Identification and Evaluation of Emission Control Measures for Units 1 and 2 at the Springerville Generating Station for Purposes of the Regional Haze Second Planning Period Under 40 CFR § 51.308(f)(2)

Tucson Electric Power

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TABLE OF CONTENTS

1. Introduction and Background 1-1
1.1 Introduction 1-1
1.2 Statutory and Regulatory Background 1-1
1.3 Facility Background 1-3
1.4 Analysis Process 1-4

2. Analysis Step 1: Identification of Technically Feasible Control Measures 2-1
2.1 Emissions of PM 2-1
2.1.1 Fabric Filter Baghouses 2-1
2.1.2 Dry Electrostatic Precipitators 2-1
2.1.3 Operation without Selective Catalytic Reduction 2-2
2.1.4 Wet Electrostatic Precipitators 2-2
2.2 Emissions of NO_X 2-2
2.2.1 Low-NO_X Burners, Overfire Air, and Other Combustion Controls 2-2
2.2.2 Selective Catalytic Reduction Systems 2-3
2.2.3 Selective Non-Catalytic Reduction Systems 2-3
2.3 Emissions of NH_3 2-3
2.3.1 Operation without SCR and SNCR Systems 2-3
2.4 Emissions of SO_2 2-3
2.4.1 Spray Dry Absorber Systems 2-3
2.4.2 Dry Sorbent Injection Systems 2-3
2.4.3 Circulating Dry Scrubber Systems 2-4
2.4.4 Wet Flue Gas Desulfurization 2-4
2.5 Emissions of VOC 2-4
2.6 Summary of Control Measure Scenarios 2-4

3. Analysis Step 2: Emissions Information 3-1
3.1 Baseline Scenario (Scenario #1) (2028 Projection) 3-1
3.2 Control Scenario #2 3-2
3.3 Control Scenario #3 3-2
3.4 Control Scenario #4 3-3
3.5 Control Scenario #5 3-3
3.6 Control Scenario #6 3-3
3.7 Control Scenario #7 3-4
3.8 Control Scenario #8 3-4
3.9 Control Scenario #9 3-4
3.10 Control Scenario #10 3-5
3.11 Control Scenario #11 3-5
3.12 Control Scenario #12 3-6
3.13 Control Scenario #13 3-6

3.14 Control Scenario #14 3-6
3.15 Control Scenario #15 3-7

4. Analysis Step 3: Cost of Compliance 4-1
4.1 Installation of DSI Systems for SO_2 Emission Control is an Economically Inferior Option 4-1
4.2 Replacement of SDA Systems for SO_2 Emission Control is Economically Unreasonable 4-1
4.3 Installation of SCR Systems for NO_X Emission Control is Economically Unreasonable 4-3
4.4 Control Scenario #2 (SNCR) 4-4
4.5 Control Scenario #4 (SDA Upgrades) 4-6
4.6 Control Scenario #5 (SNCR plus SDA Upgrades) 4-7

5. Analysis Step 4: Time Necessary for Compliance 5-1

6. Analysis Step 5: Other Statutory Factors 6-1

APPENDICES

Appendix A Ramboll Photochemical Grid Modeling Report
Appendix B Sargent & Lundy Cost Evaluation Report
Appendix C EPA Cost Spreadsheets for SCR and SNCR

1. Introduction and Background

1.1 Introduction

This report presents an analysis of potential control measures that could be used to achieve emission reductions in visibility-impairing pollutants at Units 1 and 2 at the Springerville Generating Station ("SGS") located in Apache County, approximately 15 miles north of Springerville, Arizona.

SGS comprises four coal-fired electric generating units with a combined, nominal, net generating capacity of 1,620 megawatts ("MWe"). Units 1 and 2 at SGS are owned and operated by Tucson Electric Power Company ("TEP").

TEP hired RTP Environmental Associates, Inc. ("RTP") to prepare this analysis. RTP subcontracted with Ramboll US Corporation to perform photochemical grid modeling as presented in Appendix A to this report. In addition, TEP contracted with Sargent & Lundy, L.L.C. for cost evaluations for certain control measures. A report summarizing these evaluations is presented in Appendix B to this report.

The analyses presented herein are provided in response to a request by Arizona Department of Environmental Quality ("ADEQ") to assist in developing a long-term strategy for demonstrating that Arizona is makng reasonable progress under the Regional Haze program as discussed below.

1.2 Statutory and Regulatory Background

The Federal Clean Air Act ("CAA") establishes as a national goal "the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution"[1] and requires States periodically to develop plans for making reasonable progress toward meeting the national goal.[2] The statute further requires that, in determining what constitutes reasonable progress, "there shall be taken into consideration the costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements."[3] These are referred to as the four reasonable progress factors or simply the four factors.

The U.S. Environmental Protection Agency ("EPA") has promulgated prescriptive Federal rules establishing minimum requirements concerning the timing and content of the initial Regional Haze State Implementation Plan ("SIP") for each State and for periodic, comprehensive revisions.[4] Each SIP revision must be submitted to EPA; if it is not approved, then EPA may

[1] 42 U.S.C. § 7491(a)(1).
[2] *See generally* 42 U.S.C. § 7491(b)(2).
[3] 42 U.S.C. § 7491(g)(1).
[4] 40 CFR § 51.308.

have authority to develop a Federal Implementation Plan ("FIP") to meet the statutory requirements.[5] ADEQ developed and submitted the initial Regional Haze SIP for Arizona addressing reasonable progress for the first implementation period in 2011.[6] This SIP was partially approved and partially disapproved, leading EPA to promulgate a FIP to satisfy some Regional Haze program requirements for Arizona in 2014.[7] EPA determined that no additional controls were required for SGS during the first implementation period.[8]

Regional Haze SIPs establishing a long-term strategy for the second implementation period, which ends in 2028, must be submitted to EPA by July 31, 2021.[9] The State's submittal must include, among other things:

- The enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress;[10]
- A description of how the four factors listed in the statute (*i.e.*, costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source) were considered in evaluating and determining the emission reduction measures that are necessary to make reasonable progress;[11]
- A demonstration that the State has included in its SIP all measures agreed to during the State-to-State consultation process or the regional planning process, or measures that will provide equivalent visibility improvement, as well as documentation of the State's consideration of measures that other States identified as necessary to make reasonable progress for their sources;[12]
- Documentation of the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary;[13] and
- A description of the State's consideration of the five additional factors listed in 40 CFR § 51.308(f)(2)(iv), including the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during the planning period.[14]

The objectives and content of the required periodic SIP revisions were summarized succinctly in the 2011 Arizona RH SIP:

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[5] *See generally* 42 U.S.C. § 7410(c)(1).

[6] ADEQ, Air Quality Division, *Arizona State Implementation Plan: Regional Haze Under Section 308 of the Federal Regional Haze Rule* (Jan. 2011) https://legacy.azdeq.gov/environ/air/haze/download/haze308sip.pdf ("2011 Arizona RH SIP"). Arizona had previously submitted a Regional Haze SIP under the alternative provisions of 40 CFR § 51.309, but this SIP was never approved by EPA.

[7] 79 *Fed. Reg.* 52420 (Sept. 3, 2014).

[8] *See Id.*; *See* 78 *Fed. Reg.* 46142 (Jul. 30, 2013).

[9] 40 CFR § 51.308(f). Note that this deadline was originally July 31, 2018, and was extended by three years in a recent rulemaking. *See* 82 *Fed. Reg.* 3078 (Jan. 10, 2017).

[10] *See generally* 40 CFR § 51.308(f).

[11] 40 CFR § 51.308(f)(2)(i).

[12] 40 CFR § 51.308(f)(2)(ii).

[13] 40 CFR § 51.308(f)(2)(iii).

[14] 40 CFR § 51.308(f)(2)(iv)(E).

> Determine the effectiveness of the long-term strategy for achieving the presumptive goal for the prior SIP period. If the long-term strategy or prior presumptive goal was insufficient to attain natural conditions by 2064, the state/tribe must look at additional or new control measures that may be adopted considering compliance cost, compliance time, compliance energy and non-air quality environmental impacts, and the affected source remaining useful life.[15]

In January 2017, EPA significantly revised the Regional Haze rule, including the provisions that govern implementation of the program during the second planning period and subsequent planning periods.[16] In August 2019, EPA issued guidance for consideration by States in developing Regional Haze SIPs for the second implementation period.[17] In September 2019, EPA released modeling results and a Technical Support Document demonstrating that many Class I areas are already on track to attain natural conditions by 2064, i.e., that those Class I areas are at or below the "glidepath" to natural conditions.[18] That modeling further demonstrates that the majority of Class I areas are below the glidepath when it is adjusted to reflect the impacts of international anthropogenic emissions as provided for in EPA's rules.

ADEQ has recently begun a stakeholder process for development of the Regional Haze SIP for the second implementation period.[19] Neither the CAA nor any Federal or State regulation expressly requires the evaluation of emission reduction measures for individual facilities.[20] However, ADEQ has indicated that it will perform such facility-specific analyses and will consider analyses prepared by the owners and operators of those facilities.[21]

1.3 Facility Background

SGS comprises four coal-fired electric generating units and ancillary equipment such as coal and ash handling. RTP's analysis as documented herein pertains only to the following two coal-fired electric generating units:

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[15] *See* 2011 Arizona RH SIP, *supra* note 6, at 211.
[16] 82 *Fed. Reg.* 3078 (Jan. 10, 2017).
[17] U.S. EPA, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (EPA-457/B-19-003) (Aug. 2019) https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period ("2nd Period Regional Haze Guidance").
[18] U.S. EPA, *Technical Support Document for EPA's Updated 2028 Regional Haze Modeling* (Sept. 2019) www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf.
[19] *See generally*, ADEQ, 2021 Regional Haze SIP Planning, https://azdeq.gov/node/5377.
[20] *See* 82 *Fed. Reg.* 3078, 3088 (Jan. 10, 2017) ("Neither the 1999 RHR nor the revised regulations in this rulemaking require states to conduct four-factor analyses on a source-specific basis…. Thus, the EPA has consistently interpreted the CAA to provide states with the flexibility to conduct four-factor analyses for specific sources, groups of sources or even entire source categories, depending on state policy preferences and the specific circumstances of each state.")
[21] *See, e.g.*, e-mail message from William Barr, ADEQ, to Patrick Fahey, TEP, Aug. 3, 2019.

Unit 1 at SGS includes a tangentially-fired, subcritical steam generating unit burning primarily subbituminous coal from the El Segundo mine in New Mexico. The unit began commercial operation in 1985 and has a nameplate capacity of 424.8 MWe.

Unit 2 at SGS includes a tangentially-fired, subcritical steam generating unit burning primarily subbituminous coal from the El Segundo mine in New Mexico. The unit began commercial operation in 1990 and has a nameplate capacity of 424.8 MWe.

Unit 1 and Unit 2 are each equipped with fabric filter baghouses for control of particulate matter ("PM") emissions; low-NO_X burners and overfire air systems ("OFA") for control of nitrogen oxides ("NO_X") emissions; and spray dry absorber ("SDA") systems for control of sulfur dioxide (SO_2) emissions. Representative emission rates with this configuration are discussed in Section 3.1 herein.

1.4 Analysis Process

The federal Regional Haze rule does not prescribe a methodology which ADEQ must follow in determining the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress; the primary requirements are that the evaluation include consideration of the four factors listed in the statute (*i.e.*, costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source), that the evaluation is supported with adequate documentation, and that the evaluation is reasonable.[22] The analysis presented in this report generally follows the steps outlined in EPA guidance.[23]

The first step in the analysis for a particular source is to identify the technically feasible control measures for those pollutants that contribute to visibility impairment.[24] EPA guidance indicates that for reasonable progress, a State need only "reasonably pick and justify the measures that it will consider."[25] One potentially informative definition can be found in long-standing EPA guidance in the context of Best Available Control Technology ("BACT") determinations under the Prevention of Significant Deterioration ("PSD") program, which explains that, for purposes of that program, a technically feasible control measure is one that has been demonstrated to function efficiently on a source or unit that is identical or similar to the source or unit under review.[26]

The second step in the analysis involves development of emissions-related information for the source under review.[27] This includes both a baseline scenario and, for each control measure

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[22] *See* 2nd Period Regional Haze Guidance, *supra* note 17, at II.B.3.
[23] *See Id.* at 28-45.
[24] *See Id.* at 28-9.
[25] *Id*. at 29.
[26] *See* U.S. EPA, *Prevention of Significant Deterioration Workshop Manual* (EPA-450/2-80-081) (Oct. 1980) at I-B-6 through I-B-7, https://nepis.epa.gov/Exe/ZyPDF.cgi/2000Z81A.PDF?Dockey=2000Z81A.pdf.
[27] *See* 2nd Period Regional Haze Guidance, *supra* note 17, at 29-30.

under consideration, characterization of the emissions reductions and emissions limitations that may be achievable at the source.[28]

The third step in the analysis involves characterization of the cost of compliance for each control measure (*i.e.*, each set of emissions limitations) under consideration.[29] This is the first of the four statutory factors. The analytical approach to cost estimation described in Chapter 2 of Section 1 of EPA's Air Pollution Control Cost Manual, including the use of the so-called overnight method for accounting for capital investments, while nonbinding,[30] is generally followed in this evaluation. For certain types of add-on air pollution control equipment, the Control Cost Manual includes recommended methodologies and factors for estimating capital and operating costs.[31,32] In order to ensure the cost information is meaningful for purposes of evaluating whether any of the control measures under consideration are necessary to make reasonable progress, both absolute costs (*e.g.*, capital costs and total annualized cost) and relative costs (*e.g.*, incremental cost per incremental ton of emission reduction and incremental cost per incremental inverse megameter, or per deciview, of visibility improvement) are presented.[33]

The fourth step in the analysis involves, for each control measure remaining under consideration, characterization of the time necessary for compliance.[34] This is the second of the four statutory factors. EPA has recommended that States consider this factor in making a determination as to when compliance can be achieved, not whether it is necessary to make reasonable progress.[35]

The fifth step in the analysis involves, for each control measure remaining under consideration, characterization of the energy and non-air quality environmental impacts of compliance and the

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[28] *Id.*

[29] *See Id.* at 31.

[30] *See* 79 *Fed. Reg.* 52420, 52466 (Sept. 3, 2014) (noting that "nothing in the [Regional Haze Rule] requires use of the [Control Cost Manual] for calculating the cost of compliance for [reasonable progress] sources").

[31] Mussatti, David, et. al, U.S. EPA, *EPA Air Pollution Control Cost Manual, Sixth Edition* (EPA/452/B-02-001) (Jan. 2002), https://www3.epa.gov/ttn/ecas/docs/cs1ch2.pdf ("Control Cost Manual"). The sixth edition is the most up-to-date, complete edition of this guidance document. U.S. EPA also is developing and making available on its internet web site individual chapters of the upcoming 7th edition at www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[32] The calculation methodologies presented in the Control Cost Manual consistently use 7.0 percent as the real or "social" interest rate, as prescribed by Circular No. A-94, "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs." *See* Control Cost Manual, *supra* note 30 at 2-13, 4-22. The same 7.0 percent interest rate has been consistently used for control technology determinations under the Regional Haze program. *See generally*, ADEQ, *Arizona Best Available Retrofit Technology (BART) Analysis and Determination: Technical Support Document* (May 2013) http://static.azdeq.gov/aqd/haze/2013_308_revison.pdf ("ADEQ BART Technical Support Document"); *See also*, U.S. EPA Region IX, *Arizona Regional Haze Technical Support Document* (Jul. 2012), https://www3.epa.gov/region9/air/actions/pdf/az/arizona-rh-tsd-final.pdf ("AZ RH Technical Support Document"). Using a lower interest rate as the basis for a decision to require additional control measures in the second planning period would be arbitrary, capricious, and inappropriate. Nonetheless, and solely for the purposes of being consistent with the methodology suggested by EPA's cost spreadsheets discussed in Section 4.4 of this report and presented in Appendix B to this report, RTP and TEP have conservatively used a nominal interest rate of 5.25 percent for all cost analyses presented herein. This should not be construed as an admission that use of an interest rate lower than 7.0 percent is appropriate or permissible.

[33] *See* 2nd Period Regional Haze Guidance, *supra* note 17, at 29, 31.

[34] *See Id.* at 32.

[35] *See Id.* at 41.

remaining useful life of the source or unit under review.[36] These are the remaining two of the four statutory factors. In the evaluation of whether a particular control measure is necessary to make reasonable progress, these statutory factors may generally be considered as part of a State's characterization of the costs of compliance.[37]

The sixth step in the analysis involves, for each control measure under consideration, characterization of the visibility improvement (*e.g.*, in units of inverse megameters or delta deciviews) that would result from installation and operation of such control measure.[38] Although visibility improvement is not one of the four reasonable progress factors, EPA guidance states expressly that such benefits can be considered as part of a four factor analysis "to inform the determination of whether it is reasonable to require a certain measure."[39] For purposes of determining whether a particular control measure is necessary to make reasonable progress, these potential visibility improvements are considered in relation to the reasonable progress goals.[40]

[36] *See Id.* at 33.
[37] *See Id.* at 41-2.
[38] *See Id*. at 16, 35.
[39] *See* 2nd Period Regional Haze Guidance, *supra* note 17, at 34.
[40] *See* 40 CFR § 51.308(f)(2)(iii).

2. Analysis Step 1: Identification of Technically Feasible Control Measures

As discussed in Section 1.4 above, the first step in the reasonable progress analysis for a particular source involves identification of technically feasible control measures for those pollutants that contribute to visibility impairment.

The pollutants emitted by Units 1 and 2 at SGS that have the potential to impair visibility are PM, SO_2, NO_X, volatile organic compounds ("VOC") and ammonia (NH_3).[41] Potential control measures for these pollutants, and the technical feasibility of those measures, are discussed in the following subsections.

2.1 Emissions of PM

2.1.1 Fabric Filter Baghouses

Units 1 and 2 at SGS are already equipped with fabric filter baghouses. As has been recognized by EPA, this is the most effective add-on control technology available for filterable PM emissions.[42]

The baghouses installed at Units 1 and 2 are highly efficient. The projected emissions of filterable PM and total PM10 from these units in the 2028 baseline scenario, as presented in Section 3.1 herein, are less than 0.007 pounds per million British thermal unit ("lb/MMBtu") and less than 0.009 lb/MMBtu, respectively. These rates compare very favorably with the lowest emission rates generally viewed as achievable with fabric filter baghouses.[43]

2.1.2 Dry Electrostatic Precipitators

As noted in Section 2.1.1 above, Units 1 and 2 at SGS are already equipped with fabric filter baghouses, which are the most effective add-on control technology available for filterable PM emissions. Because dry electrostatic precipitators ("ESPs") are not superior to fabric filter

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[41] *See, e.g.,* 2nd Period Regional Haze Guidance, *supra* note 17, at 11.

[42] *See, e.g.,* AZ RH Technical Support Document, *supra* note 32, at 27-28, finding that fabric filter baghouse is "the most stringent control technology available" for control of filterable PM emissions from a coal-fired electric generating unit. Where the most effective controls have already been installed, EPA rules and policy generally support the use of a streamlined reasonable progress analysis. For instance, EPA's Guidelines for the best available retrofit technology ("BART") requirement of the regional haze program state that a source need not undergo additional emission control technology review to satisfy BART if the source installed controls to satisfy certain other CAA standards and "major new technologies" had not been developed in the meantime. 70 *Fed. Reg.* 39104, 39163-64 (Jul. 6, 2005). This same concept is reflected in the 2nd Period Regional Haze Guidance, *supra* note 17, at 22-25.

[43] *See* 76 *Fed. Reg.* 58570 (Sept. 21, 2011), proposing to approve North Dakota's Regional Haze SIP with respect to particulate matter emissions from several coal-fired electric generating units, including the use of 0.015 lb/MMBtu to calculate the projected estimate of filterable PM emissions following installation of a new fabric filter baghouse.

baghouses in terms of achievable levels of control, no improvement in control of filterable PM emissions from Units 1 and 2 at SGS through retrofit of ESPs is feasible.

2.1.3 Operation without Selective Catalytic Reduction

Operation with selective catalytic reduction ("SCR") significantly increases formation of PM in the exhaust from coal-fired electric generating units.[44]

As discussed in Section 2.2.2 below, Units 1 and 2 at SGS are not equipped with SCR. This configuration has the effect of minimizing formation of PM in the exhaust from these units. Conversely, in the absence of other changes to mitigate this effect, retrofit of SCR would significantly increase PM emissions from Units 1 and 2.

2.1.4 Wet Electrostatic Precipitators

Wet ESPs are typically used downstream of wet flue gas desulfurization systems to control sulfuric acid mist emissions on utility boilers firing high-sulfur eastern coals. Because the flue gas temperature is below the sulfuric acid and water saturation temperatures, droplets and other condensable materials in the flue gas, including sulfuric acid, are charged and collected on the ESP plates. In theory, additional control of PM emissions could be achieved at Units 1 and 2 through retrofit of wet ESPs.

The projected total PM10 emissions in the 2028 baseline scenario from Units 1 and 2, as presented in Section 3.1 herein, are less than 0.009 lb/MMBtu. Even with retrofit of SCR systems, as discussed in Sections 2.1.3 and 2.2.2 herein, projected total PM10 emissions from Units 1 and 2 are less than 0.011 lb/MMBtu. These emission rates are consistent with the most stringent limit achieved in practice, or demonstrated to be achievable, at a coal-fired electric generating unit.[45] No quantifiable improvement in control of total PM emissions through retrofit of wet ESPs is feasible.

2.2 Emissions of NO_X

2.2.1 Low-NO_X Burners, Overfire Air, and Other Combustion Controls

Units 1 and 2 at SGS are already equipped with low-NO_X burners and overfire air systems. These combustion controls are effective. Projected NO_X emissions in the 2028 baseline scenario, as presented in Section 3.1 herein, are approximately 0.17 lb/MMBtu. No improvement in control of NO_X emissions through replacement or upgrade of the existing combustion controls is technically feasible.

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[44] *See, e.g.,* ADEQ *Technical Review and Evaluation of Application for Air Quality Significant Revision No. 63088 to Operating Permit No. 64169*, at 4 (Dec. 2016) http://static.azdeq.gov/permits/63088/63088_tsd_proposed_permit.pdf ("ADEQ's Review of CGS Air Permit").

[45] *See* Wisconsin Department of Natural Resources, *Construction Permit No. 12-SDD-047* issued to Wisconsin Electric Power Company at 6 (Jan. 2013), dnr.wi.gov/cias/am/amexternal/AM_DownloadObject.aspx?id=321028 ("WI Electric Power Construction Permit") (imposing a PM10/PM2.5 emission limit of 0.012 lb/MMBtu as lowest achievable emission rate).

2.2.2 Selective Catalytic Reduction Systems

The combination of combustion controls and SCR can achieve substantial overall reductions in NO_X emissions.[46] Units 1 and 2 at SGS are not equipped with SCR systems. Improvement in control of NO_X emissions from Units 1 and 2 through retrofit of SCR systems is technically feasible.

2.2.3 Selective Non-Catalytic Reduction Systems

Units 1 and 2 at SGS are not equipped with selective non-catalytic reduction ("SNCR") systems. Improvement in control of NO_X emissions from Units 1 and 2 through retrofit of SNCR systems is technically feasible.

2.3 Emissions of NH_3

2.3.1 Operation without SCR and SNCR Systems

Operation with SCR or SNCR systems significantly increases emissions of ammonia from coal-fired electric generating units due to ammonia slip. As discussed in Sections 2.2.2 and 2.2.3 above, Units 1 and 2 at SGS are not equipped with these NO_X control technologies. This configuration has the effect of minimizing ammonia emissions from these units. Conversely, retrofit of SCR or SNCR systems would significantly increase ammonia emissions from Units 1 and 2.

2.4 Emissions of SO_2

2.4.1 Spray Dry Absorber Systems

Units 1 and 2 at SGS are already equipped with SDA systems. The units are fueled primarily with subbituminous coal from the El Segundo mine in New Mexico. The typical sulfur content of this coal is equivalent to an uncontrolled SO_2 emission rate of approximately 2.3 to 2.4 lb/MMBtu. These systems are highly efficient. Projected SO_2 emissions in the 2028 baseline scenario, as discussed in Section 3.1 herein, are approximately 0.24 lb/MMBtu from Unit 1 and approximately 0.22 lb/MMBtu from Unit 2. This represents approximately 90 percent SO_2 removal efficiency at each unit. Improvement in control of SO_2 emissions through upgrade of the existing SDA systems is technically feasible.

2.4.2 Dry Sorbent Injection Systems

Improvement in control of SO_2 emissions through installation of dry sorbent injection ("DSI") systems upstream of the existing SDA systems and fabric filter baghouses is technically feasible.

[46] *See, e.g.*, AZ RH Technical Support Document, *supra* note 32, at 52 (finding that SCR with low-NO_X burners and overfire air is "the most stringent option" for control of NO_X emissions from a coal-fired electric generating unit).

2.4.3 Circulating Dry Scrubber Systems

Improvement in control of SO_2 emissions through replacement of the existing SDA systems with circulating dry scrubber ("CDS") systems is technically feasible.

2.4.4 Wet Flue Gas Desulfurization

Improvement in control of SO_2 emissions through replacement of the existing SDA systems with wet flue gas desulfurization ("wet FGD") systems is technically feasible.

2.5 Emissions of VOC

As discussed in Section 3.1 herein, projected total VOC emissions from Units 1 and 2 in the 2028 baseline scenario are 0.003 lb/MMBtu. These emission rates are consistent with the most stringent limit achieved in practice, or demonstrated to be achievable, at a coal-fired electric generating unit.[47] No technically feasible control measures for further reductions in VOC emissions from coal-fired electric generating units such as Units 1 and 2 have been identified. In addition, EPA has indicated that it is reasonable for a state to exclude VOC control measures from consideration in developing its long-term strategy "based on the expectation that anthropogenic VOC emissions make only a small contribution to visibility impairment."[48]

2.6 Summary of Control Measure Scenarios

Taking into account all of the identified, technically feasible control measures listed in Sections 2.1 through 2.5 above, the table below presents a matrix of the scenarios for Units 1 and 2 for which further analysis was performed. For reference purposes, control scenario #1 represents the baseline as described in Section 1.3 above: Burning primarily subbituminous coal from the El Segundo mine in New Mexico and equipped with low-NO_X burners, overfire air systems, nominally 90 percent efficient SDA systems, and fabric filter baghouses.

	LNB + OFA	LNB + OFA SNCR	LNB + OFA SCR
Current SDA, baghouse	1	2	3
Upgraded SDA, baghouse	4	5	6
DSI+current SDA, baghouse	7	8	9
CDS, baghouse	10	11	12
Baghouse, wet FGD	13	14	15

[47] *See* WI Electric Power Construction Permit, *supra* note 45, at 18 (imposing a VOC emission limit of 0.0035 lb/MMBtu as lowest achievable emission rate).
[48] *See* 2nd Period Regional Haze Guidance, *supra* note 17, at 12.

