Application for Significant Permit Revision and Regional Haze State Implementation Plan Revision for the Coronado Generating Station

Submitted to:

Arizona Department of Environmental Quality
Air Quality Division
1110 West Washington, Phoenix, AZ 85007

Prepared by:

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ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

Air Quality Division

1110 West Washington • Phoenix, AZ 85007 • Phone: (602) 771-2338

STANDARD CLASS I PERMIT APPLICATION FORM

(As required by A.R.S. § 49-426, and Chapter 2, Article 3, Arizona Administrative Code)

1. Permit to be issued to (Business license name of organization that is to receive permit): Salt River Project

2. Mailing Address: P.O. Box 52025 PAB 352
   City: Phoenix State: AZ ZIP: 85072-2025

3. Name (or names) of Owners/ Principals: Salt River Project
   Phone: (928) 337-2116 Fax: (928) 337-2961 Email: ____________

4. Name of Owner's Agent: ____________
   Phone: ____________ Fax: ____________ Email: ____________

5. Plant/Site Manager/ Contact Person and Title: Barbara Sprungl, SGS/KGS O&M Eng. Manager
   Phone: (602) 236-5374 Fax: (602) 236-2331 Email: barbara.sprungl@srpnet.com

6. Plant Site Name: Coronado Generating Station

7. Plant Site Location Address: 6 miles northeast St. Johns off U.S. Highway 191
   City: St. Johns County: Apache Zip Code: 85936
   Indian Reservation (if applicable, which one): NA
   Latitude/ Longitude, Elevation: 34° 34' 40" E, 109° 16' 18" N, 5,794 Feet
   Section/ Township/ Range: ____________

8. General Nature of Business: Electric Power Generation

9. Type of Organization:
   ☐ Corporation ☐ Individual Owner ☐ Partnership ☐ Government Entity (Government Facility Code:-----)
   ■ Other Agricultural Improvement District/Political Subdivision of State

8. Permit Application Basis: ☐ New Source ■ Revision ☐ Renewal of Existing Permit
   (Check all that apply.)
   For renewal or modification, include existing permit number (and exp. date): 52639, December 6, 2016
   Date of Commencement of Construction or Modification: ____________
   Primary Standard Industrial Classification Code: 4911

9. I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by ADEQ as public record. I also attest that I am in compliance with the applicable requirements of the Permit and will continue to comply with such requirements and any future requirements that become effective during the life of the Permit. I will present a certification of compliance to ADEQ no less than annually and more frequently if specified by ADEQ. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with Arizona Administrative Code, Title 18, Chapter 2 and any permit issued thereof.

   Signature of Responsible Official: [signature]
   Official Title of Signer: Plant Manager
   Typed or Printed Name of Signer: Dan Bevier
   Date: 1/19/16 Telephone Number: (928) 337-5501

2.0 Project Overview

2.1 Introduction

The Salt River Project Agricultural Improvement and Power District ("SRP") owns and operates the Coronado Generating Station ("CGS") located approximately six miles northeast of St. Johns off U.S. Highway 191, in Apache County, Arizona. Figure 2-1 is a map showing the location of CGS. CGS consists of two pulverized coal-fired, electric utility steam boilers (Units 1 and 2), which generate approximately 762 megawatts (MW) (net) of electricity.[1] Units 1 and 2 were completed and started operation in 1979-1980. CGS generates electricity for sale and the SIC code for this operation is 4911. Units 1 and 2 are dry-bottom turbo-fired boilers with a net rated output of 380 MW and 382 MW, respectively, primarily firing low-sulfur western coals.

CGS Unit 1 and Unit 2 are Regional Haze Program - Best Available Retrofit Technology ("BART") eligible units per 40 CFR § 51.301. The Arizona Department of Environmental Quality ("ADEQ") determined that the CGS units may reasonably be anticipated to cause or contribute to visibility impairment at a Class I area and, as such, are subject to BART. This document provides information necessary for revision and supplementation of the Regional Haze Rule ("RHR") section of the Arizona State Implementation Plan ("Regional Haze SIP" or "SIP") and the U.S. Environmental Protection Agency ("EPA") Federal Implementation Plan ("FIP"), as well as the associated permit revisions to incorporate relevant requirements.

2.2 Background

On February 28, 2011, ADEQ submitted to EPA the state's initial Regional Haze SIP for the first planning period of the regional haze program. This submission included BART determinations for CGS Units 1 and 2. On December 5, 2012, EPA issued a final rule approving in part and disapproving in part ADEQ's Regional Haze SIP. EPA also promulgated a FIP for the CGS units with an oxides of nitrogen ("NOx") emission limit of 0.065 pounds per million British thermal unit ("lb/MMBtu"), applicable across both CGS units on a 30-boiler operating day average basis. The final compliance date for the BART FIP NOx limit is December 5, 2017 (five years from the date of publication of the FIP) and involves installation and operation of selective catalytic reduction ("SCR") systems for control of NOx emissions on both CGS units. Unit 2 was equipped with SCR in 2014, as required by a consent decree between SRP and the United States.[2]

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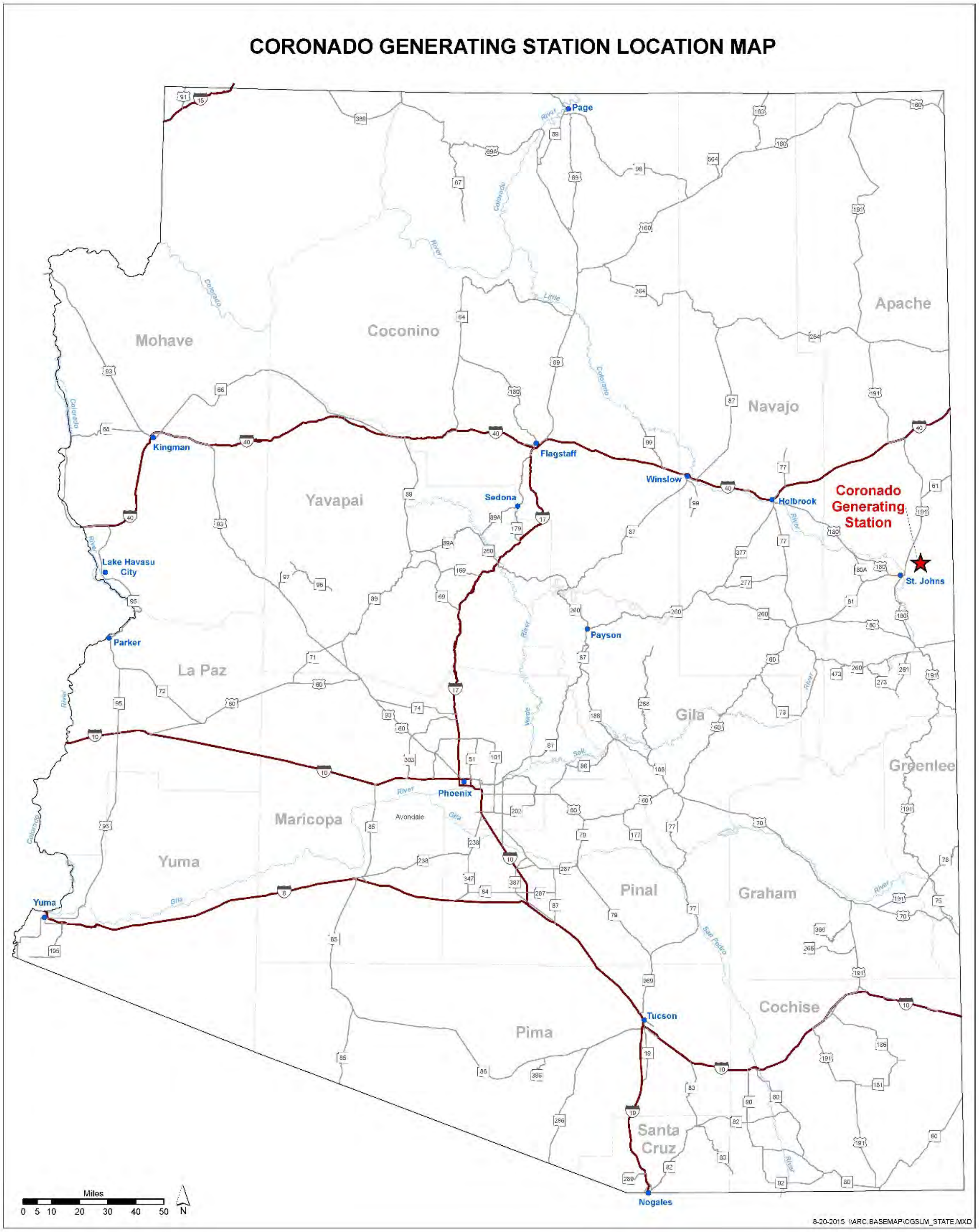
[1] Prior to installation of emissions controls, CGS generation capacity was 772 MW (net).

[2] *United States v. Salt River Project Agricultural Improvement and Power District*, Civil Action No. 2:08-cv-1479-JAT (D. Ariz.), August 12, 2008.

Figure 2-1. Project Location Map



SRP filed a petition for administrative reconsideration of the NOx BART determination for CGS with EPA in February 2013. EPA granted reconsideration of the NOx emission limit and compliance methodology (i.e., the methodology used to calculate compliance with the plantwide average) in April 2013. On March 31, 2015, EPA proposed revisions to the NOx BART determination for the CGS units.[3] The proposal established a Unit 1 BART NOx limit of 0.065 lb/MMBtu and a Unit 2 BART NOx limit of 0.080 lb/MMBtu. Both limits are to be met on a 30-boiler operating day average. EPA did not propose to change the initial compliance date for the NOx BART limits, which remains December 5, 2017. EPA has committed to taking final action on the reconsideration proposal by March 31, 2016.

In June 2014, EPA released its proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units, commonly referred to as the Clean Power Plan ("CPP"). This rule package was finalized in August 2015.[4] In the final rule, EPA has given states until September 2018 to submit final plans outlining how they will meet the requirements set forth by EPA in the final CPP. Ultimately, these plans must be approved by EPA. Efforts to comply with the CPP may conflict with SRP's existing obligations under EPA's BART FIP. For instance, if the state plan under the CPP entails shutting down CGS Unit 1 to achieve CO_2 reduction goals for the state, investment in NOx controls for the unit will not be cost effective.

2.3 Proposed Compliance Options

SRP has developed a solution that will address potential conflicts between the BART requirements and the CPP, while still ensuring compliance with the RHR. This solution includes an interim better-than-BART ("BTB") compliance strategy and two final BART compliance options, as shown in Figure 2-2 and outlined below, which would supersede EPA's Regional Haze FIP under 40 CFR § 51.308 and 40 CFR § 52.145(f). [5] These compliance options and associated visibility improvements fulfill the visibility requirements of the Clean Air Act, 42 U.S.C. § 7491, and its implementing regulations.

2.3.1 Interim BTB Compliance Strategy

SRP's interim compliance strategy comprises four separate BTB alternative operating scenarios ("BTB alternatives") that include specified curtailment periods for CGS Unit 1 coupled with operation at a lower sulfur dioxide ("SO_2") emissions rate below the BART limits for both units and a NOx emissions rate below the current permit limit for Unit 1. The length of the curtailment period for CGS Unit 1 is dependent on the NOx emissions performance of Unit 1 and the SO_2 emissions performance of Units 1 and 2. Each of the BTB alternatives addresses the visibility impacts from the CGS units on nearby Class I areas in accordance with EPA's RHR at 40 CFR § 51.308, and achieves greater overall visibility benefits on average as compared to the EPA BART determination. The analyses associated with this strategy are described in detail in Section 3.0 of this application.

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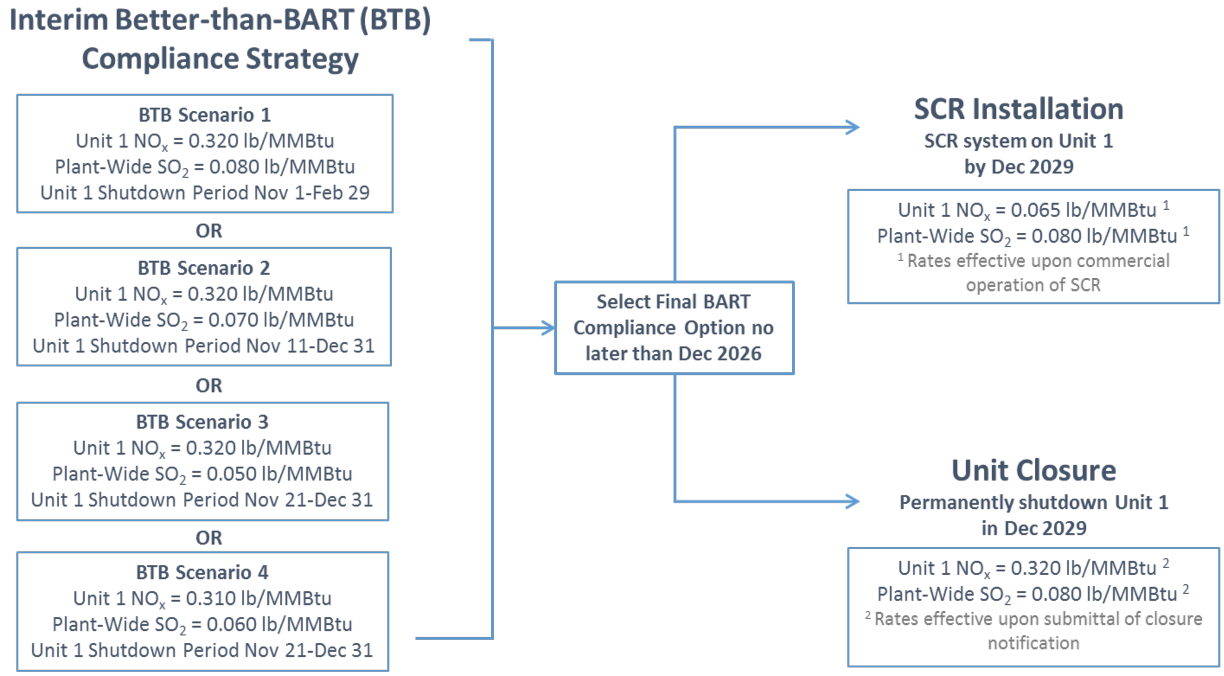
[3] 80 Fed. Reg. 170910, March 31, 2015.

[4] The final rule was published at 80 Fed. Reg, 64,662 (Oct, 23, 2015).

[5] Per 40 CFR § 51.308(e)(2), the BTB scenarios achieve greater reasonable progress than would be achieved through the installation and operation of BART.

Figure 2-2. Proposed Compliance Options



2.3.2 Final BART Compliance Options

Once SRP achieves more certainty regarding future operation of CGS Unit 1 under the final approved CPP state plan, SRP will select one of the following final BART compliance options no later than December 31, 2026:

- Install an SCR system on Unit 1 that achieves a NOx limit of 0.065 lb/MMBtu on a 30-boiler operating day average no later than December 31, 2029; or
- Permanently cease operation of Unit 1 on December 31, 2029.

Under the first final BART compliance option, in which an SCR system is installed on Unit 1, prevention of significant deterioration ("PSD") review will be triggered for collateral emissions increases for three pollutants: particulate matter less than 10 micrometers (µm) mean aerodynamic diameter ("PM10"), particulate matter less than 2.5 µm mean aerodynamic diameter ("PM2.5"), and sulfuric acid mist ("H_2SO_4"). As such, PSD requirements associated with this compliance option are addressed in Section 4.0 of this application.

Under the second final BART compliance option, in which SRP chooses to cease operation of Unit 1 on December 31, 2029, the remaining useful life ("RUL") of the unit is reduced to 12 years. In its BART control technology assessment, EPA assumed an RUL of 20 years. Accordingly, SRP has revised EPA's BART control technology assessment – specifically related to the cost effectiveness evaluation and the ultimate BART determination – to reflect a shorter RUL (i.e., 12 years as opposed to 20 years). These revisions are described in detail in Section 5.0 of this application.

2.4 Application Elements

With this application, SRP is requesting incorporation of the proposed interim and final compliance options into the Title V permit for CGS and ADEQ's Regional Haze SIP. The application is broken out into sections based on the compliance options as follows:

- The interim compliance strategy that would be in effect until SRP has clarity on the final requirements of the CPP state plan includes four BTB alternatives and is outlined in Section 3.0.
- The final compliance options, one of which would be selected to replace the interim compliance strategy, are outlined in Sections 4.0 and 5.0. Section 4.0 addresses the SCR installation option and Section 5.0 addresses closure of CGS Unit 1 in December 2029. The SCR installation will require a prevention of significant deterioration (PSD) permit. This application includes all elements for issuance of the PSD permit for the SCR installation.

Proposed permit and SIP requirements associated with the interim compliance strategy and each of the final options are provided in Appendix A.

3.0 Interim Compliance Strategy: BTB Alternatives

SRP is proposing four BTB alternatives with varying emission parameters for Units 1 and 2, and seasonal curtailments of Unit 1, as outlined in Table 3-1. This section presents the evaluation of the BTB alternatives in accordance with EPA's RHR requirements.

Table 3-1. BTB Alternatives Overview[6]

Scenario	Unit 1 NOx Emission Limit	Plant-Wide SO_2 Emission Limit	Unit 1 Curtailment Period
BTB1	0.320	0.080	Nov 1 – Feb 29
BTB2	0.320	0.070	Nov 11 – Dec 31
BTB3	0.320	0.050	Nov 21 – Dec 31
BTB4	0.310	0.060	Nov 21 – Dec 31

3.1 Evaluation Criteria

Under the RHR, evaluations of BART alternatives must contain the following three elements:[7]

- A demonstration that the alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the state and covered by the alternative program.
- A requirement that all necessary emissions reductions take place during the period of the first long-term planning period for regional haze.
- A demonstration that the emissions reductions resulting from the alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the Clean Air Act as of the baseline date of the SIP.

The following sections outline how SRP's proposal achieves these three elements.

3.2 Demonstration of Greater Reasonable Progress

40 CFR § 51.308(e)(2)(i) establishes five criteria for demonstrating that BART alternative measures will achieve greater reasonable progress than would have resulted from installation and operation of BART, as follows:

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[6] For each of the BTB alternative scenarios, the NOx emission limit for CGS Unit 2 (0.080 lb/MMBtu) and the PM emission limit for CGS Units 1 and 2 (0.030 lb/MMBtu) remain constant.
[7] 79 FR 56322, September 19, 2014, Page 56325-26. 40 CFR § 51.308(e)(2)(i),(iii),(iv).

- A list of all BART-eligible sources. ADEQ included a list of all BART-eligible sources in the Arizona Regional Haze SIP.[8]
- A list of all BART-eligible sources that would be covered by the BART alternative. The BART alternative covers emissions from CGS Units 1 and 2.
- An analysis of BART and associated emissions reductions from the units covered by the BART alternative. This information is provided in the sections below and in Appendix B and Appendix C of this application.
- An analysis of projected emissions reductions through application of the BART alternatives. This information is provided in Section 4 and Appendix C of this application.
- A determination that the alternative "achieves greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources." The determination is to be made based either on the relevant criteria in 40 CFR § 51.308(e)(3) or on the "clear weight of evidence" as provided in 40 CFR § 51.308(e)(2)(i)(E). This information is provided below and in Appendix B of this application.

40 CFR § 51.308(e)(3), in turn, specifies two tests for determining whether the alternative achieves greater reasonable progress than BART. If the distribution of emissions under the alternative measure is not substantially different than under BART, and the alternative measure results in greater emissions reductions, then the alternative measure may be deemed to achieve greater reasonable progress. However, if the distribution of emissions is significantly different, then a dispersion modeling analysis to determine differences in visibility between BART and the BART alternative is required for each impacted Class I area, for the worst and best 20% of days. The modeling demonstrates "greater reasonable progress" if both of the following criteria are met:[9]

- Visibility does not decline in any Class I area; and
- There is an overall improvement in visibility, determined by comparing the average differences between BART and the BART alternative over all affected Class I areas.

In the case of CGS, in addition to the two-prong test above, based on recommendations from EPA Region 9, SRP analyzed annual average visibility impacts from BART and from the BTB alternatives. SRP also evaluated the BTB alternatives based on the following to further demonstrate "greater reasonable progress" when compared to EPA's BART determination for Unit 1:[10]

- Reductions in emissions of visibility-impairing pollutants;
- IMPROVE monitoring data; and
- Dispersion modeling to show improvements in modeled visibility impacts.

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[8] See 79 FR 56322, 77 FR 75704, 75719–75720; 78 FR 46142, 46151–46152.
[9] 40 CFR § 51.308(e)(3)(i)-(ii); 79 FR 56322, September 19, 2014.
[10] *ibid*.

Detailed visibility assessments for the BTB alternatives are provided in Appendix B of this application.

3.3 Timing of Emissions Reductions

SRP is proposing that the BTB alternatives take effect on the same compliance date established by EPA's BART FIP, December 5, 2017. Thus, the reductions will occur during the first long-term planning period under Arizona's regional haze requirements, consistent with EPA's approach.

3.4 Surplus Emissions Reductions Associated with BTB Alternatives

The BTB alternative operating scenarios involve seasonal curtailment periods for Unit 1, which will produce reductions in NOx, SO_2, and particulate matter ("PM") emissions. As shown in Table 3-2 below, under the proposed BTB alternative operating scenarios, the NOx emission reductions range from 9% to 26% when compared to the 2014 baseline. A detailed emissions assessment is provided in Appendix C of this application.

Table 3-2. Comparison of Reductions Associated with EPA's BART Determination and BTB Alternative Operating Scenarios with 2014 Baseline for CGS Units

Scenario Comparison	NOx	SO_2	PM
2015 EPA BART Reconsideration (NOx) / 2012 ADEQ BART (PM and SO_2) to 2014 Baseline	63%	0%	0%
BTB1 to 2014 Baseline	26%	16%	16%
BTB2 to 2014 Baseline	11%	18%	7%
BTB3 to 2014 Baseline	9%	41%	5%
BTB4 to 2014 Baseline	11%	29%	5%

Although the NOx reductions from the BTB alternative operating scenarios would be less than the 63% reduction under EPA's BART Reconsideration, each of these scenarios would produce significant SO_2 and PM emissions reductions. SO_2 emissions reductions from the CGS units would range from 16% to 41%, and PM emissions reductions would range from 5% to 16%. This is because, under the BTB alternatives, SRP would reduce SO_2 emissions from both of the CGS units through (1) annual operation at a lower emissions rate and/or (2) seasonal curtailment of CGS Unit 1. In addition, under the BTB scenarios, SRP would reduce PM emissions from both units through seasonal curtailment of CGS Unit 1.

For the seasonal curtailment periods for Unit 1, SRP proposes periods ranging from 40 days to 120 days to minimize visibility impacts based on the modeling demonstration included in Appendix B.

As these data show, SRP's BTB alternatives provide significant reductions in emissions of NOx, SO_2, and PM as compared to the 2014 baseline. Furthermore, the reductions in NOx and SO_2

emissions under the BTB alternatives would be surplus to the emission reductions resulting from measures adopted to meet the requirements of the Clean Air Act, as of the baseline date of the SIP.

The relative contribution of NOx, SO_2, and PM emissions reductions to visibility improvement is another important factor for determining the “better-than-BART” alternative operating scenarios. Visibility extinction due to SO_2-attributed ammonium sulfate averaged 3.4, 3.5, and 3.8 times the magnitude of NOx-attributed ammonium nitrate visibility extinction for the 20% best days, 20% worst days, and all days, respectively. This is based on the average visibility extinction from the IMPROVE monitoring data for the period between 2000 and 2010 for the Class I areas impacted by the emissions from the CGS units, presented in Appendix D.[11]

ADEQ discussed the relative contribution of statewide NOx and SO_2 emissions to visibility impairment in the BART alternative Technical Support Document for the Apache Generating Station.[12] Specifically, ADEQ noted in the Apache BART report that SO_2-attributable visibility extinction is generally more than three times the NOx-attributable visibility extinction.

Ultimately, the visibility monitoring data for the CGS-affected Class I areas show that SO_2 emissions reductions produce greater Class I area visibility improvements than do NOx emissions reductions. The BTB alternative operating scenarios proposed by SRP would realize a greater degree of visibility improvement than other control scenarios presented here due to significant reductions in SO_2 emissions under the BTB alternative operating scenarios.

[11] Data obtained from: http://vista.cira.colostate.edu/improve/Data/IMPROVE/summary_data.htm.

[12] “AEPCO Apache Generating Station BART Alternative Control Review Technical Support Document,” ADEQ, April 15, 2014.

4.0 Final Compliance Option: Unit 1 SCR Installation

As one of the final compliance options, SRP is requesting authorization to install an SCR system for control of NOx emissions from CGS Unit 1 ("SCR Project"). This section provides information necessary for issuance of a PSD permit for the installation of the SCR Project.

Apache County is designated as attainment for all National Ambient Air Quality Standards ("NAAQS") in 40 CFR § 81.303. Thus, the potentially applicable major new source review ("NSR") program is the PSD permit program at Arizona Administrative Code ("A.A.C.") R18-2-406. CGS is a fossil-fuel-fired steam electric plant that is a categorical major stationary source under PSD.

Installation of an SCR system would result in significant increases in emissions of PM10, PM2.5, and H_2SO_4. Therefore, the SCR Project on CGS Unit 1 is a major modification under PSD and is subject to PSD review for PM10, PM2.5, and H_2SO_4 under A.A.C. R18-2-406.

4.1 Project Description

The SCR system, shown in Figure 4-1, will consist of two reactors (one for each of the flue gas streams between the hot side electrostatic precipitator ("HESP") outlet and the air heater inlet) through which the flue gas will pass. The reactors contain multiple layers of catalysts. Ammonia vapor will be injected into the flue gas upstream of the catalyst. Ammonia reacts with NOx in the flue gas on the catalyst surface forming nitrogen and water. A small amount of ammonia is emitted as ammonia slip.

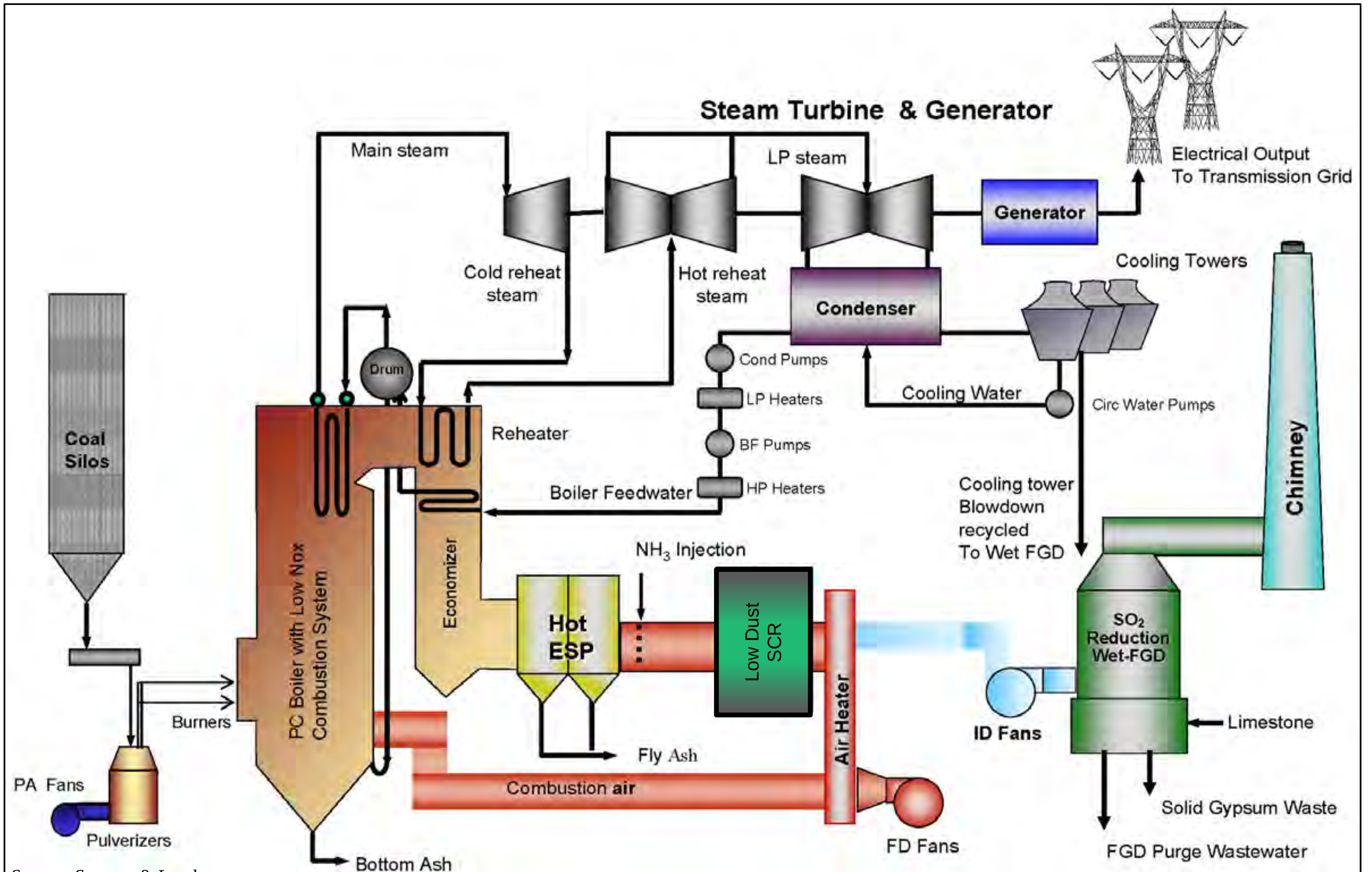
Existing or new anhydrous ammonia storage will be used to serve the Unit 1 SCR.[13] The system uses storage tanks, interconnecting piping, ammonia injection pumps, and a vaporization skid. The tanks and auxiliary equipment are surrounded by a concrete berm to contain the fluid in the event of a spill. An ammonia vaporization skid will be located near the SCR reactor to avoid long lengths of interconnecting vaporization piping. SRP will either develop and implement a risk management plan or update the current plan in accordance with Part 68 of Title 40 of the Code of Federal Regulations (CFR) for the ammonia storage facilities.

4.1.1 Equipment List

This compliance option involves installation of new equipment – an SCR system on CGS Unit 1. If this compliance option is selected, SRP will complete design and engineering for the SCR system and submit the requisite information to ADEQ.

[13] There is existing anhydrous ammonia storage system that serves the Unit 2 SCR.

Figure 4-1. Process Schematic for CGS Unit 1 SCR



Source: Sargent & Lundy

4.2 Emissions Calculations

This subsection provides emissions increase calculations for the regulated NSR pollutants affected by the proposed SCR Project for Unit 1. Emissions calculations are for Unit 1 only as that is the only emissions unit affected by the proposed SCR Project.

As shown in Table 4-1 below, the SCR Project is expected to result in increases in emissions of PM10, PM2.5, and H_2SO_4 that are significant. Therefore, the SCR Project is a major modification for these regulated NSR pollutants and is subject to PSD review under A.A.C. R18-2-406 and -407. Detailed emissions calculations are provided in Appendix E.

Table 4-1. Projected Emissions Increases for Unit 1 in Tons per Year

Pollutant	Baseline Actual Emissions	Projected Actual Emissions	Excluded Emissions	Project Emissions Increases	Significant Emission Rate
NOx	4,986.8	1,226.6	N/A	-3,760.2	40
PM	132.8	169.8	37.1	0.00	25
PM10	171.4	622.7	364.5	86.8	15
PM2.5	171.4	622.7	364.5	86.8	10
H_2SO_4	6.7	94.4	0.8	86.8	7

4.3 Regulatory Analysis

Title 18 Chapter 2 of the Arizona Administrative Code contains requirements related to permitting and the control of various air pollutants. A review of the potentially applicable rules was conducted for the proposed SCR Project for Unit 1. The following subsections summarize the applicability of state and federal air quality regulations.

4.3.1 State Regulations

This analysis is based on the latest version of code available as of October 2015 from the Arizona Secretary of State website at: http://www.azsos.gov/rules/arizona-administrative-code#ID18.

4.3.1.1 Permit Requirements for New Major Sources and Major Modifications to Existing Major Sources [Title 18 Chapter 2 Article 4]

CGS is located in Apache County, which is designated as attainment for all NAAQS for criteria pollutants. Therefore, the requirements of the PSD program will apply to the SCR Project since it is a major modification, as noted in A.A.C. R18-2-406. As shown in Table 4-1, the proposed SCR Project results in significant increases in emissions of PM10, PM2.5, and H_2SO_4 from Unit 1. The following PSD permitting requirements must be met for a major modification:

- R18-2-402(I)(4) Termination of authority to construct and operate – Provides for termination of the permit revision if construction is not commenced within 18 months of permit issuance.[14] The rule allows the Director to extend the presumptive 18-month period upon a satisfactory showing that an extension is justified. SRP is proposing the use of an SCR system as one of the compliance options for CGS Unit 1, but may not be in a position to decide whether to proceed with SCR installation until after EPA and ADEQ provide clarity regarding the requirements for CGS Unit 1 under the CPP. SRP's proposed deadline to make the final decision regarding the use of the SCR compliance option for Unit 1 is December 31, 2026. SRP may elect to install the SCR any time before that date. With this application, SRP is requesting that the commence construction deadline under the PSD permit be extended to December 31, 2026.

- R18-2-406(A)(2) Apply Best Available Control Technology – Included in Section 4.4 and Appendix F of this application.
- R18-2-406(A)(5) Air impact analysis and monitoring requirements – Included in Section 4.5 and Appendix G of this application.
- R18-2-406(F) Class I area impacts – Included in Section 4.5 and Appendix G of this application.
- R18-2-407(A) Air quality monitoring – Where sufficient data exist to provide representative regional background concentrations, the permitting authority may allow the use of existing data to satisfy the preconstruction monitoring requirement. SRP has provided this demonstration in Appendix G.[15]
- R18-2-407(I) Additional impacts analysis for soils, vegetation, growth and visibility – See Section 4.6 and Appendix H for soils, vegetation, and growth analysis. See Section 4.6 and Appendix G for visibility impacts assessment due to the major modification.
- R18-2-409 Air quality models – Included in Appendix G of this application.
- R18-2-409 Visibility protection – Included in Section 4.6 and Appendix G of this application.

4.3.1.2 Significant Permit Revision [R18-2-320]

In accordance with A.A.C. R18-2-302(A), a permit revision is required prior to beginning actual construction for a proposed modification to a stationary source. The proposed SCR Project is a modification under Title I of the Clean Air Act. Therefore, this change will be incorporated as a significant permit revision to a Class I permit under A.A.C. R18-2-320. This document and its appendices constitute SRP's application for such a revision.

[14] Notably, the currently SIP-approved PSD rule (R9-3-304) does not provide for a PSD permit to become invalid if the commencement of construction is delayed.

[15] See, for example, "Circuit Court Decision on PM2.5 Significant Impact Levels and Significant Monitoring Concentration," USEPA, March 4, 2013, at http://epa.gov/nsr/documents/20130304qa.pdf.

4.3.1.3 Other Applicable Requirements

The current Class I air quality control operating permit for CGS addresses all other applicable requirements under the applicable regulations.

4.3.2 Federal Regulations

The proposed SCR Project, if implemented, will be undertaken to comply with the requirements of 40 CFR § 52.145 (visibility protection) by installing an SCR system on CGS Unit 1. BART requirements to address visibility protection are addressed in other parts of this submittal.

No other federal requirements will be triggered for the SCR Project.[16]

4.4 Best Available Control Technology Analysis

The SCR Project is subject to preconstruction PSD review, including the best available control technology ("BACT") requirements under A.A.C. R18-2-406(A)(2), with respect to three regulated NSR pollutants: H_2SO_4, PM10, and PM2.5. The following section presents SRP's proposed BACT determinations for these pollutants. Detailed BACT reviews for H_2SO_4 and PM10/PM2.5 are provided in Appendix F.

4.4.1 H_2SO_4 BACT Determination

SRP proposes an emission limit of 0.005 pounds per MMBtu heat input as BACT for H_2SO_4 emissions from CGS Unit 1. Compliance with this limit will be determined using EPA Conditional Test Method 13, based on the average of three test runs of at least two hours each. This limit reflects the use of low-sulfur western coals and ultra-low activity SCR catalyst, and continuous performance of the existing boiler, HESP, and wet flue gas desulfurization (WFGD) system in accordance with good air pollution control practice.

