Regional Haze Reasonable Further Progress Four Factor Analysis

MEC Louisa and Walter Scott Jr. Coal-Fired Boilers

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1.0 EXECUTIVE SUMMARY

The Iowa Department of Natural Resources (DNR) requested that MidAmerican Energy Company (MEC) provide a Four Factor Analysis for the Louisa Generating Station and Walter Scott Jr. Energy Center. The DNR will use the Four Factor Analysis results in its development of a State Implementation Plan (SIP) for the Second Decadal Review period of the federal Regional Haze Rule (RHR) promulgated by the Environmental Protection Agency (EPA) under the Clean Air Act. *See* 42 USC § 7491 ("Visibility Protection for Federal Class I Areas") *and* 40 CFR Part 51 Subpart P ("Protection of Visibility"). The RHR calls for state and federal agencies to work to improve visibility in national parks and wilderness areas throughout the country with the ultimate goal of achieving "natural background" visibility in these Class I areas by the year 2064. Every ten years, agencies are required to evaluate and revise their plans and consider whether additional emission reductions are warranted to continue "reasonable progress" in visibility improvement. The DNR identified the coal-fired generating units at the Louisa Generating Station and the Walter Scott Jr. Energy Center as sources to be analyzed regarding the potential for additional controls of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) for improvement of visibility in Class I areas.

This analysis, referred to as a "Four Factor Analysis," first identifies all technically feasible control technologies for additional SO_2 and NO_x control. Then, each technically feasible control is evaluated to determine whether it may be "necessary to make reasonable progress toward meeting the national goal" of the RHR, based on the following four "statutory factors" found in the definition of "reasonable progress" provided in 42 U.S.C. § 7491(g)(1):

(1) Cost of compliance;
(2) Time necessary for compliance;
(3) Energy and non-air quality impacts of compliance; and
(4) The remaining useful life of any existing source.

This analysis has been completed in accordance with the statute, the RHR, and the EPA's guidance on regional haze, including both the "Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period" issued in 2016 (the "2016 Draft Guidance"), the final "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" (the "2019 Final Guidance"), and EPA's July 8, 2021 "Clarifications Regarding Regional Haze State Implementation Plants for the Second implementation Period" (the "2021 Clarification Memo"). Where any inconsistencies may exist among EPA's guidance, this analysis follows the binding statutory and regulatory requirements and the direction provided by the DNR in its request.

As noted in the RHR and all of EPA's guidance, states may consider visibility benefits in addition to the four statutory factors when making their reasonable progress determinations and selecting among the available control measures to include in their long term strategy.[1] Accordingly, Section 7 of this analysis evaluates the potential visibility benefits of reducing emissions at the two facilities for which the DNR requested this Four Factor Analysis. The consideration of potential visibility benefits is particularly important in determining the reasonableness of additional control measures for these two power plants because they are very far away from any Class I area—the nearest Class I area that is downwind to either plant is over 550 kilometers away.[2]

As presented in this report, MEC found that there are no reasonable emission control options to further reduce the NOx and SO_2 emissions of Unit 4 at the Walter Scott Jr. Energy Center. This boiler already has highly effective selective catalytic reduction and flue gas desulfurization systems that minimize its NOx and SO_2 emissions. These existing controls on Unit 4 were required as Best Available Control Technology (BACT) at the time of this unit's installation in 2007 and remain the most effective controls available for these pollutants. No further control measures are reasonable for this unit.

This Four Factor Analysis considers several potential control options for the other units at these two facilities, Louisa Unit 101 and Walter Scott Jr. Unit 3. The Four Factor Analysis for Louisa Unit 101 and Walter Scott Jr. Unit 3 concludes that making operational improvements to the existing dry flue gas desulfurization processes at both of these other units is possible and could be completed for a reasonable cost. As such, MEC proposes these operating improvements in order to lower SO_2 emissions from these units. The proposed improved emissions performance for these two units together are forecast to provide a 9,688 ton/year reduction to SO_2 versus recent past average emissions (2017-2019 baseline). MEC also evaluated the use of Wet flue gas desulfurization (FGD) system for further SO_2 control, as well as the possible use of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) for NOx control for these two coal-fired units. However, these other control options are not cost effective and, therefore, they are not necessary to make reasonable progress toward visibility improvement at any Class I areas. In addition, including these costly control measure in the SIP would be unreasonable because the impact of those controls on Class I visibility would be *de minimis*.

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[1] 40 CFR 51.308(f)(2)(iv) ("The State must consider the following additional factors in developing its long-term strategy: … The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy."); 2016 Draft Guidance, at 14-15 ("[G]iven that the goal of the regional haze program is to improve visibility, the EPA believes that states may consider visibility in addition to the four statutory factors when making their reasonable progress determinations, as long as they do so in a reasonable fashion."); 2019 Final Guidance, at 36-37 ("Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal."); 2021 Clarification Memo, at 12 ("EPA has interpreted the CAA and RHR as allowing states to consider visibility alongside the four statutory factors when determining the emission reduction measures that are necessary to make reasonable progress.").

[2] The nearest Class I area in any other direction is Mingo Wilderness Area in Missouri, which is approximately 485 km south of the Louisa Generating Station, but the wind does not blow frequently in that direction.

2.0 FACILITY DESCRIPTION/LOCATION

This Four Factor Analysis addresses the NOx and SO_2 emissions from the coal-fired boilers at the Louisa Generating Station at 8602 172nd Street, Muscatine, Iowa, and the Walter Scott Jr. Energy Center located at 7215 Navajo Street, Council Bluffs, Iowa. There are three coal-fired electric generating units at these two facilities. These units are listed in Table 1 below.

Table 1 MEC Units Subject to Four Factor Analysis

Facility/Unit	Nameplate Capacity	Rated Coal Heat Input	Year In-Service
Louisa Unit 101	811.9 MW	8,000 MMBtu/hr	1983
Walter Scott Unit 3	725.8 MW	7,700 MMBtu/hr	1978
Walter Scott Unit 4	922.8 MW	7,675 MMBtu/hr	2007

Louisa Unit 101 and Walter Scott Unit 3: Both these units burn low-sulfur subbituminous coal and have similar types of emissions controls and fairly similar emissions performance for NOx and SO_2 on a lb/MMBtu basis. NOx emissions are controlled with low NOx burners and overfire air. SO_2 emissions are controlled by a Dry FGD system. Both units also have halogenated powder activated carbon (PAC) sorbent injection for control of mercury emissions and baghouse filters for control of particulate emissions.

Walter Scott Unit 4: This unit burns low-sulfur subbituminous coal in a high efficiency supercritical coal-fired boiler that was installed in 2007. Unit 4's permitting imposed Best Available Control Technology requirements of Low NOx burners and overfire air for NOx control, as well as Selective Catalytic Reduction (SCR) to reduce NOx emissions. SO_2 is controlled by a Dry FGD system, and it also has halogenated PAC sorbent injection and baghouse filters for the control of mercury and particulate emissions.

Proximity of Class I Areas

As previously mentioned, there are no Class I areas within several hundred kilometers of the Louisa or Walter Scott Jr. power plants. The regional Class I areas of greatest interest relative to potential emissions impacts from Louisa and Walter Scott Jr. are those to the north, northeast, or east of the facilities, which are the predominant wind directions. Table 2 indicates the distance from each plant to these Class I areas.

Table 2 – Distances to Class I Areas of Interest[3]

	Louisa Generating Station	Walter Scott Jr. Energy Center
Isle Royale National Park, MI	721 km	927 km
Seney National Park, MI	670 km	960 km
Rainbow Lake Wilderness, WI	555 km	670 km
Boundary Waters Canoe Area Wilderness, MN	720 km	810 km

3.0 FIRST REGIONAL HAZE PLANNING PERIOD REASONABLE PROGRESS DETERMINATION

In the first regional haze planning period, the RHR generally required large emissions sources that had been constructed after August 7, 1962 and were in existence by August 7, 1977 to conduct a Best Available Retrofit Technology (BART) review, which was similar to the currently required Four Factor Analysis. The Walter Scott Jr. Unit 3 met those criteria and was BART-eligible. However, for electric generating units (EGUs), the EPA determined that the Clean Air Interstate Rule (CAIR) cap and trade program improved visibility more than implementing BART in states subject to CAIR. The EPA later extended that determination to the Cross-State Air Pollution Rule (CSAPR) when it replaced CAIR with CSAPR. The DNR accepted the EPA's overall finding that CAIR/CSAPR is a "better-than-BART" "substitute" for EGUs and, thus, no additional controls were required for NOx and SO_2 at any MEC unit.[4] In this same timeframe, the Walter Scott Jr. Unit 3 was retrofitted with Low NOx burners and Overfire Air, which decreased its NOx emissions.

These NOx controls on Unit 3 and other actions responding to CAIR/CSAPR and other regulatory requirements resulted in both the Louisa and Walter Scott Jr. power plants making significant reductions to emissions during the previous regional haze planning period. The current baseline emissions (2017-2019 average) discussed in the next section represents a reduction of more than 16,000 tons/yr of NOx and over 5,000 tons/yr SO_2 since 2008.[5]

4.0 BASELINE EMISSIONS SUMMARY

Table 3 summarizes the most recent three-year average NOx and SO_2 emissions and other operating parameters from these coal-fired units for calendar years 2017-2019.

[3] The Class I areas listed in Table 2 are to the north and northeast of the MEC facilities. These are the most common wind directions. The wind also frequently blows towards the east, but there are no Class I areas for over 1000 km to the east of these facilities. As noted above, Mingo Wilderness Area is approximately 485 km south of Louisa, but the wind does not blow frequently in that direction.
[4] Iowa DNR State Implementation Plan for Regional Haze, at 27 (March 2008). https://www.iowadnr.gov/portals/idnr/uploads/air/insidednr/implementation/rh_sip_final.pdf
[5] Emissions reduction comparison reflects 2005-2007 average emissions to 2017-2019 average emissions from EPA Clean Air Markets Program Data tool, available at https://ampd.epa.gov/ampd/.

Table 1 - Most Recent 3-Year Average Emissions and Operation Baseline (2017-2019)

Parameters	Louisa Unit 101	Walter Scott Jr. Unit 3	Walter Scott Jr. Unit 4
SO_2 (tons/yr)	5,592	8,041	1,500
SO_2 (lb/MMBtu)	0.292	0.357	0.067
NOx (tons/yr)	3,774	5,030	1,239
NOx (lb/MMBtu)	0.184	0.223	0.054
Capacity Factor based on MWh	59.4%	72.0%	61.5%
Gross Heat Input MMBTU/yr	40,985,344	45,119,088	45,065,502
Power Output (MWh)	4,224,041	4,576,617	4,967,733

In addition to any changes that might be required by the RHR, the average annual utilization of these units will likely decrease due to increased integration of renewable energy, particularly wind, into the grid. However, for conservatism, the following analysis assumes future utilization for the above units would not change significantly between now and 2028, the end of the second regional haze planning period, except for any RHR controls.

5.0 FOUR FACTOR ANALYSIS SULFUR DIOXIDE (SO_2)

5.1 Identification of Potentially Feasible Emission Controls

The first step in a Four Factor Analysis is the identification of all potentially feasible emissions control options for each source. This section presents an evaluation of the technical feasibility of potential SO_2 control options for the Louisa and Walter Scott Jr. coal-fired boilers. The following sections then evaluate each option relative to the statutory four factors (cost, timing, other impacts, and remaining useful life), the requirements of the RHR, and potential visibility benefits.

There are multiple technology options for controlling the emissions of SO_2 from coal-fired power plants. These options fall into three general categories: (Wet FGD; Dry FGD; or Dry Sorbent Injection (DSI). The most effective of these options for controlling SO_2 for coal-fired boilers is a Wet FGD system. The next most effective control is a Dry FGD system. All three of the MEC coal-fired boilers under review are already equipped with Dry FGD systems.

The third type of control, DSI, is an alternative method of contacting lime or other reagent with the exhaust gas. However, as a stand-alone control it is less effective than the boilers' existing controls. Also, while adding DSI might provide some additional benefit to a Dry-FGD-equipped boiler burning high sulfur coal, which can have reagent addition constrained due to limitations associated with inlet and outlet temperatures, MEC's boilers burn low sulfur coal, and therefore the Dry-FGDs on the boilers are not constrained by temperature. Since DSI is less effective than the existing Dry-FGD systems and its addition would not improve overall performance, DSI is not considered further in this analysis.

Walter Scott Jr. Unit 4

Walter Scott Jr. Unit 4 has a Babcock & Wilcox Dry-FGD system for SO_2 control. The existing FGD system operates very efficiently and achieves average performance levels below 0.067 lb SO_2 per MMBtu (2017-2019 average). This unit was subject to Best Available Control Technology (BACT) when it was initially installed, and its current extremely low emission rate is still consistent with recent BACT determinations based on a review of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database (see Attachment C). MEC has not identified any changes to the current Dry FGD system that could improve its performance, which already provides the same level of emission control as a Wet FGD system. Accordingly, there are no technically feasible better SO_2 control options for Walter Scott Unit 4.[6]

Louisa Unit 101 and Walter Scott Jr. Unit 3

Louisa Unit 101 and Walter Scott Jr. Unit 3 have been retrofitted with Alstom Dry FGD systems for SO_2 control. The performance of these Dry FGD systems currently average 0.292 lb/MMBtu and 0.359 lb/MMBtu, respectively, for Unit 101 and Unit 3 (2017-2019 average). MEC identified two possible control options for reducing SO_2 emissions from these two units:

- Operational Improvements to Existing Dry FGD; or
- Replace existing system with a new Wet FGD system.

<u>Operating Improvements to Existing Dry-FGD system.</u>

The Alstom Dry FGD systems used by Unit 101 and Unit 3 spray an aqueous sorbent slurry into the boiler exhaust in a spray dryer absorber vessel. The spray dryer absorber is upstream of the particulate control baghouse. The system uses lime (CaO) as the sorbent, creating an alkaline calcium hydroxide slurry. The absorber vessel has sufficient residence time to allow the SO_2 in the flue gas to absorb into the alkaline slurry and chemically react with the lime forming calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$). The heat from the flue gas evaporates the water from the slurry droplets forming a dry waste byproduct that is collected in the bottom of the absorber vessel and in the downstream baghouse. A portion of the collected dry solids, which contain some unreacted lime, are recycled with the slurry and fresh lime is added to maintain reactivity.

Table 4 below shows the current allowable SO_2 emissions rate (lb/hr or tons/yr) in the Title V air permit for these two boilers along with their actual performance (2017-2019 average).

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[6] 2016 Draft Guidance, at 77 ("A source subject to a federally enforceable emission limit that effectively requires it to apply the most effective control technology for a given PM species or precursor may be screened out of further analysis for that pollutant."); 2019 Final Guidance, at 22-24 ("If a source owner has recently made a significant expenditure that has resulted in significant reductions of visibility impairing pollutants at an emissions unit, it may be reasonable for the state to assume that additional controls for that unit are unlikely to be reasonable for the upcoming implementation period.").

Table 4 – SO_2 Permit Allowable Emissions and Unit Actual Performance

	Louisa Unit 101	Walter Scott Jr. Unit 3
SO_2 Permit Emissions Limit	3,449.6 lb/hr	12,632.1 tons/yr
SO_2 lb/MMBtu Permit Limit	0.96 lb/MMBtu	1.2 lb/MMBtu
SO_2 Actual Average Performance	0.292 lb/MMBtu	0.357 lb/MMBtu

The Dry FGD systems on both boilers currently achieve emissions performance much better than required by their current permits. However, MEC estimates that, with an increase to the lime addition rate, SO_2 emissions can be lowered further. MEC determined that the units are capable of consistently achieving performance of 0.10 lb/MMBtu by sufficiently increasing lime addition. This improvement of the existing Dry FGD systems operation is a technically feasible SO_2 control option.

