Appendix A – Department Four-Factor Analyses

A.1 – Coyote Station

1 Introduction and Representative Operations

Otter Tail Power Company – Coyote Station (Coyote) is a single unit electrical generating utility (EGU) with a capacity to produce approximately 450 megawatts (MW) per hour of electricity. The boiler is a Babcock and Wilcox cyclone fired boiler with a heat input capacity of 5,800 million British thermal units (MMBtu) per hour. Coyote commenced operation in 1981. Coyote is located in Mercer County about three miles southwest of the town of Beulah, North Dakota. Coyote is a mine-mouth power plant which receives coal from North American Coal Company – Coyote Creek Mine.

The average annual amount of North Dakota lignite coal combusted at Coyote from 2009 through 2018 was 2.2 million tons. See Table 1 for detailed information.

Table 1: Yearly Coal Combusted (tons)

Year	Coal Combusted (tons)
2009	2,032,400
2010	2,445,773
2011	2,444,280
2012	1,824,595
2013	2,105,090
2014	2,248,483
2015	1,959,351
2016	2,011,974
2017	2,154,856
2018	2,501,698
Average	**2,172,850**

Over the same 10-year period (2009–2018), Coyote operated at a 60% annual capacity factor (ACF), as determined on an actual heat input basis. Future operations are expected to be consistent with this 10-year period and the 60% annual capacity factor was used when calculating the baseline and future projected emissions discussed in Section 2.

Table 2 displays the operational information from 2009–2018. The ACF is calculated by dividing the actual heat input by the maximum potential heat input of 50.8×10^{6} MMBtu per year.

Table 2: Utilization and Annual Capacity Factor

Year	Actual Heat Input (MMBtu/yr)	Annual Capacity Factor (ACF)
2009	28,835,063	0.57
2010	35,201,254	0.69
2011	35,579,248	0.70
2012	27,008,173	0.53
2013	31,206,229	0.61
2014	32,197,996	0.63

Year	Actual Heat Input (MMBtu/yr)	Annual Capacity Factor (ACF)
2015	22,757,213	0.45
2016	27,102,662	0.53
2017	29,849,117	0.59
2018	34,550,493	0.68
Average	**30,428,745**	**0.60**

2 NO_X and SO_2 Emissions Controls and History

Coyote commenced operation in 1981. Coyote was not a BART eligible source since construction of the facility commenced after the August 7, 1977 end date for facilities in existence. Coyote was, however, subject to the reasonable progress requirements during the first round of the regional haze program.

2.1 NOx

2.1.1 NO_X Emissions Controls

Coyote's cyclone boiler is equipped with separated overfire air (SOFA) to reduce the formation of NO_X during the combustion process. The Department reached an agreement with Coyote for the installation of SOFA during the first planning period of the regional haze program. Under Permit to Construct No. PTC10008, Coyote was required to install SOFA by July 1, 2018 and meet an emissions limit of 0.50 pounds NO_X per MMBtu on a 30-day rolling average. This construction permit was incorporated as Appendix A.4 to the July 2011 Amendment No. 1 to the North Dakota State Implementation Plan for Regional Haze. On June 15, 2016 Coyote commenced start-up of the SOFA system to comply with the requirements of Permit to Construct No. PTC10008. No add-on NO_X controls have been installed at Coyote.

2.1.2 NO_X Emissions History

The time period from July 2016 through December 2018 was used to determine the NOx baseline emissions rate from Coyote. This information is displayed in Table 3.

Table 3: Annual NO_X emissions rate

Year	Emissions Rate (lb/MMBtu)
2016	0.50
2017	0.42
2018	0.45
Average	**0.46**

The average emissions rate of 0.46 lb NO_X per MMBtu is representative of future expected operations. This value is used as the starting point when determining the cost of compliance for the add-on controls evaluated in Section 3.2.

2.2 SO_2

2.2.1 SO_2 Emissions Controls

Coyote is equipped with dry flue gas desulfurization (DFGD) and a fabric filter (FF) baghouse for SO_2 and particulate matter control. The DFGD and FF baghouse were installed during the construction of the facility and have not been significantly modified since. Coyote was not required to install any SO_2 controls during the first round of the regional haze program.

2.2.2 SO_2 Emissions History

The time period from January 2013 through December 2018 was used to determine the SO_2 baseline emissions rate from Coyote. 2015 was removed from the baseline period since Coyote experienced operational issues in 2015 and this year was not considered representative of normal operations.[1] This information is displayed in Table 4.

Table 4: Annual SO_2 emissions rate

Year	Emissions Rate (lb/MMBtu)
2013	0.81
2014	0.79
2015[A]	0.77
2016	0.88
2017	0.90
2018	0.86
Average	**0.85**

[A] Not included in average.

3 NOx Analysis

3.1 NO_X Technologies

The reasonable progress controls evaluated by Coyote are listed in Table 5. Performance rate and expected annual emissions are included for each control technology that was determined to be technically feasible. Expected annual emissions were calculated using the performance rate, potential heat input, and the ACF (Table 2).

Table 5: Reasonable Progress NO_X Controls

Control Technology	Control Technology Abbreviation	Performance Rate (lb/MMBtu)	Emissions (tons/year)
Separated Overfire Air (baseline)	SOFA	0.46	7,015
Combustion Optimization	--	0.42	6,405
Selective Non-Catalytic Reduction	SNCR	0.28	4,270
SNCR + Rich Reagent Injection	SNCR + RRI	0.20	3,050
Selective Catalytic Reduction	SCR	--	--

[1] Appendix B.1.b, p. 4-1. PDF page 33.

3.1.1 Combustion Optimization

Optimization of the combustion process through tuning the cyclone boiler has a small beneficial impact on reducing the formation of NO_X emissions. Tuning the boiler can lower the baseline performance rate from 0.46 to 0.42 lb NO_X per MMBtu, reducing the NO_X emission by approximately 9%. There is no cost associated with this technology since tuning the boiler primarily deals with optimization of the air-to-fuel ratio into the boiler. Combustion optimization would occur prior to the installation of any add-on controls.

3.1.2 Selective Non-Catalytic Reduction (SNCR)

Installation of SNCR post combustion add-on control equipment has a significant impact on removing NO_X emissions from the flue gas. SNCR is anticipated to provide approximately a 39% reduction in NO_X emissions from the baseline scenario, lowering the expected performance rate from 0.46 to 0.28 lb NO_X per MMBtu. Installation of SNCR on Coyote's cyclone boiler is technically feasible and will be evaluated further.

3.1.3 Rich Reagent Injection (RRI)

RRI is a technology similar to SNCR, where a nitrogen-containing additive is injected to promote NO_X removal. The main differences are RRI is physically located in the lower part of the furnace near the cyclone boilers where SNCR is further downstream and RRI is done through one injection port where SNCR typically has many ports.

RRI is technically feasible at high load operations but has limitations at low loads due to the difficulty in maintaining the proper air-to-fuel ratio. RRI is typically installed after SNCR is installed for additional NO_X control. RRI is not commonly used as an individual NO_X control in lieu of SNCR since SNCR is better and more established. Therefore, RRI is evaluated as add-on control in addition to SNCR but not as a stand-alone add-on control by itself.[2]

Installation of SNCR + RRI has a significant impact on removing NO_X emissions from the flue gas. SNCR + RRI is anticipated to provide approximately a 57% reduction in NO_X emissions from the baseline scenario, lowering the expected performance from 0.46 to 0.20 lb NO_X per MMBtu. Installation of SNCR + RRI on Coyote's cyclone boiler is technically feasible and will be evaluated further.

3.1.4 Selective Catalytic Reduction (SCR)

SCR is post combustion add-on control equipment. SCR, when feasible, typically has the greatest impact on removing NO_X emissions from a flue gas stream. SCR is traditionally installed in one of three configurations: high-dust, low-dust, or tail-end. During the first regional haze program planning period in North Dakota the Department determined that installation of SCR, in any configuration, is not a technically feasible control technology since it has not been demonstrated in practice on North Dakota lignite coal.[3] The determination of technical feasibility has not changed since the first regional haze program planning period; therefore, SCR will not be evaluated further.

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[2] Appendix B.1.b, p. 5-26. PDF page 60.

[3] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.5.

3.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost for the reasonable progress controls are listed in Table 6.

Table 6: NO_X Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
SOFA (Baseline)	0.46				
SOFA Optimization	0.42	610	0	0	
SNCR + Optimization	0.28	2,745	4,753,933	1,732	
SNCR + RRI + Optimization	0.20	3,965	12,690,135	3,200	6,505

A detailed breakdown of the costs listed in Table 6 can be found in Coyote's submitted four factors analysis.[4] The Department has reviewed these costs and believes them to be accurate.

As displayed in Table 6 and stated in Section 3.1.1, there is no cost associated with optimization of the combustion process. The 0.04 lb NO_X per MMBtu improvement over the baseline performance would be required as the first step for any of the remaining technologies evaluated.

If SNCR is installed in conjunction with combustion optimization, a performance rate improvement of 0.18 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of approximately 2,750 tons NO_X per year from the baseline emissions. Fiscally, SNCR installation requires an estimated annualized cost of $4.75 million and NO_X removal cost of roughly $1,700 per ton.

The addition of RRI to SNCR and combustion optimization results in an expected performance improvement of 0.26 lb NO_X per MMBtu from the baseline performance rate. This equates to a potential reduction of approximately 3,970 tons NO_X per year from the baseline emissions. Fiscally, SNCR + RRI installation requires an estimated annualized cost of $12.7 million and NO_X removal cost of $3,200 per ton. To determine the appropriate reasonable progress control selection between SNCR and SNCR + RRI, the Department determined the stand-alone cost of installing RRI after SNCR is installed. This stand-alone cost is referred to as the incremental cost of compliance. Incremental cost of compliance is a key factor to consider when selecting reasonable progress controls since it details the cost effectiveness of RRI installation. A cost breakdown indicates approximately $8 million of the annualized cost is attributable to the installation of RRI, and results in the potential for an additional 1,220 tons of NO_X to be removed. This results in an incremental cost of compliance of roughly $6,500 per ton.

3.3 Step 2 – Time Necessary for Compliance

A summary of the anticipated timelines for the installation of controls is provided in Table 7.

[4] Appendix B.1.b, Appendix C. PDF page 102.

Table 7: Time Required for NO_X Controls

Control Technology	Total time after SIP approval (months)
SOFA Optimization	0
SNCR + Optimization	22
SNCR + RRI + Optimization	22

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy

Small changes to onsite energy consumption are likely to be experienced with the implementation of any add-on NO_X controls.[5] The impact not significant enough to eliminate add-on NO_X controls as a control option.

3.4.2 Non-Air Quality Environmental Impacts

SNCR use ammonia as a reagent. Ammonia slip emissions will result in the flue gas stream on the exhaust side of the control equipment due to the operation of the SNCR (~10 ppm). The ammonia slip emissions from the operation of SNCR would likely combine with the dry FGD solids. The ammoniated dry FGD solids would require that further safety precautions are taken for Coyote staff who perform maintenance on the ash handling system or staff who dispose of waste.

Similar to the energy impacts for add-on NO_X controls, the non-air quality environmental impacts are not significant enough to eliminate add-on NO_X controls as a control option.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, Coyote is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

4 SO_2 Analysis

4.1 SO_2 Technologies

The reasonable progress controls that were evaluated by Coyote are listed in Table 8. Performance rate and expected annual emissions are included for each control technology that was determined to be technically feasible. Expected annual emissions were calculated using the performance rate, potential heat input, and the ACF (Table 2).

Table 8: Reasonable Progress SO_2 Controls

Control Technology	Control Technology Abbreviation	Performance Rate (lb/MMBtu)	Emissions (tons/year)
Dry Flue Gas Desulfurization (baseline)	DFGD	0.85	12,963
Dry Sorbent Injection	DSI	0.58	8,845
Dry Flue Gas Desulfurization Improvements	DFGD Improvements	0.5	7,625

[5] Appendix B.1.b, p. 8-2 – 8-4. PDF page 84-86.

Control Technology	Control Technology Abbreviation	Performance Rate (lb/MMBtu)	Emissions (tons/year)
DFGD Improvements + DSI	DFGD Improvements + DSI	0.33	5,033
Absorber Replacement	--	0.09	1,373
New Dry Flue Gas Desulfurization and Fabric Filter	DFGD + FF	0.09	1,373
Wet Flue Gas Desulfurization	WFGD	0.06	915

4.1.1 Dry Sorbent Injection (DSI)

DSI is a proven technology which provides a moderate reduction of SO_2 in the flue gas stream. Sorbent is injected into the ductwork downstream of the boiler and upstream of the existing DFGD unit. Sorbent reacts with SO_2 to form particulate matter which is removed in the downstream fabric filter. DSI lowers the concentration of SO_2 entering the DFGD unit, allowing for an overall increase in SO_2 removal. Calcium- and sodium-based sorbents are the most common to reduce SO_2, each of which has pros and cons depending on the site and control equipment characteristics. The existing DFGD unit at Coyote utilizes a calcium-based system (hydrated lime); therefore, using a calcium-based sorbent is the most logical. This removes the potential for new chemical (sodium) constituents into the system which may adversely affect the existing scrubber operations.

DSI is anticipated to provide approximately a 32% reduction in SO_2 emissions from the baseline scenario, lowering the expected performance rate from 0.85 to 0.58 lb SO_2 per MMBtu. Adding DSI to the existing DFGD unit is technically feasible and will be evaluated further.

4.1.2 Flue Gas Desulfurization (FGD) Improvements

FGD Improvements are grouped into two categories, operational improvements and equipment upgrades. The operational improvements evaluated consisted of increasing the lime quality, increasing the stoichiometric ratio of calcium to sulfur (Ca:S) by increasing lime quantity, and lowering the absorber outlet temperature closer to the saturation point. The equipment upgrades consisted of atomizer replacement, slaker replacement, adding an absorber module, and replacing the existing absorber module.

For each of the operational improvements and equipment upgrades evaluated, the only technically feasible options are increasing the stoichiometric ratio of Ca:S coupled with atomizer replacement and replacing the existing absorber module. Replacing the absorber module is evaluated independent in Section 4.1.4. For complete discussion of the options determined to be technical infeasible, see Appendix B.1.b, pages 5-4 through 5-12.

For Coyote, increasing the Ca:S stoichiometry is best accomplished by increasing the quantity of fresh lime introduced into the system. Engineering testing was conducted in October of 2018 to determine the impact this type of stoichiometry adjustment could have on lowering SO_2 emissions. During the testing, it was determined that increasing the Ca:S ratio could achieve a rate as low as 0.50 lb SO_2 per MMBtu. If an increased stoichiometric ratio were to be required on a permanent basis, the existing dry scrubber atomizer nozzles would also need to be replaced from an eight nozzle design to a twelve nozzle design to achieve a more optimal slurry spray and decrease the potential for operational issues which may cause unit downtime.

Ca:S stoichiometry adjustments coupled with the atomizer replacement is anticipated to provide approximately a 41% reduction in SO_2 emissions from the baseline scenario, lowering the expected performance rate from 0.85 to 0.50 lb SO_2 per MMBtu. Increasing the Ca:S stoichiometry coupled with the atomizer replacement at the existing DFGD unit is technically feasible and will be evaluated further.

4.1.3 FGD Improvements with DSI

The technologies evaluated in Section 4.1.1 (DSI) and Section 4.1.2 (FGD Improvements) could be implemented together, resulting in a more significant overall reduction of SO_2. Implementation of FGD Improvements with DSI is anticipated to provide a 61% reduction from the baseline scenario, lowering the performance rate from 0.85 to 0.33 lb SO_2 per MMBtu. Implementation of FGD Improvements and DSI is technically feasible and will be evaluated further. It should be noted that additional flow modeling and field testing would need to be performed to ensure this performance level could be achieved and maintained without adversely affecting plant operability.

4.1.4 Absorber Replacement

Replacing the existing absorber module is technically feasible and could provide a significant improvement in reducing SO_2 emissions. Coyote originally indicated there is a no physical space for installation of a new absorber, making it an infeasible option since an approximate 12-month downtime was estimated for the replacement to occur. This inherently made an absorber replacement a less attractive control option. Since the original information was provided, Coyote submitted an analysis on June 8, 2020 indicating they could implement an absorber replacement.[6]

The absorber module replacement is anticipated to provide a 89% reduction from the baseline scenario, lowering the performance rate from 0.85 to 0.09 lb SO_2 per MMBtu. Replacement of the absorber module is technically feasible and will be evaluated further.

4.1.5 New Dry FGD (DFGD) and Fabric Filter (FF)

Two types of new DFGD systems were evaluated at Coyote, a spray dryer absorber (SDA) and a circulating dry scrubber (CDS). Each of these systems is technically feasible, commercially available, and would require significant modifications to the facility. The engineering evaluation determined the CDS would outperform the SDA at Coyote.[7] A new SDA/FF is anticipated to be able to achieve a performance rate of 0.16 lb SO_2 per MMBtu. A new CDS/FF is anticipated to be able to achieve a performance rate of 0.09 lb SO_2 per MMBtu. Given the lower performance rate with the CDS/FF system, the Department will focus the remaining analysis on the CDS/FF system. Implementation of a CDS/FF system represents an 89% reduction from the baseline scenario. Replacing the existing DFGD unit with a new CDS/FF is technically feasible. However, this option will not be evaluated further since Coyote has submitted additional information indicating an absorber replacement could

[6] Appendix B.1.b. PDF page 216

[7] Appendix B.1.b, p. 5-18. PDF page 52.

achieve the same performance rate of 0.09 lb SO_2 per MMBtu at less than half the cost of a new CDS/FF.[8]

4.1.6 Wet FGD (WFGD)

Replacing the DFGD with a WFGD system located downstream of the existing FF was the most effective and costly SO_2 control option evaluated. WFGD systems are well established in and are operated on many coal-fired power plants firing medium to high sulfur coal. All WFGD systems use an alkaline slurry that reacts with SO_2 to form calcium sulfite and calcium sulfate. A WFGD system designed for Coyote is anticipated to be able to achieve a performance rate of 0.06 lb SO_2 per MMBtu, or a 93% reduction from the baseline emissions scenario. Installation of a new WFGD system is technically feasible and will be evaluated further.

4.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost of compliance for the reasonable progress controls are listed in Table 9.

Table 9: SO_2 Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
DFGD/FF (Baseline)	0.85				
DSI + Existing FGD	0.58	4,118	12,371,000	3,004	
FGD Improvements	0.50	5,338	2,085,000	391	-8,431
DSI + FGD Improvements	0.33	7,930	14,456,000	1,823	4,772
Absorber Replacement	0.09	11,590	21,122,000	1,822	1,821
WFGD	0.06	12,048	49,094,000	4,075	61,139

A detailed breakdown of the costs listed in Table 9Table 6 can be found in Coyote's submitted four factors analysis.[9] The Department has reviewed these costs and believes them to be accurate.

There are many options available for Coyote to reduce SO_2 emissions. The control costs vary drastically in annualized cost and significantly in effectiveness. A summary of each option evaluated is provided in the following paragraphs.

Installation of DSI would provide a potential 32% reduction in emissions from the baseline scenario. This results in approximately 4,100 tons of SO_2 reduced at an annualized cost approximately $12.3 million, equating to $3,000 per ton of SO_2 reduced. The FGD Improvements discussed in the following paragraph provide for greater emissions reductions at a lower cost, therefore, stand-alone installation of DSI on the existing DFGD unit is not considered further for reasonable progress.

FGD Improvements, specifically the Ca:S stoichiometric adjustments, provide a potential 41% reduction in emissions from the baseline scenario. This results in approximately 5,300 tons of SO_2

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[8] Appendix B.1.b. PDF page 220.

[9] Appendix B.1.b. Appendix B. PDF page 94.

reduced at an annualized cost of approximately $2 million, equating to approximately $400 per ton of SO_2 reduced. A benefit to this controls option is the facility can take advantage of upgrading existing equipment at a low capital cost compared to replacement of equipment at high capital costs. Also, as stated in Section 4.3, FDG Improvements could be implemented very quickly providing for a more immediate reduction in SO_2 emissions from the facility.

FGD improvements coupled with installation of DSI would provide a 61% reduction in emissions from the baseline scenario. This results in roughly 7,900 tons of SO_2 reduced at an annualized cost of approximately $14.5 million, equating to $1,800 per ton of SO_2 reduced. Since upgrading the FGD is recommended prior to installation of DSI, the incremental effectiveness of each individual control was reviewed. Consistent with the FGD improvements discussed in above paragraph, roughly 5,300 tons of the 7,900 tons reduced are attributable to the FGD improvements at a cost of approximately $400 per ton. The remaining 2,600 tons reduction is attributable to the DSI installation at an incremental cost of $4,800 per ton. FGD improvements are expected to lower the SO_2 performance rate from 0.85 to 0.50 lb SO_2 per MMBtu and DSI would further lower this from 0.50 to 0.33 lb SO_2 per MMBtu. In other words, Coyote could reduce the baseline emission rate by 0.35 lb SO_2 per MMBtu at a cost of $400 per ton and further reduce the rate by 0.17 lb SO_2 per MMBtu at a cost of $4,800 per ton.

Replacing the existing absorber with a new absorber would provide an 89% reduction in emissions from the baseline scenario. This results in approximately 11,600 tons of SO_2 reduced at an annualized cost of $21.1 million, equating to roughly $1,800 per ton of SO_2 reduced. This control option provides for a major reduction in SO_2 at a capital cost and high annualized cost.

Replacing the existing DFGD unit with a new WFGD unit would provide for an 93% reduction in emissions from the baseline scenario. This results in approximately 12,000 tons of SO_2 reduced at an annualized cost of $49 million, equating to $4,000 per ton of SO_2 reduced. This control option provides for a major reduction in SO_2 at a capital cost and high annualized cost. To determine if the limited improvement from the absorber replacement to a WFGD unit was viable considering the increased annualized cost, the incremental cost effectiveness between the two options was calculated. This incremental cost effectiveness was determined to be approximately $61,100 per ton, meaning the addition 0.03 lb SO_2 per MMBtu improvement (0.09 – 0.06) comes at an expensive cost. Since the installation of a new WFGD unit would not significantly improve the SO_2 performance rate (over absorber module replacement), the WFGD will not be considered for reasonable progress.

Of the options evaluated, three options remain on the table as potentially reasonable controls based on cost. These include existing FGD improvements, existing FGD improvements coupled with DSI, and replacement of the existing absorber module.

4.3 Step 2 – Time Necessary for Compliance

A summary of the anticipated timelines for the installation of controls is provided in Table 10.

Table 10: Time Required for SO_2 Controls

Control Technology	**Total time after SIP approval (months)**
DSI + Existing FGD	18
FGD Improvements	0

Control Technology	Total time after SIP approval (months)
DSI + FGD Improvements	18
Absorber Replacement	32
WFGD	56

4.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

4.4.1 Energy

Small changes to onsite energy consumption are likely to be experienced with the implementation of any SO_2 control options.[10] The impacts are not significant enough to eliminate and SO_2 controls as viable control options.

4.4.2 Non-Air Quality Environmental Impacts

Similar to the energy impacts for SO_2 controls, any non-air quality environmental impacts are not significant enough to eliminate additional SO_2 controls as a viable option.[11]

4.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, Coyote is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

[10] Appendix B.1.b, p. 8-2 – 8-4. PDF page 84-86.
[11] Appendix B.1.b, p. 8-2 – 8-4. PDF page 84-86.

A.2 – Basin AVS

1 Introduction and Representative Operations

Basin Electric Power Cooperative (Basin) – Antelope Valley Station (AVS) is a two-unit electrical generating utility (EGU). Each unit has the capacity to produce approximately 470 megawatts (MW) per hour of electricity. Unit 1 and Unit 2 are identical Combustion Engineering boilers firing pulverized lignite coal tangentially. Unit 1 and Unit 2 each have a heat input capacity of 6,275 MMBtu per hour. Unit 1 began commercial operation in 1984. Unit 2 began commercial operation in 1986. AVS is located in Mercer County about eight miles northwest of the town of Beulah, North Dakota and approximately six miles north of US Highway 200. AVS receives most of its lignite coal from the coal that is too fine-grained to be used by the Great Plains Synfuels Plant (GPSP). GPSP is located just south of AVS. The remaining coal is delivered from the nearby Freedom Mine, which is located approximately two miles north of AVS.

The average annual amount of North Dakota lignite coal combusted at AVS from 2009 through 2018 was approximately 5.3 million tons. See Table 1 for detailed information.

Table 1: Yearly Coal Combusted (tons)

Year	Unit 1 (tons)	Unit 2 (tons)
2009	2,908,708	2,876,852
2010	3,017,251	2,435,302
2011	1,899,776	2,642,530
2012	2,732,031	2,660,454
2013	2,804,599	2,369,861
2014	2,332,119	2,583,418
2015	2,736,138	2,833,973
2016	2,797,996	2,184,054
2017	2,442,876	2,826,520
2018	2,809,117	2,628,612
Average	**2,648,061**	**2,604,158**
Combined Average	**5,252,219**	

Over the same 10-year period (2009–2018), AVS operated at a 63% annual capacity factor (ACF), as determined on an actual heat input basis. Based on information provided to the North Dakota Department of Environmental Quality, Division of Air Quality (Department), future operations are expected to be consistent with this 10-year period and the 63% annual capacity factor was used when calculating the baseline and future projected emissions discussed in Section 2.

Table 2 displays the operational information from 2009–2018. The ACF is calculated by dividing the actual heat input by the maximum potential heat input of 55.0 x 10^6 MMBtu per year.

Table 2: Utilization and Annual Capacity Factor

Year	Unit 1 Heat Input (MMBtu/yr)	Unit 2 Heat Input (MMBtu/yr)	Unit 1 Annual Capacity Factor	Unit 2 Annual Capacity Factor
2009	38,437,954	37,867,178	0.70	0.69

Year	Unit 1 Heat Input (MMBtu/yr)	Unit 2 Heat Input (MMBtu/yr)	Unit 1 Annual Capacity Factor	Unit 2 Annual Capacity Factor
2010	39,571,458	31,668,162	0.72	0.58
2011	24,197,378	36,027,754	0.44	0.66
2012	35,197,379	35,877,026	0.64	0.65
2013	36,715,597	33,019,271	0.67	0.60
2014	31,118,421	36,431,873	0.57	0.66
2015	37,115,552	39,565,968	0.68	0.72
2016	37,148,044	29,420,896	0.68	0.54
2017	30,310,984	37,550,654	0.55	0.68
2018	34,370,105	35,494,838	0.63	0.65
Average	**34,418,287**	**35,292,362**	**0.63**	**0.64**
		Combined Average	**0.63**	

2 NO_X and SO_2 Emissions Controls and History

AVS commenced operation in 1984 when Unit 1 was started up. As is stated above, Unit 2 was started up in 1986. AVS was not a BART eligible source since construction of the facility commenced after the August 7, 1977 end date for "facilities in existence". AVS was, however, subject to the reasonable progress requirements during the first round of the regional haze program.

During the first round of the regional haze program, the Department determined that no NO_x or SO_2 controls were required for AVS Unit 1 or AVS Unit 2.[1] However, the United States Environmental Protection Agency (EPA) disapproved the Department's determination[2] and promulgated a Federal Implementation Plan (FIP)[3], which required that a separated overfire air and low-NO_x concentric firing system (SOFA/LNCFS) be installed on AVS Unit 1 and Unit 2. The FIP also required that a new NO_x emission limit of 0.17 lb/MMBtu (30-day rolling average) be established for AVS Unit 1 and Unit 2. The FIP required that the NO_x control technologies be installed by July 31, 2018 on both Unit 1 and Unit 2.[4]

2.1 NO_x

2.1.1 NO_X Emissions Controls

The overfire air pollution control system, which was operational during the decision-making process of the first round of the regional haze program, was retired from Unit 1 on May 27, 2014 and replaced with SOFA/LNCFS on May 28, 2014. The overfire air system was retired from Unit 2 on June 10, 2016 and replaced with SOFA/LNCFS on June 11, 2016. The current air pollution control system operating on both Unit 1 and Unit 2 includes SOFA/LNCFS.

[1] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 177-188.
[2] https://www.federalregister.gov/d/2012-6586/p-124
[3] https://www.federalregister.gov/d/2012-6586/p-amd-6
[4] https://www.federalregister.gov/d/2012-6586/p-780

2.1.2 NO_X Emissions History

Since the NO_x control technologies were installed on Unit 1 and Unit 2 in different years, the baseline emissions rate was determined using different time frames for Unit 1 and Unit 2. The time period from January 2015 through December 2018 was used to determine the NO_x baseline emissions rate for Unit 1. The time period from January 2017 through December 2018 was used to determine the NO_x baseline emissions rate for Unit 2. This information is displayed in Table 3.

Table 3: NO_X emissions

	Unit 1 Emissions		Unit 2 Emissions		Difference Between Units	
Year	**lb NO_X/MMBtu**	**tons NO_X**	**lb NO_X/MMBtu**	**tons NO_X**	**lb NO_X/MMBtu**	**tons NO_X**
2014 [A]	0.20	3,196	0.32	6,052	0.12	2,856
2015	0.11	2,103	0.36	7,283	0.25	5,180
2016 [B]	0.13	2,358	0.19	2,683	0.06	325
2017	0.11	1,662	0.11	2,045	0.00	383
2018	0.10	1,783	0.10	1,806	0.00	23
Baseline	**0.11**	**1,723**	**0.11**	**1,926**	**0.01**	**203**

[A] SOFA/LNCFS began operation on Unit 1 in May 2014
[B] SOFA/LNCFS began operation on Unit 2 in July 2016

The average emissions rate of 0.11 lb NO_X per MMBtu is representative of future expected operations. This value is used as the starting point when determining the cost of compliance for the add-on controls evaluated in Section 3.2.

2.2 SO_2

2.2.1 SO_2 Emissions Controls

AVS is equipped with dry flue gas desulfurization (DFGD) and a fabric filter (FF) baghouse for SO_2 and particulate matter control. The DFGD and FF baghouse were installed during the construction of the facility and have not been significantly modified since. AVS was not required to install any additional SO_2 controls during the first round of the regional haze program.[5]

2.2.2 SO_2 Emissions History

The time period from January 2014 through December 2018 was used to determine the SO_2 baseline emissions rate from AVS. This information is displayed in Table 4.