4.4.2 PM10/PM2.5 BACT Determination

SRP proposes an emission limit of 0.033 pounds per MMBtu heat input as BACT for PM10/PM2.5 (filterable and condensable) emissions from CGS Unit 1.[17] Compliance with this limit will be determined using EPA Reference Methods 5 and 202, based on the average of three test runs of at least two hours each. This limit reflects the use of low-sulfur western coals and ultra-low activity SCR catalyst, and continuous performance of the existing boiler, HESP, and WFGD system in accordance with good air pollution control practice.

[16] The current air quality permit for CGS (permit number 52639) requires SRP to use a NOx continuous emissions monitoring system ("CEMS") for determining compliance with the NOx emission limitations. In accordance with 40 CFR § 64.2(b)(v), compliance assurance monitoring ("CAM") requirements do not apply for emissions limitations for which the permit specifies a continuous compliance determination method. Since the requirement to use CEMS is already included in the permit for CGS, and is also specifically required under 40 CFR § 52.145(f), the CAM requirements do not apply to CGS Unit 1.

[17] The proposed PM10/PM2.5 limit includes both filterable and condensable fractions. Whereas, the Unit 1 PM limit in the Title V permit 52639 of 0.030 lb/MMBtu only applies to the filterable particulate matter emissions.

4.5 Air Dispersion Modeling Results

This section presents a summary of the PSD required ambient air modeling results. The full modeling report, including detailed information regarding model selection, receptor location, and modeling procedures, are included in Appendix G. As described in Section 4.2, the proposed SCR Project will result in PSD significant emission increases of PM10, PM2.5, and H_2SO_4. In accordance with PSD permitting requirements, dispersion modeling demonstrations were performed in support of this application, as described in the following subsections.

4.5.1 Significant Impact Level Results

The PM10 and PM2.5 emission increases resulting from the project were modeled in accordance with ADEQ's guidance. The resulting ambient impacts were compared with the Class II Significance Impact Levels ("SILs"). In accordance with EPA guidance, if the maximum ambient impacts resulting from the proposed emission increase are below their respective SILs, a full impact analysis (NAAQS and PSD Increment) for that pollutant is generally not required.[18] As the results presented in Table 4-2 and 4-3 indicate, the maximum ambient impacts for PM10 are below the Class I and Class II SILs. As a result, full NAAQS and PSD increment analyses are not required for PM10. The additional modeling required for PM2.5 is discussed in Section 4.5.2 below.

Table 4-2. Summary of Maximum Impacts Compared to PSD Modeling Class II Significant Impact Levels (SILs)

Pollutant	Averaging Period	Maximum Concentration (μg/m^3)	Class II Significant Impact Level (SIL) (μg/m^3)	Additional Modeling Required?
PM10	24-hour	1.61	5	No
	Annual	0.35	1	
PM2.5	24-hour	1.42	1.2	Yes
	Annual	0.32	0.3	

[18] 1990 NSR Workshop Manual, p. C.30. Also, please note that on January 22, 2013, the US Court of Appeals for the District of Columbia Circuit Court granted a request from the EPA to vacate and remand the PM2.5 SILs. EPA has stated that as long as the difference between the background monitored PM2.5 value and the NAAQS is greater than the SIL, the SIL can still be used in evaluating significance (see the March 3, 2013, "Draft Guidance for PM2.5 Permit Modeling"). As shown in Table 8 above, the difference between the NAAQS and the background values are greater than the PM2.5 Class I SILs.

Table 4-3. Summary of Maximum Impacts Compared to PSD Modeling Class I Significant Impact Levels (SILs)

Pollutant	Averaging Period	Maximum Concentration (μg/m^3)	Class I Significant Impact Level (SIL) (μg/m^3)	Additional Modeling Required?
PM10	24-hour	0.14	0.30	No
	Annual	0.01	0.20	
PM2.5	24-hour	0.08	0.07	Yes
	Annual	0.01	0.06	

For the Class I analysis CALPUFF was run for the two Class I located towards the direction from CGS to the receptors where AERMOD show impacts that exceeded the Class I SIL. Results of this model are presented in Appendix G that show impacts below the Class I SIL and therefore will not threaten the Class I increment.

4.5.2 NAAQS and PSD Increment Modeling Results

The PM2.5 emission increases resulting from the SCR Project were modeled for demonstrating compliance with the PM2.5 NAAQS and PSD increment. For the NAAQS analysis, the other PM2.5 emissions points at CGS, along with nearby sources, were included in the modeling. As the results presented in Table 4-4 and Table 4-5 show, the maximum ambient impacts for PM2.5 are below the applicable NAAQS and PSD increment. Therefore, the proposed SCR Project will not cause or contribute to air pollution in violation of the NAAQS and PSD increment.

Table 4-4. Summary of PM2.5 Modeled NAAQS Impacts

Pollutant	Averaging Period	Maximum Concentration (μg/m^3)	Background Concentration (μg/m^3)	Total Concentration (μg/m^3)	NAAQS (μg/m^3)
PM2.5	24-hour	10.49	12.0	22.96	35
	Annual	4.04	5.3	9.34	12

Table 4-5. Summary of PM2.5 Modeled Increment Assessment

Pollutant	Averaging Period	Modeled Concentration for Increment (μg/m^3)	Increment Concentration (μg/m^3)
PM2.5	24-hour	1.42	9
	Annual	0.32	4

4.6 Additional Impact Analyses

4.6.1 Growth Impact Analysis

Pursuant to A.A.C. R18-2-407(I), the general commercial, residential, industrial, and other growth associated with a major modification must be characterized in order to allow for analyses of air quality impacts and impairment to visibility, soils, and vegetation that would occur as a result of this growth.

The proposed SCR Project is not expected to affect commercial, residential, industrial, or other growth in the area. No new jobs are anticipated to result from the SCR Project. Any additional labor needed during the construction phase of the project is expected to be drawn from the existing labor force. Therefore, no effects on air quality or on impairment to visibility, soils, and vegetation as a result of growth have been identified.

Growth impacts are discussed in more detail in Appendix H of this application.

4.6.2 Analysis of Impairment to Soils and Vegetation

Emissions from the proposed SCR Project are not expected to result in significant impairment to soils, crops, or plant species of concern, within the vicinity of the project site. For each pollutant of concern, the predicted ambient concentration or the predicted deposition rate is well below the secondary NAAQS and the minimum screening values established by EPA. Nothing in the scientific literature identified during this review indicates that the secondary NAAQS and minimum EPA screening values are not protective of any identified crops, and the predicted ambient concentration and deposition rate are less than the screening values established by other governmental authorities.

Soil and vegetation impacts are discussed in more detail in Appendix H of this application.

4.6.3 Visibility Analysis

Visibility impacts from the proposed SCR Project are discussed in Appendix G of this application.

5.0 Final Compliance Option: Unit 1 Shutdown

As one of the final compliance options, SRP is proposing an earlier retirement date for CGS Unit 1 than had been assumed in previous BART evaluations. Specifically, SRP would permanently cease operation of Unit 1 on December 31, 2029, reducing the RUL of the unit to only 12 years. This section presents revisions to EPA's BART control technology assessment to address this change.

5.1 EPA's BART Control Technology Assessment

The BART evaluation approach is based on a five-factor analysis for determining BART control. States (or EPA, as appropriate) are required to consider the following factors in determining BART:[19]

- Costs of compliance for each technically feasible control technology;
- Energy and non-air quality environmental impacts of compliance;
- Any existing pollution control technology in use at the source;
- RUL of the source; and
- Degree of improvement in visibility that may reasonably be anticipated to result from the use of such technology.

The BART Guidelines recommend that a BART analysis include the following five steps, which cover the five factors identified above:[20]

- Step 1—Identify All Available Retrofit Control Technologies
- Step 2—Eliminate Technically Infeasible Options
- Step 3—Evaluate Control Effectiveness of Remaining Control Technologies
- Step 4—Evaluate Impacts and Document the Results
- Step 5—Evaluate Visibility Impacts

EPA conducted a five-factor BART analysis for NOx at CGS Unit 1 in order to evaluate Arizona's SIP and to document the technical basis for proposing BART determinations in EPA's own proposed FIP. Because EPA generally concurred with ADEQ's BART analyses in Steps 1 and 2, EPA focused its technical analysis on Steps 3, 4 and 5.[21]

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[19] 40 CFR § 51.308(e)(1)(ii)(A).
[20] 40 CFR Part 51, Appendix Y, § IV.D.
[21] 77 FR 42834, July 20, 2012.

As part of the BART reconsideration proposal for CGS issued in March 2015, EPA proposed separate NOx limits for Units 1 and 2 of 0.065 lb/MMBtu and 0.080 lb/MMBtu, respectively, each on a rolling 30-boiler-operating-day basis.[22] The proposed limits are based on the outcome of EPA's five-factor analysis, which called for the installation and use of SCR to reduce NOx emissions, based on an assumed 20-year RUL.

5.2 Required Revisions to EPA's Assessment

SRP has revised EPA's BART control technology assessment, specifically related to the cost effectiveness evaluation and the ultimate BART determination, to reflect a shorter RUL (i.e., 12 years as opposed to 20 years). A detailed overview of the specific changes to the cost effectiveness evaluation is provided in Appendix I of this application.

EPA used its Integrated Planning Model (IPM) to calculate the capital costs and annual operating costs associated with the various NOx control options.[23] In SRP's proposed revisions, the estimates of capital costs, annual operating costs, and the overall cost effectiveness for SCR are based on cost estimates from Sargent and Lundy (S&L) that take into account site- and unit-specific factors. Table 5-1 presents a comparison of these costs, along with the overall cost effectiveness of SCR, calculated in terms of annualized dollars per ton of pollutant removed, or $/ton. EPA has stated that it is sufficient to analyze the cost effectiveness of potential BART controls using $/ton, in conjunction with an assessment of the modeled visibility benefits of the BART control.[24]

Table 5-1. Comparison of BART Control Technology Cost Results for CGS Unit 1

VARIABLE	EPA 20-year RUL	SRP 12-year RUL
Capital, Egr, & Const Costs Subtotal, $	64,962,439	112,788,000
Amortization Period, years	20	12
Capital Recovery Factor, %	9.44	12.59
Annual O&M Costs, $/year	2,516,338	3,332,209
Annualized Capital Costs, $/year	6,911,544	15,553,689
Total Annual Costs, $/year	9,427,881	18,885,898
Delta Tons of NOx Removed, tons/year	3,721	3,543
Annual Cost $ per Ton NOx Removed	2,534	5,330

SRP estimates the cost effectiveness of SCR for NOx control as greater than $5,300 per ton of NOx removed. EPA's calculations using the IPM capital and annual cost estimates for CGS Unit 1 resulted in a NOx cost effectiveness of approximately $2,500 per ton of NOx removed.

Besides the change to RUL, the other significant cost differential is the anticipated capital costs for an SCR system. SRP's costs for CGS Unit 1 are based on the actual costs SRP incurred when

[22] 80 FR 17010, March 31, 2015.
[23] IPM Base Case v4.10 (August 2010).
[24] 77 FR 72512, December 5, 2012.

installing an SCR system on CGS Unit 2 in 2014. These costs are more accurate than those provided by EPA's IPM.

Based on a retirement date of no later than December 31, 2029 (i.e., an expected 12-year unit life after the effectiveness date of the FIP), the analysis confirms that the use of SCR is not cost effective as BART for Unit 1. As such, SRP requests a revised BART determination associated with this option that incorporates the future retirement date as a permit condition in the Title V permit without use of SCR for NOx control.

Appendix A – Proposed SIP/Permit Revision Requirements

A. Proposed SIP/Permit Revision Requirements

In order to implement the proposed BART compliance options, SRP has prepared the following draft permit conditions for CGS for incorporation in the Class I, Title V permit for the facility and the Regional Haze SIP.

A. Regional Haze Requirements

1. Compliance Options

a. Interim Compliance Strategy

i. Beginning no later than December 5, 2017 and continuing until such time as the Permittee is subject to a final compliance option under Condition A.1.b, the Permittee shall comply with the interim Better-than-BART ("BTB") requirements specified in Condition A.2 below.

b. Final Compliance Options

i. No later than December 31, 2029, the Permittee shall comply with one of the following final compliance options:
   1. Install an SCR system on Unit 1 in accordance with Condition A.3 below.
   2. Shutdown Unit 1 in accordance with Condition A.4 below.

ii. The Permittee shall submit notification to ADEQ and EPA of the selection of a final compliance option under Condition A.1.b.i no later than December 31, 2026. This notification shall include the final compliance option selected and the effective date of the requirements associated with that compliance option.

2. BTB Requirements

a. The Permittee shall not exceed the following NOx emission rates on a 30-boiler-operating-day average:
   i. 0.320 lb/MMBtu for Unit 1.
   ii. 0.080 lb/MMBtu for Unit 2.

b. The Permittee shall not exceed the following SO_2 emission rates on a 30-boiler-operating-day average:
   i. 0.080 lb/MMBtu for Unit 1.
   ii. 0.080 lb/MMBtu for Unit 2.

c. At all times during the operation of Unit 1, the Permittee shall operate the low-NOx burners and overfire air in accordance with manufacturer's specifications and good engineering practices to minimize emissions.

d. At all times during the operation of Unit 2, the Permittee shall operate the low-NOx burners, overfire air, and SCR system in accordance with manufacturer's specifications and good engineering practices to minimize emissions.

e. For the first compliance year (2017), the Permittee shall shutdown Unit 1 beginning on December 5, 2017 and shall not restart the unit before December 31, 2017 or February 28, 2018 depending on the BTB scenario in A.2.g below.

f. Beginning in calendar year 2018 and continuing thereafter, the Permittee shall select a BTB Scenario as outlined in the table below:

g.

BTB Scenarios	Unit 1 (lb/MMBtu) (30-boiler-operating-day average)		Unit 2 SO_2 (lb/MMBtu) (30-boiler-operating-day average)	Unit 1 Curtailment Period
	NOx	SO_2		
BTB1	0.320	0.080	0.080	Nov 1-Feb 28 (or Feb 29)
BTB2	0.320	0.070	0.070	Nov 11-Dec 31
BTB3	0.320	0.050	0.050	Nov 21-Dec 31
BTB4	0.310	0.060	0.060	Nov 21-Dec 31

i. To qualify for a BTB Scenario, the Permittee must demonstrate that NOx emissions from Unit 1, and SO_2 emissions from Unit 1 and Unit 2, did not exceed the emission limits specified for the elected BTB Scenario during the current calendar year.

ii. The Permittee shall make this selection no later than October 1 of each calendar year.

iii. Once a BTB Scenario is selected, the Permittee shall not allow NOx emissions from Unit 1 to exceed the emission rate associated with that BTB Scenario beginning on October 1 of the calendar year in which the BTB Scenario was selected through the start of the Unit 1 Curtailment Period.

iv. Once a BTB Scenario is selected, the Permittee shall not allow SO_2 emissions from Unit 1 or Unit 2 to exceed the emission rates associated with that BTB Scenario beginning on October 1 of the calendar year in which the BTB Scenario was selected through the end of the Unit 1 Curtailment Period.

h. Beginning no later than October 1, 2018, and by October 1 of each calendar year thereafter, the Permittee shall notify ADEQ and EPA of the selected BTB Scenario for the current calendar year. This notification shall include the 30-boiler-operating-day average NOx and SO_2 emissions for each boiler-operating day for each unit during the current calendar year up to the date of the notification.

3. Unit 1 SCR Installation Requirements

a. If the Permittee elects to install an SCR system at Unit 1 pursuant to Condition A.1.b, no later than December 31, 2029, the Permittee shall not exceed the following NOx emission rates on a 30-boiler-operating-day average:

i. 0.065 lb/MMBtu for Unit 1.

ii. 0.080 lb/MMBtu for Unit 2.

b. The Permittee shall not exceed the following SO_2 emission rates on a 30-boiler-operating-day average:

i. 0.080 lb/MMBtu for Unit 1.

ii. 0.080 lb/MMBtu for Unit 2.

c. After December 31, 2029, at all times during the operation of Unit 1, the Permittee shall operate the SCR in accordance with manufacturer's specifications and good engineering practices to minimize emissions.

d. At all times during the operation of Unit 2, the Permittee shall operate the SCR system in accordance with manufacturer's specifications and good engineering practices to minimize emissions.

4. Unit 1 Shutdown Requirements

a. The Permittee shall not exceed the following NOx emission rates on a 30-boiler-operating-day average:
   i. 0.320 lb/MMBtu for Unit 1.
   ii. 0.080 lb/MMBtu for Unit 2.

b. The Permittee shall not exceed the following SO_2 emission rates on a 30-boiler-operating-day average:
   i. 0.080 lb/MMBtu for Unit 1.
   ii. 0.080 lb/MMBtu for Unit 2.

c. At all times during the operation of Unit 1, the Permittee shall operate the low-NOx burners and overfire air in accordance with manufacturer's specifications and good engineering practices to minimize emissions.

d. At all times during the operation of Unit 2, the Permittee shall operate the SCR in accordance with manufacturer's specifications and good engineering practices to minimize emissions.

e. If the Permittee elects to shut down Unit 1 pursuant to Condition A.1.b, the Permittee shall permanently retire CGS Unit 1 no later than December 31, 2029.

f. The Permittee shall notify ADEQ and EPA of the date on which CGS Unit 1 is permanently retired within 30 days of the retirement date.

5. NOx Compliance Determination Requirements

a. At all times, the Permittee shall calibrate, maintain, and operate a continuous emissions monitoring system for monitoring NOx emissions in accordance with 40 CFR Part 75 requirements.

b. The Permittee shall calculate the 30-boiler-operating-day average NOx emission rate for each unit in accordance with the following procedure:
   i. Sum the total pounds of NOx emitted from each unit during the current boiler-operating day and the preceding twenty-nine (29) boiler-operating days.
   ii. Sum the total heat input from each unit, in MMBtu, during the current boiler operating day and the preceding twenty-nine (29) boiler-operating days.
   iii. Divide the total pounds of NOx emitted during the 30-day period by the total heat input during the 30-day period. A new 30-boiler-operating-day average NOx emission rate shall be calculated for each new boiler-operating day. Each 30-boiler-operating-day average NOx emission rate shall include all emissions and all heat input that occur during all periods within any boiler-operating day, including emissions from startup, shutdown, and malfunction.

c. In determining the 30-boiler-operating-day average NOx emission rate, the Permittee shall use CEMS in accordance with the procedures of 40 CFR Part 75, except that NOx emissions data for the 30-boiler-operating-day average NOx emission rate need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. Diluent capping (i.e., 5% CO_2) will be applied to the NOx emission calculation for any hours where the measured CO_2 concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1. If a valid NOx pounds per hour value or a valid heat input value is not available for any hour for a unit in a given boiler operating day, the heat input value and NOx pounds per hour value for that hour shall not be used in the calculation of the 30-boiler-operating-day average.

d. The Permittee shall maintain records of the 30-boiler-operating-day average NOx emission rate for each unit for each boiler operating day.

e. The Permittee shall maintain all NOx continuous emissions monitoring system records required by 40 CFR Part 75.

6. SO_2 Compliance Determination Requirements

a. At all times, the Permittee shall calibrate, maintain, and operate a continuous emissions monitoring system for monitoring SO_2 emissions in accordance with 40 CFR Part 75 requirements.

b. The 30-boiler-operating-day average SO_2 emission rate for each unit shall be calculated in accordance with the following procedure:

   i. Sum the total pounds of SO_2 emitted from each unit during the current boiler-operating day and the preceding twenty-nine (29) boiler-operating days.

   ii. Sum the total heat input from each unit, in MMBtu, during the current boiler operating day and the preceding twenty-nine (29) boiler-operating days.

   iii. Divide the total pounds of SO_2 emitted during the 30-day period by the total heat input during the 30-day period. A new 30-boiler-operating-day average SO_2 emission rate shall be calculated for each new boiler-operating day. Each 30-boiler-operating-day average SO_2 emission rate shall include all emissions and all heat input that occur during all periods within any boiler-operating day, including emissions from startup, shutdown, and malfunction.

c. In determining the 30-boiler-operating-day average SO_2 emission rate, the Permittee shall use CEMS in accordance with the procedures of 40 CFR Part 75, except that SO_2 emissions data for the 30-boiler-operating-day average SO_2 emission rate need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. Diluent capping (i.e., 5% CO_2) will be applied to the SO_2 emission calculation for any hours where the measured CO_2 concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1. If a valid SO_2 pounds per hour value or a valid heat input value is not available for any hour for a unit in a given boiler operating day, the heat input and SO_2 pounds per hour value for that hour shall not be used in the calculation of the 30-boiler-operating-day average.

d. The Permittee shall maintain records of the 30-boiler-operating-day average SO_2 emission rate for each unit for each boiler operating day.

e. The Permittee shall maintain all SO_2 continuous emissions monitoring system records required by 40 CFR Part 75.

Appendix B – BTB Alternatives: Visibility Assessment

Better-than-BART Analysis for the Coronado Generating Station using the CAMx Photochemical Grid Model

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RAMBOLL ENVIRON

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TABLES

FIGURES

1.0 INTRODUCTION

The Salt River Project Agricultural Improvement and Power District (SRP) operates the Coronado Generating Station (CGS), a coal-fired steam electric generating station, located in Apache County, near St. Johns, Arizona. The CGS facility consists of two coal-fired units (unit 1 and unit 2) with a combined net power generating capacity of approximately 762 MW. The CGS facility became operational in 1979-1980. The Clean Air Act's Regional Haze Rule (RHR) contains a provision that each State has to address the Best Available Retrofit Technology (BART) requirements when preparing the State's Regional Haze State Implementation Plan (SIP).

1.1 CGS BART Analysis

A BART analysis for the CGS was performed by ENSR (2008) following the Environmental Protection Agency's (EPA) July 6, 2005 final rule entitled "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule" ("BART Guidelines"; EPA, 2005). The BART Guidelines include presumptive BART requirements for coal-fired electric steam generating sources greater than 750 MW.

The Arizona Department of Environmental Quality (ADEQ) determined that the CGS is a "BART-eligible source". Based on air dispersion modeling performed by ENSR (2008), CGS is subject to BART. ENSR performed a BART analysis for the two units at CGS for two pollutants: sulfur dioxide (SO_2) and oxides of nitrogen (NO_x). A BART analysis was not performed for particulate matter (PM) because the hot-side electrostatic precipitators at CGS are considered to represent highly effective emission controls and because PM emissions are not a substantive contributor to regional haze in the region.

1.2 EPA BART Determination

After EPA failed to approve the BART provision in the Arizona RHR State Implementation Plan (SIP), EPA produced a Federal Implementation Plan (FIP) to define the CGS BART requirements. EPA determined[1] that existing SO_2 and PM emissions control at CGS satisfies BART so both CGS unit 1 and unit 2 retain the 0.08 lb/MMBtu emissions limit for SO_2 emissions. On March 31, 2015, EPA published a Federal Register notice[2] proposing that CGS BART requirements are unit-specific with a NO_X control limit of 0.065 lb/MMBtu for unit 1 and 0.08 lb/MMBtu for unit 2 (both on a rolling 30-boiler-operating-day basis). The CGS unit 2 currently can meet the 0.08 lb/MMBtu NO_X emissions limit and it is presumed that CGS unit 1 could meet the 0.065 lb/MMBtu emissions limit by installing Selective Catalytic Reduction (SCR) NO_X controls.

[1] http://www.epa.gov/region9/air/actions/pdf/az/haze/epa-r09-oar-2015-0165-coronado-nprm-factsheet-2015-03-13.pdf

[2] http://www.regulations.gov/#!documentDetail;D=EPA-R09-OAR-2015-0165-0001

1.3 SRP Proposed BART Alternatives

On August 3, 2015, EPA finalized the Clean Power Plan (CPP)[3] rulemaking to control carbon pollution from power plants to address climate change. The CPP sets state-specific goals for reducing carbon dioxide (CO_2) emissions from fossil-fuel electrical generating units (EGUs). SRP is in the process of evaluating options for complying with the CPP CO_2 emission reductions. In addition to evaluating options to comply with the CPP, SRP has developed alternative emission control strategies for CGS to comply with the RHR BART requirements. The SRP CGS proposed BART alternative emissions control strategies include NO_X and SO_2 emission limit options coupled with shutdown periods for CGS unit 1. Emissions from unit 1 of the CGS are zero during the shutdown period for all pollutants.

Table 1-1 lists the CGS unit 1 and unit 2 current (Baseline) SO_2 and NO_X emissions along with those for the EPA BART (SCR NOx controls) and the four CGS Better-than-BART (BtB) alternative emission scenarios that also include shutdown periods for CGS unit 1.

Table 1-1. CGS Unit 1 and Unit 2 NOx and SO_2 emission limits for Baseline (current), EPA BART and four SRP BtB alternative emission scenarios.

Scenario	NO_X (lb/MMBtu)		SO_2 (lb/MMBtu)		Unit 1 Shutdown Period
	Unit#1	Unit#2	Unit#1	Unit#2	
Baseline	0.320	0.080	0.080	0.080	None
EPA BART	0.065	0.080	0.080	0.080	None
BtB1	0.320	0.080	0.080	0.080	Nov 1 - Feb 29
BtB2	0.320	0.080	0.070	0.070	Nov 11 - Dec 31
BtB3	0.320	0.080	0.050	0.050	Nov 21 - Dec 31
BtB4	0.310	0.080	0.060	0.060	Nov 21 - Dec 31

1.4 Document Purpose

When a proposed BART alternative emissions control strategy has a different emissions distribution than the EPA BART control strategy, air quality modeling is used to quantify the visibility benefits of the proposed BART alternative strategy compared to the EPA BART strategy with the Better-than-BART test. This document presents the results of the Better-than-BART modeling analysis for the CGS using the Comprehensive Air-quality Model with extensions (CAMx; www.camx.com) photochemical grid model.

[3] http://www2.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants

1.5 The Better-than-BART Test

The requirements for demonstrating an alternative control strategy is better than a BART control strategy are outlined in EPA's BART Guidelines (EPA, 2005[4]). When the alternative control strategy has a different distribution of emissions, these regulations require the comparison of the modeled visibility impacts at Class I areas. EPA (2005) requires a two-pronged test to demonstrate that the proposed alternative control strategy is better than the BART control scenario (i.e., Better-than-BART):

> *"(t)he modeling study would demonstrate 'greater reasonable progress' if both of the following two criteria are met:*
>
> - *Visibility does not decline in any Class I area, and*
> - *Overall improvement in visibility, determined by comparing the average differences over all affected Class I areas."* (EPA, 2005)

To facilitate the comparisons, three emissions scenarios are evaluated: (1) Baseline scenario (current conditions); (2) the BART control scenario; and (3) the proposed alternative control scenario. Modeled visibility impacts for each scenario are calculated and compared. The comparison is performed for the observed best 20 percent (B20%) and worst 20 percent (W20%) days of the modeled year(s) for each Class I area. These days comprise the 20 % clearest and 20 % haziest days throughout a year based on observational data from the Interagency Monitoring of Protected Visual Environments network of monitors (IMPROVE[5]). Average visibility impacts over all B20% and W20% days are calculated and compared.

1.5.1 Better-than-BART Test - Prong 1: No Decline in Visibility over Current Conditions at any Class I Area

The difference in visibility impacts between the Baseline scenario and the proposed alternative control scenario is calculated for each Class I area for the B20% and W20% days in the modeled year. If the alternative control scenario has the same or lower visibility impacts than the Baseline scenario at all Class I areas and for both the B20% and W20% days, then *"visibility does not decline in any Class I area".* Therefore, the proposed alternative control scenario passes the 1st Prong of the Better-than-BART test.

1.5.2 Better-than-BART Test - Prong 2: Overall Improvement in Visibility compared to BART control strategy

To test the 2nd Prong of the Better-than-BART test, the difference in visibility between the BART control scenario and the proposed alternative control scenario is calculated. If the proposed alternative control scenario shows lower visibility impacts than the BART control scenario when averaged over all Class I areas for both the B20% and W20% days in the modeled year, then an

[4] 40 CFR Part 51 "Regional Haze Regulations and Guidelines for Best Available Retrofit Determinations" Federal Register/ Vol. 70, No. 128/Wednesday, July 6, 2005/Rules and Regulations, pp.39104-39172. (http://www.gpo.gov/fdsys/pkg/FR-2005-07-06/pdf/05-12526.pdf). (USEPA, 2005)

[5] http://vista.cira.colostate.edu/improve/

"*overall improvement in visibility*" has been demonstrated. In this case, the proposed alternative control scenario passes the 2nd prong of the Better-than-BART test.

1.6 Previous CALPUFF BART Modeling

The CGS Subject-to-BART modeling was conducted using the CALPUFF non-steady-state Gaussian puff screening model (ENSR, 2008). CALPUFF was designated the EPA-preferred long range transport model in EPA's 2003 modeling guidelines. However, in July 2015, EPA proposed revisions to their modeling guidelines that would delist CALPUFF as the EPA-preferred long range transport model. Instead, EPA would recommend photochemical grid models (PGMs) for applications involving secondary $PM_{2.5}$ formation, including visibility impairment due to sulfate and nitrate as in the case of the CGS BtB modeling. Foremost among EPA's concerns about CALPUFF is its simplistic treatment of sulfate and nitrate formation (chemistry) as CALPUFF has been shown to understate sulfate formation in summer, overstate sulfate formation in winter and overstate nitrate formation year-round (Morris et al., 2003; 2005; 2006). Given that the CGS BtB modeling trades off visibility benefits from reductions in SO_2 emissions and operation (in the proposed alternative strategies) versus visibility benefits from reduced NO_X emissions (BART control strategy), accurate and unbiased treatment of sulfate and nitrate formation chemistry is needed. Thus, the CGS BtB modeling is following EPA's latest draft guidelines and using a PGM.

1.7 Report Organization

Chapter 1 presents background for the CGS BtB modeling. Development of the CAMx 2008 modeling database, and 2008 CAMx base case model performance evaluation (MPE) is contained in Chapter 2, with more details on the MPE provided in Appendix A. Chapter 3 describes the BtB tests and how the CAMx PGM modeling results were post-processed for the BtB tests. Chapter 4 presents the results of BtB tests using the CAMx modeling results from the Baseline, EPA BART, and BtB alternatives model output. References are provided in Chapter 5.

2.0 DEVELOPMENT OF CAMX MODELING DATABASE

In this Chapter we present the development of the modeling database for conducting the photochemical grid model (PGM) visibility assessment. The Comprehensive Air-quality Model with extensions (CAMx) was used for this assessment for reasons listed below. The CAMx modeling used a 2008 modeling database that was originally developed as part of the Western Regional Air Partnership (WRAP) West-wide Jump-Start Air Quality Modeling Study (WestJumpAQMS[6]; ENVIRON, Alpine and UNC, 2013[7]) and then adopted by the Western Air Quality Study (WAQS, Adelman, Shanker, Yang and Morris, 2014) and is available on the Intermountain West Data Warehouse (IWDW[8]). The WestJumpAQMS website contains detailed documentation of the study including modeling plans and protocols, the meteorological model evaluation, technical memorandums detailing the emissions and the final report. The CGS CAMx Better-than-BART modeling highly leverages the WestJumpAQMS 2008 CAMx modeling database.

2.1 Model Selection

The CAMx PGM was selected for the CGS Better-than-BART modeling for the following reasons:

- CAMx includes full science chemistry algorithms for secondary $PM_{2.5}$ formation (e.g., sulfate and nitrate) that is of high importance in this application. EPA's proposed modeling guidelines acknowledges that PGMs are generally most appropriate for addressing secondary $PM_{2.5}$ which is needed for the simulation of regional visibility impairment (EPA, 2015). This is in contrast to the CALPUFF model that is recommended for Subject-to-BART screening modeling that has highly simplified chemical transformation algorithms that have been shown to have bias in sulfate and nitrate formation (Morris et al., 2003; 2005; 2006).
- CAMx is one of the two PGMs mentioned in EPA's latest modeling guidelines (EPA, 2015) and guidance (EPA, 2014d) that satisfies all the requirements for simulating secondary $PM_{2.5}$ formation. CMAQ is the other PGM mentioned.
- CAMx includes two-way grid nesting, which is not available in CMAQ. This is used to perform the simulation efficiently at 4 km grid cell resolution within 300 km of CGS.
- CAMx includes a Plume-in-Grid module to simulate the near-source chemistry and plume dynamics that are subgrid-scale that is not included in CMAQ.
- CAMx includes a mature, fully tested and evaluated Particulate Source Apportionment Technology (PSAT) tool for separately tracking the particulate matter (PM) impacts associated with emissions from CGS that is not available in CMAQ.

2.2 CGS Modeling Domains

The CAMx CGS modeling domain was chosen to provide sufficient resolution around CGS and fully encompass all Class I areas within 300 km of CGS. Existing 2008 emission inventories that

[6] http://www.wrapair2.org/WestJumpAQMS.aspx
[7] http://www.wrapair2.org/pdf/WestJumpAQMS_FinRpt_Finalv2.pdf
[8] http://views.cira.colostate.edu/tsdw/

were prepared for the WestJumpAQMS (ENVIRON, Alpine and UNC, 2013) were used for the CAMx CGS modeling. The WestJumpAQMS modeling domain consisted of the 36 km resolution Regional Planning Organization (RPO) domain that covered the entire continental U.S. (CONUS), a 12 km domain that covered the western half of the U.S. (WESTUS), and a large 4 km Inter-Mountain West (IMW) domain that included most of Arizona and extended to the northeast into the western half of North Dakota. All grids used 25 vertical layers that extended up to 50 millibars (mb), or approximately 19 km above sea level.

The study area used for the CGS Better-than-BART modeling is a nested 12 and 4 km horizontal resolution modeling domain encompassing CGS. The domain is based on the same Lambert Conformal Projection (LCP) as the WestJumpAQMS domain, with domain definitions listed in Table 2-1 and shown in Figure 2-1. The CGS 12 km and 4 km domains are centered on the CGS with the 4 km domain covering an area out to 300 km from the CGS.

Table 2-1. Definition of the CGS CAMx 12 and 4 km Lambert Conformation Projection (LCP) domains.

LCP center	40° N, 97° W
LCP true latitudes	33° N, 45° N
12 km domain	SW Corner: (-1548, -972) NE Corner: (-684, 108) NX x NY: 72 x 72
4 km domain	SW Corner: (-1440, -864) NE Corner: (-792, -216) NX x NY: 162 x 162

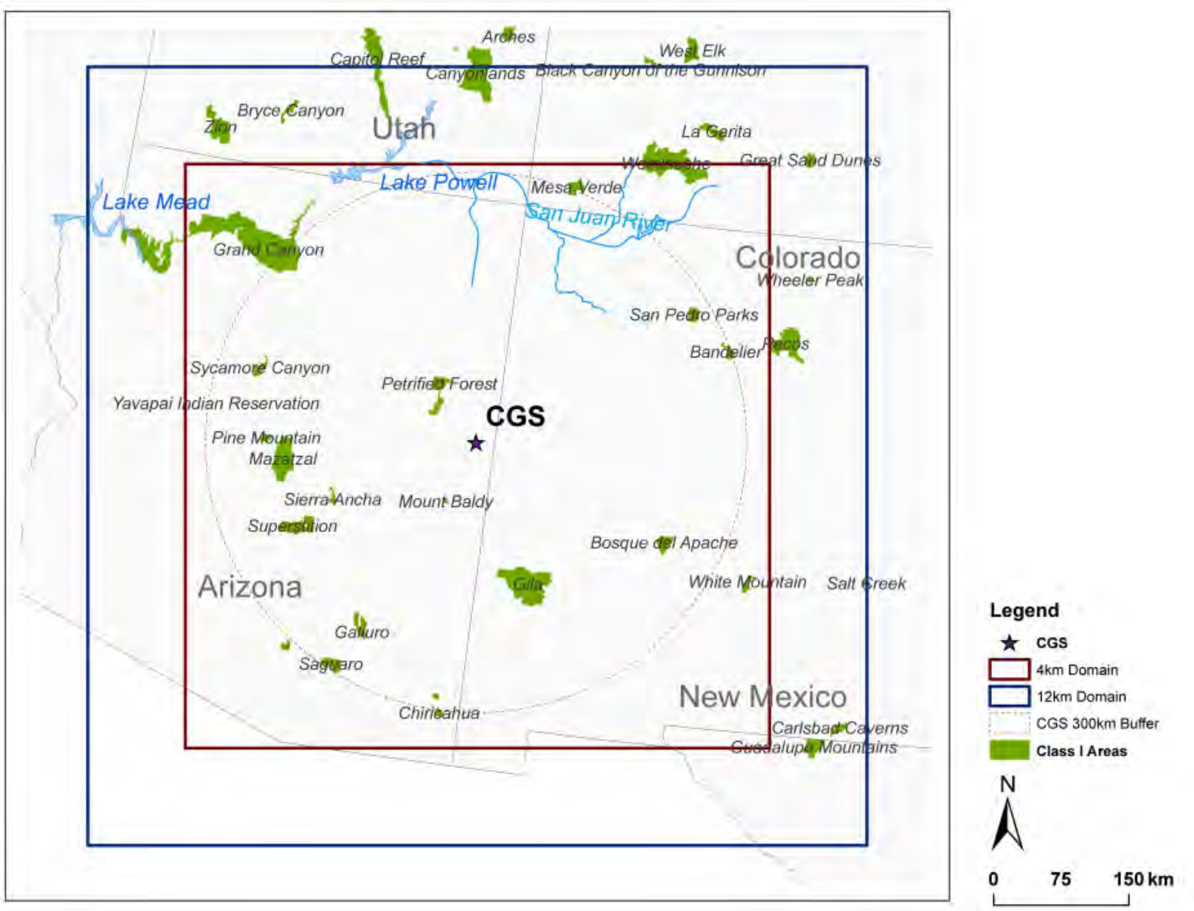

Figure 2-1. CGS CAMx 12/4 km resolution modeling domains with circle of radius 300 km centered on CGS.