3. Analysis Step 2: Emissions Information

As discussed in Section 1.4 above, the second step in the reasonable progress analysis for a particular source involves development of emissions-related information for the baseline scenario and for each control measure under consideration.[49] Emissions information for Scenarios #1 through #15, as listed in Section 2.6 above, is presented in Sections 3.1 through 3.15, respectively.

It must be emphasized that the projected emissions for each scenario are nominal projections and are not the emission limits that are achievable with the specified control measures. As with the emissions for the baseline scenario, which are based on long-term observed averages during calendar years 2016 through 2018 as discussed below, the projected emissions for each control scenario are reflective of the most likely projection of actual, long-term average emissions. If any of the control measures under consideration were implemented, the actual emissions would likely be either higher or lower than these projections. If emission limits were imposed based on the use of such control measures, those limits would have to be set at levels that allow for continuous compliance, taking into account averaging period and operational variability.

3.1 Baseline Scenario (Scenario #1) (2028 Projection)

Projected emissions for Units 1 and 2 at SGS for the 2028 baseline scenario, both as emission factors in units of lb per MMBtu of heat input and annual emissions in units of tons per year, are presented in the table below. Consistent with the direction provided by ADEQ, for each unit and each pollutant, the projected emission factor is calculated as the arithmetic mean of the annual average emission factors for calendar years 2016 through 2018. Projected emissions are calculated using the projected emission factor and the projected annual heat input, where the latter value is calculated as the arithmetic mean of the annual heat input rates for that unit for calendar years 2016 through 2018.[50]

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	1,827	60	85	2,504	36	-
	lb/MMBtu	0.17	0.006	0.008	0.24	0.003	0.00
UNIT 2	tpy	2,216	85	110	2,785	44	-
	lb/MMBtu	0.17	0.007	0.009	0.22	0.003	0.00

[49] See *supra* note 27.

[50] *See* e-mail message from William Barr, ADEQ, to Catherine Schladweiler, TEP, Aug. 28, 2019. The NO_X and SO_2 emission factors and annual emission rates presented in this report are higher than those listed in Mr. Barr's email because corrections to the facility's emissions inventories were later made by TEP. *See* e-mail message from Zig Fang, TEP, to Adam Ross, ADEQ, Jan. 23, 2020. The emission rates that Ramboll US Corporation used in performing photochemical grid modeling for SGS, as presented in Appendix A and as discussed in Sections 4.4 and 4.5 herein, are the emission rates listed in Mr. Barr's email.

3.2 Control Scenario #2

This scenario is the same as the baseline scenario (*i.e.*, current SDA and baghouse), but with retrofit of SNCR systems. For purposes of this analysis, this control measure is projected to decrease NO_X emissions from each unit to 0.15 lb/MMBtu.[51] In addition, the SNCR systems are projected to cause NH_3 emissions of 0.0022 lb/MMBtu (equivalent to ammonia slip of 5 parts per million by volume, ppmv, in the exhaust).[52]

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	1,568	60	85	2,504	36	23
	lb/MMBtu	0.15	0.006	0.008	0.240	0.003	0.002
UNIT 2	tpy	1,930	85	110	2,785	44	28
	lb/MMBtu	0.15	0.007	0.009	0.216	0.003	0.002

3.3 Control Scenario #3

This scenario is the same as the baseline scenario (*i.e.*, current SDA and baghouse), but with retrofit of SCR systems. For purposes of this analysis, this control measure is projected to decrease NO_X emissions from each unit to 0.060 lb/MMBtu.[53] In addition, the SCR systems are projected to increase total PM emissions by an amount equal to 1.0 percent of the SO_2 emissions (*i.e.*, by approximately 0.002 lb/MMBtu)[54] and to cause NH_3 emissions of 0.0009 lb/MMBtu (equivalent to ammonia slip of 2 parts per million by volume, ppmv, in the exhaust).[55]

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	627	60	110	2,504	36	9
	lb/MMBtu	0.06	0.006	0.011	0.240	0.003	0.001
UNIT 2	tpy	772	85	138	2,785	44	11
	lb/MMBtu	0.06	0.007	0.011	0.216	0.003	0.001

[51] *See* Section 4.4 of this report.

[52] This value is conservative. *See*, U.S. EPA, *Alternative Control Technologies Document: NO_X Emissions from Utility Boilers* EPA-453/R-94-023, (Mar. 1994) https://www3.epa.gov/airquality/ctg_act/199403_nox_epa453_r-94-023_utility_boilers.pdf at 7-24 (describing typical ammonia slip levels of 10 to 110 ppmv from utility boilers on which urea-based SNCR is used).

[53] *See generally* 81 *Fed. Reg.* 21735 (Apr. 13, 2016), finding the achievable NO_X limit for a new SCR system at Unit 1 at the Coronado Generating Station in Arizona is 0.065 lb/MMBtu.

[54] This estimate is believed to be conservative. *See*, ADEQ's Review of CGS Air Permit, *supra* note 44 at 4 (explaining the decision to approve an increase in PM10 emissions of 86.8 tons per year, equivalent to 0.0046 lb/MMBtu, due to retrofit of SCR).

[55] *See*, ADEQ BART Technical Support Document, *supra* note 32, at Section XIV.D ("The various SCR vendors typically guarantee ammonia slip of about 2 ppm for systems designed for very high NO_X performance levels.").

3.4 Control Scenario #4

This scenario is the same as the baseline scenario (*i.e.*, current SDA and baghouse), but with upgrade of the existing SDA systems. For purposes of this analysis, this control measure is projected to decrease SO_2 emissions from each unit to 0.15 lb/MMBtu.

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	1,827	60	85	1,568	36	0
	lb/MMBtu	0.17	0.006	0.008	0.150	0.003	0.000
UNIT 2	tpy	2,216	85	110	1,930	44	0
	lb/MMBtu	0.17	0.007	0.009	0.150	0.003	0.000

3.5 Control Scenario #5

This scenario is the same as control scenario #4 (*i.e.*, upgraded SDA and baghouse), but with retrofit of SNCR systems. For purposes of this analysis, this control measure is projected to decrease NO_X emissions from each unit to 0.15 lb/MMBtu.[56] In addition, the SNCR systems are projected to cause NH_3 emissions of 0.0022 lb/MMBtu (equivalent to ammonia slip of 5 parts per million by volume, ppmv, in the exhaust).[57]

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	1,568	60	85	1,568	36	23
	lb/MMBtu	0.15	0.006	0.008	0.150	0.003	0.002
UNIT 2	tpy	1,930	85	110	1,930	44	28
	lb/MMBtu	0.15	0.007	0.009	0.150	0.003	0.002

3.6 Control Scenario #6

This scenario is the same as control scenario #4 (*i.e.*, upgraded SDA and baghouse), but with retrofit of SCR systems. For purposes of this analysis, this control measure is projected to decrease NO_X emissions from each unit to 0.060 lb/MMBtu.[58] In addition, the SCR systems are projected to increase total PM emissions by an amount equal to 1.0 percent of the SO_2 emissions (*i.e.*, by approximately 0.001 lb/MMBtu) and to cause NH_3 emissions of 0.0009 lb/MMBtu (equivalent to ammonia slip of 2 parts per million by volume, ppmv, in the exhaust).

[56] *See supra* note 51.
[57] *See supra* note 52.
[58] *See supra* note 53.

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	627	60	101	1,568	36	9
	lb/MMBtu	0.06	0.006	0.010	0.150	0.003	0.001
UNIT 2	tpy	772	85	130	1,930	44	11
	lb/MMBtu	0.06	0.007	0.010	0.150	0.003	0.001

3.7 Control Scenario #7

This scenario is the same as the baseline scenario (*i.e.*, current SDA and baghouse), but with retrofit of DSI systems in conjunction with the existing controls. For purposes of this analysis, this control measure is projected to decrease SO_2 emissions from each unit to 0.18 lb/MMBtu.

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	1,827	60	85	1,881	36	0
	lb/MMBtu	0.17	0.006	0.008	0.180	0.003	0.000
UNIT 2	tpy	2,216	85	110	2,316	44	0
	lb/MMBtu	0.17	0.007	0.009	0.180	0.003	0.000

3.8 Control Scenario #8

This scenario is the same as control scenario #7 (*i.e.*, DSI, SDA, and baghouse), but with retrofit of SNCR systems. For purposes of this analysis, this control measure is projected to decrease NO_X emissions from each unit to 0.15 lb/MMBtu.[59] In addition, the SNCR systems are projected to cause NH_3 emissions of 0.0022 lb/MMBtu (equivalent to ammonia slip of 5 parts per million by volume, ppmv, in the exhaust).[60]

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	1,568	60	85	1,881	36	23
	lb/MMBtu	0.15	0.006	0.008	0.180	0.003	0.002
UNIT 2	tpy	1,930	85	110	2,316	44	28
	lb/MMBtu	0.15	0.007	0.009	0.180	0.003	0.002

3.9 Control Scenario #9

This scenario is the same as control scenario #7 (*i.e.*, DSI, SDA, and baghouse), but with retrofit of SCR systems. For purposes of this analysis, this control measure is projected to decrease NO_X emissions from each unit to 0.060 lb/MMBtu. In addition, the SCR systems are projected to

[59] *See supra* note 51.
[60] *See supra* note 52.

increase total PM emissions by an amount equal to 1.0 percent of the SO_2 emissions (*i.e.*, by approximately 0.001 lb/MMBtu) and to cause NH_3 emissions of 0.0009 lb/MMBtu (equivalent to ammonia slip of 2 parts per million by volume, ppmv, in the exhaust).

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	627	60	104	1,881	36	9
	lb/MMBtu	0.06	0.006	0.010	0.180	0.003	0.001
UNIT 2	tpy	772	85	134	2,316	44	11
	lb/MMBtu	0.06	0.007	0.010	0.180	0.003	0.001

3.10 Control Scenario #10

This scenario is the same as the baseline scenario (*i.e.*, current SDA and baghouse), but with retrofit of CDS systems to replace the existing SDA systems. For purposes of this analysis, this control measure is projected to increase SO_2 control efficiency to 97 percent, thereby decreasing SO_2 emissions from each unit to 0.070 lb/MMBtu.

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	1,792	60	85	730	36	0
	lb/MMBtu	0.17	0.006	0.008	0.070	0.003	0.000
UNIT 2	tpy	2,192	85	110	899	44	0
	lb/MMBtu	0.17	0.007	0.009	0.070	0.003	0.000

3.11 Control Scenario #11

This scenario is the same as control scenario #10 (*i.e.*, CDS and baghouse), but with retrofit of SNCR systems. For purposes of this analysis, this control measure is projected to decrease NO_X emissions from each unit to 0.15 lb/MMBtu.[61] In addition, the SNCR systems are projected to cause NH_3 emissions of 0.0022 lb/MMBtu (equivalent to ammonia slip of 5 parts per million by volume, ppmv, in the exhaust).[62]

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	1,568	60	85	730	36	23
	lb/MMBtu	0.15	0.006	0.008	0.070	0.003	0.002
UNIT 2	tpy	1,930	85	110	899	44	28
	lb/MMBtu	0.15	0.007	0.009	0.070	0.003	0.002

[61] *See supra* note 51.
[62] *See supra* note 52.

3.12 Control Scenario #12

This scenario is the same as control scenario #10 (*i.e.*, CDS and baghouse), but with retrofit of SCR systems. For purposes of this analysis, this control measure is projected to decrease NO_X emissions from each unit to 0.060 lb/MMBtu. In addition, the SCR systems are projected to increase total PM emissions by an amount equal to 1.0 percent of the SO_2 emissions (*i.e.*, by approximately 0.001 lb/MMBtu) and to cause NH_3 emissions of 0.0009 lb/MMBtu (equivalent to ammonia slip of 2 parts per million by volume, ppmv, in the exhaust).

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	627	60	92	730	36	9
	lb/MMBtu	0.06	0.006	0.009	0.070	0.003	0.001
UNIT 2	tpy	772	85	119	899	44	11
	lb/MMBtu	0.06	0.007	0.009	0.070	0.003	0.001

3.13 Control Scenario #13

This scenario is the same as the baseline scenario (*i.e.*, current SDA and baghouse), but with retrofit of wet FGD systems to replace the existing SDA systems. For purposes of this analysis, this control measure is projected to decrease SO_2 emissions from each unit to 0.030 lb/MMBtu, which is the lowest SO_2 emission rate achievable with any control technology.[63]

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	1,792	60	85	314	36	0
	lb/MMBtu	0.17	0.006	0.008	0.030	0.003	0.000
UNIT 2	tpy	2,192	85	110	386	44	0
	lb/MMBtu	0.17	0.007	0.009	0.030	0.003	0.000

3.14 Control Scenario #14

This scenario is the same as control scenario #13 (*i.e.*, baghouse and wet FGD), but with retrofit of SNCR systems. For purposes of this analysis, this control measure is projected to decrease NO_X emissions from each unit to 0.15 lb/MMBtu.[64] In addition, the SNCR systems are projected to cause NH_3 emissions of 0.0022 lb/MMBtu (equivalent to ammonia slip of 5 parts per million by volume, ppmv, in the exhaust).[65]

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[63] WI Electric Power Construction Permit, *supra* note 45, at 18 (imposing an SO_2 emission limit of 0.030 lb/MMBtu representing lowest achievable emission rate).
[64] *See supra* note 51.
[65] *See supra* note 52.

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	1,568	60	85	314	36	23
	lb/MMBtu	0.15	0.006	0.008	0.030	0.003	0.002
UNIT 2	tpy	1,930	85	110	386	44	28
	lb/MMBtu	0.15	0.007	0.009	0.030	0.003	0.002

3.15 Control Scenario #15

This scenario is the same as control scenario #13 (*i.e.*, baghouse and wet FGD), but with retrofit of SCR systems. For purposes of this analysis, this control measure is projected to decrease NO_X emissions from each unit to 0.060 lb/MMBtu. In addition, the SCR systems are projected to increase total PM emissions by an amount equal to 1.0 percent of the uncontrolled SO_2 emissions (*i.e.*, by approximately 0.002 lb/MMBtu) and to cause NH_3 emissions of 0.0009 lb/MMBtu (equivalent to ammonia slip of 2 parts per million by volume, ppmv, in the exhaust).

	Units	NO_X	PM (filterable)	PM10 (total)	SO_2	VOC	NH_3
UNIT 1	tpy	627	60	109	314	36	9
	lb/MMBtu	0.06	0.006	0.010	0.030	0.003	0.001
UNIT 2	tpy	772	85	137	386	44	11
	lb/MMBtu	0.06	0.007	0.011	0.030	0.003	0.001

4. Analysis Step 3: Cost of Compliance

As discussed in Section 1.4 above, the third step in the reasonable progress analysis for a particular source involves characterization of the cost of compliance for each control measure under consideration.

As described in Section 2.6 above, three of the fifteen identified control measure scenarios (*i.e.*, Scenarios #7 through #9) involve retrofit of DSI systems in conjunction with the SDA and baghouse. In addition, nine of the fifteen identified control measure scenarios (*i.e.*, Scenarios #3, #6, and #9 through #15) involve either replacement of the existing SDA systems with different SO_2 controls (*i.e.*, CDS or wet FGD systems) or installation of SCR systems, or both. Summary cost information for these nine scenarios is presented in Sections 4.1 through 4.3 below.

For the remaining three control measure scenarios, detailed cost information is presented in Sections 4.4 through 4.6 herein.

For purposes of this analysis, the baseline scenario is assumed not to involve any costs of compliance under the Regional Haze rule.

4.1 Installation of DSI Systems for SO_2 Emission Control is an Economically Inferior Option

Two of the identified, technically feasible options for further improving control of SO_2 emissions from Units 1 and 2 at SGS involve upgrading the existing SDA systems, as described in Section 2.4.1, and retrofitting DSI systems to operate in conjunction with the existing controls, as described in Section 2.4.2. As shown in Appendix B, the DSI system retrofit option is less effective and more costly than the SDA system upgrade option.[66] Because it is an inferior control option, and detailed cost effectiveness analyses are warranted only for those dominant control options that lie on the least-cost curve,[67] the DSI system retrofit option will be given no further consideration.

4.2 Replacement of SDA Systems for SO_2 Emission Control is Economically Unreasonable

As noted in Sections 2.4.3 and 2.4.4, respectively, two of the identified, technically feasible options for further improving control of SO_2 emissions from Units 1 and 2 at SGS involve replacement of the existing SDA systems with CDS systems or wet FGD systems. As explained below, the costs of these control measures far exceed any accepted measure of reasonableness.

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[66] *Compare* Section 4.5, indicating the projected SO_2 emission rate with SDA upgrades is 0.15 lb/MMBtu at a total annual cost of approximately $0.5 to $0.6 million per unit, and Appendix B, indicating the projected SO_2 emission rate with DSI is 0.18 lb/MMBtu at a total annual cost of approximately $8.6 to $8.8 million per unit.

[67] *See*, U.S. EPA, New Source Review Workshop Manual (Draft), (Oct. 1990) at I-B-42 – I-B-43, https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf.

This is consistent with EPA's expectations when developing the guidelines for Best Available Retrofit Technology ("BART") determinations under the Regional Haze rule, which require States only to consider requiring upgrades to existing SO_2 control systems having at least 50 percent SO_2 removal efficiency. In contrast, where existing SO_2 control systems have less than 50 percent SO_2 removal efficiency, the guidelines require States to consider requiring replacement of those systems because replacement in those circumstances may be cost effective.[68]

Based on an approximate capital cost of $400/kW,[69] the capital cost of replacing the existing SDA system on either Unit 1 or Unit 2 with a CDS system would be approximately $170 million per unit. Even assuming no increase in operating and maintenance ("O&M") costs, the annual cost of capital recovery would be in excess of $16 million per unit. The maximum reductions in SO_2 emissions potentially achievable at SGS are approximately 1,800 tpy at Unit 1 (*i.e.*, the difference between 2,504 tpy in Scenario #1 and 730 tpy in Scenario #10) and approximately 1,800 tpy at Unit 2 (*i.e.*, the difference between 2,785 tpy in Scenario #1 and 899 tpy in Scenario #10). The cost effectiveness of replacing the existing SDA system on either Unit 1 or Unit 2 with a CDS system, even without consideration of any increase in O&M costs, is approximately $7,500 per ton of SO_2 emissions reduction. This cost is not reasonable.[70] Accordingly, no further analysis of CDS systems (*i.e.*, Scenarios #10 through #12) for Units 1 and 2 at SGS is warranted.

Based on an approximate capital cost of $600/kW,[71] the capital cost of replacing the existing SDA system on either Unit 1 or Unit 2 with a wet FGD system would be approximately $250

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[68] *See generally* 70 *Fed. Reg.* 39104 (Jul. 6, 2005); *see also* 77 *Fed. Reg.* 57864, 57892 (Sept. 18, 2012), where EPA explains its decision not to consider requiring replacement of existing SO_2 controls at Units 1 and 2 at the Colstrip Power Plant as part of the Regional Haze Federal Implementation Plan for Montana because those controls achieve greater than 50 percent SO_2 removal efficiency.

[69] *See*, U.S. Energy Information Administration, Form EIA-860 data reported on Schedules 3 and 6F, available at www.eia.gov/electricity/data/eia860/ (last accessed Sept. 18, 2019). Based on U.S. Energy Information Administration data, four coal-fired units of at least 400 MW have been retrofitted with CDS systems since 2014. *Id.* Reported CDS system costs, both total and $/kW, with no escalation, are as follows: Boswell Unit 4 in Minnesota: $290 million and $519 per kW (based on nameplate capacity of 558 MW); Homer City Units 1 and 2 in Pennsylvania: $400 million per unit and $606/kW (based on nameplate capacity of 660 MW per unit); Big Stone Unit 1 in South Dakota: $161 million and $359 per kW (based on nameplate capacity of 450 MW). *Id.*

[70] EPA has routinely approved State decisions to reject SO_2 controls under the Regional Haze rules based on determinations that cost effectiveness values in excess of $7,000 per ton represent unreasonable or unacceptable costs. *See* 78 *Fed. Reg.* 58616,51692 (Aug. 21, 2013), proposing to approve Oklahoma's Regional Haze SIP with respect to SO_2 emissions from Units 3 and 4 at the Northeastern Power Station based on incremental cost effectiveness of $7,362 per ton; *See also* 79 *Fed. Reg.* 12944 (Mar. 7, 2014), finalizing this approval.

[71] It is likely that these values underestimate the actual costs of constructing wet FGD systems at Springerville Generating Station. The wet FGD capital cost estimates developed by U.S. EPA and relied upon in determining that it would not be reasonable to require additional SO_2 controls at Springerville in the first planning period were slightly more than $200 million per unit. *See* 77 *Fed. Reg.* 75704, 75729 (Dec. 21, 2012), indicating U.S. EPA's cost effectiveness calculation is documented in "Springerville FGD costs.xls." *See also* "Springerville FGD costs.xls," available in U.S. EPA's rulemaking docket at https://www.regulations.gov/contentStreamer?documentId=EPA-R09-OAR-2012-0904-

million per unit. Even assuming no increase in O&M costs, the annual cost of capital recovery would be in excess of $24 million per unit. The maximum reductions in SO_2 emissions potentially achievable at SGS are approximately 2,200 tpy at Unit 1 (*i.e.*, the difference between 2,504 tpy in Scenario #1 and 314 tpy in Scenario #13) and 2,400 tpy at Unit 2 (*i.e.*, the difference between 2,686 tpy in Scenario #1 and 386 tpy in Scenario #13). The cost effectiveness, even without consideration of any increase in O&M costs, is approximately $9,000 per ton of SO_2 emissions reduction. This cost is not reasonable.[72] Accordingly, no further analysis of wet FGD systems (*i.e.*, Scenarios #13 through #15) for Units 1 and 2 at SGS is warranted.

4.3 Installation of SCR Systems for NO_X Emission Control is Economically Unreasonable

As noted in Section 2.2.2 above, one of the identified, technically feasible options for further improving control of NO_X emissions from Units 1 and 2 at SGS involves installation of SCR systems. As explained below, the costs of this control measure far exceed any accepted measure of reasonableness.

Calculations of capital costs and total annual costs for retrofit of SCR on Units 1 and 2, conservatively based on EPA's SCR cost spreadsheet,[73] are provided in Appendix C to this report. As shown in the appendix, the estimated capital cost is nearly $180 million per unit and the estimated total annual cost is approximately $16 million per unit.

The maximum reductions in NO_X emissions potentially achievable at SGS are 1,200 tpy at Unit 1 (*i.e.*, the difference between 1,827 tpy in Scenario #1 and 627 tpy in Scenario #3) and approximately 1,400 tpy at Unit 2 (*i.e.*, the difference between 2,216 tpy in Scenario #1 and 772 tpy in Scenario #3). The cost effectiveness is more than $11,000 per ton of NO_X emissions reduction. This cost is not reasonable.[74] Accordingly, no further analysis of SCR systems (*i.e.*, Scenarios #3, #6, #9, #12, and #15) for Units 1 and 2 at SGS is warranted.

0007&attachmentNumber=11&contentType=excel12book (last accessed Sept. 18, 2019). *See also Technical Support Document for the Proposed Phase 3 Action on the Federal Implementation Plan for the Regional Haze Program in the State of Arizona*, U.S. EPA (Jan. 27, 2013) at 19, indicating capital cost estimates were developed using U.S. EPA's IPM Base Case v4.10. *See also*, U.S. EPA, *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model*, at 8-3 (Aug. 2010) https://www.epa.gov/sites/production/files/2015-07/documents/chapter_1_introduction.pdf, indicating all values are based on 2007 dollars. Using the Chemical Engineering Plant Cost Index for escalation of U.S. EPA's capital cost estimate from 2007 dollars to current dollars yields a capital cost of $232 million per unit, before considering any additional costs for a surface impoundment designed to comply with the recently promulgated federal *Standards for the Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments*. *See*, 80 *Fed. Reg.* 21301 (Apr. 17, 2015).

[72] *See supra* note 70.

[73] Available at www.epa.gov/sites/production/files/2019-06/sncrcostmanualspreadsheet_june2019vf.xlsm (last accessed Mar. 4, 2020).

[74] EPA has routinely approved State decisions to reject NO_X controls under the Regional Haze rules based on determinations that cost effectiveness values in excess of $2,000 to $3,000 per ton represent unreasonable or unacceptable costs. *See* 77 *Fed. Reg.* 21896 (Apr. 12, 2012), proposing to approve Nevada's Regional Haze SIP with respect to use of SCR for control of NO_X emissions from Unit 3 at the Reid Gardner Generating Station based on average and incremental cost effectiveness $2,183 per ton and $2,756 per ton, respectively; *See also* 77 *Fed. Reg.* 50936 (Aug. 23, 2012), finalizing this approval.

4.4 Control Scenario #2 (SNCR)

As described in detail in the cost evaluation report included in Appendix B to this report, the total capital cost of SNCR systems designed to achieve a nominal outlet emission rate of 0.15 lb/MMBtu at each of Units 1 and 2 is approximately $15.5 million per unit. The estimated total annualized costs, including capital recovery, are $3.7 million per year at Unit 1 and $3.4 million per year at Unit 2. The cost effectiveness for NO_X emission reductions with SNCR is as follows:

		UNIT 1	UNIT 2
Base Case (LNB + OFA)	NO_X lb/MMBtu	0.175	0.172
	NO_X tpy	1,827	2,216
Control Scenario #2 (LNB + OFA + SNCR)	NO_X lb/MMBtu	0.15	0.15
	NO_X tpy	1,568	1,930
	NO_X reduction tpy	259	286
	Annualized Cost ($/yr)	$3,659,000	$3,414,000
	Cost Effectiveness ($/ton)	$14,100	$11,950

These costs for SNCR, well in excess of $10,000 per ton at each unit, are not reasonable.[75]

It should be noted that this analysis projects only a 13 percent to 14 percent reduction in NO_X emissions at Units 1 and 2 as a result of installing SNCR. Most analyses of SNCR as a control measure under consideration in the context of the Regional Haze program have projected an efficiency of 20 percent or more.[76] This is a result of the low NO_X levels currently achieved at Units 1 and 2 through use of low-NO_X burners and overfire air systems. The NO_X concentration in the exhaust from these units is less than 100 ppmv. Higher NO_X removal efficiencies with SNCR require higher inlet concentration. Computational fluid dynamic modeling and temperature mapping would be required in order to confirm the NO_X emission reduction achievable without creating unacceptable operational issues.

The SNCR cost estimate used herein is based on up-to-date, proprietary industry data from Sargent & Lundy, L.L.C. It is reflective of the actual costs that TEP would be expected to incur if SNCR were required at Units 1 and 2. These costs are higher, in several respects, than the costs that would be estimated using EPA's SNCR cost spreadsheet.[77] Completed spreadsheets are included in Appendix C to this report for comparison purposes. The key areas in which the EPA spreadsheet underestimates cost are as follows:

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[75] *See supra* note 74.