Table 4: SO_2 emissions

	Unit 1 Emissions		Unit 2 Emissions		Difference Between Units	
Year	**lb SO_2/MMBtu**	**tons SO_2**	**lb SO_2/MMBtu**	**tons SO_2**	**lb SO_2/MMBtu**	**tons SO_2**
2014	0.38	5,809	0.38	6,975	0.00	1,166
2015	0.34	6,312	0.34	6,716	0.00	404
2016	0.39	7,254	0.34	5,089	0.05	2,165
2017	0.35	5,259	0.41	7,603	0.06	2,344
2018	0.35	5,911	0.35	6,126	0.00	215

[5] https://www.federalregister.gov/d/2012-6586/p-127

Year	Unit 1 Emissions		Unit 2 Emissions		Difference Between Units	
	lb SO_2/MMBtu	tons SO_2	lb SO_2/MMBtu	tons SO_2	lb SO_2/MMBtu	tons SO_2
Baseline	**0.36**	**6,109**	**0.36**	**6,502**	**0.00**	**393**

The average emissions rate of 0.36 lb SO_2 per MMBtu is representative of future expected operations. This value is used as the starting point when determining the cost of compliance for the add-on controls evaluated in Section 4.2.

3 NO_X Analysis

3.1 NO_X Technologies

Rich reagent injection (RRI), gas reburn, and innovative technologies such as NO_XStar™, PerNO_Xide, LoTO_X, and water injection were evaluated in Basin's four-factors analysis but were determined to not be available or technically feasible.[6]

RRI is a technology created for cyclone boilers. Unit 1 and Unit 2 at AVS are tangentially fired coal boilers. Therefore, RRI is considered to not be technically feasible.

Gas reburn would require extensive testing at both Unit 1 and Unit 2. Therefore, gas reburn is considered to not be technically feasible.

NO_XStar™ is currently an emerging technology and long-term full-scale demonstration testing would be required to demonstrate its effectiveness at AVS. PerNO_Xide has only been tested on a pilot-scale and has not yet been demonstrated on any coal-fired boilers. Although LoTO_X has been successfully applied in refinery applications, there are not currently any full-scale installations on coal-fired boilers. The injection of atomized water spray to lower NO_X production has been well demonstrated for combustion turbine applications but has not been sufficiently demonstrated in coal-fired applications. Therefore, further testing is required for each of these innovative technologies to demonstrate that any of them could be installed effectively at AVS. They are considered to not be technically feasible at this time.

The reasonable progress controls evaluated by AVS and determined to be available and technically feasible are listed in Table 5. Note that the expected annual emissions in Table 5 were calculated using the performance rate, potential heat input, and the ACF (Table 2). Therefore, the tons of NO_X emissions are different than the tons of NO_X emissions displayed in Table 3 since Table 5 contains calculated emissions based on representative operations.

Table 5: Reasonable Progress NO_X Controls

Control Technology	Control Technology Abbreviation	Performance Rate (lb NO_X/MMBtu)	Emissions (tons/year)
Separated Overfire Air with Low-NO_x Concentric Firing System (baseline)	SOFA/LNCFS	0.11	1,917
Selective Non-Catalytic Reduction	SNCR	0.09	1,568
Selective Catalytic Reduction - Tail End Configuration	TE-SCR	0.05	871

[6] Appendix B.2.b, p. 5-17. PDF page 312.

3.1.1 Selective Non-Catalytic Reduction (SNCR)

Installation of SNCR post combustion add-on control equipment has a limited impact on removing NO_X emissions from the flue gas. The limited removal is due to low NO_X concentrations in the flue gas stream affecting the reaction kinetics.[7] Sources that are well suited for SNCR typically have an uncontrolled NO_X concentration above 200 ppm.[8] AVS is generally around 60 ppm uncontrolled NO_X, making AVS not well suited for SNCR application. SNCR is anticipated to provide an approximately 18% reduction in NO_X emissions from the baseline scenario, lowering the expected performance rate from 0.11 to 0.09 lb NO_X per MMBtu. SNCR has a limited impact on reducing NOx, however, installation of SNCR on Unit 1 and Unit 2 at AVS is technically feasible and will be evaluated further.

3.1.2 Selective Catalytic Reduction (SCR)

SCR is post combustion add-on control equipment. SCR, when feasible, has a significant impact on removing NO_X emissions from a flue gas stream. SCR is traditionally installed in one of three configurations: high-dust, low-dust, or tail-end. During the first regional haze program planning period in North Dakota, the Department determined that installation of SCR, in any configuration, is not a technically feasible control technology since it has not been demonstrated in practice on North Dakota lignite coal.[9] However, the earlier determination focused on cyclone-fired boilers. Successful use of TE-SCR controls have since been demonstrated at existing bituminous- and subbituminous-fired units. Therefore, the current determination is deeming TE-SCR as being technically feasible. TE-SCR is anticipated to provide an approximately 55% reduction in NO_X emissions from the baseline scenario, lowering the expected performance rate from 0.11 to 0.05 lb NO_X per MMBtu. TE-SCR is assumed technically feasible for installation on Unit 1 and Unit 2 at AVS and will be evaluated further.

3.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost for the reasonable progress controls are listed in Table 6.

Table 6: NO_X Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
SOFA/LNCFS (Baseline)	0.11				
SNCR	0.09	349	3,285,412	9,426	
TE-SCR	0.05	1,046	36,344,908	34,758	47,424

A detailed breakdown of the costs listed in Table 6 can be found in Basin's submitted four factors analysis.[10] The Department has reviewed these costs and believes them to be accurate.

[7] John Sorrels, EPA Cost control Manual, Section 4, Chapter 1, p 1-16.
[8] John Sorrels, EPA Cost control Manual, Section 4, Chapter 1, p 1-5.
[9] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.5.
[10] Appendix B.2.b. Appendix D. PDF page 356.

If SNCR is installed, a performance rate improvement of 0.02 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of 349 tons NO_X per year from the baseline emissions. Fiscally, SNCR installation requires an estimated annualized cost of $3.3 million and a NO_X removal cost of $9,400 per ton.

If TE-SCR is installed, a performance rate improvement of 0.06 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of 1,046 tons NO_X per year from the baseline emissions. Fiscally, TE-SCR installation requires an estimated annualized cost of $36.3 million and a NO_X removal cost of approximately $35,000 per ton.

3.3 Step 2 – Time Necessary for Compliance

A summary of the anticipated timelines for the installation of SNCR and TE-SCR is provided in Table 7.

Table 7: Time Required for NO_X Controls

Control Technology	Total time after SIP approval (months)
SNCR	22
TE-SCR	52

The anticipated timelines for the installation of SNCR and TE-SCR indicate either option could be installed prior to the end of the second planning period.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy

The installation and operation of a TE-SCR would increase the pressure drop through the control systems, which would increase the auxiliary power requirements. This would adversely affect the net plant heat rate. This impact is significant but not significant enough to eliminate TE-SCR as a control option.

3.4.2 Non-Air Quality Environmental Impacts

The installation and operation of the TE-SCR could result in an increase in sulfur emissions due to the potential oxidation of SO_2 to SO_3 and the subsequent reaction with moisture in the stack to form H_2SO_4.

Both TE-SCR and SNCR use ammonia as a reagent. Ammonia slip emissions will result in the flue gas stream on the exhaust side of the control equipment due to the the operation of TE-SCR (~2 ppm) and SNCR (~10 ppm). The ammonia slip emissions from the operation of SNCR would likely combine with the dry FGD solids. The ammoniated dry FGD solids would require that further safety precautions are taken for AVS staff who perform maintenance on the ash handling system or staff who dispose of waste. Ammonia slip emissions from the operation of the TE-SCR would be emitted to the atmosphere. Subsequently, the ammonia could combine with SO_X and NO_X to form sulfates and nitrates, which will affect visibility.

The non-air quality environmental impacts for TE-SCR and SNCR are significant but not significant enough to eliminate either of them as a control option.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, AVS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

4 SO_2 Analysis

4.1 SO_2 Technologies

Fuel switching was evaluated in Basin's four-factors analysis but was not determined to be available since AVS is a mine mouth generation facility.

The reasonable progress controls evaluated by AVS are listed in Table 8. Performance rate and expected annual emissions are included for each control technology that was determined to be technically feasible. Note that the expected annual emissions in Table 8 were calculated using the performance rate, potential heat input, and the ACF (Table 2). Therefore, the tons of SO_2 emissions are different than the tons of SO_2 emissions displayed in Table 4 since Table 8 contains calculated emissions based on representative operations.

Table 8: Reasonable Progress SO_2 Controls

Control Technology	Control Technology Abbreviation	Performance Rate (lb SO_2/MMBtu)	Emissions (tons/year)
Dry Flue Gas Desulfurization / Fabric Filter (baseline)	DFGD/FF	0.36	6,274
Existing DFGD Operational Improvement: Station Work Practice	Station Work Practice	0.35	6,100
Existing DFGD Operational Improvement: Increase Ca:S Stoichiometric Ratio [A]	Ca:S Stoichiometry	0.20	3,486
New Retrofit DFGD (Circulating Dry Scrubber / Fabric Filter)	DFGD (CDS/FF)	0.09	1,568
New Retrofit Wet Flue Gas Desulfurization	WFGD	0.07	1,220

[A] Dry sorbent injection was also considered but would not provide any additional SO_2 removal beyond what can be achieved by increasing the Ca:S stoichiometric ratio.

4.1.1 Flue Gas Desulfurization (FGD) Improvements

FGD Improvements are grouped into two categories: 1) equipment upgrades and 2) operational improvements. The proposed equipment upgrades consisted of atomizer replacement, lime-slaker replacement, adding an absorber module, and replacing the existing absorber module. The proposed operational improvements evaluated consisted of station work practices, increasing the lime quality, increasing the stoichiometric ratio of calcium to sulfur (Ca:S) by increasing lime quantity, and lowering the absorber outlet temperature closer to the saturation point.

None of the equipment upgrades are considered technically feasible.[11] It is not technically feasible to replace the atomizer in order to improve air pollution control because there has not been any significant moisture carry-over into the baghouse or wetting of the absorber walls that would indicate

[11] Appendix B.2.b, p 4-20. PDF page 284.

that the atomizers are not operating properly. Since additional slaking capacity was installed in 2011, it is not technically feasible to replace the slakers in order to reduce emissions. In addition, an additional absorber module or the replacement of any existing absorber modules would not provide any significant improvements towards removing additional sulfur. Therefore, adding an absorber module or replacing any existing absorber modules are considered to not be technically feasible SO_2 control strategies.

When considering the potential operational improvements, increasing the lime quality and lowering the absorber outlet temperature closer to the saturation point are not considered technically feasible. The lime used at AVS is already of high quality for use in dry scrubbers. Therefore, it is not technically feasible to increase the quality of the lime to reduce SO_2 emissions. Similarly, it is not technically feasible to further lower the outlet temperature closer to the saturation point because the AVS dry scrubbers currently operate at a temperature near the adiabatic saturation temperature. Station work practices and increasing the stoichiometric ratio of Ca:S are both considered technically feasible.

The initiation of certain "station work practices" has the ability to decrease SO_2 emissions at AVS. Unit 1 and Unit 2 at AVS have a combined 3-hour rolling average SO_2 limit of 3,845 lb/hr in their Title V Permit to Operate (T5-F86003).[12] When either Unit 1 or Unit 2 is in an extended major outage, operators decrease the SO_2 removal on the other Unit, while maintaining compliance with the SO_2 permit limit. This typically occurs once every three years on each unit. Station work practices are anticipated to provide an approximately 3% reduction in SO_2 emissions from the baseline scenario, lowering the expected performance rate from 0.36 lb SO_2 per MMBtu to 0.35 lb SO_2 per MMBtu. A change to the current station work practices is considered a technically feasible SO_2 control option for AVS Unit 1 and Unit 2.

For AVS, increasing the Ca:S stoichiometric ratio is best accomplished by increasing the quantity of fresh lime introduced into the system. Basin contracted with Babcock and Wilcox (B&W), the original equipment manufacturer of AVS's DFGD system, to determine whether additional SO_2 could be removed if the amount of fresh lime added to the system was increased. Based on simulations conducted by B&W's proprietary software, AVS could achieve a performance rate of 0.16 lb SO_2 per MMBtu by increasing the amount of fresh lime added to the system. This equates to a 44% reduction in SO_2 emissions from the baseline scenario of 0.36 lb SO_2 per MMBtu. Increasing the Ca:S stoichiometric ratio is considered a technically feasible SO_2 control option for AVS Unit 1 and Unit 2.

4.1.2 New Dry FGD (DFGD) and Fabric Filter (FF)

Two types of new DFGD systems were evaluated at AVS: 1) a spray dryer absorber (SDA) and 2) a circulating dry scrubber (CDS). Each of these systems is technically feasible, commercially available, and would require significant modifications to the facility. The engineering evaluation determined that the CDS would outperform the SDA at AVS.[13] A new SDA/FF is anticipated to be able to achieve a performance rate of 0.15 lb SO_2 per MMBtu. A new CDS/FF is anticipated to be able to achieve a performance rate of 0.09 lb SO_2 per MMBtu. Given the better performance rate with the CDS/FF system, the Department will focus the remaining analysis on the CDS/FF system. Implementation of a CDS/FF system represents a 75% reduction from the baseline scenario of 0.36 lb SO_2 per MMBtu.

[12] Appendix B.2.c. PDF page 373.

[13] Appendix B.2.b, p 4-17. PDF page 281.

Replacing the existing DFGD unit with a new CDS/FF is technically feasible and will be evaluated further.

4.1.3 Wet FGD (WFGD)

Replacing the DFGD with a WFGD system located downstream of the existing FF was the most effective and most costly SO_2 control option evaluated. WFGD systems are well established and are operated on many coal-fired power plants that fire medium- to high-sulfur coal. All WFGD systems use an alkaline slurry that reacts with SO_2 to form calcium sulfite and calcium sulfate. A WFGD system designed for AVS is anticipated to be able to achieve a performance rate of 0.07 lb SO_2 per MMBtu, or an 81% reduction from the baseline emissions scenario of 0.36 lb SO_2 per MMBtu. Installation of a new WFGD system is technically feasible and will be evaluated further.

4.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost of compliance for the reasonable progress controls are listed in Table 9.

Table 9: SO_2 Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Rate (lb SO_2/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
DFGD/FF (Baseline)	0.36				
Station Work Practice	0.35	174	135,000	775	
Ca:S Stoichiometry	0.20	2,788	1,938,773	695	690
DFGD (CDS/FF)	0.09	4,705	35,603,658	7,566	17,561
WFGD	0.07	5,054	39,267,491	7,770	10,512

A detailed breakdown of the costs listed in Table 9 can be found in Basin's submitted four factors analysis.[14] The Department has reviewed these costs and believes them to be accurate.

There are many options available for AVS to reduce SO_2 emissions. The control costs vary drastically in annualized cost and significantly in effectiveness. A summary of each option evaluated is provided in the following paragraphs.

A change to the current station work practices would provide a potential 3% reduction in emissions from the baseline scenario. This would result in approximately 170 tons of SO_2 being reduced at an annualized cost of approximately $135,000, equating to $775 per ton of SO_2 reduced. As stated in Section 4.3, a change to the current station work practices can be implemented very quickly, which would provide for a quick reduction in SO_2 emissions from the facility.

[14] Appendix B.2.b. Appendix C. PDF page 343.

FGD Improvements, specifically Ca:S stoichiometric adjustments, provide a potential 44% reduction in emissions from the baseline scenario. This would result in approximately 2,790 tons of SO_2 being reduced at an annualized cost of approximately $1.9 million, equating to approximately $700 per ton of SO_2 reduced. A benefit of this control option is that the facility can take advantage of upgrading existing equipment at a low capital cost when compared to replacement with new equipment at a high capital cost.

Replacing the existing DFGD unit and FF with a new CDS/FF unit would provide for a 75% reduction in emissions from the baseline scenario. This would result in approximately 4,700 tons of SO_2 being reduced at an annualized cost of $35.6 million, equating to approximately $7,600 per ton of SO_2 reduced.

Replacing the existing DFGD unit with a new WFGD unit would provide for an 81% reduction in emissions from the baseline scenario. This would result in approximately 5,050 tons of SO_2 reduced at an annualized cost of $39.3 million, equating to approximately $7,800 per ton of SO_2 reduced.

4.3 Step 2 – Time Necessary for Compliance

A summary of the anticipated timelines for the installation of the technically feasible control technologies is provided in Table 10.

Table 10: Time Required for SO_2 Controls

Control Technology	**Total time after SIP approval (months)**
Station Work Practice	3
Ca:S Stoichiometry	51
DFGD (CDS/FF)	56
WFGD	60

The anticipated timelines for the installation of each of the control technologies indicates all options could be installed prior to the end of the second planning period.

4.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

4.4.1 Energy

The replacement of the existing drying scrubbing system with a CDS/FF or WFGD would increase the pressure drop through the control systems, which will increase the auxiliary power requirements. This would adversely affect the net plant heat rate. This impact is significant but not significant enough to eliminate either CDS/FF or WFGD as a control option.

4.4.2 Non-Air Quality Environmental Impacts

The installation and operation of a WFGD control option would generate a liquid calcium sulfate by-product that would need to be dewatered prior to disposal. In addition, WFGD control systems generate wastewater streams that typically contain a saturated solution of calcium sulfate, calcium sulfite, sodium chloride, trace amounts of fly ash, and unreacted limestone. The wastewater stream would need to be treated prior to discharge. WFGD systems also require significantly more water than dry systems. The non-air quality environmental impacts for WFGD are significant but not significant enough to eliminate WFGD as a control option.

4.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, AVS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

A.3 – Basin LOS

1 Introduction and Representative Operations

Basin Electric Power Cooperative (Basin) – Leland Olds Station (LOS) is a two-unit electrical generating station. Unit 1 and Unit 2 both primarily fire lignite with a small amount of subbituminous coal combusted. Unit 1 began commercial operation in 1966 and is a Babcock & Wilcox opposed wall-fired boiler that has the capacity to produce approximately 216 Megawatts (MW) per hour of electricity. Unit 2 began commercial operation in 1975 and is a Babcock & Wilcox cyclone-fired boiler that has the capacity to produce approximately 440 MW per hour of electricity. LOS is located on the banks of the Missouri River in eastern Mercer county, approximately four miles southeast of the town of Stanton, North Dakota. LOS receives lignite from the Coteau Properties Freedom Mine, which is located approximately thirty miles west of LOS.

The average annual amount of coal combusted at LOS from 2009 through 2018 was approximately 1 million tons for Unit 1 and 2 million tons for Unit 2. See Table 1 for detailed information.

Table 1: Yearly Coal Combusted (tons)

Year	Unit 1	Unit 2
2009	1,287,756	2,125,157
2010	1,163,282	2,081,633
2011	877,802	1,821,590
2012	1,013,575	1,826,247
2013	1,114,170	2,373,552
2014	888,389	2,151,508
2015	1,172,715	1,872,825
2016	1,164,055	2,266,471
2017	944,117	2,270,661
2018	1,104,951	1,797,457
Average	**1,073,081**	**2,058,710**

Over the same 10-year period (2009–2018), LOS operated at a 62% annual capacity factor (ACF) for Unit 1 and 60% ACF for Unit 2, as determined on an actual heat input basis. Based on information provided to the North Dakota Department of Environmental Quality, Division of Air Quality (Department), future operations are expected to be consistent with this 10-year period. The 62% and 60% annual capacity factors were used when calculating the baseline and future projected emissions discussed in Section 2.

Table 2 and Table 3 display the operational information from 2009–2018 for LOS Unit 1 and Unit 2, respectively. The ACF is calculated by dividing the actual heat input by the maximum potential heat input of each unit. The maximum potential heat input of Unit 1 is 23.0 x 10^6 MMBtu per year and the maximum potential heat input of Unit 2 is 44.9 x 10^6 MMBtu per year.

Table 2: Unit 1 Utilization and Annual Capacity Factor

Year	Unit 1 Heat Input MMBtu/yr	Unit 1 Annual Capacity Factor
2009	17,175,940	0.75

Year	Unit 1 Heat Input MMBtu/yr	Unit 1 Annual Capacity Factor
2010	15,297,310	0.67
2011	11,653,716	0.51
2012	13,716,670	0.60
2013	14,639,199	0.64
2014	11,933,747	0.52
2015	15,787,030	0.69
2016	15,566,955	0.68
2017	12,515,725	0.54
2018	14,285,928	0.62
Average	**14,257,222**	**0.62**

Table 3: Unit 2 Utilization and Annual Capacity Factor

Year	Unit 2 Heat Input MMBtu/yr	Unit 2 Annual Capacity Factor
2009	27,865,279	0.62
2010	26,903,299	0.60
2011	23,660,990	0.53
2012	23,477,374	0.52
2013	30,526,164	0.68
2014	28,352,132	0.63
2015	24,730,648	0.55
2016	30,344,385	0.68
2017	29,914,155	0.67
2018	23,585,131	0.52
Average	**26,935,956**	**0.60**

2 NO_X and SO_2 Emissions Controls and History

LOS commenced operation in 1966 when Unit 1 was started up. As is stated above, Unit 2 was started up in 1975. LOS was a best available retrofit technology (BART) eligible source since construction of the facility commenced before the August 7, 1977 end date for "facilities in existence" and after August 7, 1962. The Department determined that BART for LOS Unit 1 and Unit 2 included new wet limestone flue gas desulfurization (WFGD) for SO_2 control and selective non-catalytic reduction (SNCR) and separated overfire (SOFA) air for NO_X control.[1]

LOS was also subject to the reasonable progress requirements during the first round of the Regional Haze program. The Department determined that no additional NO_x or SO_2 controls were required for LOS Unit 1 or Unit 2 within the reasonable progress requirements.[2]

[1] North Dakota State Implementation Plan for Regional Haze, Appendix B.1.

[2] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 188.

The United States Environmental Protection Agency (EPA) proposed to partially approve and partially disapprove of North Dakota's State Implementation Plan for Regional Haze submitted on March 3, 2010. In regard to LOS, the EPA proposed to disapprove the NO_X BART determination and emissions limit for Unit 2.[3] The EPA proposed the promulgation of a Federal Implementation Plant (FIP), which proposed advanced separated overfire air (ASOFA) plus selective catalytic reduction (SCR) and an emission rate of 0.07 lb/MMBtu (30-day rolling average) as BART for NO_X control on LOS Unit 2.[4] Following the public notice and comment period, the EPA issued its Final Rule on April 6, 2012.[5] In the Final Rule, EPA reversed its position regarding the technical feasibility of SCR on LOS Unit 2 and approved North Dakota's BART determination for NO_X control on Unit 2.[6] Therefore, a FIP was not promulgated for NO_X BART on LOS Unit 2 and the Department's initial BART determination for both LOS Unit 1 and Unit 2 was approved.

2.1 NO_X

2.1.1 NO_X Emissions Controls

The NO_X air pollution control system upgrades including SOFA and SNCR for Unit 1 and Unit 2 were placed into service in stages over several years. The final stages included the startup of SNCR on Unit 1 and Unit 2 in August 2015. Optimization of the NO_X air pollution control system upgrades were needed through 2015. The SNCR on Unit 1 and Unit 2 were again optimized in 2017, lowering the NO_X emissions rate. The current NO_X air pollution control system operating on Unit 1 and Unit 2 includes SOFA and SNCR.

2.1.2 NO_X Emissions History

The baseline emissions rate for NO_X was determined using the time period of January 2017 through December 2018 for both Unit 1 and Unit 2. This information is displayed in Table 4 and Table 5.

Table 4: Unit 1 Annual NO_X Rate and Emissions

Year	Emissions Rate (lb/MMBtu)	NO_x Emissions (tons)
2014	0.22	1,373
2015 [A]	0.24	1,814
2016	0.25	1,856
2017 [B]	0.18	1,121
2018	0.15	1,065
Baseline	**0.16**	**1,093**

[A] SNCR began operation in August 2015

[B] SNCR was reoptimized in 2017

[3] https://www.federalregister.gov/d/2011-23372/p-253.
[4] https://www.federalregister.gov/d/2011-23372/p-705.
[5] https://www.federalregister.gov/d/2012-6586/p-3.
[6] https://www.federalregister.gov/d/2012-6586/p-159.

Table 5: Unit 2 Annual NOX Rate and Emissions

Year	Emissions Rate (lb/MMBtu)	NO_x Emissions (tons)
2014	0.37	5,202
2015 [A]	0.37	4,557
2016	0.37	5,434
2017 [B]	0.29	4,418
2018	0.29	3,599
Baseline	**0.29**	**4,009**

[A] SNCR began operation in August 2015

[B] SNCR was reoptimized in 2017

Unit 1 and Unit 2 contain different boiler types and are not expected to operate in similar ways. Table 4 and Table 5 show that Unit 1 and Unit 2 are not comparable in terms of emissions rate or emissions. Therefore, each unit has its own value for baseline emissions rate. The average emissions rate of 0.16 lb NO_X per MMBtu is representative of future expected operations for Unit 1. The average emissions rate of 0.29 lb NO_X per MMBtu is representative of future expected operations for Unit 2. These values are used as the starting point when determining the cost of compliance for the add-on controls evaluated in Section 3.2.

2.2 SO_2

2.2.1 SO_2 Emissions Controls

The new WFGD for SO_2 control was started up on Unit 1 in June 2013 and on Unit 2 in October 2012. The current SO_2 air pollution control system operating on Unit 1 and Unit 2 consists of WFGD, as required by BART.

2.2.2 SO_2 Emissions History

The time period from January 2015 through December 2018 was used to determine the SO_2 baseline emissions rate from Unit 1 and Unit 2 at LOS. This information is displayed in Table 6 and Table 7.

Table 6: Unit 1 Annual SO_2 Rate and Emissions

Year	Emissions Rate (lb/MMBtu)	SO_2 Emissions (tons)
2014	0.06	412
2015	0.09	681
2016	0.09	711
2017	0.09	554
2018	0.09	652
Baseline	**0.09**	**650**

Table 7: Unit 2 Annual SO2 Rate and Emissions

Year	Emissions Rate (lb/MMBtu)	SO_2 Emissions (tons)
2014	0.07	1,025
2015	0.09	1,066
2016	0.08	1,217
2017	0.09	1,364
2018	0.08	1,052
Baseline	**0.08**	**1,175**

As displayed in Table 6 and Table 7, Unit 1 and Unit 2 are not comparable in terms of tons of SO_2 emitted since Unit 2 is approximately twice as large. However, the emission rates, in terms of lb SO_2 per MMBtu are comparable between Unit 1 and Unit 2, due to each unit operating a WFGD unit and firing similar coal.[7] The average emissions rate of 0.09 lb SO_2 per MMBtu for Unit 1 is representative of future expected operations. The average emissions rate of 0.08 lb SO_2 per MMBtu for Unit 2 is representative of future expected operations for Unit 2. These values are used as starting points when determining the cost of compliance for the add-on controls evaluated in Section 4.2.

3 NO_X Analysis

3.1 NO_X Technologies

Gas reburn and innovative technologies such as NO_XStar™, PerNO$_X$ide, LoTO$_X$, and water injection were evaluated in Basin's four-factors analysis but were determined to not be available or technically feasible.[8]

Gas reburn would require extensive testing at both Unit 1 and Unit 2. Therefore, gas reburn is considered to not be technically feasible.

NO_XStar™ is currently an emerging technology and long-term full-scale demonstration testing would be required to demonstrate its effectiveness at LOS. PerNO$_X$ide has only been tested on a pilot-scale and has not yet been demonstrated on any coal-fired boilers. Although LoTO$_X$ has been successfully applied in refinery applications, there are not currently any full-scale installations on coal-fired boilers. The injection of atomized water spray to lower NO_X production has been well demonstrated for combustion turbine applications but has not been sufficiently demonstrated in coal-fired applications. Therefore, further testing is required for each of these innovative technologies to demonstrate that any of them could be installed effectively at LOS. They are considered to not be technically feasible at this time for either Unit 1 or Unit 2.

The reasonable progress controls evaluated by LOS determined to be available and technically feasible are listed in Table 8 (Unit 1) and Table 9 (Unit 2). Performance rate and expected annual emissions are included for each control technology determined to be technically feasible. Note that the expected annual emissions in Table 8 and Table 9 were calculated using the performance rate, potential heat input, and the ACF (Table 2 and Table 3). Therefore, the tons of NO_X emissions are

[7] When rounded to three decimal places, Unit 1 average is 0.088 and Unit 2 average is 0.084.

[8] Appendix B.3.b, p. 5-18 – 5-20. PDF page 448-450.

different than the tons of NO_X emissions displayed in Table 4 and Table 5 since the tables below contain calculated emissions based on representative operations.

Table 8: Reasonable Progress NO_X Controls (Unit 1)

Control Technology	Control Technology Abbreviation	Performance Rate (lb NO_X/MMBtu)	Emissions (tons/year)
Low-NO_X Burner with Selective Non-Catalytic Reduction and Separated Overfire Air (baseline)	LNB/SNCR/SOFA	0.16	1,152
Selective Catalytic Reduction - Tail End Configuration	TE-SCR	0.05	356

Table 9: Reasonable Progress NO_X Controls (Unit 2)

Control Technology	Control Technology Abbreviation	Performance Rate (lb NO_X/MMBtu)	Emissions (tons/year)
Selective Non-Catalytic Reduction with Separated Overfire Air (baseline)	SNCR/SOFA	0.29	3,894
Optimized Selective Non-Catalytic Reduction	Optimized SNCR	0.27	3,636
Optimized Selective Non-Catalytic Reduction with Rich Reagent Injection	Optimized SNCR + RRI	0.22	2,963

3.1.1 Optimized Selective Non-Catalytic Reduction (SNCR)

SNCR is currently installed on Unit 1 and Unit 2 at LOS, as required by the first round of Regional Haze planning for North Dakota. Therefore, optimization of SNCR is being considered as an option to reduce NO_X emissions.

Based on computational fluid dynamics modeling conducted for Unit 1 at LOS, any additional urea injection could result in negative impacts with ammonia slip emissions. In addition, during installation of the SNCR control equipment on Unit 1, it was determined that it would not be possible to install any multi-nozzle lances in their optimal locations due to physical interferences. Therefore, the current SNCR system on Unit 1 is considered fully optimized.