<u>Replace with New Wet FGD system</u>

Wet FGD systems use a recirculating liquid stream in a scrubber to absorb SO_2 from the coal combustion flue gas. An alkaline reagent, typically lime (CaO) or limestone ($CaCO_3$), is used to maintain the pH of the recirculating liquid to ensure continual and effective absorption. Dissolved SO_2 forms a sulfite ion (SO_3^{-2}) which then reacts with the dissolved calcium from the reagent to form calcium sulfite ($CaSO_3$). Some FGD systems also utilize a forced oxidization process, which further oxidizes the calcium sulfite to produce marketable gypsum.

Wet FGD systems are typically somewhat more efficient than dry systems. A new state-of-the-art Wet FGD system can achieve up to 98%[7] control down to about 0.06 lb/MMBtu[8] and represents the highest level of SO_2 control for a coal-fired boiler. However, Wet FGD has very high capital and operating costs.

Replacing the existing Dry FGD systems at Louisa Unit 101 and Walter Scott Jr. Unit 3 with a new Wet FGD system is a technically feasible control option.

5.2 Analysis of Four Statutory Factors

The previous section presented an analysis of the control technologies that are technically feasible to further lower the emissions of SO_2 from the coal-fired boilers at the Louisa Generating Station and Walter Scott Jr. Energy Center. There are no technically feasible control options for further lowering the emissions of the Walter Scott Jr. Unit 4, which is already well controlled. For the other two boilers, two options were identified as being technically feasible for potential improvements to SO_2 control. These technically feasible options are:

[7] EPA Flue Gas Desulfurization Fact Sheet: https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
[8] Lowest level in RBLC Database for Coal-Boilers – See Attachment C.

1. Operational improvements to the existing Dry FGD systems; and
2. Replacing the existing controls with a new Wet FGD system.

These options are analyzed in this section relative to the four statutory factors listed in the RHR.

5.2.1 Factor 1 - Cost of Implementing Emission Controls

For technically feasible control options, the first of the four factors to be evaluated is the reasonableness of the cost of the control option. There are a number of metrics that can provide perspective on the economic reasonableness of a particular control. The economic metric detailed in this section is the control's cost-effectiveness relative to its emissions reduction determined by taking total annualized costs for the control divided by the total annual emissions reduction. This yields a "cost-effectiveness" value expressed as dollars per ton of pollutant reduced. High $/ton values indicate that a control measure is not cost-effective. Another economic metric presented in Section 7.0 of this report is the cost-effectiveness in units of $/visibility improvement.

Table 5 below shows the current baseline emissions for these two boilers and the projected 2028 emissions employing each of the two identified technically feasible control options.

Table 5 – Projected Emissions with Each SO_2 Control Option

Unit	Current Baseline SO_2 (tons/yr)	Option 1 Projection w/Improvements to Dry FGD SO_2 (tons/yr)	Option 2 Further Improvement if Wet FGD (tons/yr)
Louisa Unit 101	5,592	2,049	1,230
Walter Scott Jr. Unit 3	8,041	2,256	1,354

<u>SO_2 Option 1: Improvement of Existing Dry FGD</u>

MEC determined that the existing Dry FGD systems on these two boilers are capable of consistently achieving performance of 0.10 lb/MMBtu by increasing lime addition. MEC estimated the increased cost to operate the existing Dry FGD system at this higher level of performance using the EPA's Retrofit Cost Analyzer (RCA) spreadsheet, which is an Excel-based tool developed by the EPA and includes a spreadsheet tab for estimating the cost of a Spray Dryer Absorber Dry-FGD system.[9] Since these units already have an existing Dry FGD system, MEC ignored the capital cost portion of the Retrofit Cost Tool and only included the operating costs increases associated with increased lime usage and commensurate increased waste disposal charges.

[9] Available at: https://www.epa.gov/airmarkets/retrofit-cost-analyzer. This EPA-generated spreadsheet uses the same equations as the FGD section of the EPA Control Cost Manual. Therefore, the two are equivalent.

As shown in Table 6 below, the cost-effectiveness of this control option is less than $300/ton. Therefore, the statutory factor for the cost of compliance weighs in favor of making operational improvements to the existing Dry FGD systems at Louisa Unit 101 and Walter Scott Jr. Unit 3.

SO_2 Option 2: New Wet FGD System

The capital costs estimate for installing Wet Limestone FGD systems relies on the EPA's RCA spreadsheet tab for Wet FGD systems. MEC considers the budgetary costs estimated by this method and shown in Table 6, to be conservative.

The operating costs estimates for a Wet FGD system reflect the incremental increased annual operating and maintenance expenses associated with use of a Wet FGD system (excluding capital recovery) versus continued operation of the existing Dry FGD system. Annual operating and maintenance (O&M) costs for both a new Wet FGD system and the operating cost credits for removing the existing Dry FGD system are based on the EPA RCA spreadsheet discussed above. This cost estimating tool estimates both fixed and variable O&M costs for a Wet FGD system and Dry FGD systems. The operating costs of a Wet FGD system include limestone reagent, waste disposal, wastewater treatment, and auxiliary power. The operating costs credit for discontinued operation of the dry system are based on operating that system at each unit's current "baseline" performance (not the higher cost associated with improved Dry FGD performance).

Table 6 summarizes the control cost evaluations for each of the above SO_2 control options for both these boilers. A further description of the basis of these costs is provided below and full details are provided in Attachment A.

Table 6 – Summary of SO_2 Control Option Cost-Effectiveness

	Louisa Unit 101		Walter Scott Jr. Unit 3	
	Improved Dry FGD	Wet FGD	Improved Dry FGD	Wet FGD
Current Baseline Emissions (Tons/Yr)	5952	5952	8041	8041
Emissions With Controls (Tons/yr)	2049	1230	2256	1354
lb/MMBtu with Controls	0.1	0.06	0.1	0.06
Capital Cost ($)	n/a	$398,140,000	n/a	$370,150,000
Capital Cost Recovery ($/yr)	n/a	$40,136,000	n/a	$37,314,000
Annual O&M ($)	$1,102,000	$1,986,000	$1,248,000	$3,849,000
Total Annualized Costs($)	$1,102,000	$42,122,000	$1,248,000	$41,163,000
Emission Reduction vs Baseline (T/yr)	3,903	4,722	5,785	6,687
Cost Effectiveness ($/Ton)	$282	$8,920	$216	$6,160
Incremental Cost-Effectiveness $/Ton	n/a	$50,090	n/a	$44,250

Annual Capital Recovery ($/yr): For determining the control option cost-effectiveness, the one-time capital portion of the cost needs to be annualized. This is done using the Capital Recovery Factor (CRF) methodology in the EPA's Air Pollution Control Cost Manual[10], which calculates an annual cost or "annual payment" during the life of the investment that is equivalent to the one-time capital expense. The above Annual Capital Recovery is calculated assuming an interest rate of 7.862% and control equipment life of 20 years.

The interest rate assumption of 7.862% is MEC's firm-specific interest rate approved by the Iowa Utilities Board. Use of a firm-specific interest rate for annualizing capital costs is supported by the EPA Control Cost Manual which states the following[11]:

> *"For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible"*

The relevant firm-specific interest rate for MEC is the "weighted average cost" of capital as documented in the most recent (2013) General Rate Case agreement approved by the Iowa Utilities Board of 7.862%. (See Attachment D). This rate is used in calculating the allowable increase to customer's rates for MEC to recover the costs of prudent capital expenditures. The Utilities Board-approved rate recognizes that MEC's capital expenditures are partially funded through issuance of debt and partially through equity financing. Accordingly, this rate represents a weighted average of debt obligations (e.g. issued bonds) and MEC's allowed return on equity financing.

Since the boilers do not have an established retirement date, the 20-year equipment life assumption is based on the life of the control equipment itself, consistent with EPA's Control Cost Manual. However, the assumption that these units will be operating for 20 years after implementation of new Wet FGD control at current levels of utilization is considered very conservative.

Total Annual Costs ($/yr): This value is the sum of the Annual Capital Recovery and the Other Annual Operating Costs and provides a single total annual cost of the control.

Cost Effectiveness and Incremental Cost Effectiveness($/ton): This value is the Total Annual Costs $/yr divided by the Emissions Reduction tons/yr to yield a cost-effectiveness in $/ton. A high $/ton value indicates that a control option is not cost effective. The average cost effectiveness of each option is shown in Table 6, as well as the incremental cost effectiveness for using a Wet FGD system compared to the option to improve the existing Dry FGD system. Consideration of incremental cost effectiveness along with average cost effectiveness was recommended in the EPA's BART guidelines and 2019 Final Guidance[12], and it provides an

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[10] EPA Air Pollution Control Cost Manual, Section 1, Introduction, Chapter 2, Cost Estimation: Concepts and Methodology, at 22 (Nov. 2017).

[11] EPA Air Pollution Control Cost Manual, Section 1, Introduction, Chapter 2, Cost Estimation: Concepts and Methodology, Nov. 2017, pp. 16

[12] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, page 40 which states: *"States may consider the incremental differences in cost and visibility benefits between the alternative control measures for a single source and may use an incremental version of the cost/ton and cost/inverse megameters metrics when doing so."*

appropriate basis to compare the relative cost effectiveness of different control options, particularly when a more effective control is significantly more expensive but only slightly more effective than another option.

The costs of compliance for a Wet FGD system is more expensive than control measures typically required for regional haze. For example, BART determinations made in previous regional haze actions have typically been well below $5,000 per ton. Additionally, the incremental cost effectiveness of this option compared to improvements to the existing Dry FGD system confirms that Wet FGD is an extremely expensive control option. Accordingly, the statutory factor for the cost of compliance weighs against the use of a Wet FGD to make reasonable progress.

The cost-effectiveness of operational improvements to the existing system of less than $300/ton is reasonable and weighs in favor of making operational improvements to the existing Dry FGD systems at Louisa Unit 101 and Walter Scott Jr. Unit 3. These operating improvements would reduce emissions from these two units by a combined total of 9,688 tons/yr SO_2 (at past baseline operating levels).

5.2.2 Factor 2 - Time Necessary to Install Controls

MEC estimates the following time needed to install each of the options evaluated:

- Control Option 1, Improvements to Existing Dry FGD System: Since no physical modification is necessary to allow implementing improvements to the operation of the existing controls, they could be implemented relatively quickly. MEC estimates it would take approximately six months for testing and optimization of the system after SIP approval. Therefore, the time necessary for installing controls does not weigh against this control option.

- Control Option 2, New Wet FGD System: MEC estimates that these additional controls could be installed within five years after SIP approval. This time is needed to design, permit, procure, install and startup the new system. Additionally, the installation of these controls will require the units to be out of service. Therefore, the implementation schedule would need to allow a unit's planned outage to accommodate regional electricity demands and be coordinated with the maintenance shutdowns of other regionally affected utilities.

5.2.3 Factor 3 - Energy and Non-air Quality Impacts of Controls

Both of the control options evaluated have some impacts as described below. However, these impacts do not weigh heavily for or against these controls options as possible reasonable progress control measures. (Note: The operating costs associated with the below items were included in the above analysis of the costs of compliance.)

- Control Option 1, Improvements to Existing Dry FGD System: Increasing the use of lime injection will result in a small increase to material handling PM emissions and solid waste disposal costs.

- Control Option 2, New Wet FGD System: Conversion to use of a Wet FGD system has several environmental impacts compared to a dry system. Wet FGD systems create significantly greater volumes of waste that must be dewatered and disposed. A wet system uses significantly more water than dry systems. They also generate a wastewater stream that must be treated and discharged.

5.2.4 Factor 4 - Remaining Useful Life of Facility

Because no specific retirement date is yet planned, this analysis conservatively assumes that the units may be operational for the life of the control equipment for each option under evaluation. Thus, the statutory factor for remaining useful life does not weigh for or against either control option. However, the assumption that the units will be operating for 20 years at current levels of utilization is considered very conservative.

5.3 Conclusions of SO_2 Four Factor Evaluation

At the request of the DNR, a Four Factor Analysis was prepared for SO_2 emissions for Louisa Unit 101 and Walter Scott Jr. Units 3 and 4. All three units are coal-fired boilers.

Walter Scott Jr. Unit 4 is equipped with a highly efficient Dry FGD system, which achieves average performance levels of 0.067 lb SO_2/MMBtu. This extremely high level of performance is consistent with the lowest limits in the EPA's RBLC database, and no technically feasible better SO_2 control options for Walter Scott Unit 4 were identified. Accordingly, no further SO_2 emission reductions from this unit are necessary to make reasonable progress.

Louisa Unit 101 and Walter Scott Jr. Unit 3 are both retrofitted with Dry FGD systems for SO_2 control. The average performance of these units' existing FGD systems is currently 0.292 lb/MMBtu and 0.357 lb/MMBtu, respectively, for Unit 101 and Unit 3 (2017-2019 average).

One technically feasible option to reduce SO_2 emissions from these sources is to replace the existing control systems with new Wet FGD systems. This option would provide significant SO_2 emissions reductions but is extremely expensive. The average cost-effectiveness of installing a new Wet FGD system is over $6,000/ton, which weighs against this option. Additionally, the incremental cost-effectiveness of this control option versus the other SO_2 control option is over $44,000/ton. Therefore, MEC recommends that the DNR conclude that new Wet FGDs are not necessary to make reasonable progress in this regional haze planning period.

The other option identified for reducing SO_2 emissions from these sources is operational improvements of the existing Dry FGD system through an increase to the lime addition rates. This could improve the performance on both boilers to 0.10 lb SO_2/MMBtu, which would provide approximately 9,688 tons/yr of SO_2 emissions reduction (total for both units) at a cost-effectiveness of less than $300/ton SO_2. Given the low cost of this option, MEC recommends these operating improvements to lower SO_2 emissions as a reasonable progress control measure for the second regional haze planning period. Specifically, MEC recommends that the DNR include a new emission limitation of 0.10 lb/MMBtu SO_2 on a 30-boiler operating day rolling average for Unit 101 and Unit 3. Because this option does not require the installation of new equipment, MEC recommends that the DNR make the proposed emission limitation effective within six months of EPA approval of the Iowa regional haze SIP (to allow time for testing and optimization of the system).

6.0 FOUR FACTOR ANALYSIS NITROGEN OXIDES (NOx)

6.1 Identification of Potentially Feasible Emission Controls

There are multiple technology options for controlling the emissions of NOx from coal-fired power plants. All three of the coal-fired boilers at these facilities are already equipped with Low NOx burners and Overfire Air, which help minimize NOx emissions. Beyond these controls, the other technically feasible controls for NOx are SNCR or SCR. As discussed below, Walter Scott Jr. Unit 4 already has SCR.