[76] *See* 76 *Fed. Reg.* 58570 (Sept. 21, 2011), proposing to approve North Dakota's Regional Haze SIP with respect to use of SNCR for control of NO_X emissions from Unit 1 at the Stanton Station and from Unit 1 at the Leland Olds Station based on expected reductions of 31 percent and 28 percent, respectively; *See also* 77 *Fed. Reg.* 20894 (Apr. 6, 2012), finalizing this approval.

[77] Available at www.epa.gov/sites/production/files/2019-06/sncrcostmanualspreadsheet_june2019vf.xlsm (last accessed Mar. 4, 2020).

- The total capital investment for retrofit of SNCR at Unit 1 or Unit 2 is $15.5 million.[78] If a "retrofit factor" of one is assumed, the total capital cost estimated using the EPA spreadsheet is $11.6 million. The EPA spreadsheet can be made to produce a more representative value by adjusting the "retrofit factor" to 1.33, but the basis for such an adjustment is unknown as the EPA spreadsheet and underlying documentation are unclear as to the configuration of the boilers that formed the basis for EPA's cost estimates.

- The total estimated cost for installing and operating SNCR at Unit 1 or Unit 2 includes annualized sales taxes, property taxes, insurance, and administration costs totaling approximately $650,000 per year (19% of total costs).[79] Inclusion of all of these costs is consistent with the Control Cost Manual, but all of these costs are inappropriately omitted from the EPA SNCR cost spreadsheet.

- The total estimated cost for installing and operating SNCR at Unit 1 or Unit 2 includes costs for operating and supervisory labor totaling approximately $300,000 per year (9% of total costs).[80] Inclusion of these costs is consistent with the Control Cost Manual, but these costs are inappropriately omitted from the EPA SNCR cost spreadsheet.

Even if the achievable NO_X emissions reductions from installation of SNCR at Units 1 and 2 were considered to be reasonable and cost effective on a dollars per ton basis, this should not be a measure that is determined by ADEQ to be necessary to make reasonable progress in the second planning period because it is not reasonable in light of the negligible visibility benefits that could be achieved. This is illustrated in the results of the photochemical grid modeling performed by Ramboll US Corporation.[81] Modeling of a hypothetical NO_X emission reduction of 2,119 tons per year at SGS yields a visibility improvement of 0.001 deciviews on the most anthropogenically impaired days at Mount Baldy Wilderness Area and lesser improvements at other Class I areas. Assuming the relationship between visibility improvements and NO_X emissions reductions is linear within the range at issue here, and ignoring any adverse effects on visibility due to the ammonia emissions increase that would occur, the improvement at Mount Baldy from installing SNCR would be less than 0.0003 deciviews. The cost effectiveness in terms of visibility improvement is more than $26 billion per deciview. This is at least two orders

[78] *See* Appendix B.
[79] *See* Appendix B.
[80] *See* Appendix B.
[81] *See* Appendix A. As discussed in footnote 50 herein, the base case emission rates that Ramboll US Corporation used in performing photochemical grid modeling for SGS are slightly lower than than the baseline scenario emission rates used in this report because corrections to the facility's emissions inventories were made by TEP after the modeling analysis commenced. This discrepancy does not affect the conclusions regarding negligible visibility benefits because those conclusions are based on the difference in emission rates between the base case and the control measure scenario.

of magnitude beyond what has been considered reasonable for purposes of the Regional Haze program. [82]

Morevoer, the Mount Baldy Wilderness Area is already projected to be below EPA's unadjusted glidepath for 2028 (6.92 deciviews compared to 6.99 deciviews).[83] It is even further below EPA's 2028 default adjusted glidepath, which takes into account the effects of international anthropogenic emissions (6.92 deciviews compared to 7.99 deciviews). Under these circumstances, considering the miniscule visiblity impacts and significant costs that installation and operation of SNCR at SGS Units 1 and 2 would generate, SNCR should be rejected as a candidate control technology for reasonable progress in the second planning period.

4.5 Control Scenario #4 (SDA Upgrades)

Improvement in SO_2 removal using the the existing SDA systems at Units 1 and 2 can be achieved through design upgrades, such as new dampers to improve flue gas distribution among the reactor vessels, and operational improvements, such as increased fresh lime addition rate.[84] The total annualized costs of these improvements, which are projected to yield a nominal outlet emission rate of 0.15 lb/MMBtu, are $0.996 million per year at Unit 1 and $0.976 million per year at Unit 2. The cost effectiveness for SO_2 emission reductions is as follows:

		UNIT 1	UNIT 2
Base Case (current SDA)	SO_2 lb/MMBtu	0.240	0.216
	SO_2 tpy	2,504	2,785
Control Scenario #2 (upgraded SDA)	SO_2 lb/MMBtu	0.15	0.15
	SO_2 tpy	1,568	1,930
	SO_2 reduction tpy	936	855
	Annualized Cost ($/yr)	$996,000	$976,000
	Cost Effectiveness ($/ton)	$1,060	$1,140

These costs are within the range of what has been considered to be reasonable on a dollars per ton basis.

[82] EPA has routinely approved State decisions to reject controls under the Regional Haze rules, even where such controls may reasonably be considered cost effective on a $/ton basis, based on determinations that it is not reasonable to impose substantial control costs to achieve visibility benefits less than one deciview. *See for example*, 83 *Fed. Reg.* 62204 (Nov. 30, 2018), proposing to approve Arkansas' Regional Haze SIP, and specifically approving the decision not to require add-on SO_2 controls at the Independence Steam Electric Station based largely on costs of approximately $70 million per deciview of visibility improvement; *See also* 84 *Fed. Reg.* 51033 (Sept. 27, 2019), finalizing this approval.

[83] Technical Support Document for EPA's Updated 2028 Regional Haze Modeling, at 56 U.S. EPA, Sept. 2019.

[84] *See* Appendix B cost evaluation report.

In determining whether the SO_2 emission reductions achievable with SDA upgrades are necessary to make reasonable progress in the second planning period, ADEQ must also give consideration to the visibility improvement that would result from these emission reductions. The SO_2 emission reductions achievable with SDA upgrades are much less cost-effective in relation to the small visibility benefits that would be achieved than in terms of cost per ton of emission reduction. This is illustrated in the results of the photochemical grid modeling performed by Ramboll US Corporation.[85] Modeling of a hypothetical SO_2 emission reduction of 3,237 tons per year at SGS yields a visibility improvement of 0.028 deciviews on the most anthropogenically impaired days at San Pedro Parks Wilderness Area and lesser improvements at other Class I areas. Assuming the relationship between visibility improvements and SO_2 emissions reductions is linear within the range at issue here, the improvement at San Pedro from implementing SDA upgrades would be approximately 0.016 deciviews. The cost effectiveness in terms of visibility improvement is more than $120 million per deciview. This is indicative of substantial costs in relation to little visibility improvement.[86]

If further consideration is given to SDA upgrades as an SO_2 control measure, additional analysis would be required in order to determine the emission limitations achievable with this measure.

4.6 Control Scenario #5 (SNCR plus SDA Upgrades)

For the reasons presented in Section 4.4 above, SNCR should not be determined by ADEQ to be necessary to make reasonable progress in the second planning period. No additional synergies are gained by combining SNCR with SDA upgrades. The total costs and total emission reductions associated with this control strategy are equal to the sum of the costs and emission reductions of the individual control measures described previously.

[85] *See* Appendix A; *see also supra* note 81.
[86] *See supra* note 82.

5. Analysis Step 4: Time Necessary for Compliance

As discussed in Section 1.4 above, the fourth step in the analysis involves, for each control measure remaining under consideration, characterization of the time necessary for compliance. The objectives of this step are to determine whether a required control measure can be fully implemented within the second planning period (*i.e.*, by July 31, 2028), because only those measures can be considered by the State in establishing reasonable progress goals for that period,[87] and to establish a compliance schedule.

The time necessary for compliance includes all time needed for full implementation of the control measure, including, first, the time required to develop and implement the regulations; and then, the time needed to implement the control measure in conformance with the final regulations. It is important to note that implementation at an operating facility such as SGS, where scheduling of maintenance outages must be coordinated between the units and with other facilities, involves increased planning complexity. EPA guidance encourages states to consider these source-specific factors.[88]

The only technically feasible control measure determined in Step 3 to have reasonable costs on a dollars per ton basis is SDA upgrades. Based on an initial analysis, TEP and RTP expect that this control measure could be fully implementated at both Units 1 and 2 before the end of second planning period, assuming timely promulgation of a final SIP in accordance with the current schedule contemplated by ADEQ and EPA. Additional analysis of an appropriate compliance deadline may be warranted as the state and federal processes continue.

If emission limitations reflecting implementation of this control measure are adopted in the Regional Haze SIP for Arizona, the compliance deadline should be the later of (i) July 31, 2028, or (ii) three years after promulgation of a final, non-reviewable SIP approval regulation. In no event should an earlier compliance deadline be adopted, because such earlier deadline is not reasonable in light of the fact that no credit is provided for early reductions under the Regional Haze program. As acknowledged by U.S. EPA,

> Unlike for BART, there is no requirement in the Regional Haze Rule that emission control measures that have been determined to be necessary to make reasonable progress must be installed as expeditiously as practicable or within 5 years of EPA's approval of the SIP revision.[89]

For other control measures identified in Step 1 of the analysis, no characterization or evaluation of the time needed for compliance is necessary, because each such measure has been eliminated from consideration either based on technical infeasibility as discussed in Section 2 herein or unreasonable costs as discussed in Section 4 herein.

---

[87] *See* 40 CFR § 51.308(f)(3)(i). *See also* 82 *Fed. Reg.* 3078, 3089 (Jan. 10, 2017).
[88] *See* 2nd Period Regional Haze Guidance, *supra* note 17, at 45.
[89] *See* 2nd Period Regional Haze Guidance, *supra* note 17, at 33.

6. Analysis Step 5: Other Statutory Factors

As discussed in Section 1.4 above, the fifth step in the analysis involves characterization of the remaining useful life of the emissions units under review and characterization of the energy and non-air quality environmental impacts of each control measure remaining under consideration. These are the remaining two of the four statutory factors. These factors have been considered in the cost-effectiveness analyses presented in Section 3, as discussed below and as recommended in U.S. EPA guidance.[90]

For purposes of this analysis, TEP has conservatively assumed that the remaining useful life of Units 1 and 2 at SGS will be longer than the useful life of any of the control measures evaluated. Accordingly, the expected useful life of each control measure was used in Step 3 of this analysis to calculate its emission reductions, annualized costs, and cost effectiveness. For example, in the evaluation of SNCR summarized in Section 4.4 herein, the expected useful life of an SNCR system is 20 years, so this value was used in calculating the NO_X emission reductions, annualized costs, and cost effectiveness of this control measure.

The collateral energy and environmental impacts associated with each of the control measures evaluated in this analysis also were taken into account in determining costs and cost effectiveness in Step 3. For example, auxiliary power usage associated with installation and operation of SNCR systems and increased solid waste generation associated with SDA upgrades were quantified and monetized, and these costs were included in the evaluations of these control measures summarized in Sections 4.4 and 4.5, respectively.

[90] *See* 2nd Period Regional Haze Guidance, *supra* note 17, at 41-2.

Appendix A

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ASSESSING THE VISIBILITY IMPACTS OF THE SPRINGERVILLE GENERATING STATION – FINAL REPORT

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Assessing the Visibility Impacts of the Springerville Generating Station – Final Report

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CONTENTS

1.0	**Introduction**	**3**
1.1	Purpose	3
1.2	Modeling Approach	3
1.3	Overview of SGS 2028 Scenarios	3
1.4	Visibility Impact Assessment Approach	4
2.0	**EPA Regional Haze Guidance**	**5**
2.1	EPA Final Guidance for Evaluating Single-Source Visibility Impacts	5
3.0	**EPA's 2016 Modeling Platform and 2016 Base Case Modeling**	**6**
3.1	EPA's 2016 Modeling Platform	6
3.2	Development of a 2016 Southwestern U.S. Modeling Platform	7
3.3	2016 Base Case Modeling and Model Performance Evaluation	7
4.0	**2028 Emissions scenarios**	**10**
4.1	2028 SGS Base Case Emissions	10
4.2	2028 Alternative Emission Scenarios	11
4.3	Additional 2028 Emissions Specifications	13
4.3.1	SGS Stack Parameters	13
4.3.2	Temporal Profiles for SGS emissions	13
4.3.3	Other Emissions	13
5.0	**Visibilty Modeling Approach**	**14**
5.1	Class I Areas to be Analyzed	14
5.2	CAMx Visibility Modeling Approach	17
5.2.1	Tracking SGS Contributions with CAMx PSAT	17
5.2.2	Mapping of CAMx PSAT Species to the IMPROVE Equation Species	17
5.3	SGS Visibility Post-Processing Approach	18
5.3.1	SMAT Tool	18
5.3.2	Revised IMPROVE Light Extinction Equation	18
5.3.3	Deciview Haze Index	19
5.3.4	Calculating the SGS "Single-Source" Impacts using SMAT	19
6.0	**SGS Visibility Results**	**21**
6.1	SGS Visibility Impacts in Deciview Units	21
6.2	SGS Visibility Impacts in Light Extinction	25
6.3	Discussion of SGS Visibility Results	30
7.0	**REFERENCES**	**31**

Appendices

Appendix A: CAMx Runscript
Appendix B: SMAT Control File

Table of Figures

Figure 3-1. 12-km grid resolution 12US2 domain (red) and 36-km grid resolution 36US3 domain (green) used in the EPA's 2016b modeling platform. 6

Figure 3-2. EPA 12-km 12US2 continental U.S. modeling domain (red) and 12-km 12SW2 southwest U.S. modeling domain (blue). 8

Figure 5-1. Location of the Springerville Generation Station (red), Class I Areas (green) and IMPROVE monitoring sites (purple) within the 12-km 12SW2 modeling domain. 14

Table of Tables

Table 3-1. Definitions of the EPA 12US2 continental and 12SW2 southwest 12-km modeling domains. (LCC project with 33 and 45 N True Latitudes and -97 W and 40 N Central Longitude and Latitude). 8

Table 3-2. CAMx model configuration used in the SGS visibility modeling. 9

Table 4-1. 2028 Base Case NO_X and SO_2 emissions for the four SGS boilers. 10

Table 4-2. 2028 Base Case emissions for the four SGS boilers. 10

Table 4-3. 2028 SGS Base Case emissions for the Cooling Towers and Material Handling (fugitive) sources. 11

Table 4-4. Emissions assumptions for the SGS 2028 Base Case and Alternative#1 (SO_2 Reduction) and Alternative#2 (NOX Reduction) emission scenarios. 12

Table 5-1. Distance to IMPROVE sites in 12SW2 domain from the location of the SGS and CIAs that are associated with each IMPROVE site (SGS visibility impacts will only be analyzed at IMPROVE sites associated with CIAs). 15

Table 6-1. SGS visibility impacts in deciview for boilers, cooling towers and fugitives. 21

Table 6-2. SGS visibility impacts in deciview for boilers only. 23

Table 6-3. SGS Visibility impacts in light extinction (Mm^{-1}) for boilers, cooling towers and fugitives. 26

Table 6-4 SGS visibility impacts in light extinction (Mm^{-1}) for boilers only. 28

1.0 INTRODUCTION

RTP Environmental Associates, Inc. (RTP) has retained Ramboll US Corporation (Ramboll) on behalf of their client Tucson Electric Power Company (TEP) to conduct preliminary visibility modeling of the Springerville Generating Station (SGS). The Arizona Department of Environmental Quality (ADEQ) is developing the second-round regional haze State Implementation Plan (SIP) that is due to the U.S. Environmental Protection Agency (EPA) by July 31, 2021. ADEQ is working with the Western Regional Air Partnership (WRAP) who are assisting the 13 western states with the development of their regional haze SIPs. One important component of the regional haze SIP is conducting a four-factor analysis for sources to determine whether additional reasonable progress controls should be included in the SIP. The four-factors are: (1) costs of compliance; (2) time necessary for compliance; (3) energy and non-air quality environmental impacts of compliance; and (4) remaining useful life. In addition to the four factors, states may take the visibility impacts of a source and the visibility benefits of feasible control options into account when assessing what may be required for reasonable progress. The TEP SGS is a source that may undergo review for reasonable progress controls in the next ADEQ regional haze SIP.

1.1 Purpose

This document summarizes the procedures and results for conducting preliminary visibility modeling of the SGS for alternative emissions control scenarios.

1.2 Modeling Approach

SGS visibility modeling was performed with the Comprehensive Air-quality Model with extensions (CAMx) photochemical grid model using EPA's 2016 beta (2016b) modeling platform. CAMx is a state-of-the-science photochemical grid model that comprises a "one-atmosphere" treatment of tropospheric air pollution over spatial scales ranging from neighborhoods to continents. The CAMx modeling procedures follow a Modeling Plan dated September 17, 2019. Visibility impacts of the SGS were estimated at nearby Class I Areas for three SGS 2028 emission scenarios that are described below.

EPA's 2016 beta (2016b) CAMx modeling platform was adapted for the SGS visibility modeling. A 12-km resolution southwest U.S. domain (12SW2) was extracted (windowed) from the EPA's 12-km (12US2) continental U.S. modeling domain. Boundary Conditions (BCs) for the 12SW2 domain were obtained from three-dimensional concentrations from a CAMx simulation of the 12US2 domain.

A CAMx 2016 12SW2 actual base case simulation was conducted using actual SGS emissions based on measured hourly Continuous Emissions Monitoring System (CEMS) data from 2016. The CAMx 2016 actual base case was subjected to a model performance evaluation with a focus on PM performance at IMPROVE monitoring sites.

1.3 Overview of SGS 2028 Scenarios

Three 2028 CAMx simulations were performed that varied emissions from the SGS:

1. 2028 Base Case Simulation: A CAMx 2028 base case simulation with SGS emissions set at 2028 on-the-book (OTB) values as provided by RTP. Note that the 2028 base case estimates are similar to estimates from a WRAP EGU emissions analysis study for western states.[1]

[1] https://www.wrapair2.org/EGU.aspx

2. Alternative#1: SO_2 Reductions: Assumes control measures are implemented at SGS Units 1 and 2 resulting in a lower SO_2 emissions rate of 0.08 lb/MMBtu and no change in NO_X emissions. SO_2 emissions are reduced by a total of 3,236 tons per year relative to the 2028 base case.

3. Alternative #2: NO_X Reductions: Assumes control measures are implemented at SGS Units 1 and 2 resulting in a lower NO_X emissions rate of 0.08 lb/MMBtu and no change in SO_2 emissions. NO_X emissions are reduced by a total of 2,118 tons per year relative to the 2028 base case.

1.4 Visibility Impact Assessment Approach

The effects of the alternative SGS emission scenarios on visibility at Class I Areas (CIAs) were examined using the Software for Modeled Attainment Test – Community Edition (SMAT[2]). SMAT uses the visibility projection technique outlined in EPAs latest (2018) regional haze modeling guidance[3] that uses the modeling results in a relative fashion to scale observed visibility impairment, by projecting current observed visibility for the most impaired days (MID) for the various SGS emission scenarios.

[2] https://www.epa.gov/scram/photochemical-modeling-tools

[3] https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf

2.0 EPA REGIONAL HAZE GUIDANCE

To assist states with the preparation of regional haze state implementation plans (SIPs) for the second implementation period (due to EPA by July 31, 2021), EPA has provided a "*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period,*" which was distributed on August 20, 2019 (EPA, 2019a). It replaces the 2016 draft regional haze guidance. One important revision (compared to the first implementation period) is the usage of the new Most Impaired Days (MID) visibility tracking metric, which focuses attention on days when anthropogenic emissions impair visibility instead of days when wildfires and natural dust storms are the greatest contributors to reduced visibility.

2.1 EPA Final Guidance for Evaluating Single-Source Visibility Impacts

When evaluating a single-source's visibility impacts at a Class I area, EPA's guidance (EPA, 2019a) recommends using light extinction (in inverse megameters or Mm^{-1}; EPA, 2019a, pp. 16), rather than deciviews that have been used in the past, for comparing the Reasonable Progress Goals (RPGs) to the URP. However, EPA guidance recognizes that the deciview metric may also be used, especially when comparing to past work based on deciviews (e.g., visibility benefits per cost has used the deciview metric) and in this report results for both light extinction and deciview are presented. Light extinction (Bext) is related to Deciview Haze Index (dv) as follows:

$$dv = 10 \ln(Bext/10)$$

EPA recommends that single-source modeling of visibility impacts uses estimates of actual 2028 emissions accounting for any controls or changes in operation that occur between now and 2028 (EPA, 2019a, pp. 17). EPA does not recommend any specific visibility metric or procedure for evaluating which alternative control measure provides greater visibility benefits.

EPA's modeling guidance for making regional haze projections (EPA, 2018b)[4] recommends using the modeling results in a relative fashion to scale the observed visibility on the 20% MIDs to project 2028 future year 20% MID visibility levels. EPA provides the Software for the Modeled Attainment Test (SMAT[5]) tool to make future year 20% MID visibility projections using base year and future year modeling results and observed visibility conditions. Thus, for this analysis we are using the 20% MID visibility metric at IMPROVE monitoring sites that represent CIAs to evaluate the effects that the alternative control scenarios for the SGS would have on visibility impairment at CIAs.

[4] https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf

[5] https://www.epa.gov/scram/photochemical-modeling-tools

3.0 EPA'S 2016 MODELING PLATFORM AND 2016 BASE CASE MODELING

3.1 EPA's 2016 Modeling Platform

EPA routinely develops national PGM modeling platforms that are used to evaluate air quality impacts of national rules, such as the Cross-State Air Pollution Rule (CSAPR[6]). National PGM modeling platforms typically coincide with the triennial National Emission Inventory (NEI[7]) years (e.g., 2008, 2011, 2014, 2017). The most recent EPA PGM modeling platform that was available for the SGS visibility modeling was the EPA 2016 beta (2016b) modeling platform which is built off 2014NEIv2 emissions.

2016 Modeling Platform: The EPA and Multi-Jurisdictional Organizations (MJO) performed a joint 2016 inventory collaborative study to develop a 2016 emissions inventory of comparable quality to the NEI. EPA used the EPA/MJO 2016 emissions to develop a 2016 PGM modeling platform. The 2016 Beta platform was released in April 2019 and is available[8] on the Intermountain West Data Warehouse (IWDW). The first full version of the 2016 platform (2016v1) became available later in 2019 which was not in time for this study, the full version includes future year emissions including 2028. The EPA 2016 platform uses the 12-km 12US2 domain embedded in a North America 36-km 36US3 domain that are shown in Figure 3-1.

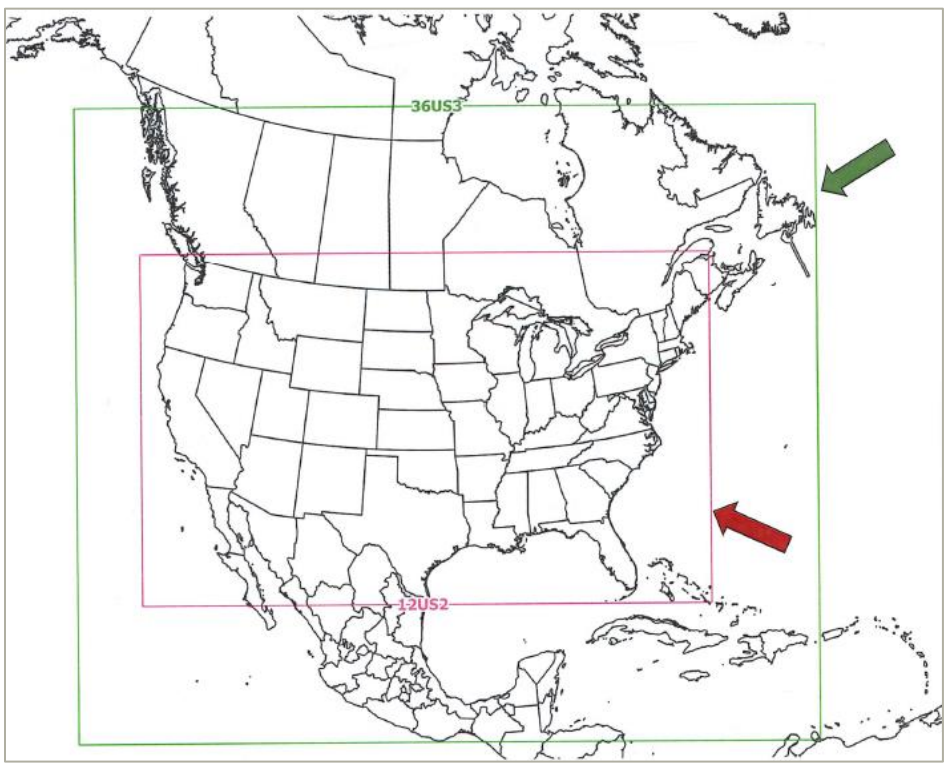

Figure 3-1. 12-km grid resolution 12US2 domain (red) and 36-km grid resolution 36US3 domain (green) used in the EPA's 2016b modeling platform.

[6] https://www.epa.gov/csapr
[7] https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei
[8] https://views.cira.colostate.edu/iwdw/RequestData/Default.aspx?pid=USEPA_2016

3.2 Development of a 2016 Southwestern U.S. Modeling Platform

For the SGS visibility modeling, we reduced the size of the EPA 2016 12US2 modeling domain to cover just the southwest U.S. so that the CAMx simulations are more computationally efficient.[9] A 12-km resolution southwest U.S. domain (12SW2) was extracted (i.e. windowed out) from the 12US2 continental U.S. domain. Figure 3-2 displays the 12US2 modeling domain (same as red domain in Figure 3-1) and the 12SW2 modeling domain used in the SGS visibility modeling, with the parameters for the definitions of the two domains given in Table 3-1.

Additional steps for developing the 2016 CAMx 12SW2 domain database for the SGS visibility modeling were as follows:

1. Obtain boundary conditions for the extracted 12WS2 domain:
    - Conducted a CAMx 12US2 domain simulation for 2016 calendar year plus 10 spin-up days to obtain 3-D output files of hourly concentrations.
    - Processed the CAMx 2016 12US2 domain 3-D output to generate hourly boundary conditions (BCs) for the 12SW2 domain.
2. Windowed out gridded inputs for the 12SW2 domain from the 12US2 domain:
    - Meteorological, emissions and other gridded inputs
3. Developed other CAMx ancillary inputs (e.g., photolysis rates, ozone column, etc.) for the 12SW2 domain.

3.3 2016 Base Case Modeling and Model Performance Evaluation

A 2016 CAMx 12SW2 domain actual base case simulation for the SGS visibility study was conducted using actual SGS emissions based on measured hourly CEMS data. The CAMx model configuration used in the SGS visibility modeling are summarized in Table 3-2 with details found in a sample CAMx run script in Appendix A.

The CAMx 2016 12SW2 domain base case simulation was subjected to a model performance evaluation (MPE) that compared model predictions against concurrent observations using EPA's Atmospheric Model Evaluation Tool (AMET) tool. The focus of the MPE was on reproducing the observed PM species concentrations at IMPROVE sites.