Optimization of the SNCR control equipment on Unit 2 is considered technically feasible. The SNCR original equipment manufacturer proposed that the SNCR system on Unit 2 could be further optimized by relocating all cyclone vent ports to improve stoichiometry and relocating the current urea injection lances to better utilize the reagent. Optimization of the SNCR control equipment is anticipated to provide an approximately 7% reduction in NO_X emissions from the baseline scenario. This would lower the expected performance rate from 0.29 to 0.27 lb NO_X per MMBtu. Optimization of SNCR is assumed to be technically feasible for installation on Unit 2 at LOS and will be evaluated further.

3.1.2 Selective Catalytic Reduction (SCR)

SCR is post combustion add-on control equipment. SCR, when feasible, can have a significant impact on removing NO_X emissions from a flue gas stream. SCR is traditionally installed in one of three configurations: high-dust, low-dust, or tail-end. During the first regional haze program planning period in North Dakota, the Department determined that installation of SCR, in any configuration, is not a technically feasible control technology since it has not been demonstrated in practice on North Dakota lignite.[9]

The earlier determination focused on North Dakota lignite-fired cyclone boilers. Therefore, SCR is not considered technically feasible for Unit 2 at LOS.

Successful use of TE-SCR controls has since been demonstrated at existing bituminous- and subbituminous-fired units. Even though this has not been demonstrated on North Dakota lignite-fired boilers, the current determination is deeming TE-SCR as being technically feasible for Unit 1 at LOS, which is an opposed wall-fired boiler. TE-SCR is anticipated to provide an approximately 69% reduction in NO_X emissions from the baseline scenario on Unit 1. This would lower the expected performance rate from 0.16 to 0.05 lb NO_X per MMBtu for Unit 1. TE-SCR is assumed to be technically feasible for installation on Unit 1 at LOS and will be evaluated further.

3.1.3 Optimized Selective Non-Catalytic Reduction (SNCR) Plus Rich Reagent Injection (RRI)

Rich reagent injection (RRI) is a technology created for cyclone boilers. Therefore, RRI is not considered to be a technically feasible option for Unit 1.

RRI alone only provides a beneficial NO_X reduction at full load. However, if RRI is coupled with SNCR, NO_X reduction can be achieved through a wider range of operating loads on Unit 2. Optimized SNCR + RRI is anticipated to provide an approximately 24% reduction in NO_X emissions from the baseline scenario on Unit 2. This would lower the expected performance rate from 0.29 to 0.22 lb NO_X per MMBtu for Unit 2. Optimized SNCR + RRI is assumed to be technically feasible for installation on Unit 2 at LOS and will be evaluated further.

3.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost for the reasonable progress controls are listed in Table 10 (Unit 1) and Table 11 (Unit 2).

Table 10: NO_X Cost of Compliance and Incremental Cost of Compliance (Unit 1)

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
LNB/SNCR/SOFA (Baseline)	0.16			
TE-SCR	0.05	796	33,663,928	42,316

[9] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.5.

Table 11: NO_X Cost of Compliance and Incremental Cost of Compliance (Unit 2)

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
SNCR/SOFA (Baseline)	0.29				
Optimized SNCR	0.27	258	924,151	3,582	
Optimized SNCR + RRI	0.22	931	5,402,503	5,801	6,650

A detailed breakdown of the costs listed in Table 10 and Table 11 can be found in Basin's submitted four factors analysis.[10] The Department has reviewed these costs and believes them to be accurate.

If TE-SCR is installed on Unit 1, a performance rate improvement of 0.09 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of approximately 800 tons NO_X per year from the baseline emissions. Fiscally, TE-SCR installation requires an estimated annualized cost of $33.6 million and a NO_X removal cost of approximately $42,000 per ton.

If SNCR is optimized on Unit 2, a performance rate improvement of 0.02 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of approximately 260 tons NO_X per year from the baseline emissions. Fiscally, SNCR optimization on Unit 2 requires an estimated annualized cost of approximately $924,000 and a NO_X removal cost of $3,600 per ton.

If SNCR is optimized with RRI on Unit 2, a performance rate improvement of 0.07 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of approximately 930 tons NO_X per year from the baseline emissions. Fiscally, SNCR optimization with RRI requires an estimated annualized cost of $5.4 million and a NO_X removal cost of $5,800 per ton.

3.3 Step 2 – Time Necessary for Compliance

A summary of the anticipated timeline for the installation of TE-SCR on Unit 1 is provided in Table 12.

Table 12: Time Required for NO_X Controls (Unit 1)

Control Technology	Total time after SIP approval (months)
TE-SCR	52

The anticipated timeline for the installation of TE-SCR on Unit 1 indicates that TE-SCR could be installed prior to the end of the second planning period.

A summary of the anticipated timelines for the optimization of SNCR and the optimization of SNCR plus RRI for Unit 2 is provided in Table 13.

[10] Appendix B.3.b. Appendix D. PDF page 493

Table 13: Time Required for NO_X Controls (Unit 2)

Control Technology	Total time after SIP approval (months)
Optimized SNCR	12
Optimized SNCR + RRI	16

The anticipated timelines for the optimization of SNCR and the optimization of SNCR plus RRI indicate either option could be installed prior to the end of the second planning period.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy

The installation and operation of a TE-SCR on Unit 1 would increase the pressure drop through the control systems, which would increase the auxiliary power requirements. This would adversely affect the net plant heat rate. This impact is significant but not significant enough to eliminate TE-SCR as a control option.

Optimization of the SNCR and optimization of the SNCR plus RRI on Unit 2 will adversely affect the net plant heat rate due to the amount of water that will be injected with urea, which will negatively impact boiler efficiency. This impact is significant but not significant enough to eliminate optimization of the SNCR or optimization of the SNCR plus RRI as control options.

3.4.2 Non-Air Quality Environmental Impacts

The installation and operation of the TE-SCR on Unit 1 could result in an increase in sulfur emissions due to the potential oxidation of SO_2 to SO_3 and the subsequent reaction with moisture in the stack to form H_2SO_4. In addition, TE-SCR uses ammonia as a reagent. Ammonia slip emissions will result in the flue gas stream on the exhaust side of the control equipment due to the operation of TE-SCR (~2 ppm). Ammonia slip emissions from the operation of the TE-SCR would be emitted to the atmosphere. The non-air quality environmental impacts for TE-SCR are significant but not significant enough to eliminate either of them as a control option.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, LOS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

4 SO_2 Analysis

4.1 SO_2 Technologies

As part of the first planning period for Regional Haze, LOS was required to install WFGD for SO_2 control on Unit 1 and Unit 2 at LOS. Therefore, improvements or upgrades to the existing WFGD systems are now considered for reasonable progress control options. The reasonable progress controls evaluated by LOS are listed in Table 14 (Unit 1) and Table 15 (Unit 2). Performance rate and expected annual emissions are included for each control technology that was determined to be technically feasible. Note that the expected annual emissions in Table 14 and Table 15 were calculated using the performance rate, potential heat input, and the ACF (Table 2 and Table 3). Therefore, the tons of SO_2 emissions are different than the tons of SO_2 emissions displayed in Table 6 and Table 7 since the tables below contain calculated emissions based on representative operations.

Table 14: Reasonable Progress SO_2 Controls (Unit 1)

Control Technology	Control Technology Abbreviation	Performance Rate (lb SO_2/MMBtu)	Emissions (tons/year)
Wet Limestone Flue Gas Desulfurization (baseline)	WFGD	0.088	630
Increase Ca:S Stoichiometric Ratio	Ca:S Stoichiometry	0.080	570
Incorporation of pH Buffer and Increasing Limestone Addition	pH Buffer Additive	0.055	392

Table 15: Reasonable Progress SO_2 Controls (Unit 2)

Control Technology	Control Technology Abbreviation	Performance Rate (lb SO_2/MMBtu)	Emissions (tons/year)
Wet Limestone Flue Gas Desulfurization (baseline)	WFGD	0.084	1138
Increase Ca:S Stoichiometric and Liquid-to-Gas Ratios	Ca:S Stoichiometry and L/G Ratio	0.075	1010
Incorporation of pH Buffer and Increasing Limestone Addition	pH Buffer Additive	0.050	673

Three decimal places are shown in Table 14 and Table 15 for the performance rate in order to properly illustrate the difference in performance rates between WFGD and Ca:S Stoichiometry.

4.1.1 Flue Gas Desulfurization (FGD) Improvements and Upgrades

FGD Improvements are grouped into two categories: 1) operational improvements and 2) design changes and equipment upgrades. The proposed operational improvements evaluated consisted of increasing the limestone quality, increasing the stoichiometric ratio of calcium to sulfur (Ca:S) by increasing limestone quantity, and improving the liquid-to-gas ratio. The proposed design changes and equipment upgrades consisted of adding an additional spray level, optimizing the spray level coverage, and the incorporation of a pH buffer.

When considering the potential operational improvements, increasing the quality of the limestone is not considered technically feasible for Unit 1 or Unit 2. The limestone used at LOS is already of high quality for use in wet scrubbers. Therefore, it is not technically feasible to increase the quality of the limestone to reduce SO_2 emissions.

Increasing the stoichiometric ratio of Ca:S is considered technically feasible. For LOS Unit 1 and Unit 2, increasing the Ca:S stoichiometric ratio is best accomplished by increasing the quantity of fresh limestone introduced into the system.

The limestone feed rate for Unit 1 is maintained near the maximum design stoichiometry based on the inlet SO_2 concentration. Therefore, increasing the fresh limestone addition rate slightly could provide minor additional SO_2 removal for Unit 1. Increasing the amount of fresh limestone added to the system would provide a performance rate improvement of 0.01 lb SO_2 per MMBtu. This equates to a 10% reduction in SO_2 emissions from the baseline scenario of 0.09 lb SO_2 per MMBtu. Increasing the Ca:S stoichiometric ratio is considered a technically feasible SO_2 control option for LOS Unit 1.

The recycle slurry flow rates for Unit 1 indicate that Unit 1 operating pumps typically operate at their maximum capacity. The recycle pumps are not adjusted for operating load or SO_2 loading. Therefore, changes to the liquid-to-gas (L/G) ratio at Unit 1 is not considering to be technically feasible.

As stated above, increasing the limestone feed rate for Unit 2 is technically feasible, but would need to be done in tandem with increasing the liquid-to-gas (L/G) ratio, since Unit 2 is not currently operating at its maximum design L/G ratio. Only three of the four recycle pumps have been operating at a time. Increasing the amount of fresh limestone added to the system in tandem with increasing the L/G ratio would provide a performance rate improvement of 0.01 lb SO_2 per MMBtu. This equates to an 11% reduction in SO_2 emissions from the baseline scenario of 0.08 lb SO_2 per MMBtu. Increasing the Ca:S stoichiometric ratio in tandem with increasing the L/G ratio is considered a technically feasible SO_2 control option for LOS Unit 2.

Regarding design changes, it is not technically feasible to add an additional spray level or to optimize the spray level coverage for Unit 1 or Unit 2. There is no room for an additional spray level on either unit. After reviewing the operations at LOS, the original equipment manufacturer of LOS's WFGD spray coverage concluded that no additional improvements could be made to the spray nozzle design that would reduce SO_2 emissions. Therefore, adding an additional spray level and optimizing the spray level coverage are not considered to be technically feasible SO_2 control strategies and will not be considered further.

The use of dibasic acid (DBA), a pH buffer additive, in conjunction with increasing the rate of injection of fresh limestone is expected to reduce SO_2 emissions at both Unit 1 and Unit 2.

Unit 1 could achieve a performance rate of 0.06 lb SO_2 per MMBtu using DBA in conjunction with increasing the fresh limestone injection rate. This equates to a 38% reduction in SO_2 emissions from the baseline scenario of 0.09 lb SO_2 per MMBtu. A pH buffer additive is considered a technically feasible SO_2 control option for LOS Unit 1.

Unit 2 could achieve a performance rate of 0.05 lb SO_2 per MMBtu using DBA in conjunction with increasing the fresh limestone injection rate. This equates to a 41% reduction in SO_2 emissions from the baseline scenario of 0.08 lb SO_2 per MMBtu. A pH buffer additive is considered a technically feasible SO_2 control option for LOS Unit 2.

4.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost of compliance for the reasonable progress controls are listed in Table 16 (Unit 1) and Table 17 (Unit 2).

Table 16: SO_2 Cost of Compliance and Incremental Cost of Compliance (Unit 1)

Control Technology	Performance Rate (lb SO_2/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
WFGD (Baseline)	0.09				
Ca:S Stoichiometry	0.08	59	752,000	12,698	
pH Buffer Additive	0.06	237	4,833,418	20,357	22,902

Table 17: SO_2 Cost of Compliance and Incremental Cost of Compliance (Unit 1)

Control Technology	Performance Rate (lb SO_2/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
WFGD (Baseline)	0.09				
Ca:S Stoichiometry and L/G Ratio	0.08	128	1,439,000	11,264	
pH Buffer Additive	0.05	464	8,287,368	17,843	20,340

A detailed breakdown of the costs listed in Table 16 and Table 17 can be found in Basin's submitted four factors analysis.[11] The Department has reviewed these costs and believes them to be accurate.

Ca:S stoichiometric adjustments on Unit 1 would provide a potential 10% reduction in emissions from the baseline scenario. This would result in approximately 60 tons of SO_2 being reduced at an annualized cost of approximately $752,000, equating to approximately $12,700 per ton of SO_2 reduced. This control option does not provide a significant reduction in emissions.

Ca:S stoichiometric adjustments in tandem with increasing the L/G ratio on Unit 2 would provide a potential 11% reduction in emissions from the baseline scenario. This would result in approximately 130 tons of SO_2 being removed at an annualized cost of approximately $1.4 million, equating to approximately $11,300 per ton of SO_2 reduced.

Incorporation of a pH buffer additive on Unit 1 would provide a potential 38% reduction in emissions from the baseline scenario. This would result in approximately 240 tons of SO_2 being reduced at an annualized cost of approximately $4.8 million, equating to approximately $20,400 per ton of SO_2 reduced.

Incorporation of a pH buffer additive on Unit 2 would provide a potential 41% reduction in emissions from the baseline scenario. This would result in approximately 460 tons of SO_2 being reduced at an annualized cost of approximately $8.3 million, equating to approximately $17,800 per ton of SO_2 reduced.

[11] Appendix B.3.b. Appendix C. PDF page 482.

4.3 Step 2 – Time Necessary for Compliance

A summary of the anticipated timelines for the installation of the technically feasible control technologies for Unit 1 is provided in Table 18.

Table 18: Time Required for SO_2 Controls (Unit 1)

Control Technology	Total time after SIP approval (months)
Ca:S Stoichiometry	3
pH Buffer Additive	12

The anticipated timelines for the installation of each of the control technologies indicates all options could be installed prior to the end of the second planning period.

A summary of the anticipated timelines for the installation of the technically feasible control technologies for Unit 2 is provided in Table 19.

Table 19: Time Required for SO_2 Controls (Unit 2)

Control Technology	Total time after SIP approval (months)
Ca:S Stoichiometry and L/G Ratio	3
pH Buffer Additive	12

The anticipated timelines for the installation of each of the control technologies indicates all options could be installed prior to the end of the second planning period.

4.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

4.4.1 Energy

Adjustment of the Ca:S stoichiometric ratio would require an increased operation of the recycle pump, which will increase the auxiliary power requirements. This would adversely affect the net plant heat rate. This impact is significant but not significant enough to eliminate adjustment of the Ca:S stoichiometric ratio as a control option.

4.4.2 Non-Air Quality Environmental Impacts

There are no known significant non-air quality environmental impacts associated with any of the technically feasible SO_2 control technologies.

4.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, LOS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

A.4 – CCS

1 Introduction and Representative Operations

Coal Creek Station (CCS) is a two-unit electrical generating utility (EGU). Each unit has the capacity to produce approximately 605 megawatts (MW) of power on a gross basis. Unit 1 and Unit 2 are identical Combustion Engineering boilers firing pulverized lignite coal tangentially. Unit 1 has a heat input capacity of 6,015 MMBtu per hour; Unit 2 has a heat input capacity of 6,022 MMBtu per hour. Unit 1 began commercial operation in 1979. Unit 2 began commercial operation in 1980. CCS is located in south central McLean County about five miles south of the town of Underwood, North Dakota and approximately three miles west of US Highway 83. CCS receives its lignite coal from the Falkirk Mine that is operated by the Falkirk Mining Company, which is a subsidiary of the North American Coal Corporation.

The average annual amount of North Dakota lignite coal combusted at CCS from 2009 through 2018 was approximately 7.2 million tons. See Table 1 for detailed information.

Table 1: Yearly Coal Combusted (tons)

Year	Unit 1 (tons)	Unit 2 (tons)
2009	4,095,584	3,941,997
2010	3,835,877	3,284,752
2011	4,371,455	4,801,722
2012	3,645,837	3,579,986
2013	3,623,564	3,304,313
2014	3,407,090	3,528,472
2015	3,439,201	3,446,814
2016	3,355,393	2,862,056
2017	2,752,937	3,394,443
2018	3,750,337	3,667,824
Average	**3,627,728**	**3,581,238**
Combined Average	**7,208,966**	

Over the same 10-year period (2009–2018), CCS operated at an 87% annual capacity factor (ACF), as determined on an actual heat input basis. Based on information provided to the North Dakota Department of Environmental Quality, Division of Air Quality (Department), future operations are expected to be consistent with this 10-year period and the 87% annual capacity factor was used when calculating the baseline and future projected emissions discussed in Section 2.

Table 2 displays the operational information from 2009–2018. The ACF is calculated by dividing the actual heat input by the maximum potential heat input for Unit 1 (52.69×10^6 MMBtu/yr) and Unit 2 (52.75×10^6 MMBtu/yr).

Table 2: Utilization and Annual Capacity Factor

Year	Unit 1 Heat Input (MMBtu/yr)	Unit 2 Heat Input (MMBtu/yr)	Unit 1 Annual Capacity Factor	Unit 2 Annual Capacity Factor
2009	49,625,416	48,220,581	0.94	0.91

Year	Unit 1 Heat Input (MMBtu/yr)	Unit 2 Heat Input (MMBtu/yr)	Unit 1 Annual Capacity Factor	Unit 2 Annual Capacity Factor
2010	49,409,811	41,998,558	0.94	0.80
2011	43,014,802	46,942,626	0.82	0.89
2012	48,676,811	47,951,409	0.92	0.91
2013	48,686,810	43,924,548	0.92	0.83
2014	46,286,312	46,530,063	0.88	0.88
2015	47,059,790	46,053,317	0.89	0.87
2016	45,437,239	38,498,049	0.86	0.73
2017	37,327,033	44,826,636	0.71	0.85
2018	48,250,097	47,761,484	0.92	0.91
Average	**46,377,412**	**45,270,727**	**0.88**	**0.86**
		Combined Average	**0.87**	

2 SO_2 Emissions Controls and History

CCS commenced operation in 1979 when Unit 1 was started up. As is stated above, Unit 2 was started up in 1980. CCS was deemed BART eligible in round 1 of Regional Haze and an analysis determined that 0.15 lb/MMBtu of SO_2 as a 30-day rolling average met BART requirements. CCS currently operates four-module wet flue gas desulfurization scrubbers to comply with the 0.15 lb/MMBtu SO_2 limit.

2.1 SO_2

2.1.1 SO_2 Emissions Controls

CCS is equipped with wet flue gas desulfurization (WFGD) for SO_2 control on Unit 1 and Unit 2. CCS also utilizes DryFining™, a multi-pollutant control technology. DryFining™ provides a heat input reduction that correspondingly decreases the amount of flue gas created in the combustion process. In 2017 a novel flue gas reheat system was installed. This allows for an additional proportion of gas to be routed to the wet scrubber instead of having to bypass, providing a decrease in the lb/MMBtu SO_2 emission rate.[1] Both exhaust stacks are equipped with a SO_2 continuous emissions monitoring system (CEMS).

2.1.2 SO_2 Emissions History

June 2017 through December 2018 was used to determine the SO_2 baseline emissions rate from CCS. This time period was chosen since it serves as the best representation of expected emissions and performance rate of the WFGD operations. This information is displayed in Table 3.

Table 3: SO_2 emissions

Year	Unit 1 Emissions		Unit 2 Emissions	
	lb SO_2/MMBtu	tons SO_2	lb SO_2/MMBtu	tons SO_2
2017	0.14	1,938	0.14	1,793
2018	0.14	3,458	0.14	3,400

[1] Appendix B.4.b, p 5. PDF page 1051.

Year	Unit 1 Emissions		Unit 2 Emissions	
	lb SO_2/MMBtu	**tons SO_2**	**lb SO_2/MMBtu**	**tons SO_2**
Baseline	0.14	2,698	0.14	2,596

The average emissions rate of 0.14 lb SO_2 per MMBtu is representative of future expected operations. This value is used as the starting point when determining the cost of compliance for the add-on controls evaluated in Section 3.2.

3 SO_2 Analysis

3.1 SO_2 Technologies

The reasonable progress controls that were identified for analysis for CCS Unit 1 and Unit 2 are listed in Table 4, along with their approximate annual control efficiency. All controls were deemed technically feasible.

Table 4: SO_2 Controls Identified for Analysis

Control Technology	Approximate Annual Control Efficiency
Dry Sorbent Injection	50-70%
Spray Dry Absorption	70-90%
Natural Gas Reheat System	96%
New Wet Stack	96%

CCS currently utilizes a minor bypass in limited situations to maintain dry stack conditions. A natural gas reheat system or new wet stacks would theoretically remove the need for this bypass, maximizing the proportion of flue gas to the wet scrubber.[2] Both methods were analyzed as potential options and result in the same control efficiency. The existing WFGD system currently achieves an annual average removal efficiency of approximately 94% to 95%.[3] Dry sorbent injection and spray dry absorption would not provide improvement over CCS's existing SO_2 emissions control system and were not evaluated further.

3.1.1 New Wet Stack

One control option that was analyzed was the replacement of the current stacks on Unit 1 and Unit 2. CCS Unit 1 and Unit 2 are both dry stacks, despite using a wet scrubber. Converting the existing stacks to a wet stack design is not possible and instead new wet stacks would need to be constructed and the current stacks would be abandoned and demolished. For the evaluation of a new wet stack, Hamon Custodis, Inc. provided an initial high-level concept to effectively replace the two existing stacks with a rough budget price. CCS has added to this price a high-level and conservatively low set of cost estimates to convert the Custodis cost to an appropriate diameter and

[2] Appendix B.4.b, pp 25-26. PDF pages 1071-1072.
[3] Appendix B.4.b, p 25. PDF page 1071.

to include foundations, duct work, and continuous emissions monitoring systems (CEMS).[4] A new wet stack would result in an approximate 1,377 ton per year reduction of SO_2.

3.1.2 Natural Gas Reheat System

CCS Units 1 and 2 currently utilize a novel flue gas reheat system that can maintain a dry stack under most operating situations, while maximizing the proportion of flue gas to the wet scrubber. During low load and cold weather operation, the existing reheat system does not provide enough thermal energy to reheat the stack gas to a dry state. The existing reheat system adds approximately 11 MMBtu/hr, and CCS estimates that approximately 31.5 MMBtu/hr of additional energy would be required to maintain a dry stack under all operating conditions. WBI Energy provided a cost estimate for a new gas line, with the cost split between both units. Barr Engineering provided an estimate for the natural gas-fired duct burner system, with additional consideration for site-specific installation factors. [5] The installation of a new natural gas reheat system would result in an approximate 1,377 ton per year reduction of SO_2.

3.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost of compliance for the reasonable progress controls are listed in Table 5.

Table 5: SO_2 Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Rate (lb SO_2/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
WFGD(Baseline)	0.14			
New Wet Stack	0.08	1,377	3,979,749	2,890
Natural Gas Reheat System	0.08	1,377	3,388,308	2,460

A detailed breakdown of the costs listed in Table 5 can be found in Great River Energy's submitted four factors analysis.[6] The Department has reviewed these costs and believes them to be accurate.

A new wet stack would result in a cost of compliance value of $2,890 per ton of SO_2 removed. A new natural gas reheat system would result in a cost of compliance value of $2,460 per ton of SO_2 removed.

3.3 Step 2 – Time Necessary for Compliance

Both the new wet stack and natural gas reheat system would require at least two to three years to engineer, permit, and install the equipment. Therefore, time necessary for compliance is not a limiting factor when determining additional reasonable controls. The anticipated timeline would allow for either option to be installed prior to the end of the second round of regional haze.

[4] Appendix B.4.b, p 26. PDF page 1072.
[5] Appendix B.4.b, pp 26-27. PDF pages 1072-1073.
[6] Appendix B.4.b. Appendix A. PDF page 1078.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

The replacement wet stack would result in the demolition and disposal of a significant amount of materials with associated use of demolition equipment and portable engines to accommodate these activities.

The natural gas-fired reheat system would result in additional non-SO_2 pollutant emissions from the combustion of natural gas onsite. Potential NO_x emissions are estimated to be between 14 and 27 tons per year.[7]

The energy and non-air quality environmental impacts from the new wet stack or the natural gas reheat system are significant but do not significant enough to remove the control technology from consideration.

3.5 Step 4 – Remaining Useful Life

For the purposes of this analysis, a 20-year life was used for CCS to calculate emission reductions, amortized costs, and cost effectiveness. Therefore, remaining useful life does not need to be considered for the purposes of round 2 planning.

[7] Appendix B.4.b, p 29. PDF page 1075.

A.5 – Minnkota MRY

1 Introduction and Representative Operations

Minnkota Power Cooperative, Inc. (Minnkota) – Milton R. Young Station (MRYS) is a two-unit electrical generating station. Unit 1 is a Babcock & Wilcox cyclone-fired boilers fired on lignite coal. Unit 1 commenced commercial operation in 1970. Unit 1 has a turbine-generator nameplate rating of 257 megawatts (MW) and a nominal rated heat input capacity of 3,200 MMBtu per hour. MRYS is located approximately five miles southeast of the town of Center, North Dakota. MRYS receives lignite from BNI Coal, Ltd's Center Mine, which is located adjacent to the facility.

The average annual amount of North Dakota lignite coal combusted at MRYS Unit 1 from 2009 through 2018 was 1.5 million tons. See Table 1 for detailed information.

Table 1: MRYS Unit 1 Coal Combusted

Year	Coal Combusted (tons)
2009	1,324,257
2010	1,582,806
2011	1,408,716
2012	1,610,825
2013	1,465,413
2014	1,545,188
2015	1,373,362
2016	1,683,786
2017	1,626,840
2018	1,320,317
Average	**1,494,151**

Over this same period (2009–2018), MRYS Unit 1 operated at a 70% annual capacity factor (ACF), as determined on an actual heat input basis. Future operations are expected to be consistent with this 10-year period and the 70% annual capacity factor was used when calculating the baseline and future projected emissions discussed in Section 2.

Table 2 displays the operational information from 2009-2018. The ACF is calculated by dividing the actual heat input by the maximum potential heat input of 28.0×10^6 MMBtu per year.

Table 2: Utilization and Annual Capacity Factor

Year	Actual Heat Input (MMBtu/yr)	Annual Capacity Factor
2009	17,449,077	0.62
2010	20,765,112	0.74
2011	18,534,017	0.66
2012	20,670,979	0.74
2013	18,864,309	0.67

Year	Actual Heat Input (MMBtu/yr)	Annual Capacity Factor
2014	19,129,722	0.68
2015	17,646,175	0.63
2016	23,097,486	0.82
2017	21,628,091	0.77
2018	17,453,674	0.62
Average	**19,523,864**	**0.70**

2 NO_X and SO_2 Emissions Controls and Representative History

MRYS Unit 1 commenced commercial operation in 1970. In April 2006, the Environmental Protection Agency, Department of Justice and the State of North Dakota, reached a Clean Air Act (CAA) major New Source Review Program settlement with Minnkota Power Cooperative and Square Butte Power Cooperative. Minnkota was required to spend approximately $100 million to install or upgrade state-of-the-art pollution controls between the time of the settlement and 2011. Minnkota was also required to reduce 23,561 tons per year (tpy) of SO_2 by 2012, 9,458 tpy of NO_x by 2010, and to comply with declining plant-wide caps for SO_2. The proposed Consent Decree requirements were incorporated into enforceable permits. The agreement resolved CAA violations that occurred at MRYS. MRYS was deemed BART-eligible in the first round of the regional haze program.

2.1 NOx

2.1.1 NO_X Emissions Controls

MRYS Unit 1 is equipped with Advanced Separated Over Fire Air (ASOFA) and selective non-catalytic reduction (SNCR) for NO_x control. These were the BART controls selected in the first round of the Regional Haze program.[1] Minnkota previously entered into a Consent Decree that required MRYS to install BACT for NO_x, which was determined to be SNCR with ASOFA.[2,3]

2.1.2 NO_X Emissions History

To determine the baseline emission rates, the time period of 2016-2018 was used. These results are shown in Table 3, along with the NO_x emissions for each year.

Table 3: Annual NOx Rate and Emissions

Year	Emissions Rate (lb/MMBtu)	NO_x Emissions (tons)
2016	0.33	3,841
2017	0.33	3,579
2018	0.33	2,924
Average	**0.33**	**3,448**

[1] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 74.
[2] Available at: https://www.epa.gov/enforcement/minnkota-power-cooperative-and-square-butte-electric-cooperative-settlement (Last visited March 23, 2021)
[3] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.4, p.16-19.

The baseline was established in consultation with the NDDEQ. It is the most recent time period that includes two non-major outage years, and one major outage year. Outages on these units follow a three-year cycle, so the time period of 2016-2018 is the most representative of future expected emissions.[4] The average emissions rate of 0.33 lb NO_x per MMBtu is used as the starting point when determining the cost for the add-on controls evaluated in Section 3.2.