Class I areas that are wholly or partially within 300 km of CGS were evaluated for visibility impacts. The CGS CAMx 12/4 km modeling domain shown in Figure 2-1 includes a ring of 300 km around the CGS source and displays all Class I areas within the 12/4 km modeling domain. If any part of a Class I area is included within 300 km of CGS, the visibility impacts were evaluated at that Class I area. For example, Grand Canyon National Park has only a small portion of the Class I area within 300 km of the CGS, but the entire Class I area was still included in the visibility assessment. However, Class I areas like Zion, Canyonlands, Weminuche, White Mountain and others that completely reside more than 300 km from CGS were not included in the visibility assessment.

2.3 Meteorology

The CGS Better-than-BART visibility assessment used meteorology generated by the prognostic Weather Research and Forecast (WRF) meteorological model (Skamarock et al., 2004; 2005;

2006) that was applied as part of the WestJumpAQMS study (ENVIRON and Alpine, 2012[9]). Version 3.3.1 of WRF was used in WestJumpAQMS to generate the CAMx meteorological input files for the 2008 calendar year (PGMs, due to their complexity, are typically run with only one year of modeled meteorology). WRF was configured with a 36/12/4 km nested domain structure using the LCP projection parameters given in Table 2-2 and extent shown in Figure 2-2. WRF was run with 37 vertical layers up to 50 mb (approximately 19 km above sea level) that were collapsed to 25 CAMx layers as shown in Table 2-3.

Table 2-2. Definition of the WRF 12/4 km modeling domains using LCP projection parameters from Table 2-1.

LCP center	40° N, 97° W
LCP true latitudes	33° N, 45° N
12 km domain	(-2448, -1404) to (612, 1620) 255 x 252
4 km domain	(-1632, -984) to (-156, 1236) 369 x 555

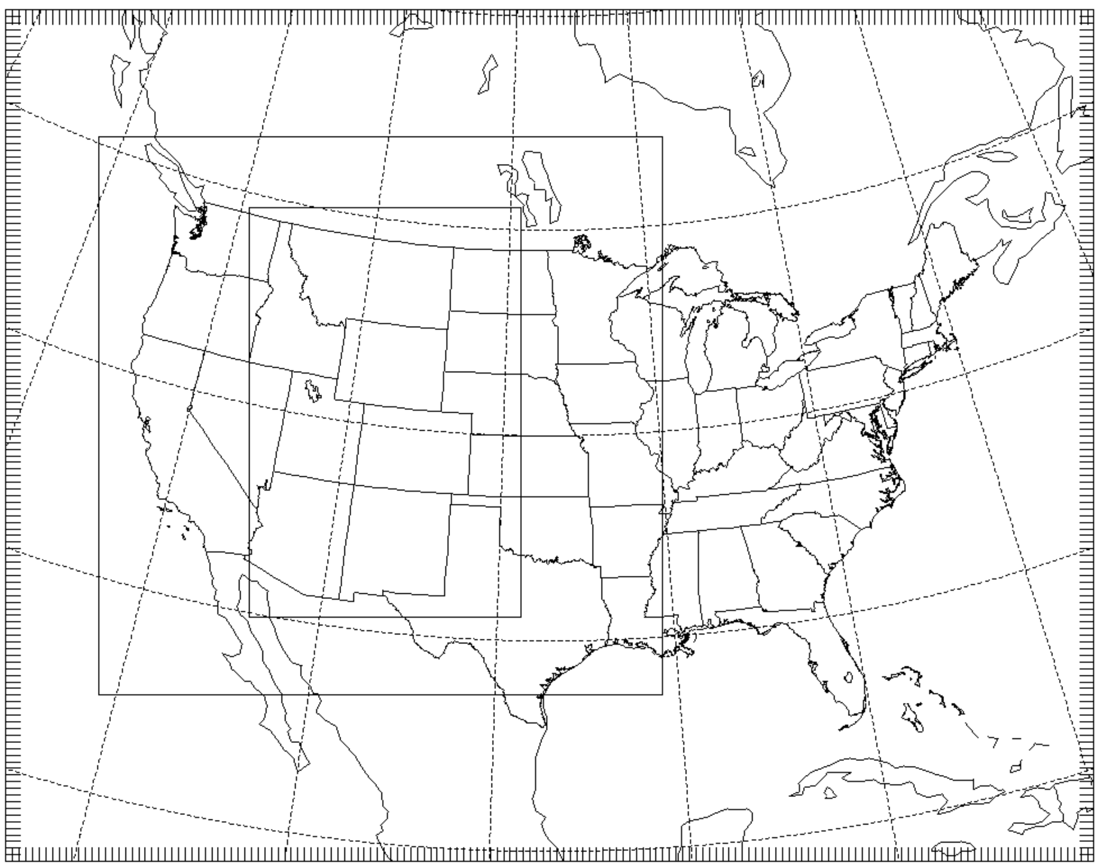

Figure 2-2. WRF 36/12/4 km modeling domains used in the 2008 modeling.

[9] http://www.wrapair2.org/pdf/WestJumpAQMS_2008_Annual_WRF_Final_Report_February29_2012.pdf

Table 2-3. Vertical layer structure in WRF and CAMx.

WRF Meteorological Model					CAMx Air Quality Model		
WRF Layer	Sigma	Pressure (mb)	Approx. Height (m)	Thickness (m)	CAMx Layer	Approx. Height (m)	Thickness (m)
37	0.0000	50.00	19260	2055	25	19260.0	3904.9
36	0.0270	75.65	17205	1850			
35	0.0600	107.00	15355	1725	24	15355.1	3425.4
34	0.1000	145.00	13630	1701			
33	0.1500	192.50	11930	1389	23	11929.7	2569.6
32	0.2000	240.00	10541	1181			
31	0.2500	287.50	9360	1032	22	9360.1	1952.2
30	0.3000	335.00	8328	920			
29	0.3500	382.50	7408	832	21	7407.9	1591.8
28	0.4000	430.00	6576	760			
27	0.4500	477.50	5816	701	20	5816.1	1352.9
26	0.5000	525.00	5115	652			
25	0.5500	572.50	4463	609	19	4463.3	609.2
24	0.6000	620.00	3854	461	18	3854.1	460.7
23	0.6400	658.00	3393	440	17	3393.4	439.6
22	0.6800	696.00	2954	421	16	2953.7	420.6
21	0.7200	734.00	2533	403	15	2533.1	403.3
20	0.7600	772.00	2130	388	14	2129.7	387.6
19	0.8000	810.00	1742	373	13	1742.2	373.1
18	0.8400	848.00	1369	271	12	1369.1	271.1
17	0.8700	876.50	1098	177	11	1098.0	176.8
16	0.8900	895.50	921	174	10	921.2	173.8
15	0.9100	914.50	747	171	9	747.5	170.9
14	0.9300	933.50	577	84	8	576.6	168.1
13	0.9400	943.00	492	84			
12	0.9500	952.50	409	83	7	408.6	83.0
11	0.9600	962.00	326	82	6	325.6	82.4
10	0.9700	971.50	243	82	5	243.2	81.7
9	0.9800	981.00	162	41	4	161.5	64.9
8	0.9850	985.75	121	24			
7	0.9880	988.60	97	24	3	96.6	40.4
6	0.9910	991.45	72	16			
5	0.9930	993.35	56	16	2	56.2	32.2
4	0.9950	995.25	40	16			
3	0.9970	997.15	24	12	1	24.1	24.1
2	0.9985	998.58	12	12			
1	1.0000	1000	0			0	

Physics options used in the WestJumpAQMS 2008 WRF modeling are provided in Table 2-4. Detailed information on the WRF WestJumpAQMS application including a model performance evaluation can be found in the WestJumpAQMS WRF Application/Evaluation Report (ENVIRON and Alpine, 2012).

Table 2-4. Physics options used in the WestJumpAQMS 2008 WRF simulation modeling.

WRF Treatment	Option Selected	Notes
Microphysics	Thompson scheme	New with WRF 3.1.
Longwave Radiation	RRTMG	Rapid Radiative Transfer Model for Global Circulation Models includes random cloud overlap and improved efficiency over RRTM.
Shortwave Radiation	RRTMG	Same as above, but for shortwave radiation.
Land Surface Model (LSM)	NOAH	Two-layer scheme with vegetation and sub-grid tiling.
Planetary Boundary Layer (PBL) scheme	YSU	Yonsie University (Korea) Asymmetric Convective Model with non-local upward mixing and local downward mixing.
Cumulus parameterization	Kain-Fritsch in the 36 km and 12 km domains. None in the 4 km domain.	4 km can explicitly simulate cumulus convection so parameterization not needed.
Analysis nudging	Nudging applied to winds, temperature and moisture in the 36 km and 12 km domains	Temperature and moisture nudged above PBL only.
Observation Nudging	Nudging applied to surface wind only in the 4 km domain	Surface temperature and moisture observation nudging can introduce instabilities.
Initialization Dataset	12 km North American Model (NAM)	Also used in analysis nudging

2.4 Land Use

The CGS 12 and 4 km resolution land use files were based on United States Geological Survey (USGS) Geographic Information Retrieval and Analysis System (GIRAS) data. These files contain the fraction of land cover in each of the 26 land use categories in the dry deposition scheme of Zhang et al. (2001; 2003) used by CAMx . In addition, monthly leaf area indices in each grid cell were prepared for the Zhang deposition scheme.

2.5 Photolysis Rates

The CAMx photolysis rates file is a lookup table of photolysis rates under clear sky conditions for a range of ozone column values, albedo, solar zenith angles, and heights above ground. Global and daily ozone column data were obtained from the database of space-based measurements from the Ozone Monitoring Instrument (OMI) on the Aura satellite (http://ozoneaq.gsfc.nasa.gov/OMIOzone.md) and processed for the 12 and 4 km domains using the O3MAP program. The Tropospheric Ultraviolet and Visible (TUV; NCAR, 2011) radiative transfer model developed by NCAR used ozone column outputs and appropriate chemical mechanism to calculate the photolysis rates.

2.6 Initial and Boundary Conditions

CAMx initial and boundary conditions for the CGS 12/4 km domain (Figure 2-1) were prepared by extracting hourly atmospheric concentrations of all modeled pollutants from the WestJumpAQMS 36 km CONUS and 12 km WESTUS 3-dimensional CAMx model outputs.

2.7 Emissions

Emissions inputs were prepared for the CAMx 12/4 km CGS modeling domains shown in Figure 2-1 for multiple CAMx simulations. The first simulation was used for a model performance evaluation (MPE) to establish confidence in the model for this application. For this simulation the emissions were taken directly from the WestJumpAQMS emissions inventory and are referred to as the Actual 2008 Base Case emissions. The inventory is summarized in the following section but note that the CGS emissions for the Actual 2008 Base Case simulation were hour-specific from the 2008 Continuous Emissions Monitoring (CEM) database. For the subsequent CAMx simulations that evaluate the proposed alternative emissions control scenarios with the Better-than-BART test, the CGS CEM emissions were removed from the WestJumpAQMS database and replaced with specific emission rates for the various scenarios that are described in Section 2.7.2.

2.7.1 2008 Actual Base Case Inventory

The 2008 Actual Base Case emissions inventory were used for the CAMx 2008 12/4 km base case simulation that is used in the model performance evaluation. The 2008 WestJumpAQMS emission inventory formed the framework for these data. The primary source for the 2008 WestJumpAQMS emission was the 2008 National Emission Inventory, version 2 (2008 NEIv2.0[10]).

[10] http://www.epa.gov/ttn/chief/net/2008inventory.html

Table 2-5 summarizes the sources of data and methods used to develop the 2008 base case emissions. The 2008 Actual Base Case emissions are based on the 2008 NEIv2.0 with the following improvements:

- Emissions of SO_2 and NO_X from major Electrical Generating Units (EGUs) (i.e., those exceeding 25 MW), including CGS, were obtained from 2008 Continuous Emissions Monitor (CEM) measurement data that are available from the EPA Clean Air Markets Division (CAMD[11]). These data are hour-specific for SO_2, NO_x and heat input. The temporal variability of other pollutant emissions (e.g., PM and VOC) for the CEM sources were estimated using the hourly CEM heat input data to allocate the annual emissions from the 2008 NEIv2.0 to each hour of the year. Emissions, locations and stack parameters for point sources without CEM devices were based on the 2008 NEIv2.0.
- The WRAP-IPAMS Phase III 2006 oil and gas emission inventories that WestJumpAQMS projected to 2008 were used in the emissions development. In addition, WestJumpAQMS developed new 2008 oil and gas emissions inventory for the Permian Basin in southern New Mexico and northwestern Texas. The CGS 12/4 km domain also includes portions of the WRAP 2008 oil and gas emissions for the North and South San Juan and Permian Basins.
- On-road mobile source emissions were derived from the MOVES on-road mobile source emissions model.
- The WRAP windblown dust (WBD) model[12] was used to generate WBD emissions using day-specific hourly meteorology from the 2008 WRF simulation.
- Sea salt and lightning emissions were generated using the 2008 WRF model hourly gridded output.
- Emissions from fires (wildfires, prescribed burns and agricultural burning) were based on the 2008 fire emissions inventory developed in the Joint Fire Sciences Program (JFSP) Deterministic and Empirical Assessment of Smoke's Contribution to Ozone (DEASCO3[13]) study (Moore et al., 2011). Wildfire emissions were assumed to be constant across all scenarios.
- Biogenic emissions were generated using an enhanced version of MEGAN that was updated by WRAP to better represent biogenic emissions for the western states. Biogenic emissions will be assumed constant across all scenarios.
- Mexico emissions were based on the 2008 projections from the 1999 Mexico national emissions inventory.
- The Environment Canada 2006 emissions inventory based on the National Pollutant Release Inventory (NPRI) were used for Canada.
- New spatial surrogates for the emissions developed using the latest 2010 Census and other data that are now available were used in emissions modeling. Details on the new spatial

[11] http://www.epa.gov/airmarkets
[12] http://www.wrapair.org/forums/dejf/fderosion.html
[13] https://wraptools.org/pdf/ei_methodology_20130930.pdf

surrogates used for allocating county-level emissions to the 4 km grid cells can be found in the WestJumpAQMS Emissions Technical Memorandum Number 13 (available at http://www.wrapair2.org/pdf/Memo13_Parameters_Sep30_2013.pdf).

The 2008 Actual Base Case emissions are fully documented in 16 Technical Memorandums that are available on the WestJumpAQMS website[14].

[14] http://www.wrapair2.org/WestJumpAQMS.aspx

Table 2-5. Summary of emission sources used to develop the 2008 Actual Base Case emissions for model evaluation.

Emissions Component	Configuration	Details
Oil and Gas Emissions	Update WRAP Phase III 2006 to 2008	Seven WRAP Phase III Basins in CO, NM, UT and WY plus add 2008 Permian Basin O&G Emissions
Area Source Emissions	2008 NEI Version 2.0	Western state updates, then SMOKE processing of http://www.epa.gov/ttn/chief/net/2008inventory.html
On-Road Mobile Sources	MOVES	MOVES 2008 emissions run in inventory mode
Point Sources	2008 CEM and Non-CEM Sources	Use 2008 day-specific hourly measured CEM for SO_2 and NO_X emissions for CEM sources, 2008 NEIv2.0 for other pollutants and non-CEM sources
Off-Road Mobile Sources	2008 NEIv2.0	Based on EPA NONROAD model http://www.epa.gov/oms/nonrdmdl.htm
Wind Blown Dust Emissions	WRAP Wind Blown Dust (WBD)	WRAP WBD Model with 2008 WRF meteorology adjusted to be consistent with 2002 WBD modeling
Ammonia Emissions	NEIv2.0	Based on CMU Ammonia Model. Review and update spatial allocation if appropriate.
Biogenic Sources	MEGAN	Enhanced version of MEGAN Version 2.1 from WRAP Biogenics study http://www.wrapair2.org/pdf/WGA_BiogEmisInv_FinalReport_March20_2012.pdf
Fires	2008 DEASCO3	2008 DEASCO3 fire inventory used. https://wraptools.org/pdf/ei_methodology_20130930.pdf
Temporal Adjustments	Seasonal, day, hour	Based on latest collected information
Chemical Speciation	CB6r2 Chemical Speciation	Revision 2 of the Carbon Bond Version 6 chemical mechanism
Gridding	Spatial Surrogates based on land use	Develop new spatial surrogates using 2010 census data and other data
Quality Assurance	SMOKE QA Tools; PAVE, VERDI plots; Summary reports	Follow WRAP emissions QA/QC plan.

2.7.2 CGS Emission Scenarios

Emissions for all sources besides CGS were identical to the 2008 Actual Base Case emissions. For the Better-than-BART CAMx simulations, the following CGS emission scenarios were modeled:

1. CGS Baseline conditions that represents current emissions conditions at the facility;
2. CGS EPA BART that represents CGS with the EPA BART NO_X emission limits; and
3. Several CGS proposed alternative emission scenarios that have specific emission limits along with shutdown periods for CGS unit 1.

2.8 CAMx Model Performance Evaluation

The WestJumpAQMS and Western Air Quality Study (WAQS) CAMx 2008 base case modeling results were subjected to one of the most detailed and comprehensive model performance evaluations (MPE) ever conducted. The results of the MPE are documented in the WestJumpAQMS final report (ENVIRON, Alpine and UNC, 2013) and the WAQS report (Adelman, Shanker, Yang and Morris, 2014[15]). Thus, the MPE for the CGS CAMx 2008 12/4 km Actual Base Case simulation focused on the model's ability to simulate $PM_{2.5}$ total mass, $PM_{2.5}$ individual species mass, and species specific visibility extinctions since the focus of this study is to assess visibility impacts only. The MPE will rely on the WestJumpAQMS and WAQS model evaluations for the other components.

In this section we present a summary of the evaluation of the CGS 2008 12/4 km Actual Base Case simulation for visibility. Additional details are provided in Appendix A.

2.8.1 Model Performance Evaluation Approach

The CGS CAMx 2008 12/4 km Actual Base Case was evaluated by comparing the model's $PM_{2.5}$ and visibility predictions at IMPROVE sites in the CGS 4 km domain as shown in Figure 2-3. The predicted and observed $PM_{2.5}$ species and NO_2 concentrations were converted to visibility extinction using the latest IMPROVE equation and Class I area-specific relative humidity adjustment factors [f(RH)] following the procedures in FLAG (2010). The total and species-specific $PM_{2.5}$ mass and visibility extinction model performance statistics were compared against established PM Performance Goals and Criteria as well as the more stringent ozone Performance Goals. In addition, numerous graphical displays of model performance were used to illustrate model performance as follows:

- Scatter plots of predicted and observed total extinction with summary model performance statistics.
- Soccer plots of monthly bias and error for total extinction and by species extinction that are compared against ozone performance goals and PM performance goals and criteria. Monthly soccer plots allow the easy identification of when performance goals/criteria are achieved and a seasonal evaluation of performance. Note that because we are only evaluating visibility and $PM_{2.5}$, the ozone performance goals are not relevant. However, they are included on the soccer plot displays and represent very good performance for visibility and $PM_{2.5}$.
- Time series plots that compare predicted and observed daily total visibility extinction and by species visibility extinction at individual monitoring sites.
- Stacked bar charts that compare predicted and observed annual and seasonal total visibility extinction and by species visibility extinction at individual monitoring sites.

[15] http://views.cira.colostate.edu/tsdw/Documents/

- Spatial statistical performance maps that display bias/error on a map at the locations of the monitoring sites in order to better understand spatial attributes of model performance along with tabular summaries of statistical performance metrics. (See Appendix A).

All performance statistics and displays are performed matching the predicted and observed concentrations by time and location using the modeled prediction in the 4 km grid cell containing the monitoring site.

The model performance statistics and displays were generated using the Atmospheric Model Evaluation Tool (AMET) developed by EPA, which is the MPE tool mentioned in EPA's latest PGM modeling guidance (EPA, 2014d). Thus, the statistics and displays are limited to those produced by AMET. AMET uses screening criteria to make sure that sufficient observations are available at a monitoring site for use in the model evaluation. Consequently, some of the IMPROVE sites are dropped from the visibility MPE.

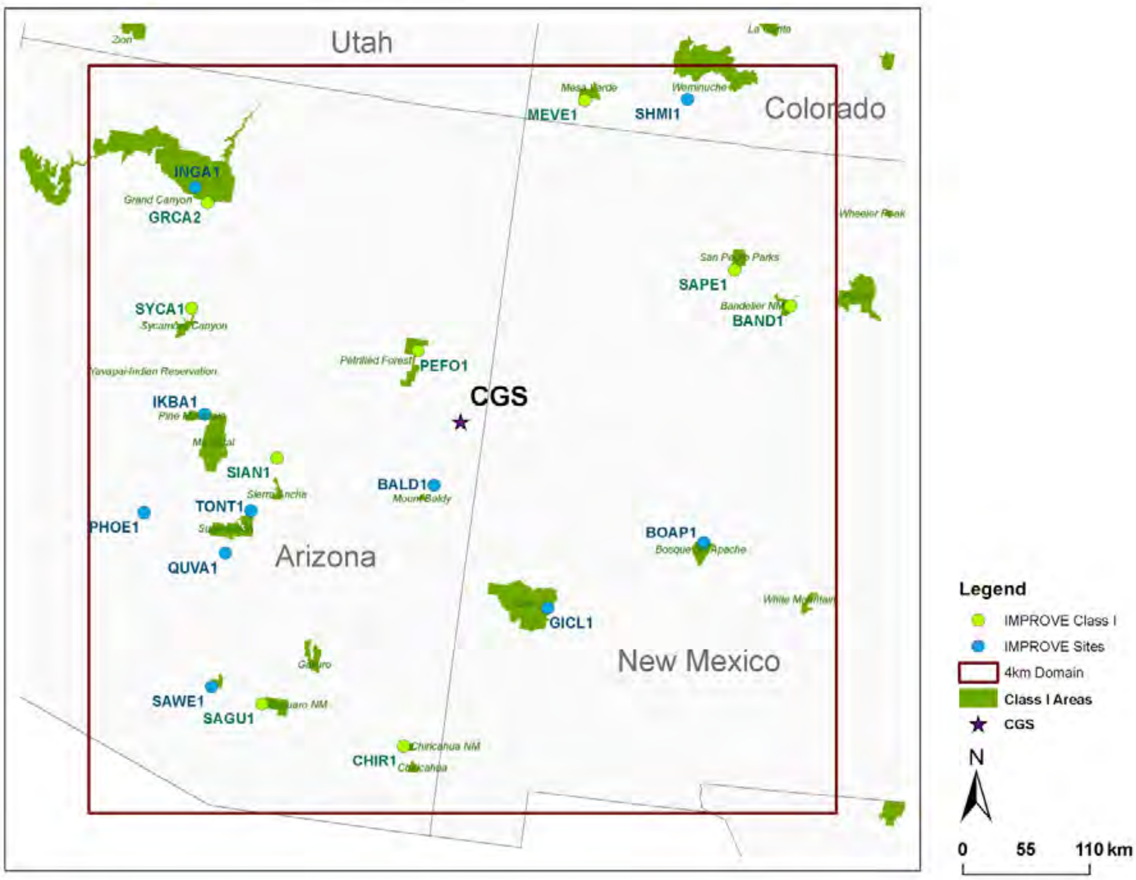

Figure 2-3. Locations of IMPROVE monitoring sites in the CGS 4 km modeling domain where the CAMx 2008 Actual Base Case was evaluated for $PM_{2.5}$ and subset of IMPROVE sites (green) where visibility evaluation was also performed.

2.8.2 Total Visibility Extinction Model Performance

The upper plot in Figure 2-4 is a scatter plot that displays predicted and observed 24-hour average total visibility extinction. The plot reports annual average performance statistics averaged across IMPROVE monitoring sites in the 4 km CGS domain (Figure 2-3). The lower plot in Figure 2-4 is a soccer plot of model performance (i.e. model bias and error) of total visibility extinction averaged by month and averaged across all the IMPROVE sites. Also shown in the soccer plots are boxes that represent performance goals for ozone (most inner) and PM (middle), and PM performance criteria (most outer). More details regarding performance goals and criteria are provided in Appendix A.

The annual average total visibility extinction bias (14%) and error (34%) reported on Figure 2-4 (top) achieve the most stringent ozone performance goals for bias (≤±15%) and error (≤35%). The monthly average total visibility model performance achieves the PM performance criteria for bias (≤±60%) and error (≤75%) for all 12 months of the year (Figure 2-4, top). In addition, the monthly average total visibility performance also achieves the PM performance goals for bias (≤±30%) and error (≤50%) for 9 months of the year with the three winter months (blue symbols) not achieving the PM performance goal due to an overestimation bias. The monthly average total visibility performance even achieves the most stringent ozone performance goal for 6 months of the year, with the summer months of July and August exhibiting extremely good visibility performance with zero bias and extremely low error.

The scatter plot of the predicted and observed 24-hour total visibility extinctions across IMPROVE sites in the 4 km domain also indicate good visibility model performance with the data points clustered around the 1:1 line of perfect agreement (Figure 2-4, top). However, there are some outliers. For example, there are two modeled daily extinction values in excess of 100 Mm-1 when observed values are less than 40 Mm-1. These high modeled extinction outliers are due to modeled wildfire impacts that are not reflected in the observations. For example, one of the modeled daily extinction values in excess of 100 Mm-1 is at the Bandelier (BAND1) IMPROVE site with the majority of the extinction due to carbon (EC and OA). Carbon is a fire signature.

2.8.3 Species-Specific Visibility Model Performance

Figure 2-5 displays soccer plots of monthly averaged performance statistics averaged across IMPROVE sites in the 4 km domain for visibility extinction due to each major PM species.

<u>SO4:</u> With the exception of the three winter months, the ammonium sulfate (AmmSO4) visibility performance achieves the PM performance criteria. In addition, the PM performance goal is achieved for 5 months and the ozone performance goal is achieved for August (Figure 2-5, top left). For the three winter months, AmmSO4 extinction has an overestimation bias that makes it fall slightly outside of the range of the PM performance criteria.

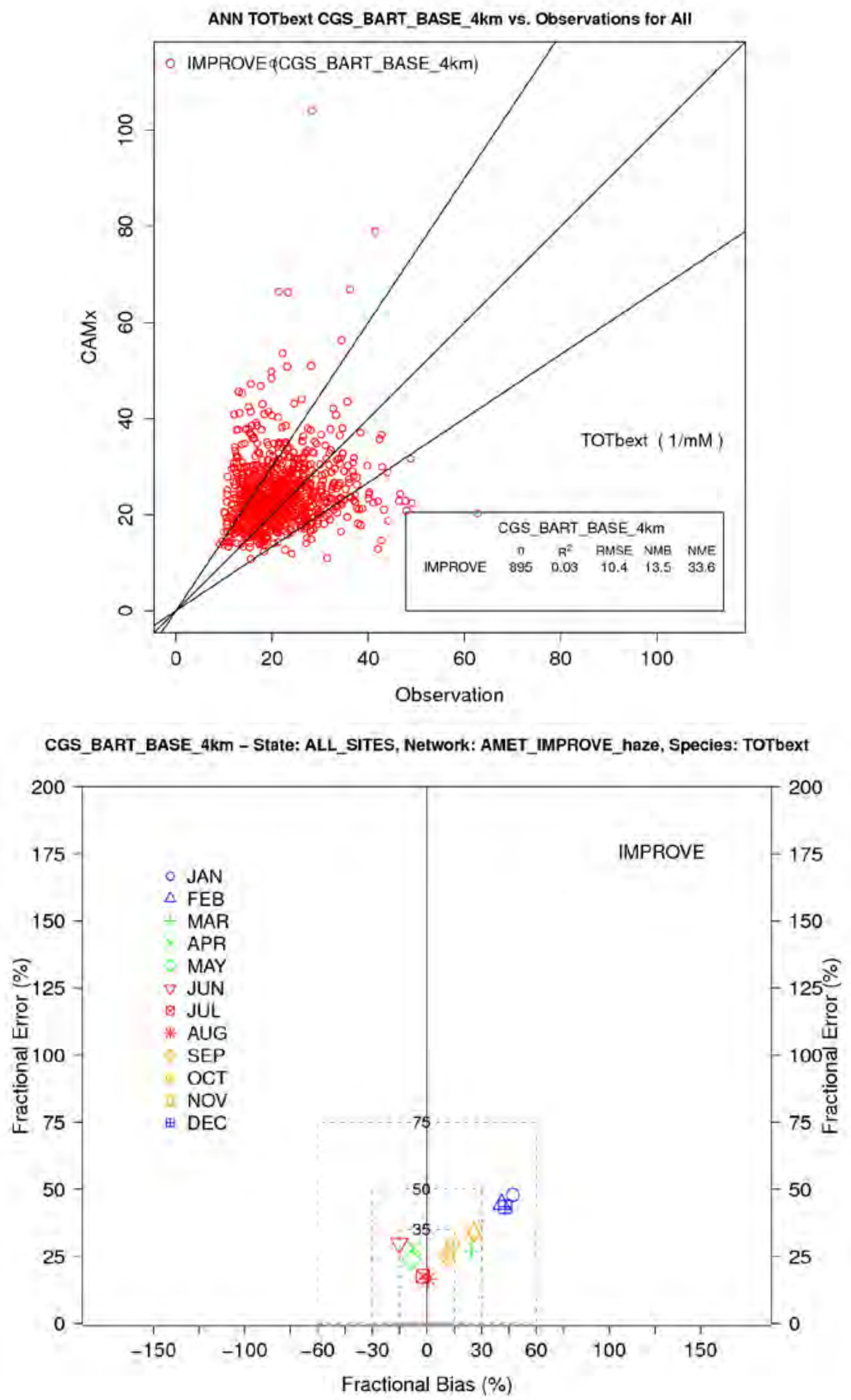

Figure 2-4. Scatter plot (top) and monthly soccer plot (bottom) of 24-hour average total visibility extinction model performance across the IMPROVE sites in the 4 km CGS domain.

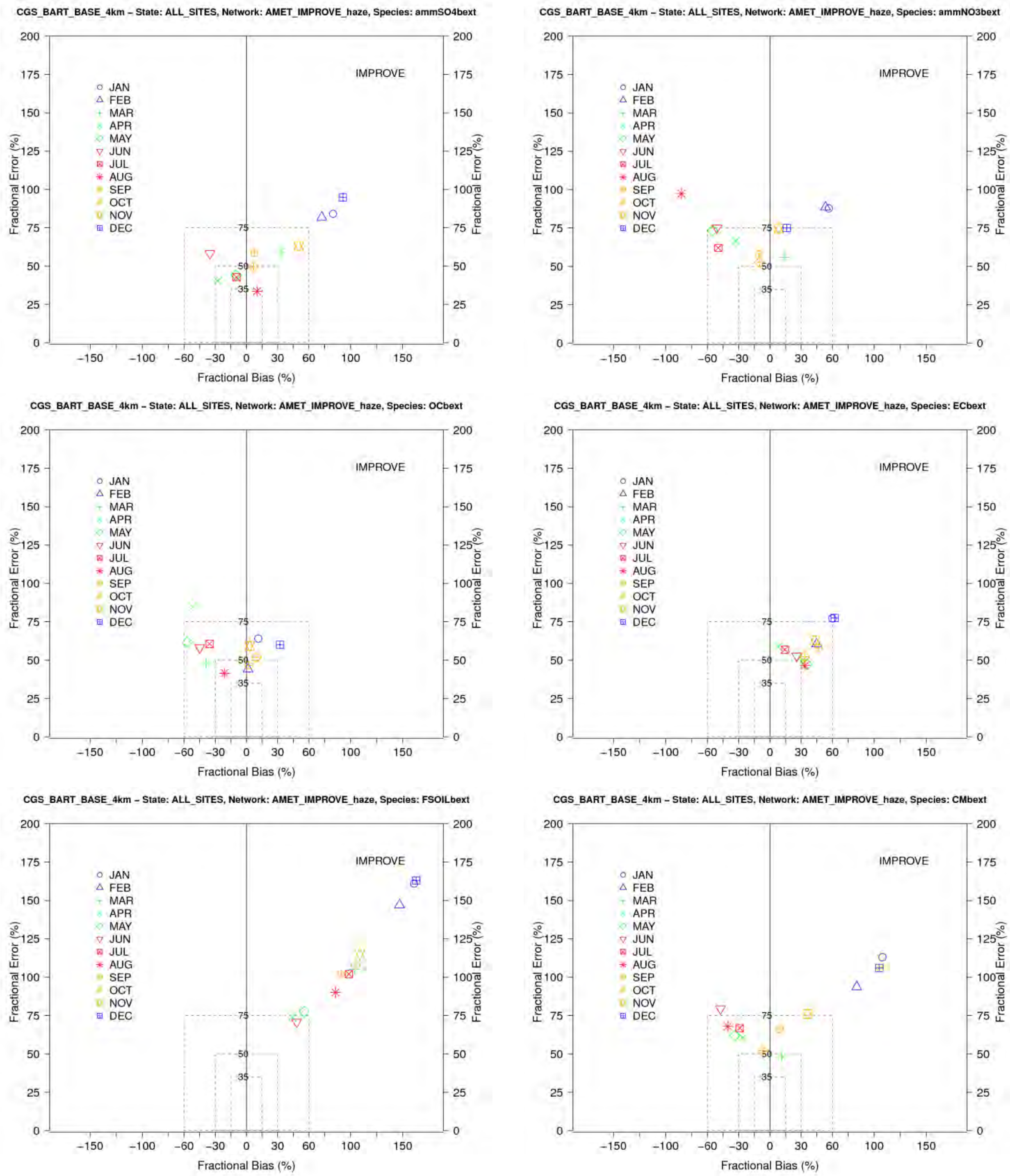

Figure 2-5. Soccer plots of monthly averaged visibility performance for sulfate (top left), nitrate (top right), organic aerosol (middle left), elemental carbon (middle right), soil (bottom left) and coarse mass (bottom right).

NO3: Ammonium nitrate (AmmNO3) visibility performance for most months falls between the PM performance goals and criteria with just August and two winter months failing to achieve the performance criteria (Figure 2-5, top right). AmmNO3 extinction performance exhibits a general underestimation bias in summer and a general overestimation bias in winter, which is fairly typical of PGM models. During the summer, the observed and modeled AmmNO3 are very low and usually a negligible portion of visibility impairment. During the winter, nitrate formation is very episodic and depends on numerous processes and the presence of ammonia, whose emissions are highly uncertain. AmmNO3 visibility performance that mostly achieves the PM performance criteria is considered fairly good PGM model performance.

OA: The monthly visibility model performance for Organic Aerosol (OA) is shown in the left middle panel in Figure 2-5. With the exception of April whose error is > 75 %, the OA visibility performance for the remaining 11 months achieves the PM performance criteria. The best performing months for OA visibility occur in the fall and have essentially zero bias. The summer months have a slight underestimation bias and the winter months have a slight overestimation bias. We suspect there may be missing SOA processes in the model that may help explain the summer underestimation bias for OA.

EC: Elemental Carbon (EC) visibility model performance achieves or nearly achieves the PM performance criteria, albeit with an overestimation bias for all months (Figure 2-5, middle right). The EC extinction overestimation bias is greater for the cooler than warmer months.

Soil: The model performance for extinction due to Soil, which is also called other PM2.5 (OPM2.5), is characterized by an over-prediction bias that is at the +60% PM Performance Criteria for Apr-May-Jun and as high as 150% for the winter months, with the rest of the months falling in between (Figure 2-5, lower left). There are model-measurement incommensurability issues with this species. The IMPROVE soil measurements are based on a linear combination of individual elements, whereas the modeled Soil/OPM2.5 species is based on primary PM2.5 emissions that have not been explicitly speciated into other compounds. So both measurement and speciation artifacts impact this comparison. The model OPM2.5 overestimation of the IMPROVE Soil measurements is routine for PGM modeling because of this issue.