Walter Scott Jr. Unit 4

Walter Scott Jr. Unit 4 currently utilizes SCR for NOx control, as well as low NOx burners and overfire air. This boiler's overall control system performance achieves average levels of 0.054 lb/MMBtu. This extremely high level of performance is consistent with the lowest limits in the EPA's RBLC database (see Attachment C), which also use SCR. Operation of a well-performing SCR system is the highest level of NOx control available. Accordingly, there are no technically feasible better NOx control options for Walter Scott Unit 4. Therefore, this Four Factor Analysis does not contain any further evaluation of this well-controlled boiler.[13]

Louisa Unit 101 and Walter Scott Jr. Unit 3

Louisa Unit 101 and Walter Scott Jr. Unit 3 are both controlled with low NOx burners and overfire air for NOx control. The average NOx performance of these boilers is currently 0.184 lb/MMBtu and 0.223 lb/MMBtu, respectively, for Unit 101 and Unit 3 (2017-2019 average). These NOx performance levels are very consistent and are an inherent function of each boiler's current combustion control equipment design. MEC identified two possible control options for further reducing NOx emissions from these two units. These are the additional add-on controls of SNCR or SCR:

<u>SNCR</u>

In a selective non-catalytic reduction system, urea or ammonia-based chemicals are injected into the combustion unit. The ammonia (NH_3) in the reagent reacts with the NOx in the flue gas to form elemental nitrogen (N_2). The reaction is very temperature dependent and only occurs in a narrow temperature window that is ideally between 1,600 °F to 1,900 °F. Below those

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[13] 2016 Draft Guidance, at 77 ("A source subject to a federally enforceable emission limit that effectively requires it to apply the most effective control technology for a given PM species or precursor may be screened out of further analysis for that pollutant."); 2019 Final Guidance, at 22-24 ("If a source owner has recently made a significant expenditure that has resulted in significant reductions of visibility impairing pollutants at an emissions unit, it may be reasonable for the state to assume that additional controls for that unit are unlikely to be reasonable for the upcoming implementation period.").

temperatures, the reaction is not initiated. Much above those temperatures, ammonia can be converted into NOx, increasing emissions and ammonia consumption.

A successful SNCR installation requires injection of the reagent at a location within the boiler where the flue gas is in the optimal temperature range and with sufficient residence time at that temperature to promote the reaction. The optimum location within a combustion unit can change at different loads, decreasing the average effectiveness of SNCR on units with wide variations in loading, as is the case with these units. SNCR systems are typically designed with multiple injection levels that approximately match the optimum temperature window at varying loads.

In addition to temperature, other site-specific factors can influence the effectiveness of SNCR on NOx control. These influencing variables include mixing, residence time, reagent to NOx ratio, NOx concentration in the flue gas, and allowable ammonia slip levels (unreacted ammonia).

SNCR is considered a technically feasible control option. However, MEC estimates that SNCR would achieve no better than 15% NOx reduction on these units based on three factors. First, SNCRs are less effective on larger boilers because it is more difficult to evenly distribute the reagent throughout the volume of the furnace, particularly towards the center of the furnace. When the reagent is not evenly distributed, ammonia slip increases for a given level of NOx reduction, which limits the practical ability to achieve greater NOx reduction efficiencies. Second, widely varying loads likewise inhibits mixing and necessary reaction conditions by affecting flue gas flow patterns and optimal flue gas temperature locations, increasing the difficulty associated with determining the proper amount of reagent to inject, and the optimum location of those injections. Although multiple injection locations can be employed, the locations are typically fixed by boiler geometry. It is not possible to optimize reagent injection and mixing at all load conditions, and the impact of this is an increase in ammonia slip, thus reducing the NOx reduction potential. Third, removal efficiencies are typically lower at units that already have relatively low pre-control NOx concentrations, since there is less NOx available for generating the chemical reactions intended with SNCR. Unlike a technology such as SCR, the driving force for SNCR-type reactions falls off quickly when the baseline NOx concentration falls below about 0.2 lb/MMBtu.

All three of these factors are likely to reduce the effectiveness of SNCR at these boilers—they are larger than most (726 and 812 MW, compared to the average utility boiler with SNCR of about 350 MW), they have operated, and are expected to continuing operating, at widely varying loads (the units are often called to ramp from low to high load on a daily basis to inversely follow the increased penetration of renewable energy generation), and pre-control NOx is well below the industry average (0.18-0.22 lb/mmbtu, compared to more typical utility boiler SNCR application of about 0.4 lb/mmBtu). A removal efficiency of 15% for SNCR is not only consistent with these site-specific characteristics, it is consistent with MEC's experience with SNCR removal at other similar facilities.

<u>SCR</u>

An SCR system utilizes similar chemical reactions as discussed above for an SNCR system. However, the presence of a catalyst facilitates the preferred chemical reactions and allows them to occur at lower operating temperatures and at much higher efficiencies.

A nitrogen-based reagent such as ammonia or urea is injected into the flue gas ductwork. The gases mix with the reagent and then enter a reactor module containing a specialized catalyst typically composed of active metals such as vanadium and tungsten. The reagent selectively reacts with the NOx in the presence of the catalyst and oxygen and converts to elemental nitrogen. An SCR system is typically capable of achieving 70% to 90% removal of NOx. This increased effectiveness comes at a significantly increased capital and operating cost than SNCR.

SCR is considered a technically feasible NOx control option for these boilers and is assumed to be capable of achieving 0.05 lb/MMBtu, which is the lowest NOx emissions limit for SCR in the RBLC database.

Table 7 below shows the current actual NOx emissions performance of these boilers and the NOx estimated to be achievable with the two candidate control options

Table 7 – Actual and Projected NOx Emission Rates

	Louisa Unit 101	Walter Scott Jr. Unit 3
NOx Actual Average Performance	0.184 lb/MMBtu	0.223 lb/MMBtu
NOx with SNCR	0.157 lb/MMBtu	0.181 lb/MMBtu
NOx with SCR	0.05 lb/MMBtu	0.05 lb/MMBtu

6.2 Analysis of Four Statutory Factors for NOx Controls

The previous section identified the control technologies that are technically feasible to further lower the emissions of NOx from the coal-fired boilers at MEC’s Louisa Generating Station and Walter Scott Jr. Energy Center. There are no technically feasible control options for further lowering the emissions of the Walter Scott Jr. Unit 4, which is already well-controlled. For the other two units, two options were identified as being technically feasible for further reducing NOx emissions. These technically feasible options are

- Selective Non-Catalytic Reduction (SNCR); or
- Selective Catalytic Reduction (SCR).

These options are analyzed in this section relative to the four statutory factors.

6.2.1 Factor 1 - Cost of Implementing Emission Controls

For technically feasible control options, the first of the four factors to be evaluated is the reasonableness of the cost of the control option. The economic metric detailed in this section is the control's cost-effectiveness relative to its emissions reduction. High $/ton values indicate that a control measure is not cost-effective. Another economic metric presented in Section 7.0 of this report is the cost-effectiveness in units of $/visibility improvement.

Table 8 below shows the current baseline emissions for these two boilers and the 2028 emissions projected with each of the two identified technically feasible control options.

Table 8 – Projected Emissions with Each NOx Control Option

Unit	Current Baseline NOx (tons/yr)	Option 1 Projection with SNCR (tons/yr)	Option 2 Projection with SCR (tons/yr)
Louisa Unit 101	3,774	3,208	1,025
Walter Scott Jr. Unit 3	5,030	4,275	1,128

<u>Option 1: SNCR</u>

The capital costs and operating costs for SNCR for these units are based on the EPA's SNCR Retrofit Cost Tool Calculation Spreadsheet which follows the cost methodology outlined in the EPA's Control Cost Manual[14]. A retrofit factor of 1.0 was used for these units, which assumes that retrofit of SNCR would not have any significant site-specific cost complications. MEC considers the use of this methodology and assumptions to be conservative compared to MEC's actual experience on other units. Therefore, actual SNCR retrofit costs may be higher than assumed in this analysis. Details of these capital and operating cost estimates are provided in Attachment A.

<u>Option 2: SCR</u>

The capital and annual operating costs for SCR for these units were estimated using cost estimating spreadsheets developed by the EPA for this purpose, which follow the methodology and formulas for SCR cost estimates in the EPA's Control Cost Manual.[15] A retrofit factor of 1.0

[14] <u>EPA Air Pollution Control Cost Manual</u>, Section 4 (NOx Controls) Chapter 1: "Selective Noncatalytic Reduction," April 2019 and spreadsheet available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer#:~:text=The%20Retrofit%20Cost%20Analyzer%20(RCA,were%20developed%20to%20inform%20modelinghttps://www.epa.gov/airmarkets/retrofit-cost-analyzer#:~:text=The%20Retrofit%20Cost%20Analyzer%20(RCA,were%20developed%20to%20inform%20modeling.

[15] <u>EPA Air Pollution Control Cost Manual</u>, Section 4 (NOx Controls) Chapter 2: "Selective Catalytic Reduction," April 2019, and spreadsheet available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

was used for these units, which assumes that retrofit of SCR would not have any significant site-specific complications. This approach is conservative because actual retrofit costs may be higher.

Tables 9 and 10 below summarize the control cost evaluations for SNCR and SCR for improved NOx control of these two boilers. Each of these options is a stand-alone control option.

Table 9 – SNCR Retrofit Cost Effectiveness (NOx Option 1)

SNCR	Louisa Unit 101	Walter Scott Jr. Unit 3
Capital Costs	$14,175,300	$ 13,851,200
Annual Capital Recovery	$1,429,000	$1,396,300
Annual Operating Costs	$2,192,000	$2,844,000
Total Annual Costs	$3,621,000	$4,240,300
NOx Reduction tons/yr	566	755
Cost-Effectiveness $/ton	$6,398	$5,616

Table 10 – SCR Retrofit Cost Effectiveness (NOx Option 2)

SCR	Louisa Unit 101	Walter Scott Jr. Unit 3
Capital Costs	$236,140,160	$238,436,408
Annual Capital Recovery	$20,709,492	$20,910,873
Annual Operating Costs	$3,562,450	$3,860,815
Total Annual Costs	$24,271,942	$24,771,688
NOx Reduction tons/yr	2,739	3,849
Cost-Effectiveness $/ton	$8,862	$6,436

For annualization of the capital expenditures, MEC assumed an interest rate of 7.862% as explained in Section 5.2.1. For equipment life, MEC assumed 20 years for SNCR and 30 years for SCR, which is consistent with the EPA Control Cost Manual typical life for these types of controls.

The above NOx control options range in cost-effectiveness from approximately $5,600/ton to $8,800/ton. These values are relatively expensive on a dollar per ton basis and extremely expensive from a total capital investment standpoint. Many states have used $5,000/ton as a screening cutoff for excluding further evaluation of controls in this and previous RHR reviews.

As such, the statutory factor for the cost of compliance weighs against a determination that these control options are necessary to make reasonable progress toward visibility improvements.

As a sensitivity case, MEC also considered whether the cost effectiveness of SNCR would change significantly if the analysis assumed SNCR could achieve 20% control of NOx instead of the 15% removal efficiency projected due to the site-specific characteristics identified above. That sensitivity analysis concluded that a 20% removal efficiency assumption would not significantly improve the cost-effectiveness of SNCR—the cost-effectiveness on this basis for Louisa would be $5,660/ton and Walter Scott Jr Unit 3 would be $5,120/ton. These values aren't significantly different because, although NOx reductions would be higher, the cost would also be higher, due to, increase the operating costs (reagent injection, waste costs, water costs, etc.).

6.2.2 Factor 2 - Time Necessary to Install Controls

MEC estimates that SNCR could be implemented within three years and SCR would be implemented within five years from the date the control requirements become effective. This time is needed to design, permit, procure, install, and startup the new system. Additionally, the installation of either of these controls will require the units to be out of service. Therefore, the implementation schedule would need to accommodate regional electricity demands and be coordinated with the maintenance shutdowns of other regionally affected utilities.

6.2.3 Factor 3 - Energy and Non-air Quality Impacts of Controls

Both of the control options evaluated have some impacts as described below. However, these impacts do not weigh heavily for or against these controls options as possible reasonable progress control measures.

- Both SNCR and SCR utilize some form of ammonia as a reagent to promote the conversion of NOx to elemental nitrogen and water. As a result of imperfect mixing between the flue gas and the reagent, a greater than stoichiometric amount of reducing agent must be injected in order for the NOx reduction target to be achieved. The excess ammonia remains unreacted in the process and is emitted out the stack as ammonia "slip". Ammonia emissions associated with SCR are typically between 2 to 10 ppm and with SNCR are between 10 to 20 ppm. Ammonia emissions can combine with other pollutants to form fine particulate matter.

- Ammonia for these processes can be provided using either anhydrous ammonia, aqueous ammonia, or urea. Storage and use of these forms of ammonia, especially anhydrous ammonia, can raise significant safety concerns. However, with proper system design and operation, these safety issues are manageable.

- Retrofitting SCR would result in an increase in the parasitic electrical load of the station. SCR systems require that auxiliary power for the ancillary systems that support the SCR. Additionally, placement of the SCR catalyst grid in the exhaust flow path of the boiler causes backpressure, which must be overcome by supplying additional power to the existing flue gas fan systems. SNCR systems would also have some smaller auxiliary power consumption.

6.2.4 Factor 4 - Remaining Useful Life of Facility

Because no specific retirement date is yet planned, this analysis assumes that the units may be operational for the life of the equipment comprising the control options under evaluation. Thus, the statutory factor for remaining useful life does not weigh for or against either control option. However, the assumption that the units will be operating for 20 years at current levels of utilization is considered very conservative.

6.3 Conclusions of NOx Four Factor Evaluation

At the request of the DNR, this Four Factor Analysis was prepared for NOx emissions for MEC Louisa Unit 101 and Walter Scott Jr. Units 3 and 4.

Walter Scott Jr. Unit 4 is equipped with SCR for NOx control, as well as low NOx burners and overfire air. This boiler's current NOx performance averages 0.054 lb NOx per MMBtu. This extremely high level of performance is consistent with the lowest limits in the EPA's RBLC database (see Attachment C), which also use SCR. Operation of a well-performing SCR system is the highest level of NOx control available. Accordingly, there are no technically feasible better NOx control options for Walter Scott Jr. Unit 4. Therefore, no further NOx emission reductions from this unit are feasible for the second regional haze planning period.

Louisa Unit 101 and Walter Scott Jr. Unit 3 are controlled with low NOx burners and overfire air for NOx control. The NOx performance of these boilers currently average 0.184 lb/MMBtu and 0.223 lb/MMBtu, respectively, for Unit 101 and Unit 3 (2017-2019 average). MEC identified two possible control options for further reducing NOx emissions from these two units: SNCR or SCR. While both options are technically feasible, they are both very expensive.

SNCR capital costs for each unit are approximately $14 million dollars and total annual costs for each unit would exceed $2 million per year. The resulting cost-effectiveness of SNCR is approximately $6,400/ton for Unit 101 and $5,600/ton for Unit 3.

SCR capital costs are over $230 million per unit with total annual costs of over $24 million. The resulting SCR cost-effectiveness is approximately $8,860 for Unit 101 and $6,400 for Unit 3.

These cost-effectiveness values for SNCR and SCR are higher than are typically required for RHR controls. Therefore, MEC recommends that the DNR conclude that neither SNCR nor SCR are necessary to make reasonable progress in this second regional haze planning period.

7.0 ADDITIONAL CONSIDERATIONS - VISIBILITY IMPACTS

The goal of the RHR is to improve visibility in Class I areas. Accordingly, when evaluating possible emissions reduction projects or programs, it is appropriate to consider the degree to which individual control options might contribute towards the goal of improving visibility. Although states have a statutory requirement to consider the four "statutory factors" addressed in the earlier portion of this report, the statute, EPA's RHR, and EPA's guidance also allow consideration of visibility impacts of candidate control options. This section of the report addresses the potential visibility benefits of the candidate control options for SO_2 and NOx control at Louisa and Walter Scott Jr. As explained below, because the units at Louisa and Walter Scott Jr. are extremely far away from any Class I area, modeling indicates that further improvements to their emission controls would have little visibility benefits at any of the regional Class I areas.