2.2 SO2

2.2.1 SO_2 Emissions Controls

MRYS Unit 1 is equipped with wet flue gas desulfurization (WFGD) for SO_2 control. This control technology was installed in 2011 as a result of the BART determination made in the first round of the Regional Haze program.[5] The WFGD system typically achieves an annual removal efficiency of approximately 97% and complies with a 30-day rolling average 95% SO_2 removal efficiency.[6]

2.2.2 SO_2 Emissions History

To determine the baseline emission rates, the time period of 2016-2018 was used. These results are shown in Table 4, along with the SO_2 emissions for each year.

Table 4: Annual SO2 Emissions Rate

Year	Emissions Rate (lb/MMBtu)	SO_2 Emissions (tons)
2016	0.08	909
2017	0.08	905
2018	0.06	518
Average	**0.07**	**777**

The average emission rate of 0.07 lb SO_2 per MMBtu is representative of future expected operations and is used as the starting point when determining the cost of compliance for the additional controls evaluated in Section 4.2. Note that the tons of SO_2 listed in Table 4 do not equal the calculated tons used for the baseline emissions (Table 8). The baseline emissions are calculated using the recent emissions rate with the average ACF over the last 10 years. This results in a difference of approximately 60 tons of SO_2.

3 NOx Analysis

3.1 NO_X Technologies

The reasonable progress controls evaluated by MRYS for Unit 1 are listed in Table 5. Performance rate and expected annual emissions are included for both control technologies that were determined to be technically feasible. MRYS evaluated optimizing their current SNCR control technologies as well as adding Rich Reagent Injection (RRI). Note that the expected annual emissions in Table 5 were calculated using the performance rate, potential heat input, and the ACF (Table 2).

[4] Appendix B.5.b., p. 1-4. PDF page 1157.
[5] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 71.
[6] Appendix B.5.b., p. 3-3 – 3-4. PDF page 1179-1180.

Therefore, the tons of NO_X emissions are different than the tons of NO_X emissions displayed in Table 3 since the table below contains calculated emissions based on representative operations..

Table 5: Reasonable Progress NOx Controls

Control Technology	Performance Rate (lb/MMBtu)	Emissions (tons/year)
SNCR/ASOFA (baseline)	0.33	3,241
Optimized SNCR/ASOFA	0.33	3,221
RRI/SNCR/ASOFA	0.28	2,733

Selective catalytic reduction (SCR) was identified as a potential NO_x control technology but was deemed technically infeasible at MRYS in the previous BART and BACT analysis. No new information or experience has occurred since those analyses to change the conclusions that were made. SCR remains technically infeasible at MRYS.[7]

3.1.1 Optimization of Selective Non-Catalytic Reduction (SNCR)

Utilizing operating and vendor experience acquired since the original installation, enhancements to the existing system were identified to potentially reduce NO_x emission rates. Enhancements include changing the nozzles on existing lances, replacing the existing lances, adding lances in new locations and allowing for higher ammonia slip rates. Higher ammonia slip rates would allow for higher levels of urea injection, potentially reducing NO_x emission rates further. The ASOFA system would be operated in conjunction with the optimized SNCR system. These enhancements are projected to amount to minimal NO_x reductions per year. The optimization of SNCR was deemed technically feasible.

3.1.2 Rich Reagent Injection (RRI)

RRI is a NO_x emission control technology specifically intended for use on cyclone boilers. RRI adds dilute urea reagent to the hot boiler gases near the cyclones. This location must be devoid of free oxygen to avoid oxidation of the urea, which results in the formation of additional NO_x.[8]

The use of RRI control technology in conjunction with SNCR and ASOFA results in a 16% reduction in NO_x emissions from the baseline scenario. The expected performance rate would drop from 0.33 to 0.28 lb NO_x per MMBtu. The 0.28 lb per MMBtu performance rate was determined using MRYS unit-specific operations. Maximum NO_x reductions from both RRI and SNCR systems occur when the boiler is at or near full load, and in a steady-state condition. Emission rates stated by vendors are based on these conditions, and do not always account for site specific operating conditions. RRIs operational effectiveness depends on oxygen-deprived conditions. Both Unit 1 and Unit 2 at MRYS are designed to still be able to achieve full load even if one cyclone burner is out of service. This situation is not unusual during routine maintenance. When this occurs however, air can leak through

[7] Appendix B.5.b., p. 2-3. PDF page 1163.
[8] Appendix B.5.b., p. 2-3. PDF page 1163.

the combustion air dampers of an out-of-service cyclone and will result in the increase of NO_x formation, due to the addition of oxygen in the fuel-rich zone of the in-service boiler.[9]

Another problem MRYS encounters with RRI and other control technologies, is that MRYS is a mine-mouth plant that utilizes run-of-mine fuel. This results in significant coal quality variability. These variations can lead to cyclones becoming fouled, meaning that insufficient temperature exists for the slag to flow properly from the cyclone. When this occurs, fuel oil is co-burned in the fouled cyclone which results in increased oxygen levels in the fuel-rich zone. This leads to additional formation of NO_x.[10] While these factors impact the performance rate for NO_x, the installation of RRI with SNCR and ASOFA was deemed technically feasible under limited conditions and will be evaluated further.

3.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost for the reasonable progress controls are listed in Table 6. Cost estimates are based on a vendor proposal and were calculated based on a 20-year project life.

Table 6: NOx Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
SNCR/ASOFA (Baseline)	0.33				
Optimized SNCR/ASOFA	0.33	20	1,996,685	102,269	
RRI/SNCR/ASOFA	0.28	508	5,996,594	11,813	8,195

A detailed breakdown of the costs listed in Table 6 can be found in Minnkota's submitted four factor analysis.[11] The Department has reviewed these costs and believes them to be accurate.

MRYS relied on a vendor proposal for cost estimates to account for certain site-specific costs that would be incurred implementing these NO_x control technologies. In the case of optimizing the SNCR, the detailed vendor evaluation identified new recommended SNCR injection locations, along with current nozzle and lance enhancements. The resulting annualized cost is approximately $2,000,000, with 83% of that being attributed to the cost of urea reagent. These changes would result in an annual reduction of approximately 20 tons of NO_x, and a cost of compliance value of approximately $102,000 per ton of NO_x reduced.

The implementation of RRI with the SNCR and ASOFA systems would result in an approximate annual reduction of 500 tons of NO_x. The annualized total cost is approximately $6,000,000, with a cost of compliance at $11,800 per ton of NO_x reduced. MRYS submitted its original four-factor analysis on January 31, 2019. NDDEQ questioned the excessive cost estimates for RRI at that time. In the revised four-factor analysis that was submitted on May 29, 2019, MRYS defended these

[9] Appendix B.5.b, p. 2-5. PDF page 1165.
[10] Appendix B.5.b, p. 2-5. PDF page 1165.
[11] Appendix B.5.b. Appendix A. PDF page 1196 and 1211.

estimates. The cost estimates are site-specific and utilized computational fluid dynamic (CFD) modeling and boiler mapping along with vendor proposals.[12] The CFD modeling, boiler mapping, and RRI injection analysis determined that the necessary injection locations needed are not in easily accessible locations on either unit. This results in added cost for new platforms and stairs to access new injection locations, significant new piping for increased urea, cooling water, dilution water and atomization air, expansion of the microfiltration and reverse osmosis water system, and supply and installation of the boiler bent tube openings for the new RRI and SNCR injectors.[13] Minnkota firmly believes that these costs are accurate and represent the actual costs for installation and implementation of RRI with SNCR and ASOFA.

3.3 Step 2 – Time Necessary for Compliance

The time necessary for compliance is not a limiting factor when determining additional reasonable controls for MRYS Unit 1 NO_x emissions since SNCR optimization and/or RRI could be installed prior to the end of the second planning period.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy

The primary energy impact of utilizing RRI with SNCR or optimizing existing SNCR system is reduced boiler efficiency due to evaporation of large amounts of dilute urea. This results in excess coal needing to be burned to evaporate the expected amount of dilute urea in the boiler. An incremental increase in energy will also result from providing more compressed air for reagent atomization. Auxiliary power requirements result in a 66 kW increase in an optimized SNCR, and a 132 kW increase with RRI and SNCR.[14] These energy impacts are only incrementally higher than the existing system, and do not remove either option from consideration.

3.4.2 Non-Air Quality Environmental Impacts

Non-air quality impacts of the control technologies are very similar to the impacts of the existing SNCR system. There may be an increase in ammonia slip, but a majority will be captured in the WFGD system. There will also be additional reverse osmosis/condensate waste due to the increase in demand from the systems and the need to dilute concentrated urea. This would result in millions of gallons of additional water treatment wastewaters being discharged from the MRYS facility on an annual basis. These impacts are considered acceptable and do not remove either option from consideration.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, MRYS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

[12] Appendix B.5.b., p. 2-4. PDF page 1164.
[13] Appendix B.5.b., p.2-7. PDF page 1167.
[14] Appendix B.5.b., p. 2-14. PDF page 1174.

4 SO_2 Analysis

4.1 SO_2 Technologies Evaluated

The reasonable progress controls that were identified for analysis for MRYS Unit 1 are listed in Table 7, along with their approximate annual control efficiency. A new WFGD was not evaluated for Unit 1, as the current system was installed in 2011. All controls were deemed technically feasible.

Table 7: SO_2 Controls Identified for Analysis

Control Technology	Approximate Annual Control Efficiency
ReACT Scrubber	92-98%
Modification of Existing WFGD	96-98%
Circulating Semi-Dry FGD	90-97%
Semi-Dry FGD	90-95%

As discussed in Section 2.2.1, the existing WFGD system currently achieves an annual average removal efficiency of approximately 97%. The approximate annual control efficiencies listed in Table 7 start from an estimate of uncontrolled SO_2 emissions based on inlet sulfur concentration.

4.1.1 Semi-Dry Flue Gas Desulfurization

Semi-dry FGD technology is an alternative to WFGD technology in SO_2 emission control. Spray Dryer Absorber (SDA) is the most common semi-dry FGD system. Circulating Dry Scrubber is another variation of the semi-dry process. SDA technology has never been clearly demonstrated to achieve the same SO_2 removal levels as WFGD technology.[15] The CDS system can achieve better control efficiency than the SDA process, but only achieves similar levels to those of the current WFGD system. Because the semi-dry FGD technologies achieve less or equal SO_2 removal to that of the current WFGD system, neither was evaluated further.

4.1.2 Regenerative Activated Coke Technology

Regenerative Activated Coke Technology (ReACT) is a multipollutant control system that utilizes activated coke to remove SO_2, NO_x and mercury. The ReACT process has been demonstrated to achieve 99% SO_2 removal on low sulfur coal units. However, the supplier of the ReACT process determined that MRYS is not a good candidate for the technology. MRYS factors that would impact the performance and cost of ReACT are that the inlet temperature is too high, higher oxidation of the activated coke would be expected, and the sulfuric acid production rates would be very high.[16] MRYS also utilizes high sulfur coal.[17] ReACT has only been applied on low sulfur fuel, and pilot tests on high sulfur coal have only shown 92-98% SO_2 removal rates. Because these levels could be achieved by the existing wet FGD system, ReACT was not evaluated further.

[15] Appendix B.5.b., p. 3-5. PDF page 1181.
[16] Appendix B.5.b., p. 3-5. PDF page 1181.
[17] Appendix B.5.b., p. 3-5. PDF page 1181.

4.1.3 Modification of Existing Wet FGD (WFGD) System

The original equipment manufacturer for the existing WFGD system on Unit 1 evaluated potential modifications that could increase the SO_2 removal efficiency of the system. The upgrades that were evaluated include increasing the liquid-to-gas ratio, installation of new types of spray nozzles, running additional pumps, and adjusting the operating conditions of the scrubber. The evaluation determined that Unit 1 could achieve 97.4% SO_2 removal by increasing the Calcium/Sulfur stoichiometry to 1.025[18] and replacing three of four recirculation pump motors to increase the liquid to gas ratio in the scrubber.[19] This modification was deemed technically feasible and was evaluated further. The performance rate and SO_2 annual emissions are shown for this technology and the baseline in Table 8. Note that the expected annual emissions in Table 8 were calculated using the performance rate, potential heat input, and the ACF (Table 2). Therefore, the tons of SO_2 emissions are different than the tons of SO_2 emissions displayed in Table 4 since the table below contains calculated emissions based on representative operations..

Table 8: Reasonable Progress SO_2 Controls

Control Technology	Performance Rate (lb/MMBtu)	Emissions (tons/year)
WFGD (Baseline)	0.07	721
Modify WFGD	0.06	595

4.2 Step 1 – Cost of Compliance

The cost of compliance for modification of the existing WFGD is shown in Table 9.

Table 9: SO_2 Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
WFGD	0.074			
Modified WFGD	0.061	126	365,562	2,903

A detailed breakdown of the costs listed in Table 9 can be found in Minnkota's submitted four factor analysis.[20] The Department has reviewed these costs and believes them to be accurate.

The cost estimates for modifying the existing WFGD system were provided by the original equipment manufacturer. These costs were supplemented with engineering estimates for installation from Burns & McDonnell. The cost estimates are limited to these factors and assumes that all other existing systems, including the existing electrical system, are capable of supporting the modifications with no further upgrades.[21] It is also assumed that no change in operating staff will

[18] Appendix B.5.b., p. 3-4. PDF page 1180.
[19] Appendix B.5.b., p.3-9. PDF page 1185.
[20] Appendix B.5.b., p.3-9 – 3-13. PDF page 1185-1189.
[21] Appendix B.5.b., p. 3-9. PDF page 1185.

occur from the modifications. These conservative estimates result in a cost of compliance value of $2,900 per ton of SO_2 removed.

4.3 Step 2 – Time Necessary for Compliance

The process to bid, design, purchase, and install retrofits to an existing WFGD system can take two to three years.[22] The time necessary for compliance is not a limiting factor when determining additional reasonable controls for MRYS Unit 1 SO_2 emissions since the WFDG could be modified prior to the end of the second planning period.

4.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

4.4.1 Energy

Modifying the existing WFGD will result in an energy demand increase of 586 kW, a 0.3% increase in the percent of nominal generation. This increase is acceptable and does not remove WFGD modification as a control option.

4.4.2 Non-Air Quality Environmental Impacts

Modifying the existing WFGD system will have similar non-air quality environmental impacts to those of the existing system. However, there will be an incremental increase in the solids disposal rate as additional removal of SO_2 will result in increased byproduct. This is not a significant impact and does not remove the control technology from consideration.

4.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, MRYS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

[22] Appendix B.5.b., p. 3-14. PDF page 1190

1 Introduction and Representative Operations

Minnkota Power Cooperative, Inc. (Minnkota) – Milton R. Young Station (MRYS) is a two-unit electrical generating station. Unit 2 is a Babcock & Wilcox cyclone-fired boilers fired on lignite coal. Unit 2 commenced commercial operation in 1977. Unit 2 has a turbine-generator nameplate rating of 477 MW and a nominal rated heat input capacity of 6,300 MMBtu per hour. MRYS is located approximately five miles southeast of the town of Center, North Dakota. MRYS receives lignite from BNI Coal, Ltd's Center Mine, which is located adjacent to the facility.

The average annual amount of North Dakota lignite coal combusted at MRYS Unit 2 from 2009 through 2018 was 2.6 million tons. See Table 1 for detailed information.

Table 1: MRYS Unit 2 Coal Combusted

Year	Coal Combusted (tons)
2009	2,690,168
2010	2,119,700
2011	2,949,190
2012	2,746,928
2013	2,102,746
2014	2,290,214
2015	2,845,985
2016	2,160,413
2017	3,010,361
2018	2,978,138
Average	**2,589,384**

Over this same period (2009–2018), MRYS Unit 2 operated at a 61% annual capacity factor (ACF), as determined on an actual heat input basis. Future operations are expected to be consistent with this 10-year period and the 61% annual capacity factor was used when calculating the baseline and future projected emissions discussed in Section 2.

Table 2 displays the operational information from 2009–2018 for Unit 2. The ACF is calculated by dividing the actual heat input by the maximum potential heat input of 55.1×10^6 MMBtu per year.

Table 2: Utilization and Annual Capacity Factor

Year	Actual Heat Input (MMBtu/yr)	Annual Capacity Factor
2009	36,697,676	0.66
2010	29,507,936	0.53
2011	41,664,019	0.75
2012	34,923,781	0.63

Year	Actual Heat Input (MMBtu/yr)	Annual Capacity Factor
2013	26,539,099	0.48
2014	29,840,051	0.54
2015	36,389,744	0.66
2016	26,618,855	0.48
2017	38,455,791	0.70
2018	37,990,222	0.69
Average	**33,862,717**	**0.61**

2 NO_X and SO_2 Emissions Controls and Representative History

MRYS Unit 2 commenced commercial operation in 1977. In April 2006, the Environmental Protection Agency, Department of Justice and the State of North Dakota, reached a Clean Air Act (CAA) major New Source Review Program settlement with Minnkota Power Cooperative and Square Butte Power Cooperative. Minnkota was required to spend approximately $100 million to install or upgrade state-of-the-art pollution controls between the time of the settlement and 2011. Minnkota was also required to reduce 23,561 tons per year (tpy) of SO_2 by 2012, 9,458 tpy of NO_x by 2010, and to comply with declining plant-wide caps for SO_2. The proposed Consent Decree requirements were incorporated into enforceable permits. The agreement resolved CAA violations that occurred at MRYS. It was deemed BART-eligible in the first round of the regional haze program.

2.1 NOx

2.1.1 NO_X Emissions Controls

MRYS Unit 2 is equipped with Advanced Separated Over Fire Air (ASOFA) and selective non-catalytic reduction (SNCR) for NO_x control. These were the BART controls selected in the first round of the Regional Haze program.[1] Minnkota previously entered into a Consent Decree that required MRYS to install BACT for NO_x, which was determined to be SNCR with ASOFA.[2,3]

2.1.2 NO_X Emissions History

To determine the baseline emission rates, the time period of 2016-2018 was used. These results are shown in Table 3, along with the NO_x emissions for each year.

Table 3: Annual NOx Rate and Emissions

Year	Emissions Rate (lb/MMBtu)	NO_x Emissions (tons)
2016	0.33	4,466
2017	0.33	6,390
2018	0.33	6,351
Average	**0.33**	**5,736**

[1] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 74.
[2] Available at: https://www.epa.gov/enforcement/minnkota-power-cooperative-and-square-butte-electric-cooperative-settlement (Last visited March 23, 2021)
[3] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.4, p.16-19.

The baseline was established in consultation with the NDDEQ. It is the most recent time period that includes two non-major outage years, and one major outage year. Outages on these units follow a three-year cycle, so the time period of 2016-2018 is the most representative of future expected emissions.[4] The average emissions rate of 0.33 lb NO_x per MMBtu is used as the starting point when determining the cost of compliance for the add-on controls evaluated in Section 3.2.

2.2 SO2

2.2.1 SO_2 Emissions Controls

MRYS Unit 2 is equipped with wet flue gas desulfurization (WFGD) for SO_2 control. This control technology was installed prior to the first round of the Regional Haze program. In the first round, the BART selected by the Department for Unit 2 was a 95% reduction efficiency or a limit of 0.15 lb/MMBtu on a 30-day rolling average, which could be achieved by modifying the existing scrubber. The Consent Decree for MRYS required a minimum of 90% reduction of SO_2 and was included in the BART permit.[5] The WFGD system typically achieves an annual removal efficiency of approximately 95% and complies with a 30-day rolling average 90% SO_2 removal efficiency and a 30-day rolling average 0.15 lb/MMBtu emission rate.

2.2.2 SO_2 Emissions History

To determine the baseline emission rates, the time period of 2016-2018 was used. These results are shown in Table 4, along with the SO_2 emissions for each year.

Table 4: Annual SO2 Emissions Rate

Year	Emissions Rate (lb/MMBtu)	SO_2 Emissions (tons)
2016	0.13	1,729
2017	0.13	2,507
2018	0.12	2,258
Average	**0.13**	**2,165**

The average emission rate of 0.13 lb SO_2 per MMBtu is representative of future expected operations and is used as the starting point when determining the cost of compliance for the additional controls evaluated in Section 4.2. Note that the tons of SO_2 listed in Table 4 do not equal the calculated tons used for the baseline emissions (Table 8). The baseline emissions are calculated using the recent emissions rate with the average ACF over the last 10 years. This results in a difference of approximately 30 tons of SO_2.

3 NOx Four-Factor Analysis

3.1 NO_X Technologies

The reasonable progress controls evaluated by MRYS for Unit 2 are listed in Table 5. Performance rate and expected annual emissions are included for both control technologies that were determined to be technically feasible. MRYS evaluated optimizing their current SNCR control technologies as well as adding Rich Reagent Injection (RRI). Note that the expected annual emissions

[4] Appendix B.5.b., p. 1-4. PDF page 1157.
[5] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 71.

in Table 5 were calculated using the performance rate, potential heat input, and the ACF (Table 2). Therefore, the tons of NO_X emissions are different than the tons of NO_X emissions displayed in Table 3 since the table below contains calculated emissions based on representative operations.

Table 5: Reasonable Progress NOx Controls

Control Technology	Performance Rate (lb/MMBtu)	Emissions (tons/year)
SNCR/ASOFA (baseline)	0.33	5,655
Optimized SNCR/ASOFA	0.32	5,418
RRI/SNCR/ASOFA	0.26	4,402

Selective catalytic reduction (SCR) was identified as a potential NO_x control technology but was deemed technically infeasible at MRYS in the previous BART and BACT analysis. No new information or experience has occurred since those analyses to change the conclusions that were made. SCR remains technically infeasible at MRYS.[6]

3.1.1 Optimization of Selective Non-Catalytic Reduction (SNCR)

Utilizing operating and vendor experience acquired since the original installation, enhancements to the existing system were identified to potentially reduce NO_x emission rates. Enhancements include changing the nozzles on existing lances, replacing the existing lances, adding lances in new locations and allowing for higher ammonia slip rates. Higher ammonia slip rates would allow for higher levels of urea injection, potentially reducing NO_x emission rates further. The ASOFA system would be operated in conjunction with the optimized SNCR system. These enhancements are projected to amount to approximately 240 tons of NO_x reductions per year. The optimization of SNCR was deemed technically feasible for Unit 2.

3.1.2 Rich Reagent Injection (RRI)

RRI is a NO_x emission control technology specifically intended for use on cyclone boilers. RRI adds dilute urea reagent to the hot boiler gases near the cyclones. This location must be devoid of free oxygen to avoid oxidation of the urea, which results in the formation of additional NO_x.[7]

The use of RRI control technology in conjunction with SNCR and ASOFA results in a 22% reduction in NO_x emissions from the baseline scenario. The expected performance rate would drop from 0.33 to 0.26 lb NO_x per MMBtu. The 0.26 lb per MMBtu performance rate was determined using MRYS unit-specific operations. Maximum NO_x reductions from both RRI and SNCR systems occur when the boiler is at or near full load, and in a steady-state condition. Emission rates stated by vendors are based on these conditions, and do not always account for site specific operating conditions. RRIs operational effectiveness depends on oxygen-deprived conditions. Both Unit 1 and Unit 2 at MRYS are designed to still be able to achieve full load even if one cyclone burner is out of service. This situation is not unusual during routine maintenance. When this occurs however, air can leak through

[6] Appendix B.5.b., p. 2-3. PDF page 1163.
[7] Appendix B.5.b., p. 2-3. PDF page 1163.

the combustion air dampers of an out-of-service cyclone and will result in the increase of NO_x formation, due to the addition of oxygen in the fuel-rich zone of the in-service boiler.[8]

Another problem MRYS encounters with RRI and other control technologies, is that MRYS is a mine-mouth plant that utilizes run-of-mine fuel. This results in significant coal quality variability. These variations can lead to cyclones becoming fouled, meaning that insufficient temperature exists for the slag to flow properly from the cyclone. When this occurs, fuel oil is co-burned in the fouled cyclone which results in increased oxygen levels in the fuel-rich zone. This leads to additional formation of NO_x.[9] While these factors impact the performance rate for NO_x, the installation of RRI with SNCR and ASOFA was deemed technically feasible under limited conditions and will be evaluated further.

3.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost of compliance for the reasonable progress controls are listed in Table 6. Cost estimates are based on a vendor proposal and were calculated based on a 20-year project life.

Table 6: NOx Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
SNCR/ASOFA (Baseline)	0.33				
Optimized SNCR/ASOFA	0.32	237	1,786,833	7,538	
RRI/SNCR/ASOFA	0.26	1,253	7,496,503	5,983	5,620

A detailed breakdown of the costs listed in Table 6 can be found in Minnkota's submitted four factor analysis.[10] The Department has reviewed these costs and believes them to be accurate.

MRYS relied on a vendor proposal for cost estimates to account for certain site-specific costs that would be incurred implementing these NO_x control technologies. In the case of optimizing the SNCR, the detailed vendor evaluation identified new recommended SNCR injection locations, along with current nozzle and lance enhancements. The resulting annualized cost for Unit 2 is approximately $1,800,000. These changes would result in an annual reduction of approximately 240 tons of NO_x, and a cost of compliance value of $7,500 per ton of NO_x reduced.

The implementation of RRI with the SNCR and ASOFA systems would result in an approximate annual reduction of 1,250 tons of NO_x. The annualized total cost is approximately $7,500,000, with a cost of compliance at $6,000 per ton of NO_x reduced. MRYS submitted its original four-factor analysis on January 31, 2019. NDDEQ questioned the excessive cost estimates for RRI at that time. In the revised four-factor analysis that was submitted on May 29, 2019, MRYS defended these estimates. The cost estimates are site-specific and utilized computational fluid dynamic (CFD)

[8] Appendix B.5.b, p. 2-5. PDF page 1165.
[9] Appendix B.5.b, p. 2-5. PDF page 1165.
[10] Appendix B.5.b. Appendix A. PDF page 1196 and 1211.

modeling and boiler mapping along with vendor proposals.[11] The CFD modeling, boiler mapping, and RRI injection analysis determined that the necessary injection locations needed are not in easily accessible locations on either unit. This results in added cost for new platforms and stairs to access new injection locations, significant new piping for increased urea, cooling water, dilution water and atomization air, expansion of the microfiltration and reverse osmosis water system, and supply and installation of the boiler bent tube openings for the new RRI and SNCR injectors.[12] Minnkota firmly believes that these costs are accurate and represent the actual costs for installation and implementation of RRI with SNCR and ASOFA.

3.3 Step 2 – Time Necessary for Compliance

The time necessary for compliance is not a limiting factor when determining additional reasonable controls for MRYS Unit 2 NO_x emissions since SNCR optimization and/or RRI could be installed prior to the end of the second planning period.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy

The primary energy impact of utilizing RRI with SNCR or optimizing existing SNCR system is reduced boiler efficiency due to evaporation of large amounts of dilute urea. This results in excess coal needing to be burned to evaporate the expected amount of dilute urea in the boiler. An incremental increase in energy will also result from providing more compressed air for reagent atomization. Auxiliary power requirements result in a 66 kW increase in an optimized SNCR, and a 132 kW increase with RRI and SNCR.[13] These energy impacts are only incrementally higher than the existing system, and do not remove either option from consideration.

3.4.2 Non-Air Quality Environmental Impacts

Non-air quality impacts of the control technologies are very similar to the impacts of the existing SNCR system. There may be an increase in ammonia slip, but a majority will be captured in the WFGD system. There will also be additional reverse osmosis/condensate waste due to the increase in demand from the systems and the need to dilute concentrated urea. This would result in millions of gallons of additional water treatment wastewaters being discharged from the MRYS facility on an annual basis. These impacts are considered acceptable and do not remove either option from consideration.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, MRYS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

[11] Appendix B.5.b., p. 2-4. PDF page 1164.
[12] Appendix B.5.b., p.2-7. PDF page 1167
[13] Appendix B.5.b., p. 2-14. PDF page 1174.

4 SO_2 Four-Factor Analysis

4.1 SO_2 Technologies Evaluated

The reasonable progress controls that were identified for analysis for MRYS Unit 2 are listed in Table 7, along with their approximate annual control efficiency. All controls were deemed technically feasible.

Table 7: SO_2 Controls Identified for Analysis

Control Technology	Approximate Annual Control Efficiency
ReACT Scrubber	92-98%
New WFGD	98%
Modification of Existing WFGD	96-98%
Circulating Semi-Dry FGD	90-97%
Semi-Dry FGD	90-95%

As discussed in Section 2.2.1, the existing WFGD system currently achieves an annual average removal efficiency of approximately 95%. The approximate annual control efficiencies listed in Table 7 start from an estimate of uncontrolled SO_2 emissions based on inlet sulfur concentration.

4.1.1 Semi-Dry Flue Gas Desulfurization

Semi-dry FGD technology is an alternative to WFGD technology in SO_2 emission control. Spray Dryer Absorber (SDA) is the most common semi-dry FGD system. Circulating Dry Scrubber is another variation of the semi-dry process. SDA technology has never been clearly demonstrated to achieve the same SO_2 removal levels as WFGD technology.[14] The CDS system can achieve better control efficiency than the SDA process, but only achieves similar levels to those of the current WFGD system. Because the semi-dry FGD technologies achieve less or equal SO_2 removal to that of the current WFGD system, neither was evaluated further.

4.1.2 Regenerative Activated Coke Technology

Regenerative Activated Coke Technology (ReACT) is a multipollutant control system that utilizes activated coke to remove SO_2, NO_x and mercury. The ReACT process has been demonstrated to achieve 99% SO_2 removal on low sulfur coal units. However, the supplier of the ReACT process determined that MRYS is not a good candidate for the technology. MRYS factors that would impact the performance and cost of ReACT are that the inlet temperature is too high, higher oxidation of the activated coke would be expected, and the sulfuric acid production rates would be very high.[15] MRYS also utilizes high sulfur coal.[16] ReACT has only been applied on low sulfur fuel, and pilot tests

[14] Appendix B.5.b., p. 3-5. PDF page 1181.
[15] Appendix B.5.b., p. 3-5. PDF page 1181.
[16] Appendix B.5.b., p. 3-5. PDF page 1181.

on high sulfur coal have only shown 92-98% SO_2 removal rates. Because these levels could be achieved by the existing WFGD system, ReACT was not evaluated further.