A full suite of AMET model performance plots (e.g. spatial plots, timeseries plots, scatter plots) were generated and inspected for reasonableness. In addition, we compared: (1) the SGS CAMx visibility modeling simulation with (2) EPA's CAMx 2016 beta modeling which is documented in the "Technical Support Document for EPA's Updated 2028 Regional Haze Modeling" (EPA 2019). The comparison focused on spatial plots of NMB (%) and NME (%) for PM2.5 nitrate and PM2.5 sulfate at IMPROVE sites and showed that these two CAMx simulations had very similar model performance statistics, which was to be expected since they are based on the same modeling platform.

[9] The CAMx simulations using the 12SW2 domain will run almost 6 times faster than if the original 12US2 domain was used.

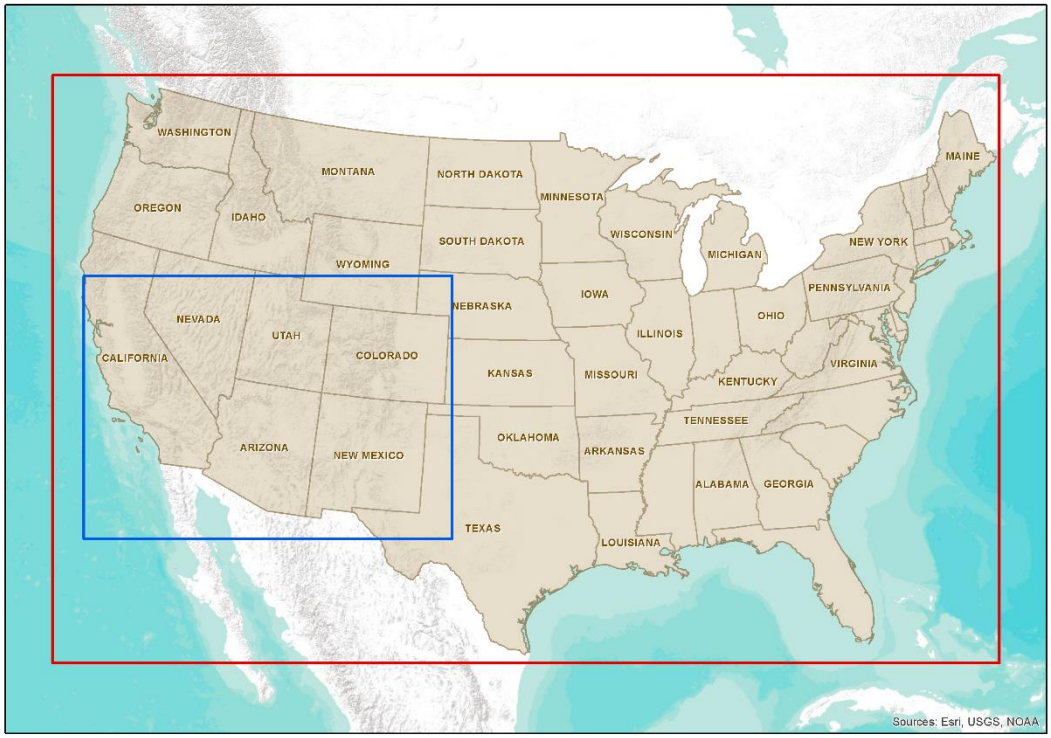

Figure 3-2. EPA 12-km 12US2 continental U.S. modeling domain (red) and 12-km 12SW2 southwest U.S. modeling domain (blue).

Table 3-1. Definitions of the EPA 12US2 continental and 12SW2 southwest 12-km modeling domains. (LCC project with 33 and 45 N True Latitudes and -97 W and 40 N Central Longitude and Latitude).

Grid	Origin (SW, km)	Extent (NE, km)	NX	NY
12US2	(-2412, -1620)	(2340, 1332)	396	246
12SW2	(-2256, -996)	(-408, 324)	154	110

Table 3-2. CAMx model configuration used in the SGS visibility modeling.

Science Options	EPA 2016 Beta CAMx	SGS 2016 CAMx	Comment
Model Codes	CAMx V6.5 - Apr 2018	CAMx v6.5 - Apr 2018	CAMx v7.0 schedule to release late summer/fall 2019
Horizontal Grid Mesh	36/12-km	12-km	LCC Projection
36 km grid	36US3: 172 x 148 cells	None	36US3 Domain
12 km grid	12US2: 396 x 246 cells	12SW2: 154 x 110 cells	6x faster on 12SW2 than 12US1
Vertical Grid Mesh	25 vertical layers	25 vertical layers	Layer 1 thickness 20 m. Model top at ~19 km AGL
Grid Interaction	36/12-km one-way nesting	Just 12-km 12SW2 domain	One-way nesting from 12US2
Initial Conditions	10-day spin-up	5-day spin-up	
Boundary Conditions	2016 HCMAQ for 36US2	From CAMx 2016 12US2	CAMx 12US2 used HCMAQ BCs
Emissions			
Baseline Emissions	SMOKE, SMOKE-MOVES2014, BEIS	SMOKE, SMOKE-MOVES2014, BEIS	EPA 2016 Beta Emissions
Sub-grid Plumes	No Plume-in-Grid	No Plume-in-Grid	
Chemistry			
Gas Phase Chemistry	CB6r2h	CB6r2h	(Yarwood et al., 2010)
Meteorological Processor	WRFCAMx	WRFCAMx	Compatible with CAMx V6.5
Horizontal Diffusion	Spatially varying	Spatially varying	K-theory with Kh grid size dependence
Vertical Diffusion	CMAQ-like Kv	CMAQ-like Kv	Minimum Kv 0.1 to 1.0 m^2/s
Diffusivity Lower Limit	Kz-min = 0.1 to 1.0 m^2/s or 2.0 m^2/s	Kz-min = 0.1 to 1.0 m^2/s or 2.0 m^2/s	Depends on fraction of urban land use fraction
Deposition Schemes			
Dry Deposition	Zhang dry deposition	Zhang dry deposition	(Zhang et. al, 2001; 2003)
Wet Deposition	CAMx -specific formulation	CAMx -specific formulation	rain/snow/graupel
Numerics			
Gas Phase Chemistry	Euler Backward Iterative(EBI)	Euler Backward Iterative(EBI)	EBI fast and accurate solver
Vertical Advection	Implicit scheme w/ vertical velocity update	Implicit scheme w/ vertical velocity update	Emery et al., (2009a,b; 2011)
Horizontal Advection	Piecewise Parabolic Method (PPM) scheme	Piecewise Parabolic Method (PPM) scheme	Colella and Woodward (1984)
Integration Time Step	Wind speed dependent	Wind speed dependent	~0.5-1 min (4-km), 1-5 min (12-km), 5-15 min (36-km)
Simulation Strategy			
MPI/OpenMP	8/3	8/3	Each run segment using 24 cores
Run Segments	4-Segments (~3 months each)	4-Segments (~3 months each)	4 run-segments run at the same time
CPU	DQUAD 1.6 GHz	DHEX	~60-hour clock time per run

4.0 2028 EMISSIONS SCENARIOS

The visibility impacts for three future year (2028) SGS emissions scenarios were evaluated:

1. 2028 Base Case
2. 2028 Alternative#1 – SO_2 emission reduction scenario
3. 2028 Alternative#2 –NO_X emission reduction scenario

4.1 2028 SGS Base Case Emissions

RTP provided SGS 2028 Base Case SO_2 and NO_X emissions for the four units that are shown in Table 4-1.

Table 4-1. 2028 Base Case NO_X and SO_2 emissions for the four SGS boilers.

2028 Base Case	NO_X Emissions (tpy)	SO_2 Emissions (tpy)
SGS Boiler	**RTP**	**RTP**
UNIT 1 BOILER	1792.2	2416.5
UNIT 2 BOILER	2191.9	2685.7
UNIT 3 BOILER	962.6	963.4
UNIT 4 BOILER	910.8	926.2

Table 4-2 expands the lists of SGS 2028 Base Case emissions to all pollutants modeled in CAMx. The PM_{10} and $PM_{2.5}$ emissions list the total primary (PRI) PM emissions and filterable (FIL) component, with the condensable component being the difference of the two. Since Units 3 and 4 have selective catalytic reduction (SCR) NO_X controls, they also include NH_3 emissions (ammonia slip).

Table 4-2. 2028 Base Case emissions for the four SGS boilers.

2028 Base SGS Boiler	CO	NO_X	SO_2	VOC	PM_{10}-PRI	PM_{10}-FIL	PM_{25}-PRI	PM_{25}-FIL	NH_3
UNIT 1	297.3	1792.2	2416.5	40.28	85.06	59.92	23.77	15.62	0
UNIT 2	366.3	2191.9	2685.7	48.58	110.34	84.77	30.76	22.11	0
UNIT 3	345.9	962.6	963.4	46.09	159.11	16.24	44.34	4.23	34.6
UNIT 4	314.2	910.8	926.2	41.08	31.66	9.14	9.04	2.37	31.5
Total	**1323.7**	**5857.5**	**6991.9**	**176.0**	**386.2**	**170.1**	**107.9**	**44.3**	**66.2**

ADEQ provided particulate matter (PM) emissions for SGS Cooling Towers and SGS material handling (i.e., fugitive dust) sources. Table 4-3 displays the PM emissions rates for these two classes of sources. In this case the primary and filterable PM emissions are identical which means there are no condensable PM emissions for these sources. EPA regional haze guidance (EPA, 2019a) is not specific on which sources at SGS should be modeled for reasonable progress control considerations, therefore, we performed CAMx modeling and calculate SGS visibility impacts results for: (1) Boilers-only; and (2) Boilers + Cooling Towers + Material Handling combined.

Table 4-3. 2028 SGS Base Case emissions for the Cooling Towers and Material Handling (fugitive) sources.

2028 Base Case SGS Source	PM_{10} Emissions (tpy)		$PM_{2.5}$ Emissions (tpy)	
	PRI	FIL	PRI	FIL
Unit 1 Cooling Twr	234.0	234.0	194.1	194.1
Unit 2 Cooling Twr	277.7	277.7	230.4	230.4
Unit 3 Cooling Twr	46.7	46.7	38.7	38.7
Unit 4 Cooling Twr	43.6	43.6	36.2	36.2
Material Handling	918.0	918.0	270.0	270.0

4.2 2028 Alternative Emission Scenarios

Two alternative 2028 SGS emission scenarios were also modeled, in addition to the 2028 Base Case:

1. Alternative#1 -- SO_2 Reduction Scenario: Assume control measures are implemented at SGS Units 1 and 2 resulting in a SO_2 emissions rate for both units of 0.08 lb/MMBtu, which is similar to Units 3 and 4. The NO_X emissions from Units 1 and 2 remain at the 2028 Base Case levels. No change in SO_2 emissions or NO_X emissions at Units 3 and 4.

2. Alternative#2 – NO_X Reduction Scenario: Assumes control measures are implemented at SGS Units 1 and 2 resulting in a NO_X emissions rate for both units of 0.08 lb/MMBtu. The SO_2 emissions from Units 1 and 2 remain at the 2028 Base Case levels. No change in SO_2 emissions or NO_X emissions at Units 3 and 4.

Table 4-4. Emissions assumptions for the SGS 2028 Base Case and Alternative#1 (SO_2 Reduction) and Alternative#2 (NOX Reduction) emission scenarios.

Unit =	1	2	3	4
Avg. NO_X Rate (lb/MMBtu)				
Base Case	**0.172**	**0.170**	**0.077**	**0.080**
Alternative#1 (SO_2 reduction)	**0.172**	**0.170**	**0.077**	**0.080**
Diff	0	0	0	0
Diff%	0.0%	0.0%	0.0%	0.0%
Alternative#2 (NO_x reduction)	**0.08**	**0.08**	**0.077**	**0.080**
Diff	-0.092	-0.090	0.000	0.000
Diff%	-53.4%	-53.0%	0.0%	0.0%
Avg. SO_2 Rate (lb/MMBtu)				
Base Case	**0.231**	**0.209**	**0.077**	**0.081**
Alternative#1 (SO_2 reduction)	**0.08**	**0.08**	**0.077**	**0.081**
Diff	-0.151	-0.129	0.000	0.000
Diff%	-65.4%	-61.7%	0.0%	0.0%
Alternative#2 (NO_x reduction)	**0.231**	**0.209**	**0.077**	**0.081**
Diff	0	0	0	0
Diff%	0.0%	0.0%	0.0%	0.0%
NO_X Emissions (tons per year)				
Base Case	**1,792.2**	**2,191.8**	**962.6**	**910.8**
Alternative#1 (SO_2 reduction)	**1,792.2**	**2,191.8**	**962.6**	**910.8**
Diff	0	0	0	0
Diff%	0.0%	0.0%	0.0%	0.0%
Alternative#2 (NO_x reduction)	**836.0**	**1,029.4**	**962.6**	**910.8**
Diff	-956	-1,162	0	0
Diff%	-53.4%	-53.0%	0.0%	0.0%
SO_2 Emissions (tons per year)				
Base Case	**2,416.5**	**2,685.7**	**963.4**	**926.2**
Alternative#1 (SO_2 reduction)	**836.0**	**1,029.4**	**963.4**	**926.2**
Diff	-1,580	-1,656	0	0
Diff%	-65.4%	-61.7%	0.0%	0.0%
Alternative#2 (NO_x reduction)	**2416.5**	**2685.7**	**963.4**	**926.2**
Diff	0	0	0	0
Diff%	0.0%	0.0%	0.0%	0.0%

4.3 Additional 2028 Emissions Specifications

4.3.1 SGS Stack Parameters

All three 2028 SGS emissions scenarios use the same SGS stack parameters as in the 2016 base case simulation. Note that some emissions control technologies may alter stack parameters (e.g., wet FGD controls would cool the effluent and change its exit velocity). In this case, for simplicity, the Alternative#1 SO_2 Reduction Scenario and the Alternative#2 NO_X Reduction Scenario are assumed to have no or minimal effect on stack parameters and on emissions of pollutants other than SO_2 or NO_X, such as ammonia.

4.3.2 Temporal Profiles for SGS emissions

To determine temporal profiles for the Springerville 2028 future year emissions, we inspected the Springerville 2016 CEMS NOx/SO_2/Heat Input profiles and determined:

- All Units operated as base load units with operations generally throughout the entire year
- There was only moderate seasonal variation (i.e. Units may be down altogether for relatively short periods (typically < 1 month) and Unit 1 had a moderate seasonal adjustment (Jan-May is different than Jul-Dec) and Unit 3 had a moderate seasonal adjustment in May)
- Whether the moderate seasonal variations would be applicable in 2028 is unknown
- There was a relatively well-defined (but also moderate) diurnal profile. However, for long range transport (LRT) 24-hour $PM_{2.5}$ concentrations and resultant visibility, the impact of the diurnal profile would be minimal.

Therefore, we used a flat temporal profile (i.e. of annual average emissions for each Unit distributed equally over each hour of the year) for the 2028 Springerville CAMx modeling.

4.3.3 Other Emissions

All other emissions sources sectors (e.g., mobile sources) were kept at 2016 emissions levels since 2028 emissions estimates were not available as part of the EPA 2016 beta modeling platform. Note that 2028 emissions for all emissions source sectors are now available with the EPA 2016 version 1 platform.

5.0 VISIBILTY MODELING APPROACH

In this section we describe how the SGS CAMx visibility modeling was conducted and the post-processing procedures used to evaluate the SGS visibility impacts at Class I Areas (CIAs) for the SGS emission scenarios.

5.1 Class I Areas to be Analyzed

Figure 5-1 displays the location of the SGS, CIAs and 52 IMPROVE monitoring sites within the 12SW2 modeling domain. Each CIA has an associated IMPROVE monitoring site whose measured PM concentrations are used to represent visibility impairment at the CIA. In some cases, multiple CIAs are associated with the same IMPROVE site (e.g., the Canyonlands IMPROVE site is used to represent visibility at both Canyonlands and Arches National Parks). And there are some IMPROVE sites that are not associated with any CIA, which are usually IMPROVE protocol sites. According to the Forest Service website, the IMPROVE data for the Mount Zirkel IMPROVE site should be used to represent visibility impairment at the Flat Tops Wilderness CIA even though there is a Flat Tops IMPROVE site. The visibility impacts of the SGS emission scenarios will be examined only at IMPROVE sites that are associated with CIAs.

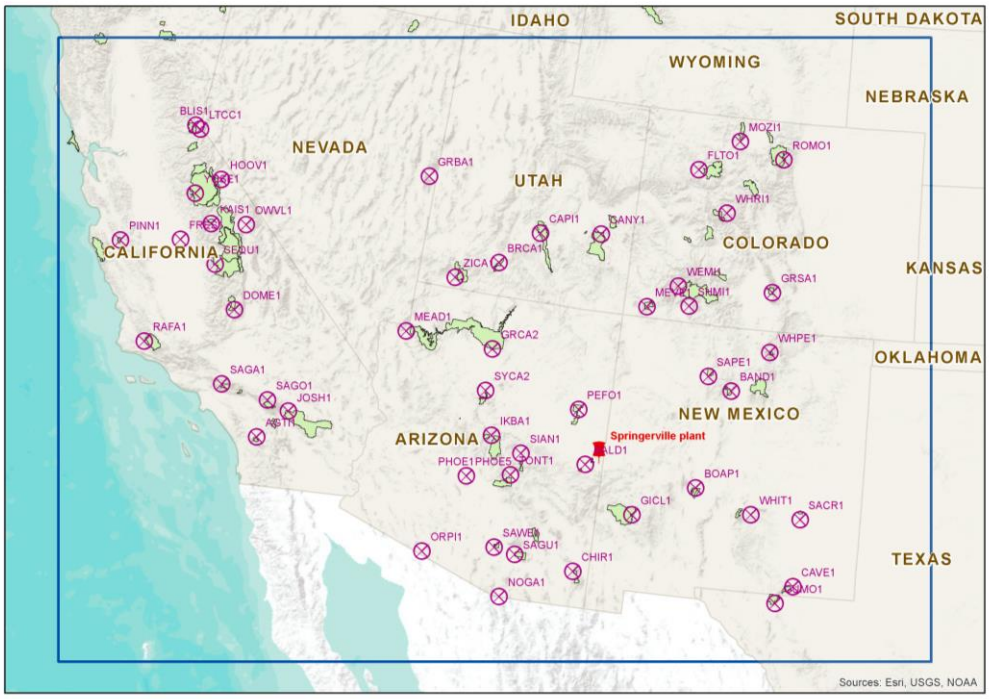

Figure 5-1. Location of the Springerville Generation Station (red), Class I Areas (green) and IMPROVE monitoring sites (purple) within the 12-km 12SW2 modeling domain.

EPA's guidance does not specify a distance from a source that CIAs should be included in a modeled visibility evaluation. Uncertainty in modeling results increases as a function of distance from a source, and at longer distances there is the potential that visibility impacts from a single source become very small and close to model "noise" so are not reliable. In the past, a 300-km distance from a source has been used in CIA visibility analyses, however that distance was based on limitations in the CALPUFF

model that do not apply to CAMx. When WRAP conducted a Q/D analysis[10] to rank sources to assist in the selection of sources for the four-factor analysis, a 400-km distance between a source and CIA was initially used for inclusion in the Q/D analysis. WRAP later determined that the 400-km distance limitation may undesirably screen out larger sources (such as SGS) so they did additional analyses to determine the contributions of larger emitting sources to CIAs further than 400-km downwind. Table 5-1 lists the distance between IMPROVE sites and the SGS for all the IMPROVE sites in the 12SW2 domain. Also given in Table 5-1 are the number and names of the CIAs associated with each IMPROVE site. There is one IMPROVE site within 100-km of SGS (Mount Baldy Wilderness), five within 200-km and 14 within 300-km.

Table 5-1. Distance to IMPROVE sites in 12SW2 domain from the location of the SGS and CIAs that are associated with each IMPROVE site (SGS visibility impacts will only be analyzed at IMPROVE sites associated with CIAs).

IMPROVE ID	IMPROVE Site Name	No. CIAs	State	Distance to Springerville Facility (km)	Associated CIAs
BALD1	Mount Baldy	1	AZ	38	Mount Baldy Wilderness
PEFO1	Petrified Forest National Park	1	AZ	101	Petrified Forest National Park
GICL1	Gila	1	NM	149	Gila Wilderness
SIAN1	Sierra Ancha	1	AZ	165	Sierra Ancha Wilderness
TONT1	Tonto National Forest	1	AZ	193	Tonto National Forest Wilderness
BOAP1	Bosque del Apache	1	NM	218	Bosque del Apache Wilderness
IKBA1	Ike's Backbone	2	AZ	231	Mazatzal Wilderness Pine Mountain Wilderness
CHIR1	Chiricahua National Monument	3	AZ	257	Chiricahua NM Chiricahua Wilderness Galiuro Wilderness
SYCA2	Sycamore Canyon	1	AZ	273	Sycamore Canyon Wilderness
SAGU1	Saguaro	1	AZ	279	Saguaro NP
SAPE1	San Pedro Parks	1	NM	282	San Pedro Parks Wilderness
PHOE1	Phoenix	0	AZ	285	
PHOE5	Phoenix	0	AZ	285	
SAWE1	Saguaro West	1	AZ	299	Saguaro West NP
BAND1	Bandelier	1	NM	309	Bandelier NM
GRCA2	Hance (Grand Canyon)	1	AZ	315	Hance (Grand Canyon) NP
MEVE1	Mesa Verde	1	CO	325	Mesa Verde NP
WHIT1	White Mountain	1	NM	348	White Mountain Wilderness
SHMI1	Shamrock Mine	0	CO	364	
NOGA1	Nogales	0	AZ	370	
WEMI1	Weminuche	3	CO	390	Weminuche Wilderness Black Canyon of the Gunnison National Park La Garita Wilderness
WHPE1	Wheeler Peak	2	NM	419	Wheeler Peak Wilderness Pecos Wilderness

[10] http://views.cira.colostate.edu/tssv2/Emissions/QDAnalysis.aspx

IMPROVE ID	IMPROVE Site Name	No. CIAs	State	Distance to Springerville Facility (km)	Associated CIAs
ORPI1	Organ Pipe	0	AZ	429	
SACR1	Salt Creek Wilderness	1	NM	449	Salt Creek Wilderness
BRCA1	Bryce Canyon	1	UT	454	Bryce Canyon NP
CANY1	Canyonlands	2	UT	462	Canyonlands NP Arches National Park
ZICA1	Zion Canyon	1	UT	480	Zion Canyon NP
CAPI1	Capitol Reef	1	UT	480	Capitol Reef NP
MEAD1	Meadview	0	AZ	483	
GUMO1	Guadalupe Mountains	1	TX	491	Guadalupe Mountains NP
GRSA1	Great Sand Dunes	1	CO	499	Great Sand Dunes NP
CAVE1	Carlsbad Caverns	1	NM	499	Carlsbad Caverns NP
WHRI1	White River	3	CO	574	Eagles Nest Wilderness Maroon Bells-Snowmass Wilderness West Elk Wilderness
FLTO1	Flat Tops	0	CO	634	
JOSH1	Joshua Tree	1	CA	663	Joshua Tree NP
GRBA1	Great Basin	0	NV	686	
SAGO1	San Gorgonio	2	CA	710	San Gorgonio Wilderness San Jacinto Wilderness
MOZI1	Mount Zirkel	3	CO	722	Flat Tops Wilderness Mount Zirkel Wilderness Rawah Wilderness
AGTI1	Agua Tibia	1	CA	725	Agua Tibia Wilderness
ROMO1	Rocky Mountain	1	CO	733	Rocky Mountain NP
SAGA1	San Gabriel	2	CA	812	San Gabriel Wilderness Cucamonga Wilderness
DOME1	Dome Land	1	CA	829	Dome Land Wilderness
OWVL1	Owens Valley	0	CA	889	
SEQU1	Sequoia National Park	2	CA	905	Sequoia National Park Kings Canyon National Park
KAIS1	Kaiser Wilderness	3	CA	953	Kaiser Wilderness Ansel Adams Wilderness John Muir Wilderness
HOOV1	Hoover	1	CA	986	Hoover Wilderness
RAFA1	San Rafael	1	CA	991	San Rafael Wilderness
FRES1	Fresno	0	CA	994	
YOSE1	Yosemite	2	CA	1,016	Yosemite NP Emigrant Wilderness
LTCC1	Lake Tahoe Community College	0	CA	1,086	
BLIS1	D. L. Bliss State Park	2	CA	1,099	Desolation Wilderness Mokelumne Wilderness
PINN1	Pinnacles	2	CA	1,108	Pinnacles NM Ventana Wilderness
PORE	Point Reyes National Seashore	1	CA	1,300	Point Reyes National Seashore

5.2 CAMx Visibility Modeling Approach

The 2028 future year CAMx modeling used the same modeling platform as the 2016 CAMx base case modeling except for emissions inputs for the SGS. Three CAMx simulations were performed corresponding to the three SGS emissions scenarios described in Chapter 4. All other inputs besides SGS emissions (e.g. meteorological inputs) were identical to the CAMx 2016 base case simulation.

All emissions besides SGS emissions (e.g., mobile sources) were kept at 2016 emissions levels since 2028 emissions were not available as part of the EPA 2016 beta modeling platform, which was the basis for this study. Note that 2028 emissions for all emissions source sectors became available after the modeling was conducted as part of the EPA 2016 version 1 platform.

5.2.1 Tracking SGS Contributions with CAMx PSAT

The CAMx Particulate Source Apportionment Technology (PSAT) was used to track Particulate Matter (PM) contributions due to emissions from the SGS. PSAT uses reactive tracers (tagged species) that operate in parallel to the host model to track PM contributions due to emissions from user selected source groups. Emissions from each unit of the SGS (i.e. 4 units) were separately tagged for tracking by PSAT. We also separately tagged the combined emissions from all the cooling towers and the material handling (fugitive dust) emissions from the SGS as two separate source groups. Since PSAT needs to keep track of all sources, a seventh Source Group was all other emissions (i.e., the leftover group). The PSAT sulfate (SO4), nitrate/ammonium (NO3/NH4) and primary Particulate Matter (PM) families of tracers were used in the simulation. The PSAT Secondary Organic Aerosol (SOA) family of tracers was not used since SGS does not have any SOA precursor emissions. The PSAT SO4 family consists of two tracers (SO2 and SO4) for each Source Group to track the contributions of the source group emissions to particle SO4. The PSAT NO3/NH4 family of tracers consists of 8 separate tracers for each Source Group that includes 6 reactive nitrogen species that tracks the formation of particle NO3 from NO and NO2 emissions with many intermediate products including accounting for the re-nitrification of NOx from nitric acid and PAN. The other two NO3/NH4 tracers are NH3 and NH4 reduced nitrogen species. The PSAT primary PM family of tracers includes elemental carbon (EC), primary organic carbon (POA), fine and coarse crustal species and fine and coarse other PM species. More details on the formulation of PSAT can be found in the CAMx User's Guide (Ramboll, 2018[11]).