7.1 EPA Guidance Regarding Considerations of Visibility Impacts

The EPA issued draft regional haze guidance in 2016 and finalized that guidance in August 2019.[16] Both versions of the guidance and a recent July 2021 clarification memo[17] all allow a state, as part of its consideration of emission controls, the discretion to consider the visibility benefits of candidate control options. The EPA's guidance states the following:

> **2016 Draft Guidance:**
>
> *[G]iven that the goal of the regional haze program is to improve visibility, the EPA believes that states may consider visibility in addition to the four statutory factors when making their reasonable progress determinations, as long as they do so in a reasonable fashion."*
>
> **2019 Final Guidance**
>
> *Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal.*
>
> *EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress.*
>
> **2021 Clarification Memo**
>
> *EPA has interpreted the CAA and RHR as allowing states to consider visibility alongside the four statutory factors when determining the emission reduction measures that are necessary to make reasonable progress.*

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[16] https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

[17] EPA Memorandum, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period, Peter Tsirigotis, EPA, July 8, 2021.

Consequently, a control option that has insignificant or very small Class I visibility benefits and a relatively high cost can be rejected as unnecessary to make reasonable progress.

The preamble to the 1999 Regional Haze Rule (64 FR 35730) provides helpful context by specifying that an impact of less than 0.1 deciview constitutes a “no degradation” visibility change. Natural background visibility in most areas is about 10 -14 deciviews, so a 0.1 deciview impact is only about 1% of the 2064 natural visibility goal.

As background, it is also helpful to understand the two common parameters used to characterize the visibility impairment:

- **Light Extinction (bext, Mm^{-1})** is the reduction in light due to scattering and absorption as it passes through the atmosphere. Light extinction is directly proportional to pollutant particulate and aerosol concentrations in the air and is expressed in units of inverse megameters or Mm^{-1}.
- **Deciview (DV)** is a unitless metric of haze that is proportional to the logarithm of the light extinction. Deciview correlates to a person’s perception of a visibility change, with a change of 1 deciview being barely perceptible. This perceptibility threshold is ten times higher than the “no degradation” value of 0.1 DV referenced above.

While DV is the best parameter to relate the significance of a perceived visibility change, modeling produces results in the form of light extinction (Mm^{-1}). Light extinction is directly proportional to pollutant concentrations.

7.2 Approach to Understanding RHR Visibility Impacts of Iowa Sources

The visibility impacts to Class I areas from potential reductions of SO_2 or NO_x emissions at the Louisa Generating Station and Walter Scott Jr. Energy Center can be estimated by analyzing the results of recent visibility modeling. The most useful modeling for this purpose for Iowa sources is the modeling recently completed by the Lake Michigan Air Directors Consortium (LADCO), which is the Great Lakes/Upper Midwest Regional Planning Organization (RPO) for regional haze. Although Iowa is not in the geographic area covered by this RPO, LADCO included Iowa emissions in their visibility modeling. Additionally, LADCO “tagged” Iowa state-wide emissions in their modeling, which allows the identification of portions of the model predicted visibility impact of each haze species (e.g., sulfates and nitrates) attributable to all Iowa emission sources. The LADCO modeling did not tag individual Iowa facilities, but instead grouped all state of Iowa’s emissions impacts into a single group for impact apportionment purposes. As a result of this grouping, their modeling provides only a single impact value for each haze species reflecting the combined the impact of all Iowa statewide sources. Therefore, to use these Iowa statewide impact results to estimate the impacts of specific facilities requires making some assumptions regarding the apportionment of the impacts based upon a proportion of precursor emissions for various sectors.

The most straightforward impact apportionment assumption would be to assume that the impacts of individual Iowa sources are directly proportional to their emissions. Because Iowa sources are a long distance from any Class I area, the “per ton” impact of statewide emissions should be a reasonable approximation of the “per ton” visibility impact of any source within the state, regardless of its specific location or emission point characteristics. However, MEC has employed more conservative apportionment assumptions discussed below and further detailed in Attachment B.

7.3 Estimated Louisa and Walter Scott Visibility Impacts

The key data used to generate a conservative estimate of the potential impact of Louisa and Walter Scott emissions to Class I regional haze are a) the LADCO Iowa apportionment results shown below in Table 11 and b) the emissions rates of Iowa sources used in LADCO's modeling summarized below in Table 12.

Table 11 Modeled Impacts (Mm^{-1}) of All Iowa Emissions by LADCO for 2028 (20% Most Impaired)

Modeled Iowa Total Impacts Mm^{-1}	Sulfate	Nitrate
Boundary Waters Canoe Area	0.400	0.460
Voyageurs NP	0.440	0.320
Isle Royale NP	**0.650**	0.650
Seney Wilderness Area	0.590	**0.800**
Maximum Impacts are Highlighted		

Table 12 Iowa Emissions Modeled By LADCO for 2028 Projection

Projected 2028 Emissions Modeled by LADCO	SO2 (Tons/yr)	Emiss. % of Anthro. Sources	NOx (Tons/yr)	Emiss. % of Anthro. Sources
All Iowa Projected 2028 (tons/yr)	36,287		136,635	
All Iowa Anthropogenic (exclude fire and biogenic)	35,538		96,398	
All Iowa Point Sources only	34,786	98%	40,651	42%
All Iowa EGU Emissions	28,002	79%	21,442	22%
Louisa Tons/yr (modeled)	5,605	16%	3,403	4%
Walter Scott Tons/yr (modeled)	9,897	28%	6,025	6%

To provide an estimate of very conservative worst-case possible visibility impact from these two power plants, MEC has in effect treated them as if they were the only power plants in the state and that all statewide power plant visibility impacts were attributable to just these two plants. The details of these assumptions are as follows:

1) First, although fire and biogenic sources were included in the LADCO modeling, MEC has conservatively ignored their share of the visibility impacts (attributing any impact of these emissions to anthropogenic sources.)

2) Next, it is assumed that Iowa statewide nitrate and sulfate impacts attributable to all EGU's as a group is proportional to the total of all electrical generating units (EGUs) emissions relative to all statewide emissions. Since there are multiple EGU sources, and they are located throughout the state, this straight-proportional assumption is reasonable.
3) Next, it is assumed that the visibility impact of all EGUs from "step 2" is 100% attributable to just Louisa and Walter Scott Generating Stations, even though they represent only a fraction of the total EGU emissions. This is clearly an extremely conservative assumption.
4) Lastly, the split of the total EGU impacts between Louisa and Walter Scott are based on their emissions relative to each other only.

Table 13 below shows the results of these assumptions for Louisa and Walter Scott visibility impacts. This conservative approach results in 79% of the statewide sulfate impacts assumed attributable to these two power plants even though they contribute only 44% of the statewide anthropogenic SO_2 emissions. Likewise, these assumptions allocate 22% of the statewide nitrate impacts to these two power plants even though they represent only 10% of the statewide anthropogenic NOx emissions (and only 7% of the total statewide NOx). These are very conservative assumptions and actual impacts are expected to be much lower.

Table 13 Very Conservative Assumed Potential Impact of Louisa and Walter Scott

Conservative Assumption of Max Impact	Sulfate (Mm-1)	Resultant Plant Sulfate Impact. % of Statewide	Nitrate (Mm-1)	Resultant Plant Nitrate Impact. % of Statewide
Max. Statewide All Iowa Impacts (Mm-1)	**0.65**		**0.80**	
Louisa Impact (Very Conserv. Assumed)	0.19	28%	0.06	8%
Walter Scott (Very Conserv. Assumed)	0.33	50%	0.11	14%
		79%		22%

Dividing these conservative estimates of these power plant visibility impacts by their modeled emissions provides an estimated visibility impact per ton of emissions.

- 3.30 x 10-5 Sulfate Mm-1/ton SO_2, and
- 1.89 x 10-5 Nitrate Mm-1/ton NOx

The above factors can then be used to estimate the cost-effectiveness of each MEC candidate control options in units of dollars/visibility improvement.

Table 14 below shows each of the MEC NOx and SO_2 candidate control options discussed earlier in this report and their visibility impacts calculated with the above factors. The visibility improvements noted in Table 14 for each candidate control option are very small both individually, as well as collectively, and are each well below the "no degradation" benchmark of

0.1 DV. This indicates that the visibility benefits from these control options would be inconsequential.

Additionally, dividing the annual costs for each control by that control's visibility benefits yields cost-effectiveness values that are extraordinarily expensive for all options except the option to improve the existing Dry flue gas desulfurization (FGD) system. The other control options would cost between $300 million to $1.5 billion dollars per Mm-1. These costs per unit of visibility improvement are more than an order of magnitude higher than were considered reasonable as Best Available Retrofit Technology (BART) during the RHR first decadal review[18], which were typically less than $8 million/Mm-1.

Table 14 – Cost of Candidate Controls Relative to Visibility Benefits

Candidate Control Improvements		Total Annualized Costs ($/yr)	Emissions Reduction (tons/yr)	Maximum Visibility Improv. (Mm^{-1})	Maximum Visibility Improv. (DV)	Cost Effectiveness ($/$Mm^{-1}$)	Cost Effectiveness ($/DV)
Louisa Generating Station (Unit 101)							
Dry FGD Improvement	SO_2	$1,102,000	3,903	0.13	0.046	$8,550,000	$24,110,000
Wet FGD Increm. Impr.	SO_2	$41,020,000	819	0.03	0.010	$1,515,960,000	$4,272,920,000
SNCR[1]	NOx	$3,621,000	566	0.01	0.004	$338,970,000	$883,170,000
SCR[2]	NOx	$24,271,942	2,739	0.05	0.020	$469,520,000	$1,225,860,000
Walter Scott Jr. Energy Center (Unit 3)							
Dry FGD Improvement	SO_2	$1,248,000	5,785	0.19	0.068	$6,530,000	$18,430,000
Wet FGD Increm. Impr.	SO_2	$39,915,000	902	0.03	0.011	$1,339,380,000	$3,765,570,000
SNCR	NOx	$4,240,300	755	0.01	0.006	$297,570,000	$770,960,000
SCR	NOx	$24,771,688	3,849	0.07	0.028	$341,000,000	$891,070,000

[1] Selective non-catalytic reduction
[2] Selective catalytic reduction

As previously stated, MEC is offering to implement operating improvements to the existing Dry FGD systems at both Louisa (Units 101) and Walter Scott (Unit 3) to assist with reasonable progress under the RHR. This control measure provides the vast majority of the available visibility benefit and is also the most cost-effective of all the control options. In contrast, the other identified candidate NOx and SO_2 control measures for Louisa Generating Station and

[18] Compilation of BART analyses generated in 2009 by the National Park services showed the majority of emissions controls proposed had a cost per DV of less than $20 million/DV which corresponds to approximately $8 million/Mm-1. National Park Service letter to Minnesota Pollution Control Agency regarding BART proposals for EGUs dated Sept. 3, 2009, p. 6. https://www.fws.gov/refuges/AirQuality/docs/Comments/MN%20-%2002-02-12%20Signed%20NPS%20Comments%20RH%20SIP.pdf

Walter Scott Jr. Energy Center sources provide very little visibility benefit, are not cost-effective options to improve visibility as demonstrated above, and are very expensive based on their $/ton costs discussed in earlier sections.

8.0 SUMMARY

At the request of the DNR, a Four Factor Analysis was prepared for NOx and SO_2 emissions for coal-fired boilers at the Louisa Generating Station and the Walter Scott Energy Center. The following is a summary of the key findings of this analysis for the three coal-fired boilers at these facilities:

Walter Scott Jr. Unit 4 is already equipped with SCR for NOx control and a very effective Dry FGD system for control of SO_2. These controls were required as BACT when this unit was permitted and remain consistent with the lowest limits in the EPA's RBLC database. Accordingly, there are no technically feasible better control options for Walter Scott Jr. Unit 4. Therefore, no further NOx or SO_2 emission reductions from this unit are feasible.

Louisa Unit 101 and Walter Scott Jr. Unit 3 both have low NOx burners and overfire air for NOx control and Dry FGD systems for SO_2 control. MEC identified two possible control options for further reducing NOx emissions from these two units:

- Selective Non-Catalytic Reduction (SNCR); or
- Selective Catalytic Reduction (SCR).

Additionally, MEC identified two possible control options for reducing SO_2 emissions:

- Operational Improvements to Existing Dry FGD system: or
- Wet FGD system.

All of the above options are technically feasible and were further evaluated with respect to the four statutory factors and other relevant considerations.

MEC estimates that implementing operational improvements to the existing Dry FGD system can be achieved at a modest increased operating cost. This SO_2 control option would have a cost-effectiveness below $300 per ton and is capable of lowering SO_2 emissions from both Louisa Unit 101 and Walter Scott Jr. Unit 3 to 0.10 lb/MMBtu SO_2. This improvement over current performance equates to 9,688 ton/yr SO_2 emissions reduction (combined both units) at current average firing rates. MEC recommends that the DNR include these operating improvements to lower SO_2 emissions from these units in its regional haze SIP for the second planning period.

The other NOx and SO_2 control options for Unit 101 and Unit 3 are extremely expensive both from a total cost perspective and particularly in comparison to their insignificant benefit to visibility in Class I areas.

Further lowering of SO_2 emissions would be possible by replacing the existing SO_2 controls with a Wet FGD system. This could improve these units' performance to approximately 0.06 lb/MMBtu. However, the average cost-effectiveness of this option is over $6,000/ton, and its incremental cost-effectiveness (vs. the DFGD option) is over $44,000/ton. These costs weigh against including this control option in the SIP. Additionally, as discussed Section 7, the additional SO_2 control provided by replacing the existing DFGD system with a wet FGD system would result in very little visibility benefit and have a cost-effectiveness of over $1,300,000,000/Mm^{-1}. This is orders of magnitude more expensive than would be considered reasonable, confirming that a wet-FGD system is not considered appropriate for RHR progress this decadal period.

Lowering NO_x emissions would be possible by either implementation of SNCR or SCR. The cost-effectiveness per ton of NOx of these options range from $5,616/ton to $8,862/ton. These cost-effectiveness values for SNCR and SCR are higher than are typically required for RHR controls. Additionally, these NOx controls would result in very little benefit to Class I visibility because these sites are so far away from any Class I area. The visibility cost-effectiveness of these additional NOx controls are over $290,000,000/Mm^{-1}, which is significantly more expensive than would be considered reasonable.

Based on MEC's Four Factor Analysis, MEC concludes that the only technically feasible control option that could reasonably be included in the Iowa regional haze SIP for the Louisa Generation Station Unit 101 and Walter Scott Jr. Energy Center Unit 3 would be operational improvements to the existing Dry FGD system. Both boilers could reasonably achieve improved performance of 0.10 lb/MMBtu (30-boiler operating day rolling average). This option will provide approximately 9,688 tons/yr of SO_2 emissions reduction (total both units). Since this option does not require the installation of new equipment, MEC recommends that the DNR make the proposed emission limitation effective within six months of EPA approval of the Iowa regional haze SIP (to allow time for testing and optimization of the system).