4.1.3 Modification of Existing Wet FGD (WFGD) System

The original equipment manufacturer for the existing WFGD system on Unit 1 evaluated potential modifications that could increase the SO_2 removal efficiency of both systems. The upgrades that were evaluated include increasing the liquid-to-gas ratio, installation of new types of spray nozzles, running additional pumps, and adjusting the operating conditions of the scrubber. The evaluation determined that Unit 2 could achieve 97.6% SO_2 removal by increasing the Calcium/Sulfur stoichiometry to 1.020[17] and replacing all of the absorber spray nozzles with dual flow nozzles.[18] This modification was deemed technically feasible and was evaluated further.

4.1.4 New WFGD System

A new WFGD system was evaluated at a 98% SO_2 removal efficiency. While some new SO_2 control projects have achieved higher control efficiency, 98% was evaluated to account for upsets, fuel variability, and operation variability.[19] A new WFGD system was deemed technically feasible for MRYS Unit 2. The performance rate and SO_2 annual emissions are shown for this technology, along with a modified WFGD and the baseline, in Table 8. Note that the expected annual emissions in Table 8 were calculated using the performance rate, potential heat input, and the ACF (Table 2). Therefore, the tons of SO_2 emissions are different than the tons of SO_2 emissions displayed in Table 4 since the table below contains calculated emissions based on representative operations.

Table 8: Reasonable Progress SO_2 Controls

Control Technology	Performance Rate (lb/MMBtu)	Emissions (tons/year)
WFGD (Baseline)	0.13	2,133
Modify WFGD	0.06	965
New WFGD	0.05	804

4.2 Step 1 – Cost of Compliance

The cost of compliance for reasonable progress SO_2 controls are shown in Table 9.

Table 9: SO_2 Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost ($/ton)
WFGD (Baseline)	0.13				
Modify WFGD	0.06	1,168	839,319	718	
New WFGD	0.05	1,329	15,978,200	12,022	94,119

[17] Appendix B.5.b., p. 3-4. PDF page 1180.
[18] Appendix B.5.b., p.3-9. PDF page 1185.
[19] Appendix B.5.b., p. 3-3. PDF page 1179.

A detailed breakdown of the costs listed in Table 9 can be found in Minnkota's submitted four factor analysis.[20] The Department has reviewed these costs and believes them to be accurate.

The cost estimates for modifying the existing WFGD system were provided by the original equipment manufacturer. These costs were supplemented with engineering estimates for installation from Burns & McDonnell. The cost estimates are limited to these factors and assumes that all other existing systems, including the existing electrical system, are capable of supporting the modifications with no further upgrades.[21] It is also assumed that no change in operating staff will occur from the modifications. These conservative estimates result in a cost of compliance value of $700 per ton of SO_2 removed.

The cost estimates for a new WFGD system were determined using the 'IPM Model – Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology' available from the U.S. Environmental Protection Agency and supplemented with engineering estimates based upon Burns & McDonnell's in-house experience.[22] One option for the addition of a new WFGD would require new ductwork at the facility, modifications to the coal pile to create needed space, and electrical replacement/upgrades for the new scrubber. This option allows the new WFGD to be installed without an extended outage. The other option would require a significantly extended outage to allow for the existing WFGD system to be shut down while the new system was tied in, commissioned and started up.[23] A conservative approach was taken with the cost estimate of a new WFGD by assuming that all existing plant systems are capable of supporting the new system with no upgrades. The costs are representative of a typical furnish and erect contract by a WFGD system supplier. The resulting cost of compliance for a new WFGD system is approximately $12,000, with an incremental cost of compliance of $94,000.

4.3 Step 2 – Time Necessary for Compliance

The process to bid, design, purchase, and install retrofits to an existing WFGD system can take two to three years, with the installation of a new WFGD system taking significantly longer.[24] The time necessary for compliance is not a limiting factor when determining additional reasonable controls for MRYS Unit 2 since all reasonable cost effective SO_2 control technologies could be installed prior to the end of the second planning period.

4.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

4.4.1 Energy

Modifying the existing WFGD will result in an energy demand increase of 965 kW, a 0.2% increase in the percent of nominal generation. A new WFGD will result in an increase of 2,195 kW, a 0.5%

[20] Appendix B.5.b., p.3-9 – 3-13. PDF page 1185-1189.
[21] Appendix B.5.b., p. 3-9. PDF page 1185.
[22] Appendix B.5.b., p. 3-7. PDF page 1183.
[23] Appendix B.5.b., p. 3-8. PDF page 1184.
[24] Appendix B.5.b., p. 3-14. PDF page 1190.

increase in the percent of nominal generation.[25] These increases are acceptable and do not remove these as control options.

4.4.2 Non-Air Quality Environmental Impacts

Modifying the existing WFGD system will have similar non-air quality environmental impacts to those of the existing system. However, there will be an incremental increase in the solids disposal rate as additional removal of SO_2 will result in increased byproduct. This is not a significant impact and does not remove the control technology from consideration.

4.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, MRYS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

[25] Appendix B.5.b., p. 3-13. PDF page 1189.

A.6 – MDU Heskett

MONTANA-DAKOTA
UTILITIES CO.
A Subsidiary of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
701-222-7900

March 9, 2022

Jim Semerad, Air Program Director
NDDEQ Division of Air Quality
4201 Normandy Street - 2nd Floor
Bismarck ND 58503-1324

Re: Acid Rain Program Retired Unit Exemption Notice
Montana-Dakota Utilities
R.M. Heskett Station Unit 2 (Coal-fired)

Dear Mr. Semerad:

On behalf of Montana-Dakota Utilities (Montana-Dakota), please allow the following correspondence and attached form to serve as Montana-Dakota's timely and formal Retired Unit Exemption Notice. As of January 31, 2022, R.M. Heskett Station Unit 2 will be permanently retired. As such, Unit 2 qualifies for the retired unit exemption pursuant to Title 40 of the Code of Federal Regulations (CFR), Part 72 (40 CFR 72.8).

A signed Retired Unit Exemption form (EPA Form 7610-20) is attached. Montana-Dakota will maintain records demonstrating R.M. Heskett Station Unit 2 is permanently retired for a period of five (5) years, as required by 40 CFR 72.8(d)(5). We would also like to formally inform you the smaller, older 25 MW R.M. Heskett Unit 1 (coal-fired) was permanently shut down (and did not operate) beginning February 25, 2022. Both units are undergoing decommissioning now and anticipated demolition starting late this year. Thank you for your time and attention to this filing.

Should additional information or detail be necessary, please feel free to contact Mark Dihle at 701.222.7865 or mark.dihle@mdu.com

Respectfully submitted,

Mark Dihle
Sr. Environmental Specialist

Attachment

cc: United States Environmental Protection Agency
Andy McDonald, Environmental Compliance Manager

United States Environmental Protection Agency
Acid Rain, CSAPR, and Texas SO_2 Programs

OMB Nos. 2060-0258 and 2060-0667
Approval Expires 03/31/2022

EPA

Retired Unit Exemption

For more information, see instructions and refer to 40 CFR 72.8, 97.405, 97.505, 97.605, 97.705, 97.805, 97.905, 97.1005 or a comparable state regulation, as applicable.

This submission is: ☒ New ☐ Revised

STEP 1

Identify the unit by plant (source) name, State, plant code and unit ID#.

Plant (Source) Name	State	Plant Code	Unit ID#
R.M. Heskett Station	ND	2790	B2

STEP 2

Indicate the program(s) that the unit is subject to.

☒ Acid Rain
☐ CSAPR NO_x Annual
☐ CSAPR NO_x Ozone Season Group 1
☐ CSAPR NO_x Ozone Season Group 2
☐ CSAPR NO_x Ozone Season Group 3
☐ CSAPR SO_2 Group 1
☐ CSAPR SO_2 Group 2
☐ Texas SO_2

STEP 3

Identify the date on which the unit was (or will be) permanently retired.

01/31/2022

STEP 4

If the unit is subject to the Acid Rain Program, identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.8(d).

Calendar year starting January 1, 2023

STEP 5 Read the applicable special provisions.

Acid Rain Program Special Provisions

(1) A unit exempt under 40 CFR 72.8 shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with 40 CFR part 73 subpart B.

(2) A unit exempt under 40 CFR 72.8 shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain permit application under 40 CFR 72.31 for the unit not less than 24 months prior to the date on which the unit is first to resume operation.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.8 shall comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) For any period for which a unit is exempt under 40 CFR 72.8, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 72.8 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) On the earlier of the following dates, a unit exempt under 40 CFR 72.8(b) or (c) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the designated representative submits an Acid Rain permit application under paragraph (2); or (ii) the date on which the designated representative is required under paragraph (2) to submit an Acid Rain permit application. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.8 shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

CSAPR NO_X Annual Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.405 shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.405 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.405 shall comply with the requirements of the CSAPR NO_X Annual Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.405 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart AAAAA, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_X Ozone Season Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.505 shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.505 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.505 shall comply with the requirements of the CSAPR NO_X Ozone Season Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.505 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart BBBBB, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_X Ozone Season Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.805 shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.805 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.805 shall comply with the requirements of the CSAPR NO_X Ozone Season Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.805 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart EEEEE, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_X Ozone Season Group 3 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.1005 shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.1005 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.1005 shall comply with the requirements of the CSAPR NO_X Ozone Season Group 3 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.1005 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.605 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.605 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.605 shall comply with the requirements of the CSAPR SO_2 Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.605 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart CCCCC, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.705 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.705 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.705 shall comply with the requirements of the CSAPR SO_2 Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.705 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart DDDDD, as a unit that commences commercial operation on the first date on which the unit resumes operation.

Texas SO_2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.905 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.905 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.905 shall comply with the requirements of the Texas SO_2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.905 shall lose its exemption on the first date on which the unit resumes operation. A retired unit that resumes operation will not receive an allowance allocation under 40 CFR 97.911. The unit may receive allowances from the Supplemental Allowance Pool pursuant to 40 CFR 97.912. All other provisions of 40 CFR part 97 subpart FFFFF regarding monitoring, reporting, recordkeeping and compliance will apply on the first date on which the unit resumes operation.

STEP 6 Read the statement of compliance and the applicable certification statements, sign, and date.

Statement of compliance

I certify that the unit identified above at STEP 1 was (or will be) permanently retired on the date identified at STEP 3 and will comply with the applicable Special Provisions listed at STEP 5.

Certification by designated representatives or alternate designated representatives

I am authorized to make this submission on behalf of the owners and operators of the source and unit for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Jay Skabo	Title VP Electric Supply
Owner Company Name Montana-Dakota Utilities Co.	
Email jay.skabo@mdu.com	Phone 701.222.7722
Signature	Date 3/7/2023

Certification by certifying officials of units subject <u>only</u> to the Acid Rain Program for which no designated representative has been authorized

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name NA	Title
Owner Company Name	
Email	Phone
Signature NA	Date

Instructions for the Retired Unit Exemption Notice

Please type or print. If you have any questions regarding the submission of the Retired Unit Exemption notice, please send an email to CAMDForms@epa.gov, or contact your local, State, or EPA Regional contact for the Acid Rain Program (ARP), Cross-State Air Pollution Rule (CSAPR), or Texas SO_2 Trading Program ($TXSO_2$), as appropriate. You may also call EPA's Acid Rain Hotline at (202) 343- 9620.

Submission Deadline: For units subject only to the ARP, submit the Retired Unit Exemption notice by December 31 of the first year the unit is to be exempt. For units subject to the CSAPR or $TXSO_2$ programs (including units also subject to the ARP), submit the Retired Unit Exemption notice no later than 30 days after the date the unit is permanently retired (i.e., within 30 days of the date entered at STEP 3).

STEP 1 Enter the plant name and state where the unit is located, the Plant Code for the facility, and the Unit ID for the unit, consistent with the data listed on the most current Certificate of Representation for the facility. A Plant Code is a number assigned by the Department of Energy's (DOE) Energy Information Administration (EIA) to facilities that generate electricity. For older facilities, "Plant Code" is synonymous with "ORISPL" and "Facility" codes. If the facility generates electricity but no Plant Code has been assigned, or if there is uncertainty regarding what the Plant Code is, contact EIA at (202) 586-1029. For facilities that do not produce electricity, use the facility identifier assigned by EPA (beginning with "88"). If the facility does not produce electricity and has not been assigned a facility identifier, please send an email to CAMDForms@epa.gov.

STEP 2 Identify the programs to which the unit is subject.

STEP 3 Enter the date on which the unit was (or will be) permanently retired.

STEP 4 If the unit is subject to the ARP, identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.8(d).

STEP 5 Read the applicable special provisions.

STEP 6 Read the statement of compliance and the applicable certification statements, sign, and date. For units subject only to the ARP, if no designated representative has been authorized, a certifying official for each owner of the unit must read the certification at STEP 6 labeled " certifying officials of units subject only to the Acid Rain Program", enter his or her name, title, name of the owner company for which he or she is the certifying official, phone number, email address, and then sign and date. A certifying official is not required to submit a Certificate of Representation. If there is more than one owner of a unit for which no designated representative has been authorized, each owner of the unit must have a certifying official sign the appropriate certification at STEP 6.

Submit the **original** Retired Unit Exemption notice to the title V permitting authority for the facility, and **mail a copy** to **one** of the following mailing addresses **(please note the different zip codes)**:

For Regular or Certified Mail:

U.S. Environmental Protection Agency
CAMD – Market Operations Branch
Attention: Exemptions
1200 Pennsylvania Avenue, NW
Mail Code 6204M
Washington, DC **20460**

For Overnight Mail:

U.S. Environmental Protection Agency
CAMD – Market Operations Branch
Attention: Exemptions
1200 Pennsylvania Avenue, NW
4th Floor, Room # 4153C
Washington, DC **20004**
(202) 564-8717

Paperwork Burden Estimate

This collection of information is approved by OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. (OMB Control Nos. 2060-0258 and 2060-0667). Responses to this collection of information are mandatory (40 CFR 72.8, 97.405, 97.505, 97.605, 97.705, 97.805, 97.905 and 97.1005). An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The public reporting and recordkeeping burden for this collection of information is estimated to be 3.5 hours per response annually. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the Regulatory Support Division Director, U.S. Environmental Protection Agency (2821T), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed form to this address.

February 16, 2021

Mr. Jay Skabo
Vice President – Electric Supply
Montana-Dakota Utilities Co.
400 N Fourth Street
Bismarck, ND 58501

Re: Air Pollution Control
Permit to Construct

Dear Mr. Skabo:

Pursuant to the Air Pollution Control Rules of the State of North Dakota, the Department of Environmental Quality (Department) has reviewed the application dated April 30, 2020 (updated January 11, 2021) to obtain a Permit to Construct for the removal of two existing coal-fired boilers and ancillary equipment as well as the installation of a new, 88 megawatt natural gas-fired simple cycle combustion turbine unit at the R.M. Heskett Station located in Morton County, ND.

Based on the results of the documents submitted on April 30, 2020 (updated January 11, 2021) the Department hereby issues the enclosed North Dakota Air Pollution Control Permit to Construct No. ACP-17983 v1.0.

Please advise the Department within 15 days after completing the project to allow for an inspection by the Department.

Note that the above-referenced permit addresses only air quality requirements applicable to your facility. Other divisions (Water Quality, Waste Management and Municipal Facilities) within the Department of Environmental Quality may have additional requirements. Contact information for the various divisions is listed at the bottom of this letter.

Please contact me at (701)328-5283 or at cristy.jones@nd.gov with any questions.

Sincerely,

Cristy Jones
Environmental Scientist
Division of Air Quality

CMJ:csc
Enc:
xc: Daniel Fagnant EPA/R8

AIR POLLUTION CONTROL
PERMIT TO CONSTRUCT

Pursuant to Chapter 23.1-06 of the North Dakota Century Code, and the Air Pollution Control Rules of the State of North Dakota (Article 33.1-15 of the North Dakota Administrative Code), and in reliance on statements and representations heretofore made by the owner designated below, a Permit to Construct is hereby issued authorizing such owner to construct and initially operate the source unit(s) at the location designated below. This Permit to Construct is subject to all applicable rules and orders now or hereafter in effect of the North Dakota Department of Environmental Quality (Department) and to any conditions specified below:

I. **General Information**:

A. **Permit to Construct Number**: ACP-17983 v1.0

B. **Source**:

1. Name: Montana-Dakota Utilities Co.
2. Location: R. M. Heskett Station
   2025-38th Street
   Mandan, ND 58554
   Morton County
3. Source Type: Electric Generating Unit; Simple Cycle Combustion Turbine
4. Existing Equipment at the Facility:

Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment
Coal-fired boiler with a rated heat input of 387.63 x 10^6 Btu/hr (Unit 1 boiler)	1	1	Electrostatic Precipitator (ESP)
Coal-fired boiler with a rated heat input of 916.5 x 10^6 Btu/hr (Unit 2 boiler)	2	2	Multiclone, ESP and Limestone addition to bed media (limestone addition operates on an as-needed basis)
Natural gas-fired IC engine rated at 134 bhp, 100 kW output, built 1963 (Emergency generator engine)	3	3	None

Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment
Natural gas-fired sand dryer with a rated heat input of 3.0 x 10^6 Btu/hr (Sand dryer)	5	2	ESP (Emissions from EU 5 discharge into the inlet of the Unit 2 ESP)
Natural gas-fired combustion turbine nominally rated at 986 x 10^6 Btu/hr, built 2013 (Unit 3 turbine)	6	6	Dry Low NO_x (DLN) Combustion
Natural gas-fired in-line heater nominally rated at 2.75 x 10^6 Btu/hr (Unit 3 in-line heater)	7	7	None
Unit 1 coal storage silo	M1	M1	Fabric Filter
Unit 1 coal gallery	M2	M1	Fabric Filter
Three Unit 2 coal storage silos	2A, 2B & 2C	M3	Fabric Filters
Ash conveyor system	M4	M4	Fabric Filter
Unit 1 bottom ash silo	M5	M5	Fabric Filter
Sand storage silos	S2B	M6	Fabric Filter
Limestone hopper	S2A	M6	Fabric Filter
Fly ash silo	M7	M7	Fabric Filters
Gasoline storage tank, 1000 gal, built Dec. 2006	M8 [B]	M8	Submerged fill pipe
Limestone silo and limestone receiving	M9	M9	Fabric Filter
Limestone conveyor	M11	M11	Fabric Filters
Fugitive emissions	FUG	FUG	None

5. Equipment to be removed:

Emission Unit Description [A]	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment
Coal-fired boiler with a rated heat input of 387.63 x 10^6 Btu/hr (Unit 1 boiler)	1	1	Electrostatic Precipitator (ESP)
Coal-fired boiler with a rated heat input of 916.5 x 10^6 Btu/hr (Unit 2 boiler)	2	2	Multiclone, ESP and Limestone addition to bed media
Natural gas-fired IC engine rated at 134 bhp, 100 kW output, built 1963 (Emergency generator engine)	3	3	None

Natural gas-fired sand dryer with a rated heat input of 3.0 x 10^6 Btu/hr (Sand dryer)	5	2	ESP
Unit 1 coal storage silo	M1	M1	Fabric Filter
Unit 1 coal gallery	M2	M1	Fabric Filter
Three Unit 2 coal storage silos	2A, 2B & 2C	M3	Fabric Filters
Ash conveyor system	M4	M4	Fabric Filter
Unit 1 bottom ash silo	M5	M5	Fabric Filter
Sand storage silos	S2B	M6	Fabric Filter
Limestone hopper	S2A	M6	Fabric Filter
Fly ash silo	M7	M7	Fabric Filters
Gasoline storage tank, 1000 gal, built Dec. 2006	M8	M8	Submerged fill pipe
Limestone silo and limestone receiving	M9	M9	Fabric Filter
Limestone conveyor	M11	M11	Fabric Filters

[A] Emission units must be removed or permanently decommissioned prior to the commencement of operation of the Unit 4 turbine (EU 12).

6. New equipment to be added to the facility:

Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment
Natural gas-fired combustion turbine nominally rated at 986 x 10^6 Btu/hr (Unit 4 turbine) (KKKK) (TTTT)	12 [A]	12	Dry Low NO_x (DLN) Combustion
Natural gas-fired in-line heater nominally rated at 5 x 10^6 Btu/hr (Unit 4 in-line heater)	13	13	None
One (4SLB) natural gas-fired emergency generator rated at 5,364 bhp (2020 or newer) (JJJJ) (ZZZZ)	14 [A]	14	None

[A] The potential to emit for an emergency stationary reciprocating internal combustion engine (RICE) is based on operating no more hours per year than is allowed by the subparts (40 CFR 60, Subpart JJJJ and 40 CFR 63, Subpart ZZZZ) for other than emergency situations. For engines to be considered emergency stationary RICE under the RICE rules, engine operations must comply with the operating hour limits as specified in the applicable subparts. There is no time limit on the use of emergency stationary RICE in emergency situations.

C. **Owner/Operator (Permit Applicant)**:

1. Name: Montana-Dakota Utilities Co.
2. Address: 400 N Fourth Street
   Bismarck, ND 58501
3. Application Date: April 30, 2020

II. **Conditions**: This Permit to Construct allows the construction and initial operation of the above-mentioned new or modified equipment at the source. The source may be operated under this Permit to Construct until a Permit to Operate is issued unless this permit is suspended or revoked. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect of the North Dakota Department of Environmental Quality and to the conditions specified below.

A. **Emission Limits**: Emission limits from the operation of the source unit(s) identified in Item I.B of this Permit to Construct (hereafter referred to as "permit") are as follows. Source units not listed are subject to the applicable emission limits specified in the North Dakota Air Pollution Control Rules.

Emission Unit Description	EU	EP	Pollutant / Parameter	Emission Limit
Natural gas-fired combustion turbine nominally rated at 986 x 10^6 Btu/hr (Unit 4 turbine)	12	12	NOx: >50 MW (gross) & >0°F	15 ppmvd @ 15% O_2 or 54 ng/J (0.43 lb/MWh) [A, B, C, D]
			NO_x: ≤50 MW (gross) or <0°F	96 ppmvd @ 15% O_2 or 590 ng/J (4.7 lb/MWh) [A, B, C, D]
			NO_x	515.8 lb/hr [I]
			SO_2	110 ng/J (0.90 lb/MWh) (gross) or 0.060 lb/MMBtu (fuel use) [E]
			CO_2	50 kg CO_2/GJ heat input (120 lb CO_2/MMBtu) [F, G]
			Opacity	20% [H]

[A] CEMs installed in lieu of annual performance tests (40 CFR 60.4340(b)).

[B] CEMs installation, operation, and performance testing must meet the applicable standards of 40 CFR 60 Subpart KKKK.

[C] Based on a 4-hr rolling average.

[D] The higher NO_x limit emission limit applies for the entire hour if at any point in the hour the unit was subject to a higher limit.

E Sulfur content of the fuel must be determined using total sulfur methods per 40 CFR 60.4415 and 60.4370.

F Emissions standards must be met at all times; however, compliance must be determined only at the end of each applicable operating month.

G Emission limit is based on operations that supply less than or equal to its design efficiency (33.34%) or 50%, whichever is less, times its potential electric output as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts > 90% natural gas.

H 40% permissible for not more than one six-minute period per hour.

I Based on a 1-hr average.

B. **Fuel Restriction:**

The simple cycle combustion turbines, in-line heater, and emergency generator (EUs 12, 13, and 14) are restricted to combusting only natural gas containing no more than 2 grains of sulfur per 100 standard cubic feet.

C. **Emissions Testing:**

1. Initial Testing: Within 180 days after initial startup, the permittee shall conduct emissions tests at the emission units listed below using an independent testing firm, to determine the compliance status of the facility with respect to the emission limits specified in Condition II.A. Emissions testing shall be conducted for the pollutant(s) listed below in accordance with EPA Reference Methods listed in 40 CFR 60, Appendix A. Test methods other than those listed below may be used upon approval by the Department.

Emission Unit Description	EU	Pollutant/ Parameter	Number of Runs	Length of Runs	EPA Ref. Method(s)
Unit 4 turbine	12	NO_x CEMS Relative Accuracy Test Audit (RATA)	9	21 min	See 40 CFR 60.4405 for alternative method

A RATA must be conducted at a single load level, within plus or minus 25% of 100% of peak load and the ambient temperature must be greater than 0°F during the RATA runs.

A signed copy of the test results shall be furnished to the Department within 60 days of the test date. The basis for this condition is NDAC 33.1-15-01-12 which is hereby incorporated into this permit by reference. To facilitate preparing for and conducting such tests, and to facilitate reporting the test results to the Department, the owner/operator shall follow the procedures and formats in the Department's Emission Testing Guideline.

2. Notification: The permittee shall notify the Department using the form in the Emission Testing Guideline, or its equivalent, at least 30 calendar days in advance of any tests of emissions of air contaminants required by the Department. If the permittee is unable to conduct the performance test on the scheduled date, the permittee shall notify the Department at least five days prior to the scheduled test date and coordinate a new test date with the Department.

3. Sampling Ports/Access: Sampling ports shall be provided downstream of all emission control devices and in a flue, conduit, duct, stack or chimney arranged to conduct emissions to the ambient air.

   The ports shall be located to allow for reliable sampling and shall be adequate for test methods applicable to the facility. Safe sampling platforms and safe access to the platforms shall be provided. Plans and specifications showing the size and location of the ports, platform and utilities shall be submitted to the Department for review and approval.

4. Other Testing:

   a) The Department may require the permittee to have tests conducted to determine the emission of air contaminants from any source, whenever the Department has reason to believe that an emission of a contaminant not addressed by the permit applicant is occurring, or the emission of a contaminant in excess of that allowed by this permit is occurring. The Department may specify testing methods to be used in accordance with good professional practice. The Department may observe the testing. All tests shall be conducted by reputable, qualified personnel. A signed copy of the test results shall be furnished to the Department within 60 days of the test date.

      All tests shall be made and the results calculated in accordance with test procedures approved by the Department. All tests shall be made under the direction of persons qualified by training or experience in the field of air pollution control as approved by the Department.

   b) The Department may conduct tests of emissions of air contaminants from any source. Upon request of the Department, the permittee shall provide necessary holes in stacks or ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices, as may be necessary for proper determination of the emission of air contaminants.

D. **Stack Heights**: The stack height of the turbine shall be at least 56 feet.

E. **New Source Performance Standards (NSPS)**: The owner/operator shall comply with all applicable requirements of the following NSPS subparts as referenced in Chapter 33.1-15-12 of the North Dakota Air Pollution Control Rules and 40 CFR 60.

1. **40 CFR 60, Subpart KKKK**: The owner/operator shall comply with all applicable requirements of 40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines (EU 12).

2. **40 CFR 60, Subpart JJJJ**: The owner/operator shall comply with all applicable requirements of 40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (EU 14).

3. **40 CFR 60, Subpart TTTT**: The owner/operator shall comply with all applicable requirements of 40 CFR 60, Subpart TTTT - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units (EU 12).

F. **Maximum Achievable Control Technology Standards (MACT)**: The permittee shall comply with all applicable requirements of the following MACT subparts as referenced in Chapter 33.1-15-22 of the North Dakota Air Pollution Control Rules and 40 CFR 63.

1. 40 CFR 63, Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (EU 1). The North Dakota Department of Environmental Quality has not adopted the area source provisions of this subpart. All required documentation must be submitted to EPA Region 8 at the following address:

   U.S. EPA Region 8
   1595 Wynkoop Street
   Mail Code 8ENF – AT
   Denver, CO 80202-1129

G. **Like-Kind Turbine Replacement**: This permit allows the permittee to replace the turbine with a like-kind turbine. Replacement is subject to the following conditions.

1. The Department must be notified within 10 days after change-out of the turbine.

2. The replacement turbine shall operate in the same manner, provide no increase in throughput and have equal or less emissions than the turbine it is replacing.

3. The date of manufacture of the replacement turbine must be included in the notification. The facility must comply with any applicable federal standards (e.g. NSPS, NESHAP, MACT) triggered by the replacement.

4. The replacement turbine is subject to the same state emission limits as the existing turbine in addition to any NSPS or MACT emission limit that is applicable. Testing shall be conducted to confirm compliance with the emission limits within 180 days after start-up of the new turbine.

H. **CEMS –Nitrogen Oxide (NO_x)**: The owner/operator shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, 0 percent excess air) of NO_x emissions into the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air. Monitoring of NO_x emissions must also meet all applicable requirements of 40 CFR 60, Subpart KKKK.

I. **Construction**: Construction of the above described facility shall be in accordance with information provided in the permit application as well as any plans, specifications and supporting data submitted to the Department. The Department shall be notified ten days in advance of any significant deviations from the specifications furnished. The issuance of this Permit to Construct may be suspended or revoked if the Department determines that a significant deviation from the plans and specifications furnished has been or is to be made.

Any violation of a condition issued as part of this permit to construct as well as any construction which proceeds in variance with any information submitted in the application, is regarded as a violation of construction authority and is subject to enforcement action.

J. **Startup Notice**: A notification of the actual date of initial startup shall be submitted to the Department within 15 days after the date of initial startup.

K. **Organic Compounds Emissions**: The permittee shall comply with all applicable requirements of NDAC 33.1-15-07 – Control of Organic Compounds Emissions.

L. **Title V Permit to Operate**: Within one year after startup of the units covered by this Permit to Construct, the owner/operator shall submit a permit application to modify the existing Title V Permit to Operate for the facility.

M. **Acid Rain Program**: The permittee shall comply with the applicable requirements of 40 CFR 72, 75 and 76. The permittee shall hold sulfur dioxide allowances, as of the allowance transfer deadline, in the unit's subaccount not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit.

N. **Permit Invalidation**: This permit shall become invalid if construction is not commenced within eighteen months after issuance of such permit, if construction is discontinued for a period of eighteen months or more; or if construction is not completed within a reasonable time.

O. **Fugitive Emissions**: The release of fugitive emissions shall comply with the applicable requirements in NDAC 33.1-15-17.

P. **Annual Emission Inventory/Annual Production Reports**: The owner/operator shall submit an annual emission inventory report and/or an annual production report upon Department request, on forms supplied or approved by the Department.

Q. **Source Operations**: Operations at the installation shall be in accordance with statements, representations, procedures and supporting data contained in the initial application, and any supplemental information or application(s) submitted thereafter. Any operations not listed in this permit are subject to all applicable North Dakota Air Pollution Control Rules.