CM: The coarse mass visibility model performance is characterized by a summer underestimation tendency and a winter overestimation tendency with ~8 months achieving the PM performance criteria (Figure 2-5, bottom right).

2.8.4 Monitor-Specific Visibility Model Performance

The visibility performance was evaluated at each IMPROVE monitoring site for total and species-specific visibility extinction and $PM_{2.5}$ concentrations. Appendix A contains time series plots and model performance statistics for each IMPROVE site, with the visibility results for Petrified Forest (PEFO1) IMPROVE site reproduced in Figure 2-6 below. Results in Appendix A show that CAMx visibility and $PM_{2.5}$ performance is much better for the southern IMPROVE sites than the more northerly sites in the CGS 4 km domain. The PEFO1 IMPROVE site is in the center of the 4 km domain and is fairly representative of average model performance. The exception to this is for elemental carbon (EC) extinction and concentration, where PEFO1 is the best performing site with the other IMPROVE sites exhibiting an overestimation bias for EC.

2.8.4.1 PEFO Time Series Analysis

The total extinction time series comparison at PEFO1 displays an overestimation in Q1, underestimation in Q2 and excellent performance in Q3 and Q4 (Figure 2-6, top left) resulting in very good annual model performance statistics with low bias (5%) and error (28%) that achieves the most stringent ozone performance goals. The AmmSO4 extinction at PEFO1 (Figure 2-6, top right) also has an overestimation bias in Q1 but good performance the rest of the year resulting in a positive annual bias (18%) that achieves the PM performance goal for bias and annual error (61%) that slightly exceeds the PM Performance Goal for error (≤±60%). The AmmNO3 extinction performance at PEFO1 (Figure 2-6, middle left) is fairly typical of AmmNO3 performance with the model underestimating the summer low values but overestimating the winter high values resulting in a low annual bias (4%) that achieves the ozone and PM performance goal for bias but much higher annual error (79%) that just barely exceeds the PM performance criterion for error (≤75%).

OA extinction is underestimated in Q2 and Q3 resulting in an annual bias (-30 %) that is equal to the PM performance goal and an annual error (42%) that achieves the PM performance goal (Figure 2-6, middle right). The EC extinction performance at PEFO1 is the best of any IMPROVE site with near zero bias (2%) and low error (33%) that achieves the most stringent ozone performance goals (Figure 2-6, bottom left). Note that EC extinction performance at all the other IMPROVE sites in the 4 km domain exhibit an overestimation bias of 23% to 79%. Soil extinction is overestimated except during Q2 with an annual bias value at PEFO1 of 127%, which is fairly typical (Figure 2-6, bottom right). As noted previously, the IMPROVE equation defines Soil using a linear combination of atmospheric elements differently than how the model defines this species. Although not included in Figure 2-6, but reported in Appendix A, extinction due to coarse mass at PEFO1 is underestimated (-24%) and achieves the PM performance goal with the error (73%) just achieving the PM performance criterion.

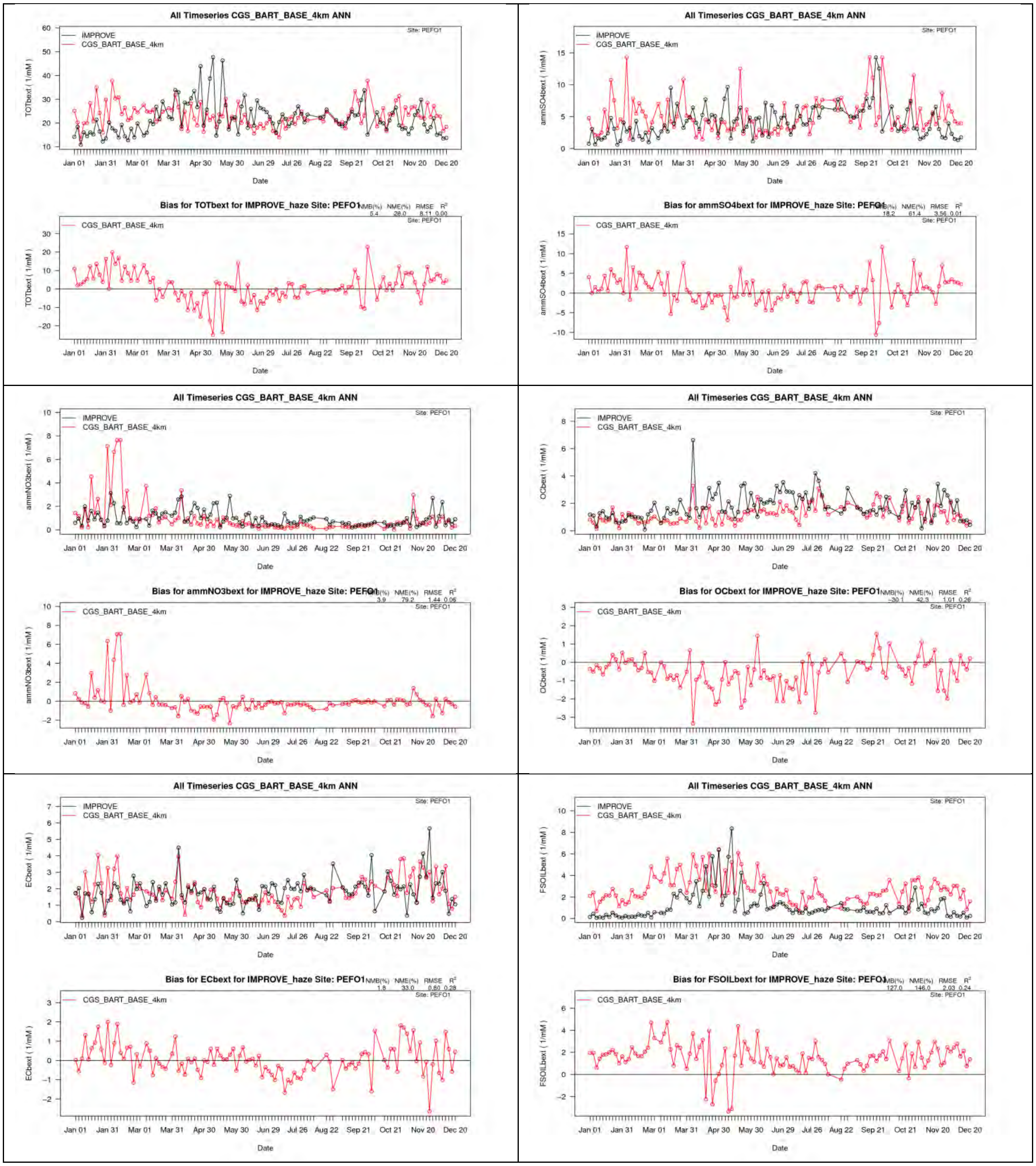

Figure 2-6. Predicted and observed 24-hour average visibility extinction and bias (Mm^{-1}) at Petrified Forest (PEFO1) for total (top left), AmmSO4 (top right), AmmNO3 (middle left), OA (middle right), EC (bottom left) and SOIL (bottom right).

2.8.4.2 Annual Average and Quarterly Average Speciated Extinction Performance by Monitor

Figure 2-7 displays stacked bar charts of annual average total extinction at each IMPROVE site with the stacked bars showing each $PM_{2.5}$ component of extinction. For most sites, the observed and predicted annual average total extinction are similar, although the modeled annual average total extinction tends to be the same or slightly higher than the observed value. Annual average AmmSO4 extinction agrees well at all IMPROVE sites. The annual AmmNO3 extinction also agrees well at most sites, although some have an annual overestimation bias (e.g., MEVE1) and others have an annual underestimation (e.g., SAGU1) bias. The predicted and observed annual average extinction due to OA (OC) are very similar. The model tends to overestimate extinction due to EC. The model consistently overstates the amount of extinction due to Soil at all sites. Finally, the annual average extinction comparison of coarse mass shows an overestimation bias at some sites (e.g., BAND1) and an underestimation bias at other sites (e.g., SYCA1). The site with the highest annual total overestimation bias is BAND1 whose overestimation is primarily due to overstated extinction due to EC, Soil and coarse mass that is partly due to modeled wildfire contributions that were not as large in the observations.

Stacked extinction bar charts by quarter are shown in Figure 2-8 that clearly show variations in the CAMx visibility model performance by quarter and by species. The modeled annual average extinction overestimation is primarily due to overstated extinction across several species in Q1 and Q4. The model extinction performance in Q2 and Q3 is quite good at all monitoring sites.

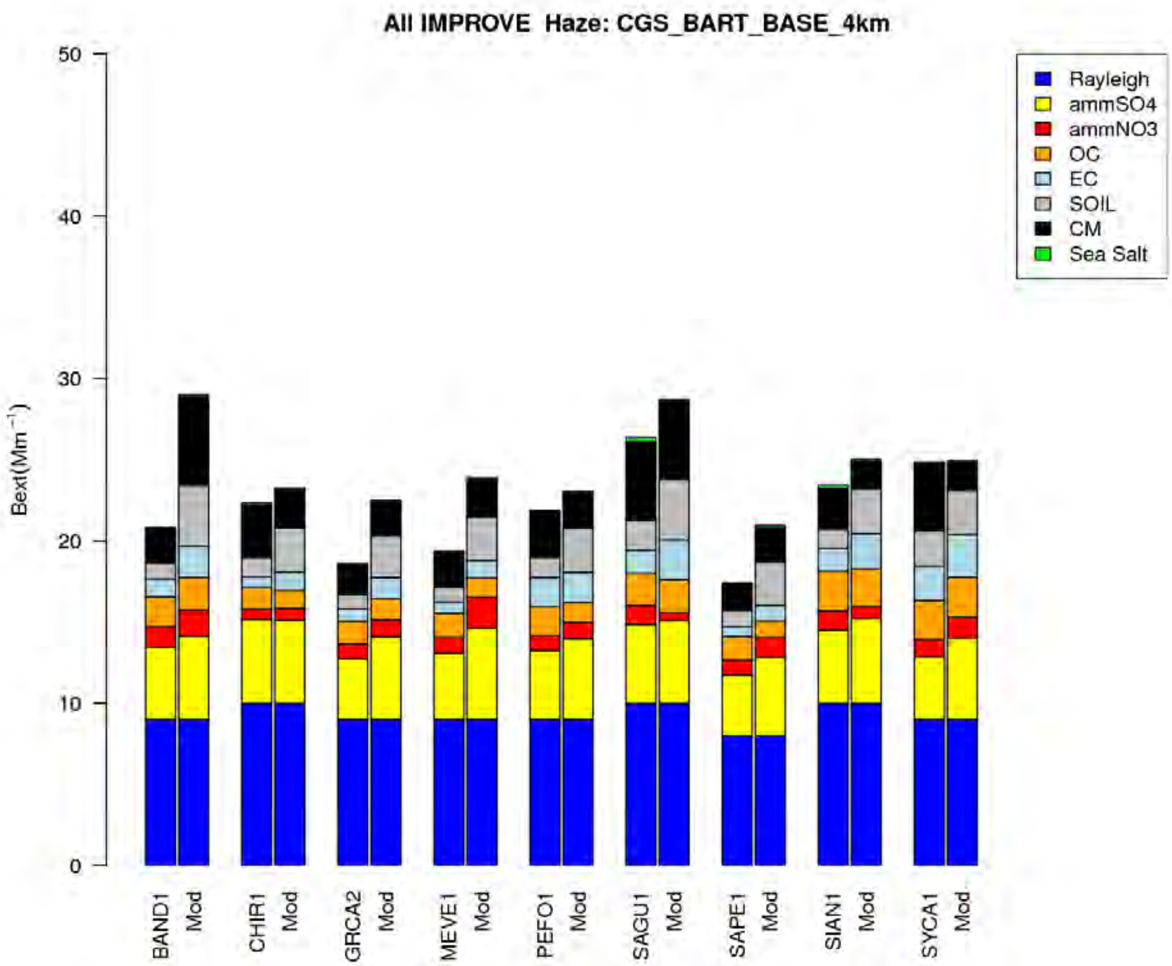

Figure 2-7. Predicted and observed annual average total extinction (Mm^{-1}) stacked bar charts.

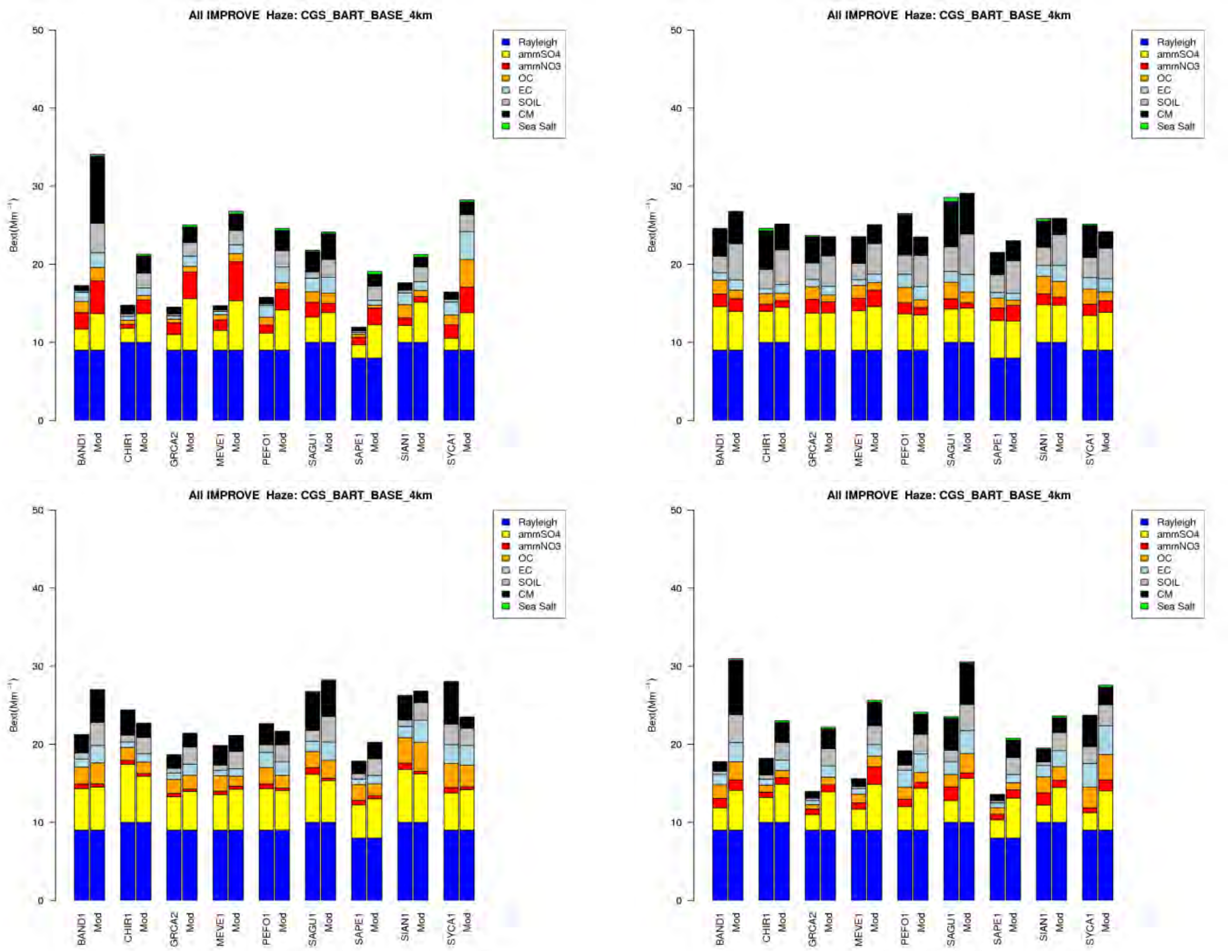

Figure 2-8. Predicted and observed quarterly average total extinction (Mm^{-1}) stacked bar charts for Q1 (top left), Q2 (top right), Q3 (bottom left) and Q4 (bottom right).

2.8.5 Conclusions of CAMx CGS 12/4 km 2008 Base Case Model Performance

The CAMx total visibility extinction achieves the PM performance goal on an annual average basis as well as for 9 months of the year. The overestimation bias in winter months results in model performance falling between the PM performance goals and performance criteria levels for those months.

Visibility performance varies geographically, seasonally and by PM species. As shown in Appendix A, the visibility model performance at IMPROVE sites in the lower two-thirds of the 4 km CGS modeling domain is quite good at meeting the most stringent ozone performance goals, whereas the visibility model performance at IMPROVE sites in the top third of the domain have an overestimation bias, but still achieve the PM performance goals except at the Bandelier (BAND1) IMPROVE site. Part of the reason that the model overestimates visibility extinction at the BAND1 IMPROVE site is because of modeled impacts from wildfires that were not as high in the observations.

The seasonal total visibility model performance shows very good performance for the warmer months (e.g., Q2 and Q3) and an overestimation bias for the cooler months (e.g., Q1 and Q4). The monthly total visibility model performance achieves the PM performance criteria for all months, the PM performance goal for 9 months and the ozone performance goal for 7 months.

The ammonium sulfate (AmmSO4) and ammonium nitrate (AmmNO3) visibility performance is fairly good with 9 months achieving the PM performance criteria. AmmSO4 visibility performance also has many months achieving the PM performance goal.

Visibility performance due to organic aerosol is fairly good, albeit with a summer underestimation bias. And visibility performance for elemental carbon and soil generally exhibit an overestimation bias.

The main objective of the CGS Better-than-BART visibility modeling is to evaluate the trade-offs of visibility benefits between reducing CGS's NO_X versus SO_2 emissions. The visibility performance for AmmSO4 and AmmNO3 is good and mostly unbiased and the bias that does occur (slight winter overestimation) is common to both AmmSO4 and AmmNO3. Given this, and the fact that CAMx incorporates state-of-the-science sulfate and nitrate formation chemistry algorithms, the CAMx 2008 12/4 km CGS modeling platform should provide an accurate and reliable database for evaluating and comparing visibility impacts of the BART modeling scenarios and proposed alternative control scenarios.

2.9 CAMx CGS Better-than-BART Source Apportionment Modeling

CAMx was applied for CGS Baseline emissions, CGS EPA BART emissions, and proposed CGS alternative emissions using the 12/4 km modeling domain, 2008 meteorological conditions and 2008 base case emissions for all other sources. The CAMx Particulate Source Apportionment Technology (PSAT) Probing Tool was used to separately track contributions of particulate matter (PM) and reactive gaseous nitrogen (RGN) concentrations (which include NO_2) due to SO_2, NO_X and PM emissions from the CGS units.

2.9.1 CAMx Particulate Source Apportionment Tool (PSAT)

The PSAT source apportionment tool uses reactive tracers (also called tagged species) that run in parallel to the host model to determine the contributions to PM from user selected Source Groups. A Source Group is a tagged group of emissions sources whose impacts are separately tracked using the reactive tracers. Source Groups are usually defined as the intersection between geographic Source Regions (e.g., grid cell definitions of states) and user selected Source Categories (e.g., point, on-road mobile, etc.). However, for the CGS CAMx source apportionment modeling, the Source Groups will consist of the two CGS units and all other natural and anthropogenic emissions.

The CAMx PSAT particulate source apportionment method has five different families of tracers that can be invoked separately or together to track source apportionment for the following particulate species: (1) Sulfate (SO_4); (2) Nitrate and Ammonium (NO_3 and NH_4); (3) Primary PM; (4) Secondary Organic Aerosol (SOA); and (5) Mercury. Because PSAT needs to track the PM source apportionment from the PM precursor emissions to the PM species, the number of tracers needed to track a Source Group's source apportionment depends on the complexity of the chemistry and number of PM and intermediate species involved. The Sulfate family is the most simple as it requires only two reactive tracer species (SO_2 and SO_4) to track the formation of particulate SO_4 from gaseous SO_2 emission for each Source Group. Whereas, the SOA family is the most complicated (expensive) PSAT family with 18 reactive tracers needed for each Source Group to track the four VOC species emissions that are SOA precursors (aromatics, isoprene, terpenes and sesquiterpenes) and the 7 condensable gas (CG) and SOA pairs that are in equilibrium.

For the CAMx CGS Better-than-BART source apportionment application, the PSAT SO_4, NO_3/NH_4, and Primary PM families of source apportionment tracers were used. The PSAT SOA family of source apportionment was not used because the CGS EGU units do not emit any VOC species that are SOA precursors.

2.9.2 CAMx PSAT Configuration

SO_2, NO_X and primary PM emissions from the CGS units were tagged for treatment by the PSAT tool for each of the emission scenarios. For the CGS baseline and CGS BART simulations, CAMx was run with 3 source groups representing: CGS unit 1; CGS unit 2; and, all other emissions sources. For the proposed alternative emission simulations, CAMx was run with 15 source groups with one source group representing non-CGS emissions and the other 14 source groups representing the CGS emissions for different time periods as follows:

- CGS Units 1 and 2 for February through October;
- CGS Unit 2 for January, November and December; and
- CGS Unit 1 for the months of November, December, January and February split into three ~10 day periods each (12 Source Groups).

Performing the CAMx simulations for the proposed alternative emissions simulations with CGS unit 1 tagged separately for ~10 day periods between November and February enabled evaluation of the CGS proposed alternative visibility impacts using different CGS unit 1 shutdown assumptions at 10-day increments without having to rerun CAMx.

3.0 POST-PROCESSING CGS CAMX MODELING RESULTS

Visibility impacts attributed to the CGS for baseline, EPA BART and proposed alternative emission scenarios were calculated at all Class I areas. The differences in visibility impacts between the different scenarios were then compared in the Better-than-BART two-pronged tests that were described in Section 1.5.

Visibility impacts were calculated based on the CAMx absolute modeled concentrations using incremental CGS concentrations as quantified by the CAMx PSAT tool in the IMPROVE extinction equation (described below). FLAG (2010) procedures were followed. The change in light extinction due to CGS emissions was calculated for each day for each grid cell that intersects a Class I area within 300 km of the CGS facility. The maximum visibility impact at any CAMx grid cell that intersects a Class I area was used to represent the visibility impact at that Class I area. Processing the CAMx concentrations to obtain visibility impacts using this method gives visibility impacts analogous to those determined by CALPUFF, except that they are based on modeled results from a full-science model.

Two averaging approaches were taken to calculate the visibility impacts. The first approach averages the visibility impacts across the W20% and B20% days, the second approach performs the averaging across all modeled days which provides an annual average assessment of visibility impacts.

An additional analysis was undertaken that looked at the visibility impacts for the W20% and B20% days following the procedures for projecting future year visibility impairment using PGMs outlined in EPA's guidance for demonstrating regional haze progress (EPA, 2007; 2014) and codified in EPA's Modeled Attainment Test Software (MATS[16]). These procedures use the ratio of the CAMx modeled concentrations from different scenarios (so called Relative Response Factors or RRFs) to scale the observed $PM_{2.5}$ component concentrations from which visibility impairment is calculated using the IMPROVE extinction equation described below. EPA believes that using the relative change in the modeling results to scale the observed concentrations will produce a more reliable estimate of future visibility as any bias in the model is minimized and the visibility projections are rooted in observed concentrations.

Two MATS methods were attempted. For the first method, each of the six emission/shutdown scenarios (baseline, EPA BART, and four alternative emissions scenarios) with and without the contributions due to emissions from the CGS facility (Table 1-1) were evaluated with MATS. The difference between the MATS projected visibility with and without the CGS emissions is the resultant visibility impact due to CGS. However, MATS outputs the visibility projections in deciviews using only two decimal places. Since the CGS visibility impacts can be smaller than a hundredth of a deciview, the resultant CGS visibility impacts from MATS ended up being zero in many cases.

[16] http://www3.epa.gov/ttn/scram/modelingapps_mats.htm

MATS calculates relative response factors (RRFs) to 4 decimal places, and effort was made to obtain higher precision in the deciview calculations by recalculating deciviews using the RRFs outside of MATS with the IMPROVE equation. However, even 4 decimal place RRFs do not provide sufficient precision to evaluate the CGS incremental visibility impacts to four decimal places.

The second method did not calculate incremental haze index (deciview) impacts from the CGS facility, but used MATS to directly compare the different scenarios within one execution of MATS (i.e., by calculating RRFs based on say BtB1 divided by Baseline, since the only difference in emissions between the runs are the CGS emissions). However, precision limitations also hindered this method, and it was not possible to obtain meaningful results with this method.

We contacted personnel at EPA's Office of Air Quality Planning and Standards (OAQPS) who are in charge of MATS to see if a higher precision version was available, but were informed that no other version was available and we could not obtain the source code to modify it for higher precision. Thus, the Better-than-BART test using the relative modeling results could not be performed.

Therefore, only the Better-than-BART tests based on absolute modeling results are presented in this report.

3.1 Visibility Calculations using CAMx PSAT Results Following FLAG (2010)

The visibility evaluation metric used in this analysis is based on 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}) and is calculated primarily from atmospheric concentrations of particulates. The incremental concentrations due to CGS emissions was added to natural background concentrations in the extinction equation (b_{ext}) and the difference between the Haze Index with added CGS concentrations to the Haze Index based solely on background concentrations was calculated. This quantity is the change in Haze Index, which is referred to as "delta deciview" (Δdv):

$$\Delta dv = 10 \times \ln[b_{ext(CGS+background)}/10] - 10 \times \ln[b_{ext(background)}/10]$$

$$\Delta dv = 10 \times \ln[b_{ext(CGS+background)}/b_{ext(background)}]$$

Here $b_{ext(CGS+background)}$ refers to atmospheric light extinction due to emissions from CGS plus natural background concentrations, and $b_{ext(background)}$ refers to atmospheric light extinction due to natural background concentrations only. In Section 4, delta deciview impacts are referred to more simply as CGS visibility impacts.

3.1.1 IMPROVE Reconstructed Mass Extinction Equations

The FLAG (2010) procedures for evaluating visibility impacts at Class I areas use the revised IMPROVE reconstructed mass extinction equation to convert 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

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

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

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

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

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

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

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

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

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

f(RH) are relative humidity adjustment factors that account for the fact that sulfate, nitrate, organic aerosol and sea salt aerosols are hygroscopic and are more effective at scattering radiation at higher relative humidity. FLAG (2010) recommends using monthly average f(RH) values rather than the hourly averages recommended in the previous FLAG (2000) guidance document in order to moderate the effects of extreme weather events on the visibility results. The Class I area-specific monthly average f(RH) values from Tables 7 through 9 from FLAG (2010) will be used.

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 new 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). 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 CGS have the same split between Large and Small Sulfate concentrations as the modeled Total Sulfate concentration.

3.1.2 Mapping of CAMx PSAT Species to the IMPROVE Equation Species

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

- Sulfate (SO4)
- Nitrate (NO3)
- Elemental Carbon (EC)
- Primary Organic Aerosol (POA, used for Organic Mass)
- Fine Crustal (FCRS) and Other (FPRM) primary $PM_{2.5}$ emissions (used for Soil).
- Coarse Crustal (CCRS) and Other (CPRM) coarse ($PM_{2.5\text{-}10}$) PM species (used for CM or PMC)
- Reactive Gaseous Nitrogen (RGN, used for NO_2)

The CGS incremental sulfate and nitrate concentrations will be assumed to be completely neutralized by ammonium.

The PSAT source apportionment algorithm does not separately track NO_2 concentrations but instead tracks total reactive nitrogen (RGN) that consists mainly of NO, NO_2 and other smaller mass reactive nitrogen species (e.g., N_2O_5, NO_3 radical, etc.). The CGS incremental concentrations of the PSAT RGN species were used to represent light extinction due to NO_2. This may overstate the CGS visibility impairment associated with NO_2. In terms of the Better-than-BART test, this assumption will be conservative by overstating the visibility reductions in the EPA BART scenario relative to the proposed alternative scenario since the EPA BART scenario has more NO_X emission reductions. In any event, the vast majority of visibility impairment due to emissions from CGS is due to ammonium sulfate and ammonium nitrate and the treatment of NO_2 in the visibility calculations has a minimal impact.

Although sodium and particulate chloride are treated in the CAMx core model, these species are not carried in the CAMx PSAT tool; neglecting sea salt in the visibility calculations in the CGS visibility assessment does not compromise the accuracy of the analysis as IMPROVE measurements show that sea salt concentrations are negligible in this inland area and there are no sodium or chloride emissions associated with the CGS units.

4.0 CGS BETTER-THAN-BART RESULTS

The Better-than-BART tests were applied for four proposed alternative emission scenarios for CGS using the CAMx absolute modeling results for the Baseline, EPA BART and four proposed alternative emission scenarios.

4.1 CGS Emission Scenarios

Six separate CGS emissions scenarios were modeled using the CAMx 2008 12/4 km annual modeling database (baseline, EPA BART, and four alternative emissions scenarios). These six CGS emission scenarios all used the same annual heat input (MMBtu) for CGS unit 1 (4691 MMBtu/hr) and unit 2 (4446 MMBtu/hr) but varied in the SO_2 and NO_X emissions rates (lb/MMBtu). Both CGS units were assumed to operate at the same emissions rate for each day and each hour of the year, except during the shutdown periods for the proposed alternative scenarios when emissions for unit 1 were set to be zero.

As discussed previously, the CAMx PSAT runs for the proposed alternative scenarios modeled emissions from CGS unit 1 using separate source groups for 10-day increments during the four month winter period of November through February. This allowed for the analysis of different shutdown periods at 10-day increments during this 4-month period. The CGS unit 1 shutdown period for each proposed alternative emissions scenario was determined so that the scenario passed the Better-than-BART test. The CGS unit 1 shutdown period was determined starting with the shutdown of the last 10 days in December and working backwards until all of December was curtailed and then adding the first 10-days of January working forward until all of January was curtailed. The same procedures were then applied to November and February until a contiguous unit 1 shutdown period was determined such that the proposed alternative emissions scenario passed the Better-than-BART tests.

Table 4-1 describes the six CGS emission scenarios modeled by CAMx in this analysis. Throughout this chapter the proposed alternative emissions scenarios are referred to as Better-than-BART (BtB) scenarios numbered 1 – 4, based on the emission rates and shutdown periods shown in Table 4-1. The CGS baseline scenario represents current emissions, note that the proposed alternative emissions scenario BtB1 is based on the same emissions and has a shutdown period of Nov 1 to February 29. The EPA BART emissions scenario has a lower CGS unit 1 NO_X emissions rate (0.065 lb/MMBtu) than all other emission scenarios (0.320-0.310 lb/MMBtu). The proposed alternative emissions scenarios BtB2, BtB3 and BtB4 have lower SO_2 emissions rates (0.070, 0.050 and 0.060 lb/MMBtu, respectively) for unit 1 and unit 2 than the Baseline, EPA BART, and BtB1 scenarios (0.080 lb/MMBtu).

Table 4-1. CGS emission rates and Unit 1 shutdown periods for the CGS Baseline, EPA BART and four proposed alternative Better-than-BART (BtB) emission scenarios.

Scenario	NO_X (lb/MMBtu)		SO_2 (lb/MMBtu)		Unit 1 Shutdown Period
	Unit#1	Unit#2	Unit#1	Unit#2	
Baseline	0.320	0.080	0.080	0.080	None
EPA BART	0.065	0.080	0.080	0.080	None
BtB1	0.320	0.080	0.080	0.080	Nov 1 - Feb 29
BtB2	0.320	0.080	0.070	0.070	Nov 11 - Dec 31
BtB3	0.320	0.080	0.050	0.050	Nov 21 - Dec 31
BtB4	0.310	0.080	0.060	0.060	Nov 21 - Dec 31

The proposed alternative emission scenarios (BtB1, BtB2, BtB3, and BtB4) have been developed to improve upon the visibility benefits of the EPA BART NO_X reductions by obtaining greater benefits in visibility due to lower SO_2 emissions and the CGS unit 1 shutdown periods.

Table 4-2 shows the hourly mass emission rates for the six CGS emission scenarios. The hourly emissions for the Baseline and BtB1 emission scenarios are the same although the annual emissions will be different as CGS unit 1 is shut down for four months. The EPA BART unit 1 NO_X emissions are reduced by approximately 79% from the Baseline level, which is assumed to be due to implementation of Selective Catalytic Reduction (SCR) post-combustion emissions control technology. The use of SCR will also increase primary sulfate emissions.

Table 4-2. CGS mass emission rates (lb/hr) for the CGS Baseline, EPA BART and four proposed alternative Better-than-BART (BtB) emission scenarios.

Scenario	Unit	CGS Emissions (pounds per hour)								
		SO_2	SO_4	NO_X	HNO_3	NO_3	PMF	PMC	EC	OA
Baseline	1	375.1	0	1,500.7	0	0	58.7	79.9	2.3	0
	2	355.5	11.6	355.5	0	0	55.5	75.6	2.1	0
EPA BART	1	375.1	12.3	296.8	0	0	58.7	79.9	2.3	0
	2	355.5	11.6	355.5	0	0	55.5	75.6	2.1	0
BtB1	1	375.1	0	1,500.7	0	0	58.7	79.9	2.3	0
	2	355.5	11.6	355.5	0	0	55.5	75.6	2.1	0
BtB2	1	328.3	0	1,500.7	0	0	58.7	79.9	2.3	0
	2	311.2	11.6	355.5	0	0	55.5	75.6	2.1	0
BtB3	1	234.5	0	1,500.7	0	0	58.7	79.9	2.3	0
	2	222.1	11.6	355.5	0	0	55.5	75.6	2.1	0
BtB4	1	281.3	0	1,453.9	0	0	58.7	79.9	2.3	0
	2	266.7	11.6	355.5	0	0	55.5	75.6	2.1	0

4.2 CGS Visibility Impacts

Visibility impacts due to emissions from the two CGS units at each Class I area are presented in this section. Table 4-3 presents CGS visibility impacts (i.e., delta deciview impacts described in Section 3.1) from the CGS Baseline emissions averaged over the B20% days, W20% days, and all days in 2008. Prong 1 of the Better-than-BART test is based on differences between these Baseline impacts and the impacts due to the proposed alternative BtB emissions. Maximum impacts for all three time-averaged methods are reported at Petrified Forest NP which is the Class I area located closest to the CGS facility.

Table 4-4 reports the CGS visibility impacts from the CGS EPA BART emissions averaged over the B20% days, W20% days, and all days in 2008. Prong 2 of the Better-than-BART test is based on differences between the CGS EPA BART impacts and the impacts due to the proposed alternative BtB emissions. Table 4-5, Table 4-6, Table 4-7, and Table 4-8 report CGS visibility impacts from the CGS proposed alternative (BtB) emissions scenarios averaged over the B20% days, W20% days, and all days in 2008. These results are used in the Better-than-BART tests in the following sections.

Annual average CGS visibility impacts averaged over all class I areas for the BtB scenarios range from 0.0130 to 0.0144 dv. The corresponding CGS Baseline impact is 0.0172 dv and the corresponding CGS EPA BART impact is 0.0146 dv. For annual average visibility impacts, all CGS BtB emissions scenarios show lower visibility impacts than the CGS EPA BART scenario. The evaluation of the Better-than-BART test using these calculated visibility impacts is presented in the following sections.

Table 4-3. CGS visibility impacts from Baseline emissions.

Case: 2008 Baseline			
	Delta Dv		
	Average Best 20% Days**	Average Worst 20% Days**	Annual Average
Class I Area	**Absolute (dv)**	**Absolute (dv)**	**Absolute (dv)**
Bandalier NM	0.0083	0.0238	0.0137
Bosque	0.0103	0.0070	0.0157
Chiricahua NM	0.0115	0.0020	0.0056
Chiricahua Wild	0.0112	0.0018	0.0051
Galiuro Wild	0.0067	0.0022	0.0041
Gila Wild	0.0349	0.0080	0.0271
Grand Canyon NP	0.0011	0.0060	0.0101
Mazatzal Wild	0.0246	0.0054	0.0088
Mesa Verde NP	0.0024	0.0081	0.0094
Mount Baldy Wild	0.0189	0.0164	0.0201
Petrified Forest NP	0.1154	0.0398	0.1203
Pine Mountain Wild	0.0151	0.0033	0.0062
Saguro NP	0.0053	0.0026	0.0036
San Pedro Parks Wild	0.0104	0.0159	0.0157
Sierra Ancha Wild			0.0120
Superstition Wild	0.0292	0.0035	0.0082
Sycamore Canyon Wild	0.0115	0.0059	0.0074
Maximum	**0.1154**	**0.0398**	**0.1203**
Cumulative (sum)	**0.3167**	**0.1517**	**0.2932**
Average	**0.0198**	**0.0095**	**0.0172**
Minimum	**0.0011**	**0.0018**	**0.0036**

*** Best and Worst Days of Monitored visibility, from MATS (IMPROVE) database, some sites/years lack data.*

Table 4-4. CGS visibility impacts from EPA BART emissions.