Attachment A

Cost Estimate Details of Technical Feasible Control Options

Attachment A-1 Capital and Operating Costs for SNCR - Louisa Unit 101

Below Calculation Methodology Utilizes EPA Cost Retrofit Tool.
https://www.epa.gov/airmarkets/retrofit-cost-analyzer#:~:text=The%20Retrofit%20Cost%20Analyzer%20(RCA,were%20developed%20to%20inform%20modeling

Variable	Designation	Units	Value	Calculation
Boiler Type	BT		Wall	<--- User Input
EPC Project?			FALSE	
Unit Size	A	(MW)	**812**	<--- User Input
Retrofit Factor	B		**1.00**	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	**9676.6**	<--- User Input
NOx Rate	D	(lb/MMBtu)	**0.1842**	<--- User Input
SO2 Rate	E	(lb/MMBtu)	**0.292**	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	H		0.96766	C/10000
Heat Input	I	(Btu/hr)	7.86E+09	A*C*1000
Capacity Factor	J	(%)	**59**	<--- User Input
NOx Removal Efficiency	K	(%)	**15**	<--- User Input
NOx Removed	L	(lb/hr)	217	D*I/10^6*K/100
Urea Rate (100%)	M	(lb/hr)	944	L/UF/46*30; If Boiler Type = CFB or D>0.3 THEN UF = 0.25 ELSE UF = 0.15
Water Required	N	(lb/hr)	17934	M*19
Heat Rate Penalty Include in VOM?	V	(%)	0.27	1175*N/I*100
Aux Power Include in VOM?	O	(%)	**0.05**	0.05 default value
Dilution Water Rate	P	(1000 gph)	2.15	N*0.1199/1000
Urea Cost (50% wt solution)	Q	($/ton)	**350**	<--- User Input (default EPA value)
Aux Power Cost	R	($/kWh)	**0.06**	<--- User Input (default EPA value)
Dilution Water Cost	S	($/klb)	**1**	<--- User Input (default EPA value)
Operating Labor Rate	T	($/hr)	**60**	<--- User Input (Labor cost including all benefits)(default EPA value)
Replacement Coal Cost	U	($/hr)	**2**	<--- User Input (default EPA value)

Correcton for Elevation Added by AECOM - following EPA CCM methodology

Site Elevation	EL	feet	**581**	<--- User Input
Atmospheric Pressure	PSIA	PSIA	14.40	$2116x[(59-(0.00356x EL)+459.7)/518.6]^{5.256}$ x (1/144)
Elevation Factor	ELEVF		1.021	14.7 psia / P

Below Chemical Engineering Plant Cost Index used to adjust Capital to current year $
541.7 CEPCI 2016
607.5 CEPCI 2019

EPA Initial Capital Costs Equations are all based on 2016 dollars

Capital Cost Calcuation		**Capital $2016**	**Capital $2019**	**Comments**
Includes - Equipment, intallation, buildings, foundations, electrical, and retrofit difficulty.				
BMS ($) =	BT*B*G*220000*(A*H)^0.42; IF CFB then BT = 0.75, ELSE BT = 1)	$ 3,692,000	$ 4,140,500	SNCR (injectors, blowers, DCS, reagent system) cost
BMA ($) =	IF E>= 3 and F = Bituminous, THEN 69000*(B)*(A*G*H)^0.78, ELSE 0	$ -	$ -	Air heater modif./SO3 control (Bituminous only and >= 3 lb/MMBtu)
BMB ($) =	BT*(L^0.12)*320000*(A)^0.33; (IF CFB then BT = 0.75, ELSE BT = 1)	$ 5,568,000	$ 6,244,300	Balance of plant costs (piping, site upgrades, water treatment for the dilution water, etc…)
BM ($) =	BMS + BMA + BMB	$ 9,260,000	$ 10,384,800	Total base module cost including retrofit factor
BM ($/kW) =		11	13	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$ 926,000	$ 1,038,500	Engineering and Construction Management costs
A2= 10% of BM		$ 926,000	$ 1,038,500	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$ 926,000	$ 1,038,500	Contractor profit and fees

CECC ($) = BM + A1 + A2 + A3	**$ 12,038,000**	**$ 13,500,200**	Capital, engineering and construction cost subtotal
CECC ($/kW) =	**15**	**17**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$ 602,000	$ 675,100	Owners costs including all "home office" costs (owners engineering, management, and procuement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$ 12,640,000**	**$ 14,175,300**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs	**16**	**17**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$ -	$ -	AFUDC (Zero for less than 1 year engineering and construction cycle)
C1 = if EPC = TRUE, 15% of (CECC+B1), else 0	$ -	$ -	EPC fees of 15%
TPC ($) = CECC + B1 + B2 + C1	**$ 12,640,000**	**$ 14,175,300**	Total project cost
TPC ($/kW) =	**16**	**17**	Total project cost per kW

Fixed O&M Cost

FOMO ($/kW yr) = (No operator time assumed)*2080*T/(A*1000)	$ -	Fixed O&M additional operating labor costs
FOMM ($/kW yr) =(0.012*BM)/(B*A*1000)	$ 0.14	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO + 0.4*FOMM)	$ 0.00	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO +FOMM+FOMA	**$ 0.14**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = M*Q/(A*1000)	$ 0.41	Variable O&M costs for Urea
VOMM ($/MWh) = P*S/A	$ 0.00	Variable O&M costs for dilution water
VOMP ($/MWh) = O*R*10	$ 0.03	Variable O&M costs for additional auxiliary power required.
VOMB ($/MWh) = 0.001175*N*U/A	$ 0.05	Variable O&M costs for heat rate increase due to water injected into the boiler
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$ 0.49**	Total Variable O&M costs

Annual Capacity Factor =	**59%**	
Annual MWhs =	4,196,741	
Annual Heat Input MMBtu =	40,610,182	
Annual Avg NOx Emission Rate, lb/MMBtu =	0.15657	

Capital Recovery Factor Calculation		Interest Rate
0.10081	$= i(1+i)^n/(1+i)^n - 1$	7.862%
	Where n = Equipment Life and i= Interest Rate	Equipment Life
		20 Years

Annual Capital Recovery Factor =	**0.101**		
	sncr 2016$	2019 $	
Annual Capital Cost (Including AFUDC), $ =	1,274,000	$ 1,429,000	Capital costs escalated to 2019$ with CEPCI above
Annual FOM Cost, $ =	115,000	$ 115,000	
Annual VOM Cost, $ =	2,077,000	$ 2,077,000	
Total Annual SNCR Cost, $ =	3,466,000	**3,621,000**	

Baseline Emissions Estimate	3774	TPY
Projected TPY NOx Reduction	566	Baseline Emissions times assumed Percent
Total SNCR Cost, $/ton =	**6,398**	$/Ton

Attachment A-2 Capital and Operating Costs for SNCR - Walter Scott Jr. # 3

Below Calculation Methodology Utilizes EPA Cost Retrofit Tool.
https://www.epa.gov/airmarkets/retrofit-cost-analyzer#:~:text=The%20Retrofit%20Cost%20Analyzer%20(RCA,were%20developed%20to%20inform%20modeling

Variable	Designation	Units	Value	Calculation
Boiler Type	BT		Wall	<--- User Input
EPC Project?			FALSE	
Unit Size	A	(MW)	**726**	<--- User Input
Retrofit Factor	B		**1.00**	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	**9870**	<--- User Input
NOx Rate	D	(lb/MMBtu)	**0.223**	<--- User Input
SO2 Rate	E	(lb/MMBtu)	**0.357**	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	H		0.987	C/10000
Heat Input	I	(Btu/hr)	7.17E+09	A*C*1000
Capacity Factor	J	(%)	**72**	<--- User Input
NOx Removal Efficiency	K	(%)	**15**	<--- User Input
NOx Removed	L	(lb/hr)	240	D*I/10^6*K/100
Urea Rate (100%)	M	(lb/hr)	1042	L/UF/46*30; If Boiler Type = CFB or D>0.3 THEN UF = 0.25 ELSE UF = 0.15
Water Required	N	(lb/hr)	19800	M*19
Heat Rate Penalty Include in VOM? ☑	V	(%)	0.32	1175*N/I*100
Aux Power Include in VOM? ☑	O	(%)	**0.05**	0.05 default value
Dilution Water Rate	P	(1000 gph)	2.37	N*0.1199/1000
Urea Cost (50% wt solution)	Q	($/ton)	**350**	<--- User Input (default EPA value already in downloaded spreadsheet)
Aux Power Cost	R	($/kWh)	**0.06**	<--- User Input (default EPA value already in downloaded spreadsheet)
Dilution Water Cost	S	($/klb)	**1**	<--- User Input (default EPA value already in downloaded spreadsheet)
Operating Labor Rate	T	($/hr)	**60**	<--- User Input (Labor cost including all benefits)(default EPA value)
Replacement Coal Cost	U	($/hr)	**2**	<--- User Input (default EPA value already in downloaded spreadsheet)

Correcton for Elevation Added by AECOM - following EPA CCM methodology

Site Elevation	EL	feet	**1089**	<--- User Input
Atmospheric Pressure	PSIA	PSIA	14.14	$2116x[(59-(0.00356x EL)+459.7)/518.6]^{5.256}$ x (1/144)
Elevation Factor	ELEVF		1.040	14.7 psia / P

Below Chemical Engineering Plant Cost Index used to adjust Capital to current year $
541.7 CEPCI 2016
607.5 CEPCI 2019

EPA Initial Capital Costs Equations are all based on 2016 dollars

Capital Cost Calcuation

Includes - Equipment, intallation, buildings, foundations, electrical, and retrofit difficulty.

		Capital $2016	Capital $2019	Comments
BMS ($) =	ELEVF* BT*B*G*220000*(A*H)^0.42; IF CFB then BT = 0.75, ELSE BT = 1)	$ 3,618,000	$ 4,057,500	SNCR (injectors, blowers, DCS, reagent system) cost
BMA ($) =	IF E>= 3 and F = Bituminous, THEN 69000*(B)*(A*G*H)^0.78, ELSE 0	$ -	$ -	Air heater modif/SO3 control (Bituminous only and >= 3 lb/MMBtu)
BMB ($) =	BT*(L^0.12)*320000*(A)^0.33; (IF CFB then BT = 0.75, ELSE BT = 1)	$ 5,430,000	$ 6,089,600	Balance of plant costs (piping, site upgrades, water treatment for the dilution water, etc…)
BM ($) =	BMS + BMA + BMB	$ 9,048,000	$ 10,147,100	Total base module cost including retrofit factor
BM ($/kW) =		12	14	Base cost per kW

Total Project Cost

A1 = 10% of BM	$	905,000	$ 1,014,900	Engineering and Construction Management costs
A2= 10% of BM	$	905,000	$ 1,014,900	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM	$	905,000	$ 1,014,900	Contractor profit and fees
CECC ($) = BM + A1 + A2 + A3	**$**	**11,763,000**	**$ 13,191,800**	Capital, engineering and construction cost subtotal
CECC ($/kW) =		**16**	**18**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	588,000	$ 659,400	Owners costs including all "home office" costs (owners engineering, management, and procuement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**12,351,000**	**$ 13,851,200**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs		**17**	**19**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	$ -	AFUDC (Zero for less than 1 year engineering and construction cycle)
C1 = if EPC = TRUE, 15% of (CECC+B1), else 0	$	-	$ -	EPC fees of 15%
TPC ($) = CECC + B1 + B2 + C1	**$**	**12,351,000**	**$ 13,851,200**	Total project cost
TPC ($/kW) =		**17.0**	**19.1**	Total project cost per kW

Fixed O&M Cost

FOMO ($/kW yr) = (No operator time assumed)*2080*T/(A*1000)	$	-	2019 O&M	Fixed O&M additional operating labor costs
FOMM ($/kW yr) =(0.012*BM)/(B*A*1000)	$	0.15	assumed same	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO + 0.4*FOMM)	$	0.00		Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO +FOMM+FOMA	**$**	**0.15**		Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = M*Q/(A*1000)	$	0.50	Variable O&M costs for Urea
VOMM ($/MWh) = P*S/A	$	0.00	Variable O&M costs for dilution water
VOMP ($/MWh) = O*R*10	$	0.03	Variable O&M costs for additional auxiliary power required.
VOMB ($/MWh) = 0.001175*N*U/A	$	0.06	Variable O&M costs for heat rate increase due to water injected into the boiler
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**0.60**	Total Variable O&M costs

Annual Capacity Factor =	**72%**
Annual MWhs =	4,579,027
Annual Heat Input MMBtu =	45,194,998
Annual Avg NOx Emission Rate, lb/MMBtu =	0.18955

Capital Recovery Factor Calculation			Interest Rate
0.10081	$= i (1+ i)^n/(1+ i)^n - 1$		7.86%
	Where n = Equipment Life and i= Interest Rate		Equipment Life
			20 Years

Annual Capital Recovery Factor =	**0.101**	SNCR 2016$	2019 $	
Annual Capital Cost (Including AFUDC), $ =		1,245,000	$ 1,396,300	Capital costs escalated to 2019$ with CEPCI above
Annual FOM Cost, $ =		110,000	$ 110,000	
Annual VOM Cost, $ =		2,734,000	$ 2,734,000	
Total Annual SNCR Cost, $ =		4,089,000	**4,240,300**	
Baseline Emissions Estimate			5030	
Projected TPY NOx Reduction			755	approx. at removal efficiency = 15%
Total SNCR Cost, $/ton =			**5,616**	

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

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

What type of fuel does the unit burn? Coal

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 812 MW

What is the higher heating value (HHV) of the fuel? 8,597 Btu/lb

What is the estimated actual annual MWhs output? 4,224,041 MWhs

Enter the net plant heat input rate (NPHR) 9.677 MMBtu/MW

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

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

Plant Elevation 581 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.240 percent by weight

For units burning coal blends:

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

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

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

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Attachment A-3
Louisa Unit 101 SCR Cost Estimate

Number of days the SCR operates (t_{SCR})	365 days		Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days		Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.184 lb/MMBtu		Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.05 lb/MMBtu	73% Lowest in RBLC	Ammonia Slip (Slip) provided by vendor	5 ppm
Stoichiometric Ratio Factor (SRF)	1.050		Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
			Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	750 °F
Estimated SCR equipment life	30 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	516 ft^3/min-MMBtu/hour

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019	
CEPCI for 2019	607.5 Enter the CEPCI value for 2019 · 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.862 Percent	*From OAQPS Cost Manual Example, which is consistent or less than MidAmeri. internal cost of capital.*
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0660 $/kWh	EIA 2019 average Industrial Sector Electricity Cost in Iowa (Commericial and Residential costs are higher)
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Facilities would use 19% solution. Assume price of 19% is 19/29* price of 29%
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	7,858	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	7,113,120	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		4,224,041	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	0.97	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.594	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5202	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	72.8	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	1052.94	lb/hour
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	2,738.69	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.91	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	4,229,352	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	195.17	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.02	
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.4	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3084	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	21,670.62	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	4,406	ft^2

Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	5,066	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	71.2	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	48	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	409	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	1,411	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	188	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	63,400	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n$/$(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0877

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	4578.51	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$167,880,492	in 2019 dollars
Reagent Preparation Cost (RPC) =	$3,603,022	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$10,162,763	in 2019 dollars
Total Capital Investment (TCI) =	$236,140,160	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$167,880,492 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$3,603,022 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

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

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

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

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529,000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529,000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$10,162,763 in 2019 dollars

Attachment A-3
Louisa Unit 101 SCR Cost Estimate

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$3,545,654	in 2019 dollars
Indirect Annual Costs (IDAC) =	$20,726,288	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$24,271,942	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$1,180,701	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$287,301	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,571,955	in 2019 dollars
Annual Catalyst Replacement Cost =		$505,697	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 selected.	
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$3,545,654	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$16,796	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$20,709,492	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$20,726,288	in 2019 dollars