R. **Alterations, Modifications or Changes**: Any alteration, repairing, expansion, or change in the method of operation of the source which results in the emission of an additional type or greater amount of air contaminants or which results in an increase in the ambient concentration of any air contaminant, must be reviewed and approved by the Department prior to the start of such alteration, repairing, expansion or change in the method of operation.

S. **Air Pollution from Internal Combustion Engines**: The permittee shall comply with all applicable requirements of NDAC 33.1-15-08-01 – Internal Combustion Engine Emissions Restricted.

T. **Recordkeeping**: The owner/operator shall maintain any compliance monitoring records required by this permit or applicable requirements. The owner/operator shall retain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, report or application. Support information may include all calibration and maintenance records and all original strip-chart recordings/computer printouts for continuous monitoring instrumentation, and copies of all reports required by the permit.

U. **Nuisance or Danger**: This permit shall in no way authorize the maintenance of a nuisance or a danger to public health or safety.

V. **Malfunction Notification**: The owner/operator shall notify the Department of any malfunction which can be expected to last longer than twenty-four hours and can cause the emission of air contaminants in violation of applicable rules and regulations.

W. **Operation of Air Pollution Control Equipment**: The owner/operator shall maintain and operate all air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

X. **Transfer of Permit to Construct**: The holder of a permit to construct may not transfer such permit without prior approval from the Department.

Y. **Right of Entry**: Any duly authorized officer, employee or agent of the North Dakota Department of Environmental Quality may enter and inspect any property, premise or place at which the source listed in Item I.B of this permit is located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules. The Department may conduct tests and take samples of air contaminants, fuel, processing material, and other materials which affect or may affect emissions of air contaminants from any source. The Department shall have the right to access and copy any records required by the Department's rules and to inspect monitoring equipment located on the premises.

Z. **Other Regulations**: The owner/operator of the source unit(s) described in Item I.B of this permit shall comply with all State and Federal environmental laws and rules. In addition, the owner/operator shall comply with all local burning, fire, zoning, and other applicable ordinances, codes, rules and regulations.

AA. **Permit Issuance**: This permit is issued in reliance upon the accuracy and completeness of the information set forth in the application. Notwithstanding the tentative nature of this information, the conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has, or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23.1-06.

BB. **Odor Restrictions**: The owner/operator shall not discharge into the ambient air any objectionable odorous air contaminant which is in excess of the limits established in NDAC 33.1-15-16.

The owner/operator shall not discharge into the ambient air hydrogen sulfide (H_2S) in concentrations that would be objectionable on land owned or leased by the complainant or in areas normally accessed by the general public. For the purpose of complaint resolution, two samples with concentrations greater than 0.05 parts per million (50 parts per billion) sampled at least 15 minutes apart within a two-hour period and measured in accordance with Section 33.1-15-16-04 constitute a violation.

CC. **Sampling and Testing**: The Department may require the owner/operator to conduct tests to determine the emission rate of air contaminants from the source. The Department may observe the testing and may specify testing methods to be used. A signed copy of the test results shall be furnished to the Department within 60 days of the test date. The basis for this condition is NDAC 33.1-15-01-12 which is hereby incorporated into this permit by reference. To facilitate preparing for and conducting such tests, and to facilitate reporting the test results to the Department, the owner/operator shall follow the procedures and formats in the Department's Emission Testing Guideline.

FOR THE NORTH DAKOTA DEPARTMENT
OF ENVIRONMENTAL QUALITY

Date 2/16/2021

By James L. Semerad
James L. Semerad
Director
Division of Air Quality

Air Quality Effects Analysis For Permit to Construct ACP-17983 v1.0

I. **Date of Review**:
February 16, 2021 (FINAL)

II. **Applicant**:
Montana-Dakota Utilities Co.
400 N Fourth Street
Bismarck, ND 58501

III. **Source Location**:
R.M. Heskett Station
2025 - 38th Street
Mandan, ND 58554
Morton County
Sec. 10, T139N, R81W
Lat. 46.866808, Long.-100.883669

IV. **Introduction and Background**:

Montana-Dakota Utilities Co. (MDU) submitted a Permit to Construct (PTC) application on April 30, 2020, for the MDU R.M. Heskett Station. The PTC application proposes the removal of two existing coal-fired boilers (Unit 1 and Unit 2) and ancillary equipment as well as the installation of a new, 88 megawatt (MW) natural gas-fired simple cycle combustion turbine (SCCT), which will be used as a peaking (non-baseload) unit to provide sellable energy. There are no proposed operational or physical changes proposed to the existing simple cycle combustion turbine (Unit 3), or its ancillary equipment.

The MDU R.M. Heskett station will cease current operations as a coal-fired, steam energy generation facility, and will replace all gross energy generation operations with two natural gas-fired SCCTs, which will both act as peaking units. The coal-fired boilers and associated equipment will be removed prior to the commencement of operation of the additional SCCT.

Project proposed changes include the following:

- Removal of the coal-fired boiler rated at 387.63 x 10^6 Btu/hr (Unit 1 boiler),
- Removal of the coal-fired boiler rated at 916.5 x 10^6 Btu/hr (Unit 2 boiler),
- Removal of all ancillary equipment associated with the two coal-fired boilers,
- Installation of one 88 MW natural gas-fired SCCT (nominal output is based upon the proposed site elevation, 60% relative humidity, 43 degrees Fahrenheit, and 100% load),

- Installation of one 5,364 bhp natural gas-fired emergency generator, and
- Installation of one 5 x 10^6 Btu/hr fuel line heater.

The outcome of the project will comprise of an overall air emissions reduction for NO_x, CO, SO_2, PM and greenhouse gases; however, the MDU R. M. Heskett station will remain a major source of criteria pollutants.

In addition, air dispersion modeling of NO_x and air toxics was conducted as a part of the PTC application review process.

Table 1 - Equipment to be Removed

Emission Unit Description [A]	**Emission Unit (EU)**	**Emission Point (EP)**	**Air Pollution Control Equipment**
Coal-fired boiler with a rated heat input of 387.63 x 10^6 Btu/hr (Unit 1 boiler)	1	1	Electrostatic Precipitator (ESP)
Coal-fired boiler with a rated heat input of 916.5 x 10^6 Btu/hr (Unit 2 boiler)	2	2	Multiclone, ESP and Limestone addition to bed media
Natural gas-fired IC engine rated at 134 bhp, 100 kW output, built 1963 (Emergency generator engine)	3 [B, C]	3	None
Natural gas-fired sand dryer with a rated heat input of 3.0 x 10^6 Btu/hr (Sand dryer)	5	2	ESP
Unit 1 coal storage silo	M1	M1	Fabric Filter
Unit 1 coal gallery	M2	M1	Fabric Filter
Three Unit 2 coal storage silos	2A, 2B & 2C	M3	Fabric Filters
Ash conveyor system	M4	M4	Fabric Filter
Unit 1 bottom ash silo	M5	M5	Fabric Filter
Sand storage silos	S2B	M6	Fabric Filter
Limestone hopper	S2A	M6	Fabric Filter
Fly ash silo	M7	M7	Fabric Filters
Gasoline storage tank, 1000 gal, built Dec. 2006	M8	M8	Submerged fill pipe
Limestone silo and limestone receiving	M9	M9	Fabric Filter
Limestone conveyor	M11	M11	Fabric Filters

A Emission units must be removed or permanently decommissioned prior to the commencement of operation of the Unit 4 turbine (EU 12).

Table 2 - Remaining Equipment

Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment
Natural gas-fired combustion turbine nominally rated at 986 x 10^6 Btu/hr, built 2013 (Unit 3 turbine) (2013) (KKKK)	6	6	Dry Low NO_x (DLN) Combustion
Natural gas-fired in-line heater nominally rated at 2.75 x 10^6 Btu/hr (Unit 3 in-line heater)	7	7	None
Fugitive emissions	FUG [A]	FUG	None

[A] Insignificant unit/activity or no specific emission limit.

Table 3 - New Equipment

Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment
Natural gas-fired combustion turbine nominally rated at 986 x 10^6 Btu/hr (Unit 4 turbine) (KKKK) (TTTT)	12	12	Dry Low NO_x (DLN) Combustion
Natural gas-fired in-line heater nominally rated at 5 x 10^6 Btu/hr (Unit 4 in-line heater)	13	13	None
One (4SLB) natural gas-fired emergency generator rated at 5,364 bhp (2020 or newer) (JJJJ) (ZZZZ)	14 [A]	14	None

[A] The potential to emit for an emergency stationary reciprocating internal combustion engine (RICE) is based on operating no more hours per year than is allowed by the subparts (40 CFR 60, Subpart JJJJ and 40 CFR 63, Subpart ZZZZ) for other than emergency situations. For engines to be considered emergency stationary RICE under the RICE rules, engine operations must comply with the operating hour limits as specified in the applicable subparts. There is no time limit on the use of emergency stationary RICE in emergency situations.

V. **Potential to Emit (PTE) Emissions**:

Emissions from the facility are as follows:

Table 4 - Unit 4 SCCT Project PTE Calculations (in tons per year)[A]

PROJECT POTENTIAL TO EMIT POLLUTANTS (TONS/YEAR)							
Description of PTE Source	**$PM/PM_{10}/PM_{2.5}$ (tpy)**	**SO_2 (tpy)**	**NO_x (tpy)**	**CO (tpy)**	**VOCs (tpy)**	**HAPs (tpy)[A, B]**	**H_2SO_4 (tpy)**
Unit 4 turbine	9.60/9.60/9.60	11.84	312.03	555.03	16.17	1.16	1.53
In-line heater	0.16/0.16/0.16	0.01	2.15	1.80	0.12	0.04	0.00
Emergency generator	0.02/0.02/0.02	0.01	1.18	2.37	0.59	0.11	0.00
Total PTE (without fugitives)	**9.78/9.78/9.78**	**11.86**	**315.36**	**559.20**	**16.88**	**1.31**	**1.53**
Total PTE (with fugitives)	**9.78/9.78/9.78**	**11.86**	**315.36**	**559.20**	**16.88**	**1.31**	**1.53**

A Pollutants are abbreviated as follows:
PM: particulate matter
PM_{10}: particulate matter under 10 microns (<10 μg), includes $PM_{2.5}$.
$PM_{2.5}$: particulate matter under 2.5 microns (<2.5 μg)
SO_2: sulfur dioxide
NO_x: nitrogen oxides
VOC: volatile organic compounds
CO: carbon monoxide

B HAPs: hazardous air pollutants as defined in Section 112(b) of the Clean Air Act Amendments of 1990

See application for more detailed emission calculations.

Table 5 - Emission Reduction After Coal-Fired Boiler Removal (Netting) (in tons per year)

NETTED POTENTIAL TO EMIT POLLUTANTS (TONS/YEAR)							
Time Period	**Description of PTE Source**	**$PM/PM_{10}/PM_{2.5}$ (tpy)**	**SO_2 (tpy)**	**NO_x (tpy)**	**CO (tpy)**	**VOCs (tpy)**	**H_2SO_4 (tpy)**
Pre-Project [A]	Unit 1	-2.7/-3.1/-2.6	-953.6	-247.8	-203.3	-1.2	-146.0
	Unit 2	-8.5/-216.6/-215.0	-1,166.5	-945.1	-907.6	-5.5	-178.6
Post-Project	Unit 4	9.8/9.8/9.8	11.9	315.4	559.2	16.9	1.5
Netted Emissions [B]		**-1.4/-209.9/-207.8**	**-2,108.2**	**-877.5**	**-551.7**	**10.1**	**-323.0**

A Emissions based on the 24-month contemporaneous period from 2018 to 2019.

B Netted emissions are calculated by subtracting the pre-project emissions from the post-project emissions.

Table 6 - Total Post-Project Facility-Wide Emissions (in tons per year) [A]

TOTAL POST-PROJECT POTENTIAL TO EMIT POLLUTANTS (TONS/YEAR)							
Description of PTE Source	**$PM/PM_{10}/PM_{2.5}$ (tpy)**	**SO_2 (tpy)**	**NO_x (tpy)**	**CO (tpy)**	**VOCs (tpy)**	**HAPs (tpy)**	**H_2SO_4 (tpy)**
Unit 3 [A]	24.4/24.4/24.4	18.4	159.7	263.3	9.7	1.9	NA
Unit 4	9.8/9.8/9.8	11.9	315.4	559.2	16.9	1.3	1.5
Total	**34.2/31.2/34.2**	**30.2**	**475.1**	**822.5**	**26.6**	**3.2**	**1.5**

[A] Emission values from PTC13016 application were used to estimate total emissions.

VI. **Applicable Standards**:

Table 7 - Applicable Standards

Emission Unit Description	Emission Unit (EU)	Applicable Standards
Unit 4 turbine	12	NDAC 33.1-15-02 NDAC 33.1-15-03 NDAC 33.1-15-05 NDAC 33.1-15-07 NDAC 33.1-15-21 NDAC 33.1-15-12, Subpart KKKK NDAC 33.1-15-12, Subpart TTTT
In-line heater	13	NDAC 33.1-15-02 NDAC 33.1-15-03 NDAC 33.1-15-05
Emergency generator	14	NDAC 33.1-15-03 NDAC 33.1-15-12, Subpart JJJJ 40 CFR 63, Subpart ZZZZ [EPA [A]]

[A] The Department has not adopted this subpart; all required documentation should be sent to EPA Region 8.

A. **NDAC 33.1-15-02 – Ambient Air Quality Standards**

The facility must comply with the Ambient Air Quality Standards (AAQS). Other requirements of this chapter include general prohibitions against harming health, causing damage to plants, animals, other property, and visible degradation. In addition to these standards, compliance with the Department's Air Toxics Policy is required.

Expected Compliance

In the *Criteria Pollutant Modeling Requirements for a Permit to Construct* Department memorandum dated October 6, 2014, dispersion modeling is required if the potential emissions exceed 100 tpy for NO_2 with some emissions vented from stack heights greater than 1.5 times the nearby building height. The facility's potential NO_2 emissions exceed 100 tons per year and emissions are vented from stack heights greater than 1.5 times nearby building height. Therefore, NO_2 1-hour and annual air dispersion modeling was conducted to demonstrate compliance with NAAQS. Modeling was also conducted for Class II increment consumption.

Table 8 below, as well as the accompanying Air Quality Impact Analysis demonstrate that the modeled 1-hour NO_2 design values of 149.86 μg/m³, 150.51 μg/m³ and 149.69 μg/m³, are less than the NAAQS of 188 μg/m³. The modeled annual NO_2 design values of 9.92 μg/m³, 10.31 μg/m³ and 10.18 μg/m³, are less than the NAAQS of 100 μg/m³. Therefore, compliance with this chapter is expected.

Table 8 - Cumulative – Ambient Air Quality Standards (AAQS) Results Summary

POLLUTANT	AVERAGING TIME	MODELED IMPACT (μg/m³)	Class II/ AAQS SIL (μg/m³)	BACKGROUND (μg/m³)	TOTAL IMPACT (μg/m³)	NAAQS/ NDAASQ (μg/m³)	PASSED (Y/N)
PM_{10}	24-HR	--	5.0	30	--	150	--
$PM_{2.5}$	Annual	--	0.2	4.75	--	12	--
	24-HR	--	1.2	13.7	--	35	--
SO_2	Annual	--	0.2	3	--	80	--
	24-HR	--	5.0	9	--	365	--
	3-HR	--	25	11	--	1,309	--
	1-HR	--	7.8	13	--	196	--
NO_2 Baseload	Annual	4.92	1.0	5	**9.92**	100	Yes
	1-HR	114.69	7.5	35	**149.86**	188	Yes
NO_2 Worst Case	Annual	5.31	1.0	5	**10.31**	100	Yes
	1-HR	115.15	7.5	35	**150.15**	188	Yes
NO_2 Turndown	Annual	5.18	1.0	5	**10.18**	100	Yes
	1-HR	114.69	7.5	35	**149.69**	188	Yes
CO	8-HR	--	500	1,149	--	10,000	--
	1-HR	--	2,000	1,149	--	40,000	--

Air Toxics Policy (*Policy for the Control of Hazardous Air Pollutant Emissions in North Dakota*) Expected Compliance

The Air Toxics Policy (Policy) establishes guidelines to evaluate HAPs emitted into the ambient air (off-property). The evaluation includes a determination of both carcinogenic and non-carcinogenic risks due to the HAPs emissions. Individual HAP species, emission rates (gram/second), building downwash effects, and distances to nearby sources are modeled. The modeled HAP concentrations (μg/m³) are used to calculate both a maximum individual carcinogenic risk (MICR) and a hazard index (HI). Modeled HAPs include those with potential to emit greater than 0.1 tpy. Tier 3 modeling (AERMOD v. 19191) is utilized to predict the following impacts:

Table 9 - Maximum Individual Carcinogenic Risk and Hazard Index Analyses

HAP	MICR	HAZARD INDEX (HI) (MC/GC Ratio)
Acetaldehyde	3.8×10^{-10}	3.3×10^{-5}
Acrolein	--	1.0×10^{-3}
Benzene	4.0×10^{-10}	9.6×10^{-5}
1,3-Butadiene	5.5×10^{-11}	1.2×10^{-6}
Ethyl benzene	3.4×10^{-10}	2.2×10^{-6}
Formaldehyde	1.1×10^{-8}	0.02
Naphthalene	1.9×10^{-10}	6.2×10^{-7}
PAH	--	
Propylene Oxide	4.6×10^{-10}	7.8×10^{-5}
Toluene	--	2.2×10^{-5}
Xylene	--	3.7×10^{-6}
Total	1.31×10^{-8}	0.022
Standard	1×10^{-5}	1.0
Pass (Y/N)	Yes	Yes

The calculated MICR is the probability of an individual developing cancer after being exposed to the highest concentration of HAPs over a defined period of time. Only HAPs with known or possible carcinogenic risks are used to calculate the MICR. The MICR threshold stated in the Policy is 1×10^{-5}, which represents a probability of one person out of 100,000 people. The MICR calculated above at 1.31×10^{-8} is less than 1×10^{-5} and compliance with Air Toxics Policy is expected.

The HI calculation incorporates both carcinogenic and non-carcinogenic HAPs with acute and/or chronic health effects to determine both compliance with 1-hour and 8-hour guidelines concentrations. The HI is a sum of all modeled concentrations and guideline concentration ratios. A HI of less than 1 indicates that HAP modeled concentration are less than 1-hour and 8-hour guideline concentrations. The HI calculated above of 0.022 is less than 1.0 and compliance with the Air Toxics Policy is expected.

Total combined HAP emissions are low, with the MDU R.M. Heskett Station emissions at 3.2 tpy. Formaldehyde is the largest single HAP at 0.53 tpy, and compliance with applicable NSPS/MACT standards is expected. The facility is expected to comply with the ambient air quality standards and the *Air Toxics Policy*[1].

B. **<u>NDAC 33.1-15-03 – Restriction of Emission of Visible Air Contaminants</u>**

This chapter restricts the amount of visible air contaminants, primarily particulate matter, from incinerators and fuel-burning units.

1 August 25, 2010 NDDOH *Policy for the Control of Hazardous Air Pollutant (HAP) Emissions in ND (aka Air Toxics Policy)*, https://deq.nd.gov/publications/AQ/policy/Modeling/Air_Toxics_Policy.pdf

Expected Compliance

Based on the fuels used, visible air emissions are expected to be well below the 20% opacity limit established by this chapter.

Table 10 - Opacity Limits

Emission Unit Description	EU	Pollutant/ Parameter	Emission Limit
Unit 4 turbine	12	Opacity	20% [A]
In-line heater	13	Opacity	20% [A]
Emergency generator	14	Opacity	20% [A]

[A] 40% permissible for not more than one six-minute period per hour.

C. **NDAC 33.1-15-05-Emissions of Particulate Matter Restricted**

This chapter applies to any operation, process, or activity from which particulate matter is emitted except for the indirect heating in which the products of combustion do not come into direct contact with process materials.

Expected Compliance

Table 11 - Particulate Matter Limits

Emission Unit Description	EU	Pollutant/ Parameter	Emission Limit
Unit 4 turbine	12	PM	0.324 lb/MMBtu
In-line heater	13	PM	0.710 lb/MMBtu

Particulate matter emission limits are well below applicable standards when units are fueled by pipeline quality natural gas, therefore compliance with this chapter is expected.

D. **NDAC 33.1-15-06-Emissions of Sulfur Compounds Restricted**

This chapter applies to any installation in which fuel is burned in which the SO_2 emissions are substantially due to the sulfur content of the fuel burned and in which the fuel is burned primarily to produce heat. This chapter is not applicable to installations which are subject to a SO_2 emission limit under Chapter 33.1-15-12, Standards for Performance for New Stationary Sources, or installations which burn pipeline quality natural gas.

Expected Compliance

The facility is restricted to combusting only natural gas containing no more than 2 grains of sulfur per 100 standard cubic feet, therefore compliance with this chapter is expected.

D. **NDAC 33.1-15-07 – Control of Organic Compounds Emissions**

This chapter requires compressors handling volatile organic compounds must be equipped and operated with properly maintained seals.

Expected Compliance

Based on Department experience with similar sources, the facility is expected to comply with this chapter.

E. **NDAC 33.1-15-12 - Standards of Performance for New Stationary Sources [40 Code of Federal Regulations Part 60 (40 CFR Part 60)]**

This chapter adopts most of the Standards of Performance for New Stationary Sources (NSPS) under 40 CFR Part 60. The facility is subject to subparts listed under 40 CFR Part 60 which have been adopted by the North Dakota Department of Environmental Quality.

Table 12 - NSPS Requirements

Emission Unit Description	Emission Unit (EU)	Applicable Standards
Unit 4 turbine	12	NDAC 33.1-15-12, Subpart KKKK NDAC 33.1-15-12, Subpart TTTT
Emergency generator	14	NDAC 33.1-15-12, Subpart JJJJ

1. **Subpart A-General Provisions**

Subpart A contains the NSPS General Provisions, since the facility is subject to one or more NSPS (NDAC 33.1-15-12/40 CFR 60) it is subject to this subpart.

Expected Compliance

Compliance with the requirements of Subpart A is expected through compliance with each applicable NSPS subpart.

2. **Subpart KKKK – Standards of Performance for Stationary Combustion Turbines, as incorporated by reference into NDAC 33.1-15-12**

This subpart establishes emission standards and compliance schedules for the control of NO_x and SO_2 emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005.

Expected Compliance

The SCCT (EU 12) is subject to this subpart. As such it will have a dry low NO_x combustion control installed as well as a NO_x continuous emissions monitor (CEMs) per 40 CFR 60.4340(b) and 60.4345, which will assess excess emissions based on a 4-hour rolling average.

Table 13 - NO_x Emissions Per Operational Status

Operational Status	NO_x Hourly Emissions (lb/hr)	Total Number of Hours
Normal Operations	81.1	2,859
Start-up/Shutdown	4.6	450
Turn-down	515.0	691

Table 14 - SO_2 Emissions Per Operational Status

Operational Status	NO_x Hourly Emissions (lb/hr)	Total Number of Hours
Normal Operations	6.6	2,859
Start-up/Shutdown	0.41	450
Turn-down	6.6	691

Table 15 - Emission Limits

Emission Unit Description	EU	EP	Pollutant / Parameter	Emission Limit
Natural gas-fired combustion turbine nominally rated at 986 x 10^6 Btu/hr (Unit 4 turbine)	12	12	NO_x: >50 MW (gross) & >0°F	15 ppmvd @ 15% O_2 or 54 ng/J (0.43 lb/MWh) [A, B, C, D]
			NO_x: ≤50 MW (gross) or <0°F	96 ppmvd @ 15% O_2 or 590 ng/J (4.7 lb/MWh) [A, B, C, D]
			NO_x	515.8 lb/hr [H]
			SO_2	110 ng/J (0.90 lb/MWh) (gross) or 0.060 lb/MMBtu (fuel use) [E]
			CO_2	50 kg CO_2/GJ heat input (120 lb CO_2/MMBtu) [F, G]

A CEMs installed in lieu of annual performance tests (40 CFR 60.4340(b)).

B CEMs installation, operation, and performance testing must meet the applicable standards of 40 CFR 60 Subpart KKKK.

C Based on a 4-hr rolling average.

D The higher NO_x limit emission limit applies for the entire hour if at any point in the hour the unit was subject to a higher limit.

E Sulfur content of the fuel must be determined using total sulfur methods per 40 CFR 60.4415 and 60.4370.

F Emissions standards must be met at all times; however, compliance must be determined only at the end of each applicable operating month.

G Emission limit is based on operations that supply less than or equal to its design efficiency (33.34%) or 50%, whichever is less, times its potential electric output as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts > 90% natural gas.

H Based on a 1-hr average.

NO_x concentration is dependent upon the combustion temperature; therefore, NO_x emission limits vary based on ambient temperatures.

For demonstrating compliance with SO_2 emission limits, the facility may conduct SO_2 performance tests per §60.4415(a) or monitor sulfur content of the fuel combusted in the turbine per §60.4360. A representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil, per 60.4415.

Compliance with this chapter is expected.

3. **Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, as incorporated by reference into NDAC 33.1-15-12**

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a stationary combustion turbine that commences construction after January 8, 2014. An applicable unit shall be referred to as an affected electrical generating unit (EGU).

An affected EGU (per the definition in 40 CFR 60.5580), with a base load rating greater than 260 GJ/h (250 x 10^6 Btu/hr) of fossil fuel and capable of selling more than 25 MW to a power distribution system is subject to this subpart. Therefore, the Unit 4 turbine is considered an affected EGU per 40 CFR 60, Subpart TTTT and must comply with all applicable standards set forth in this rule.

Expected Compliance

Table 16 - Emission Limits

Emission Unit Description	EU	Pollutant/ Parameter	Emission Limit	Compliance Method
Unit 4 turbine	12	CO_2	50 kg CO_2/GJ heat input (120 lb CO_2/MMBtu) [A, B]	Notification and Recordkeeping

A Emissions standards must be met at all times; however, compliance must be determined only at the end of each applicable operating month.

B Emission limit is based on operations that supply less than or equal to its design efficiency (33.34%) or 50%, whichever is less, times its potential electric output as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts > 90% natural gas.

Within 30 days after the end of a compliance period, an initial compliance determination must be made with respect to the applicable emissions limits. Since MDU R.M. Heskett is subject to the Acid Rain Program, emissions reporting is required to begin under 40 CFR 60.5525(c).

Compliance with this chapter is expected.

4. **Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines, as incorporated by reference into NDAC 33.1-15-12**

This rule states that natural gas-fired emergency generators (spark-ignited) greater that 500 bhp manufactured after July 1, 2010 are subject to this subpart. The emergency generator (EU 14) is an affected unit according to this rule.

Expected Compliance

Table 17 - NSPS JJJJ Requirements

Emission Unit Description	EU	Requirements
Emergency generator	14	-The emergency engine may be operated for up to 50 hours or less per year (January through December) for non-emergency uses. -The emergency engine may be operated for a maximum total of 100 hours per year (January through December) for non-emergency uses such as maintenance and testing (50 hours of general non-emergency use must be counted toward the 100 total hours of use).

Table 18 - NSPS JJJJ Emission Limits

Emission Unit Description	EU	Pollutant / Parameter	Emission Limit
Emergency generator	14	NO_x	2.0 g/hp-hr or 160 ppmvd [A]
		CO	4.0 g/hp-hr or 540 ppmvd [A]
		VOC	1.0 g/hp-hr or 86 ppmvd [A]

A The emission limits in g/hp-hr and ppmvd (at 15% O_2) are from 40 CFR 60, Subpart JJJJ.

The emergency generator (EU 14) is subject to the requirements of this subpart. Compliance with this subpart is expected.

F. **Chapter 33.1-15-14 – Designated Air Contaminant Sources, Permit to Construct, Minor Source Permit to Operate, Title V Permit to Operate**

This chapter requires the facility to obtain a Permit to Construct prior to installation of sources of air pollution. This chapter also applies to Permit to Operate requirements for facilities that have sources of air pollution.

Expected Compliance

The company has submitted an application for a Permit to Construct and has met those requirements.

G. **Chapter 33.1-15-15 – Prevention of Significant Deterioration of Air Quality**

A Prevention of Significant Deterioration (PSD) review could potentially apply to this facility if it is classified as a "major stationary source" under Chapter 33.1-15-15.

This facility source category will have a PSD major source threshold of 250 tpy, not including fugitive emissions. Due to annual NO_x emissions greater than 250 tpy the facility is classified as a "major stationary source"; therefore, additional construction and modification projects may be subject to PSD review if the emissions increase due to the project exceeds the Significant Emission Rates (SERs) in Table 19 below.

Expected Compliance

Table 19 - Prevention of Significant Deterioration (PSD) Requirements

Pollutant	Project Emissions	Past Actual Emissions [A]	Net Emissions Increase	PSD Significant Emission Rate
NO_x	315.36	1,192.3	-877.49	40
PM_{10}	9.78	219.7	-209.9	15

Pollutant	Project Emissions	Past Actual Emissions [A]	Net Emissions Increase	PSD Significant Emission Rate
$PM_{2.5}$	9.78	217.6	-207.81	10
SO_2	11.86	2,120.1	-2,108.19	40
VOC	16.88	6.7	10.18	40
H_2SO_4	1.53	324.6	-323.04	7
CO_2e	267,276	669,155	-401,879	75,000

A Past actual emissions based on 24-month contemporaneous period from 2018 to 2019, which is within five years of construction.

Based on the table above, emissions from the new equipment proposed in ACP-17983 v1.0 are expected to be well below the PSD SERs; therefore, the new units are not subject to PSD review.

H. **Chapter 33.1-15-16 – Restriction of Odorous Air Contaminants**

The owner/operator shall not discharge into the ambient air any objectionable odorous air contaminant which is in excess of the limits established in NDAC 33.1-15-16.

Expected Compliance Status

Based on Department experience with similar sources, the facility is expected to comply with this chapter.

H. **Chapter 33.1-15-21 – Acid Rain Program**

The SCCT will be considered a utility under the requirements of Chapter 33.1-15-21. Therefore, the owner/operator must apply for, and obtain, an Acid Rain Permit in accordance with NDAC 33-15-21-08.1. In addition, the owner/operator must hold sulfur dioxide allowances, as of the allowance transfer deadline, in the unit's subaccount not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit. Monitoring of emissions must be accomplished in accordance with NDAC 33-15-21-09 (40 CFR 75).