For each SGS 2028 emissions scenario, a CAMx PSAT simulation was performed using the 12SW2 modeling domain with 5-days of spin-up. The SGS 2028 emissions scenarios are presented in detail in Chapter 4.

5.2.2 Mapping of CAMx PSAT Species to the IMPROVE Equation Species

The CAMx PSAT source apportionment runs provide incremental concentration contributions due to SGS emissions for the following species that will be used in the revised IMPROVE visibility equation discussed below:

- Sulfate (SO4) [multiplied by 1.375 to make AmmSO4]
- Nitrate (NO3) [multiplied by 1.29 to make AmmNO3]
- Elemental Carbon (EC)
- Primary Organic Aerosol (POA, used for Organic Mass)
- Fine Crustal (FCRS) and Other (FPRM) primary PM2.5 emissions (used for Soil).
- Coarse Crustal (CCRS) and Other (CPRM) coarse (PM2.5-10) PM species (used for CM or PMC)
- Nitrogen Dioxide (NO_2)

[11] http://www.camx.com/files/camxusersguide_v6-50.pdf

5.3 SGS Visibility Post-Processing Approach

EPA's modeling guidance for making regional haze projections (EPA, 2018b)[12] recommends using modeling results in a relative fashion to scale the observed visibility on the 20% most impaired days (MID) to project 2028 future year 20% MID visibility levels. EPA provides the Software for the Modeled Attainment Test (SMAT[13]) tool to make future year 20% MID visibility projections using base year and future year modeling results and observed visibility conditions.

5.3.1 SMAT Tool

SMAT extracts model concentrations from the grid cells around IMPROVE sites or CIAs for the base and future year and calculates the ratio of future over base year concentrations for each pollutant for a set of days (i.e. MID) that are defined based on observational data at that IMPROVE site. These model-derived ratio values are referred to as relative response factors (RRFs) and are site- and species-specific. Model-derived RRFs are used to scale observed base year concentrations, and future year visibility is then calculated (based on the scaled base year concentrations) using the "revised" or "second" IMPROVE light extinction equation. The results are reported in terms of light extinction (in Mm^{-1}) as well as Haze Index (deciviews).

5.3.2 Revised IMPROVE Light Extinction Equation

The "revised" (or Second) IMPROVE equation (Pitchford et al, 2007) replaced the original IMPROVE equation since it reduced the bias for high and low light extinction extremes. It has been in use for at least the last 10 years. The revised IMPROVE light extinction equation converts PM species in μgm^{-3} to light extinction (b_{ext}) in inverse megameters (Mm^{-1}) as follows:

$$b_{ext} = b_{SO4} + b_{NO3} + b_{EC} + b_{OCM} + b_{Soil} + b_{PMC} + b_{SeaSalt} + b_{Rayleigh} + b_{NO2}$$

where

$b_{SO4} = 2.2 \times f_S(RH) \times [\text{Small Sulfate}] + 4.8 \times f_L(RH) \times [\text{Large Sulfate}]$

$b_{NO3} = 2.4 \times f_S(RH) \times [\text{Small Nitrate}] + 5.1 \times f_L(RH) \times [\text{Large Nitrate}]$

$b_{OCM} = 2.8 \times [\text{Small Organic Mass}] + 6.1 \times [\text{Large Organic Mass}]$

$b_{EC} = 10 \times [\text{Elemental Carbon}]$

$b_{Soil} = 1 \times [\text{Fine Soil}]$

$b_{PMC} = 0.6 \times [\text{Coarse Mass}]$

$b_{SeaSalt} = 1.7 \times f_{SS}(RH) \times [\text{Sea Salt}]$

$b_{Rayleigh}$ = Rayleigh Scattering (Site-specific)

$b_{NO2} = 0.33 \times [NO_2\ (ppb)]$ {or as: $0.1755 \times [NO_2\ (\mu g/m^3)]$}.

f(RH) are relative humidity adjustment factors that account for the fact that sulfate, nitrate, organic aerosols and sea salt aerosols are hygroscopic and are more effective at scattering radiation at a higher relative humidity. Class I area-specific "climatological" monthly average f(RH) values are used.

[12] https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf

[13] https://www.epa.gov/scram/photochemical-modeling-tools

Sulfate and nitrate in the IMPROVE extinction equation above are assumed to be completely neutralized by ammonium, so the CAMx SO4 and NO3 concentrations are multiplied by 1.375 and 1.29, respectively, to account for the presence of ammonium. Thus, the CAMx PSAT NH4 concentrations are not directly used in the IMPROVE extinction equation, but ammonia/ammonium in the model simulation does affect how much nitrate is in the form of particle NO3 versus gaseous nitric acid.

The revised IMPROVE equation treats "large sulfate" and "small sulfate" separately because large and small aerosols affect an incoming beam of light differently. However, the IMPROVE measurements do not separately measure large and small sulfate; they measure only the total $PM_{2.5}$ sulfate. Similarly, CAMx writes out a single concentration of particulate sulfate for each grid cell. Part of the definition of the revised IMPROVE equation is a procedure for calculating the large and small sulfate contributions based on the magnitude of the model output sulfate concentrations; the procedure is documented in FLAG (2010) and Pitchford et al, (2007) and is an empirically derived formula. The sulfate concentration magnitude is used as a surrogate for distinguishing between large and small sulfate concentrations. For a given grid cell, the large and small sulfate contributions are calculated from the model output sulfate (which is the "Total Sulfate" referred to in the FLAG (2010) guidance) as:

For Total Sulfate < 20 μg/m^3:

[Large Sulfate] = ([Total Sulfate] / 20 μg/m^3) × [Total Sulfate]

For Total Sulfate ≥ 20 μg/m^3:

[Large Sulfate] = [Total Sulfate]

For all values of Total Sulfate:

[Small Sulfate] = [Total Sulfate] – [Large Sulfate]

The procedure is identical for nitrate and organic mass. The split between Large and Small Sulfate is based on the Total Sulfate concentrations from the model. We assume that the incremental Sulfate concentrations due to just emissions from SGS have the same split between Large and Small Sulfate concentrations as the modeled Total Sulfate concentration.

5.3.3 Deciview Haze Index

Another key visibility evaluation metric used in regional haze analysis is the Haze Index which is measured in deciview (dv) units and is defined as follows:

$$HI = 10 \times \ln[b_{ext}/10]$$

b_{ext} is the atmospheric light extinction reported in inverse megameters (Mm^{-1}) that was described in the previous section. The SMAT tool reports future year visibility projections using both light extinction (Mm^{-1}) and Haze Index (dv).

5.3.4 Calculating the SGS "Single-Source" Impacts using SMAT

To estimate incremental visibility impacts due to SGS emissions at IMPROVE sites representing CIAs using the SMAT tool, we performed multiple SMAT runs and followed the following procedure:

1. Use SMAT to project the 2013-2017 observed visibility for the MID to 2028 visibility conditions for each SGS emissions case (i.e. 2028 base, 2028 Alt #1, and 2028 Alt #2) for the MIDs

2. Estimate 2028 visibility conditions in the absence of SGS emissions for each case (i.e. 2028 base, 2028 Alt #1, and 2028 Alt #2) by subtracting the PSAT-estimated SGS concentrations for each particulate matter (PM) component from total modeled concentration for the MIDs

3. Find the difference between the SMAT-estimated visibility conditions with and without the PSAT-estimated SGS concentrations to obtain SGS visibility impacts on the MIDs

For step #2, we performed two variations. For one variation we subtracted concentrations from the SGS boilers-only, for the other variation we subtracted concentrations from the SGS boilers plus the impacts from emissions from the SGS cooling towers and fugitive dust sources. This produced a total of 9 SMAT runs (i.e. 3 for step #1, and 6 for step #2). In each case the SMAT base year input file was the same 2016 base year CAMx simulation. A sample SMAT control file is presented in Appendix B.

As previously noted, EPA's new regional haze guidance recommends evaluating single-source visibility impacts using extinction (Mm^{-1}) and not deciview (dv). However, we report visibility impacts in both metrics so that the SGS visibility cost-effectiveness may be evaluated using deciview (i.e., $/Δdv) facilitating comparisons with results from the first round of regional haze SIPs.

6.0 SGS VISIBILITY RESULTS

This section presents results of the CAMx visibility impact modeling for the SGS. The visibility impacts are calculated at IMPROVE monitoring sites using the current version of EPA's SMAT tool v1.6. Visibility results at IMPROVE monitors are listed in order of the distance of the IMPROVE monitor from the SGS location (see Table 5-1).

The additional sites towards the bottom of the tables, (with #N/A in the approximate distance to SGS column) are output from SMAT for additional Class I areas. Some of these results are redundant. For example, ARCH (Arches National Park) Class I area is represented by the CANY IMPROVE monitor for which impacts are also listed in the table with the distance to the IMPROVE site under CANY. Other results are not redundant. For example, DESO (Desolation Wilderness) and MOKE (Mokelumne Wilderness) Class I areas are both represented by the BLIS IMPROVE monitor, for which impacts are not listed elsewhere in the table because BLIS is not a CIA. Likewise, MAZA (Mazatzal Wilderness) and PIMO (Pine Mountain Wilderness) Class I areas are both represented by the IKBA IMPROVE monitor, for which impacts are not listed elsewhere in the table because IKBA also is not a CIA.

Note that the SMAT tool did not generate results for the Sycamore Canyon Wilderness (SYCA) IMPROVE site. This is apparently due to issues with the SMAT tool's database which contains the IMPROVE observational data.[14]

6.1 SGS Visibility Impacts in Deciview Units

Results of SGS CAMx visibility modeling are reported in deciview units in Table 6-1 for boilers, cooling towers and fugitives combined, and Table 6-2 for boilers only. The tables report SGS visibility impacts for each of the three 2028 scenarios, and visibility impact reductions of the two alternative scenarios compared to the 2028 base case. The maximum impacts are at SAPE and PEFO that are, respectively, 282-km to the northeast and 101-km to the north-northwest of the SGS.

Table 6-1. SGS visibility impacts in deciview for boilers, cooling towers and fugitives.

		Deciview Impact from SGS (dv) on MIDs				
		Boilers + CT + Fugitives				
		SGS Visibility Impacts			SGS Visibility Impacts Reductions compared to Base Case	
Sites: IMPROVE monitors and/or Class I Areas	**Approximate Distance to SGS**	**2028 Base**	**Scenario #1 (SO_2 reductions)**	**Scenario #2 (NOx reductions)**	**Scenario #1 - 2028 Base**	**Scenario #2 - 2028 Base**
BALD	**38**	0.0375	0.0256	0.0364	-0.01191	-0.00106
PEFO	**101**	0.0589	0.0457	0.0586	-0.01312	-0.00031
GICL	**149**	0.0530	0.0324	0.0529	-0.02062	-0.00012
BOAP	**218**	0.0197	0.0129	0.0190	-0.00681	-0.00073
CHIR	**257**	0.0074	0.0042	0.0075	-0.00323	0.00001
SAGU	**279**	0.0089	0.0052	0.0088	-0.00374	-0.00015

[14] It is our understanding that recently updated observational data is available for the SYCA monitor, but it is not yet available within the EPA's SMAT tool. Attemptes to modify the IMPROVE database to generate results for SYCA were unsuccessful.

		Deciview Impact from SGS (dv) on MIDs				
		Boilers + CT + Fugitives				
		SGS Visibility Impacts			SGS Visibility Impacts Reductions compared to Base Case	
Sites: IMPROVE monitors and/or Class I Areas	**Approximate Distance to SGS**	**2028 Base**	**Scenario #1 (SO_2 reductions)**	**Scenario #2 (NOx reductions)**	**Scenario #1 - 2028 Base**	**Scenario #2 - 2028 Base**
SAPE	**282**	0.0672	0.0392	0.0676	-0.02801	0.00033
BAND	**309**	0.0413	0.0239	0.0410	-0.01736	-0.00029
GRCA	**315**	0.0145	0.0087	0.0142	-0.00576	-0.00033
MEVE	**325**	0.0240	0.0137	0.0232	-0.01029	-0.00084
WHIT	**348**	0.0287	0.0165	0.0286	-0.01219	-0.00013
WEMI	**390**	0.0129	0.0073	0.0126	-0.00561	-0.00031
SACR	**449**	0.0192	0.0115	0.0184	-0.00777	-0.00081
BRCA	**454**	0.0041	0.0024	0.0041	-0.00172	0.00000
CANY	**462**	0.0090	0.0053	0.0085	-0.00368	-0.00047
CAPI	**480**	0.0039	0.0023	0.0039	-0.00165	0.00000
GUMO	**491**	0.0134	0.0079	0.0133	-0.00553	-0.00012
GRSA	**499**	0.0091	0.0052	0.0090	-0.00384	-0.00010
CAVE	**499**	0.0134	0.0079	0.0133	-0.00553	-0.00012
FLTO	**634**	0.0063	0.0037	0.0061	-0.00253	-0.00015
JOSH	**663**	0.0004	0.0003	0.0004	-0.00014	-0.00003
SAGO	**710**	0.0001	0.0001	0.0001	-0.00004	-0.00001
MOZI	**722**	0.0028	0.0016	0.0027	-0.00117	-0.00008
AGTI	**725**	0.0003	0.0002	0.0003	-0.00013	0.00000
ROMO	**733**	0.0032	0.0020	0.0030	-0.00119	-0.00018
SAGA	**812**	0.0001	0.0000	0.0001	-0.00004	0.00000
DOME	**829**	0.0004	0.0002	0.0004	-0.00018	0.00000
SEQU	**905**	0.0002	0.0001	0.0002	-0.00007	0.00000
KAIS	**953**	0.0001	0.0000	0.0001	-0.00004	0.00000
HOOV	**986**	0.0006	0.0003	0.0006	-0.00024	-0.00001
RAFA	**991**	0.0001	0.0001	0.0001	-0.00003	0.00000
YOSE	**1016**	0.0002	0.0001	0.0002	-0.00007	0.00000
PINN	**1108**	0.0000	0.0000	0.0000	0.00000	0.00000
PORE	**1300**	0.0000	0.0000	0.0000	0.00000	0.00000
ANAD	**#N/A**	0.0001	0.0000	0.0001	-0.00004	0.00000
ARCH	**#N/A**	0.0090	0.0053	0.0085	-0.00368	-0.00047
BLCA	**#N/A**	0.0129	0.0073	0.0126	-0.00561	-0.00031
CHIW	**#N/A**	0.0074	0.0042	0.0075	-0.00323	0.00001
CUCA	**#N/A**	0.0001	0.0000	0.0001	-0.00004	0.00000
DESO	**#N/A**	0.0001	0.0001	0.0001	-0.00006	-0.00001

		Deciview Impact from SGS (dv) on MIDs				
		Boilers + CT + Fugitives				
		SGS Visibility Impacts			SGS Visibility Impacts Reductions compared to Base Case	
Sites: IMPROVE monitors and/or Class I Areas	**Approximate Distance to SGS**	**2028 Base**	**Scenario #1 (SO_2 reductions)**	**Scenario #2 (NOx reductions)**	**Scenario #1 - 2028 Base**	**Scenario #2 - 2028 Base**
EANE	**#N/A**	0.0063	0.0037	0.0061	-0.00253	-0.00015
EMIG	**#N/A**	0.0002	0.0001	0.0002	-0.00007	0.00000
GALI	**#N/A**	0.0074	0.0042	0.0075	-0.00323	0.00001
JOMU	**#N/A**	0.0001	0.0000	0.0001	-0.00004	0.00000
KICA	**#N/A**	0.0002	0.0001	0.0002	-0.00007	0.00000
LAGA	**#N/A**	0.0129	0.0073	0.0126	-0.00561	-0.00031
MABE	**#N/A**	0.0063	0.0037	0.0061	-0.00253	-0.00015
MAZA	**#N/A**	0.0105	0.0076	0.0098	-0.00283	-0.00070
MOKE	**#N/A**	0.0001	0.0001	0.0001	-0.00006	-0.00001
PIMO	**#N/A**	0.0105	0.0076	0.0098	-0.00283	-0.00070
RAWA	**#N/A**	0.0028	0.0016	0.0027	-0.00117	-0.00008
SAJA	**#N/A**	0.0001	0.0001	0.0001	-0.00004	-0.00001
SUPE	**#N/A**	0.0155	0.0103	0.0150	-0.00514	-0.00050
VENT	**#N/A**	0.0000	0.0000	0.0000	0.00000	0.00000
WEEL	**#N/A**	0.0063	0.0037	0.0061	-0.00253	-0.00015
ZION	**#N/A**	0.0134	0.0085	0.0127	-0.00484	-0.00064
Maximum		***0.0672***	***0.0457***	***0.0676***	***0.00000***	***0.00033***
Average		***0.0104***	***0.0065***	***0.0102***	***-0.00394***	***-0.00018***
Minimum		***0.0000***	***0.0000***	***0.0000***	***-0.02801***	***-0.00106***

Table 6-2. SGS visibility impacts in deciview for boilers only.

		Deciview Impact from SGS (dv) on MIDs				
		Boilers only				
		SGS Visibility Impacts			SGS Visibility Impacts Reductions compared to Base Case	
Sites: IMPROVE monitors and/or Class I Areas	**Approximate Distance to SGS**	**2028 Base**	**Scenario #1 (SO_2 reductions)**	**Scenario #2 (NOx reductions)**	**Scenario #1 - 2028 Base**	**Scenario #2 - 2028 Base**
BALD	**38**	0.0272	0.0153	0.0262	-0.01189	-0.00105
PEFO	**101**	0.0323	0.0192	0.0320	-0.01308	-0.00030
GICL	**149**	0.0488	0.0282	0.0487	-0.02062	-0.00014

		Deciview Impact from SGS (dv) on MIDs				
		Boilers only				
		SGS Visibility Impacts			SGS Visibility Impacts Reductions compared to Base Case	
Sites: IMPROVE monitors and/or Class I Areas	**Approximate Distance to SGS**	**2028 Base**	**Scenario #1 (SO_2 reductions)**	**Scenario #2 (NOx reductions)**	**Scenario #1 - 2028 Base**	**Scenario #2 - 2028 Base**
BOAP	**218**	0.0172	0.0103	0.0165	-0.00684	-0.00072
CHIR	**257**	0.0071	0.0039	0.0071	-0.00322	0.00001
SAGU	**279**	0.0087	0.0049	0.0085	-0.00375	-0.00015
SAPE	**282**	0.0651	0.0370	0.0654	-0.02803	0.00033
BAND	**309**	0.0401	0.0228	0.0398	-0.01737	-0.00030
GRCA	**315**	0.0133	0.0075	0.0130	-0.00576	-0.00033
MEVE	**325**	0.0235	0.0132	0.0226	-0.01030	-0.00083
WHIT	**348**	0.0274	0.0152	0.0273	-0.01219	-0.00014
WEMI	**390**	0.0125	0.0069	0.0121	-0.00561	-0.00032
SACR	**449**	0.0186	0.0108	0.0178	-0.00776	-0.00081
BRCA	**454**	0.0040	0.0023	0.0040	-0.00170	0.00000
CANY	**462**	0.0088	0.0051	0.0083	-0.00367	-0.00046
CAPI	**480**	0.0037	0.0021	0.0038	-0.00165	0.00001
GUMO	**491**	0.0126	0.0071	0.0125	-0.00554	-0.00012
GRSA	**499**	0.0087	0.0048	0.0086	-0.00383	-0.00011
CAVE	**499**	0.0126	0.0071	0.0125	-0.00554	-0.00012
FLTO	**634**	0.0060	0.0034	0.0058	-0.00253	-0.00015
JOSH	**663**	0.0004	0.0003	0.0004	-0.00015	-0.00003
SAGO	**710**	0.0001	0.0001	0.0001	-0.00004	-0.00001
MOZI	**722**	0.0027	0.0015	0.0026	-0.00117	-0.00008
AGTI	**725**	0.0003	0.0002	0.0003	-0.00013	0.00000
ROMO	**733**	0.0030	0.0018	0.0028	-0.00119	-0.00018
SAGA	**812**	0.0001	0.0000	0.0001	-0.00004	0.00000
DOME	**829**	0.0004	0.0002	0.0004	-0.00019	0.00000
SEQU	**905**	0.0002	0.0001	0.0002	-0.00007	0.00000
KAIS	**953**	0.0001	0.0000	0.0001	-0.00004	0.00000
HOOV	**986**	0.0005	0.0003	0.0005	-0.00024	-0.00001
RAFA	**991**	0.0001	0.0001	0.0001	-0.00004	0.00000
YOSE	**1016**	0.0002	0.0001	0.0002	-0.00007	0.00000
PINN	**1108**	0.0000	0.0000	0.0000	0.00000	0.00000
PORE	**1300**	0.0000	0.0000	0.0000	0.00000	0.00000
ANAD	**#N/A**	0.0001	0.0000	0.0001	-0.00004	0.00000
ARCH	**#N/A**	0.0088	0.0051	0.0083	-0.00367	-0.00046
BLCA	**#N/A**	0.0125	0.0069	0.0121	-0.00561	-0.00032

		Deciview Impact from SGS (dv) on MIDs				
		Boilers only				
		SGS Visibility Impacts			SGS Visibility Impacts Reductions compared to Base Case	
Sites: IMPROVE monitors and/or Class I Areas	**Approximate Distance to SGS**	**2028 Base**	**Scenario #1 (SO_2 reductions)**	**Scenario #2 (NOx reductions)**	**Scenario #1 - 2028 Base**	**Scenario #2 - 2028 Base**
CHIW	**#N/A**	0.0071	0.0039	0.0071	-0.00322	0.00001
CUCA	**#N/A**	0.0001	0.0000	0.0001	-0.00004	0.00000
DESO	**#N/A**	0.0001	0.0000	0.0001	-0.00006	0.00000
EANE	**#N/A**	0.0060	0.0034	0.0058	-0.00253	-0.00015
EMIG	**#N/A**	0.0002	0.0001	0.0002	-0.00007	0.00000
GALI	**#N/A**	0.0071	0.0039	0.0071	-0.00322	0.00001
JOMU	**#N/A**	0.0001	0.0000	0.0001	-0.00004	0.00000
KICA	**#N/A**	0.0002	0.0001	0.0002	-0.00007	0.00000
LAGA	**#N/A**	0.0125	0.0069	0.0121	-0.00561	-0.00032
MABE	**#N/A**	0.0060	0.0034	0.0058	-0.00253	-0.00015
MAZA	**#N/A**	0.0091	0.0063	0.0084	-0.00285	-0.00072
MOKE	**#N/A**	0.0001	0.0000	0.0001	-0.00006	0.00000
PIMO	**#N/A**	0.0091	0.0063	0.0084	-0.00285	-0.00072
RAWA	**#N/A**	0.0027	0.0015	0.0026	-0.00117	-0.00008
SAJA	**#N/A**	0.0001	0.0001	0.0001	-0.00004	-0.00001
SUPE	**#N/A**	0.0138	0.0087	0.0133	-0.00514	-0.00052
VENT	**#N/A**	0.0000	0.0000	0.0000	0.00000	0.00000
WEEL	**#N/A**	0.0060	0.0034	0.0058	-0.00253	-0.00015
ZION	**#N/A**	0.0127	0.0078	0.0120	-0.00484	-0.00064
Maximum		***0.0651***	***0.0370***	***0.0654***	***0.00000***	***0.00033***
Average		***0.0093***	***0.0054***	***0.0091***	***-0.00394***	***-0.00018***
Minimum		***0.0000***	***0.0000***	***0.0000***	***-0.02803***	***-0.00105***

6.2 SGS Visibility Impacts in Light Extinction

Results of SGS CAMx visibility modeling are reported using light extinction (Mm^{-1}) in Table 6-3 for Boilers, Cooling Tower and Fugitives combined and Table 6-4 for Boilers only. The tables report SGS visibility impacts for each of the three 2028 scenarios, and visibility impact reductions of the two alternative scenarios compared to the 2028 base case. The maximum impacts are at PEFO and SAPE.

Table 6-3. SGS Visibility impacts in light extinction (Mm^{-1}) for boilers, cooling towers and fugitives.