Direct Annual + Administr. $3,562,450

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$24,271,942	per year in 2019 dollars
NOx Removed =	2,739	tons/year
Cost Effectiveness =	$8,862	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

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

What type of fuel does the unit burn? Coal

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 777 MW

What is the higher heating value (HHV) of the fuel? 8,827 Btu/lb

What is the estimated actual annual MWhs output? 4,576,617 MWhs

Enter the net plant heat input rate (NPHR) 9.87 MMBtu/MW

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

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

Plant Elevation 1089 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.240 percent by weight

For units burning coal blends:

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

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

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

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days		Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days		Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.223 lb/MMBtu		Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.05 lb/MMBtu	78% Lowest in RBLC	Ammonia Slip (Slip) provided by vendor	5 ppm
Stoichiometric Ratio Factor (SRF)	1.050		Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
			Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	750 °F
Estimated SCR equipment life	30 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	516 ft^3/min-MMBtu/hour

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019	
CEPCI for 2019	607.5 Enter the CEPCI value for 2019 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.862 Percent	*From OAQPS Cost Manual Example, which is consistent or less than MidAmeri. internal cost of capital.*
Reagent ($Cost_{reag}$)	0.293 $/gallon for 29% ammonia* — converted to 19% equiv.	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0660 $/kWh	
Catalyst cost (CC $_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	0.66 $/KWh EIA 2019 average Industrial Sector Electricity Cost in Iowa (Commericial and Residential costs are higher)
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	7,669	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	6,806,520	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		4,576,617	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	0.99	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.672	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5890	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	77.6	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	1326.74	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	3,907.31	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.97	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	4,127,768	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	183.78	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04	
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.1	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3084	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	22,459.96	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	4,300	ft^2

Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst})) + 1$ (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst}$	4,945	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	70.3	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	48	feet
		29	

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	516	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/Csol$ =	1,778	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density	238	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24)$/Reagent Density =	79,900	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	0.293
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0877

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1{,}000 \times 0.0056 \times (CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	4418.52	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$169,348,621	in 2019 dollars
Reagent Preparation Cost (RPC) =	$3,817,356	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$10,246,644	in 2019 dollars
Total Capital Investment (TCI) =	$238,436,408	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$169,348,621	in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$3,817,356	in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

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

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

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

Air Pre-Heater Costs (APH_{cost}) =	$0	$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)
For Coal-Fired Utility Boilers >25MW:
$BPC = 529{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$
For Coal-Fired Industrial Boilers >250 MMBtu/hour:
$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$

Balance of Plant Costs (BOP_{cost}) =	\$10,246,644 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$3,843,881	in 2019 dollars
Indirect Annual Costs (IDAC) =	$20,927,807	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$24,771,688	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$1,192,182	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$409,894	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,717,688	in 2019 dollars
Annual Catalyst Replacement Cost =		$524,117	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x $(CC_{replace}/R_{layer})$ x FWF	* Calculation Method 1 selected.	
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x $(CC_{replace})$ x 35.3		
Direct Annual Cost =		$3,843,881	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$16,934	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$20,910,873	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$20,927,807	in 2019 dollars
		Direct Annual + Administr.	$3,860,815

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

	Total Annual Cost (TAC) =	$24,771,688	per year in 2019 dollars
	NOx Removed =	3,849	tons/yr 2017-2019 MMBtu at 0.05 lb/mmbtu
	Cost Effectiveness =	$6,436	per ton of NOx removed in 2019 dollars

Attachments A-5.1-5.7

SO2 Control Option Costs

Attachment A-5.1 Summary of SO2 Control Options for MEC Facilities

	Louisa Unit 101		Walter Scott Jr. Unit 3	
	Improved D-FGD	**W-FGD**	**Improved D-FGD**	**W-FGD**
Current Baseline Emissions (Tons/Yr)	5952	5952	8041	8041
Emissions With Control (Tons/yr)	2049	1230	2256	1354
lb/MMBtu with Controls	0.1	0.06	0.1	0.06
Capital Cost ($)	n/a	$398,140,000	n/a	$370,150,000
Capital Cost Recovery ($/yr)	n/a	$40,136,000	n/a	$37,314,000
Annual O&M ($/yr)	$1,102,000	$1,986,000	$1,248,000	$3,849,000
Total Annualized Costs($/yr)	$1,102,000	$42,122,000	$1,248,000	$41,163,000
Emissions Reduction (Tons/yr)	3,903	4,722	5,785	6,687
Cost Effectiveness ($/Ton)	$282	$8,920	$216	$6,160
Incremental Cost-Effectiveness ($/ton)	n/a	$50,090	n/a	$44,250

This spreadsheet calculates the total costs for a new Wet FGD system, and then subtracts the existing operating costs for the existing DFGD system

Attachment A-5.2 Capital and Operating Costs for Wet FGD - Louisa Unit 101

Below Calculation Methodology Utilizes EPA Cost Retrofit Tool.
https://www.epa.gov/airmarkets/retrofit-cost-analyzer#:~:text=The%20Retrofit%20Cost%20Analyzer%20(RCA,were%20developed%20to%20inform%20modeling

Variable	Designation	Units	Value	Calculation
EPC Project?			FALSE	
Wastewater Treatment		Phys Chem-Biological		
Unit Size	A	(MW)	**812**	<--- User Input (Greater than 100 MW)
Retrofit Factor	B		**1.00**	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	**9679**	<--- User Input
SO2 Rate	D	(lb/MMBtu)	**0.502**	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.9679	C/10000
Heat Input	H	(Btu/hr)	7.86E+09	A*C*1000
Capacity Factor	I	(%)	**59.4**	<--- User Input
Operating SO2 Removal	J	(%)	**88.058**	<--- User Input (Used to adjust actual operating costs)
Design Limestone Rate	K	(ton/hr)	3	17.52*A*D*G/2000 (Based on 98% removal)
Design Waste Rate	L	(ton/hr)	6	1.811*K (Based on 98% removal)
Aux Power Include in VOM?	M	(%)	1.17	(1.12e^(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	59	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	**30**	<--- User Input (used default already in EPA spreadsheet)
Waste Disposal Cost	Q	($/ton)	**30**	<--- User Input (used default already in EPA spreadsheet)
Aux Power Cost	R	($/kWh)	**0.06**	<--- User Input (used default already in EPA spreadsheet)
Makeup Water Cost	S	($/kgal)	**1**	<--- User Input (used default already in EPA spreadsheet)
Operating Labor Rate	T	($/hr)	**60**	<--- User Input (Labor cost including all benefits)(Default in Sheet)

Costs are all based on 2016 dollars

Capital Cost Calcuation		Example	Comments
Includes - Equipment, intallation, buildings, foundations, electrical, and retrofit difficulty.			
BMR ($) =	584000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	$ 67,476,000	Base absorber island cost
BMF ($) =	202000*(B)*((D*G)^0.3)*(A^0.716)	$ 19,704,000	Base reagent preparation cost
BMW ($) =	106000*(B)*((D*G)^0.45)*(A^0.716)	$ 9,279,000	Base waste handling cost
BMB ($) =	1070000*(B)*((F*G)^0.4)*(A^0.716)	$ 127,926,000	Base balance of plant costs including: ID or booster fans, new wet chimney, piping, ductwork modifications and strengthening, minor WWT, etc...
BMWW ($) =	If type is Bio-Chem, then 10600000*(B)*A/500^0.6), else 0	$ 14,179,388	Base wastewater treatment facility, beyond minor physical/chemical treatment
BM ($) =	BMR + BMF + BMW + BMB + BMWW	$ 238,564,388	Total base module cost including retrofit factor
BM ($/kW) =		294	Base cost per kW

Total Project Cost	Example	Comments
A1 = 10% of BM	$ 23,856,000	Engineering and Construction Management costs
A2= 10% of BM	$ 23,856,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM	$ 23,856,000	Contractor profit and fees

CECC (\$) = BM + A1 + A2 + A3	**\$**	**310,132,388**	Capital, engineering and construction cost subtotal
CECC (\$/kW) =		**382**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	\$	15,507,000	Owners costs including all "home office" costs (owners engineering, management, and procuement activities)
TPC' (\$) - Includes Owner's Costs = CECC + B1	**\$**	**325,639,388**	Total project cost without AFUDC
TPC' (\$/kW) - Includes Owner's Costs		**401**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	\$	32,564,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of CECC+B1	\$	-	EPC fees of 15%
TPC (\$) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1	**\$**	**358,203,388**	Total project cost
TPC (\$/kW) = Includes Owner's Costs and AFUDC		**441**	Total project cost per kW
Fixed O&M Cost			
FOMO (\$/kW yr) = (if MW>500 then 16 additional operators, else 12 operators)*2080*T/(A*1000)	\$	2.46	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) =(BM*0.015)/(B*A*1000)	\$	4.41	Fixed O&M additional maintenance material and labor costs
FOMA (\$/kW yr) = 0.03*(FOMO + 0.4*FOMM)	\$	0.13	Fixed O&M additional administrative labor costs
FOMWW (\$/kW yr) =		0	Fixed O&M costs for wastewater treatment facility
FOM (\$/kW yr) = FOMO +FOMM+FOMA+ FOMWW	**\$**	**6.99**	Total Fixed O&M costs
Variable O&M Cost			
VOMR (\$/MWh) = K*P/(A*J)/98	\$	0.12	Variable O&M costs for limestone reagent
VOMW (\$/MWh) = L*Q/(A*J)/98	\$	0.21	Variable O&M costs for waste disposal
VOMP (\$/MWh) = M*R*10	\$	0.70	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = N*S/A	\$	0.07	Variable O&M costs for makeup water
VOMWW (\$/MWh) =	\$	0.17	Variable O&M costs for wastewater treatment facility
VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**\$**	**1.27**	Total Variable O&M costs

Annual Capacity Factor =	**59%**	
Annual MWhs =	4,225,193	
Annual Heat Input MMBtu =	40,895,646	
Annual Tons SO2 Created =	10,265	at 100% S conversion
Annual Tons SO2 Removed =	9,039	at removal efficiency = 88.058%
Annual Tons SO2 Emission =	1,226	
Annual Avg SO2 Emission Rate, lb/MMBtu =	0.060	Value is BELOW a 0.06 floor rate

Capital Recovery Factor Calculation		Interest Rate
0.10081	$= i\,(1+i)^n/(1+i)^n - 1$	7.862%
	Where n = Equipment Life and i= Interest Rate	Equipment Life
		20 Years

	Converstion from 2016\$ to 2019\$
541.7	2016 CEPCI (Chemical Engineering Plant Cost Index
602.1	2019 CEPCI

Annual Capital Recovery Factor =	**0.1008**	**Wet FGD 2016\$**	**Wet FGD 2019\$**
Annual Capital Cost (Including AFUDC), \$ =		36,110,000	40,136,295
Annual FOM Cost, \$ =			5,678,000
Annual VOM Cost, \$ =			5,362,000
Total Annual Wet FGD Cost, \$ =			51,176,295

Note: Annual O&M Costs are not escalated
(assume unit prices reflect current prices)

Annual Operating Cost Savings S/D Dry-FGD (at current Performance 0.292 lb/mmbtu)		**Dry FGD Savings**
Annual FOM Cost, \$ =		(4,423,000)
Annual VOM Cost, \$ =		(4,631,000)
Total Annual Wet FGD Cost, \$ =	-	(9,054,000)

Attachments A-5.1-5.7

SO2 Control Option Costs

	Louisa 101 Wet FGD
Capital Cost	398,140,000
Capital Cost Recovery	40,136,000
Annual O&M	1,986,000
Total Annualized Costs	42,122,000

Attachment A-5.3 Operating Costs Estimate for Existing D-FGD - Louisa Unit 101

This cost estimate is used to estimate the "operating cost credit" for S/D of existing D-FGD if replaced with Wet FGD

Below Calculation Methodology Utilizes EPA Cost Retrofit Tool.
https://www.epa.gov/airmarkets/retrofit-cost-analyzer#:~:text=The%20Retrofit%20Cost%20Analyzer%20(RCA,were%20developed%20to%20inform%20modeling

Variable	Designation	Units	Value	Calculation
EPC Project?			☐ **FALSE**	
Unit Size	A	(MW)	**812**	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		**1.00**	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	**9679**	<--- User Input
SO2 Rate	D	(lb/MMBtu)	**0.502**	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.9679	C/10000
Heat Input	H	(Btu/hr)	7.86E+09	A*C*1000
Capacity Factor	I	(%)	**59.4**	<--- User Input
Operating SO2 Removal	J	(%)	**41.8**	<--- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	3	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	6	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Aux Power Include in VOM?	M	(%)	1.26	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate ☑	N	(1000 gph)	44	(0.04898*D^2+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	**125**	<--- User Input (used default already in EPA spreadsheet)
Waste Disposal Cost	Q	($/ton)	**30**	<--- User Input (used default already in EPA spreadsheet)
Aux Power Cost	R	($/kWh)	**0.06**	<--- User Input (used default already in EPA spreadsheet)
Makeup Water Cost	S	($/kgal)	**1**	<--- User Input (used default already in EPA spreadsheet)
Operating Labor Rate	T	($/hr)	**60**	<--- User Input (Labor cost including all benefits)(Default in Sheet)

Costs are all based on 2016 dollars

			Comments
Fixed O&M Cost			
FOMO ($/kW yr) = (8 operators)*2080*T/(A*1000)	$	1.23	Fixed O&M additional operating labor costs
FOMM ($/kW yr) =(BM*0.015)/(B*A*1000)	$	4.13	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO + 0.4*FOMM)	$	0.09	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO +FOMM+FOMA	**$**	**5.45**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = K*P/(A*J)/98	$	0.18	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/(A*J)/98	$	0.10	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	$	0.76	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)

VOMM ($/MWh) = N*S/A	$	0.05	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**1.10**	Total Variable O&M costs

Annual Capacity Factor =	**59%**	
Annual MWhs =	4,225,193	
Annual Heat Input MMBtu =	40,895,646	
Annual Tons SO2 Created =	10,265	at 100% S conversion
Annual Tons SO2 Removed =	4,294	at removal efficiency = 41.8326693227092%
Annual Tons SO2 Emission =	5,971	
Annual Avg SO2 Emission Rate, lb/MMBtu =	0.292	Value is AT or ABOVE a 0.06 floor rate

Annual Capital Recovery Factor = **n/a**		Wet FGD
Annual Capital Cost (Including AFUDC), $ =	-	Facility is existing - no new capital
Annual FOM Cost, $ =	4,423,000	
Annual VOM Cost, $ =	4,631,000	
Total Annual D-FGD Cost, $ =	9,054,000	Estimated Operating costs of Existing DFGD operating to current 0.292 lb/mmbtu control

Attachment A-5.4 Operating Costs Estimate for Existing D-FGD - Louisa Unit 101

This cost estimate is used to estimate the Increased costs to improve the performance of the existing D-FGD from 0.292 to 0.1 lb/mmbtu

Below Calculation Methodology Utilizes EPA Cost Retrofit Tool.
https://www.epa.gov/airmarkets/retrofit-cost-analyzer#:~:text=The%20Retrofit%20Cost%20Analyzer%20(RCA,were%20developed%20to%20inform%20modeling