Expected Compliance Status

The proposed Unit 4 turbine at MDU R.M. Heskett station must operate the unit in compliance with a complete Acid Rain permit application including any application for permit renewal or a superseding Acid Rain permit issued by the North Dakota Department of Environmental Quality, Division of Air Quality

MDU R.M. Heskett has submitted an Acid Rain Permit Application and compliance with this chapter is expected.

I. Chapter 33.1-15-22 – Emission Standards for Hazardous Air Pollutants for Source Categories

This chapter adopts most of the National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT) under 40 CFR Part 63.

1. Subpart A-General Provisions

This chapter adopts the 40 CFR Part 63 regulations, also known as the Maximum Achievable Control Technology (MACT) standards, which regulates HAPs from regulated source categories. Typically, these standards apply to major sources of air pollution that are a regulated source category. In addition to the major source requirements, some of the regulations have "area source" standards (for non-major sources). Some of the area source standards have not been adopted by the Department and compliance will be determined by the United States Environmental Protection Agency (USEPA) (e.g. 40 CFR Part 63, Subpart ZZZZ area source provisions have not been adopted by the Department).

Expected Compliance

Subpart A contains the MACT General Provisions. Compliance with the requirements of Subpart A is expected through compliance with each applicable MACT subpart.

2. Subpart ZZZZ-National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The facility appears to have engines subject to the requirements under this subpart. The requirements of Subpart ZZZZ for the engines are met by complying with the requirements of NDAC 33.1-15-12, Subpart JJJJ for EU 14.

Expected Compliance

Table 20 - ZZZZ Requirements

Emission Unit Description	Emission Unit (EU)	Applicable Standards
One (4SLB) natural gas-fired emergency generator rated at 5,364 bhp	14	Comply with NDAC 33.1-15-12, Subpart JJJJ [A, B]

A The Department has not adopted the area source requirements of this subpart; EPA Region 8 is the implementing and enforcement authority for this subpart at minor sources of hazardous air pollutants.

B The requirements of Subpart ZZZZ for the engine is met by complying with the requirements of NDAC 33.1-15-12 [40 CFR 60], Subpart JJJJ.

Conclusions and Recommendations:

The facility is expected to comply with applicable federal and state rules. No comments were received during the 30-day public comment period. It is recommended that Permit to Construct No. ACP-17983 v1.0 be issued for the MDU R.M. Heskett Station.

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CMJ:csc

A.7 – Little Knife Gas Plant

1 Introduction and Representative Operations

Petro-Hunt, L.L.C. (Petro-Hunt) – Little Knife Gas Plant (LKGP) is comprised of numerous fuel gas combustion units, process equipment, tankage, flares, and a sulfur recovery process controlled by an incinerator. The major emissions source onsite is the 2-stage 2-bed Cold Bed Absorption (CBA) sulfur recovery unit (SRU) tail gas incinerator. The LKGP is located approximately 18 miles southwest of Killdeer, North Dakota in Billings County.

LKGP receives associated gas produced from North Dakota oilfields. Since the development of the Bakken shale formation, LKGP has continued to experience a decrease in sour gas received onsite. This is primarily due to the low concentrations of H_2S in Bakken shale gas paired with an increase in Bakken shale gas delivered to the facility. To determine representative operations for the facility, data from 2016–2018 was used. 2016–2018 was chosen since the SRU was converted from a four-stage unit to a two-stage Claus unit with cold bed absorption (CBA) in 2015. The SRU tail gas incinerator combusts the remaining unreacted H_2S after the gas passes through the SRU process. The SRU tail gas incinerator accounted for at least 85% of the total facility emissions since 2016, Table 1 displays the annual emissions reported in tons from 2016-2018.

Table 1: Facility Emissions in Tons

Year	$PM_{2.5}$	PM_{10}	SO_2	NO_x	CO	VOC	Total
2016	2	2	248	22	18	2	293
2017	1	1	389	19	16	2	428
2018	1	1	363	22	18	1	406

The SO_2 emissions displayed in Table 1 are primarily from the operation of the tail gas incinerator on the SRU. Due to the significant amount of emissions from the SRU compared to the rest of the facility, the Department focused the review of additional controls on the SRU process.

2 SO_2 Emissions Controls and Representative History

2.1 SO2

2.1.1 SO_2 Emissions Controls

The historical controls at Petro-Hunt LKGP consisted of two sulfur recovery units, a three-stage four-bed CBA unit and a standard 3-stage Claus unit. The units recovered approximately 98% of the sulfur from the acid gas and converted it to elemental sulfur. The remainder of the acid gas is converted from H_2S to SO_2 by the tail gas incinerator. SO_2 emissions from the incinerator are monitored by a continuous emission rate monitoring system (CERMS).

In September 2015 due to operational difficulty arising from the decrease in inlet H_2S gas to the facility, the sulfur recovery process was modified to handle the reduced H_2S. The three-stage Claus unit was removed from service and the four-bed CBA was converted to a two-stage Claus unit with CBA.

2.1.2 SO_2 Emissions History

Over the years 2016–2018, the SRU recovered approximately 94% of the sulfur entering the unit. The total sulfur recovered, the SO_2 emissions from the tail gas incinerator and the calculated sulfur mass emitted (SO_2 is twice as heavy as elemental sulfur) was used to calculate the SRU recovery efficiency. This information is displayed in Table 2.

Table 2: Sulfur Recovery Unit Efficiency

Year	Sulfur Recovered (tons)	SO2 Emissions from Incinerator (tons)	Sulfur Emissions (tons)	Sulfur Recovery (%)
2016	2975	242	121	96%
2017	2504	315	157	94%
2018	2284	363	181	93%
Average	**2588**	**307**	**153**	**94%**

The other potential significant source of SO_2 emissions from the facility occurs when a process malfunction occurs, and the facility needs to route H_2S inlet or process gas to the facility flare. This does not happen on a routine basis and there is no ability to reduce the emissions during these malfunction events. From 2016–2018 a combined total of 80 tons of SO_2 were emitted from the facility flare, with 74 tons SO_2 occurring in 2017.

3 SO_2 Analysis

3.1 SO_2 Technologies Evaluated

The reasonable progress controls evaluated by LKGP and determined to be technically feasible are listed in Table 3. Expected annual emissions were based on the three-year average SO_2 emissions from the SRU incinerator at LKGP (Table 2). LKGP expects no operational changes, therefore, these emissions are also repetitive of future expected emissions.

Table 3: Reasonable Progress SO_2 Controls

Control Technology	Control Technology Abbreviation	Emissions (tons/year)
Existing SRU (baseline)	--	307
Acid Gas Injection	AGI	0

LKGP also evaluated a catalyst replacement in the SRU reactors to increase the efficiency of unit. Catalyst replacement due to degradation and/or fouling happens on a regular basis and is not considered for reasonable progress controls.

3.1.1 Acid Gas Injection

Acid gas injection (AGI) is a process in which acid gases (H_2S and CO_2) are injected into deep underground wells to dispose of the acid gases produced during the sweeting process of natural gas at a gas processing facility. Installation of AGI eliminates the need for a facility to operate a SRU since the acid gases produced from the natural sweetening process are disposed of underground versus being processed in a SRU.

AGI eliminates all SO_2 emissions except for those emissions due to a malfunction of the injection equipment. When a malfunction occurs, the gas goes to a flare which will combust the H_2S to form SO_2.

3.2 Step 1 – Cost of Compliance

The cost of compliance for the reasonable progress controls are listed in Table 4.

Table 4: SO_2 Cost of Compliance

Control Technology	Emissions (tons/year)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
Existing SRU (baseline)	307			
Acid Gas Injection	0	307	490,009	1,598
Acid Gas Injection[A]	0	307	628,523	2,050

[A] AGI includes redundant compressor and plumbing costs

A detailed breakdown of the costs listed in Table 4 can be found in LKGP's submitted four factors analysis.[1] The Department has reviewed these costs and believes them to be accurate.

If AGI is installed, all the routine SO_2 emissions from the current SRU process will be eliminated. This equates to a reduction of 307 tons SO_2 per year from the baseline emissions. Fiscally, AGI installation requires an estimated annualized cost of $490,000 and SO_2 removal cost of $1,600 per ton.

As mentioned in Table 4, if redundant AGI equipment is installed, the estimated annualized cost increases to $628,500 and SO_2 removal cost increases to roughly $2,100 per ton. Redundant AGI equipment would be utilized to dispose the acid gas in the event when a malfunction occurs. These malfunctions are generally unplanned, short duration-episodes (a few hours) with very high SO_2 emission rates that vary from year-to-year. Without redundancy, controlling emissions during malfunctions is not feasible and the acid gas is flared to prevent the release of high concentrations of H_2S.

3.3 Step 2 – Time Necessary for Compliance

Petro-Hunt indicated installation of AGI would require at least 72 months to complete.[2] The time necessary for compliance is not a limiting factor when determining additional reasonable controls for the LKGP since it could be installed prior to the end of the second planning period.

[1] Appendix B.7.b. PDF page 1300-1311.

[2] Appendix B.7.b. PDF page 1298.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy and Non-Air Quality Environmental Impacts

LKGP's submitted four factors analysis indicated various energy and non-air quality environmental impacts ranging from increased electrical demand to added fuel cost.[3] While these impacts can be significant, none of the impacts eliminate AGI as a potential add-on control option.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, the Petro-Hunt LKGP is expected to operate beyond the life of the control equipment.[4] Therefore, remaining useful life was not considered.

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[3] Appendix B.7.b. PDF page 1299.

[4] Appendix B.7.b. PDF page 1299.

A.8 – Hess Tioga Gas Plant

BEFORE
THE DEPARTMENT OF ENVIRONMENTAL QUALITY
STATE OF NORTH DAKOTA

IN THE MATTER OF: Hess Tioga Gas Plant, LLC	ADMINISTRATIVE CONSENT AGREEMENT Case No. 21-169 APC

The North Dakota Department of Environmental Quality (Department), together with **Hess Tioga Gas Plant, LLC (Respondent)**, agree to settle this administrative action on the following terms:

PRELIMINARY STATEMENT

1. The Department is the state agency responsible for administering and enforcing the state's air pollution control laws and rules, N.D.C.C. ch. 23.1-06 and N.D. Admin Code art. 33.1-15, and has the authority to enter into this Administrative Consent Agreement under N.D.C.C. chs. 23.1-06 and 28-32.

2. Respondent is a Delaware limited liability company in the business of owning and operating a gas processing plant in North Dakota.

3. The parties enter into this Agreement to avoid the expense of litigation and ensure prompt compliance with the state's environmental laws. The Agreement is in the public interest and has been chosen as the most appropriate means of resolving this matter.

STIPULATIONS & VIOLATIONS

4. Respondent owns and operates a gas processing plant located in Tioga, North Dakota (Tioga Gas Plant).

5. Respondent is subject to the requirements of N.D.C.C. ch. 23.1-06 and the rules adopted thereunder.

6. On January 16, 2019, the Department issued Respondent Permit to Operate No. AOP-28424 v5.1 (Permit to Operate) for the Tioga Gas Plant, which is **Attachment A** to this Agreement and incorporated herein by reference. Included in Respondent's Permit to Operate are Clark engines, source units C-1A through 1G (collectively "the Clark engines"). Clark engines C-1D and C-1F have been retrofitted in order to reduce emissions. The non-retrofitted Clark engines are C-1A, C-1B, C-1C, C-1E, and C-1G.

7. While reviewing the WBI Energy Transmission (WBI) Permit to Construct application dated February 14, 2020, the Department determined that WBI

triggered a cumulative air dispersion modeling analysis for the 1-hour NO_2 National Ambient Air Quality Standards (NAAQS) and that the Tioga Gas Plant should be included in the WBI's cumulative modeling analysis.

8. In a letter dated March 4, 2020, the Department notified Respondent that preliminary air dispersion modeling using permitted NO_x emission limits, conducted by the Department in association with the review of the WBI application, identified modeled 1-hour NO_2 concentrations (referred to as "design value") above the 1-hour standard. The Department asserted that the modeled NO_2 concentrations were primarily due to permitted emissions from the Clark engines and not necessarily actual emissions from the Tioga Gas Plant.

9. Based on Potential to Emit calculations and conservative operations assumptions used in the modeling, the Department alleges that Respondent's operation of the Tioga Gas Plant has violated N.D. Admin. Code § 33.1-15-02-07(1), which states that "no person may cause or permit the emission of contaminants to the ambient air from any source in such a manner and amount that causes or contributes to a violation in the ambient air of those standards stated in section 33.1-15-02-04."

10. This Agreement is for the purpose of settlement only. Respondent admits to the Department's jurisdiction but does not admit to the violations alleged in Paragraph 9. Respondent agrees that the Department may consider this matter and any enforcement documents relating to this matter – including inspection reports, the March 4, 2020, letter, and this Agreement – when determining Respondent's compliance history in connection with any future enforcement or permitting action by the Department against Respondent. In any such action, Respondent shall be stopped from objecting to the above-referenced documents being considered by the Department or entered into evidence in any administrative or judicial proceeding for the purpose of determining Respondent's compliance history.

SETTLEMENT TERMS

NOW, THEREFORE, in consideration of the foregoing and the mutual covenants and conditions in this Agreement, and desiring to be legally bound, the Parties agree as follows:

11. Respondent agrees to pay an administrative penalty of Sixty-Five Thousand Dollars ($65,000), of which Forty-Five Thousand Dollars ($45,000) shall be suspended and may be ultimately dismissed according to the provisions of Paragraph 14 of these Settlement Terms. The remaining Twenty Thousand ($20,000) shall be due within 30 days after this Agreement's effective date. Payment of the penalty shall be in a check made payable to the North Dakota

Department of Environmental Quality, shall reference Case No. 21-169 APC, and shall be directed to the attention of L. David Glatt, Director, North Dakota Department of Environmental Quality, 4201 Normandy St., Bismarck, ND 58503-1324. If any payment required by this Agreement is not made, or if any negotiable instrument presented as payment is not honored, the Department may file a civil action to collect the amount due under this Agreement plus interest, attorney's fees, and costs. In any collection action, the validity, amount, and appropriateness of penalties is not subject to review.

12. Compliance Measures. Respondent shall comply with the following Compliance Measures:

    a. The non-retrofitted Clark engines will be removed from service before July 1, 2024. The retrofitted Clark engines shall be removed from service before June 30, 2025.

    b. Until the Clark engines are removed from service, Respondent shall:

        i. Evaluate and implement operational controls, as appropriate, designed to reduce operating time for the Clark engines, within 90 days of this Agreement's effective date. When operationally practical, the Clark engines, specifically the non-retrofitted Clark engines, will be the last compressors to be activated and the first to be taken offline at the Tioga Gas Plant.

            1. Respondent shall submit a semiannual report to the Department detailing the operational controls, designed to reduce the operating time of the Clark engines, implemented at the Tioga Gas Plant. The semiannual report must also show the dates of operation and number of hours each Clark engine was operated during the period.

        ii. Install one NO_2 ambient monitoring station. Respondent shall continue to operate the NO_2 ambient monitoring station until the Clark engines are removed from service.

            1. Respondent shall submit a proposal to the Department to determine the location of the NO_2 ambient monitor station within 60 days of this Agreement's effective date. Respondent shall install the NO_2 ambient monitor station within 90 days after the Department's written approval.

            2. Respondent shall submit quarterly ambient air quality monitoring data and quality assurance reports to the Department. Information to be included in the quarterly reports can be found in the Permit to Operate, Condition 10.G.

3. If any exceedance of the ambient air quality standards are measured by the NO_2 ambient monitor, Respondent shall investigate the cause of the exceedance and promptly provide a report of the results of its investigation to the Department.

iii. Complete a study of compression needs and submit a Permit to Construct application for the Tioga Gas Plant to the Department, within 18 months of this Agreement's effective date, to undertake permitting actions, as necessary, to remove the Clark engines from service at the Tioga Gas Plant as described in this Paragraph.

c. Between July 1, 2024, and the date the retrofitted Clark engines are removed from service, Respondent shall only operate the retrofitted Clark engines in a back-up capacity as needed during non-normal operations at the Tioga Gas Plant.

13. Reservation of Rights. The Department reserves the right to enforce this Agreement and bring new enforcement action should Respondent fail to complete the Compliance Measures required by this Agreement. The Department also reserves the right to bring new enforcement action for any additional violations disclosed under this Agreement.

14. Suspended Penalty. The Department shall dismiss the Forty-Five Thousand Dollar ($45,000) suspended penalty if Respondent complies with the conditions of Paragraph 12 of these Settlement Terms. Failure to complete the conditions of Paragraph 12 according to the schedule provided in these Settlement Terms shall result in the entire Forty-Five Thousand Dollar ($45,000) suspended penalty becoming immediately due and payable. Upon notification from the Department, Respondent shall immediately pay the suspended penalty according to the terms of Paragraph 11. Payment of the suspended penalty does not relieve Respondent of its obligation to complete the remaining conditions of these Settlement Terms, and Respondent shall complete all the Compliance Measures as provided in these Settlement Terms.

GENERAL TERMS

15. Respondent agrees that it was properly notified of the violations listed herein.

16. Respondent acknowledges that, regarding the violations listed herein, it is knowingly and voluntarily waiving the rights and procedures that would otherwise protect it and that it would have in any formal administrative adjudicatory proceeding or any civil action in a court of law, including the right to the filing of a notice of intent to file suit, to present evidence and witnesses on its behalf, to cross-examine Department's witnesses, to a jury trial, and to administrative and judicial review.

17. Respondent agrees that an administrative order may be entered incorporating the Agreement's terms and agrees that such an order may be enforced by a court of competent jurisdiction. Respondent agrees that it will not contest Department's jurisdiction to compel compliance with such an order in any subsequent enforcement proceedings. Nothing herein shall be construed as limiting Department's right to seek penalties for violations of such an order.

18. Any judicial action brought by either party to enforce or adjudicate any of the Agreement's terms, or an order incorporating the Agreement's terms, shall be brought in the Burleigh County Court in the State of North Dakota (South Central Judicial District).

19. If any term of this Agreement is declared by a court having jurisdiction to be illegal or unenforceable, the validity of the remaining terms will not be affected and, if possible, the rights and obligations of the parties are to be construed and enforced as if the Agreement did not contain that term.

20. The Agreement shall constitute full settlement of the violations listed herein but does not limit Department from taking enforcement action concerning other violations.

21. No failure by Department to enforce any of the Agreement's terms after any breach or default will be deemed as a waiver of its rights regarding that breach or default, nor will such failures be construed as a waiver of the right to enforce all of the Agreement's terms on any further breach or default.

22. This Agreement constitutes the entire agreement between the parties. Except as otherwise provided in the Agreement, no amendment, alteration, or addition to the Agreement shall be binding unless reduced to writing and signed by both parties.

23. The Agreement shall apply to, and be binding on, the parties, their officers, agents, servants, employees, successors, and assigns.

24. No change in ownership of any property, or in Respondent's corporate status, shall in any way alter Respondent's obligations and responsibilities under this Agreement.

25. Each party shall bear its own costs incurred in this action, including attorney fees.

26. The Agreement becomes effective when signed by both parties.

27. Respondent enters into the Agreement freely and voluntarily. Respondent discussed this Agreement with its attorney.

Department of Environmental Quality

By: L. David Glatt, P.E.
Director

1-10-2022
Date

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

The foregoing instrument was acknowledged before me on this 10 day of January, 2021, by L. David Glatt.

Sheri A. Jahraus
Notary Public
My Commission Expires: 10/18/24

(Seal)

SHERRI A JAHRAUS
Notary Public
State of North Dakota
My Commission Expires Oct 18, 2024

Hess Tioga Gas Plant, LLC

By: John Gatling
Title: Vice President

Date: 12/15/2021

STATE OF)
ss.
COUNTY OF)

The foregoing instrument was acknowledged before me on this 15 day of December, 2021, by John Gatling, Vice President – Hess Tioga Gas Plant, LLC. a Delaware limited liability company, on behalf of the limited liability company.

(Seal)

Notary Public Robin T. Hensley
My Commission Expires: 11/27/22

ROBIN T. HENSLEY
MY COMMISSION EXPIRES
NOVEMBER 27, 2022
NOTARY ID: 125922769

NOTARY PUBLIC STATE OF TEXAS

1 Introduction and Representative Operations

Hess Tioga Gas Plant, LLC (Hess) – Hess Tioga Gas Plant (TGP) is comprised of numerous boilers, heaters, compressor engines, turbines, storage tanks, process equipment, flares, and a sulfur recovery process controlled by an incinerator. Most of the emissions are sourced from the compressor engines and the amine gas sweetening unit (the SRU tail gas incinerator). Tioga is located just to the east of Tioga, North Dakota in Williams County.

The average annual amount of inlet gas received, natural gas produced, and sulfur recovered from 2015 through 2018 is listed in Table 1. The time period of 2015–2018 was chosen as representative since Hess TGP completed a plant expansion in 2014, allowing the facility to process more inlet gas.

The process data does not directly correlate with the emissions from the facility but helps to show consistent operations over the recent years from the facility. With this consistent operation, emissions from this time period can be averaged to determine representative baseline emissions in order to evaluate additional feasible controls. See Table 1 for detailed information.

Table 1: Process Data from 2015-2018

Year	Gas Received (MMscf)	Gas Produced (MMscf)	Sulfur Produced (tons)
2015	70,800	36,200	8,970
2016	62,200	36,300	8,030
2017	63,900	39,200	8,170
2018	70,200	45,100	8,240

Hess TGP's future operations are expected to be in line with the 4-year average of 2014–2018.

2 NO_X and SO_2 Emissions Controls and Representative History

The emissions sources which contribute the largest to the overall emissions profile for Hess TGP are the Clark compressor engines and the sulfur recovery unit operations.

Over the years of 2014–2018, the Clark compressor engines accounted for 91% of the facilities total NO_X emissions. A breakdown of the NO_X emissions profile can be found in Section 2.1.2.

Over the years of 2014–2018, the sulfur recovery operation accounted for 94% of the facilities total SO_2 emissions, where 79% of the total was from the tail gas incinerator. A breakdown of the SO_2 emissions profile can be found in Section 2.2.2.

The sulfur recovery unit tail gas incinerator has a SO_2 continuous emissions rate monitor system (CERMS) installed. The Clark compressor engines are tested semi-annually to ensure they are operating in compliance with the total tons of NO_X restriction in the facility's Title V Permit to Operate.

During the first round of the regional haze program, the Department determined that no NO_X or SO_2 controls were required the Hess TGP.[1]

2.1 NOx

2.1.1 NO_X Emissions Controls

A summary of the existing NO_X controls for the applicable Hess TGP emissions units are discussed in Section 2.1.1.1 and 2.1.1.2.

2.1.1.1 Clark Compressor Engines

Hess TGP operates seven Clark compressor engines, identified as C1A through C1G. These engines are fueled by a portion of the natural gas produced by the facility and are used to boost the pressure of the inlet field gas received for processing. All the Clark engines are lean burn integral engines, meaning the engine and compressor structure are a single unit, making it both difficult and costly to replace the units. Two of the engines (C1D and C1F) required modification in 2004, which entailed adding turbocharging systems. The turbocharging system significantly reduced NO_X emissions from these engines compared to the other five engines. The other five engines (C1A, C1B, C1C, C1E, and C1G) have not been significantly modified since construction in the 1950's but have been kept in good working order.[2] Feasible add-on controls for the remaining five engines are evaluated in Section 3.1. A discussion on the breakdown of emissions from these engines can be found in Section 2.1.2.

2.1.1.2 Remaining NO_X Emissions Units

Hess TGP does not operate any other units which are significant contributors of NO_X emissions, therefore, no additional equipment is evaluated for additional controls with this analysis. Hess TGP included an evaluation of NO_X controls on the sulfur recovery unit tail gas incinerator and considered the feasibility of a flare management plan to reduce emissions from this activity. Neither of these evaluations yielded any feasible controls.[3]

2.1.2 NO_X Emissions History

No recent NO_X controls have been installed at the facility, therefore, the baseline emissions from the facility were determined based on the average emissions from 2015–2018. This information is displayed in Table 2.

Table 2: Annual NO_X Emissions (tons)

Year	Clark Engines	Remaining Units [A]	Total
2015	1,366	106	1,472
2016	1,133	76	1,209
2017	535	93	627
2018	614	92	706
Average	**912**	**92**	**1,004**

[A] Accounts for all other onsite emissions units.

[1] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 182-188.

[2] Appendix B.8.b., p. 11. PDF page 1386.

[3] Appendix B.8.b, p. 28. PDF page 1403.

Given the magnitude of emissions produced from the Clark engines (91% of the facility total NO_X), they are the focus of determining the need for NO_X controls under the reasonable progress requirements. The NO_X emissions from the Clark Engines (Table 2), have been further separated by individual engines in Table 3 to show the variation between each engine and the impact the modification of C1D and C1F had on the NO_X emissions rate.

Table 3: Annual NO_X Emissions from Clark Engines (tons)

Year	C1A	C1B	C1C	C1E	C1G	C1D[A]	C1F[A]
2015	238	293	209	353	207	30	35
2016	171	215	255	257	150	25	30
2017	18	99	127	81	155	26	29
2018	107	148	139	0	186	19	16
Average	**134**	**189**	**183**	**231**	**175**	**25**	**27**

[A] C1D and C1F were modified in 2004

Since each engine does not have the same operating hours per year, looking only at total emissions does not directly help with determining the best sources for individual controls. Therefore, the Department used the annual emissions (Table 3) and the annual operating hours (Table 4) to calculate the average pounds per hour of NO_X emissions from each engine (Table 5).

Table 4: Clark Engine Operation (hours)

Year	C1A	C1B	C1C	C1E	C1G	C1D	C1F
2015	6,520	7,749	5,818	7,437	7,885	8,314	8,568
2016	3,720	6,417	6,965	6,600	5,217	7,045	7,962
2017	528	3,506	4,258	2,070	6,240	8,165	6,708
2018	3,228	4,438	4,648	0	5,325	5,133	3,668
Average	**3,499**	**5,528**	**5,422**	**5,369**	**6,167**	**7,164**	**6,727**

Table 5: Non-modified Clark Engine NO_X Emissions (lb/hr)

Year	C1A	C1B	C1C	C1E	C1G
2015	73	76	72	95	53
2016	92	67	73	78	57
2017	66	56	60	78	50
2018	66	67	60	0	70
Average	**75**	**66**	**66**	**84**	**57**

Averaging the pound per hour data across the five non-modified Clark engines from Table 5, and pairing this with the average operating hours for the non-modified Clark engines (Table 4), yields a baseline emissions value of 181 tons per year from each of the five non-modified Clark engines. By chance, this happens to compare to the simple average of the five non-modified Clark engines, which is 182 tons per year.

181 tons per year of NO_X is used as the baseline rate for each non-modified Clark engine when evaluating the cost of additional controls in Section 3.2.

2.2 SO2

2.2.1 SO_2 Emissions Controls

A summary of the existing SO_2 controls for the Hess TGP sulfur recovery process is discussed in Section 2.2.1.1.

2.2.1.1 Sulfur Recovery Process

The sulfur recovery process at Hess TGP consists of an amine gas sweeting unit and sulfur recovery unit (SRU). The SRU consists of a 2-stage Claus process followed by cold bed adsorption. Over the baseline years of 2015–2018 sulfur recovery has averaged 96%, see Table 6.

Table 6: Sulfur Recovery Process Data

Year	Sulfur Produced (Tons)	Sulfur from Tail Gas Incineration (Tons)	SRU Efficiency (%)
2015	8,968	307	96.7%
2016	8,029	241	97.1%
2017	8,167	359	95.8%
2018	8,243	497	94.3%
Average	**8,352**	**351**	**96.0%**

Remaining gas (tail gas) not converted to elemental sulfur during the reaction process is combusted in the tail gas incinerator. The tail gas incinerator accounted for an average of 79% of the facility SO_2 emissions (Table 7).

Another aspect of the sulfur recovery process produces SO_2 emissions is during acid gas flaring events. Acid gas produced by the amine sweeting unit feeds the sulfur recovery unit and acid gas flaring occurs when the sulfur recovery unit malfunctions and needs to be taken offline. Acid gas flaring is very intermittent, averaging 70 hours a year over the baseline years. This does, however, account for 15% of the facility SO_2 due to the high concentration of hydrogen sulfide in the acid gas. Since acid gas flaring is not a routine source of emissions, SO_2 reductions from this activity are not evaluated.

2.2.1.2 Remaining SO_2 Emissions Units

The only source of SO_2 emissions from the facility not associated with the sulfur recovery process come from the flaring of inlet (feedstock) gas. Hess TGP considered the feasibility of a flare management plan to reduce emissions from this activity.[4] Since flaring only occurs during emergency events and other malfunctions related occurrences and is highly intermittent, a flare management plan was deemed unnecessary. Flaring accounts for approximately 6% of the SO_2 emissions over the baseline years, see Table 7.

2.2.2 SO_2 Emissions History

No recent SO_2 controls have been installed at Hess TGP, therefore, the baseline emissions from the facility were determined based on the average emissions from 2015–2018. This information is displayed in Table 7.

[4] Appendix B.8.b, p. 15 and 30. PDF pages 1390 and 1405.

Table 7: Annual SO_2 Emissions (tons)

Year	Tail Gas Incineration	Acid Gas Flaring	Inlet Gas Flaring	Total
2015	614	178	114	906
2016	481	308	77	866
2017	719	29	2	749
2018	994	20	26	1,040
Average	**702**	**134**	**55**	**890**

As shown in Table 7, most of the SO_2 emissions from Hess TGP come from the incineration of the tail gas produced by the sulfur recovery unit. During normal operations, this is the only significant source of SO_2 emissions. Tail gas incineration accounts for an average of 79% of the facility SO_2 emissions. Acid gas flaring (15%) and inlet gas flaring (6%) account for the remaining portion of SO_2 emissions where controls could theoretically be evaluated. However, as both inlet and acid gas flaring are intermittent and not intended operations, controls are not evaluated from these sources.

3 NOx Analysis

3.1 NO_X Technologies

The NO_X controls evaluated for the non-modified Clark engine are discussed in Sections 3.1.1 and 3.1.2.