		Extinction Impacts from SGS (Mm^-1) on MIDs				
		Boilers + CT + Fugitives				
		SGS Visibility Impacts			SGS Visibility Impacts Reductions compared to Base Case	
Sites: IMPROVE monitors and/or Class I Areas	Approximate Distance to SGS	2028 Base	Scenario #1 (SO_2 reductions)	Scenario #2 (NOx reductions)	Scenario #1 - 2028 Base	Scenario #2 - 2028 Base
BALD	38	0.0809	0.0552	0.0786	-0.02572	-0.00229
PEFO	101	0.1371	0.1067	0.1364	-0.03048	-0.00072
GICL	149	0.1188	0.0725	0.1186	-0.04629	-0.00026
BOAP	218	0.0582	0.0383	0.0559	-0.01991	-0.00237
CHIR	257	0.0198	0.0112	0.0199	-0.00858	0.00003
SAGU	279	0.0271	0.0158	0.0266	-0.01136	-0.00048
SAPE	282	0.1343	0.0783	0.1349	-0.05594	0.00063
BAND	309	0.0998	0.0579	0.0990	-0.04191	-0.00083
GRCA	315	0.0295	0.0178	0.0288	-0.01172	-0.00066
MEVE	325	0.0486	0.0278	0.0469	-0.02079	-0.00172
WHIT	348	0.0837	0.0482	0.0833	-0.03548	-0.00045
WEMI	390	0.0258	0.0146	0.0252	-0.01124	-0.00063
SACR	449	0.0922	0.0552	0.0880	-0.03694	-0.00414
BRCA	454	0.0083	0.0049	0.0083	-0.00345	-0.00001
CANY	462	0.0188	0.0112	0.0177	-0.00757	-0.00109
CAPI	480	0.0082	0.0048	0.0082	-0.00347	0.00000
GUMO	491	0.0497	0.0292	0.0492	-0.02045	-0.00042
GRSA	499	0.0209	0.0121	0.0207	-0.00882	-0.00025
CAVE	499	0.0497	0.0292	0.0492	-0.02045	-0.00042
FLTO	634	0.0106	0.0063	0.0104	-0.00428	-0.00025
JOSH	663	0.0016	0.0011	0.0015	-0.00053	-0.00012
SAGO	710	0.0006	0.0004	0.0005	-0.00019	-0.00003
MOZI	722	0.0050	0.0029	0.0048	-0.00209	-0.00015
AGTI	725	0.0016	0.0009	0.0015	-0.00068	-0.00002
ROMO	733	0.0079	0.0050	0.0075	-0.00291	-0.00048
SAGA	812	0.0003	0.0002	0.0003	-0.00016	-0.00002
DOME	829	0.0019	0.0010	0.0019	-0.00086	-0.00002
SEQU	905	0.0011	0.0007	0.0011	-0.00042	-0.00001
KAIS	953	0.0002	0.0001	0.0003	-0.00011	0.00001
HOOV	986	0.0013	0.0007	0.0013	-0.00056	-0.00001
RAFA	991	0.0004	0.0003	0.0004	-0.00015	-0.00001

		Extinction Impacts from SGS (Mm^-1) on MIDs				
		Boilers + CT + Fugitives				
		SGS Visibility Impacts			SGS Visibility Impacts Reductions compared to Base Case	
Sites: IMPROVE monitors and/or Class I Areas	**Approximate Distance to SGS**	**2028 Base**	**Scenario #1 (SO_2 reductions)**	**Scenario #2 (NOx reductions)**	**Scenario #1 - 2028 Base**	**Scenario #2 - 2028 Base**
YOSE	**1016**	0.0005	0.0003	0.0005	-0.00023	0.00001
PINN	**1108**	0.0000	0.0000	0.0000	-0.00002	0.00000
PORE	**1300**	0.0000	0.0000	0.0000	0.00000	0.00000
ANAD	**#N/A**	0.0002	0.0001	0.0003	-0.00011	0.00001
ARCH	**#N/A**	0.0188	0.0112	0.0177	-0.00757	-0.00109
BLCA	**#N/A**	0.0258	0.0146	0.0252	-0.01124	-0.00063
CHIW	**#N/A**	0.0198	0.0112	0.0199	-0.00858	0.00003
CUCA	**#N/A**	0.0003	0.0002	0.0003	-0.00016	-0.00002
DESO	**#N/A**	0.0003	0.0001	0.0003	-0.00017	-0.00001
EANE	**#N/A**	0.0106	0.0063	0.0104	-0.00428	-0.00025
EMIG	**#N/A**	0.0005	0.0003	0.0005	-0.00023	0.00001
GALI	**#N/A**	0.0198	0.0112	0.0199	-0.00858	0.00003
JOMU	**#N/A**	0.0002	0.0001	0.0003	-0.00011	0.00001
KICA	**#N/A**	0.0011	0.0007	0.0011	-0.00042	-0.00001
LAGA	**#N/A**	0.0258	0.0146	0.0252	-0.01124	-0.00063
MABE	**#N/A**	0.0106	0.0063	0.0104	-0.00428	-0.00025
MAZA	**#N/A**	0.0281	0.0208	0.0259	-0.00732	-0.00215
MOKE	**#N/A**	0.0003	0.0001	0.0003	-0.00017	-0.00001
PIMO	**#N/A**	0.0281	0.0208	0.0259	-0.00732	-0.00215
RAWA	**#N/A**	0.0050	0.0029	0.0048	-0.00209	-0.00015
SAJA	**#N/A**	0.0006	0.0004	0.0005	-0.00019	-0.00003
SUPE	**#N/A**	0.0452	0.0303	0.0437	-0.01491	-0.00154
VENT	**#N/A**	0.0000	0.0000	0.0000	-0.00002	0.00000
WEEL	**#N/A**	0.0106	0.0063	0.0104	-0.00428	-0.00025
ZION	**#N/A**	0.0320	0.0205	0.0304	-0.01150	-0.00158
Maximum		***0.1371***	***0.1067***	***0.1364***	***0.00000***	***0.00063***
Average		***0.0255***	***0.0159***	***0.0250***	***-0.00962***	***-0.00050***
Minimum		***0.00000***	***0.00000***	***0.00000***	***-0.05594***	***-0.00414***

Table 6-4 SGS visibility impacts in light extinction (Mm^{-1}) for boilers only.

		Extinction Impact from SGS (Mm^-1) on MIDs				
		Boilers only				
		SGS Visibility Impacts			SGS Visibility Impacts Reductions compared to Base Case	
Sites: IMPROVE monitors and/or Class I Areas	Approximate Distance to SGS	2028 Base	Scenario #1 (SO_2 reductions)	Scenario #2 (NOx reductions)	Scenario #1 - 2028 Base	Scenario #2 - 2028 Base
BALD	38	0.0588	0.0331	0.0565	-0.02570	-0.00227
PEFO	101	0.0750	0.0446	0.0743	-0.03040	-0.00071
GICL	149	0.1093	0.0630	0.1090	-0.04629	-0.00030
BOAP	218	0.0508	0.0308	0.0485	-0.01999	-0.00234
CHIR	257	0.0189	0.0104	0.0190	-0.00855	0.00003
SAGU	279	0.0264	0.0150	0.0259	-0.01140	-0.00048
SAPE	282	0.1298	0.0739	0.1305	-0.05598	0.00062
BAND	309	0.0970	0.0551	0.0962	-0.04193	-0.00086
GRCA	315	0.0271	0.0154	0.0264	-0.01173	-0.00067
MEVE	325	0.0475	0.0267	0.0458	-0.02081	-0.00170
WHIT	348	0.0800	0.0445	0.0795	-0.03548	-0.00048
WEMI	390	0.0250	0.0137	0.0243	-0.01124	-0.00064
SACR	449	0.0891	0.0522	0.0850	-0.03691	-0.00414
BRCA	454	0.0080	0.0046	0.0080	-0.00342	0.00000
CANY	462	0.0183	0.0108	0.0173	-0.00756	-0.00106
CAPI	480	0.0079	0.0044	0.0079	-0.00347	0.00002
GUMO	491	0.0467	0.0262	0.0462	-0.02050	-0.00045
GRSA	499	0.0200	0.0112	0.0197	-0.00880	-0.00027
CAVE	499	0.0467	0.0262	0.0462	-0.02050	-0.00045
FLTO	634	0.0101	0.0058	0.0098	-0.00428	-0.00025
JOSH	663	0.0015	0.0010	0.0014	-0.00055	-0.00011
SAGO	710	0.0005	0.0004	0.0005	-0.00019	-0.00003
MOZI	722	0.0048	0.0027	0.0047	-0.00209	-0.00014
AGTI	725	0.0015	0.0008	0.0015	-0.00068	-0.00003
ROMO	733	0.0075	0.0046	0.0070	-0.00291	-0.00048
SAGA	812	0.0003	0.0001	0.0003	-0.00016	-0.00002
DOME	829	0.0018	0.0010	0.0018	-0.00087	-0.00002
SEQU	905	0.0011	0.0007	0.0011	-0.00044	-0.00001
KAIS	953	0.0002	0.0001	0.0003	-0.00011	0.00001
HOOV	986	0.0012	0.0007	0.0012	-0.00056	-0.00003
RAFA	991	0.0004	0.0003	0.0004	-0.00016	-0.00001

		Extinction Impact from SGS (Mm^-1) on MIDs				
		Boilers only				
		SGS Visibility Impacts			SGS Visibility Impacts Reductions compared to Base Case	
Sites: IMPROVE monitors and/or Class I Areas	**Approximate Distance to SGS**	**2028 Base**	**Scenario #1 (SO_2 reductions)**	**Scenario #2 (NOx reductions)**	**Scenario #1 - 2028 Base**	**Scenario #2 - 2028 Base**
YOSE	**1016**	0.0005	0.0003	0.0005	-0.00023	0.00000
PINN	**1108**	0.0000	0.0000	0.0000	-0.00002	0.00000
PORE	**1300**	0.0000	0.0000	0.0000	0.00000	0.00000
ANAD	**#N/A**	0.0002	0.0001	0.0003	-0.00011	0.00001
ARCH	**#N/A**	0.0183	0.0108	0.0173	-0.00756	-0.00106
BLCA	**#N/A**	0.0250	0.0137	0.0243	-0.01124	-0.00064
CHIW	**#N/A**	0.0189	0.0104	0.0190	-0.00855	0.00003
CUCA	**#N/A**	0.0003	0.0001	0.0003	-0.00016	-0.00002
DESO	**#N/A**	0.0003	0.0001	0.0003	-0.00016	-0.00001
EANE	**#N/A**	0.0101	0.0058	0.0098	-0.00428	-0.00025
EMIG	**#N/A**	0.0005	0.0003	0.0005	-0.00023	0.00000
GALI	**#N/A**	0.0189	0.0104	0.0190	-0.00855	0.00003
JOMU	**#N/A**	0.0002	0.0001	0.0003	-0.00011	0.00001
KICA	**#N/A**	0.0011	0.0007	0.0011	-0.00044	-0.00001
LAGA	**#N/A**	0.0250	0.0137	0.0243	-0.01124	-0.00064
MABE	**#N/A**	0.0101	0.0058	0.0098	-0.00428	-0.00025
MAZA	**#N/A**	0.0246	0.0172	0.0224	-0.00736	-0.00220
MOKE	**#N/A**	0.0003	0.0001	0.0003	-0.00016	-0.00001
PIMO	**#N/A**	0.0246	0.0172	0.0224	-0.00736	-0.00220
RAWA	**#N/A**	0.0048	0.0027	0.0047	-0.00209	-0.00014
SAJA	**#N/A**	0.0005	0.0004	0.0005	-0.00019	-0.00003
SUPE	**#N/A**	0.0404	0.0255	0.0388	-0.01491	-0.00159
VENT	**#N/A**	0.0000	0.0000	0.0000	-0.00002	0.00000
WEEL	**#N/A**	0.0101	0.0058	0.0098	-0.00428	-0.00025
ZION	**#N/A**	0.0303	0.0188	0.0287	-0.01151	-0.00160
Maximum		***0.1298***	***0.0739***	***0.1305***	***0.00000***	***0.00062***
Average		***0.0228***	***0.0132***	***0.0223***	***-0.00962***	***-0.00050***
Minimum		***0.00000***	***0.00000***	***0.00000***	***-0.05598***	***-0.00414***

6.3 Discussion of SGS Visibility Results

As shown in Tables 6-2 through 6-4 above, the SGS SO_2 emissions reduction scenario (Alt#1) produces greater visibility benefits at all the CIAs than the NO_X emissions reduction scenario (Alt#2) whether using deciview or extinction units and whether the emissions from the cooling towers and fugitive emission sources are included or not. Focusing on the light extinction results from SGS boilers only (i.e., Table 6-4), across all 56 CIAs, the average visibility improvement (i.e., reduction in extinction for the MID) due to Alt#1 is -0.00962 Mm^{-1} that is much greater than the average improvement due to Alt#2 (-0.00050 Mm^{-1}). For the seven IMPROVE monitors within 300-km of the SGS, the average visibility improvement for Alt#1 (-0.02833 Mm^{-1}) is much greater than Alt#2 (-0.00078 Mm^{-1}), but the predicted improvements from both alternative control scenarios are small. It is interesting to note that except for Point Reyes (PORE) that is the furthest distance from SGS (1,300 km) where both alternative scenarios show zero change for the 2028 base case levels, Alt#1 produces visibility improvements at all CIAs, whereas Alt#2 does not. At the SAPE CIA that had the highest SGS visibility impact in the 2028 Base Case (0.1298 Mm^{-1}; boilers only), the Alt#1 SO_2 controls produces an improvement in visibility impairment, whereas the Alt#2 NO_X controls slightly degrades visibility impairment.

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APPENDIX A:

CAMX Runscript

APPENDIX A: CAMX Runscript

```
 &CAMx_Control

 Run_Message      = 'camx650_soa_cb6r4, 20160331,
RTP_Springerville_base',

!--- Model clock control ---

 Time_Zone        = 0,                 !
(0=UTC,5=EST,6=CST,7=MST,8=PST)
 Restart          = .true.,
 Start_Date_Hour  = 2016,03,31,0000,   ! (YYYY,MM,DD,HHmm)
 End_Date_Hour    = 2016,03,31,2400,   ! (YYYY,MM,DD,HHmm)

 Maximum_Timestep    = 15.,            ! minutes
 Met_Input_Frequency = 60.,            ! minutes
 Ems_Input_Frequency = 60.,            ! minutes
 Output_Frequency    = 60.,            ! minutes

!--- Map projection parameters ---

 Map_Projection = 'LAMBERT',  ! (LAMBERT,POLAR,UTM,LATLON)
 UTM_Zone       =   0,
 Longitude_Pole = -97.,      ! deg (west<0,south<0)
 Latitude_Pole  =  40.,      ! deg (west<0,south<0)
 True_Latitude1 =  33.,      ! deg (west<0,south<0)
 True_Latitude2 =  45.,      ! deg (west<0,south<0)

!--- Parameters for the master (first) grid ---

 Number_of_Grids      = 1,
 Master_SW_XCoord     = -2256.,        ! km or deg, SW corner of cell
(1,1)
 Master_SW_YCoord     = -996.,        ! km or deg, SW corner of cell
(1,1)
 Master_Cell_XSize    = 12.,           ! km or deg
 Master_Cell_YSize    = 12.,           ! km or deg
 Master_Grid_Columns  = 154,
 Master_Grid_Rows     = 110,
 Number_of_Layers     = 35,

!--- Model options ---

 Diagnostic_Error_Check = .false.,    ! True = will stop after  st
timestep
 Advection_Solver       = 'PPM',     ! (PPM,BOTT)
 Chemistry_Solver       = 'EBI',     ! (EBI,IEH,LSODE)
 PiG_Submodel           = 'GREASD',  ! (None,GREASD,IRON)
 Probing_Tool           = 'SA',      ! (None,SA,DDM,PA,RTRAC)
```

```
 Chemistry              = .true.,
 Drydep_Model           = 'ZHANG03', ! (NONE,WESELY89,ZHANG03)
 Wet_Deposition         = .true.,
 ACM2_Diffusion         = .false.,
 Super_Stepping         = .true.,
 Gridded_Emissions      = .true.,
 Point_Emissions        = .true.,
 Ignore_Emission_Dates  = .true.,
 Flexi_Nest             = .false., ! allow flexi-nest of input files
including restart
 Inline_Ix_Emissions    = .true.,

!--- Output specifications ---

 Root_Output_Name         =
'/dquad8a/RTP_Springerville/camx/outputs/RTP_Springerville_base/Q1/cam
x650_soa_cb6r4.RTP_Springerville_base.20160331',
 Average_Output_3D        = .false.,
 NetCDF_Format_Output     = .false.,
 NetCDF_Use_Compression   = .false.,
 Output_Species_Names(1) = 'NO',
 Output_Species_Names(2) = 'NO2',
 Output_Species_Names(3) = 'O3',
 Output_Species_Names(4) = 'SO2',
 Output_Species_Names(5) = 'CO',
 Output_Species_Names(6) = 'HNO3',
 Output_Species_Names(7) = 'NH3',
 Output_Species_Names(8) = 'PNO3',
 Output_Species_Names(9) = 'PSO4',
 Output_Species_Names(10) = 'PNH4',
 Output_Species_Names(11) = 'POA',
 Output_Species_Names(12) = 'PEC',
 Output_Species_Names(13) = 'FPRM',
 Output_Species_Names(14) = 'SOPA',
 Output_Species_Names(15) = 'SOPB',
 Output_Species_Names(16) = 'FCRS',
 Output_Species_Names(17) = 'SOA1',
 Output_Species_Names(18) = 'SOA2',
 Output_Species_Names(19) = 'SOA3',
 Output_Species_Names(20) = 'SOA4',
 Output_Species_Names(21) = 'NA',
 Output_Species_Names(22) = 'PCL',

!--- Input files ---

 Chemistry_Parameters =
'/disk4/ADEQ_PHX/camx/src.v6.50_soa/inputs/CAMx6.5.chemparam.CB6r4_CF_
SOAP_ISORROPIA',
 Photolyis_Rates      =
'/disk4/ADEQ_PHX/camx/inputs/tuv/tuv.ADEQ_PHX.12km.do_CB6.20160331',
 Ozone_Column         =
'/disk4/ADEQ_PHX/camx/inputs/o3map/o3map.ADEQ_PHX.12km.20160331.txt',
```

```
 Initial_Conditions   = ' ',
 Boundary_Conditions  =
'/disk4/ADEQ_PHX/camx/inputs/bcon/camx.nest.20160331.bc',
 Point_Sources        =
'/dquad8a/RTP_Springerville/emis/camx_ready/mrgpt_w_SGS/mrgpt.springer
ville.pig_tagged.adeq12km.20160331.bin',
 Master_Grid_Restart  =
'/dquad8a/RTP_Springerville/camx/outputs/RTP_Springerville_base/Q1/cam
x650_soa_cb6r4.RTP_Springerville_base.20160330.inst',

 Surface_Grid(1) =
'/disk4/ADEQ_PHX/camx/inputs/met/landuse.151221.12US2.zhang.camx.salt'
,
 Met3D_Grid(1)   =
'/disk4/ADEQ_PHX/camx/inputs/met/met3d.160331.12US2.35.wrf.camx',
 Met2D_Grid(1)   =
'/disk4/ADEQ_PHX/camx/inputs/met/met2d.160331.12US2.35.wrf.camx',
 Vdiff_Grid(1)   =
'/disk4/ADEQ_PHX/camx/inputs/met/vdif.160331.12US2.35.wrf.camx.0.1.YSU
.kvpatch',
 Cloud_Grid(1)   =
'/disk4/ADEQ_PHX/camx/inputs/met/clra.160331.12US2.35.wrf.camx',
 Emiss_Grid(1)   =
'/disk4/ADEQ_PHX/camx/inputs/emis/base/area/emis2d.20160331.adeq12k.20
16ff_16j+ss.camx',

 /
!-----------------------------------------------------------------------
----------
 &SA_Control

 SA_File_Root                 =
'/dquad8a/RTP_Springerville/camx/outputs/RTP_Springerville_base/Q1/cam
x65_CB6r4.20160331.RTP_Springerville_base',
 SA_Summary_Output            = .false.,
 SA_Stratify_Boundary         = .false.,
 SA_Deposition_Output         = .false.,
 SA_Number_of_Source_Regions  = 7,
 SA_Number_of_Source_Groups   = 1,
 Use_Leftover_Group           = .false.,
 SA_Treat_SULFATE_Class       = .true.,
 SA_Treat_NITRATE_Class       = .true.,
 SA_Treat_SOA_Class           = .false.,
 SA_Treat_PRIMARY_Class       = .true.,
 SA_Treat_MERCURY_Class       = .false.,
 SA_Treat_OZONE_Class         = .false.,
 SA_Use_APCA                  = .false.,

 SA_Receptor_Definitions      = '',
 SA_Source_Area_Map(1)        =
'/disk4/RTP_Springerville/camx/runfiles/srcmap/springerville_12km.srcm
ap',
```

```
 SA_Use_Partial_SourceMap     = .false.,
 SA_PT_Override               = .true.,

 SA_Master_Restart            =
'/dquad8a/RTP_Springerville/camx/outputs/RTP_Springerville_base/Q1/cam
x65_CB6r4.20160330.RTP_Springerville_base.sa.inst',
 SA_Nested_Restart            = ' ',

 SA_Points_Group(1)           = ' ',
 /
 &
!-----------------------------------------------------------------------
----------
```

APPENDIX B:

SMAT Control File

APPENDIX B: SMAT Control File

```
RunType=RunVisibility
OutputFileDir=C:\Users\Jguo\Documents\My SMAT-CE Files\Result\Output
OutputFileName=Springerville_BY2016_FY2028.cfg
scenarioName=Springerville_BY2016_FY2028
doTemporallyAdjVisibilityLevelsForecast=1
choiceUseOldVersionforIMPROVEAlgorithm=0
choiceUseNewVersionforIMPROVEAlgorithm=1
choiceUseModelGridCellAtMonitor=1
choiceUseModelGridCellatClassIAreaCentroid=0
doAutomaticallyExtract=1
monitorDataFileOldAlgorithm=
monitorDataFileNewAlgorithm=C:\Program Files (x86)\SMAT-CE\Data\SampleData\Monitor_data\ClassIareas_NEWIMPROVEALG_2000to2017_2019_feb11_IMPAIRMENT.csv
forecastIMPROVEDataFile=C:\Program Files (x86)\SMAT-CE\Data\SampleData\Monitor_data\ClassIareas_NEWIMPROVEALG_2000to2017_2019_feb11_IMPAIRMENT.csv
needCreateForecastIMPROVEDataFile=1
checkForecastIMPROVEAdvance=0
baselineModelDataFile=\\wcnovfps1\share\jguo\SMAT\MATS_PM25.ADEQ_PHX_base.avrg.grd01_noSALT.csv
forecastModelDataFile=\\wcnovfps1\share\jguo\SMAT\MATS_PM25.RTP_Springerville_base.avrg.grd01_noSALT.csv
temporalAdjustmentAtMonitorGrid=3x3
startMonitorYear=2013
endMonitorYear=2017
baseModelYear=2015
minYearsForValidVisibilityMonitors=3
```

Appendix B

Tucson Electric Power Company

SPRINGERVILLE GENERATING STATION UNITS 1 AND 2

COST EVALUATION TO SUPPORT FOUR FACTOR ANALYSIS

SL-015476

March 27, 2020

Project No. A13357.071

Sargent & Lundy

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TABLE OF CONTENTS

1. PURPOSE 1
1.1 TECHNOLOGIES EVALUATED 1
1.1.1 SO_2 Control Technologies Evaluated 2
1.1.2 NO_X Control Technologies Evaluated 2
1.2 APPROACH 2
1.3 CURRENT EMISSIONS 2
2. SO_2 EMISSIONS TECHNOLOGY EVALUATIONS 4
2.1 DFGD OPERATIONAL IMPROVEMENTS AND EQUIPMENT UPGRADES 4
2.1.1 Lime Quality 4
2.1.2 Improved Flue Gas Distribution 5
2.1.3 Increased Ca:S Stoichiometric Ratio 5
2.1.4 Approach to Saturation Temperature 6
2.1.5 Atomizer Upgrades 7
2.1.6 Adding an Absorber Vessel 8
2.2 EXISTING DFGD + DSI 8
3. NO_X EMISSIONS TECHNOLOGY EVALUATIONS 11
3.1 NEURAL NETWORK (COMBUSTION OPTIMIZATION) 11
3.2 OPTIMIZATION OF LNB/OFA 11
3.3 SNCR 12
4. SUMMARY OF EMISSIONS TECHNOLOGY EVALUATION 14
5. CAPITAL AND OPERATIONS AND MAINTETANCE COST ESTIMATES 15
6. DFGD OPERATIONAL IMPROVEMENTS AND EQUIPMENT UPGRADES COST ESTIMATE BASIS 16
6.1 CAPITAL COST ESTIMATE 17
6.2 VARIABLE O&M COSTS 17
6.3 FIXED O&M COSTS 18
6.4 INDIRECT OPERATING COSTS 19

7. DSI COST ESTIMATE BASIS 19
7.1 CAPITAL COST ESTIMATE 20
7.2 VARIABLE O&M COSTS 21
7.3 FIXED O&M COSTS 22
7.4 INDIRECT OPERATING COSTS 23
8. SNCR COST ESTIMATE BASIS 24
8.1 CAPITAL COST ESTIMATE 25
8.2 VARIABLE O&M COSTS 25
8.3 FIXED O&M COSTS 26
9. SUMMARY OF COST EVALUATION 28

TABLES

Table 1-1. Current Coal SO_2 3
Table 1-2. Current Stack Emissions 3
Table 4-1. Feasible Control Technologies to be Included in Cost Estimate 14
Table 6-1. DFGD Operational Improvements and Equipment Upgrades Capital Cost Estimate ($2020) 17
Table 6-2. Variable O&M Costs ($2020) 17
Table 6-3. Variable O&M Rates and First-Year Costs 17
Table 6-4. First-Year Fixed O&M Costs for DFGD Operational Improvements and Equipment Upgrades 18
Table 6-5. First-Year Fixed O&M Costs for DFGD Operational Improvements and Equipment Upgrades 19
Table 7-1. DSI Capital Cost Estimate ($2020) 20
Table 7-2. Variable O&M Costs 21
Table 7-3. Variable O&M Rates and First-Year Costs 21
Table 7-4. First-Year Fixed O&M Costs for DSI 22
Table 7-5. First Year Indirect Operating Costs for DSI 23
Table 8-1. SNCR Capital Cost Estimate ($2020) 25
Table 8-2. Variable O&M Costs 25
Table 8-3. Variable O&M Rates and First-Year Costs 25
Table 8-4. First Year Fixed O&M Costs for SNCR 27
Table 8-5. First-Year Indirect Operating Costs for SNCR 27
Table 9-1. Springerville Annualized Costs Summary ($2020) 28

APPENDIX

A. Summary Control Cost Evaluation Tables

1. PURPOSE

Tucson Electric Power's (TEP's) Springerville Generating Station (SGS) is located in Apache County, approximately 15 miles north of Springerville, Arizona. SGS consists of four coal-fired generating units, Units 1-4. This report addresses only Units 1 and 2 with respect to evaluating the costs associated with complying with the Regional Haze Rule Four Factor analysis.

Units 1 and 2 are owned and operated by TEP. These units were commissioned in 1985 and 1990, respectively, and have a nameplate rating of 425 MW each. Units 1 and 2 fire coal from the El Segundo mine in New Mexico. Units 1 and 2 are equipped with low-nitrogen oxide (NOx) concentric firing systems (LNCFS, also known as low-NO_X burners) and overfire air (OFA) for NOx control, spray dryer absorber (SDA) dry flue gas desulfurization (DFGD) systems for sulfur dioxide (SO_2) control, and reverse air fabric filter (FF) baghouses for particulate matter (PM) control.

As part of the Round II Regional Haze State Implementation Plan Determination (Round II Determination), the Arizona Department of Environmental Quality (ADEQ) requested that TEP prepare a four-factor analysis of control measures for visibility-impairing pollutants for SGS. **RTP Environmental Associates, Inc. ("RTP") will be preparing the overall four-factor analysis (FFA). Sargent and Lundy, L.L.C ("S&L") was only engaged to assist in the technical evaluation of control effectiveness and developing capital and operating and maintenance (O&M) cost estimates for retrofit or upgrade options specified by RTP.**

1.1 TECHNOLOGIES EVALUATED

Sargent & Lundy was contracted to evaluate the emission control technologies listed below.

1.1.1 SO_2 Control Technologies Evaluated

- DFGD operational improvements and equipment upgrades[1]
  - Lime quality
  - Improved flue gas distribution
  - Increase Ca:S stoichiometric ratio
  - Approach to saturation temperature
  - Atomizer upgrades
  - Adding an absorber vessel
- Existing DFGD + Dry Sorbent Injection (DSI)

1.1.2 NO_X Control Technologies Evaluated

- Neural network (combustion optimization)
- Optimization of low-NO_X burner (LNB)/overfire air (OFA)
- Selective non-catalytic reduction (SNCR)

S&L evaluated each control technology's reduction capability on an individual unit basis, as compared to the current emissions using recently obtained site-specific vendor information to determine if meaningful improvements could be achieved. This evaluation includes options for achieving lower SO_2 emissions in the future utilizing the projected El Segundo sulfur content on Units 1 and 2.

1.2 APPROACH

In order to determine the additional emission reduction potential, S&L conducted a site walkdown and desktop review of the existing systems: including review of Process Information (PI) Data, the U.S. Environmental Protection Agency's (EPA) Air Markets Program Data (AMPD), existing equipment and component data pages, and process flow diagrams (PFD). Based on this review, current operations were evaluated, limitations of the systems were determined, and the list of potential DFGD upgrade technologies were finalized. S&L then contacted original equipment manufacturers (OEMs) to collect performance and cost information for each option.

