.

We note that the 2028 visibility projections in the plan are equal (in the case of the BWCAW) or higher (for Voyagers) than current conditions. This would seemingly indicate that no progress will be made in improving visibility over the next 10 years, which would normally be a cause for concern. However, the plan notes several future emission reduction projects that are not captured in the outyear modeling that will lead to clearer skies than predicted.

Source Selection

We are pleased with the number of sources selected for a four-factor analysis, 17 facilities with a total of 44 emission units, which represents 80-85% of the cumulative emission over distance (Q/d) values for each Class I area. In this process you also considered specific suggestions by the Federal Land Managers (FLMs).

Unit Shutdowns

Further screening of these sources revealed that 12 emission units at 6 facilities are scheduled for economic shutdowns. We appreciate that you ensured that all of these shutdowns are associated with enforceable documents.

- As mentioned previously, we are very interested in the Administrative Order (AO) associated with the idling of the two power boilers at Northshore Mining. We have not seen the language in this agreement and are particularly interested in sections associated with a possible restart. To comply with the Regional Haze Rule we feel that prior to any restart, the installation of the emission controls identified in the plan for these boilers (see subsequent section of this letter) should be installed. We are concerned that under the terms of the AO the facility may submit an alternate operating scenario at a reduced capacity and use it to recalculate an artificially elevated cost effectiveness value of controls and thereby circumvent reasonable progress requirements. The cost effectiveness of controls has been determined to be reasonable in this SIP and does not need to be recalculated.
- Also, we feel it is important that any future change in the AO needs to go thru public notice and comment. We have seen AOs in the past contain a requirement to submit analyses/plans/reports for State review and this turns into an unending cycle of submit, review, repeat – all outside of FLM and public review and comment. This path could serve to delay the application of Regional Haze requirements and even potentially avoid them entirely depending on the ultimate decision of your agency at some future time.

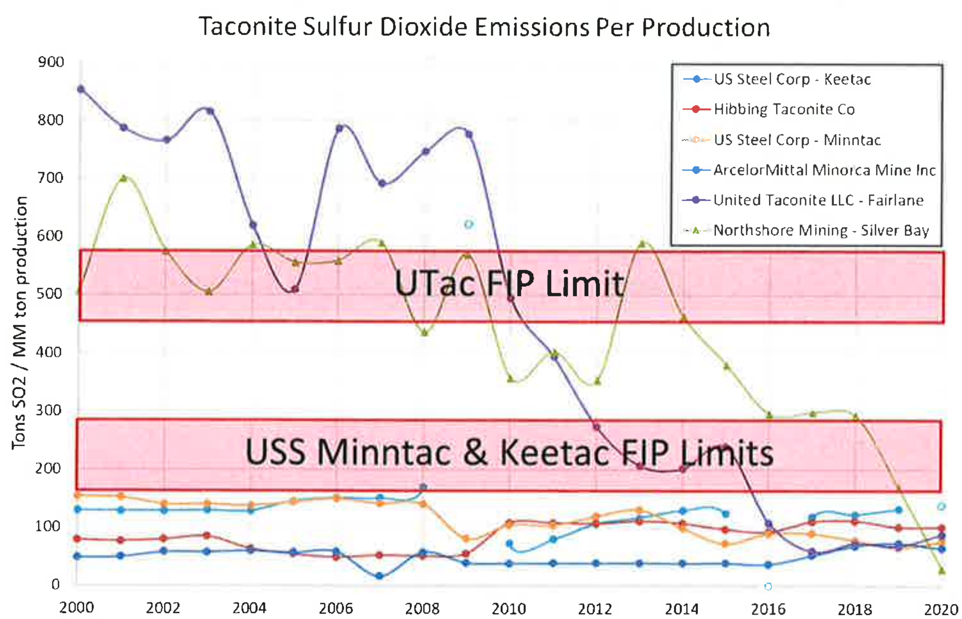
Effective Controls

Another group of the remaining emission units (19 emission units at nine facilities) were removed from consideration because they were determined to be effectively controlled. One group of these, the taconite plants, deserve further comment.