Variable	Designation	Units	Value	Calculation
EPC Project?			**FALSE**	
Unit Size	A	(MW)	**812**	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		**1.00**	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	**9679**	<--- User Input
SO2 Rate	D	(lb/MMBtu)	**0.502**	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.9679	C/10000
Heat Input	H	(Btu/hr)	7.86E+09	A*C*1000
Capacity Factor	I	(%)	**59.4**	<--- User Input
Operating SO2 Removal	J	(%)	**80.1**	<--- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	3	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	6	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Aux Power	M	(%)	1.26	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	(1000 gph)	44	(0.04898*D^2+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	**125**	<--- User Input (used default already in EPA spreadsheet)
Waste Disposal Cost	Q	($/ton)	**30**	<--- User Input (used default already in EPA spreadsheet)
Aux Power Cost	R	($/kWh)	**0.06**	<--- User Input (used default already in EPA spreadsheet)
Makeup Water Cost	S	($/kgal)	**1**	<--- User Input (used default already in EPA spreadsheet)
Operating Labor Rate	T	($/hr)	**60**	<--- User Input (Labor cost including all benefits)(Default in Sheet)

TPC ($) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1	**$**	**335,708,000**	Total project cost
TPC ($/kW) = Includes Owner's Costs and AFUDC		**413**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (8 operators)*2080*T/(A*1000)	$	1.23	Fixed O&M additional operating labor costs
FOMM ($/kW yr) =(BM*0.015)/(B*A*1000)	$	4.13	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO + 0.4*FOMM)	$	0.09	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO +FOMM+FOMA	**$**	**5.45**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = K*P/(A*J)/98	$	0.35	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/(A*J)/98	$	0.19	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	$	0.76	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.05	Variable O&M costs for makeup water

VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**1.36**	Total Variable O&M costs

Annual Capacity Factor =	**59%**	
Annual MWhs =	4,225,193	
Annual Heat Input MMBtu =	40,895,646	
Annual Tons SO2 Created =	10,265	at 100% S conversion
Annual Tons SO2 Removed =	8,220	at removal efficiency = 80.0796812749004%
Annual Tons SO2 Emission =	2,045	
Annual Avg SO2 Emission Rate, lb/MMBtu =	0.100	Value is AT or ABOVE a 0.06 floor rate

Annual Capital Recovery Factor = **n/a**	Wet FGD	
Annual Capital Cost (Including AFUDC), $ =	-	Facility is existing - no new capital
Annual FOM Cost, $ =	4,423,000	
Annual VOM Cost, $ =	5,733,000	
Total Annual D-FGD Cost, $ =	**10,156,000**	**Estimated Operating costs of Existing DFGD operating to 0.1 lb/mmbtu control**

Estimated cost from separate spreadsheet (Attachment A-5.3) of D-FGD operating at current 0.292 lb/mmbtu performance

Annual FOM Cost, $ =	4,423,000	
Annual VOM Cost, $ =	4,631,000	
Total Annual D-FGD Cost, $ =	9,054,000	Estimated Operating costs of Existing DFGD

Increased Cost to improve existing SDA Dry FGD from 0.292 to 0.1 lb/mmbtu performance

Total Increased Annual D-FGD Cost, $ = 1,102,000

Attachment A-5.5 Capital and Operating Costs for Wet FGD - WSEC Unit #3

Below Calculation Methodology Utilizes EPA Cost Retrofit Tool.
https://www.epa.gov/airmarkets/retrofit-cost-analyzer#:~:text=The%20Retrofit%20Cost%20Analyzer%20(RCA,were%20developed%20to%20inform%20modeling

Variable	Designation	Units	Value	Calculation
EPC Project?			FALSE	
Wastewater Treatment		Phys Chem-Biological		
Unit Size	A	(MW)	**725.8**	<--- User Input (Greater than 100 MW)
Retrofit Factor	B		**1.00**	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	**9874**	<--- User Input
SO2 Rate	D	(lb/MMBtu)	**0.483**	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.9874	C/10000
Heat Input	H	(Btu/hr)	7.17E+09	A*C*1000
Capacity Factor	I	(%)	**72**	<--- User Input
Operating SO2 Removal	J	(%)	**87.62**	<--- User Input (Used to adjust actual operating costs)
Design Limestone Rate	K	(ton/hr)	3	17.52*A*D*G/2000 (Based on 98% removal)
Design Waste Rate	L	(ton/hr)	5	1.811*K (Based on 98% removal)
Aux Power Include in VOM?	M	(%)	1.19	(1.12e^(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	54	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	**30**	<--- User Input (used default in EPA spreadsheet)
Waste Disposal Cost	Q	($/ton)	**30**	<--- User Input (used default in EPA spreadsheet)
Aux Power Cost	R	($/kWh)	**0.06**	<--- User Input (used default in EPA spreadsheet)
Makeup Water Cost	S	($/kgal)	**1**	<--- User Input (used default in EPA spreadsheet)
Operating Labor Rate	T	($/hr)	**60**	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calcuation				**Comments**
Includes - Equipment, intallation, buildings, foundations, electrical, and retrofit difficulty.				
BMR ($) =	584000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	$	62,967,000	Base absorber island cost
BMF ($) =	202000*(B)*((D*G)^0.3)*(A^0.716)	$	18,081,000	Base reagent preparation cost
BMW ($) =	106000*(B)*((D*G)^0.45)*(A^0.716)	$	8,491,000	Base waste handling cost
BMB ($) =	1070000*(B)*((F*G)^0.4)*(A^0.716)	$	118,994,000	Base balance of plant costs including: ID or booster fans, new wet chimney, piping, ductwork modifications and strengthening, minor WWT, etc...
BMWW ($) =	If type is Bio-Chem, then 10600000*(B)*A/500^0.6), else 0	$	13,256,047	Base wastewater treatment facility, beyond minor physical/chemical treatment
BM ($) =	BMR + BMF + BMW + BMB + BMWW	$	221,789,047	Total base module cost including retrofit factor
BM ($/kW) =			306	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	22,179,000	Engineering and Construction Management costs
A2= 10% of BM		$	22,179,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	22,179,000	Contractor profit and fees

Attachments A-5.1-5.7

SO2 Control Option Costs

CECC ($) = BM + A1 + A2 + A3	**$**	**288,326,047**	Capital, engineering and construction cost subtotal
CECC ($/kW) =		**397**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	14,416,000	Owners costs including all "home office" costs (owners engineering, management, and procuement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**302,742,047**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs		**417**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	$	30,274,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of CECC+B1	$	-	EPC fees of 15%
TPC ($) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1	**$**	**333,016,047**	Total project cost
TPC ($/kW) = Includes Owner's Costs and AFUDC		**459**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (if MW>500 then 16 additional operators, else 12 operators)*2080*T/(A*1000)	$	2.75	Fixed O&M additional operating labor costs
FOMM ($/kW yr) =(BM*0.015)/(B*A*1000)	$	4.58	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO + 0.4*FOMM)	$	0.14	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =		0	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO +FOMM+FOMA+ FOMWW	**$**	**7.47**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = K*P/(A*J)/98	$	0.11	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/(A*J)/98	$	0.20	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	$	0.72	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.08	Variable O&M costs for makeup water
VOMWW ($/MWh) =	$	0.17	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**$**	**1.28**	Total Variable O&M costs

Annual Capacity Factor =	**72%**	
Annual MWhs =	4,577,766	
Annual Heat Input MMBtu =	45,200,859	
Annual Tons SO2 Created =	10,916	at 100% S conversion
Annual Tons SO2 Removed =	9,565	at removal efficiency = 87.62%
Annual Tons SO2 Emission =	1,351	
Annual Avg SO2 Emission Rate, lb/MMBtu =	0.060	Value is BELOW a 0.06 floor rate

	Capital Recovery Factor Calculation	Interest Rate
0.10081	$= i(1+i)^n/(1+i)^n - 1$	7.862%
	Where n = Equipment Life and i= Interest Rate	Equipment Life
		20 Years

	Converstion from 2016$ to 2019$
541.7	2016 CEPCI (Chemical Engineering Plant Cost Index
602.1	2019 CEPCI

Annual Capital Recovery Factor =	**0.101**	**Wet FGD 2016$**	**Wet FGD 2019$**
Annual Capital Cost (Including AFUDC), $ =		33,571,000	37,314,194
Annual FOM Cost, $ =		5,424,000	6,028,781
Annual VOM Cost, $ =		5,837,000	6,487,830
Total Annual Wet FGD Cost, $ =		44,832,000	49,830,805

Note: Annual O&M Costs are not escalated (assume unit prices reflect current prices)

Annual Operating Cost Savings to S/D Dry-FGD at current 0.357 lb/mmbtu	**Dry FGD Savings**	(From Attachment A-5.6)
Annual FOM Cost, $ =	(4,085,000)	
Annual VOM Cost, $ =	(4,583,000)	
Total Annual Wet FGD Cost, $ =	(8,668,000)	

Attachments A-5.1-5.7
SO2 Control Option Costs

Reduction with Wet-FGD relative to DFGD at 0.357 lb/mmbtu

	WSEC #3
Capital Cost	$370,150,000
Capital Cost Recovery	$37,314,000
Annual O&M	$3,849,000
Total Annualized Costs	$41,163,000

Attachment A-5.6 Operating Costs Estimate for Existing D-FGD - WSEC Unit #3

This cost estimate is used to estimate the "operating cost credit" for S/D of existing D-FGD if replaced with Wet FGD

Below Calculation Methodology Utilizes EPA Cost Retrofit Tool.

Variable	Designation	Units	Value	Calculation
EPC Project?			**FALSE**	
Unit Size	A	(MW)	**725.8**	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		**1.00**	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	**9874**	<--- User Input
SO2 Rate	D	(lb/MMBtu)	**0.483**	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.9874	C/10000
Heat Input	H	(Btu/hr)	7.17E+09	A*C*1000
Capacity Factor	I	(%)	**72**	<--- User Input
Operating SO2 Removal	J	(%)	**26.1**	<--- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	2	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	5	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Aux Power Include in VOM?	M	(%)	1.29	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	(1000 gph)	40	(0.04898*D^2+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	**125**	<--- User Input (used default already in EPA spreadsheet)
Waste Disposal Cost	Q	($/ton)	**30**	<--- User Input (used default already in EPA spreadsheet)
Aux Power Cost	R	($/kWh)	**0.06**	<--- User Input (used default already in EPA spreadsheet)
Makeup Water Cost	S	($/kgal)	**1**	<--- User Input (used default already in EPA spreadsheet)
Operating Labor Rate	T	($/hr)	**60**	<--- User Input (Labor cost including all benefits)(Default in Sheet)

Costs are all based on 2016 dollars

			Comments
Fixed O&M Cost			
FOMO ($/kW yr) = (8 operators)*2080*T/(A*1000)	$	1.38	Fixed O&M additional operating labor costs
FOMM ($/kW yr) =(BM*0.015)/(B*A*1000)	$	4.16	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO + 0.4*FOMM)	$	0.09	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO +FOMM+FOMA	**$**	**5.63**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = K*P/(A*J)/98	$	0.11	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/(A*J)/98	$	0.06	Variable O&M costs for waste disposal
VOMP ($/MWh) = M*R*10	$	0.77	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.06	Variable O&M costs for makeup water

VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**1.00**	Total Variable O&M costs

Annual Capacity Factor =	**72%**	
Annual MWhs =	4,577,766	
Annual Heat Input MMBtu =	45,200,859	
Annual Tons SO2 Created =	10,916	at 100% S conversion
Annual Tons SO2 Removed =	2,848	at removal efficiency = 26.0869565217391%
Annual Tons SO2 Emission =	8,068	
Annual Avg SO2 Emission Rate, lb/MMBtu =	0.357	Value is AT or ABOVE a 0.06 floor rate

Annual Capital Recovery Factor =	**n/a**	Wet FGD	
Annual Capital Cost (Including AFUDC), $ =		-	Facility is existing - no new capital
Annual FOM Cost, $ =		4,085,000	
Annual VOM Cost, $ =		4,583,000	
Total Annual D-FGD Cost, $ =		8,668,000	Estimated Operating costs of Existing DFGD operating at existing 0.357 lb/mmbtu control

Attachment A-5.7 Operating Costs Estimate for Existing D-FGD - WSEC Unit 3

This cost estimate is used to estimate the Increased costs to improve the performance of the existing D-FGD from 0.357 to 0.1 lb/mmbtu

Below Calculation Methodology Utilizes EPA Cost Retrofit Tool.
https://www.epa.gov/airmarkets/retrofit-cost-analyzer#:~:text=The%20Retrofit%20Cost%20Analyzer%20(RCA,were%20developed%20to%20inform%20modeling

Variable	Designation	Units	Value	Calculation
EPC Project?			FALSE	
Unit Size	A	(MW)	**725.8**	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		**1.00**	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	**9874**	<--- User Input
SO2 Rate	D	(lb/MMBtu)	**0.483**	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		0.9874	C/10000
Heat Input	H	(Btu/hr)	7.17E+09	A*C*1000
Capacity Factor	I	(%)	**72**	<--- User Input
Operating SO2 Removal	J	(%)	**79.3**	<--- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	2	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	5	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Aux Power Include in VOM?	M	(%)	1.29	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	(1000 gph)	40	(0.04898*D^2+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	**125**	<--- User Input (used default already in EPA spreadsheet)
Waste Disposal Cost	Q	($/ton)	**30**	<--- User Input (used default already in EPA spreadsheet)
Aux Power Cost	R	($/kWh)	**0.06**	<--- User Input (used default already in EPA spreadsheet)
Makeup Water Cost	S	($/kgal)	**1**	<--- User Input (used default already in EPA spreadsheet)
Operating Labor Rate	T	($/hr)	**60**	<--- User Input (Labor cost including all benefits)(Default in Sheet)

Costs are all based on 2016 dollars

			Comments
Fixed O&M Cost			
FOMO ($/kW yr) = (8 operators)*2080*T/(A*1000)	$	1.38	Fixed O&M additional operating labor costs
FOMM ($/kW yr) =(BM*0.015)/(B*A*1000)	$	4.16	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO + 0.4*FOMM)	$	0.09	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO +FOMM+FOMA	**$**	**5.63**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = K*P/(A*J)/98	$	0.34	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/(A*J)/98	$	0.19	Variable O&M costs for waste disposal

VOMP ($/MWh) = M*R*10	$	0.77	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.06	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**1.36**	Total Variable O&M costs

Annual Capacity Factor =	**72%**	
Annual MWhs =	4,577,766	
Annual Heat Input MMBtu =	45,200,859	
Annual Tons SO2 Created =	10,916	at 100% S conversion
Annual Tons SO2 Removed =	8,656	at removal efficiency = 79.296066252588%
Annual Tons SO2 Emission =	2,260	
Annual Avg SO2 Emission Rate, lb/MMBtu =	0.100	Value is AT or ABOVE a 0.06 floor rate

Annual Capital Recovery Factor = **n/a**	Wet FGD	
Annual Capital Cost (Including AFUDC), $ =	-	Facility is existing - no new capital
Annual FOM Cost, $ =	4,085,000	
Annual VOM Cost, $ =	6,217,000	
Total Annual D-FGD Cost, $ =	**10,302,000**	**Estimated Operating costs of Existing DFGD operating to 0.1 lb/mmbtu control**

Estimated cost from separate spreadsheet of SDA FGD operating at Current 0.357 lb/mmbtu performance

Annual FOM Cost, $ =	4,423,000	
Annual VOM Cost, $ =	4,631,000	
Total Annual D-FGD Cost, $ =	9,054,000	Estimated Operating costs of Existing DFGD

Increased Cost to improve existing SDA Dry FGD from 0.292 to 0.1 lb/mmbtu performance

Total Increased Annual D-FGD Cost, $ =	**1,248,000**

Attachment B

LADCO Visibility Analysis - Louisa and Walter Scott Jr. Impacts

Attachment B

VISTA Visibility Modeling - Louisa and Walter Scott Jr. Impacts

Visibility Emissions Estimates for Iowa sources were generated by LADCO for 2028.