3.1.1 Low-emission Controls (LEC)

LEC is s system of upgrades, modifications, and tuning on the Clark engines to achieve a lower emissions rate. LEC is anticipated to achieve 70-90% reduction in NO_X emissions and achieve a controlled emissions rate of 1 gram per brake horsepower hour, which is consistent with most new internal combustion engines.[5] LEC installation on non-modified Clark engines is technically feasible and will be further evaluated.

3.1.2 Selective Catalytic Reduction (SCR)

SCR is an exhaust control that could be applied to lean combustion engines which reduces NO_x emissions by reacting NO_x with ammonia or urea over a catalyst.[6] SCR is anticipated to achieve 70-90% reduction in NO_X emissions and achieve a controlled emissions rate of 1 gram per brake horsepower hour, the same rate which could be achieved through installation of LEC. Since LEC could achieve the emissions same rate as SCR with less impacts elsewhere, SCR will not be evaluated further. Additional impacts with SCR consist of multiple energy and non-environmental issues associated with installation and operation.[7] While technically feasible, SCR is rarely used in the natural gas transmission and related industries, giving further support to remove this from further evaluation.[8]

[5] Appendix B.8.b, p. 12. PDF page 1387.
[6] Appendix B.8.b., p. 12. PDF page 1387.
[7] Appendix B.8.b., p. 12-13 and 24. PDF page 1387-1388.
[8] Appendix B.8.b., p. 13 and 29. PDF pages 1388 and 1404.

3.2 Step 1 – Cost of Compliance

The cost of compliance for the reasonable progress controls are listed in Table 8. These costs are for each individual non-modified Clark engines (C1A, C1B, C1C, C1E, and C1G). The costs have been determined on an average basis spread across each of the five engines due to the variability in each engines operation, as discussed in Section 2.1.2.

Table 8: NO_X Cost of Compliance for each non-modified Clark Engine

Control Technology	Annual Emissions (tpy)	Annual Emissions Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
Baseline	181			
Low-Emissions Controls	36	145	1,271,977	8,784

A detailed breakdown of the costs listed in Table 8 can be found in Hess TGP's submitted four factors analysis.[9] The Department has reviewed these costs and believes them to be accurate.

As displayed in Table 8, installation of LEC would reduce emissions by approximately 145 tons NO_X on each of the five non-modified Clark engines. This amounts to a combined total of 724 tons of NO_X from each non-modified engine. Individually, this reduction comes at a cost of approximately $8,800 per ton of NO_X reduced at an annualized cost of approximately $1.3 million. Installing LEC on each of these five engines amounts to a total annualized cost of roughly $6.4 million.

3.3 Step 2 – Time Necessary for Compliance

Hess TGP indicated a timeline of five to seven years for installation of LEC on the non-modified Clark engines. This is due to the sequential order of installing controls to eliminate facility downtime.[10] The time necessary for compliance is not a limiting factor when determining additional reasonable controls for the Hess TGP since LEC controls could be installed prior to the end of the second planning period.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

There are no energy or non-air quality environmental impacts associated with the installation of LEC on the non-modified Clark engines.

3.5 Step 4 – Remaining Useful Life

Hess TGP is expected to operate beyond the useful life of additional controls, therefore, remaining useful life is not a factor for consideration.

4 SO_2 Analysis

4.1 SO_2 Technologies

The SO2 controls evaluated for the sulfur recovery process are discussed in Sections 4.1.1 through 4.1.3.

[9] Appendix B.8.b., Appendix A. PDF page 1406
[10] Appendix B.8.b., p. 21. PDF page 1396

4.1.1 Tail Gas Treatment

Tail gas treatment or tail gas scrubbing treatment (TGST) adds an additional scrubbing system on the exhaust of the current sulfur recovery unit prior to the tail gas incineration. There are many types of tail gas treatment options available, each of which serves a specific purpose or industry.[11]

A TGST system reduces the amount of sulfur sent to the tail gas incinerator, thereby increasing the overall sulfur recovery efficiency by reducing the SO_2 emissions produced during tail gas incineration. LO-CAT® technology was chosen for evaluation as this technology is commonly associated with the natural gas industry.[12] The LO-CAT® removes H_2S from an acid gas (or SRU tail gas) stream and converts it to elemental sulfur, essentially supplementing the current sulfur production at the facility. LO-CAT® is expected to reduce an additional 90% sulfur beyond the existing sulfur recovery, increasing the overall sulfur recovery to greater than 99%. Additional tail gas scrubbing treatment is technically feasibility and will be evaluated further.

4.1.2 Flue Gas Desulfurization (FGD)

Flue gas desulfurization was briefly explored as an alternative control option for Hess TGP. There are multiple reasons why traditional flue gas desulfurization is not reasonable to implement for control of SO_2 emissions from a gas processing facility.[13] Tail gas treatment and acid gas disposal options are more effective and have less disadvantages associated with implementation, therefore, FGD will not be carried forward for further evaluation.

4.1.3 Acid Gas Disposal Injection Well

As an alternative to additional tail gas treatment discussed in Section 4.1.1, Hess TGP evaluated the feasibility of installing an acid gas disposal (AGD) injection well. In lieu of additional tail gas scrubbing, an AGD injection well can dispose of the tail gas produced by the SRU, eliminating the emissions associated with tail gas incineration. Infrastructure requirements and geological uncertainty both pose significant risk associated with implementation of an AGD injection well.[14] Nevertheless, AGD is technically feasible and will be evaluated further.

4.2 Step 1 – Cost of Compliance

The cost of compliance for the reasonable progress controls evaluated for the sulfur recovery process are listed in Table 9. These costs are for the SO_2 controls deemed technically feasible.

Table 9: SO_2 Cost of Compliance for the Sulfur Recovery Process

Control Technology	Annual Emissions (tpy)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
Baseline (96% recovery)	702			
Tail Gas Treatment	70	632	7,151,657	11,321
Acid Gas Disposal Injection Well	7	695	2,256,837	3,248
Acid Gas Disposal Injection Well [A]	7	695	3,087,549	4,443

[11] Appendix B.8.b., p. 6-8. PDF page 1381-1383
[12] Appendix B.8.b., p. 7. PDF page 1382
[13] Appendix B.8.b., p. 8-9 and 28. PDF pages 1383-1384 and 1403.
[14] Appendix B.8.b., p.10, 18-19, and 23. PDF pages 1385, 1393-1394, and 1398.

Control Technology	Annual Emissions (tpy)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)

[A] Includes redundant compressor and plumbing costs

A detailed breakdown of the costs listed in Table 9 can be found in Hess TGP's submitted four factors analysis.[15] The Department has reviewed these costs and believes them to be reasonably accurate. As indicated in the submitted report, the AGD injection well costs provided are expected to increase significantly if a further detailed evaluation is required.[16] The cost of compliance for AGD injection well can be thought of as the very minimum cost for implementing this technology.

If a tail gas treatment system is installed, such as the LO-CAT® technology, a 90% reduction from the current SO_2 emissions can be achieved. This equates to a reduction of 632 tons SO_2 per year from the baseline emissions. Fiscally, tail gas treatment system comes at an estimated annualized cost of approximately $7,152,000 and SO_2 removal cost of roughly $11,300 per ton.

If an AGD injection well is installed, 99% of the current SO_2 emissions from the current SRU process will be eliminated. This equates to a reduction of 695 tons SO_2 per year from the baseline emissions. Fiscally, AGD requires an estimated annualized cost of approximately $2,257,000 and SO_2 removal cost of roughly $3,250 per ton.

As mentioned in Table 9, if redundant AGD equipment is installed, the estimated annualized cost increases to approximately $3.1 million and SO_2 removal cost increases to roughly $4,400 per ton. Redundant AGD equipment would be utilized to dispose the acid gas in the event when a malfunction occurs. These malfunctions are generally unplanned, short duration-episodes (a few hours) with very high SO_2 emission rates that vary from year-to-year. Without redundancy, controlling emissions during malfunctions is not feasible and the acid gas is flared to prevent the release of high concentrations of H_2S, negating the benefit of injecting the gas underground.

4.3 Step 2 – Time Necessary for Compliance

Hess TGP indicated a timeline of four to five years for installation and operation of a LO-CAT® unit.[17] Construction and operation of an AGD injection well was estimated at a minimum of five years. This estimate is highly uncertain given all the variables associated with installation.[18] The variables, such as equipment procurement, land surveying and acquisition, permitting, sub-surface research, and pipeline construction, would also likely add significant unforeseen expenses. The time necessary for compliance is not a limiting factor when determining additional reasonable controls for the Hess TGP since the projects could likely be completed prior to the end of the second-round planning period or an agreed upon schedule could be negotiated between the Department and Hess TGP.

[15] Appendix B.8.b., p. Appendix A. PDF page 1406
[16] Appendix B.8.b., p.18-19. PDF page 1939-1394.
[17] Appendix B.8.b., p. 21. PDF page 1396.
[18] Appendix B.8.b., p. 21-22. PDF page 1396-1397.

4.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

Hess TGP's submitted four factors analysis indicated various energy and non-air quality environmental impacts from the LO-CAT® unit ranging from increased electrical demand to spent catalyst disposal.[19] While these impacts can be significant, none of the impacts eliminate the LO-CAT® as a potential add-on control option.

Hess TGP's four factor analysis also indicated various energy and non-air quality environmental impacts from the AGD injection well. Risks associated with construction and operation of the AGD pipeline are potentially significant and AGD also generates a new waste stream from the compression and dehydration of the acid gas.[20] Additionally, a considerable amount of electricity is required for the operation of the AGD equipment. While these impacts can be significant, none of the impacts eliminate an AGD injection well as a potential add-on control option.

4.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, Hess TGP is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

[19] Appendix B.8.b., p. 23. PDF page 1398.
[20] Appendix B.8.b., p. 23. PDF page 1398.

A.9 – Northern Border CS4

1 Introduction and Representative Operations

Northern Border Pipeline Company (NBPC) – Compressor Station No. 4 (CS4) is a compressor station with the majority of emissions being sourced from a 20,000 horsepower simple cycle natural gas-fired combustion turbine (Unit CE1), which drives a natural gas compressor. The turbine is a Cooper-Rolls Model Coberra 2648S Avon. CS4 is located approximately nine miles west of Watford City, North Dakota in McKenzie County.

Data from 2012–2018 was used to when determining representative operations for the facility. 2012–2018 was chosen since this seven-year timeframe captured two high utilization years, two low utilization years, and three moderate utilization years. The yearly data is displayed in Table 1. Utilization was calculated by taking the annual actual hours of operation divided by total hours in a year (8760 hours per year).

Table 1: Yearly Operational Data

Year	Operating Time (hrs)	Yearly Duty (MMBtu/yr)	Utilization
2012	8,494	1,262,480	97%
2013	8,346	1,328,516	95%
2014	4,116	594,188	47%
2015	3,713	499,517	42%
2016	7,161	1,052,922	82%
2017	6,822	1,048,291	78%
2018	6,909	983,570	79%
Average	**6,509**	**967,069**	**74%**

Based on the information provided to the Department by NBPC, CS4's recent averaged operational data, Table 1, is consistent with anticipated future operations.[1]

2 NO_X Emissions Controls and Representative History

During the first round of the regional haze program, the Department determined that NBPC – CS4 was eliminated from consideration of additional controls. This was due to the average 2006–2008 NO_X plus SO_2 emissions being 118 tons per year, resulting in a Q/d of 6.6 (118 tons/18 km = 6.6).[2] The focus of this determination is on NO_X emissions. CS4 combusts pipeline quality natural gas, therefore, SO_2 emissions were not considered when reviewing emissions control options.

2.1 NOx

2.1.1 NO_X Emissions Controls

There have been no upgrades or retrofits installed on CS4's 20,000 horsepower existing turbine. Additionally, there are no existing add-on NO_X controls installed on the turbine.

[1] Appendix B.9.b., p.2. PDF page 1457.

[2] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 180.

2.1.2 NO_X Emissions History

Consistent with operational data displayed Table 1, 2012–2018 was the time period used to determine the NO_X baseline emissions for CS4. This information is displayed in Table 2.

Table 2: NO_X Emissions

Year	Representative Emissions Rate (lb/MMBtu)[A]	Emissions Rate (lb/hr)	Calculated NO_X Emissions (tpy)
2012	0.27	40.3	171
2013	0.27	43.1	180
2014	0.27	39.1	80
2015	0.27	36.5	68
2016	0.27	39.8	143
2017	0.27	41.6	142
2018	0.27	38.6	133
Average	**0.27**	**39.9**	**131**

[A] Average tested emission rate from testing completed from 2012-2018.

The representative emissions rate (lb/MMBtu) was calculated from an average of 11 tests over the 7 years. These tests are considered representative of typical operations and anticipated future operations. Load during testing ranged from 58% to 95%, with an average of 81%. Emissions rates varied from 0.21 to 0.33 lb/MMBtu, with an average of 0.27 lb/MMBtu.[3] The value of 0.27 lb/MMBtu is used as the stating point when determining the cost of compliance for add-on controls evaluated in 3.2.

3 NOx Four-Factor Analysis

3.1 NO_X Technologies Evaluated

The turbine manufacturer does not offer a burner retrofit option for lean premixed combustion, therefore, only add-on NOx controls were evaluated. Of the add-on control, selective catalytic reduction and water injections were reviewed.

Water injection is a control technology which has the potential to decrease NO_X emissions by decreasing the peak flame temperature in the turbine. Water injection is an older technology which has fallen out of favor since low emission combustion controls and/or SCRs have been refined and implemented. Factors which limit the feasibility of water injection are increased carbon monoxide emissions, heat rate penalty, and potential for flame blow-off or flame-out. The issues are significant enough to eliminate water injection as a potential NO_X control option.

The reasonable progress controls evaluated by NBPC and determined to be available and technically feasible are listed in Table 3. Performance rate and expected annual emissions are included for each control technology that was determined to be technically feasible. Expected annual emissions were calculated using the performance rate and the average yearly duty (Table 1).

[3] Appendix B.9.c., PDF page 1471.

Table 3: Reasonable Progress NO_X Controls

Control Technology	Control Technology Abbreviation	Performance Rate (lb/MMBtu)	Emissions (tons/year)
Uncontrolled (baseline)	--	0.27	131
selective catalytic reduction	SCR	0.05	26

3.1.1 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is an add-on control technology used to reduce NO_X emissions after formation during the combustion process. SCR is a well understood technology that has been implemented on many different combustion processes. SCR is anticipated to provide an approximately 80% reduction in NO_X emissions from the baseline scenario, lowering the expected performance from 0.27 to 0.05 lb NO_X per MMBtu. SCR is technically feasible and will be further evaluated.

3.2 Step 1 – Cost of Compliance

The cost of compliance for the reasonable progress controls are listed in Table 4.

Table 4: NO_X Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
Uncontrolled (baseline)	0.27			
selective catalytic reduction	0.05	105	1,374,201	13,040

A detailed breakdown of the costs listed in Table 4 can be found in NBPC's submitted four factors analysis.[4] The Department has reviewed these costs and believes them to be accurate.

If SCR is installed, a performance rate improvement of 0.22 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of 105 tons NO_X per year from the baseline emissions. Fiscally, SCR installation requires an estimated annualized cost of $1.4 million and NO_X removal cost of $13,000 per ton.

3.3 Step 2 – Time Necessary for Compliance

Installation of SCR would require at least 36 months to complete.[5] The time necessary for compliance is not a limiting factor when determining additional reasonable controls for NBPC – CS4 since it could be installed prior to the end of the second planning period.

[4] Appendix B.9.b., PDF page 1459.

[5] Appendix B.9.b., p.3. PDF page 1458.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy and Non-Air Quality Environmental Impacts

NBPC's submitted four factors analysis indicated various energy and non-air quality environmental impacts ranging from increased electrical demand to ammonia slip emissions.[6] While these impacts can be significant, none of the impacts eliminate SCR as a potential add-on control option.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, the turbine at CS4 is expected to operate beyond the life of the control equipment.[7] Therefore, remaining useful life was not considered.

[6] Appendix B.9.b., p.3. PDF page 1458.
[7] Appendix B.9.b., p.4. PDF page 1459.

A.10 – Basin DGC

1 Introduction and Representative Operations

Dakota Gasification Company (DGC) – Great Plains Synfuels Plant (GPSP) is owned and operated by Bain Electric Power Cooperative (Basin). DGC is a for-profit subsidiary of Basin and produces synthetic natural gas, fertilizers, and other byproducts resulting from the gasification of lignite coal. GPSP also captures carbon dioxide, which is transported via pipeline to oil fields in Saskatchewan Canada. The GPSP is the only facility of its kind in the United States. The GPSP commenced operation in 1984. The GPSP consists of many emissions units and emissions points. The significant sources of NO_X and SO_2 emissions include:

- Three Riley boilers each rated at 763 MMBtu per hour
- Two superheaters each rated at 169 MMBtu per hour
- One package boiler rated at 318 MMbtu per hour
- The main flare and the start-up flare

The DGC GPSP is located approximately six miles northwest of the town of Beulah, North Dakota in Mercer County. The GPSP receives lignite coal from the Coteau Properties Freedom Mine located approximately two miles north of the GPSP. Coal which is too fine for gasification is sent back to the Antelope Valley Station (AVS) electrical generating utility (EGU).

The average annual amount of North Dakota lignite gasified from 2014 through 2018 was approximately 6.1 million tons. The amount of coal gasified at the GPSP does not directly correlate with the emissions from the facility but helps show consistent operations over the recent years from the facility. With this consistent operation, emissions from this time period can be averaged to determine representative baseline emissions in order to evaluate additional feasible controls. See Table 1 for detailed information.

Table 1: Annual Coal Consumed (tons)

Year	Gasifier Feed (tons)
2014	6,071,536
2015	6,207,012
2016	5,998,365
2017	6,047,430
2018	6,186,391
Average	**6,102,147**

Representative operations for the Riley boilers and Superheaters are based on the recent emissions from the units versus the amount of fuel consumed due to the variety of fuels these unit combust and varying heat content of the fuels. The Riley Boilers are designed to burn a combination of gasification products, including liquid and gaseous fuels consisting of waste gas, stink gas, tar oil, naphtha/phenol (N/P) blend, lock gas, medium BTU purge gas, and SNG. The Superheaters are designed to combust SGN and/or tar oil; typically firing 80-90% SNG. The Riley Boilers and the Superheaters share a common stack (Main Stack), where the Superheaters' flue gas is combined with the Riley Boilers' flue gas downstream of the Riley Boilers wet flue gas desulfurization (WFGD) system.

The Package Boiler was installed in 2017 to support the operation of the urea production facility and is fired strictly on natural gas. The Package Boiler flue gas is directed through the facility Bypass Stack. The Bypass Stack also handles the flue gas from the Main Stack (Riley Boilers and Superheaters) when the WFGD system is down.

The Main Flare is the primary control device and operates during upsets to control volatile process gases. The Start-up Flare is used during start-up, shutdowns, and gasifier malfunctions. Neither the Main Flare nor the Start-up Flare is indented to operate consistently; therefore, they will not be evaluated for additional controls.

2 NO_X and SO_2 Emissions Controls and Representative History

Both the Main Stack and the Bypass have NO_X and SO_2 continuous emissions monitor systems (CEMS) installed. The Main Stack CEMS monitors the routine emissions from the Riley Boilers and Superheaters. The Bypass Stack CEMS monitors the routine emissions from the Package Boiler and malfunction (bypass of WFGD) emissions from the Riley Boilers and Superheaters.

During the first round of the regional haze program, the Department determined that no NO_X or SO_2 controls were required the GPSP.[1]

2.1 NOx

2.1.1 NO_X Emissions Controls

A summary of the existing NO_X controls for the applicable GPSP emissions units are discussed in Section 2.1.1.1 through 2.1.1.4.

2.1.1.1 Riley Boilers

The existing NO_X controls on the Riley Boilers consists of Low-NO_X burners (LNB), Overfire Air, and combustion tuning. No add-on NO_X controls are installed on the Riley Boilers. Feasible add-on controls are evaluated in Section 3.1.

2.1.1.2 Superheaters

The existing NO_X controls on the Superheaters consist of LNB, partial flue gas recirculation (FGR), and combustion tuning. No add-on NO_X controls are installed on the Superheaters. Feasible add-on controls are evaluated in Section 3.1.

2.1.1.3 Package Boiler

The existing NO_X controls on the Package Boiler consist of Ultra LNB (ULNB). No add-on NO_X controls are installed on the Package Boiler. Add-on controls for the Package Boiler were not evaluated. Operation of ULNB is considered Best Available Control Technology (BACT) for units of similar size combusting natural gas. The Package Boiler currently achieves a NO_X rate of approximately 30 parts per million by volume dry (ppmvd) and is expected to continue to achieve this rate.[2]

[1] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 182-188.
[2] Appendix B.10.b., p.7-1. PDF page 1527

2.1.1.4 Main Flare and Start-up Flare

The Main Flare and the Start-up Flare have no existing NO_X controls installed. The GPSP evaluated potential options for mitigating NO_X emissions from the flared process gases. No vendors were able to provide any viable solutions to reduce NO_X emissions from the either flare system, mainly due to the low baseline NO_X value, equivalent to approximately 0.06 lb NO_X per MMBtu.[3]

2.1.2 NO_X Emissions History

No recent NO_X controls have been installed at any facility, therefore, the baseline emissions from the facility were determined based on the average emissions from 2014–2018. This information, displayed by emissions point, is shown in Table 2.

Table 2: Annual NO_X Emissions

Year	Main Stack	Bypass Stack	Main Flare	Start-up Flare	Remaining Sources [A]	Total
2014	3,048	91	55	12	29	3,236
2015	2,777	49	105	12	40	2,982
2016	2,346	32	43	8	25	2,454
2017	2,373	120	54	10	23	2,580
2018	2,305	45	46	9	31	2,437
Average	**2,570**	**67**	**61**	**10**	**30**	**2,738**

[A] Accounts for all other onsite emissions units.

As shown in Table 2, most of the NO_X emissions from GPSP come from the Main Stack. During normal operations, the Main Stack receives flue gas from the Riley Boilers and the Superheaters. The Main Stack accounts for an average of 94% of the facility NO_X emissions. The Bypass stack accounts for the remaining portion of NO_X emissions where controls can be evaluated. The Bypass Stack only receives gas from the Package Boiler during normal operations and the Package Boiler has ULNB installed, therefore, evaluation of additional controls is focused on Riley Boilers and the Superheaters.

2.2 SO2

2.2.1 SO_2 Emissions Controls

A summary of the existing SO_2 controls for the applicable GPSP emissions units are discussed in Section 2.2.1.1 through 2.2.1.4.

2.2.1.1 Riley Boilers

The existing SO_2 controls on the Riley Boilers consists of a wet flue gas desulfurization (WFGD) system. The WFGD system is designed to treat 100% of the Riley Boiler flue gas during normal operations and often operates at a 97-98% SO_2 removal efficiency.[4] During the first-round planning period, the Department concluded that this system is comparable to BACT for this process and no additional controls were recommended.[5] There have been no significant improvements in available

[3] Appendix B.10.b., p.8-2. PDF page 1529.
[4] Appendix B.10.b., p.5-1. PDF page 1509.
[5] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 183

SO_2 controls for the Riley Boilers WFGD system, therefore, further SO_2 reductions from this source cannot be evaluated.

2.2.1.2 Superheaters

The Superheaters have no existing SO_2 controls installed. The Superheaters typically fire between 80-90% SNG, with the balance being tar oil. SNG is an inherently low sulfur fuel. The SO_2 emissions from the Superheaters come from the firing of tar oil. Given most of the Superheaters heat input comes from firing of SNG, the only potentially viable way to reduce SO_2 from this source would be to eliminate firing of tar oil in the superheaters. Retaining the flexibility to fire tar oil in the Superheaters is essential to provide process relief during unexpectedly high tar oil production rates or high accumulation rates.[6] GPSP currently minimizes the SO_2 emissions attributable to the Superheaters by mainly firing SNG. As a result, no feasible control options exist to reduce SO_2 emissions resulting from the Superheaters.

2.2.1.3 Package Boiler

The Package Boiler fires SNG, an inherently low sulfur fuel. Therefore, no SO_2 control evaluated is warranted on this unit.[7]

2.2.1.4 Main Flare and Start-up Flare

The Main Flare and the Star-up Flare have no existing SO_2 controls installed. The GPSP evaluated flare gas scrubbing as a potential option for mitigating SO_2 emissions from the flared process gases. It was determined that, at a minimum, pilot scale testing would be needed to evaluate the effectiveness of the scrubbing.[8] This source also accounts for a small percentage (8%) of the facilities SO_2 emissions, therefore, this source will not be further evaluated.

2.2.2 SO_2 Emissions History

No recent SO_2 controls have been installed at any facility, therefore, the baseline emissions from the facility were determined based on the average emissions from 2014–2018. This information, displayed by emissions point, is shown in Table 3.

Table 3: Annual SO_2 Emissions

Year	Main Stack	Bypass Stack	Main Flare	Start-up Flare	Remaining Sources [A]	Total
2014	1,922	1,347	467	82	0	3,818
2015	2,211	794	212	74	2	3,294
2016	3,063	378	212	22	1	3,677
2017	2,742	2,152	284	24	0	5,203
2018	2,139	310	369	14	0	2,832
Average	**2,415**	**996**	**309**	**43**	**1**	**3,765**

[A] Accounts for all other onsite emissions units.

As shown in Table 3, most of the SO_2 emissions from GPSP come from the Main Stack. During normal operations, the Main Stack receives flue gas from the Riley Boilers and the Superheaters. The Main

[6] Appendix B.10.b., p.6-1. PDF page 1521
[7] Appendix B.10.b., p.7-1. PDF page 1527
[8] Appendix B.10.b., p.8-1 and 8-2. PDF page 1527-1528

Stack accounts for an average of 64% of the facility SO_2 emissions. The Bypass stack accounts for the remaining portion of SO_2 emissions where controls can be evaluated, as scrubbing of the flare gas was determined technically infeasible. During normal operations, the Bypass Stack only receives flue gas from the Package Boiler and the Package Boiler fires inherently low sulfur fuel (SNG). As displayed in Table 3, the majority of SO_2 emissions from the Bypass Stack occur when the Riley Boilers WFGD system malfunctions and the flue gas needs to be routed to the uncontrolled Bypass Stack.

As stated in Section 2.2.1.1, the Riley Boilers are controlled by a WFGD system operating at BACT levels.

3 NOx Analysis

3.1 NO_X Technologies

Additional NO_X controls have been evaluated for the Riley Boilers and the Superheaters at the GPSP.

3.1.1 Combustion Optimization

Combustion optimization was evaluated as a control option to reduce NO_X emissions though implementation of on-line combustion optimization concepts, such as neural networks. Combustion optimization on the Riley Boilers is technical infeasible due to the variety of fuels consumed in the Riley Boilers and the flexibility needed for steam production rates at pressures, flow rates, and qualities.[9] Combustion optimization on the Superheaters is technically feasible, but expected to only reduce 10 tons of NO_x on an annual average.[10] Combustion optimization will not be evaluated any further given the insignificant improvement on the Superheaters and technical infeasibility on the Riley Boilers.

3.1.2 Flue Gas Recirculation

Flue gas recirculation was evaluated as a potential control option to reduce NO_X emissions at the Riley Boilers. The Riley Boilers currently fire waste gas (as one of the fuels), which contains a significant percentage of inert compounds (CO_2). The high amount of inert compound results in similar combustion flame temperatures and oxygen content as traditional flue gas recirculation. Therefore, any additional flue gas recirculation is not technically feasible for implementation.[11]

3.1.3 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) was evaluated as a control option to reduce NO_X emissions from the Riley Boilers and Superheaters. Implementation of SNCR on the Riley Boilers was deemed technically infeasible during the first-round planning period and no new developments have occurred which changes this determination.[12] Similar to the Riley Boilers, installation of SNCR on the Superheaters is not technically feasible. This is due to the low reheat duct temperatures and the presence of sulfur in the fuel which will lead to the formation of ammonia salts which will foul the superheaters reducing their efficiency.

[9] Appendix B.10.b, p.5-3. PDF page 1511.
[10] Appendix B.10.b, p.9-4. PDF page 1534.
[11] Appendix B.10.b, p.5-4. PDF page 1512.
[12] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 184.

3.1.4 Selective Catalytic Reduction

Selective catalytic reduction (SCR) was evaluated as a control option to reduce NO_X emissions from the Riley Boilers and Superheaters. Implementation of SCR on the Riley Boilers was deemed technically infeasible during the first-round planning period and no new developments have occurred which changes this determination.[13] Similar to the Riley Boilers, installation of SCR on the Superheaters is not technically feasible. This is due to the introduction of vapor phase alkali metals which degrade the SCR catalyst.[14]

3.2 Step 1 – Cost of Compliance

All NO_X controls evaluated are considered technically infeasible by the Department, therefore, no cost analysis is required to be completed. Since there was uncertainly in first-round planning period regarding the implantation of SCR on the Riley Boilers, GPSP performed a cost analysis on what tail-end SCR would cost and how much NO_X emissions would be reduced. GSPS estimated they could reduce approximately 1,800 tons of NO_X emissions from the Riley Boilers at a cost effectiveness of roughly $39,000 per tons of NO_x reduced. This comes at a total capital cost of approximately $180 million and an annualized cost of $70 million.

3.3 Step 2 – Time Necessary for Compliance

The time necessary for compliance is not considered since no feasible NO_X controls can be installed.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

The energy and non-air quality environmental impacts are not considered since no feasible NO_X controls can be installed.

3.5 Step 4 – Remaining Useful Life

The remaining useful life is not considered since no feasible NO_X controls can be installed.

4 SO_2 Analysis

There are no additional reasonable controls which could be installed at GPSP. As stated in Section 2.2.1.1, the Riley Boilers currently operate a WFGD comparable to BACT. As stated in Section 2.2.1.2, the Superheaters primarily fire inherently low natural gas and need to maintain the flexibility to combust tar oil to provide process relief during expected tar oil production rates or system build-up.

Since there are no feasible SO_2 controls being carried forward for evaluation, the cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life were not evaluated.

[13] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 184.
[14] Appendix B.10.b, p.5-8 and 6-5. PDF pages 1516 and 1525.