Case: EPA 2008 BART			
	Delta Dv		
	Average Best 20% Days**	Average Worst 20% Days**	Annual Average
Class I Area	**Absolute (dv)**	**Absolute (dv)**	**Absolute (dv)**
Bandalier NM	0.0069	0.0189	0.0109
Bosque	0.0088	0.0059	0.0128
Chiricahua NM	0.0089	0.0019	0.0047
Chiricahua Wild	0.0088	0.0017	0.0042
Galiuro Wild	0.0058	0.0019	0.0035
Gila Wild	0.0275	0.0066	0.0221
Grand Canyon NP	0.0009	0.0053	0.0098
Mazatzal Wild	0.0195	0.0047	0.0075
Mesa Verde NP	0.0019	0.0072	0.0084
Mount Baldy Wild	0.0149	0.0126	0.0159
Petrified Forest NP	0.1083	0.0341	0.1027
Pine Mountain Wild	0.0116	0.0030	0.0054
Saguro NP	0.0046	0.0022	0.0032
San Pedro Parks Wild	0.0080	0.0133	0.0127
Sierra Ancha Wild			0.0104
Superstition Wild	0.0236	0.0029	0.0069
Sycamore Canyon Wild	0.0095	0.0047	0.0068
Maximum	**0.1083**	**0.0341**	**0.1027**
Cumulative (sum)	**0.2695**	**0.1267**	**0.2477**
Average	**0.0168**	**0.0079**	**0.0146**
Minimum	**0.0009**	**0.0017**	**0.0032**

*** Best and Worst Days of Monitored visibility, from MATS (IMPROVE) database, some sites/years lack data.*

Table 4-5. CGS visibility impacts from BTB1.

Case: BtB1			
	Delta Dv		
	Average Best 20% Days**	Average Worst 20% Days**	Annual Average
Class I Area	**2008**	**2008**	**2008**
Bandalier NM	0.0038	0.0169	0.0103
Bosque	0.0058	0.0051	0.0124
Chiricahua NM	0.0067	0.0020	0.0047
Chiricahua Wild	0.0066	0.0018	0.0042
Galiuro Wild	0.0042	0.0022	0.0034
Gila Wild	0.0171	0.0080	0.0209
Grand Canyon NP	0.0004	0.0059	0.0071
Mazatzal Wild	0.0107	0.0054	0.0065
Mesa Verde NP	0.0009	0.0066	0.0067
Mount Baldy Wild	0.0076	0.0126	0.0169
Petrified Forest NP	0.0610	0.0319	0.0899
Pine Mountain Wild	0.0061	0.0032	0.0046
Saguro NP	0.0041	0.0026	0.0029
San Pedro Parks Wild	0.0042	0.0120	0.0115
Sierra Ancha Wild			0.0081
Superstition Wild	0.0163	0.0030	0.0055
Sycamore Canyon Wild	0.0041	0.0056	0.0057
Maximum	**0.0610**	**0.0319**	**0.0899**
Cumulative (sum)	**0.1594**	**0.1249**	**0.2213**
Average	**0.0100**	**0.0078**	**0.0130**
Minimum	**0.0004**	**0.0018**	**0.0029**

*** Best and Worst Days of Monitored visibility, from MATS (IMPROVE) database, some sites/years lack data.*

Table 4-6. CGS visibility impacts from BTB2.

Case: BtB2			
	Delta Dv		
	Average Best 20% Days**	Average Worst 20% Days**	Annual Average
Class I Area	**2008**	**2008**	**2008**
Bandalier NM	0.0065	0.0203	0.0111
Bosque	0.0078	0.0048	0.0133
Chiricahua NM	0.0096	0.0019	0.0049
Chiricahua Wild	0.0094	0.0017	0.0044
Galiuro Wild	0.0052	0.0020	0.0037
Gila Wild	0.0306	0.0074	0.0225
Grand Canyon NP	0.0009	0.0053	0.0076
Mazatzal Wild	0.0210	0.0052	0.0075
Mesa Verde NP	0.0016	0.0071	0.0075
Mount Baldy Wild	0.0166	0.0123	0.0175
Petrified Forest NP	0.0967	0.0290	0.0987
Pine Mountain Wild	0.0120	0.0032	0.0052
Saguro NP	0.0047	0.0023	0.0033
San Pedro Parks Wild	0.0080	0.0136	0.0127
Sierra Ancha Wild			0.0097
Superstition Wild	0.0276	0.0028	0.0069
Sycamore Canyon Wild	0.0093	0.0051	0.0060
Maximum	**0.0967**	**0.0290**	**0.0987**
Cumulative (sum)	**0.2674**	**0.1241**	**0.2425**
Average	**0.0167**	**0.0078**	**0.0143**
Minimum	**0.0009**	**0.0017**	**0.0033**

*** Best and Worst Days of Monitored visibility, from MATS (IMPROVE) database, some sites/years lack data.*

Table 4-7. CGS visibility impacts from BTB3.

Case: BtB3			
	Delta Dv		
	Average Best 20% Days**	Average Worst 20% Days**	Annual Average
Class I Area	**2008**	**2008**	**2008**
Bandalier NM	0.0056	0.0179	0.0097
Bosque	0.0071	0.0042	0.0119
Chiricahua NM	0.0087	0.0015	0.0043
Chiricahua Wild	0.0085	0.0013	0.0039
Galiuro Wild	0.0045	0.0016	0.0032
Gila Wild	0.0298	0.0063	0.0207
Grand Canyon NP	0.0008	0.0045	0.0069
Mazatzal Wild	0.0217	0.0044	0.0071
Mesa Verde NP	0.0014	0.0058	0.0064
Mount Baldy Wild	0.0156	0.0143	0.0161
Petrified Forest NP	0.0915	0.0269	0.0974
Pine Mountain Wild	0.0122	0.0026	0.0048
Saguro NP	0.0040	0.0019	0.0028
San Pedro Parks Wild	0.0071	0.0118	0.0113
Sierra Ancha Wild			0.0093
Superstition Wild	0.0258	0.0029	0.0064
Sycamore Canyon Wild	0.0085	0.0046	0.0051
Maximum	**0.0915**	**0.0269**	**0.0974**
Cumulative (sum)	**0.2529**	**0.1124**	**0.2272**
Average	**0.0158**	**0.0070**	**0.0134**
Minimum	**0.0008**	**0.0013**	**0.0028**

*** Best and Worst Days of Monitored visibility, from MATS (IMPROVE) database, some sites/years lack data.*

Table 4-8. CGS visibility impacts from BTB4.

Case: BtB4			
	Delta Dv		
	Average Best 20% Days**	Average Worst 20% Days**	Annual Average
Class I Area	**2008**	**2008**	**2008**
Bandalier NM	0.0060	0.0194	0.0106
Bosque	0.0082	0.0045	0.0130
Chiricahua NM	0.0092	0.0017	0.0046
Chiricahua Wild	0.0092	0.0015	0.0042
Galiuro Wild	0.0049	0.0018	0.0034
Gila Wild	0.0310	0.0068	0.0223
Grand Canyon NP	0.0010	0.0050	0.0079
Mazatzal Wild	0.0212	0.0046	0.0075
Mesa Verde NP	0.0018	0.0067	0.0072
Mount Baldy Wild	0.0167	0.0147	0.0172
Petrified Forest NP	0.0959	0.0295	0.1041
Pine Mountain Wild	0.0124	0.0026	0.0052
Saguro NP	0.0043	0.0022	0.0030
San Pedro Parks Wild	0.0073	0.0126	0.0122
Sierra Ancha Wild			0.0100
Superstition Wild	0.0269	0.0031	0.0069
Sycamore Canyon Wild	0.0103	0.0050	0.0060
Maximum	**0.0959**	**0.0295**	**0.1041**
Cumulative (sum)	**0.2663**	**0.1217**	**0.2453**
Average	**0.0166**	**0.0076**	**0.0144**
Minimum	**0.0010**	**0.0015**	**0.0030**

*** Best and Worst Days of Monitored visibility, from MATS (IMPROVE) database, some sites/years lack data.*

4.3 Discussions of Magnitude of Visibility Impacts

In this section the magnitude of CGS visibility impacts and the differences between the Baseline and alternative BtB scenarios impacts (i.e. Prong 1 of the Better-than-BART test) is put into context. To provide this context, the EPA BART scenario is evaluated in Prong 1 of the Better-than-BART test to examine the visibility improvements that would be expected with the EPA BART NO_X SCR emissions controls compared to current (Baseline) conditions.

As reported in Section 4.2, the largest CGS visibility impact calculated at any Class I area for any of the emissions scenarios and for any time averaging method is the annual average visibility impact at Petrified Forest National Park (NP) for the Baseline emission scenario with a visibility impact of 0.1203 dv. Note that 1.0 dv is a small but perceptible scenic change under a wide range of visibility conditions[17] that is "just perceptible to the human eye"[18]. Given that the Better-than-BART tests evaluate differences between small CGS visibility impacts, the results are even smaller deciview values (potentially nearly an order of magnitude smaller again). It is difficult to assign significance to these very small delta deciview differences between the Baseline and EPA BART versus the Better-than-BART alternative scenarios. Therefore, in addition to absolute delta deciview differences, relative percent differences are also presented in the Better-than-BART tests.

Table 4-9 presents the results of the Prong 1 evaluation of the EPA BART emissions scenario. The minimum absolute delta deciview differences over all Class I areas range from 0.0001 dv to 0.0003 dv for the three averaging methods. The minimum percent differences range from 2.7% to 8.1% for the three averaging methods. The magnitude of the Prong 1 test results for the EPA BART emission scenario will be compared to the BtB Prong 1 test results in the next section.

[17] http://www3.epa.gov/ttnamti1/files/ambient/visible/tracking.pdf
[18] http://www3.epa.gov/ttn/scram/11thmodconf/IWAQM3_LRT_Report-07152015.pdf

Table 4-9. EPA BART Scenario evaluated in Prong 1 of Better-than-BART test.

Prong 1 of BTB Test						
Case: Baseline - EPA BART						
	Delta Dv Differences					
	Average Best 20% Days		Average Worst 20% Days		Annual Average	
Class I Area	**Absolute (dv)**	**Relative**	**Absolute (dv)**	**Relative**	**Absolute (dv)**	**Relative**
Bandalier NM	0.0014	17.0%	0.0049	20.6%	0.0028	20.5%
Bosque	0.0015	14.3%	0.0011	16.0%	0.0029	18.2%
Chiricahua NM	0.0026	22.3%	0.0002	9.0%	0.0009	16.5%
Chiricahua Wild	0.0025	21.9%	**0.0001**	**8.1%**	0.0008	16.1%
Galiuro Wild	0.0009	13.2%	0.0003	13.1%	0.0007	15.8%
Gila Wild	0.0074	21.3%	0.0014	17.1%	0.0050	18.4%
Grand Canyon NP	**0.0002**	20.3%	0.0007	12.0%	**0.0003**	**2.7%**
Mazatzal Wild	0.0050	20.5%	0.0007	12.8%	0.0013	14.5%
Mesa Verde NP	0.0005	19.7%	0.0010	11.8%	0.0010	11.1%
Mount Baldy Wild	0.0040	21.1%	0.0038	23.2%	0.0043	21.1%
Petrified Forest NP	0.0071	**6.2%**	0.0057	14.3%	0.0177	14.7%
Pine Mountain Wild	0.0035	23.2%	0.0003	9.3%	0.0009	13.9%
Saguro NP	0.0007	12.9%	0.0004	15.9%	0.0005	13.3%
San Pedro Parks Wild	0.0024	22.7%	0.0026	16.6%	0.0031	19.5%
Sierra Ancha Wild					0.0016	13.4%
Superstition Wild	0.0055	18.9%	0.0006	17.2%	0.0013	16.4%
Sycamore Canyon Wild	0.0020	17.7%	0.0011	19.3%	0.0006	7.8%
Minimum	**0.0002**	**6.2%**	**0.0001**	**8.1%**	**0.0003**	**2.7%**

4.4 Better-than-BART Tests

Table 4-10 displays the results of Prong 1 of the Better-than-BART test for the four proposed alternative BtB emissions scenarios with shutdown periods. This first prong of the Better-than-BART test examines the differences in visibility impacts (delta dv) between the Baseline and the proposed alternative BtB scenarios (Baseline - BtB). The BtB scenario passes if the difference in visibility impact is positive or zero for all Class I areas for the W20% and B20% days. Also reported are differences in visibility impacts averaged over all 365 modeled days.

The results in Table 4-10 show the minimum differences in visibility impacts across all Class I areas between the Baseline and the proposed alternative BtB scenarios. Since the minimum differences are all positive, then the proposed alternative BtB scenarios exhibit visibility improvements compared to current conditions at all Class I areas. Therefore the proposed alternative BtB scenarios with the specified shutdown periods show "*Visibility does not decline in any Class I area"* and hence the BtB scenarios pass the first prong of the Better-than-BART test. Note that the results are presented to four decimal places and show positive differences, except the BtB1 W20% days case, where the number of decimal places was increased to six since results with four decimal places rounded to zero.

The Prong 1 minimum absolute differences across all Class I areas range from 0.000001 dv to 0.0009 dv for the various BtB emission scenarios and three averaging methods. The Prong 1 minimum percent differences across all Class I areas range from 0.03% to 22.7% for the various BtB emission scenarios and three averaging methods. Note that for all scenarios and averaging methods except BtB1 W20% days, this range of CGS Prong 1 absolute results is the same order of magnitude as the Prong 1 results for the EPA BART emission scenario discussed in Section 4.3 (i.e., delta deciview differences in the ten thousandths). In addition, most of the Prong 1 results for the various BtB scenarios and averaging methods result in greater visibility improvements relative to Baseline than the EPA BART scenario.

The Prong 1 results for each BtB scenario are further discussed in the following sections.

Table 4-10. Prong 1 BtB Test Summary Results

Prong 1 of BTB Test: Baseline - Scenario							
		Minimum Delta Dv Difference of Class I Areas					
		Average Best 20% Days		Average Worst 20% Days		Annual Average	
Scenario:	**Shutdown Period**	**Absolute (dv)**	**Relative**	**Absolute (dv)**	**Relative**	**Absolute (dv)**	**Relative**
BtB1	Nov 1 - Feb 29	0.0007	22.7%	0.000001	0.03%	0.0007	15.9%
BtB2	Nov 11 - Dec 31	0.0002	5.4%	0.0001	1.9%	0.0004	10.7%
BtB3	Nov 21 - Dec 31	0.0003	11.6%	0.0005	13.0%	0.0009	19.0%
BtB4	Nov 21 - Dec 31	0.0001	7.7%	0.0004	10.6%	0.0006	13.5%

Table 4-11 presents the Prong 2 Better-than-BART results. The second prong of the Better-than-BART test examines the differences in visibility impacts (delta dv) between the EPA BART and the proposed alternative BtB scenarios (EPA BART - BtB) and is passed when the average difference in visibility across all Class I areas is positive for the W20% and B20% days. Also reported are differences in visibility impacts averaged over all 365 modeled days. These annual average results provide further evidence that the proposed alternative BtB scenarios will provide more visibility benefits at the Class I areas than the EPA BART NO_X emission control strategy.

Table 4-11 reports the Prong 2 absolute and relative visibility differences averaged across all the Class I areas. The absolute modeling results are presented with 4 decimal places. For each BtB scenario and averaging method, positive visibility impact benefits are calculated. Positive visibility impact benefits show that the BtB emissions/shutdown scenarios provide an "*overall improvement in visibility*" compared to the EPA BART control case and hence all the BtB alternative scenarios pass the second prong of the Better-than-BART test.

The Prong 2 relative visibility impact improvements over the EPA BART scenario range from 0.8 % to 40.8 % for the various BtB scenarios and three averaging methods. The Prong 2 results are discussed in more detail in the following sections.

Table 4-11. Prong 2 BtB Test Summary Results.

Prong 2 of BTB Test: EPA BART - Scenario							
		Average Delta Dv of Class I Areas					
		Average Best 20% Days		Average Worst 20% Days		Annual Average	
Scenario:	**Shutdown Period**	**Absolute (dv)**	**Relative**	**Absolute (dv)**	**Relative**	**Absolute (dv)**	**Relative**
BtB1	Nov 1 - Feb 29	0.0069	40.8%	0.0001	1.5%	0.0016	10.6%
BtB2	Nov 11 - Dec 31	0.0001	0.8%	0.0002	2.1%	0.0003	2.1%
BtB3	Nov 21 - Dec 31	0.0010	6.2%	0.0009	11.3%	0.0012	8.3%
BtB4	Nov 21 - Dec 31	0.0002	1.2%	0.0003	4.0%	0.0001	1.0%

4.4.1 BtB1 Scenario

The proposed BtB1 alternative emissions scenario has the same emissions rates as the Baseline case with a shutdown period from November 1 – February 29 to account for potential leap years. Emissions from unit 1 of the CGS are zero during the shutdown period for all pollutants.

Table 4-12 presents the Prong 1 delta dv differences between the Baseline and BtB1 scenario. For the B20% days averaging method, the minimum absolute difference in delta dv is 0.0007 dv which occurs at Grand Canyon NP, and the minimum relative difference is 22.7 % at Saguro NP. The maximum relative difference is at Sycamore Canyon Wilderness area which shows a 64.6 % visibility impact benefit. Visibility impact benefits are smaller for the W20% days averaging method compared to the B20% days, since the visibility impact benefits occur during the winter shutdown period and the W20% days are less likely to occur in winter. However, visibility impact benefits are positive at every Class I area and are as high as 29.0 % at Bandalier NM. Annual average visibility impact benefits are at least 15.9 % at all Class I areas.

Table 4-13 presents the Prong 2 results for the proposed BtB1 alternative emissions/ shutdown scenario. For the B20 % days, all visibility impact differences are positive indicating that BtB1 shows benefits over the EPA BART scenario. For the W20% days, visibility impact differences are mixed, with some Class I areas experiencing smaller visibility impacts with BtB1 emissions and other Class I areas experiencing higher visibility impacts with the BtB1 emissions. However, when averaged over the Class I areas on the W20% days, the BtB1 emissions/ shutdown scenario visibility impact benefits are still positive at 0.0001 dv or 1.5 % and therefore pass the Prong 2 test. Considered on an annual average basis, visibility impact benefits are 10.6 % averaged over all the Class I areas.

Table 4-12. Prong 1 for BtB1 emissions scenario.

Prong 1 of BTB Test						
Case: EPA 2008 Baseline - BtB1						
	Delta Dv Differences					
	Average Best 20% Days		Average Worst 20% Days		Annual Average	
Class I Area	**Absolute (dv)**	**Relative**	**Absolute (dv)**	**Relative**	**Absolute (dv)**	**Relative**
Bandalier NM	0.0045	54.0%	0.006910	29.0%	0.0034	24.9%
Bosque	0.0045	44.0%	0.001855	26.5%	0.0033	21.1%
Chiricahua NM	0.0048	41.9%	0.000005	0.2%	0.0009	16.8%
Chiricahua Wild	0.0046	41.2%	0.000003	0.2%	0.0009	17.3%
Galiuro Wild	0.0025	37.7%	**0.000001**	0.1%	0.0008	18.2%
Gila Wild	0.0179	51.2%	0.000002	**0.0%**	0.0062	22.9%
Grand Canyon NP	**0.0007**	64.2%	0.000096	1.6%	0.0029	29.2%
Mazatzal Wild	0.0138	56.3%	0.000033	0.6%	0.0023	26.3%
Mesa Verde NP	0.0015	63.1%	0.001538	18.9%	0.0027	28.6%
Mount Baldy Wild	0.0112	59.6%	0.003868	23.5%	0.0032	**15.9%**
Petrified Forest NP	0.0545	47.2%	0.007904	19.9%	0.0304	25.3%
Pine Mountain Wild	0.0090	59.4%	0.000022	0.7%	0.0016	26.4%
Saguro NP	0.0012	**22.7%**	0.000014	0.5%	**0.0007**	19.8%
San Pedro Parks Wild	0.0062	59.7%	0.003944	24.8%	0.0042	26.7%
Sierra Ancha Wild					0.0039	32.6%
Superstition Wild	0.0129	44.1%	0.000429	12.4%	0.0027	32.9%
Sycamore Canyon Wild	0.0074	64.6%	0.000262	4.5%	0.0016	22.1%
Minimum	**0.0007**	**22.7%**	**0.000001**	**0.0%**	**0.0007**	**15.9%**

Table 4-13. Prong 2 for BtB1 emissions scenario.

Prong 2 of BTB Test						
Case: EPA 2008 BART - BtB1						
	Delta Dv Differences					
	Average Best 20% Days		Average Worst 20% Days		Annual Average	
Class I Area	Absolute (dv)	Relative	Absolute (dv)	Relative	Absolute (dv)	Relative
Bandalier NM	0.0031	44.5%	0.0020	10.6%	0.0006	4.4%
Bosque	0.0031	34.7%	0.0007	12.5%	0.0004	2.9%
Chiricahua NM	0.0022	25.2%	-0.0002	-9.7%	0.0000	0.2%
Chiricahua Wild	0.0022	24.7%	-0.0001	-8.6%	0.0001	0.5%
Galiuro Wild	0.0016	28.2%	-0.0003	-15.0%	0.0001	0.8%
Gila Wild	0.0104	38.0%	-0.0014	-20.5%	0.0012	26.0%
Grand Canyon NP	0.0005	55.1%	-0.0006	-11.8%	0.0027	63.0%
Mazatzal Wild	0.0088	45.0%	-0.0007	-14.0%	0.0010	29.8%
Mesa Verde NP	0.0011	54.1%	0.0006	8.0%	0.0016	7.4%
Mount Baldy Wild	0.0073	48.8%	0.0001	0.4%	-0.0010	-10.6%
Petrified Forest NP	0.0473	43.7%	0.0022	6.4%	0.0128	169.2%
Pine Mountain Wild	0.0055	47.2%	-0.0003	-9.5%	0.0008	9.3%
Saguro NP	0.0005	11.3%	-0.0004	-18.2%	0.0002	1.5%
San Pedro Parks Wild	0.0038	47.9%	0.0013	9.8%	0.0011	1.1%
Sierra Ancha Wild					0.0023	42.9%
Superstition Wild	0.0073	31.1%	-0.0002	-5.8%	0.0014	43.2%
Sycamore Canyon Wild	0.0054	56.9%	-0.0009	-18.3%	0.0011	8.3%
Average	**0.0069**	**40.8%**	**0.0001**	**1.5%**	**0.0016**	**10.6%**

4.4.2 BtB2 Scenario

The proposed BtB2 alternative emissions scenario has NOx emissions limits the same as the Baseline case but has lower SO_2 emissions for both units (0.070 lb/MMBtu compared to 0.080 lb/MMBtu). The SO_2 emissions are also lower than the EPA BART SO_2 emission which are also 0.080 lb/MMBtu. The BtB2 shutdown period is from November 11 – December 31. Emissions from unit 1 of the CGS are zero during the shutdown period for all pollutants.

Table 4-14 presents the Prong 1 delta dv differences between the Baseline and BtB2 scenario. For the B20% days averaging method, the minimum absolute difference in delta dv is 0.0002 dv which occurs at Grand Canyon NP, and the minimum relative difference is 5.4 % at Superstition Wilderness. Other Class I areas experience greater visibility impact benefits, the largest relative benefit is at Mesa Verde NP with a 34.8 % benefit. The minimum visibility impact benefits for the W20% days averaging method occur at Pine Mountain with 0.0001 dv absolute visibility impact benefits which translates to a 1.9 % benefit. Annual average visibility impact benefits are at least 10.7 % at all Class I areas. For all three averaging methods, positive visibility impact benefits are observed for the Prong 1 test.

Table 4-15 presents the Prong 2 results for the proposed BtB2 alternative emissions/ shutdown scenario. For all three averaging methods, mixed positive/negative visibility impact benefits are observed at different Class I areas. However, the average visibility impact benefits over all Class I area are positive for each averaging metric indicating overall improvement in visibility with the proposed BtB2 alternative emissions/shutdown strategy compared to the EPA BART emissions control strategy.

Table 4-14. Prong 1 for BtB2 emissions scenario.

Prong 1 of BTB Test						
Case: EPA 2008 Baseline - BtB2						
	Delta Dv Differences					
	Average Best 20% Days		Average Worst 20% Days		Annual Average	
Class I Area	**Absolute (dv)**	**Relative**	**Absolute (dv)**	**Relative**	**Absolute (dv)**	**Relative**
Bandalier NM	0.0019	22.4%	0.0035	14.6%	0.0025	18.6%
Bosque	0.0025	24.5%	0.0022	31.0%	0.0024	15.0%
Chiricahua NM	0.0019	16.4%	0.0002	9.1%	0.0007	12.6%
Chiricahua Wild	0.0019	16.5%	0.0002	8.3%	0.0006	12.6%
Galiuro Wild	0.0014	21.6%	0.0002	7.6%	0.0004	10.8%
Gila Wild	0.0043	12.3%	0.0006	6.9%	0.0046	17.0%
Grand Canyon NP	**0.0002**	19.9%	0.0007	11.7%	0.0025	24.9%
Mazatzal Wild	0.0035	14.4%	0.0002	4.3%	0.0013	14.5%
Mesa Verde NP	0.0008	34.8%	0.0010	12.7%	0.0020	20.8%
Mount Baldy Wild	0.0023	12.2%	0.0041	25.2%	0.0026	13.1%
Petrified Forest NP	0.0187	16.2%	0.0108	27.2%	0.0216	18.0%
Pine Mountain Wild	0.0032	20.9%	**0.0001**	**1.9%**	0.0010	16.5%
Saguro NP	0.0006	10.9%	0.0003	10.6%	**0.0004**	**10.7%**
San Pedro Parks Wild	0.0024	22.9%	0.0023	14.4%	0.0031	19.4%
Sierra Ancha Wild					0.0023	19.0%
Superstition Wild	0.0016	**5.4%**	0.0006	18.5%	0.0013	15.7%
Sycamore Canyon Wild	0.0022	18.7%	0.0008	13.1%	0.0013	18.2%
Minimum	**0.0002**	**5.4%**	**0.0001**	**1.9%**	**0.0004**	**10.7%**

Table 4-15. Prong 2 for BtB2 emissions scenario.

Prong 2 of BTB Test						
Case: EPA 2008 BART - BtB2						
	Delta Dv Differences					
	Average Best 20% Days		Average Worst 20% Days		Annual Average	
Class I Area	Absolute (dv)	Relative	Absolute (dv)	Relative	Absolute (dv)	Relative
Bandalier NM	0.0004	6.5%	-0.0014	-7.6%	-0.0003	-1.9%
Bosque	0.0011	11.9%	0.0010	17.9%	-0.0005	-3.2%
Chiricahua NM	-0.0007	-7.6%	0.0000	0.0%	-0.0002	-3.9%
Chiricahua Wild	-0.0006	-6.9%	0.0000	0.3%	-0.0002	-1.7%
Galiuro Wild	0.0006	9.7%	-0.0001	-6.3%	-0.0002	-1.6%
Gila Wild	-0.0031	-11.4%	-0.0008	-12.2%	-0.0004	-8.0%
Grand Canyon NP	0.0000	-0.5%	0.0000	-0.3%	0.0022	52.7%
Mazatzal Wild	-0.0015	-7.7%	-0.0005	-9.7%	0.0000	0.1%
Mesa Verde NP	0.0004	18.8%	0.0001	1.1%	0.0009	4.1%
Mount Baldy Wild	-0.0017	-11.2%	0.0003	2.6%	-0.0016	-16.4%
Petrified Forest NP	0.0116	10.7%	0.0051	15.1%	0.0039	52.2%
Pine Mountain Wild	-0.0003	-3.0%	-0.0002	-8.2%	0.0002	2.0%
Saguro NP	-0.0001	-2.3%	-0.0001	-6.3%	-0.0001	-0.6%
San Pedro Parks Wild	0.0000	0.2%	-0.0004	-2.7%	0.0000	0.0%
Sierra Ancha Wild					0.0007	12.4%
Superstition Wild	-0.0039	-16.7%	0.0000	1.6%	-0.0001	-1.6%
Sycamore Canyon Wild	0.0001	1.2%	-0.0004	-7.7%	0.0008	6.1%
Average	**0.0001**	**0.8%**	**0.0002**	**2.1%**	**0.0003**	**2.1%**

4.4.3 BtB3 Scenario

The proposed BtB3 alternative emissions scenario has NOx emissions limits the same as the Baseline case. However, the proposed BtB3 scenario has lower SO_2 emissions (0.050 lb/MMBtu) for both units than the Baseline case, the EPA BART case, and all other proposed BtB alternative cases. The shutdown period for BtB3 is from November 21 – December 31. Emissions from unit 1 of the CGS are zero during the shutdown period for all pollutants.

Table 4-16 presents the Prong 1 delta dv differences between the Baseline and BtB3 scenario. For the B20% days averaging method, the minimum absolute difference in Delta dv is 0.0003 dv which occurs at Grand Canyon NP, the minimum relative difference is 11.6 % at Superstition Wilderness. Other Class I areas experience greater visibility impact benefits, the largest relative benefit is at Mesa Verde NP with a 42.8 % benefit. The minimum absolute visibility impact benefits for the W20% days averaging method occur at Chiricahua Wilderness which reports a 0.0005 dv visibility impact benefits. Relative visibility impact benefits averaged over the W20% days are at least 13.0 %. Annual average visibility impact benefits are at least 19.0 % at all Class I areas. For all three averaging methods, positive visibility impact benefits are observed at all Class I areas.

Table 4-17 presents the Prong 2 results for the proposed BtB3 alternative emissions/ shutdown scenario. All three averaging metrics show Class I areas with negative visibility impacts, however most Class I areas report positive visibility impact benefits and the average visibility impact benefits over all Class I area are positive for each averaging metric indicating overall improvement in visibility with the proposed BtB3 alternative emissions/ shutdown strategy compared to the EPA BART emissions control strategy. The range of relative visibility impact benefits is 6.2 to 11.3 % across the three averaging methods.

Table 4-16. Prong 1 for BtB3 emissions scenario.

Prong 1 of BTB Test						
Case: EPA 2008 Baseline - BtB3						
	Delta Dv Differences					
	Average Best 20% Days		Average Worst 20% Days		Annual Average	
Class I Area	Absolute (dv)	Relative	Absolute (dv)	Relative	Absolute (dv)	Relative
Bandalier NM	0.0027	32.4%	0.0059	24.8%	0.0039	28.8%
Bosque	0.0032	30.8%	0.0028	39.7%	0.0038	24.3%
Chiricahua NM	0.0028	24.2%	0.0006	27.4%	0.0013	23.8%
Chiricahua Wild	0.0027	24.3%	**0.0005**	27.2%	0.0012	23.8%
Galiuro Wild	0.0022	32.7%	0.0005	23.9%	0.0010	23.0%
Gila Wild	0.0052	14.8%	0.0017	21.0%	0.0064	23.7%
Grand Canyon NP	**0.0003**	26.6%	0.0015	25.4%	0.0032	31.5%
Mazatzal Wild	0.0029	11.7%	0.0011	19.6%	0.0018	20.0%
Mesa Verde NP	0.0010	42.8%	0.0024	29.2%	0.0030	32.2%
Mount Baldy Wild	0.0032	17.1%	0.0021	**13.0%**	0.0041	20.3%
Petrified Forest NP	0.0239	20.7%	0.0129	32.5%	0.0229	**19.0%**
Pine Mountain Wild	0.0029	19.2%	0.0007	20.3%	0.0014	23.2%
Saguro NP	0.0013	23.9%	0.0007	25.8%	**0.0009**	23.9%
San Pedro Parks Wild	0.0033	32.0%	0.0041	26.0%	0.0045	28.3%
Sierra Ancha Wild					0.0027	22.1%
Superstition Wild	0.0034	**11.6%**	0.0006	17.3%	0.0018	21.7%
Sycamore Canyon Wild	0.0029	25.6%	0.0013	21.7%	0.0022	30.4%
Minimum	**0.0003**	**11.6%**	**0.0005**	**13.0%**	**0.0009**	**19.0%**

Table 4-17. Prong 2 for BtB3 emissions scenario.

Prong 2 of BTB Test						
Case: EPA 2008 BART - BtB3						
	Delta Dv Differences					
	Average Best 20% Days		Average Worst 20% Days		Annual Average	
Class I Area	**Absolute (dv)**	**Relative**	**Absolute (dv)**	**Relative**	**Absolute (dv)**	**Relative**
Bandalier NM	0.0013	18.5%	0.0010	5.2%	0.0011	8.3%
Bosque	0.0017	19.2%	0.0017	28.2%	0.0010	6.1%
Chiricahua NM	0.0002	2.4%	0.0004	20.1%	0.0004	7.3%
Chiricahua Wild	0.0003	3.1%	0.0003	20.8%	0.0004	3.6%
Galiuro Wild	0.0013	22.5%	0.0002	12.5%	0.0003	2.3%
Gila Wild	-0.0023	-8.2%	0.0003	4.8%	0.0014	30.7%
Grand Canyon NP	0.0001	7.9%	0.0008	15.3%	0.0029	68.4%
Mazatzal Wild	-0.0022	-11.1%	0.0004	7.8%	0.0005	13.9%
Mesa Verde NP	0.0006	28.8%	0.0014	19.7%	0.0020	8.9%
Mount Baldy Wild	-0.0007	-5.0%	-0.0017	-13.3%	-0.0002	-1.7%
Petrified Forest NP	0.0168	15.5%	0.0072	21.2%	0.0052	69.4%
Pine Mountain Wild	-0.0006	-5.2%	0.0004	12.2%	0.0006	7.0%
Saguro NP	0.0006	12.6%	0.0003	11.7%	0.0004	2.4%
San Pedro Parks Wild	0.0010	12.0%	0.0015	11.2%	0.0014	1.4%
Sierra Ancha Wild					0.0010	19.5%
Superstition Wild	-0.0021	-9.1%	0.0000	0.2%	0.0004	13.9%
Sycamore Canyon Wild	0.0009	9.6%	0.0001	3.0%	0.0017	13.1%
Average	**0.0010**	**6.2%**	**0.0009**	**11.3%**	**0.0012**	**8.3%**

4.4.4 BtB4 Scenario

The proposed BtB4 alternative emissions scenario has a NOx emissions limit of 0.310 lb/MMBtu on CGS unit 1 which is lower than the Baseline case and the other proposed BtB scenarios. The BtB4 SO_2 emissions limit is 0.060 lb/MMBtu for both units, which is lower that all the other SO_2 emissions limits, except the BtB3 scenario. The shutdown period for BtB4 is from November 21 – December 31. Emissions from unit 1 of the CGS are zero during the shutdown period for all pollutants.

Table 4-18 presents the Prong 1 delta dv differences between the Baseline and BtB4 scenario. For the B20% days averaging method, the minimum absolute difference in delta dv is 0.0001 dv which occurs at Grand Canyon NP, and the minimum relative difference is 7.7 % at Superstition Wilderness. Other Class I areas experience greater visibility impact benefits, the largest relative benefit is at San Pedro Parks Wilderness with a 29.3 % benefit. The minimum absolute visibility impact benefits for the W20% days averaging method occur at Chiricahua Wilderness which reports a 0.0004 dv visibility impact benefits. Relative visibility impact benefits averaged over the W20% days are a minimum of 10.6 %. Annual average visibility impact benefits are at least 13.5 % at all Class I areas. For all three averaging methods, positive visibility impact benefits are observed at all Class I areas.

Table 4-19 presents the Prong 2 results for the proposed BtB4 alternative emissions/ shutdown scenario. All three averaging metrics report some Class I areas with negative visibility differences, however the average visibility impact benefits over all Class I area are positive for each averaging metric indicating overall improvement in visibility with the proposed BtB4 alternative emissions/shutdown strategy compared to the EPA BART emissions control strategy. The range of relative visibility impact benefits is 1.0 % to 4.0 % across the three averaging methods.

Table 4-18. Prong 1 for BtB4 emissions scenario.