Emissions Info and Visibility Modeling Results are available at the following website:

- https://www.ladco.org/reports/technical-support/ladco-regional-haze-tsd-second-implementation-period/

Table B-1 Iowa Emissions Modeled By LADCO for 2028 Projection

Projected 2028 Emissions Modeled by LADCO	**SO2 (Tons/yr)**	**Emiss. % of Anthro. Sources**	**NOx (Tons/yr)**	**Emiss. % of Anthro. Sources**
All Iowa Projected 2028 (tons/yr)	36,287		136,635	
All Iowa Anthropogenic (exclude fire and biogenic)	35,538		96,398	
All Iowa Point Sources only	34,786	98%	40,651	42%
All Iowa EGU Emissions	28,002	79%	21,442	22%
Louisa Tons/yr (modeled)	5,605	16%	3,403	4%
Walter Scott Tons/yr (modeled)	9,897	28%	6,025	6%

- Emissions data from LADCO file: 2028_LADCO_V1b_county_monthly_report_OzoneHaze_12092020.xlsx
- EGU sources designated in modeling as "ptertac" for Eastern Regional Technical Advisory Committee (ERTAC) which is basis of EGU projected emissions. The 2028 project emissions values for Louisa and Walter Scott are similar too, although slightly different, than the base actual baseline emissions for these generating stations.

Table B-2 Modeled Impacts of All Iowa Emissions by LADCO for 2028 (20% Most Impaired)

Modeled Iowa Total Impacts Mm-1	**Sulfate**	**Nitrate**	**LADCO 2028 Projection (Mm-1)**
Boundary Waters Canoe Area	0.400	0.460	37.32
Voyageurs NP	0.440	0.320	41.29
Isle Royale NP	**0.650**	0.650	44.06
Seney Wilderness Area	0.590	**0.800**	57.95
Maximum Impacts are Highlighted			

- Modeled Iowa Impacts from "PSAT tracers-Most Impaired" tab in LADCO Spreadsheet: LADCO_RegionalHaze_2016_28abc_PSAT_Charts_05June2021.xlsx
- Sulfate Visibility Impacts are from SO2 Emissions, Nitrate are from NOx.

Table B-3 VERY Conservative Assumed Potential Impact of Louisa and Walter Scott

Conservative Assumption of Max Impact	**Sulfate (Mm-1)**	**Assumed Plant Sulfate Impact. % of Statewide**	**Each Plant's SO2 as % of Anthro.**	**Nitrate (Mm-1)**	**Assumed Plant Nitrate Impact. % of Statewide**	**Each Plant's NOx as % of Anthro.**
Max. Statewide Iowa Impacts (Mm-1)	**0.65**			**0.80**		
Louisa Impact (Very Conserv. Assumed)	0.19	28%	16%	0.06	8%	4%
Walter Scott (Very Conserv. Assumed)	0.33	50%	28%	0.11	14%	6%
		79%	44%		22%	10%
Resultant Assumed Impact per ton	**Sulfate Mm-1/ton SO2**			**Nitrate Mm-1/ton NOx**		
Louisa Impact Mm-1/ton emissions	3.30E-05			1.89E-05		
Walter Scott Mm-1/tons emissions	3.30E-05			1.89E-05		

Because of the long distance from the state of Iowa to any Class I area, it would probably be reasonable to assume that an Iowa source such as the Louisa Generating Station, which contributes approximately 2% of the statewide NOx emissions, would contribute approximately 2% of the statewide Nitrate visibility impairment. The exact impact of a single source may be slightly higher or lower that this proportional relationship dependent on its specific geographic location or source release characteristics. However, any differences vs. a straight proportional relationship is likely minimal because of the great distances involved to the Class I areas. However, to be very conservative, a worse-case possible impact has been estimated above using the following approach. First, it has been assumed that portion of the Iowa statewide nitrate and sulfate impacts attributable to all EGU's as a group is proportional to the total of all EGU emissions relative to all statewide emissions. Then, it is next assumed that the resulting impact of all EGUs is 100% attributable to just Louisa and Walter Scott Generating Stations, even though they represent only a faction of the total EGU emissions. Finally, the assumed split of the impacts are allocated between Louisa and Walter Scott based on their relative emissions. The results of this approach is that 79% of the statewide sulfate impacts are assumed attributable to these two power plants even though they contribute only 44% of the statewide anthropogenic SO2 emissions. Likewise, these assumptions allocate 22% of the statewide Nitrate impacts to these two power plants even though they represent only 10% of the statewide anthropogenic NOx emissions and only 7% of the total state NOx emissions. These are very conservative assumptions and actual impacts are expected to be much lower.

The below Table estimates the visibility benefit for each control option at the MEC facilities based on the above Visibility Factors and estimates the visibility cost-effectiveness of each option by dividing the visibility improvement by the annual cost of the control option.

Table B-4 Visibility Cost-Effectiveness of Each Candidate Control Option (using VERY Conservative Estimate of Visibility Benefit)

Candidate Control Improvements		Total Annual Costs ($/yr)	Emissions Reduction (tons/yr)	Maximum Visibility Improvement (Mm^{-1})	Maximum Visibility Improvement (DV)	Cost Effectiveness ($/$Mm^{-1}$)	Cost Effectiveness ($/DV)
Louisa Generating Station							
D-FGD Improvement (Proposed)	SO_2	$1,102,000	3,903	0.13	0.046	$8,550,000	$24,110,000
Wet FGD	SO_2	$42,122,000	4,722	0.16	0.055	$270,000,000	$761,700,000
Wet FGD Increm. Improv.	SO_2	$41,020,000	819	0.03	0.010	$1,515,960,000	$4,272,920,000
SNCR	NOx	$3,621,000	566	0.01	0.004	$338,970,000	$883,170,000
SCR	NOx	$24,271,942	2,739	0.05	0.020	$469,520,000	$1,225,860,000
Walter Scott Jr. Energy Center							
D-FGD Improvement (Proposed)	SO_2	$1,248,000	5,785	0.19	0.068	$6,530,000	$18,430,000
Wet FGD	SO_2	$41,163,000	6,687	0.22	0.078	$186,320,000	$525,710,000
Wet FGD Increm. Improv.	SO_2	$39,915,000	902	0.03	0.011	$1,339,380,000	$3,765,570,000
SNCR	NOx	$4,240,300	755	0.01	0.006	$297,570,000	$770,960,000
SCR	NOx	$24,771,688	3,849	0.07	0.028	$341,000,000	$891,070,000

Note: MEC is proposing to implement improvements to the existing Dry FGD system (highlighted above). All other options have negligible visibility benefits and are not economically cost-effective relative to their visibility improvement. These $/DV and $/Mm-1 values are more than an order of magnitude higher than costs considered reasonable as BART during the RHR first decadal review. Additionally, a visibility change of 1 deciview is considered barely perceptible and the improvement from the control options above are well below that level. The 1999 RHR preamble described a change of 0.1 DV as the "no degradation" level.

Table B-5 Adjusted Glidepath Goal used to estimated Mm-1 to DV conversion factor

Adjusted Glidepath 2064 Goal	DV	Mm-1	DV/Mm-1	
Boundary Waters Canoe Area	12.12	33.600	0.361	
Voyageurs NP	12.53	35.010	0.358	
Isle Royale NP	13.01	36.730	**0.354**	Use for SO2
Seney Wilderness Area	14.07	36.730	**0.383**	Use for NOx

The above table shows the 2064 Adjusted Glidepath Goals for each Class I area in DV and Mm-1. The Isle Royale is Iowa's most impacted area for SO2 and therefore its conversion factor is used for SO2 impacts conversion from Mm-1 to DV in Table B-5. Seney is the most impacted for NOx and its factor is used for NOx improvement conversion in Table B-5.

All above Info is obtained from LADCO website:
https://www.ladco.org/reports/technical-support/ladco-regional-haze-tsd-second-implementation-period/

Attachment C

RACT/BACT/LAER Clearinghouse Database Summary of NOx and SO_2 Controls for Coal-Fired EGU Boilers

Table A-3.1 RBLC Database Search Results for NOx Controls of Coal Fired Boilers > 250 MMBtu/hr

RBLCID	FACILITY _NAME	STATE (Permit Year)	PROCESS_NAME	FUEL	THROUGHPUT		CONTROL_METHOD_DESCRIPTION	EMISSION LIMIT		CASE-BY-CASE BASIS
AZ-0055	NAVAJO GENERATING STATION	AZ (2012)	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/ MMBTU	BACT-PSD
CA-1206	STOCKTON COGEN COMPANY	CA (2011)	CIRCULATING FLUIDIZED BED BOILER	COAL	730	MMBTU/H	LOW BED TEMPERATUR STAGED COMBUSTION; SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	50	PPM	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	KY (2010)	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2	COAL	3000	MMBTU/H	SNCR	0.07	LB/ MMBTU	BACT-PSD
MI-0399	DETROIT EDISON--MONROE	MI (2010)	Boiler Units 1, 2, 3 and 4	Coal	7624	MMBTU/H	Staged combustion, low-NOx burners, overfire air, and SCR.	0.08	LB/ MMBTU	BACT-PSD
MI-0400	WOLVERINE POWER	MI (2011)	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	Petcoke /coal	3030	MMBTU/H EACH	SNCR (Selective Non-Catalytic Reduction)	1	LB/ MW-H	BACT-PSD
MI-0400	WOLVERINE POWER	MI (2011)	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2) -	Petcoke /coal	3030	MMBTU/H each	SNCR (Selective Non-Catalytic Reduction)	0.07	LB/ MMBTU	BACT-PSD

RBLCID	FACILITY _NAME	STATE (Permit Year)	PROCESS_NAME	FUEL	THROUGHPUT		CONTROL_METHOD_DESCRIPTION	EMISSION LIMIT		CASE-BY-CASE BASIS
ND-0026	M.R. YOUNG STATION	ND (2012)	Cyclone Boilers, Unit 1	Lignite	3200	MMBTU/H	SNCR plus separated over fire air	0.36	LB/MMBTU	BACT-PSD
ND-0026	M.R. YOUNG STATION	ND (2012)	Cyclone Boilers, Unit 2	Lignite	6300	MMBTU/H	SNCR plus separated over fire air	0.35	LB/MMBTU	BACT-PSD
OK-0151	SOONER GENERATING STATION	OK (2013)	COAL-FIRED BOILERS	COAL	550	MW	LOW-NOx BURNERS AND OVERFIRE AIR.	0.15	LB/MMBTU	BART
OK-0152	MUSKOGEE GENERATING STATION	OK (2013)	COAL-FIRED BOILER	COAL	550	MW	LOW-NOx BURNERS AND OVERFIRE AIR	0.15	LB/MMBTU	BART
TX-0554	COLETO CREEK UNIT 2	TX (2010)	Coal-fired Boiler Unit 2	PRB coal	6670	MMBTU/H	low-NOx burners with OFA, Selective Catalytic Reduction	0.06	LB/MMBTU	BACT-PSD
TX-0556	HARRINGTON STATION UNIT 1 BOILER	TX (2010)	Unit 1 Boiler	Coal	3630	MMBTU/H	Separated overfire air windbox system; low-NOx burner tips and additional ya control to the burners.	1452	LB/H	BACT-PSD
TX-0557	LIMESTONE ELECTRIC GENERATING STATION	TX (2010)	LMS Units 1 and 2	Coal	9061	MMBtu/H	Tuning of existing low-NOx firing system to induce deeper state combustion.	0.25	LB/MMBTU	BACT-PSD

TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	TX (2010)	Coal-fired Boiler	Sub-bituminous coal	8307	MMBTU/H	Selective Catalytic Reduction	0.05	LB/MMBTU	BACT-PSD

Table A-3.2 RBLC Database Search Results for SO_2 Controls of Coal Fired Boilers > 250 MMBtu/hr

RBLCID	FACILITY_NAME	STATE (Year)	PROCESS_NAME	FUEL	THROUGHPUT		CONTROL METHOD DESCRIPTION	EMISSION LIMIT		CASE-BY-CASE BASIS
CA-1206	STOCKTON COGEN COMPANY	CA (2011)	CIRCULATING FLUIDIZED BED BOILER	COAL	730	MMBTU/H	LIMESTONE INJECTION W/ A MINIMUM REMOVAL EFFICIENCY OF 70% (3-HR AVG) TO BE MAINTAINED AT ALL TIMES	59	LB/H	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	KY (2010)	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2	COAL	3000	MMBTU/H	LIMESTONE INJECTION (CFB)AND A FLASH DRYER ABSORBER WITH FRESH LIME INJECTION	0.075	LB/ MMBTU	BACT-PSD
MI-0399	DETROIT EDISON--MONROE	MI (2010)	Boiler Units 1, 2, 3 and 4	Coal	7624	MMBTU/H	Wet flue gas desulfurization.	0.107	LB/ MMBTU	BACT-PSD
MI-0400	WOLVERINE POWER	MI (2011)	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	Petcoke /coal	3030	MMBTU/H EACH	Dry flue gas desulfurization (spray dry absorber or polishing scrubber).	303	LB/H	BACT-PSD
MI-0400	WOLVERINE POWER	MI (2011)	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2) -	Petcoke /coal	3030	MMBTU/H each	Dry flue gas desulfurization (spray dry absorber or polishing scrubber).	0.06	LB/ MMBTU	BACT-PSD
TX-0554	COLETO CREEK UNIT 2	TX (2010)	Coal-fired Boiler Unit 2	PRB coal	6670	MMBTU/H	Spray Dry Adsorber/Fabric Filter	0.06	LB/ MMBTU	BACT-PSD

TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	TX (2010)	Coal-fired Boiler	Coal	8307	MMBTU/H	Wet limestone scrubber	0.06	LB/ MMBTU	BACT-PSD
TX-0601	GIBBONS CREEK STEAM ELECTRIC STATION	TX (2011)	Boiler	Coal	5060	MMBtu/h	Wet Flue Gas Desulfurization	1.2	LB/ MMBTU	BACT-PSD

Attachment D

MidAmerican Energy Company Most Recent Electric Rate Case

Schedule C – Average Weighted Cost of Capital

Schedule C
Page 1 of 1

MIDAMERICAN ENERGY COMPANY
2013 IOWA ELECTRIC RATE CASE
RPU-2013-0004
Embedded Average Weighted Average Cost of Capital
Twelve Months ending September 30, 2013

Non-Ratemaking Principles Rate Base - Phase-in Proposal

	(a) Component	(b) Amount	(c) Weight	(d) Cost	(e) Weighted Average Cost
1	Long Term Debt	$3,247,655,195	47.115%	4.355%	2.052%
2	Preferred Stock	$13,405,084	0.194%	4.411%	0.009%
3	Common Equity	$3,632,049,622	52.691%	10.000%	5.269%
4	Total	$6,893,109,901	100.000%		7.329%

Overall WACC, including Ratemaking Principles Rate Base

	(a) Component	(b) Amount	(c) Weight	(d) Cost	(e) Weighted Average Cost
5	Long Term Debt	$3,247,655,195	47.115%	4.355%	2.052%
6	Preferred Stock	$13,405,084	0.194%	4.411%	0.009%
7	Common Equity	$3,632,049,622	52.691%	11.010%	5.80%
8	Total	$6,893,109,901	100.000%		7.862%

File Name: MEC Settlement Workpapers.xlsx
Tab: Sch C