1.3 CURRENT EMISSIONS

S&L reviewed SO_2 and NOx emissions rates from available historical operating data from October 2017 to September 2019. The design basis coal sulfur levels are specified in Table 1-2. The current emission levels are specified in Table

[1] Sargent & Lundy determined potential DFGD upgrade sub-options based on current facility design and operation.

1-1. Both tables form the basis for the technical and cost evaluations. It should be noted that the values presented in these tables are not representative of the baseline emissions calculations which will be performed by others.

Table 1-1. Current Coal SO_2

Parameter	Unit	Unit 1	Unit 2
SO_2 DFGD system inlet	lb/MMBtu	2.18	2.18

Table 1-2 summarizes the emission rates S&L developed based on the current operation and controls for each unit.

Table 1-2. Current Stack Emissions

Emission	Unit	Unit 1	Unit 2
SO_2	lb/MMBtu	0.25	0.25
NO_X	lb/MMBtu	0.17	0.18

2. SO_2 EMISSIONS TECHNOLOGY EVALUATIONS

Unit 1 and 2 boilers were built with DFGD systems as part of the original design to control SO_2 emissions. The DFGD systems, including the SDAs, lime preparation and supply, and atomizers were designed by Joy/NIRO. The original DFGD systems on each Unit were designed with three vessels (vessels A-C). Since the original installation, Units 1 and 2 were each upgraded in 2004 with a fourth SDA vessel (vessel D) designed by Babcock & Wilcox (B&W) and modified again in 2017 by General Electric (GE) with operation at a lower approach temperature, higher recycle solids, lower lime injection and upgraded system controls.

2.1 DFGD OPERATIONAL IMPROVEMENTS AND EQUIPMENT UPGRADES

Operational and other design changes/upgrades to the existing DFGD system may provide an opportunity for additional SO_2 removal and allow the units to achieve lower controlled SO_2 emissions. S&L identified a number of potentially feasible operational changes that may be available to increase SO_2 removal efficiency with the existing equipment. A detailed discussion of each of these options is provided in the sections below.

2.1.1 Lime Quality

The quantity of lime (CaO) available in a dry scrubbing system compared to the amount of SO_2 entering the system is called the stoichiometric ratio (generally referenced as the Ca:S stoichiometric ratio). Reagent quality directly affects the Ca:S stoichiometric ratio in DFGD control systems. Using a high-quality lime increases the availability of hydrated lime to support process chemistry and reduces the lime slurry injection rate needed for SO_2 removal.

Lime quality is measured both by the CaO content and reactivity of the lime product. In a dry scrubber system, CaO is combined with water in a slaker to form hydrated lime or calcium hydroxide (Ca(OH)2), which provides the calcium that is needed to react with SO_2 in the flue gas. With a higher quality lime, more calcium hydroxide is available to react with SO_2. Lime products with a CaO content of 90% or greater are generally considered high quality lime. Reactivity of the lime is measured by the temperature rise when the lime is slaked (i.e. water addition). In general, porous lime products have higher reactivity which is demonstrated by achieving a temperature rise of 40°C within three minutes after adding water.

Based on a review of lime analyses and operating data from the existing lime slaking system, TEP currently procures a high-quality lime for use in the dry scrubbers. The typical CaO content of the lime used at SGS is 90% or greater. As such, changing the lime quality will not provide any additional benefit to Units 1 and 2.

2.1.2 Improved Flue Gas Distribution

On Units 1 and 2, the arrangement of the four SDA vessels (A-D) in relation to the air pre-heater outlet duct, causes maldistribution of flue gas amongst the three original operating vessels (A-C); more specifically, the new vessel D (4th vessel) receives approximately 25% more flue gas flow than the original three vessels. This also corresponds to 25% more SO_2 loading which requires vessel D to provide significantly more lime in order to achieve a similar outlet SO_2 emission rate as the original three vessels. The current flue gas maldistribution can be corrected with a balancing damper on the flue gas inlets to each SDA vessel as well as perforated plates in the upstream flue gas duct. It is understood that due to the additional flue gas flow to vessel D, the lime supply system capacity to this vessel is insufficient, resulting in a higher approach to saturation operating temperature which results in higher outlet SO_2 emissions (approximately 15-20% higher emissions than vessels A-C).

Perforated plates can be specifically designed in conjunction with Computational Fluid Dynamics (CFD) modeling to provide a more uniform flow into each of the individual vessels. Furthermore, balancing dampers provide additional correction, especially since there are various operating profiles, depending on which vessels are in operation at a given time. Correcting the maldistribution will ensure better residence time through all the vessels and allow for consistent and equal lime demand to each vessel. Corrosion resistant material should be used for this application due to the high dust application and erosive nature of the El Segundo flyash. Analysis of the other control technologies assumes that these modifications are implemented, and the system will have even flue gas distribution across vessels A-D on both Units 1 and 2.

2.1.3 Increased Ca:S Stoichiometric Ratio

Other operational changes that can increase the Ca:S stoichiometric ratio or utilization include: (1) increasing the byproduct recycle rate which increases utilization of the lime injected; and/or (2) increasing the quantity of fresh hydrated lime introduced to the system.

Solids exiting a dry scrubber consist of fly ash, reaction byproduct, and residual unreacted hydrated lime. On Unit 1 and Unit 2, solids collected in the fabric filter hoppers are conveyed to either a dry storage silo for disposal or to a recycle fly ash silo where it is used as make-up for the reactant slurry. The recycle system is designed to utilize a portion of the unreacted lime rather than disposing of all of the solids. Recycle solids are combined with the fresh lime addition to provide the makeup lime needed for SO_2 reduction. Increasing the recycle rate can increase the

amount of hydrated lime added to the system (i.e., stoichiometric ratio) without increasing the quantity of fresh lime added to the system.

Based on information provided by TEP, the DFGD systems on Unit 1 and Unit 2 were upgraded in 2017 to operate the recycle system at approximately 40-55% solids. Based on S&L's experience, increasing the recycle percent solids any further is not considered a technically feasible SO_2 control option for SGS Units 1 and 2.

As an alternative to raising the recycle rate, the Ca:S stoichiometric ratio in the system may be increased by increasing the quantity of fresh lime introduced to the system. The current lime ratio for Units 1 and 2 is estimated at 1.5. Increasing the stoichiometric ratios will increase the availability of hydrated lime, which could reduce SO_2 emissions further.

As mentioned above, the controls systems on Units 1 and 2 were upgraded in 2017 in order to provide better control over the solids recycle and the lime slurry feed rates. The primary control loop is the water flow rate into the recycle mix tank, which maintains a relatively constant level in the lime slurry feed tank. The rate of change in the tank level, controlled by the addition of water, adjusts the percent solids of the recycle slurry and is a function of the boiler load and SO_2 loading. The lime slurry feed rate to the atomizer is trimmed by a temperature set point at the SDA outlet; the higher the lime slurry feed rate, the lower the SDA outlet temperature. The amount of fresh lime added to the suction of the lime slurry feed pumps is controlled by a common SO_2 setpoint in the stack. The fresh lime is distributed to each SDA slurry pump proportional to the slurry feed rate for each atomizer. The current SO_2 setpoint of the Unit 1 and 2 DFGD system is 90 parts per million (ppm) SO_2, which is approximately 0.23 lb/MMBtu. Assuming the flue gas flow distribution modifications will correct uneven flue gas distribution to the SDA vessels, lowering the SO_2 emission setpoint could achieve an average controlled SO_2 emission rate of 0.15 lb/MMBtu. This would require additional fresh lime to be used in the DFGD system. The existing Unit 1 and 2 DFGD system, lime preparation and supply systems all have sufficient capacity to lower the emission setpoint of the system. Flow modeling and field testing on SGS Units 1 and 2 would be needed to ensure that adequate residence time is available for SO_2 control and to confirm the incremental reduction in SO_2 emissions achievable without creating unacceptable operational issues.

2.1.4 Approach to Saturation Temperature

The reaction of SO_2 with Ca(OH)2 in a dry scrubber is driven by the absorber temperature. Water surrounding the lime slurry droplet allows SO_2 to dissolve into the liquid and facilitates the reaction between lime and SO_2. The

temperature differential between the inlet and the outlet of the DFGD is used as a driving force for SO_2 removal, However, outlet temperatures must be maintained above the saturation temperature to ensure byproducts exiting the absorber vessel are dry and remain dry as they pass through the baghouse, ductwork, and stack. Residence time within the absorber vessel, drying time, and exit temperature are all important design parameters for a dry scrubbing system.

Inlet temperature to the dry scrubbing vessel is relatively constant; however, there can be short term temperature variations of +/- 10°F that occur due to coal quality, boiler soot blowing, convection pass and air heater cleanliness; therefore, temperature differential across the vessel is a function of the outlet temperature. As a general rule, the closer the outlet temperature is to the adiabatic saturation temperature, the higher the SO_2 removal efficiency.

Maintaining an absorber outlet temperature close to the point of saturation, while staying above it, is vital for optimal reaction kinetics. Operating a dry scrubbing system at outlet temperatures significantly above the adiabatic saturation temperature accelerates water evaporation from the reactant slurry, limits SO_2 absorption into the droplet, and limits the reaction between the lime and SO_2. Reducing the temperature in the absorber closer to the saturation point can provide additional SO_2 removal. On the other hand, the absorber vessel may not have sufficient residence time to dry all slurry droplets if the system is operated too close to adiabatic saturation, which would result in deposits in the absorber vessel, corrosion, and severe operational problems.

As part of the 2017 DFGD system upgrade on Units 1 and 2, SGS lowered the approach temperature and are operating at approximately 155-160˚F, which is approximately 25-30˚F above the adiabatic saturation temperature. Vessels A-C generally maintain this temperature, which is in line with standard industry practice. However, vessel D operates closer to 50˚F above the adiabatic saturation temperature. As discussed in previous sections, this is primarily due to the fact that vessel D receives 25% more flue gas flow than originally designed. Correcting the maldistribution will allow vessel D to operate at an approach temperature similar to vessels A-C which will lead to improved SO_2 performance. It should be noted that operation of all four vessels would not be required when operating at mid or low load. Vessels could be taken out of service to maintain optimal velocity, flow distribution and SO_2 removal performance across the operating vessels.

2.1.5 Atomizer Upgrades

Based on discussions with the FGD OEM, all SDA vessels are equipped with modern atomizers. As such, upgrading the existing atomizers to a new atomizer design would not result in any additional SO_2 removal.

2.1.6 Adding an Absorber Vessel

Another option for extending the residence time within the reactor vessel and increasing Ca:S contact would be to add an additional absorber vessel to TEP Units 1 and 2. The existing system is designed with four absorber vessels per unit. Dry scrubbing units operating at flue gas volumes significantly above the design flow rate can benefit from adding an extra vessel to the system. The vessel would be placed in parallel with the existing vessels to achieve a similar pressure drop through each vessel and ensure equal flue gas distribution to the vessels. Units 1 and 2 were initially constructed with Joy Niro SDA FGD systems in 1988 but have since undergone some upgrades to improve SO_2 removal performance. In 2004, SGS added vessel D to the Units 1 and 2 DFGD systems. Initially, the fourth absorber vessel was installed to provide a maintenance spare and would therefore operate intermittently. Installation of a fifth absorber would not provide any significant improvement towards removing additional sulfur. Instead, SGS can operate all four vessels as needed to equalize the flowrate to each SDA vessel and increase residence time during full load operation. It should be noted that operation of all four vessels would not be required when operating at mid or low load. Vessels could be taken out of service to maintain optimal velocity, flow distribution and SO_2 removal performance across the operating vessels.

2.2 EXISTING DFGD + DSI

Alkali based Dry Sorbent Injection (DSI) is a proven technology for the removal of sulfur trioxide (SO3) and other acid gases from coal-fired power plant flue gas and can be used to provide SO_2 control. Sorbent is injected into the ductwork, after the furnace, and prior to the particulate collection device, where it reacts with SO_2 and other acid gases. DSI systems are relatively simple systems consisting of material storage, feeding mechanism, blower or transfer line, and an injection device. For SO_2 control on the SGS units, sorbent would be injected upstream of the dry scrubber to provide an incremental reduction in the concentration of SO_2 in the flue gas.

Sorbents react with SO_2, and other acid gases, in the flue gas when injected at an appropriate rate and within the proper temperature range for that sorbent. The resulting particulate matter is removed from the flue gas by the particulate control system. The process works through neutralization of the acid gases with the alkaline sorbent. The neutralization reaction occurs as long as the sorbent remains in contact with the gas, in the flue gas duct work within the required temperature range.

Dry sorbents that have been used for SO_2 control on coal-fired boilers include:

- Hydrated Lime (Ca(OH)2)

- Trona or Sodium Bicarbonate (SBC)

Dry sorbents, including hydrated lime, Trona, and SBC would be injected pneumatically as a dry powder into the flue gas ductwork upstream of the DFGD. Trona and SBC are both sodium-based sorbents, which react with SO_2 to form sodium salts. Hydrated lime would react with SO_2 to form calcium sulfate salts. The hydrated lime reactions are the same reactions that are taking place in the existing dry scrubber.

Hydrated lime is less reactive than the sodium based dry sorbents; thus, higher injection rates and longer residence time would be required to achieve the same removal efficiency. However, hydrated lime has a lower unit cost compared to other sorbent options, offsetting the higher injection rates. It is also important to note the hydrated lime chemistry involves the same reactions, and forms the same calcium salts, as those currently taking place in the dry scrubber reaction vessels. Therefore, using hydrated lime as the sorbent would not introduce any new constituents into the dry scrubbing system, and could potentially increase the Ca:S stoichiometric ratio in the dry scrubber.

With sodium-based dry sorbents, less reactant may be sufficient to achieve the same SO_2 removal efficiency, because of the sorbents' higher reactivity. However, injecting a sodium-based sorbent into the flue gas upstream of the DFGD would introduce new chemical constituents into the scrubber and into the fly ash/scrubber byproduct material. This could prove problematic as sodium compounds are water soluble and introducing sodium into the system could adversely affect the characteristics of the byproduct solids generated by the system and introduce additional corrosion related issues within the SDA and FF systems. Detailed studies and demonstration tests would be needed to ensure that introducing relatively large amounts of sodium would not adversely affect scrubber operation or result in solids disposal issues. DSI upstream of the existing dry scrubber could provide additional SO_2 removal on SGS Units 1 and 2. Taking into consideration these units are currently equipped with a calcium-based dry scrubbing system, hydrated lime dry DSI would be the most practical, and potentially the most effective, DSI control option. Unit 1 and 2 emission rates could be reduced by this technology. Based on engineering judgment, and assuming adequate residence time in the duct work upstream of the existing dry scrubber, hydrated lime injection could reduce SO_2 concentrations at the dry scrubber inlet by approximately 30%, resulting in a controlled SO_2 emission rate of 0.18 lb/MMBtu. Flow modeling and field testing on SGS Units 1 and 2 would be needed to ensure that adequate residence time is available for SO_2 control and to confirm the incremental reduction in SO_2 emissions achievable without creating unacceptable operational issues.

Although DSI is a technically feasible control option, it should be noted that DSI upstream of the existing DFGD control system at SGS would not provide any additional SO_2 removal than what could already be achieved by

increasing the fresh lime or calcium content as discussed in previous sections. The existing lime slaking system at SGS Units 1 and 2 has sufficient capacity to provide the increase in calcium content. As such, the more cost-effective control option would be to use the existing DFGD system on Units 1 and 2 and increase the fresh lime slurry to the system.

3. NO_X EMISSIONS TECHNOLOGY EVALUATIONS

3.1 NEURAL NETWORK (COMBUSTION OPTIMIZATION)

Controlling the amount of excess air, fine tuning boiler configuration, and adjusting the amount of air flow to the burners can have a significant impact to NOx formation at the boiler exit. Excess air is a necessary aspect of combustion, however, lowering the amount of excess air required will result in less oxygen in the combustion zone, leading to less oxidation of N2 and thus less NOx formation. Lower oxygen levels lead to higher carbon monoxide (CO) due to incomplete combustion. Further, incomplete combustion will reduce boiler efficiency and lower process steam temperatures. Thus, to balance these positive and negative considerations, optimization of excess air operation is required.

A relatively new approach to improving boiler performance is installing an on-line combustion optimization system such as a Neural Network (e.g. Zoloboss). These laser-based analyzers detect oxygen concentration, temperature, moisture content, and CO concentration across the plane of the boiler furnace where combustion is occurring. The system provides feedback on how the furnace is operating, allowing operators to adjust excess air levels and see how the system reacts in real time. The feedback can also be integrated into a closed-loop system for the boiler to make automatic adjustments during operation.

Boiler tuning for combustion optimization is completed on a regular basis as part of Mercury and Air Toxics Standards (MATS) compliance (CO best practices). As part of this practice, the NOx emissions are reduced during the tuning process. Implementation of a combustion optimization system will act as redundant measures to the boiler tuning; because of this, none of the units would benefit significantly from adding neural network. As such, a cost evaluation was not performed for this option.

3.2 OPTIMIZATION OF LNB/OFA

As with implementing a neural network, LNB and OFA are a way of optimizing combustion to reduce NOx emissions. Units 1 and 2 are equipped with a low NOx concentric firing system to increase combustion optimization. S&L has reviewed the fuel composition, boiler type and current combustion systems in place. Based on current emissions from both units, upgrades to the LNB or OFA would yield minimal or no reduction in NOx emissions. As such, a cost evaluation was not performed for this option.

3.3 SNCR

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia or urea (CO(NH2)2) at high flue gas temperatures (approximately 1,600ºF – 2,100ºF) in an oxidizing environment. The ammonia or urea reacts with NO_X in the flue gas to produce N2 and water as shown below.

$$(NH_2)_2CO + 2NO + \tfrac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$

$$2NH_3 + 2NO + \tfrac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reagent injection can greatly affect NO_X removal efficiencies and the quantity of NH_3 or urea that will pass through the SNCR unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective in the range of 1,600ºF – 2,100ºF. At temperatures below the desired operating range, the NO_X reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NO_X resulting in low NO_X reduction efficiencies. Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Furnace geometry, urea spray coverage, and droplet size must be considered when developing good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that temperature window. As the boiler cycles in load, the optimum injection region may change. Thus, most facilities require multiple injection zones which are placed in and out of service as the unit ramps in load. This can include modifying the zones of injectors that are operating at different loads and temperatures.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NO_X ratio, and fuel sulfur content. Increasing the normalized stoichiometric ratio can improve NO_X removal. This is completed by increasing urea solution flow through the injectors or changing the concentration of urea in the solution. However, too high of reagent injection rates will increase the ammonia slip beyond the recommended 10 ppmvd limit. Above this concentration, there are expected to be major impacts to the formation of ammonia salts on the boiler tube banks, reducing heat transfer efficiency, and air heater baskets, causing corrosion.

SNCR can be applied on pulverized coal boiler, however the potential NO_X reduction is boiler specific. SNCR has been used as a retrofit NO_X control system on pulverized coal, fluidized bed boilers, and cyclone

boilers. Furthermore, SNCR can be implemented on boilers equipped with LNB, OFA, or separated overfire air (SOFA) systems. Based on the boiler residence time, temperature profile, and stoichiometry, as well as input from SNCR OEMs, S&L estimates that an SNCR system could achieve an average controlled NO_X emission rate of approximately 0.15 lb/MMBtu while limiting ammonia slip to 10 ppmvd. It should be noted that CFD modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO_X emission is achievable without creating unacceptable operational issues.

4. SUMMARY OF EMISSIONS TECHNOLOGY EVALUATION

Table 4-1 below provides a summary of the average achievable emission rates for the feasible SO_2 and NOx options evaluated

Table 4-1. Feasible Control Technologies to be Included in Cost Estimate

Control Option	Emission Rate (lb/MMBtu)[1]
SO_2	
Lime Quality	No Reduction
Improved Flue Gas Distribution	See increased Ca:S stoichiometric ratio
Increased Ca:S stoichiometric ratio	0.15 lb SO_2/MMBtu
Approach to saturation temperature	No reduction
Atomizer upgrades	No reduction
Adding an absorber vessel	No reduction
Existing DFGD + DSI	0.18 lb NO_X/MMBtu
NO_X	
SNCR	0.15 lb NO_X/MMBtu

Note:

1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions. Emission rates are provided for comparative purposes and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

5. CAPITAL AND OPERATIONS AND MAINTETANCE COST ESTIMATES

Capital and operations and maintenance (O&M) cost estimates were developed for each of the feasible SO_2 and NO_X control options. The SGS Unit 1 and 2 cost estimates are conceptual in nature, supplemented with budgetary quotes where applicable. Equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on SGS unit-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the SGS retrofit technologies as study-level cost estimates generally based on parametric models, judgment, or analogy.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimate (e.g., mobilization and demobilization, consumables, Contractor General and Administrative (G&A) expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements. The cost of auxiliary power requirements reflects the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing SO_2 and NOx controls.

The capital cost estimates generally include the following major components:

- Purchased Equipment Costs
- Equipment and material
- Instrumentation
- Sales Tax
- Freight on Materials
- Direct Installation Costs
- Labor
- Scaffolding
- Mobilization / Demobilization

- Cost due to Overtime
- Indirect Field Costs
- Contractor's General and Administration
- Contractor's Profit
- Engineering, Procurement and Project Services
- Construction Management/Field Engineering
- Startup and Commissioning
- Spare Parts
- Owners Cost
- Project Contingency

6. DFGD OPERATIONAL IMPROVEMENTS AND EQUIPMENT UPGRADES COST ESTIMATE BASIS

The cost estimate for Unit 1 and 2 DFGD operational improvements and equipment upgrades include:

- Lowering the SO_2 stack emission setpoint to increase the fresh lime injection rate and in effect, the Ca:S ratio
- Correcting the maldistribution of flue gas to vessels A-D on each unit.

The existing lime slurry preparation and supply systems are capable of meeting the new system demand; therefore, no capital costs were included for this upgrade. To fix the maldistribution of flue gas to the four SDA vessels, the existing ductwork will require the following scope which was included in the capital cost estimate:

- CFD Modelling
- Perforated Plates (qty 1 per SDA vessel, total 4 per unit)
- Balancing Dampers (qty 2 per SDA vessel, total 8 per unit)

6.1 CAPITAL COST ESTIMATE

Table 6-1 summarizes the DFGD Operational Improvements and Equipment Upgrades capital cost estimate.

Table 6-1. DFGD Operational Improvements and Equipment Upgrades Capital Cost Estimate ($2020)

Capital Cost	Unit 1	Unit 2
Purchased Equipment	2,247,000	2,247,000
Direct Installation	223,000	223,000
Indirect	766,000	766,000
Contingency	647,000	647,000
Total Capital Investment	**3,883,000**	**3,883,000**

6.2 VARIABLE O&M COSTS

The following unit costs in Table 6-2 were used to develop the variable O&M costs. All values, except for the water costs, were provided by TEP and are consistent with typical industry values. The water costs are based on S&L's conceptual cost estimating system.

Table 6-2. Variable O&M Costs ($2020)

Unit Cost	Units	Units 1 and 2
Lime	$/ton	150.60
Water	$/1000 gal	1.00
Byproduct Disposal	$/ton	1.29
Auxiliary Power	$/MWh	36.90

Table 6-3 summarizes the estimated consumption rates as well as the first year variable O&M costs for the Dry FGD system. As stated, the O&M costs are based on the incremental costs from current operation.

Table 6-3. Variable O&M Rates and First-Year Costs

Parameter	Units	Unit 1	Unit 2
Incremental Variable O&M Rates			
Lime Consumption	lb/hr	694	694
Byproduct Waste Production	lb/hr	1,381	1,381

Parameter	Units	Unit 1	Unit 2
Auxiliary Power Consumption	kW	672	672
Water Consumption	gpm	7	7
Incremental Variable O&M[1] Cost (CF[2])			
Lime Consumption	$/year	323,000	310,000
Byproduct Waste Production	$/year	6,000	5,000
Auxiliary Power Consumption	$/year	153,000	147,000
Water Consumption	$/year	3,000	3,000
Total First Year Variable O&M Cost	**$/year**	**485,000**	**465,000**

Notes:

1. First-year costs are provided in $2020.
2. The first-year costs are calculated using the Unit 1 and Unit 2 annual capacity factor of 71% and 68%, respectively. Capacity factors were based on the average operation of each Unit between January 2018 and Septmeber 2019. The capacity factors are based on historical operation and may not represent future operation.

6.3 FIXED O&M COSTS

No additional operators will be required for this technology and therefore no costs are included for labor.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (materials and labor) were estimated to be approximately 1.5% of the total purchased equipment cost and direct installation costs.[2] Fixed O&M costs for DFGD upgrades are summarized in Table 6-4.

Table 6-4. First-Year Fixed O&M Costs for DFGD Operational Improvements and Equipment Upgrades

First Year Fixed O&M Costs[1]	Units	Unit 1	Unit 2
Operating Labor[2]	$/year	0	0
Supervisor Labor	$/year	0	0
Maintenance Material	$/year	37,000	37,000

[2] Sorrels, John, et. al, U.S. EPA, *Cost Estimation: Concepts and Methodology* (Nov. 2017), 2-31, 2-32, https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf ("Cost Control Manual").

First Year Fixed O&M Costs[1]	Units	Unit 1	Unit 2
Maintenance Labor[3]	$/year	0	0
Total First Year Fixed O&M Cost	**$/year**	**37,000**	**37,000**

Notes:
1. First-year costs are provided in $2020.
2. Operating labor costs are based on a labor rate of $60/hr, which is based on Sargent & Lundy's conceptual cost estimating system.
3. Maintenance labor cost included in maintenance materials.

6.4 INDIRECT OPERATING COSTS

Indirect operating costs necessary to own and operate a facility with a DFGD system include property taxes, insurance, and administrative services. Property taxes and insurance charges are estimated to be 1% of the total capital investment.[3] Administration is estimated to be 2% of the total capital investment.[4] Table 6-5 summarizes the indirect operating costs.

Table 6-5. First-Year Fixed O&M Costs for DFGD Operational Improvements and Equipment Upgrades

Indirect Operating Costs[1]	Units	Unit 1	Unit 2
Property Taxes	$/year	39,000	39,000
Insurance	$/year	39,000	39,000
Administration	$/year	78,000	78,000
Total Indirect Operating Cost	**$/year**	**156,000**	**156,000**

Note:
1. Indirect operating costs are provided in $2020.

A summary cost table associated with the DFGD operational improvements and equipment upgrades option is summarized in **Appendix A**.

7. DSI COST ESTIMATE BASIS

Units 1 and 2 do not currently have a DSI system. All costs associated with installing and operating a new system have been included in this estimate. The DSI retrofit estimate is based on S&L prior experience with the system and vendor quotes. Vendors included costs for DSI equipment and estimated freight. The balance of plant (BOP) costs

[3] *Id.* at 2-31 2-32.
[4] *Id.*

were estimated from S&L's conceptual cost estimating system from similar projects. The scope of work in the DSI cost estimate includes the following major items:

- Truck unloading blowers
- Hydrated lime silos (8 x 14' diameter)
- Dehumidifiers
- Conveying blowers
- Hydrated lime injection lances
- Heat exchangers
- Injection splitters
- Civil and structural BOP and pre-engineered building
- Interconnecting piping, valves, and insulation
- Pipe supports and pipe rack
- Compressed air system and receivers
- Eyewash and safety shower
- Flue gas duct modifications
- Electrical and instrumentation/controls

Costs associated with a DSI system are summarized in **Appendix A**.