Prong 1 of BTB Test						
Case: EPA 2008 Baseline - BtB4						
	Delta Dv Differences					
	Average Best 20% Days		Average Worst 20% Days		Annual Average	
Class I Area	Absolute (dv)	Relative	Absolute (dv)	Relative	Absolute (dv)	Relative
Bandalier NM	0.0024	28.3%	0.0044	18.4%	0.0031	22.4%
Bosque	0.0021	20.7%	0.0025	35.5%	0.0026	16.9%
Chiricahua NM	0.0022	19.6%	0.0004	19.0%	0.0010	17.7%
Chiricahua Wild	0.0021	18.4%	**0.0004**	19.3%	0.0009	17.4%
Galiuro Wild	0.0017	26.1%	0.0004	16.3%	0.0007	17.1%
Gila Wild	0.0039	11.2%	0.0012	14.7%	0.0048	17.7%
Grand Canyon NP	**0.0001**	10.2%	0.0010	16.8%	0.0022	21.5%
Mazatzal Wild	0.0034	13.8%	0.0008	15.6%	0.0014	15.5%
Mesa Verde NP	0.0006	25.7%	0.0014	17.2%	0.0022	23.1%
Mount Baldy Wild	0.0022	11.7%	0.0017	**10.6%**	0.0030	14.7%
Petrified Forest NP	0.0195	16.9%	0.0103	25.9%	0.0162	**13.5%**
Pine Mountain Wild	0.0027	17.8%	0.0006	19.5%	0.0011	16.9%
Saguro NP	0.0010	19.1%	0.0004	15.4%	**0.0006**	17.7%
San Pedro Parks Wild	0.0030	29.3%	0.0033	20.5%	0.0035	22.5%
Sierra Ancha Wild					0.0020	16.7%
Superstition Wild	0.0022	**7.7%**	0.0004	11.7%	0.0014	16.4%
Sycamore Canyon Wild	0.0012	10.2%	0.0009	15.3%	0.0014	19.0%
Minimum	**0.0001**	**7.7%**	**0.0004**	**10.6%**	**0.0006**	**13.5%**

Table 4-19. Prong 2 for BtB4 emissions scenario.

Prong 2 of BTB Test						
Case: EPA 2008 BART - BtB4						
	Delta Dv Differences					
	Average Best 20% Days		Average Worst 20% Days		Annual Average	
Class I Area	Absolute (dv)	Relative	Absolute (dv)	Relative	Absolute (dv)	Relative
Bandalier NM	0.0009	13.6%	-0.0005	-2.8%	0.0003	1.9%
Bosque	0.0007	7.4%	0.0014	23.2%	-0.0002	-1.3%
Chiricahua NM	-0.0003	-3.5%	0.0002	11.0%	0.0001	1.2%
Chiricahua Wild	-0.0004	-4.5%	0.0002	12.2%	0.0001	0.6%
Galiuro Wild	0.0009	14.8%	0.0001	3.8%	0.0001	0.4%
Gila Wild	-0.0035	-12.8%	-0.0002	-2.9%	-0.0002	-4.0%
Grand Canyon NP	-0.0001	-12.6%	0.0003	5.5%	0.0019	44.6%
Mazatzal Wild	-0.0017	-8.5%	0.0002	3.2%	0.0001	2.5%
Mesa Verde NP	0.0001	7.5%	0.0004	6.1%	0.0011	5.1%
Mount Baldy Wild	-0.0018	-11.8%	-0.0021	-16.4%	-0.0013	-13.3%
Petrified Forest NP	0.0124	11.4%	0.0046	13.5%	-0.0015	-19.7%
Pine Mountain Wild	-0.0008	-7.0%	0.0003	11.3%	0.0002	2.3%
Saguro NP	0.0003	7.2%	0.0000	-0.6%	0.0002	1.0%
San Pedro Parks Wild	0.0007	8.5%	0.0006	4.7%	0.0005	0.5%
Sierra Ancha Wild					0.0004	7.4%
Superstition Wild	-0.0033	-13.9%	-0.0002	-6.7%	0.0000	0.2%
Sycamore Canyon Wild	-0.0009	-9.2%	-0.0002	-4.9%	0.0008	6.5%
Average	**0.0002**	**1.2%**	**0.0003**	**4.0%**	**0.0001**	**1.0%**

4.5 Conclusions of Better-than-BART Modeling

The CAMx modeling demonstrated that all four proposed alternative BtB emissions/shutdown scenarios passed Prong 1 of the Better-than-BART test, hence “visibility does not decline in any Class I area” for all four proposed alternative BtB scenarios. In addition, since all four proposed alternative BtB emissions/shutdown scenarios also passed Prong 2 of the Better-than-BART tests, all four proposed alternative BtB emissions/shutdown scenarios provide an “overall improvement in visibility” compared to the EPA BART control scenario. Both prongs of the Better-than-BART test passed for all four proposed alternative BtB emissions/shutdown scenarios considering the B20% /W20% and annual average averaging approaches. Hence, all four proposed alternative BtB emissions scenarios with the specified shutdown periods have been demonstrated to pass the full Better-than-BART test.

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APPENDIX A
CAMX MODEL PERFORMANCE EVALUATION

A.1 Model Performance Evaluation (MPE) Introduction

The CAMx 2008 12/4 km Actual Base Case simulation was performed for the 2008 calendar year using 2008 Actual Base Case emissions on the Coronado Generating Station (CGS) 12/4 km domain depicted in Figure 2-1. The 2008 Actual Base Case emissions scenario included day-specific hourly SO_2 and NO_X emissions from Continuous Emissions Monitor (CEM) devices on large Electrical Generating Units (EGUs), including the CGS.

Previously CAMx 2008 base case simulations using essentially the same model inputs have been performed by the West-wide Jump-start Air Quality Modeling Study (WestJumpAQMS; ENVIRON, Alpine and UNC, 2013) and Western Air Quality Study (WAQS; Adelman, Shanker, Yang and Morris, 2014). Both the WestJumpAQMS and WAQS performed a comprehensive and detailed model performance evaluation (MPE) of the CAMx 2008 base case for concentrations, depositions and visibility impairment. The WestJumpAQMS and WAQS CAMx model evaluations focused mainly on surface monitoring sites, although ozone aloft was also evaluated using ozonesonde measurements with the closest site being in Boulder, Colorado.

The objective of the CGS Better-than-BART modeling is to evaluate the CGS visibility impacts in Class I areas within 300 km of the facility. Thus, CAMx MPE in this Appendix focused on visibility and $PM_{2.5}$ model performance at IMPROVE monitoring sites within the CGS 4 km modeling domain (Figure A-1). The evaluation for other parameters (e.g., ozone and deposition) has already been performed under WestJumpAQMS and WAQS so was not repeated here and the reader is referred to the WestJumpAQMS and Intermountain West Data Warehouse (IWDW) websites for documentation on the WestJumpAQMS and WAQS CAMx 2008 base case model evaluation.

A.1.1 Monitoring Data Used in the Evaluation

Figure A-1 displays the locations of the IMPROVE sites within the CGS 4 km modeling domain where the CGS CAMx 2008 Actual Base Case modeling results were evaluated for visibility extinction and $PM_{2.5}$ concentrations. The observed and predicted PM species concentrations are converted to visibility impairment units in inverse megameters (Mm^{-1}) using the latest IMPROVE extinction equation with monthly average relative humidity adjustment factors [f(RH)] and procedures from FLAG (2010). These are the same procedures as used to assess a source's emissions contribution to visibility impairment at a Class I areas that is described in Section 3.1. Note that in these procedures, NH4 is not used and the extinction is calculated assuming that SO4 and NO3 are completely neutralized by NH4. The visibility evaluation was conducted by comparing predicted and observed 24-hour total extinction in megameters (Mm^{-1}) as well as each component of extinction in a similar manner as done for $PM_{2.5}$.

Note that not all IMPROVE monitoring sites are associated with Class I areas so do not have the associated f(RH) values from FLAG (2010) that are needed to convert the IMPROVE $PM_{2.5}$ concentrations to visibility extinction. There are 19 IMPROVE monitoring sites in the 4 km domain where CAMx was evaluated for $PM_{2.5}$ concentrations. Of those, we were able to calculate visibility impairment for 9 of the IMPROVE monitoring sites that corresponded to some of the Class I areas (see green dots in Figure A-1). Note that several of the IMPROVE sites where FLAG (2010) f(RH) data were available did not make it in the visibility evaluation (e.g., BALD1, BOAP1, GILC1), which was due to the AMET evaluation tool dropping sites that it determined had insufficient data. However, the evaluation for $PM_{2.5}$ is available and the high correlation between the visibility and $PM_{2.5}$ evaluation will identify any visibility performance issues at the dropped IMPROVE sites.

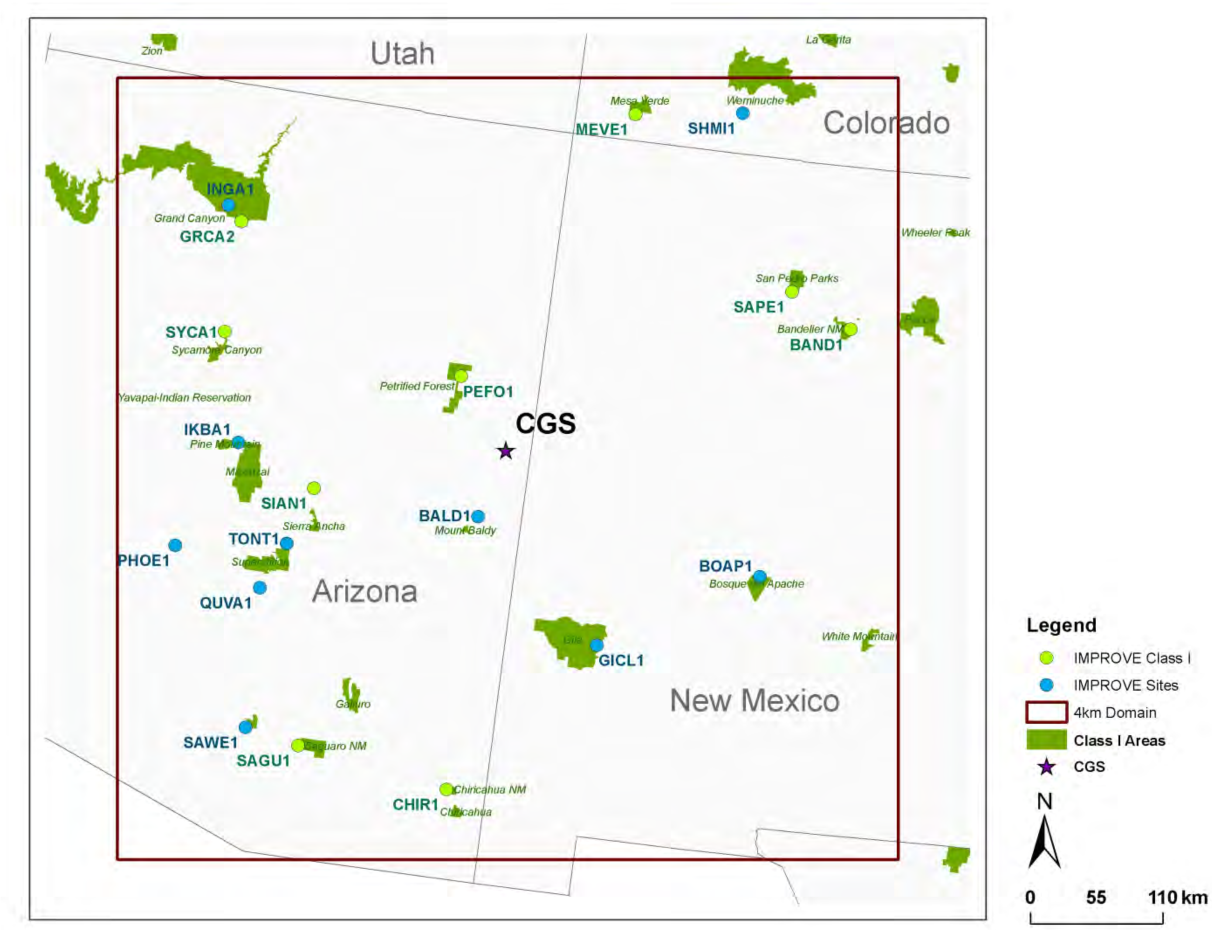


Figure A-1. Locations of IMPROVE monitoring sites in the CGS 4 km modeling domain where the CAMx 2008 Actual Base Case was evaluated for $PM_{2.5}$ and subset of IMPROVE sites (green) where visibility evaluation was also performed.

A.2 Model Performance Statistics and Goals

For over two decades, ozone model performance for bias and error has been compared against EPA's 1991 ozone modeling guidance model performance goals as follows (EPA, 1991):

- Mean Normalized Bias (MNB) ≤ ±15%
- Mean Normalized Gross Error (MNGE) ≤ 35%

For PM species, a separate set of model performance statistics and performance goals and criteria have been developed as part of the regional haze modeling performed by several Regional Planning Organizations (RPOs). EPA's modeling guidance notes that PM models might not be able to achieve the same level of model performance as ozone models. Indeed, $PM_{2.5}$ species definitions are defined by the measurement technology used to measure them and different measurement technologies can produce very different $PM_{2.5}$ concentrations. Given this, several researchers have developed PM model performance goals and criteria that are less stringent than the ozone goals that are shown in Table A-1 (Boylan, 2004; Boylan and Russell, 2006; Morris et al., 2009a,b). However, unlike the 1991 ozone model performance goals that use the MNB and MNGE performance metrics, for PM species the Fractional Bias (FB) and Fractional Error (FE) and Normalized Mean Bias (NMB) and Error (NME) are typically used with no observed concentration threshold screening. Table A-1 summarizes the ozone and PM performance goals and criteria that will be used to help evaluate the CAMx model performance. Table A-2 presents the definitions of the model performance evaluation statistics.

Table A-1. Ozone and PM model performance goals and criteria.

Bias (FB/NMB)	Error (FE/NME)	Comment
≤±15%	≤35%	Ozone model performance goal that would be considered very good model performance for PM species
≤±30%	≤50%	PM model performance Goal, considered good PM performance
≤±60%	≤75%	PM model performance Criteria, considered average PM performance.

It should be pointed out that these model performance goals and criteria are not used to assign passing or failing grades to model performance, but rather to help interpret the model performance and compare performance across locations, species, time periods and model applications. As noted in EPA's current modeling guidance *"By definition, models are simplistic approximations of complex phenomena"* (EPA, 2007, pg. 98). The model inputs to the air quality models vary hourly, but tend to represent average conditions that do not account for unusual or extreme events or conditions.

More recently, EPA compiled and interpreted the model performance from 69 PGM modeling studies in the peer-reviewed literature between 2006 and March 2012 and developed recommendations on what should be reported in a model performance evaluation (Simon, Baker and Phillips, 2012). Although these recommendations are not official EPA guidance, their recommendations were integrated in this CAMx MPE.

- PGM MPE studies should at a minimum report the Mean Bias (MB) and Error (ME or RMSE), and Normalized Mean Bias (NMB) and Error (NME) and/or Fractional Bias (FB) and Error (FE). Both the MNB and FB are symmetric around zero with the FB bounded by -200% to +200%.
- Use of the Mean Normalized Bias (MNB) and Gross Error (MNGE) is not encouraged because they are skewed toward low observed concentrations and can be misinterpreted due to the lack of symmetry around zero.
- The model evaluation statistics should be calculated for the highest resolution temporal resolution available (e.g., hourly ozone) and for important regulatory averaging times (e.g., daily maximum 8-hour ozone).
- It is important to report processing steps in the model evaluation and how the predicted and observed data were paired and whether data are spatially/temporally averaged before the statistics are calculated.
- Predicted values should be taken from the grid cell that contains the monitoring site, although bilinear interpolation to the monitoring site point can be used for higher resolution modeling (< 12 km).
- $PM_{2.5}$ should also be evaluated separately for each major component species (e.g., SO_4, NO_3, NH_4, EC, OA and remainder other $PM_{2.5}$ [$OPM_{2.5}$]).
- Evaluation should be performed for subsets of the data including, high observed concentrations (e.g., ozone > 60 ppb), by subregion and by season or month.
- Spatial displays should be used in the model evaluation to evaluate model predictions away from the monitoring sites. Time series of predicted and observed concentrations at a monitoring site should also be used.
- It is necessary to understand measurement artifacts in order to make meaningful interpretation of the model performance evaluation.

The recommendations above were accounted for where appropriate in the MPE presented in this Appendix.

Table A-2. Definitions of model performance evaluation statistical metrics.

Statistical Measure	Mathematical Expression	Notes
Ap: Accuracy of paired peak	$\frac{P - O_{peak}}{O_{peak}}$	Comparison of the peak observed value (O_{peak}) with the predicted value at same time and location
NME: Normalized Mean Error	$\frac{\sum_{i=1}^{N}\lvert P_i - O_i \rvert}{\sum_{i=1}^{N} O_i}$	Reported as %
RMSE: Root Mean Square Error	$\left[\frac{1}{N}\sum_{i=1}^{N}(P_i - O_i)^2\right]^{1/2}$	Reported as %
FE: Fractional Gross Error	$\frac{2}{N}\sum_{i=1}^{N}\left\lvert\frac{P_i - O_i}{P_i + O_i}\right\rvert$	Reported as % and bounded by 0% to 200%
MAGE: Mean Absolute Gross Error	$\frac{1}{N}\sum_{i=1}^{N}\lvert P_i - O_i \rvert$	Reported as concentration (e.g., µg/m^3)
MNGE: Mean Normalized Gross Error	$\frac{1}{N}\sum_{i=1}^{N}\frac{\lvert P_i - O_i \rvert}{O_i}$	Reported as %
MB: Mean Bias	$\frac{1}{N}\sum_{i=1}^{N}(P_i - O_i)$	Reported as concentration (e.g., µg/m^3)
MNB: Mean Normalized Bias	$\frac{1}{N}\sum_{i=1}^{N}\frac{(P_i - O_i)}{O_i}$	Reported as %
FB: Mean Fractionalized Bias	$\frac{2}{N}\sum_{i=1}^{N}\left(\frac{P_i - O_i}{P_i + O_i}\right)$	Reported as %, bounded by -200% to +200%
NMB: Normalized Mean Bias	$\frac{\sum_{i=1}^{N}(P_i - O_i)}{\sum_{i=1}^{N} O_i}$	Reported as %

A.3 Model Evaluation Approach

The additional CAMx evaluation performed as part of the CGS BART modeling study focused on visibility extinction and $PM_{2.5}$ concentrations in terms of total and their components at IMPROVE monitoring sites within the CGS 4 km modeling domain (Figure A-1). The evaluation was performed across all IMPROVE monitoring sites within the 4 km domains as well as at each individual site on an annual, seasonal (quarterly) and monthly basis. In addition to generating numerous statistical performance metrics (see Table A-2), graphical representation of model performance were generated as follows:

- Soccer Plots of monthly bias and error that are compared against the ozone performance goals and the PM performance goals and criteria (see Table A-1). Monthly soccer plots allow the easy identification of when performance goals/criteria are achieved and an evaluation of performance across seasons. Note that because we are evaluating for just visibility and $PM_{2.5}$, the ozone performance goals are not really relevant. But they are included on the soccer plot displays and represent very good performance for visibility and $PM_{2.5}$.
- Spatial statistical performance maps that display bias/error on a map at the locations of the monitoring sites in order to better understand spatial attributes of model performance along with tabular summaries of statistical performance metrics.
- Time series plots that compare predicted and observed daily visibility extinction and PM concentrations at monitoring sites.
- Scatter plots of predicted and observed concentrations.

All performance statistics and displays are performed matching the predicted and observed concentrations by time and location using the modeled prediction in the 4 km grid cell containing the monitoring site.

The model performance statistics and displays were generated using the Atmospheric Model Evaluation Tool (AMET[19]) developed by EPA that is the MPE tool mentioned in EPA's latest PGM modeling guidance (EPA, 2014). Thus, the statistics and displays are limited to those produced by AMET. AMET uses screening criteria to make sure that sufficient observations are available at a monitoring site for use in the model evaluation that ended up dropping some sites from the visibility model evaluation.

A.4 Visibility and Particulate Matter Model Performance

The CAMx performance for visibility and fine particulate matter was evaluated using total visibility extinction and $PM_{2.5}$ mass as well as each component of visibility impairment and $PM_{2.5}$ concentration. The visibility and PM performance was compared against the PM performance goals and criteria given in Table A-1. Note that the PM goals and criteria are not as stringent as those for ozone because PM measurements are much more uncertain than

[19] https://www.cmascenter.org/help/documentation.cfm?MODEL=amet&VERSION=1.1

ozone, emissions are more uncertain (e.g., dust) and there are more processes involved in PM (e.g., primary and secondary). Each PM measurement technique has its own artifacts; different measurement technology could produce different observed $PM_{2.5}$ values that differ by as much as 30 percent. EPA's latest PGM modeling guidance includes a section on PM measurement artifacts for the monitoring technologies used in routine networks in the U.S. (EPA, 2014d). Thus, the PM model performance needs to recognize these measurement uncertainties and artifacts and take them into account in the interpretation of model performance as even a "perfect" model may not achieve the PM performance goals and criteria.

PM_{10} consists of particles with a mean aerodynamic diameter of 10 microns or less and consists of fine ($PM_{2.5}$, i.e. particles with a diameter of 2.5 microns or less) and coarse (PMC, i.e., particles with diameter between 2.5 and 10 microns) modes. Visibility is calculated using the latest IMPROVE equation (FLAG, 2010) from the PM species (see Section 3.1). Visibility extinction and PM_{10} is composed of the following component species:

- Sulfate (SO4) that for visibility extinction is assumed to be in the form of ammonium sulphate (AmmSO4 = 1.37 x SO4);
- Nitrate (NO3) that is also assumed to be ammonium nitrate for calculating visibility extinction (AmmNO3 = 1.29 x NO3);
- Ammonium (NH4) that is not directly measured by IMPROVE monitors so it is derived assuming SO4 and NO3 are completely neutralized by NH4 (NH4d = 0.37 x SO4 + 0.29 x NO3) when doing $PM_{2.5}$ evaluation;
- Elemental Carbon (EC) that is also called Black Carbon (BC) and Light Absorbing Carbon (LAC);
- Organic Aerosol (OA) that includes primary (POA) and secondary organic aerosol (SOA) and is composed or Organic Carbon (OC) and other atoms (e.g., oxygen) that are adhered to the OC; and
- Other $PM_{2.5}$ (OPM2.5) that is primarily crustal in nature (SOIL) but can also include other compounds as well as measurement artifacts.

- Coarse particulate matter (PMC or $PM_{2.5\text{-}10}$) that will have a large dust component.

Note that the IMPROVE visibility extinction equation also includes visibility impairment due to nitrogen dioxide (NO_2), however NO_2 was not included in this evaluation.

A.4.1 Evaluation for Total Extinction and $PM_{2.5}$ Mass

Daily total extinction is calculated using the IMPROVE equation and total $PM_{2.5}$ mass are evaluated at IMPROVE monitoring sites in the CGS 4 km domain.

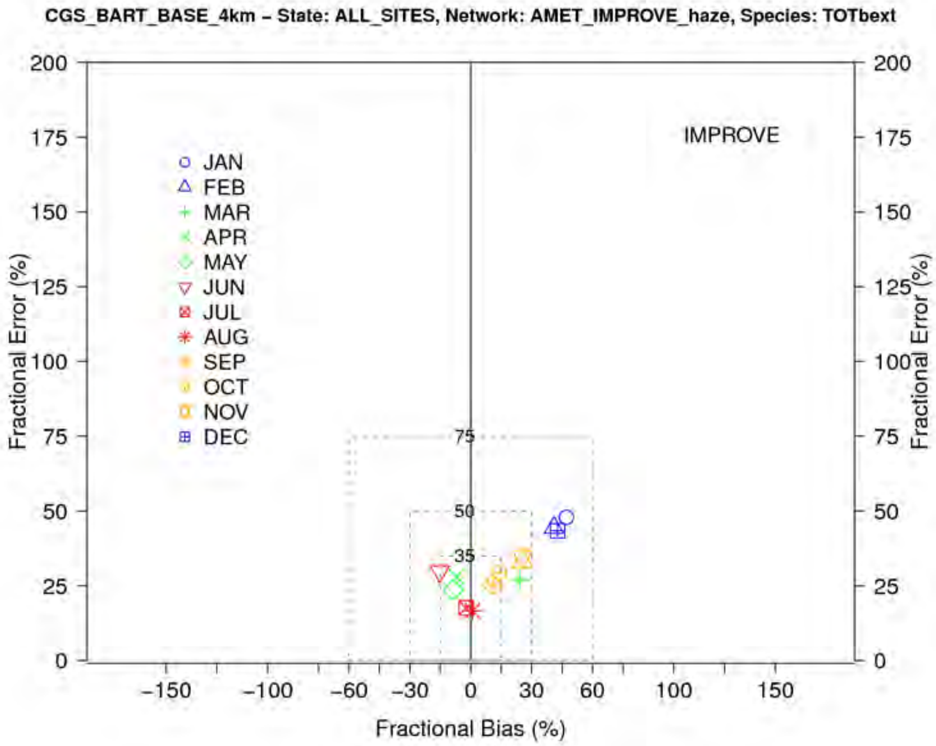
A.4.1.1 Total Visibility Extinction and $PM_{2.5}$ Mass Performance across the 4 km Domain

Figure A-2 displays Soccer Plots of total visibility extinction and $PM_{2.5}$ mass monthly model performance across the IMPROVE monitoring network in the 4 km CGS domain. Also shown in the Soccer Plots are boxes that represent the Performance Goals for ozone (most inner) and PM (middle) and the PM Performance Criteria (most outer).

The annual 24-hour visibility extinction bias and error model performance across IMPROVE sites in the 4 km domain achieves the PM Performance Criteria for all 12 months of the year (Figure A-2, top). The CAMx visibility performance achieves the PM Performance Goal for 9 months of the year with the three winter months (blue symbols) not achieving the PM Performance Goal due to an overestimation bias. The CAMx visibility performance achieves the most stringent ozone Performance Goal for 6 months of the year, with the summer months of July and August exhibiting extremely good visibility performance with zero bias and extremely low error.

The performance for total $PM_{2.5}$ mass across IMPROVE sites in the 4 km CGS domain is not as good as seen for visibility. 7 of 12 months achieve the PM Performance Goal for $PM_{2.5}$ with the best performance seen for the warmer months (April through October). For the cooler months, CAMx exhibits a $PM_{2.5}$ mass overestimation bias that is sufficiently great for the winter months (approximately +100%) that the PM Performance Criteria (≤±60%) is not achieved.

The total $PM_{2.5}$ mass performance and especially total visibility extinction performance is encouraging. The model performance mostly achieves the PM Performance Goals and when it doesn't it is due to an overestimation bias, so the resultant CAMx visibility modeling results will be conservative. The reasons why the total visibility extinction model performance is better than the total $PM_{2.5}$ mass model performance is two-fold. First is that total $PM_{2.5}$ mass and visibility extinction weigh each component of PM differently, with visibility weighting the best performing $PM_{2.5}$ species (e.g., Sulfate) more than those species that perform poorly (e.g., Soil also called OPM2.5), whereas total $PM_{2.5}$ mass weighs the mass for each $PM_{2.5}$ component equally. The second reason total visibility extinction performs better that total $PM_{2.5}$ mass is that Rayleigh Scattering (background, ~10 Mm^{-1}) for both the observed and predicted total extinction are the same and is added to the observed and modeled extinction so makes the modeled values closer to the observed values than total $PM_{2.5}$ mass concentrations.



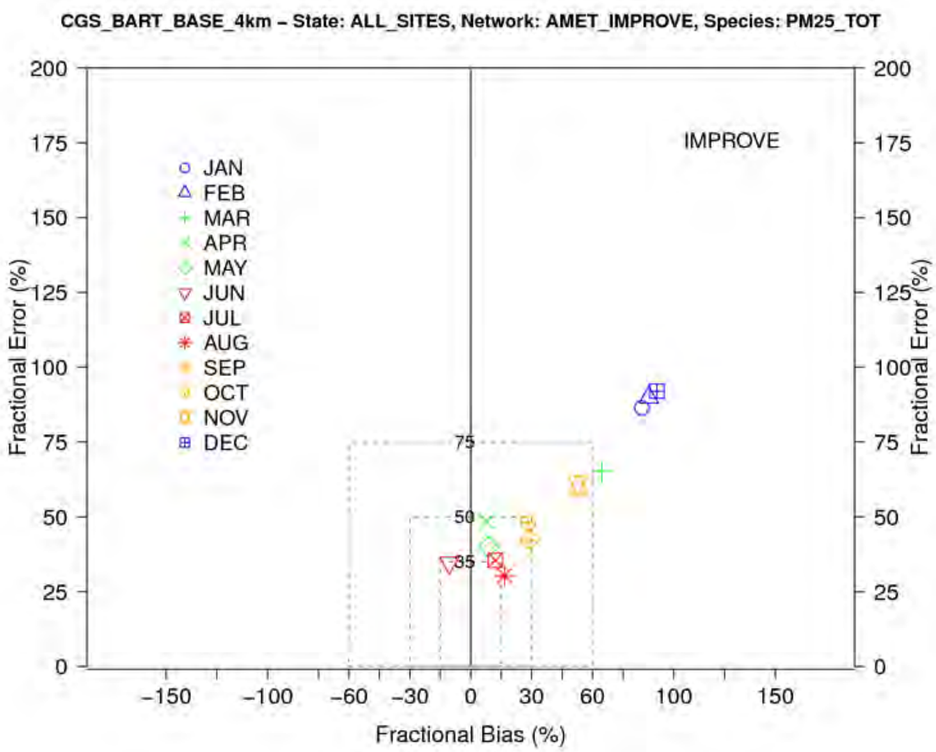
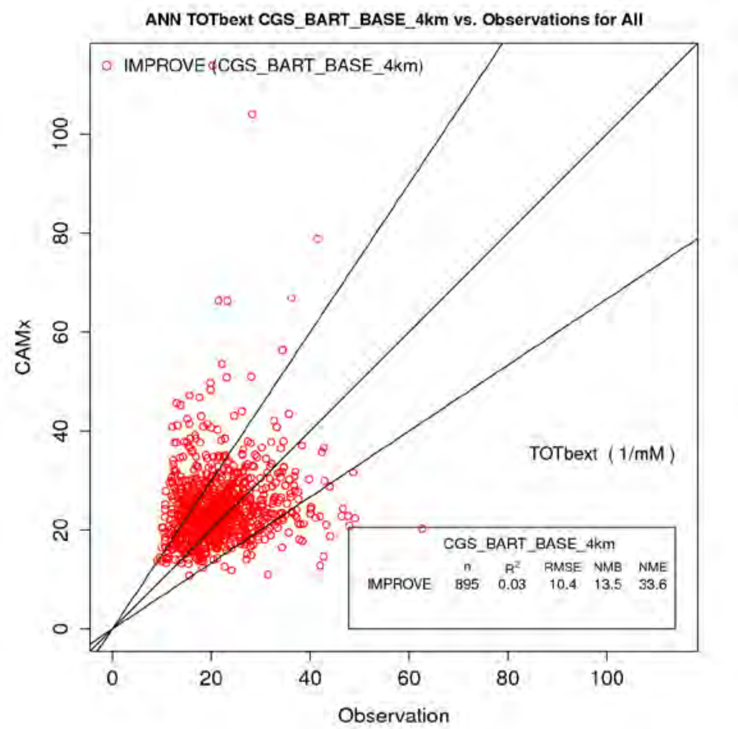


Figure A-2. Soccer plots of total visibility extinction (top) and total $PM_{2.5}$ mass (bottom) model performance across the IMPROVE sites in the 4 km CGS domain.

Scatter plots of the predicted and observed 24-hour visibility and $PM_{2.5}$ concentrations across IMPROVE sites in the 4 km domain with annual performance statistics are shown in Figure A-3. The daily visibility extinction scatter plot tends to be clustered around the 1:1 line of perfect agreement (Figure A-3, top). The good visibility performance is confirmed by the low annual bias (13%) and error (34%) that achieves the most stringent ozone Performance Goals. There are some modeled and to a lesser extent observed outliers, with two modeled daily extinction values in excess of 100 Mm^{-1} when observed values are less than 40 Mm^{-1}. These high modeled extinction outliers are due to modeled wildfire impacts that are not reflected in as high magnitude in the observations. For example, one of the modeled daily extinction values in excess of 100 Mm^{-1} is at the BAND1 IMPROVE sites with the majority of the extinction due to carbon (EC and OA), which is a fire signature.

The scatter plot for 24-hour $PM_{2.5}$ concentrations in 2008 across IMPROVE sites in the 4 km domain indicates an overestimation bias that is reflected in the annual bias (40%) and error (63%) that exceed the PM Performance Goal but achieve the PM Performance Criteria (Figure A-3, bottom). Like visibility, the highest 24-hour $PM_{2.5}$ overestimation data points in the scatter plot are due to modeled wildfire impacts.



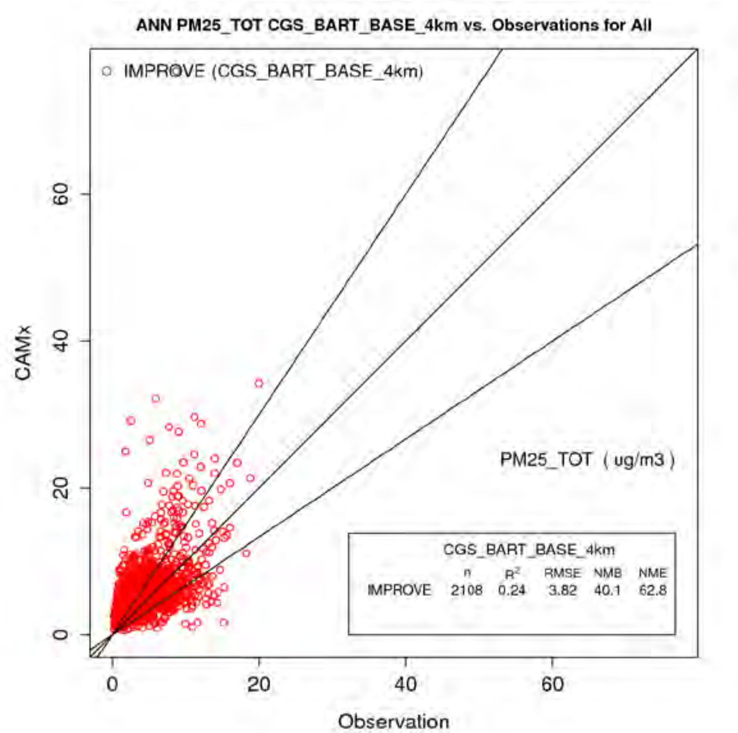


Figure A-3. Scatter plots and annual performance statistics of predicted and observed 24-hour visibility extinction (top) and $PM_{2.5}$ mass concentrations (bottom) for 2008 and all IMPROVE sites in 4 km CGS domain.

A.4.1.2 Total Visibility Extinction and $PM_{2.5}$ Mass Performance at Individual Monitoring Sites

Figures A-4 and A-5 displays spatial maps of annual total daily visibility extinction and $PM_{2.5}$ mass Normalized Mean Bias (NMB) and Normalized Mean Error (NME) performance statistics, respectively, at IMPROVE monitoring sites. Tabular summaries of total extinction and Pm2.5 performance statistics for many metrics (see Table A-2) are provided in Tables A-3 and A-4. The visibility NMB (Figure A-4, top) achieves the ≤±30% PM Performance Goal at all sites but BAND1 (39%), which is also the only site (52%) that the NME just barely doesn't achieve the error PM Performance Goal (≤50%). CAMx exhibits better visibility performance for the southern two-thirds of the 4 km domain with NMB that achieves the most stringent ozone Performance Goal ≤±15%, whereas the IMPROVE sites in the northern one-third of the 4 km domain have NMB in the 20-39% range.

The CAMx total $PM_{2.5}$ mass model performance achieves the PM Performance Criteria (≤±60%) at all sites but BAND1 (+124%), albeit with an overestimation bias. Of the 19 IMPROVE sites, only 3 have NMB that fail to achieve the ≤±30% PM Performance Goal with four sites having Fractional Bias that fails to achieve the PM Performance Goal (Table A-4; i.e., 79-84% of the IMPROVE sites have $PM_{2.5}$ bias that achieves the PM performance goal). The IMPROVE sites where the total $PM_{2.5}$ mass bias fail to achieve the PM Performance Goal are located in the northern portion of the 4 km domain (i.e., BAND1, SAPE1, MEVE1 and GRCA1). The $PM_{2.5}$ error performance statistics (NME and FE) achieve the PM Performance Criteria at all sites except BAND1. As seen in the $PM_{2.5}$ summary statistics in Table A-4, the poor $PM_{2.5}$ model performance at BAND1 appears to be an outlier with all other sites achieving the PM Performance Criteria for bias and error and most sites bias achieving the PM Performance Goal.