- Over the last few years the taconite plants have installed and begun operating low-NOx burners in their furnaces. These were required in the first round under the Best Available Retrofit Technology, Federal Implementation Plan (FIP). Table 42 of your draft plan indicates what level of performance you are expecting from these controls (33 to 73 percent reduction depending on the line).

- We remain concerned that multiple petitions for review of the FIP are still pending, and settlement discussions are ongoing between EPA and the taconite companies (as you outline on pages 4 through 6, and 92 through 93 of the plan). In the past these discussions have led to a relaxation of emission limits. The State and the FLMs have been excluded in these discussions. While we have been given an opportunity to comment during public notice when the final changes are proposed, it is not as productive as early consultation during their development. From our point of view, revising the FIP through the courts avoids the Regional Haze Rule requirement pertaining to FLM involvement. While we recognize that this letter is addressed to you, we nonetheless raise this issue here since EPA will also be subsequently reviewing your plan and our comments.
- It is unclear to us whether the current FIP NOx limits reflect the level of performance assumed in Table 42. Please include the furnace-specific FIP limits for both NOx and SO_2 in this plan and compare them to recent, measured emissions data.

- We reviewed the current level of SO_2 emissions from those plants that can burn high sulfur fuels (i.e. US Steel Minntac, Keetac and United Taconite) and compared them to the FIP limits. It appears that United Taconite has been operating well below their limit since 2010. We suggest revising their FIP limit down to at least the level of the US Steel facilities.



NOTE: Emissions from Northshore are primarily a combination of the taconite furnaces and coal-fired power boilers. The plant was transitioning away from self-generation of electricity from 2016 - 2019. In 2020 Minnesota Power began providing electricity to the plant.
NOTE2: Utac FIP limits for SO2 began in 2017.

- Regarding the general issue of air emission controls on the taconite plants furnaces, we believe a multipollutant perspective should be taken. This industry is the largest mercury emitter in the state. They also have issues with elevated concentrations of sulfate in their tailings basins that are exacerbated by the existing wet controls on their furnaces. In the permit for its expansion at Keetac several years ago, US Steel proposed dry furnace controls. This remains the best option to address the multiple issues associated with air emissions from the taconite furnaces. The addition of these controls would lead to much larger reductions in NOx, SO_2, and particulate matter and facilitate carbon injection for mercury control.

Four Factor Analyses

This leaves the following emission units for four-factor analyses which represent industrial boilers at three industries: beet sugar plants, paper mills, and utilities.

- American Crystal Sugar – Crookston: Boilers 1-3
- American Crystal Sugar – East Grand Forks: Boilers 1 and 2
- So. Minn. Beet Sugar: Boiler 1
- Boise White Paper: Boiler 1
- Sappi Cloquet: Boiler 9
- Hibbing PUC: Boilers 1A, 2A, 3A and wood
- Virginia PUC: Boilers 7 and 11 (*we note the shutdown notification received by the MPCA in April of 2022 and look forward to seeing that put into an enforceable agreement)*
- Northshore Mining Boilers 1 and 2

The plan establishes a $10,000 per ton initial screening threshold. Based on this figure and cost calculations provided by both you and the National Park Service, controls exist at a cost below this threshold for the following:

- Beet Sugar Industry
  - American Crystal Sugar – Crookston: Boilers 1-3
    - Dry sorbent injection (DSI) for SO_2
  - American Crystal Sugar – East Grand Forks: Boilers 1 and 2
    - DSI for SO_2 and selective catalytic reduction (SCR) for NOx
  - So. Minn. Beet Sugar: Boiler 1
    - DSI or spray dryer absorber (SDA) for SO_2 and SCR for NOx
    - Please explain the following statement from the plan since you are the regulator, "The MPCA maintains that the NOx controls are cost-effective and necessary to continue making reasonable progress, but the MPCA has not reached an agreed path forward with the facility to install the NOx controls."
- Paper Mills
  - We are attaching to this letter a survey of pollution controls and permit limits we did in early 2020 of all non-recovery boilers at paper mills across the states of Minnesota, Wisconsin, and Michigan. It consists of approximately 86 boilers of various firing configurations. In it are examples of boilers operating:

        - SO_2 - There are around 25 boilers that have the capability to burn coal. Of these, about half have post-combustion controls (usually DSI, although some of these don't have updated permit limits to reflect the level of performance of the controls). The others without SO_2 controls can also install DSI or take a permit limit on coal use if they burn limited amounts.
        - NOx - Combustion controls and/or selective non-catalytic reduction (SNCR) are widely applied across the industry. There were 11 examples of SNCR installed.
    - Boise White Paper: Boiler 1
        - SNCR for NOx
    - Sappi Cloquet: Boiler 9
        - Since SNCR and SCR costs are similar, we recommend SCR for NOx since it achieves greater removal.
- Hibbing PUC: Boilers 1A, 2A, 3A
    - SNCR for NOx
- Northshore Mining Boilers 1 and 2
    - SCR for NOx and DSI for SO_2 on Boiler 1; SCR plus low-NOx burners and overfire air on Boiler 2 (per discussion above, applies at initial startup if the boilers are restarted in the future).

Notes of Appreciation

We thank you for:

- The maintenance of the NE Minnesota Plan and the establishment of new emission reduction goals to manage emissions from new or modified sources.
- Following both EPA's 2019 guidance and 2021 Clarification Memo.
- Not using the fact that Minnesota's two Class I Areas are below the uniform rate of progress as a safe harbor, as other states have done.
- Not using visibility as a fifth factor to nullify the four statutory factors.
- Supporting significant in-house technical analysis in the areas of modeling and web development

Wildland Fire Smoke

Ecosystems, forests, and grasslands that exist in BWCAW today are remnants of pre-settlement systems that were created and maintained in many cases by Native American burning. The last 100 years of fire suppression and relatively smokeless skies are not indicative of the level of fire that created and maintained the Forests of the BWCAW. Recent scholarship has shown that; 1) fires were more prevalent than previously thought (Kipfmueller, 2017) and 2) Native Americans played a key role by using fire as a land management tool for centuries pre-settlement (Kipfmueller, 2021; Larson, 2020). Being that the national goal of Regional Haze program is "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution," smoke from burning at the intensity that Native Americans historically did would appear to be "manmade" and therefore subject to reduction. As we continue to manage and use fire in and around the BWCAW for ecosystem benefit and to prevent catastrophic wildfires, occasional low intensity smoke impacts in the Class I area are inevitable. We will continue to work with you to understand the effects these smoke impacts may have on IMPROVE Regional Haze Tracking Progress metrics and to determine if/when it may become necessary to adjust the 2064 glide path endpoints to account for these impacts. It is our suggestion that future implementation periods continue to focus primarily on control of sulfates and nitrates.

Etc

- On Page 44 – the most recent revision of the state Smoke Management Plan is dated April 2021
- Please add a bar that reflects the predicted 2028 emissions (taking into consideration all the known changes as reflected in Table 42) to Figure 10
- Table 42 – please include totals for the entire table for SO_2 and NOx, with subtotals for just the NE Minnesota sources.
- The sugar beet and paper industries also exist in the states neighboring Minnesota. We encourage EPA to maintain fairness across the region when they review facilities in these industries in the SIPs for North Dakota, Wisconsin, and Michigan.

References

Kipfmueller, Kurt F., Evan R. Larson, Lane B. Johnson, and Elizabeth A. Schneider. "Human Augmentation of Historical Red Pine Fire Regimes in the Boundary Waters Canoe Area Wilderness." *Ecosphere* 12, no. 7 (July 2021). https://doi.org/10.1002/ecs2.3673.

Kipfmueller, Kurt F., Elizabeth A. Schneider, Scott A. Weyenberg, and Lane B. Johnson. "Historical Drivers of a Frequent Fire Regime in the Red Pine Forests of Voyageurs National Park, MN, USA." *Forest Ecology and Management* 405 (December 2017): 31–43. https://doi.org/10.1016/j.foreco.2017.09.014.

Larson, Evan R., Kurt F. Kipfmueller, and Lane B. Johnson. 2020. "People, Fire, and Pine: Linking Human Agency and Landscape in the Boundary Waters Canoe Area Wilderness and Beyond." *Annals of the American Association of Geographers*, June, 1–25. https://doi.org/10.1080/24694452.2020.1768042.