7.1 CAPITAL COST ESTIMATE

Table 7-1 summarizes the DSI capital cost estimate.

Table 7-1. DSI Capital Cost Estimate ($2020)

Capital Cost	Unit 1	Unit 2
Purchased Equipment	10,154,000	10,154,000
Direct Installation	2,624,000	2,624,000
Indirects	3,962,000	3,962,000
Contingency	3,348,000	3,348,000
Total Capital Investment	**20,088,000**	**20,088,000**

7.2 VARIABLE O&M COSTS

The unit costs in Table 7-2 were used to develop the variable O&M costs. All values, with the exception of the reagent costs, were provided by TEP and are consistent with typical industry values. All costs are based on recent contracts executed at the facility.

Table 7-2. Variable O&M Costs

Unit Cost	Units	Value
Hydrated Lime	$/ton	150
Byproduct Disposal	$/ton	1.29
Auxiliary Power	$/MWh	36.90
Bag and Cage Replacement	$/bag	212.57

Table 7-3 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the DSI system.

Table 7-3. Variable O&M Rates and First-Year Costs

Parameters	Units	Unit 1	Unit 2
DSI System			
Reagent Consumption	lb/hr	11,700	11,700
Byproduct Waste Production	lb/hr	55,847	55,847
Auxiliary Power Consumption	kW	800	800
Bag Replacement (Net Change)	Bags	384	384
First-Year Variable O&M[1] Cost (@CF[2])			
Reagent Cost	$/year	5,430,000	5,201,000
Byproduct Waste Disposal Cost	$/year	222,000	212,000
Auxiliary Power Cost	$/year	183,000	175,000
Bag Replacement Costs	$/year	82,000	82,000
Total-First Year Variable O&M Cost	**$/year**	**5,917,000**	**5,670,000**

Notes:
1. First-year costs are provided in $2020.

2. The first-year costs are calculated using the Unit 1 and Unit 2 annual capacity factor of 71% and 68%, respectively. Capacity. factors were based on the average operation of each Unit between January 2018 and Septmeber 2019. The capacity factors are based on historical operation and may not represent future operation.

7.3 FIXED O&M COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). Based on typical design for the DSI system, the estimated staffing additions is one (1) person for both Units. Operating Labor costs are estimated based on two (2) shifts/day, 365 days per year at an operator charge rate of $60/hour. Supervisor labor is estimated to be 15% of the total operating labor costs.[5]

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (materials and labor) were estimated to be approximately 1.5% of the total purchased equipment cost and direct installation costs.[6]

Table 7-4 below summarizes the first year fixed O&M costs.

Table 7-4. First-Year Fixed O&M Costs for DSI

First Year Fixed O&M Costs[1]	Units	Unit 1	Unit 2
Operating Labor[2]	$/year	263,000	263,000
Supervisor Labor	$/year	39,000	39,000
Maintenance Material	$/year	192,000	192,000
Maintenance Labor[3]	$/year	0	0
Total First Year Fixed O&M Cost	$/year	494,000	494,000

Notes:
1. First-year costs are provided in $2020.
2. Operating labor costs are based on a labor rate of $60/hr, which is based on Sargen & Lundy's conceptual cost estimating system.
3. Maintenance labor cost included in maintenance materials.

[5] *Id*. at 2-31
[6] *Id*. at 2-31 2-32.

7.4 INDIRECT OPERATING COSTS

Indirect operating costs necessary to own and operate a facility with a DSI system include property taxes, insurance, and administrative services. Property taxes and insurance charges are estimated to be 1% of the total capital investment.[7] Administration is estimated to be 2% of the total capital investment.[8]

Table 7-5 summarizes the indirect operating costs.

Table 7-5. First Year Indirect Operating Costs for DSI

Indirect Operating Costs[1]	Units	Unit 1	Unit 2
Property Taxes	$/year	201,000	201,000
Insurance	$/year	201,000	201,000
Administration	$/year	402,000	402,000
Total Indirect Operating Cost	**$/year**	**804,000**	**804,000**

Note:
1. Indirect operating costs are provided in $2020.

[7] *Id.*
[8] *Id.*

8. SNCR COST ESTIMATE BASIS

Units 1 and 2 do not currently have an SNCR system. All costs associated with purchasing, installing and operating a new system have been included in this estimate. The SNCR retrofit estimate is based on S&L prior experience with the system and vendor quote. The SNCR system is based on delivery of 50% urea solution to site. The scope of work for the SNCR cost estimate includes the following major items:

- SNCR equipment
- Urea solution fiber-reinforced plastic (FRP) storage tank (qty 2 x 60,000 gallons)
- Forwarding pumps (2 x 100%)
- 2-Zone Metering module (qty 2)
- Wall injectors (qty 20 - 5 per zone, 2 zones per boiler)
- Circulation module (2 x 100% vertical pumps)
- Urea storage tank heater (qty 40 x 0.5kW)
- Forwarding pump motors (qty 2 x 7.5kW)
- Civil & Structural BOP
- Interconnecting piping, valves and insulation
- Compressed air system and receivers
- Eyewash and safety shower
- Boiler modifications
- Electrical and Instrumentation/Controls BOP
- Continuous emissions monitoring system (CEMS)

Costs associated with an SNCR system are summarized in **Appendix A**.

8.1 CAPITAL COST ESTIMATE

Table 8-1 summarizes the SNCR capital cost estimate.

Table 8-1. SNCR Capital Cost Estimate ($2020)

Capital Cost	Unit 1	Unit 2
Purchased Equipment	7,196,000	7,196,000
Direct Installation	2,694,000	2,694,000
Indirects	3,066,000	3,066,000
Contingency	2,591,000	2,591,000
Total Capital Investment	**15,547,000**	**15,547,000**

8.2 VARIABLE O&M COSTS

The following unit costs in Table 8-2 were used to develop the variable O&M costs. Auxiliary power cost was provided by TEP; urea costs are based on recently executed projects and are consistent with typical industry values.

Table 8-2. Variable O&M Costs

Unit Cost	Units	Value
50% Solutionized Urea	$/gal	1.05
Water	$/kgal	1.00
Auxiliary Power Cost	$/MWh	36.90
Steam Cost	$/MMbtu	1.06

Table 8-3 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the SNCR system.

Table 8-3. Variable O&M Rates and First-Year Costs

Parameter	Units	Unit 1	Unit 2
SNCR System			
50% Solutionized Urea Consumption	lb/hr	889	746
Water Consumption	gal/hr	2,100	2,100
Auxiliary Power Consumption	kW	280	280

Parameter	Units	Unit 1	Unit 2
First-Year Variable O&M Costs[1] (@CF[2])			
50% Solutionized Urea Cost	$/year	1,216,000	978,000
Water Cost	$/year	12,000	12,000
Steam Cost	$/year	22,000	18,000
Auxiliary Power Cost	$/year	64,000	61,000
Total First Year Variable O&M Cost	**$/year**	**1,314,000**	**1,069,000**

Notes:

1. First-year costs are provided in $2020.
2. The first-year costs are calculated using the Unit 1 and Unit 2 annual capacity factor of 71% and 68%, respectively. Capacity factors were based on the average operation of each Unit between January 2018 and Septmeber 2019. The capacity factors are based on historical operation and may not represent future operation.

8.3 FIXED O&M COSTS

The fixed O&M costs for the systems consist of maintenance costs (including material and labor). Based on typical design for the SNCR system, the estimated staffing addition is 1 person for both units.

Operating Labor costs are estimated based on 2 shifts/day, 365 days per year at an operator charge rate of $60/hour. Supervisor labor is estimated to be 15% of the total operating labor costs.[9]

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (materials and labor) were estimated to be approximately 1.5% of the total purchased equipment cost and direct installation costs.[10]

Table 8-4 below summarizes the first year fixed O&M costs for the design case.

[9] Id. at 2-31.
[10] Id. at 2-31, 2-32.

Table 8-4. First Year Fixed O&M Costs for SNCR

First Year Fixed O&M Costs[1]	Units	Unit 1	Unit 2
Operating Labor[2]	$/year	263,000	263,000
Supervisor Labor	$/year	39,000	39,000
Maintenance Material and Labor[3]	$/year	148,000	148,000
Total First Year Fixed O&M	**$/year**	**450,000**	**450,000**

Notes:
1. First-year costs are provided in $2020.
2. Operating labor costs are based on a labor rate of $60/hr, which is based on Sargen & Lundy's conceptual cost estimating system.
3. Maintenance labor cost included in maintenance materials.

8.4 INDIRECT OPERATING COSTS

Indirect operating costs necessary to own and operate a facility with a SNCR system include property taxes, insurance, and administrative services. Property taxes and insurance charges are estimated to be 1% of the total capital investment.[11] Administration is estimated to be 2% of the total capital investment.[12]

Table 8-5 summarizes the indirect operating costs.

Table 8-5. First-Year Indirect Operating Costs for SNCR

Indirect Operating Costs[1]	Units	Unit 1	Unit 2
Property Taxes	$/year	155,000	155,000
Insurance	$/year	155,000	155,000
Administration	$/year	311,000	311,000
Total Indirect Operating Cost	**$/year**	**621,000**	**621,000**

Note:
1. Indirect operating costs are provided in $2020.

[11] *Id.*
[12] *Id.*

9. SUMMARY OF COST EVALUATION

Table 9-1 summarizes the annualized capital cost, annual operating cost and total annualized cost for each alternative SO_2 and NOx control technology.

Table 9-1. Springerville Annualized Costs Summary ($2020)

Option	DFGD Upgrades		DSI		SNCR	
Parameter	**Unit 1**	**Unit 2**	**Unit 1**	**Unit 2**	**Unit 1**	**Unit 2**
Annualized Capital Cost, $ (per unit)	318,000	318,000	1,646,000	1,646,000	1,274,000	1,274,000
Total Annual Operating Costs, $/yr (per unit)	678,000	658,000	7,215,000	6,968,000	2,385,000	2,140,000
Total Annualized Cost, $/yr (per unit)	**996,000**	**976,000**	**8,861,000**	**8,614,000**	**3,659,000**	**3,414,000**

APPENDIX A. SUMMARY CONTROL COST EVALUATION TABLES

Springerville Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements and Equipment Upgrades

SO_2 Control Option Description	FGD Operational Improvements and Equipment Upgrades	
	Unit 1	Unit 2
Existing SO2 Emission Rate, lb/MMBtu	0.25	0.25
Post Upgrade SO_2 Emissions, lb/MMBtu	0.15	0.15
Capacity Factor used of Cost Estimates (%)	71%	68%

CAPITAL COSTS	Cost (2020$) Unit 1	Unit 2	Basis
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$2,043,000	$2,043,000	Based on Sargent & Lundy's conceptual cost estimating system and vendor quotes from previous projects. Includes Perforated Plates, Balancing Dampers and CFD
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$102,000	$102,000	5% of Equipment/Material Cost
Freight	$102,000	$102,000	5% of Equipment/Material Cost
Total PEC	$2,247,000	$2,247,000	
Direct Installation Costs			
Labor	$205,000	$205,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$5,000	$5,000	2.5% of Labor
Mobilization / Demobilization	$3,000	$3,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$10,000	$10,000	5% of Labor
Total Direct Installation Costs	$223,000	$223,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$2,470,000**	**$2,470,000**	
Indirect Costs			
Contractor's General and Administration	$247,000	$247,000	10% of Total Direct Costs
Contractor's Profit	$124,000	$124,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$198,000	$198,000	8% of Total Direct Costs
Construction Management/Field Engineering	$99,000	$99,000	4% of Total Direct Costs
S-U / Commissioning	$37,000	$37,000	1% of Total Direct Costs
Spare Parts	$12,000	$12,000	0.5% of Total Direct Costs
Owner's Cost	$49,000	$49,000	2% of Total Direct Costs
Total Indirect Costs	**$766,000**	**$766,000**	
Contingency	**$647,000**	**$647,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$3,883,000**	**$3,883,000**	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$318,000**	**$318,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Waste Disposal Cost (Net Change)	$6,000	$5,000	Based on Unit 1 and 2 average disposal cost of $1.29/ton
Lime Reagent Cost (Net Change)	$323,000	$310,000	Based on lime reagent cost of $150.60 per ton.
Auxiliary Power Cost (Net Change)	$153,000	$147,000	Based on average auxiliary power cost of Units 1 and 2. $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Increased Water Cost	$3,000	$3,000	Based on water cost of $1.00 per 1,000 gallons.
Total Variable O&M Costs	$485,000	$465,000	
Fixed O&M Costs			
Additional Operators per shift	0	0	Assume no additional operators
Operating Labor	$0	$0	N/A
Supervisor Labor	$0	$0	N/A
Maintenance Materials	$37,000	$37,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$37,000	$37,000	
Indirect Operating Cost			
Property Taxes	$39,000	$39,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$39,000	$39,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-
Administration	$78,000	$78,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-
Total Indirect Operating Cost	$156,000	$156,000	
Total Annual Operating Cost	**$678,000**	**$658,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$318,000	$318,000	
Annual Operating Cost	$678,000	$658,000	
Total Annual Cost	**$996,000**	**$976,000**	

Springerville Units 1 and 2
SO_2 Control Cost Evaluation
Existing DFGD + DSI

SO_2 Control Option Description	Existing DFGD + DSI	
	Unit 1	Unit 2
Existing SO2 Emission Rate, lb/MMBtu	0.25	0.25
Post Upgrade SO_2 Emissions, lb/MMBtu	0.18	0.18
Capacity Factor used of Cost Estimates (%)	71%	68%

CAPITAL COSTS	Cost (2020$) Unit 1	Unit 2	Basis
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$9,230,000	$9,230,000	Based on Sargent & Lundy's conceptual cost estimating system and vendor bids. Scope includes storage silo, truck unloading, pneumatic conveying, dehumidification system, piping and supports, valves, lances, sitework, foundations, steel, electrical and instrumentation.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$462,000	$462,000	5% of Equipment/Material Cost
Freight	$462,000	$462,000	5% of Equipment/Material Cost
Total PEC	$10,154,000	$10,154,000	
Direct Installation Costs			
Labor	$2,408,000	$2,408,000	Based on Sargent & Lundy's conceptual cost estimating system and vendor quotes from previous projects.
Scaffolding	$60,000	$60,000	2.5% of Labor
Mobilization / Demobilization	$36,000	$36,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$120,000	$120,000	5% of Labor
Total Direct Installation Costs	$2,624,000	$2,624,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$12,778,000**	**$12,778,000**	
Indirect Costs			
Contractor's General and Administration	$1,278,000	$1,278,000	10% of Total Direct Costs
Contractor's Profit	$639,000	$639,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$1,022,000	$1,022,000	8% of Total Direct Costs
Construction Management/Field Engineering	$511,000	$511,000	4% of Total Direct Costs
S-U / Commissioning	$192,000	$192,000	1% of Total Direct Costs
Spare Parts	$64,000	$64,000	0.5% of Total Direct Costs
Owner's Cost	$256,000	$256,000	2% of Total Direct Costs
Total Indirect Costs	**$3,962,000**	**$3,962,000**	
Contingency	**$3,348,000**	**$3,348,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$20,088,000**	**$20,088,000**	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$1,646,000**	**$1,646,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Waste Disposal Cost (Net Change)	$222,000	$212,000	Based on Unit 1 and 2 average disposal cost of $1.29/ton
Hydrated Lime Reagent Cost (Net Change)	$5,430,000	$5,201,000	Assumed $150/ton
Auxiliary Power Cost (Net Change)	$183,000	$175,000	Based on average auxiliary power cost of Units 1 and 2. $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Increased bag and cage replacement (Net Change)	$82,000	$82,000	Assumed replacement schedule would go from every 5 years down to every 4 years.
Total Variable O&M Costs	$5,917,000	$5,670,000	
Fixed O&M Costs			
Additional Operators per shift	0.5	0.5	
Operating Labor	$263,000	$263,000	Based on $60/hour
Supervisor Labor	$39,000	$39,000	15% of Operating labor cost
Maintenance Materials	$192,000	$192,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$494,000	$494,000	
Indirect Operating Cost			
Property Taxes	$201,000	$201,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$201,000	$201,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$402,000	$402,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$804,000	$804,000	
Total Annual Operating Cost	**$7,215,000**	**$6,968,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$1,646,000	$1,646,000	
Annual Operating Cost	$7,215,000	$6,968,000	
Total Annual Cost	**$8,861,000**	**$8,614,000**	

Springerville Units 1 and 2
NO_x Control Cost Evaluation
SNCR

NO_x Control Option Description	SNCR	
	Unit 1	Unit 2
Existing NOx Emission Rate, lb/MMBtu	0.17	0.18
Post Upgrade NO_x Emissions, lb/MMBtu	0.15	0.15
Capacity Factor used of Cost Estimates (%)	71%	68%

CAPITAL COSTS	Cost (2020$) Unit 1	Unit 2	Basis
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$6,542,000	$6,542,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for urea storage, conveying and distribution and injection equipment, boiler penetrations and associated materials.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$327,000	$327,000	5% of Equipment/Material Cost
Freight	$327,000	$327,000	5% of Equipment/Material Cost
Total PEC	$7,196,000	$7,196,000	
Direct Installation Costs			
Labor	$2,471,000	$2,471,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$62,000	$62,000	2.5% of Labor
Mobilization / Demobilization	$37,000	$37,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$124,000	$124,000	5% of Labor
Total Direct Installation Costs	$2,694,000	$2,694,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$9,890,000**	**$9,890,000**	
Indirect Costs			
Contractor's General and Administration	$989,000	$989,000	10% of Total Direct Costs
Contractor's Profit	$495,000	$495,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$791,000	$791,000	8% of Total Direct Costs
Construction Management/Field Engineering	$396,000	$396,000	4% of Total Direct Costs
S-U / Commissioning	$148,000	$148,000	1.5% of Total Direct Costs
Spare Parts	$49,000	$49,000	0.5% of Total Direct Costs
Owner's Cost	$198,000	$198,000	2% of Total Direct Costs
Total Indirect Costs	**$3,066,000**	**$3,066,000**	
Contingency	**$2,591,000**	**$2,591,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$15,547,000**	**$15,547,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$1,274,000**	**$1,274,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Solutionized Urea Cost	$1,216,000	$978,000	Based on solutionized urea cost of $1.05/gal.
Water Cost	$12,000	$12,000	Based on water cost of $1.00 per 1,000 gallons.
Steam Cost	$22,000	$18,000	Based on steam cost of $1.06 per MMBtu.
Auxiliary Power Cost	$64,000	$61,000	Based on average auxiliary power cost of $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Total Variable O&M Costs	$1,314,000	$1,069,000	
Fixed O&M Costs			
Additional Operators per shift	0.5	0.5	
Operating Labor	$263,000	$263,000	Assume $60/hr for each additional operator
Supervisor Labor	$39,000	$39,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$148,000	$148,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$450,000	$450,000	
Indirect Operating Cost			
Property Taxes	$155,000	$155,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$155,000	$155,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-
Administration	$311,000	$311,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-
Total Indirect Operating Cost	$621,000	$621,000	
Total Annual Operating Cost	**$2,385,000**	**$2,140,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$1,274,000	$1,274,000	
Annual Operating Cost	$2,385,000	$2,140,000	
Total Annual Cost	**$3,659,000**	**$3,414,000**	

Appendix C

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Coal

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	424.8	MW
What is the higher heating value (HHV) of the fuel?	9,012	Btu/lb
What is the estimated actual annual MWh output?	1,971,698	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	10.6	MMBtu/MW

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

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

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 1.05 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 16.62 percent by weight

For units burning coal blends:

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

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	1	1.05	16.62	9,012	1.89
Lignite	0	0.82	13.6	6,626	1.74

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

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.1748	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.15	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	

Plant Elevation: 7000 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	50	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Select the reagent used: Urea

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2018			
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI
Annual Interest Rate (i)	5.25	Percent		
Fuel ($Cost_{fuel}$)	1.89	$/MMBtu*		
Reagent ($Cost_{reag}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0361	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

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

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	4,503	MMBtu/hour
Maximum Annual MWh Output =	Bmw x 8760 =	3,721,248	MWh
Estimated Actual Annual MWh Output (Boutput) =		1,971,698	MWh
Heat Rate Factor (HRF) =	NPHR/10 =	1.06	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.53	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4641	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	14	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	111.81	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	259.49	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.29	
Atmospheric pressure at 7000 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	11.4	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.

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	627	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	1,254	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	132.1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	44,400	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0820

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	42.6	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.56	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	10.4	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$4,333,315	in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$4,622,746	in 2018 dollars
Total Capital Investment (TCI) =	$11,642,879	in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$4,333,315 in 2018 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2018 dollars

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$4,622,746 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,205,650	in 2018 dollars
Indirect Annual Costs (IDAC) =	$959,955	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$2,165,606	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$174,643	in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$1,017,744	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$7,135	in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$4,949	in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$1,178	in 2018 dollars
Direct Annual Cost =		$1,205,650	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$5,239	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$954,716	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$959,955	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,165,606	per year in 2018 dollars
NOx Removed =	259	tons/year
Cost Effectiveness =	$8,346	per ton of NOx removed in 2018 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Coal

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	424.8	MW
What is the higher heating value (HHV) of the fuel?	9,012	Btu/lb
What is the estimated actual annual MWh output?	2,499,029	MWh
Is the boiler a fluid-bed boiler?	No	
Enter the net plant heat input rate (NPHR)	10.3	MMBtu/MW

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

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

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 1.05 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 16.62 percent by weight

For units burning coal blends:

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

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	1	1.05	16.62	9,012	1.89
Lignite	0	0.82	13.6	6,626	1.74

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

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.1722	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.15	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	

Plant Elevation: 7000 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	50	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Select the reagent used: Urea

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2018			
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI
Annual Interest Rate (i)	5.25	Percent		
Fuel ($Cost_{fuel}$)	1.89	$/MMBtu*		
Reagent ($Cost_{reag}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0361	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

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

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	4,375	MMBtu/hour
Maximum Annual MWh Output =	Bmw x 8760 =	3,721,248	MWh
Estimated Actual Annual MWh Output (Boutput) =		2,499,029	MWh
Heat Rate Factor (HRF) =	NPHR/10 =	1.03	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.67	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5883	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	13	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	97.18	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	285.84	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.29	
Atmospheric pressure at 7000 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	11.4	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.

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	600	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	1,200	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	126.4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	42,500	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0820

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	41.9	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.54	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	10.0	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$4,281,376	in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$4,545,576	in 2018 dollars
Total Capital Investment (TCI) =	$11,475,038	in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$4,281,376 in 2018 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2018 dollars

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$4,545,576 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,423,104	in 2018 dollars
Indirect Annual Costs (IDAC) =	$946,117	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$2,369,221	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$172,126	in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$1,234,637	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$8,908	in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$6,004	in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$1,429	in 2018 dollars
Direct Annual Cost =		$1,423,104	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$5,164	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$940,953	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$946,117	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,369,221	per year in 2018 dollars
NOx Removed =	286	tons/year
Cost Effectiveness =	$8,289	per ton of NOx removed in 2018 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Coal

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	424.8	MW
What is the higher heating value (HHV) of the fuel?	9,012	Btu/lb
What is the estimated actual annual MWhs output?	1,971,698	MWhs
Enter the net plant heat input rate (NPHR)	10.6	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	7000	Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 1.05 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	1	1.05	9,012
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 days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1748	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.06	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

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

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

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	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.25	Percent			
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}$)	0.0361	$/kWh			* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($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)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/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.	
Percent sulfur content for Coal (% weight)	1.84	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)	11,841	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 =	4,503	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	3,721,248	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		1,971,698	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	1.06	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.530	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4641	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	65.7	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	517.07	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,199.99	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.82	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,085,455	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	136.25	/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 =	1.29	
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	11.4	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	0.3164	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})	15,305.97	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,172	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 $A_{catalyst}$	2,498	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	50.0	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	50	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} =	201	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	693	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	93	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	31,200	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	0.0820

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	2490.95	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}) =	$124,073,631	in 2018 dollars
Reagent Preparation Cost (RPC) =	$2,994,313	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2018 dollars
Balance of Plant Costs (BPC) =	$10,128,927	in 2018 dollars
Total Capital Investment (TCI) =	$178,355,931	in 2018 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}) =	$124,073,631 in 2018 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) =	$2,994,313 in 2018 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 2018 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}) =	$10,128,927 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,801,480	in 2018 dollars
Indirect Annual Costs (IDAC) =	$14,638,516	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$16,439,996	in 2018 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 =	$891,780	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$125,884	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$417,377	in 2018 dollars
Annual Catalyst Replacement Cost =		$366,439	in 2018 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($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 =		$1,801,480	in 2018 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) =	$13,329	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$14,625,186	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$14,638,516	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$16,439,996	per year in 2018 dollars
NOx Removed =	1,200	tons/year
Cost Effectiveness =	$13,700	per ton of NOx removed in 2018 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Coal

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

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

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	424.8	MW
What is the higher heating value (HHV) of the fuel?	9,012	Btu/lb
What is the estimated actual annual MWhs output?	2,499,029	MWhs
Enter the net plant heat input rate (NPHR)	10.3	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	7000	Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 1.05 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	1	1.05	9,012
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 days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1722	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.06	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

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

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

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

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

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	2018				
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.25	Percent			
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}$)	0.0361	$/kWh			* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($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)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/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.	
Percent sulfur content for Coal (% weight)	1.84	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)	11,841	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 =	4,375	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	3,721,248	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		2,499,029	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	1.03	
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 =	5883	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	65.2	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	490.97	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,444.14	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.81	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,026,432	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	137.15	/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 =	1.29	
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	11.4	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	0.3164	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})	14,775.36	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,111	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 $A_{catalyst}$	2,427	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	49.3	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	50	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} =	191	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	658	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	88	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	29,600	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	0.0820

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	2460.39	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}) =	$120,646,485	in 2018 dollars
Reagent Preparation Cost (RPC) =	$2,955,783	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2018 dollars
Balance of Plant Costs (BPC) =	$10,007,523	in 2018 dollars
Total Capital Investment (TCI) =	$173,692,728	in 2018 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}) =	$120,646,485 in 2018 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) =	$2,955,783 in 2018 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 2018 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}) =	$10,007,523 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,896,210	in 2018 dollars
Indirect Annual Costs (IDAC) =	$14,255,853	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$16,152,063	in 2018 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 =	$868,464	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$151,496	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$522,514	in 2018 dollars
Annual Catalyst Replacement Cost =		$353,736	in 2018 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($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 =		$1,896,210	in 2018 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) =	$13,050	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$14,242,804	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$14,255,853	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$16,152,063	per year in 2018 dollars
NOx Removed =	1,444	tons/year
Cost Effectiveness =	$11,185	per ton of NOx removed in 2018 dollars