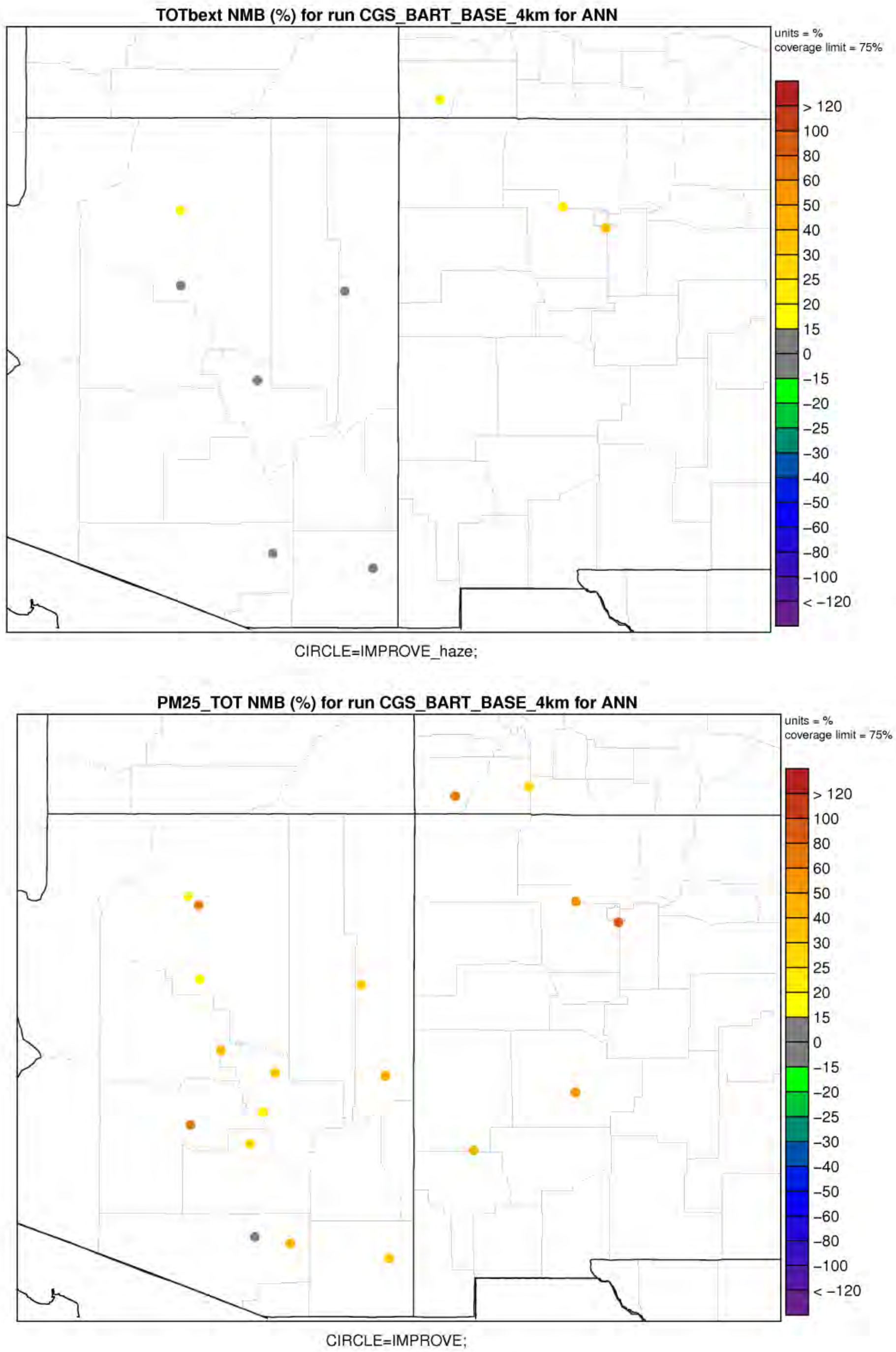
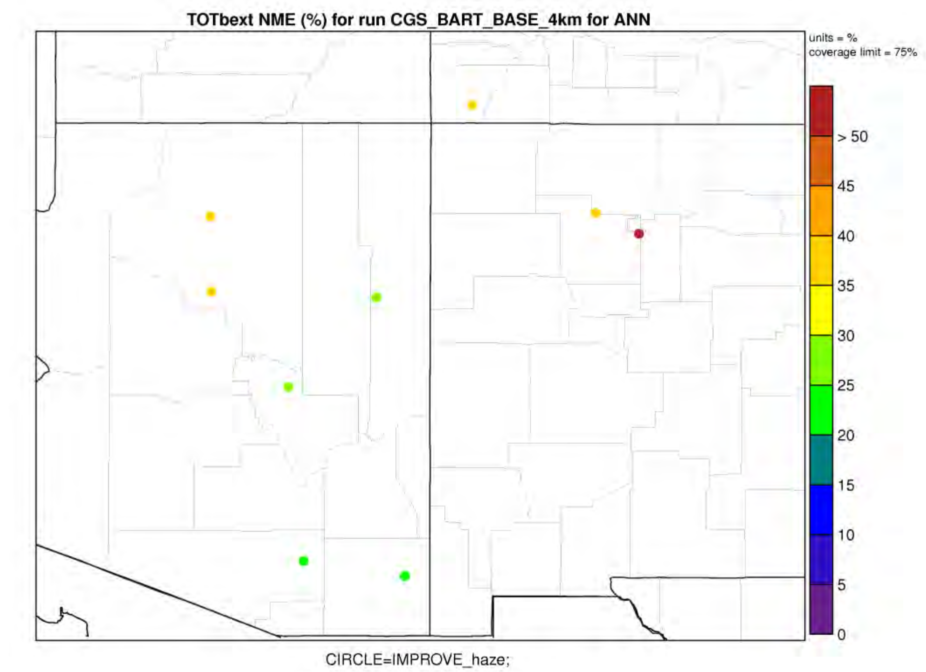


Figure A-4. Normalized Mean Bias (NMB) of total visibility extinction (top) and total $PM_{2.5}$ mass (bottom) by IMPROVE site in 4 km domain (PM Goal ≤±30% and PM Criteria ≤±60%).



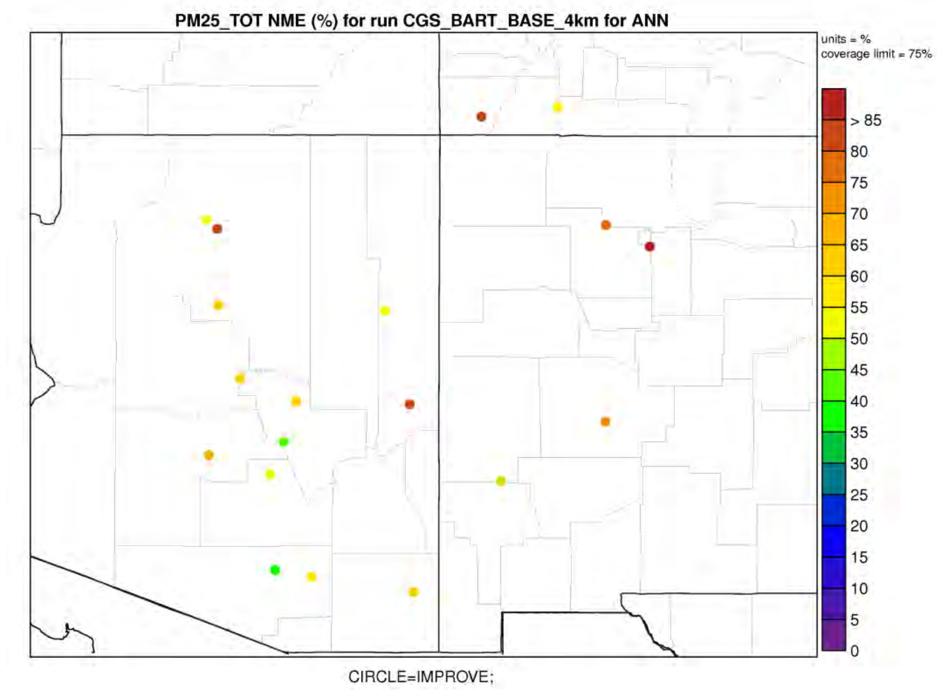


Figure A-5. Normalized Mean Error (NME) of total visibility extinction (top) and total $PM_{2.5}$ mass (bottom) by IMPROVE site in 4 km domain (PM Goal ≤50% and PM Criteria ≤75%).

Table A-3. Annual total visibility extinction model performance statistics at selected IMPROVE monitoring sites in the 4 km CGS domain and comparison with PM Performance Goals and Criteria (yellow shading indicate PM Performance Criteria is exceeded).

Site	N	AvObs	AvMod	MB	ME	NMB	NME	FB	FE	COR
Goal						≤±30%	≤50%	≤±30%	≤50%	
Criteria						≤±60%	≤75%	≤±60%	≤75%	
BAND1	102	20.8	29.0	8.2	10.8	39.3	51.8	30.5	40.6	0.012
CHIR1	104	22.3	23.3	0.9	5.6	4.1	24.9	6.6	23.7	0.225
GRCA2	97	18.6	22.5	3.9	6.6	20.9	35.7	19.3	31.8	0.069
MEVE1	111	19.3	23.9	4.5	7.5	23.5	38.6	21.1	33.4	0.071
PEFO1	110	21.9	23.1	1.2	6.1	5.4	28.0	7.2	26.4	0.057
SAGU1	93	26.4	28.7	2.3	6.4	8.9	24.4	9.0	23.8	0.187
SAPE1	95	17.4	21.0	3.6	6.1	20.4	35.0	19.3	31.0	0.158
SIAN1	72	23.4	25.0	1.6	6.9	6.9	29.5	5.2	25.7	0.202
SYCA1	111	24.8	24.9	0.1	9.0	0.4	36.2	-0.1	32.8	0.080

Table A-4. Annual total $PM_{2.5}$ mass model performance statistics at selected IMPROVE monitoring sites in the 4 km CGS domain and comparison with PM Performance Goals and Criteria (yellow shading indicates PM Performance Criteria not achieved).

Site	N	AvObs	AvMod	MB	ME	NMB	NME	FB	FE	COR
Goal						≤±30%	≤50%	≤±30%	≤50%	
Criteria						≤±60%	≤75%	≤±60%	≤75%	
BALD1	118	7.7	7.7	0.0	5.3	-0.6	68.8	11.4	57.1	0.105
BAND1	104	6.8	15.3	8.4	10.2	124.0	149.8	78.6	91.1	-0.238
BOAP1	100	9.1	10.8	1.7	5.8	18.5	64.3	25.0	57.2	0.098
CHIR1	116	8.6	8.7	0.1	4.1	0.9	47.8	14.7	49.2	0.474
GICL1	101	6.0	6.8	0.8	3.6	12.6	59.1	33.1	57.6	0.481
GRCA2	116	5.7	7.9	2.2	4.1	39.4	72.5	42.8	65.2	0.240
IKBA1	122	8.6	8.9	0.3	4.4	2.9	50.5	15.1	48.3	0.318
INGA1	119	10.3	8.3	-2.0	6.2	-19.7	60.3	-3.7	68.7	0.170
MEVE1	115	6.5	8.4	1.8	4.7	28.3	71.8	39.8	64.9	0.423
PEFO1	110	8.5	8.5	0.0	4.7	0.1	56.0	17.1	54.8	0.284
PHOE1	117	26.1	24.0	-2.0	7.9	-7.9	30.4	-6.4	31.6	0.399
QUVA1	109	14.8	11.9	-2.9	6.3	-19.7	42.4	-9.4	43.7	0.283
SAGU1	113	12.2	14.7	2.5	5.6	20.2	45.9	25.1	45.1	0.354
SAPE1	112	5.4	7.7	2.3	3.9	42.9	72.6	50.6	67.5	0.349
SAWE1	109	15.3	11.9	-3.4	6.1	-22.3	40.1	-18.7	43.5	0.255
SHMI1	119	8.4	7.2	-1.2	4.9	-14.6	58.1	5.9	64.1	0.357
SIAN1	77	7.9	8.2	0.3	4.2	4.0	52.9	14.7	51.6	0.330
SYCA1	111	11.7	8.5	-3.2	6.7	-27.3	57.5	-9.2	60.8	0.156
TONT1	116	10.4	10.2	-0.3	4.9	-2.7	46.6	13.2	48.6	0.434

A.4.2 Evaluation of Visibility and $PM_{2.5}$ by Species Across the 4 km Domain

Figure A-6 displays soccer plots of monthly performance statistics across IMPROVE sites in the 4 km domain for visibility extinction and $PM_{2.5}$ concentration for each major PM species. With the exception of the three winter months, the sulfate visibility and mass performance achieves the PM Performance Criteria and even the PM Performance Goals for 5 months and Ozone Performance Goal for August (Figure A-6a, top). For the three winter months, sulfate extinction and concentration has an overestimation bias that makes it fall outside of the range of the PM Performance Criteria.

Nitrate visibility and concentration performance for most months falls between the PM Performance Goals and Criteria with just August and two winter months failing to achieve the Criteria (Figure A6a, middle). There is a general summer underestimation and winter overestimation bias, which is fairly typical of PGM model performance for nitrate. During the summer, the observed and modeled nitrate extinction and concentrations are very low and usually a negligible portion of PM mass or visibility impairment. During the winter, nitrate formation is very episodic and depends on numerous processes and presence of ammonia, whose emissions are highly uncertain. The nitrate performance mostly achieving the PM Performance Criteria represents relatively good PGM model performance for nitrate.

The bottom panels in Figure A-6a display visibility and concentration model performance for Organic Aerosol (OA). With the exception of April, whose error is too large, the remaining 11 months achieve the PM Performance Criteria. The best performing months for OAC occur in the fall and have essentially zero bias with the summer having a slight underestimation and winter a slight overestimation bias. We suspect there may be missing SOA processes in the model that may help explain the summer underestimation bias for OA.

Elemental Carbon (EC) visibility and mass model performance achieves or nearly achieves the PM Performance Criteria, albeit with an overestimation bias for all months (Figure A-6b, top). The overestimation bias is greater for the cooler than warmer months.

The model performance for extinction due to Soil, which is also called other $PM_{2.5}$ (OPM2.5), is characterized by an over-prediction bias that is at the +60% PM Performance Criteria for Apr-May-Jun and as high as 150% for the winter months, with the rest of the months falling in between (Figure A-6b, middle). There are model-measurement incommensurability with this species with the IMPROVE Soil measurement based on a linear combination of individual elements, whereas the modeled Soil/OPM2.5 species is based on primary $PM_{2.5}$ emissions that have not been explicitly speciated into other compounds so also includes measurement and speciation artifacts. The model OPM2.5 overestimation of the IMPROVE Soil measurement is common for PGM modeling because of this.

The coarse mass visibility and mass model performance is characterized by a summer underestimation and winter overestimation tendency with 8-9 months achieving the PM Performance Criteria (Figure A-6b, bottom).

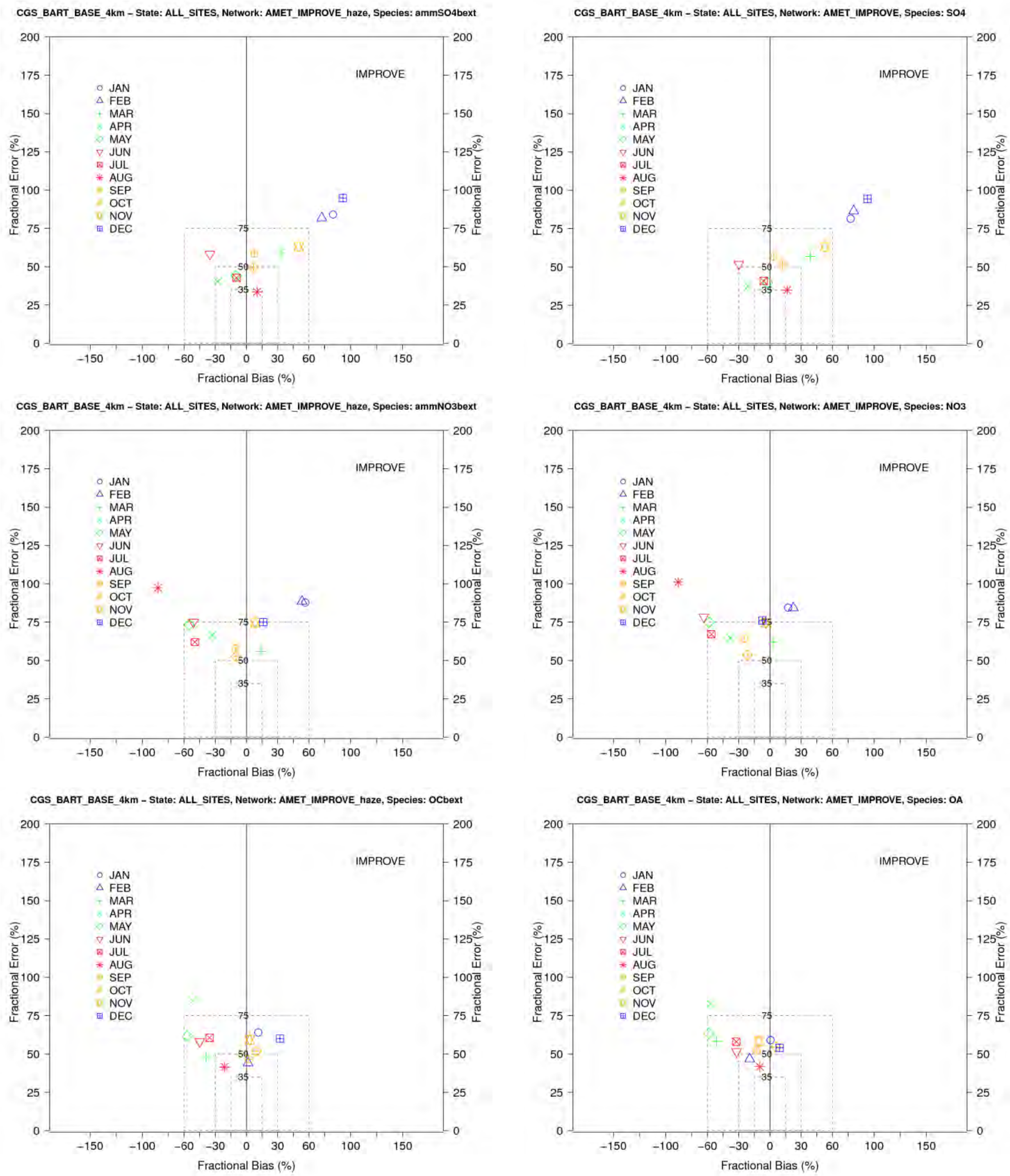


Figure A-6a. Soccer plots of monthly visibility extinction (left) and $PM_{2.5}$ concentrations (right) for sulfate (top), nitrate (middle) and organic aerosol (bottom).

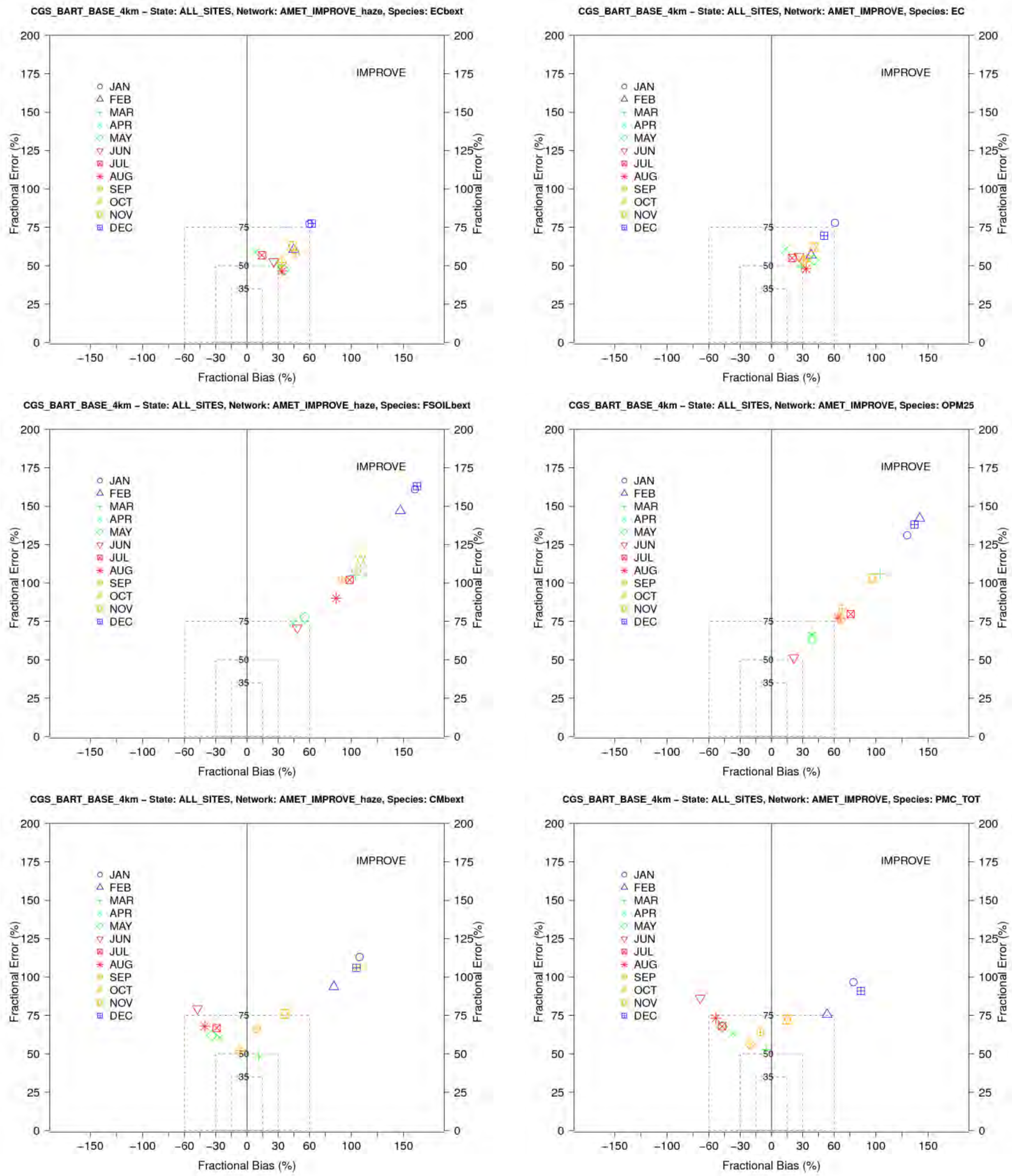


Figure A-6b. Soccer plots of monthly visibility extinction (left) and $PM_{2.5}$ concentrations (right) for elemental carbon (top), other PM2.5 or Soil (middle) and coarse mass (bottom).

Figure A-7 displays annual scatter plots of predicted and observed 24-hour extinction (left) and concentrations (right) for six PM component species. Sulfate visibility and mass performance is fairly good with a 20% bias that achieves the PM Performance Goal and an 62-65% error that falls between the PM Performance Goal and Criteria (Figure A-7a, top). The nitrate visibility extinction has a positive 13% overestimation bias but the nitrate concentration performance has a negative -29% underestimation bias (Figure A-7a, bottom). In the nitrate visibility extinction scatter plot there are numerous high overestimation points that are not as prevalent in the nitrate concentrations. This is due to the model's tendency toward overestimation nitrate in the cooler months and underestimation of nitrate in the warmer months. When averaged over the year, the nitrate concentrations end up having a negative bias. However, when nitrate visibility extinction calculations are made the f(RH) adjustments will tend to inflate the nitrate extinction more in the cooler wetter months than in the warm dry months resulting in an annual nitrate visibility extinction overestimation bias.

The annual OA extinction and concentration performance is shown in the top panels of Figure A-7b. The bias for OA extinction (-9%) and concentration (-21%) both achieve the PM Performance Goal with the error (~60%) falling between the PM Performance Goal and Criteria. The reasons why there is a reduction in the OA underestimation bias when going from concentrations (-21%) to extinction (-9%) is due to the f(RH) effects described above for nitrate and the tendency of the model to underestimate OA in the summer and overestimate in the winter (see Figure A-6a, bottom).

Elemental Caron (EC) extinction and concentrations both exhibit an annual overestimation bias (44% and 37%) and an error (73% and 71%) that falls between the PM Performance Goal and Criteria (Figure A-7b, bottom). As seen in the soccer plots, Soil/OPM2.5 extinction and concentrations are greatly overestimated and fail to achieve the PM Performance Criteria for the reasons described previously (Figure A-7c, top). Finally, coarse mass (CM or PMC) bias for visibility extinction (-3%) and concentration (-24%) achieves the PM Performance Goal but with lots of scatter so that the error (76% and 66%) is at the PM Performance Criteria (Figure A-7c, bottom). Coarse mass has a large contribution from dust whose emissions are more uncertain and has a shorter transport distance so some impacts may be local in nature and subgrid-scale to the model.

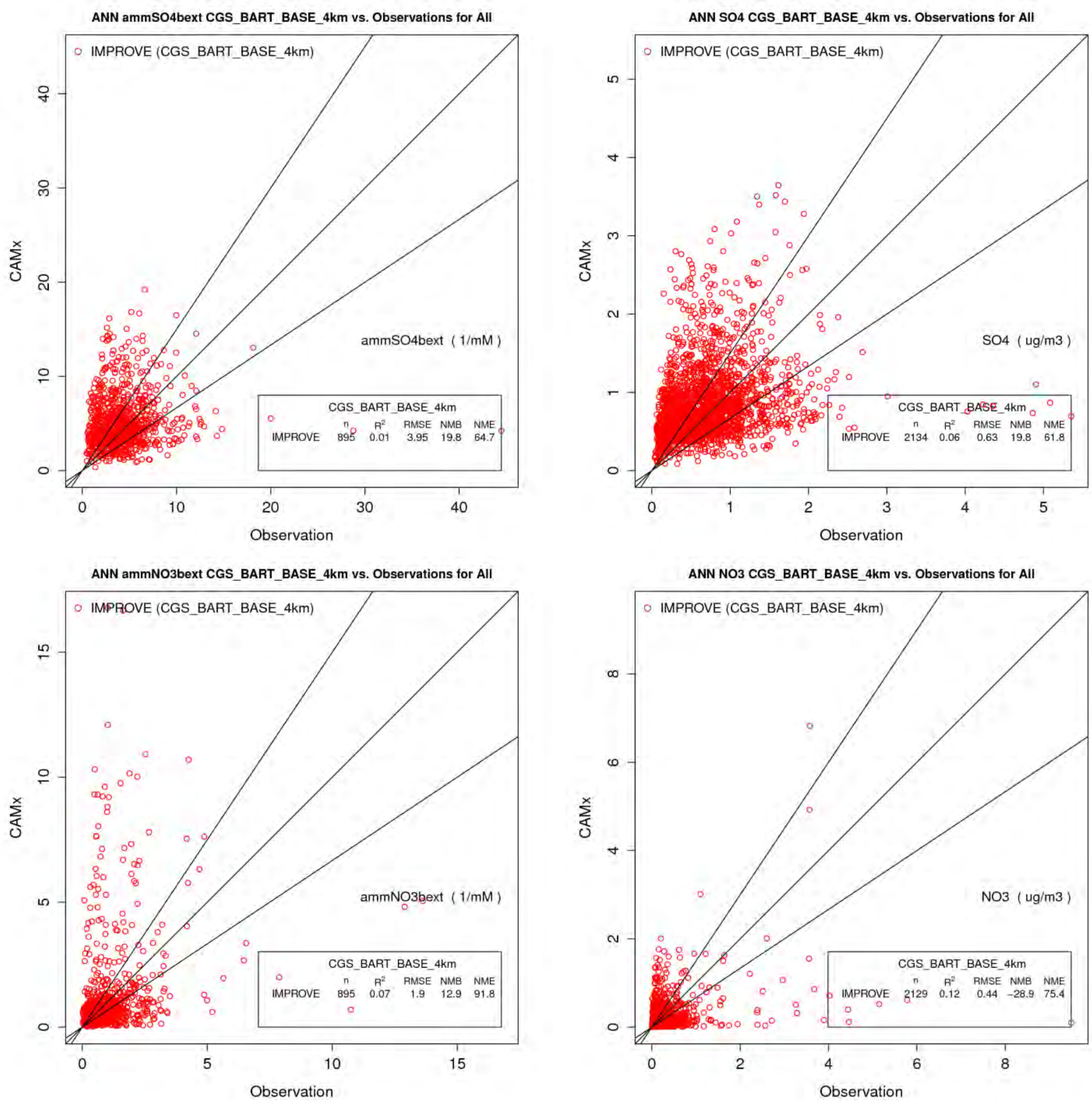


Figure A-7a. Annual scatter plots and performance statistics for 24-hour visibility extinction (left) and $PM_{2.5}$ mass (right) and sulfate (top) and nitrate (bottom).

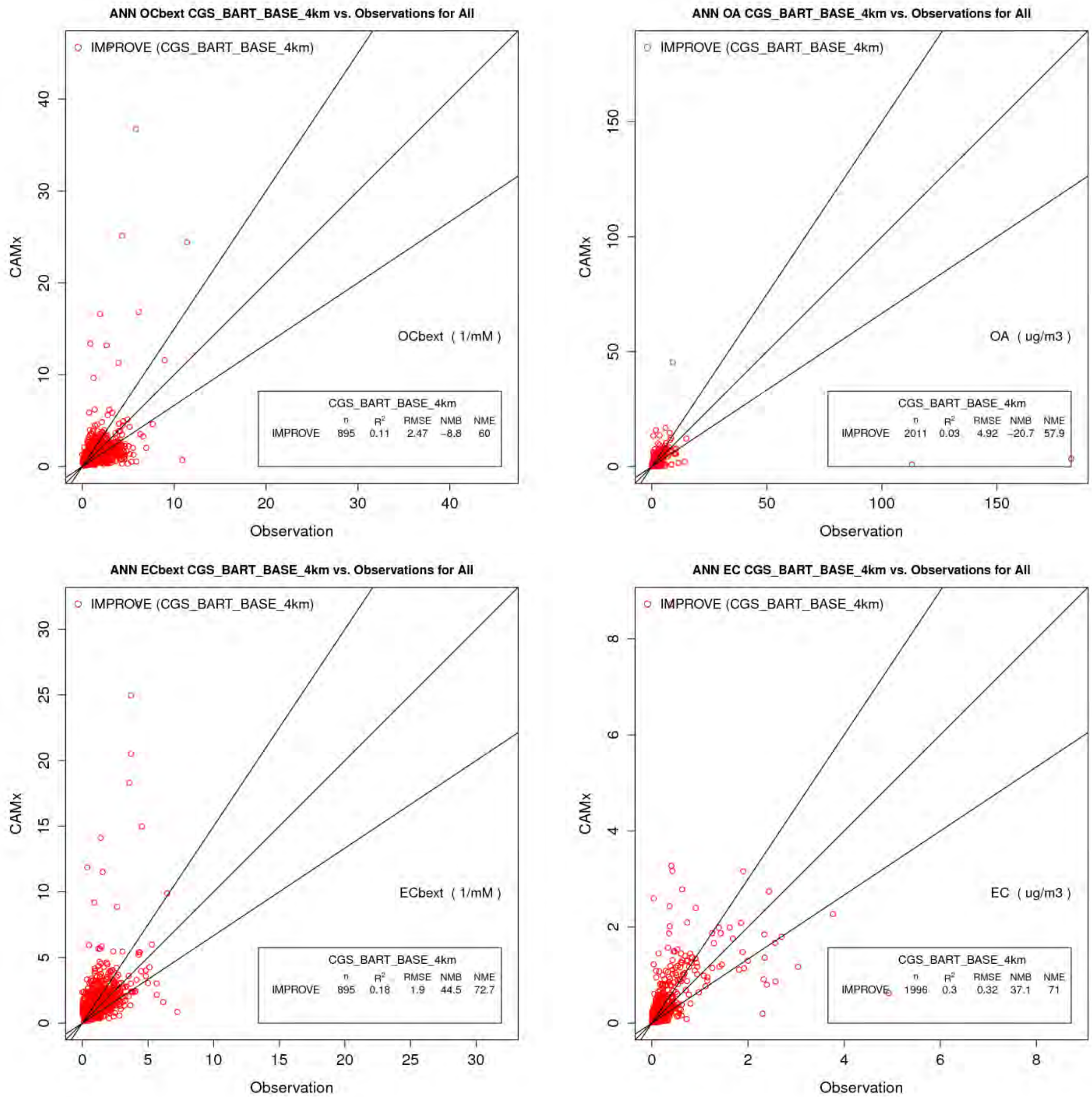


Figure A-7b. Annual scatter plots and performance statistics for 24-hour visibility extinction (left) and $PM_{2.5}$ mass (right) and organic aerosol (top) and elemental carbon (bottom).

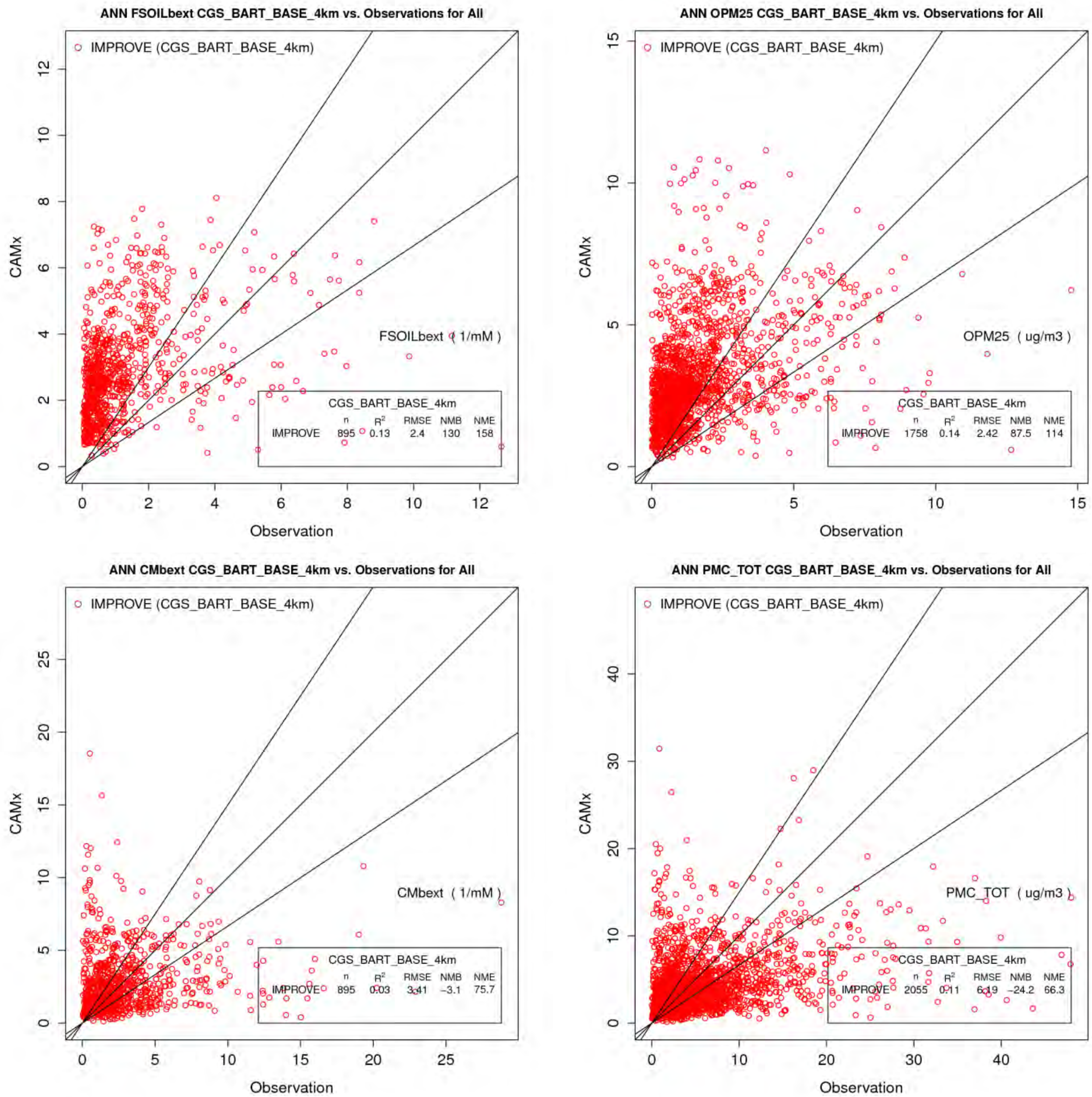


Figure A-7c. Annual scatter plots and performance statistics for 24-hour visibility extinction (left) and $PM_{2.5}$ mass (right) and other PM2.5 or SOIL (top) and coarse mass (bottom).

A.4.3 Site-Specific Evaluation of Visibility by Species

Table A-5 displays annual visibility model performance statistics at IMPROVE monitoring sites by each major component of visibility extinction: AmmSO4, AmmNO3, OA, EC, Soil and Coarse Mass. Annual time series plots of visibility extinction component for each IMPROVE site are given in Figures A-8 through A-16. The visibility performance at each IMPROVE sites by component is discussed in the following sections starting with CHIR1 in the south and going counter clockwise and finishing with BAND1 in the northeast (see Figure A-1). The emphasis of this discussion is on those species of most importance in the CGS BtB modeling, namely AmmSO4 and AmmNO3.

A.4.3.1 Chiricahua (CHIR1)

The annual total visibility extinction model performance statistics at CHIR1 are quite good with low bias (4-7% and error (24-25%) (Table A-3). This is reflected in the time series of predicted and observed total extinction that has low bias, except for one day that is underestimated near the end of September (Figure A-8, top left). The model does slightly overestimate extinction in the winter and slightly underestimate it in the summer. The high observed extinction the end of September is due to AmmSO4 with the AmmSO4 visibility performance at CHIR1 being very good for the rest of the year (Figure A-8, top right) with low bias (-1% and 7%) and error at the PM Performance Goal level (53-54%). The model also predicts the observed extinction due to AmmNO3 quite well for all days except one day in early February that is greatly overestimated (Figure A-8, middle left). The AmmNO3 extinction bias at CHIR1 achieves the PM Performance Goal with the error in between the PM Performance Goal and Criteria.

There is a lot of day-to-day variation in the predicted and observed OA extinction at CHIR1 with the model overall following the seasonal trend in the observations (higher in summer and lower in winter) with bias and error statistics that achieve the PM Performance Goal (Figure A-8, middle right). There is a high observed OA extinction day in mid-April that is not reflected in the model that could be due to fires, the high Soil extinction on this day also supports this hypothesis but the low EC extinction does not. The model tends to overestimate visibility extinction due to EC throughout the year resulting in high bias (65% and 52%) and error (87% and 68%). Extinction due to Soil is also greatly overestimated (> 100%) that is due in part to differences in how the IMPROVE equation and model defines this species (Figure A-8, bottom right). The bias for extinction due to coarse mass (-28% and -19%) achieves the PM Performance Goal with the error (55% and 63%) falling between the PM Performance Goal and Criteria (Table A-5b).

Table A-5a. Annual model performance statistics for visibility extinction (Mm^{-1}) by species (AmmSO4, AmmNO3 and OA) at IMPROVE monitoring sites in the 4 km CGS domain and comparison with PM Performance Goals and Criteria (bold statistics fail to achieve the PM Performance Criteria).

Site	N	AvObs	AvMod	MB	ME	NMB	NME	FB	FE	COR
PM Goal						≤±30%	≤50%	≤±30%	≤50%	
PM Criteria						≤±60%	≤75%	≤±60%	≤75%	
Ammonium Sulfate (AmmSO4) Extinction										
BAND1	102	4.5	5.1	0.7	2.8	15.3	62.2	16.3	55.9	0.118
CHIR1	104	5.2	5.1	-0.1	2.8	-1.1	54.6	6.7	53.3	0.242
GRCA2	97	3.7	5.1	1.3	2.9	36.0	**76.4**	28.3	64.3	0.034
MEVE1	111	4.1	5.6	1.6	2.9	38.2	70.9	30.4	57.4	0.026
PEFO1	110	4.2	5.0	0.8	2.6	18.2	61.4	18.2	55.7	0.091
SAGU1	93	4.8	5.1	0.2	2.8	4.8	57.3	2.4	56.1	0.126
SAPE1	95	3.7	4.8	1.1	2.6	29.4	70.3	27.9	60.2	0.038
SIAN1	72	4.5	5.2	0.7	2.8	15.7	62.8	22.8	57.6	0.171
SYCA1	111	3.9	5.0	1.2	2.8	30.0	72.2	28.4	61.7	0.080
Ammonium Nitrate (AmmNO3) Extinction										
BAND1	102	1.3	1.6	0.3	1.3	27.1	**99.3**	-5.5	69.4	0.327
CHIR1	104	0.6	0.7	0.1	0.5	14.5	73.6	2.4	63.8	0.215
GRCA2	97	0.9	1.0	0.1	0.9	12.5	**92.6**	-4.3	**78.1**	0.320
MEVE1	111	1.0	1.9	1.0	1.4	**98.0**	**146.3**	16.7	67.9	0.259
PEFO1	110	0.9	1.0	0.0	0.8	3.9	**79.2**	-27.5	67.2	0.238
SAGU1	93	1.2	0.5	-0.7	0.8	-57.3	67.3	-70.1	**82.0**	0.154
SAPE1	95	0.9	1.2	0.3	0.8	27.1	**86.0**	2.7	62.4	0.423
SIAN1	72	1.2	0.7	-0.4	0.8	-37.7	69.0	-40.0	74.7	0.384
SYCA1	111	1.1	1.3	0.2	1.0	18.9	**98.7**	-15.6	**80.3**	0.271
Organic Aerosol (OA) Extinction										
BAND1	102	1.8	2.0	0.1	1.2	8.1	64.8	-12.8	48.6	0.419
CHIR1	104	1.3	1.1	-0.2	0.6	-15.6	49.0	-12.3	53.9	0.326
GRCA2	97	1.4	1.3	-0.1	0.9	-6.3	68.6	2.1	69.3	0.234
MEVE1	111	1.5	1.2	-0.4	0.9	-23.4	57.5	-14.2	61.1	0.088
PEFO1	110	1.8	1.2	-0.5	0.8	-30.1	42.3	-32.6	50.7	0.506
SAGU1	93	1.9	2.0	0.1	1.1	5.0	55.3	1.0	54.1	0.046
SAPE1	95	1.4	1.0	-0.4	0.7	-27.5	53.3	-29.5	57.2	0.459
SIAN1	72	2.4	2.3	-0.1	1.6	-4.9	66.5	-37.7	63.3	0.578
SYCA1	111	2.4	2.5	0.1	1.8	3.9	74.9	-20.7	59.6	0.254

Table A-5b. Annual model performance statistics for visibility extinction (Mm^{-1}) by species (EC, Soil and PMC) at selected IMPROVE monitoring sites in the 4 km CGS domain and comparison with PM Performance Goals and Criteria (bold statistics fail to achieve the PM Performance Criteria).

Site	N	AvObs	AvMod	MB	ME	NMB	NME	FB	FE	COR
PM Goal						≤±30%	≤50%	≤±30%	≤50%	
PM Criteria						≤±60%	≤75%	≤±60%	≤75%	
Elemental Carbon (EC) Extinction										
BAND1	102	1.1	2.0	0.9	1.0	78.7	**88.5**	45.3	52.9	0.442
CHIR1	104	0.7	1.1	0.4	0.6	**65.3**	**86.5**	51.9	67.8	0.230
GRCA2	97	0.8	1.3	0.6	0.8	**75.7**	**103.0**	56.8	74.7	0.227
MEVE1	111	0.7	1.1	0.4	0.6	**65.8**	**86.0**	47.7	63.8	0.133
PEFO1	110	1.8	1.9	0.0	0.6	1.8	33.0	2.3	33.8	0.533
SAGU1	93	1.4	2.4	1.0	1.2	**67.9**	**83.1**	48.6	63.3	0.235
SAPE1	95	0.6	1.0	0.3	0.5	53.1	**82.6**	43.4	64.3	0.509
SIAN1	72	1.4	2.2	0.7	1.3	52.0	**87.9**	14.4	53.2	0.320
SYCA1	111	2.1	2.6	0.5	1.4	23.1	66.0	12.0	50.5	0.386
Fine Soil (OPM2.5) Extinction										
BAND1	102	1.0	3.7	2.7	2.9	**275.3**	**291.6**	**126.7**	**131.6**	0.179
CHIR1	104	1.2	2.7	1.6	1.9	**133.6**	**158.6**	**98.4**	**106.0**	0.449
GRCA2	97	0.9	2.6	1.7	1.8	**193.5**	**209.0**	**111.9**	**117.4**	0.501
MEVE1	111	0.9	2.7	1.7	1.9	**188.2**	**206.2**	**113.3**	**119.2**	0.542
PEFO1	110	1.2	2.7	1.5	1.7	**126.6**	**146.1**	**94.0**	**100.3**	0.486
SAGU1	93	1.8	3.8	1.9	2.2	**104.7**	**119.1**	**81.1**	**86.6**	0.432
SAPE1	95	1.0	2.7	1.7	1.9	**165.5**	**190.8**	**112.4**	**118.5**	0.406
SIAN1	72	1.2	2.8	1.6	1.9	**136.1**	**160.2**	**96.0**	**103.9**	0.378
SYCA1	111	2.2	2.7	0.5	1.9	25.1	**85.5**	50.9	**83.3**	0.205
Coarse Mass (PMC) Extinction										
BAND1	102	2.1	5.5	3.3	4.2	**157.8**	**198.8**	**89.7**	**106.2**	-0.293
CHIR1	104	3.2	2.3	-0.9	1.8	-27.8	54.9	-19.3	62.6	0.396
GRCA2	97	1.9	2.1	0.2	1.4	11.2	**77.6**	12.8	66.9	0.067
MEVE1	111	2.2	2.3	0.1	1.7	4.4	**78.6**	28.9	72.9	0.440
PEFO1	110	2.8	2.2	-0.7	2.1	-23.8	72.8	-2.6	**75.8**	0.137
SAGU1	93	4.8	4.8	0.0	2.0	-0.3	41.0	10.0	43.6	0.455
SAPE1	95	1.6	2.1	0.5	1.2	29.6	73.3	44.5	69.4	0.328
SIAN1	72	2.5	1.7	-0.8	1.5	-32.8	58.4	-20.2	67.3	0.213
SYCA1	111	4.1	1.7	-2.4	3.1	-58.3	74.2	-46.1	**87.5**	0.066

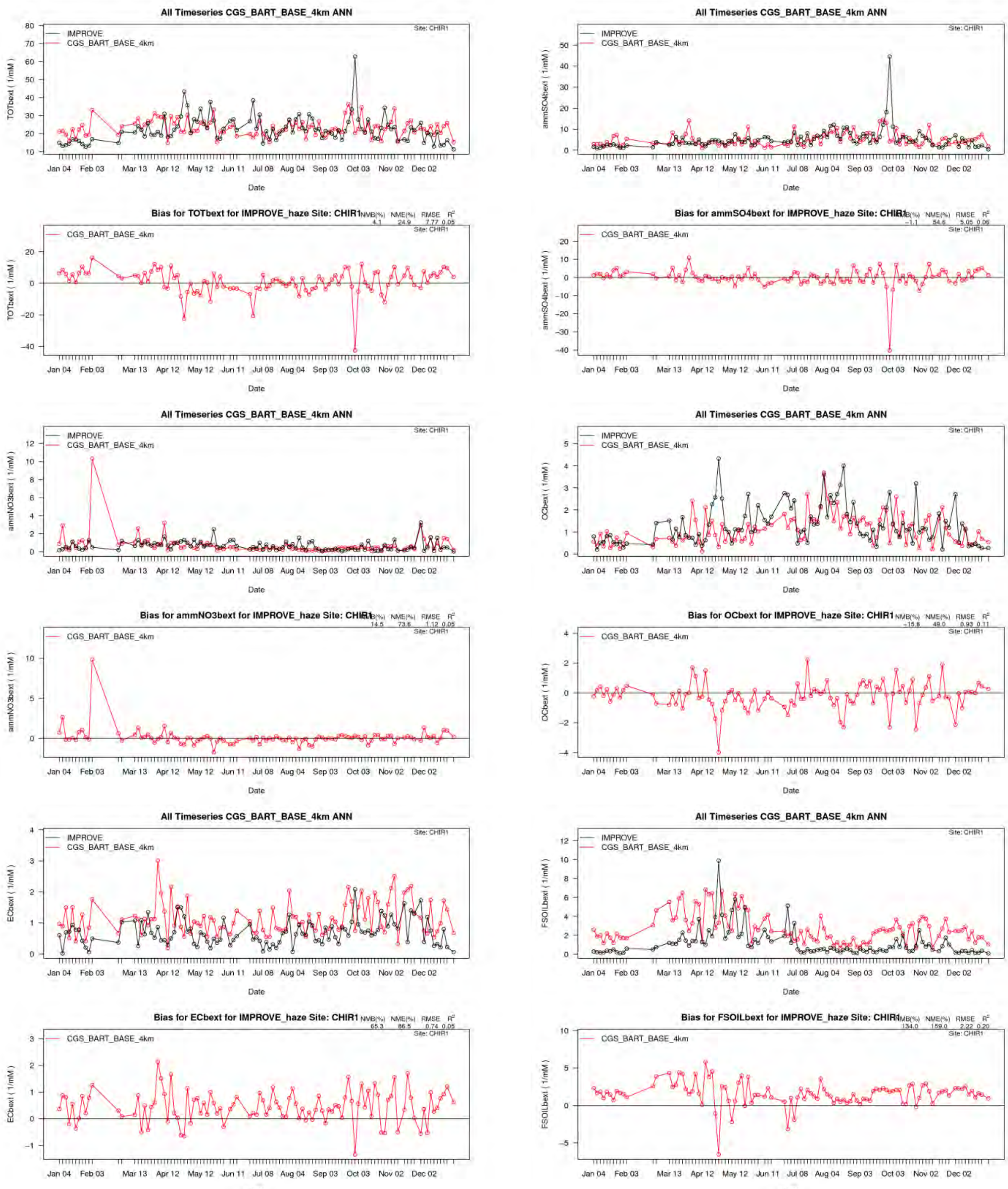


Figure A-8. Predicted and observe 24-hour average visibility extinction (Mm^{-1}) at Chiricahua (CHIR1) IMPROVE sites for total (top left), AmmSO4 (top right), AmmNO3 (middle left), OA (middle right), EC (bottom left) and SOIL (bottom right).

A.4.3.2 Saguro (SAGU1)

The total visibility extinction performance at SAGU1 was quite good with bias (9%) and error (24%) that achieves the most stringent ozone Performance Goal (Table A-3). The time series of predicted and observed total extinction at SAGU confirms the performance statistics that the model is unbiased (Figure A-9, top left). Although there are some modeled daily spikes not reflected in the observations, the AmmSO4 extinction performance at SAGU also exhibits very low bias (5% and 2%) but some scatter so the error just barely exceeds the PM Performance Goal (57% and 56%) (Table A-5a and Figure A-9, top right). The observed AmmNO3 at SAGU is generally quite low, with the exception of a large AmmNO3 spike in December (Figure A-9, middle left) . The modeled AmmNO3 at SAGU is also low, and in fact is lower than observed resulting in a large underestimate bias of -57% and -70% (Table A-5a). With the exception of the observed December AmmNO3 extinction spikes, the observations and model agree that visibility impairment due to AmmNO3 at SAGU is small and a negligible part of the extinction budget. The model is also unbiased for extinction due to OA with near zero bias (5% and 1%) and error that just barely exceeds the PM Performance Goal (54-55%) (Table A-5a). This is reflected in the OA extinction time series plots that shows lots of variation in the predicted and observed values, but no systematic bias (Figure A-9, middle right). The usual modeled OA underestimation bias is not seen at SAGU1. As seen at CHIR1, extinction due to EC is overestimated by the model resulting in bias (68% and 49%) and error (83% and 63%) that achieves or barely does not achieve the PM Performance Criteria. Soil extinction is overestimated by the model at SAGU1. Good performance is seem for extinction due to coarse mass at SAGU1 with low bias (0% and 10%) and error (41% and 4%) that achieves the PM Performance Goal (Table A-5b).

A.4.3.3 Sierra Ancha (SIAN1)

The SIAN1 total extinction achieves the PM Performance Goal with low bias (7%b and 5%; Table A-3. The AmmSO4 extinction performance is also good and achieves the PM Performance Goals (Figure A-10, top). Extinction due to AmmNO3 at SIAN has an underestimation bias of approximately -40% but achieves the PM Performance Criteria. The OA extinction performance exhibits a fairly consistent underestimation bias except during modeled daily spikes in March and in the fall. This unusual distribution results in very different bias values using the NME (-5%) and FB (-38%) that still achieve the PM Performance Criteria. The model and observed have fairly good agreement for EC extinction except for a few high modeled days that results in an overestimation bias (52% and 14%). As seen at other sites, Soil extinction is overestimated and extinction due to coarse mass is underestimated but achieves the PM Performance Criteria with some metrics also achieving the PM Performance Goal.

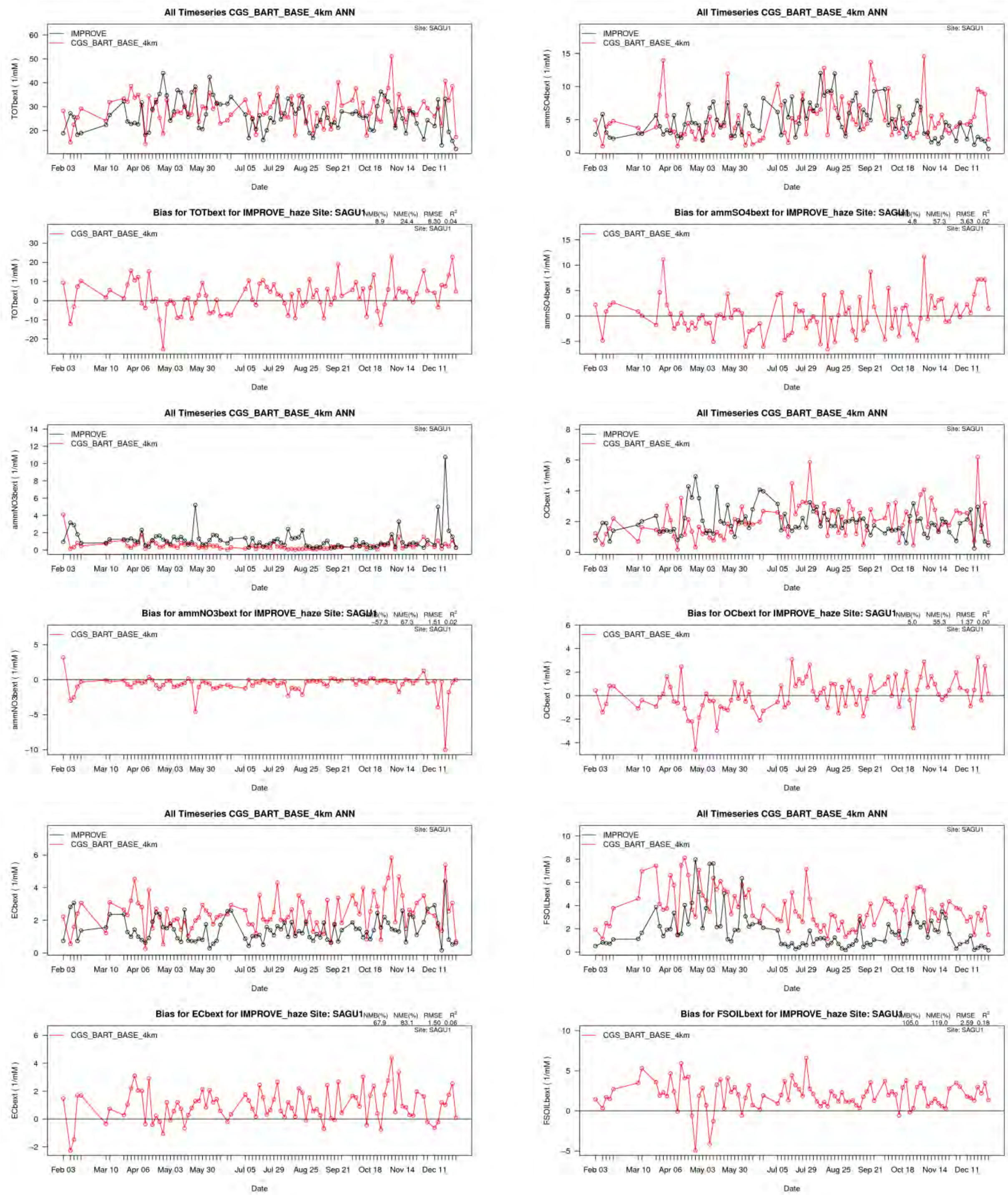


Figure A-9. Predicted and observe 24-hour average visibility extinction (Mm^{-1}) at Saguro (SAGU1) IMPROVE sites for total (top left), AmmSO4 (top right), AmmNO3 (middle left), OA (middle right), EC (bottom left) and SOIL (bottom right).

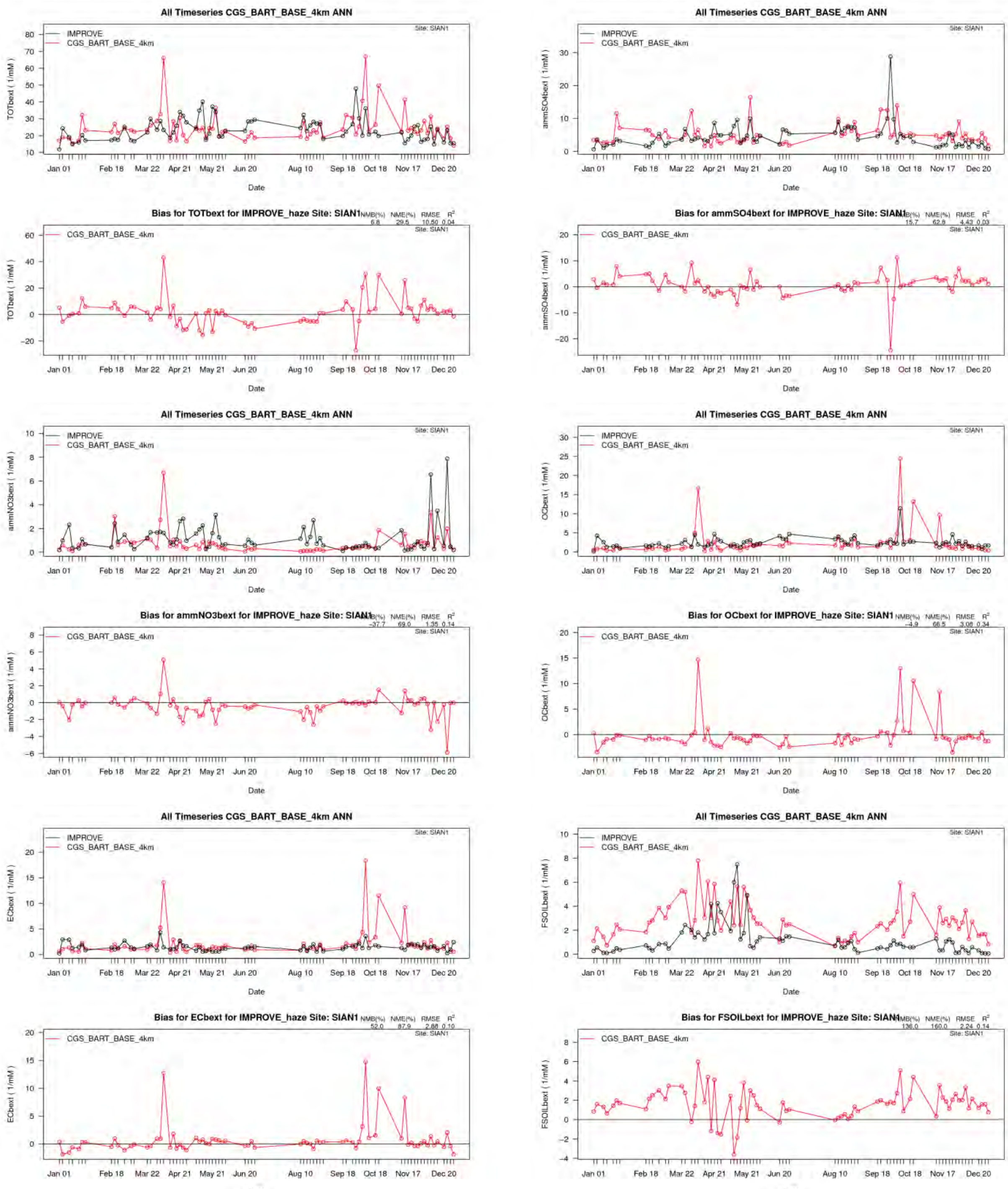


Figure A-10. Predicted and observe 24-hour average visibility extinction (Mm^{-1}) at Sierra Ancha (SIAN1) IMPROVE sites for total (top left), AmmSO4 (top right), AmmNO3 (middle left), OA (middle right), EC (bottom left) and SOIL (bottom right).

A.4.3.4 Petrified Forest (PEFO1)

The total extinction time series comparison at PEFO1 displays an overestimation bias in Q1, underestimation bias in Q2 with excellent performance in Q3 and Q4 (Figure A-11, top left) resulting in very good model performance statistics with low bias (5% and 7%) and error (28% and 26%) (Table A-3) that even achieves the most stringent ozone Performance Goals. The AmmSO4 extinction overestimation in Q1 results in positive bias (18%) that achieves the PM Performance Goal and error that is right at the PM Performance Goal (61% and 56%). The AmmNO3 extinction performance at PEFO is fairly typical with the model underestimating the summer low observed values but overestimating the winter high observed values resulting in a range of bias whether NMB (4%) or FB (-28%) is used that achieve the PM Performance Goal and errors that are right at the PM Performance Criteria. OA extinction is underestimated in Q2 and Q3 resulting in a bias that is right at the -30% PM Performance Goal and error that achieves the PM Performance Goal. The EC extinction performance at PEFO1 is the best of any IMPROVE site with near zero bias (2%) and low error (33%) that achieves the most stringent ozone Performance Goal. Soil extinction is underestimated except during Q2, which is when Asian soil transport occurs so may be influencing the results. Overall extinction due to coarse mass is underestimated (-24% and -3%) but achieves the PM Performance Goal with the error (73% and 76%) right at the PM Performance Criteria.

A.4.3.5 Sycamore Canyon (SYCA1)

With the exception of a large modeled visibility spike in January (Figure A-12, top left), the total extinction performance at SYCA1 is quite good with zero bias and error at the ozone Performance Goal (Table A-3). The AmmSO4 extinction performance is reasonably good with an annual overestimation tendency of ~30% and error approaching but achieving the PM Performance Criteria (Table A-5a and Figure A-12). The AmmNO3 extinction performance is characterized by predicted and observed daily spikes in the winter that are often out of phase with each other and low values in the summer resulting in error that exceeds the PM Performance Criteria and mixed signals on the bias from the NMB (+19%) and FB (-16%) that achieves the PM Performance Goal. With the exception of a large predicted spike in January, and smaller spikes in December, the model matches the observed OA extinction quite well resulting in bias that achieves the PM Performance Goal and error that falls between the Goal and Criteria. A large modeled spike in January is also seen in the EC extinction suggesting that it is due to fires, although the occurrence of such fires in January is not very typical. Soil extinction is overestimated and coarse mass extinction is underestimated at SYCA1.

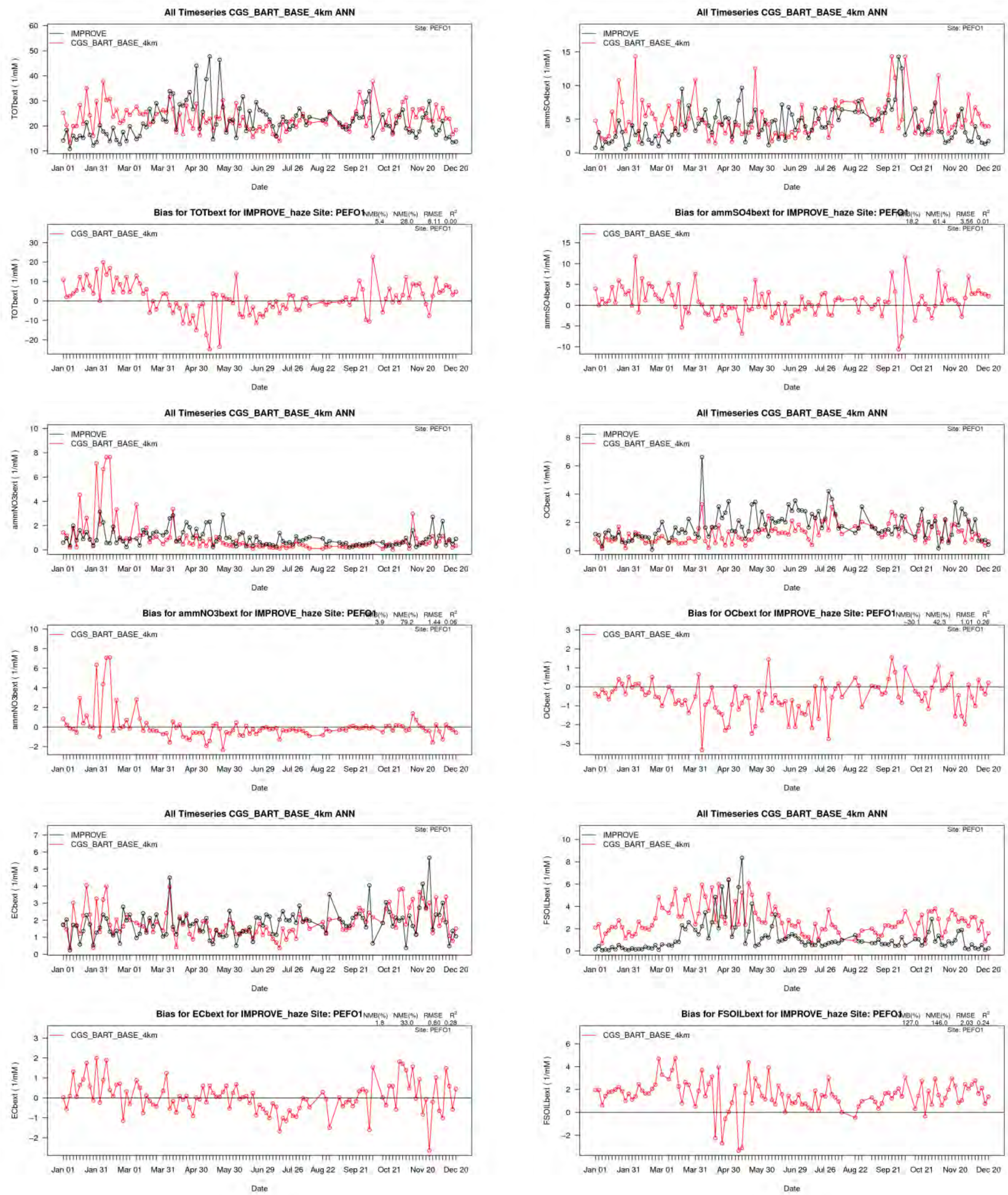


Figure A-11. Predicted and observe 24-hour average visibility extinction (Mm^{-1}) at Petrified Forest (PEFO1) IMPROVE sites for total (top left), AmmSO4 (top right), AmmNO3 (middle left), OA (middle right), EC (bottom left) and SOIL (bottom right).

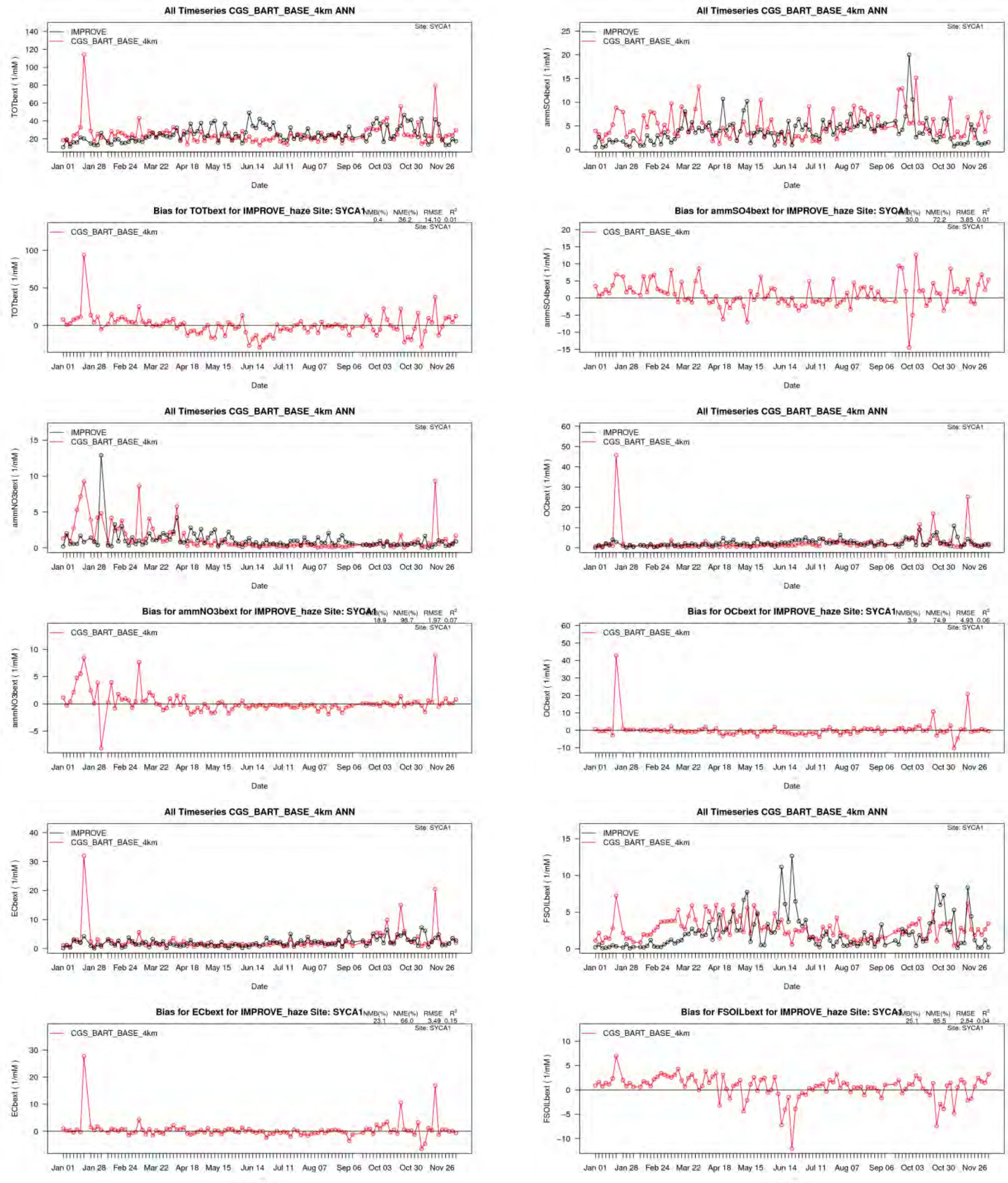


Figure A-12. Predicted and observe 24-hour average visibility extinction (Mm^{-1}) at Sycamore Canyon (SYCA1) IMPROVE sites for total (top left), AmmSO4 (top right), AmmNO3 (middle left), OA (middle right), EC (bottom left) and SOIL (bottom right).

A.4.3.6 Grand Canyon (GRCA1)

The annual total extinction performance at GRCA1 achieves the PM Performance Goal but with a 20% overestimation bias (Table A-5a). This annual extinction overestimation is due to overestimations during Q1 (72%) and Q4 (59%) with the performance during Q2 (-1%) and Q3 (15%) being quite good. The GRCA1 Q1 and Q4 total extinction overestimation is from too high extinction due to AmmSO4, AmmNO3 and Soil, as well as EC to a lesser extent (Figure A-13). The AmmSO4 extinction annual performance statistics fall between the PM Performance Goal and Criteria. The extinction due to AmmNO3 performs quite well at GRCA1 with the winter high values and summer low values replicated well resulting in low bias (13% and -4%) but high error (93% and 73%) due to the highly variable daily AmmNO3 extinction spikes during the colder months.

A.4.3.7 Mesa Verde (MEVE1)

Annual total extinction is overestimated at MEVE1 but achieves the PM Performance Goals (Table A-3). This is due to too high total extinction in Q1 and Q4 and is caused by too high AmmSO4, AmmNO3 and Soil extinction (Figure A-16). Better AmmSO4 and AmmNO3 extinction performance is seen during the warmer months, although extinction due to OA is underestimated during the summer. Except for April, when the Asian dust transport is greatest, extinction due to Soil is overestimated the rest of the year.

A.4.3.7 San Pedro Parks (SAPE1)

Total extinction at SAPE1 achieves the PM Performance Goal but with an overestimation bias of ~20% that again is mainly due to AmSO4 and AmmNO3 and Soil overestimation in Q1 and Q4 (Figure A-15). There is a large daily modeled extinction spike in September that is caused mainly from OA and EC so is clearly a modeled wildfire impact that is not reflected in the observations.

A.4.3.8 Bandelier (BAND1)

BAND1 is close to SAPE1 (Figure A-1) so shares many of its performance characteristics but with a larger overestimation bias (39% and 31%; Table A-3). The modeled daily fire impact in September is even greater at BAND1 than at SAPE1 with modeled total extinction exceeding 100 Mm^{-1}. AmmSO4 and AmmNO3 are overestimated with the modeled AmmNO3 overestimation in Q1 being particularly high (Figure A-16).

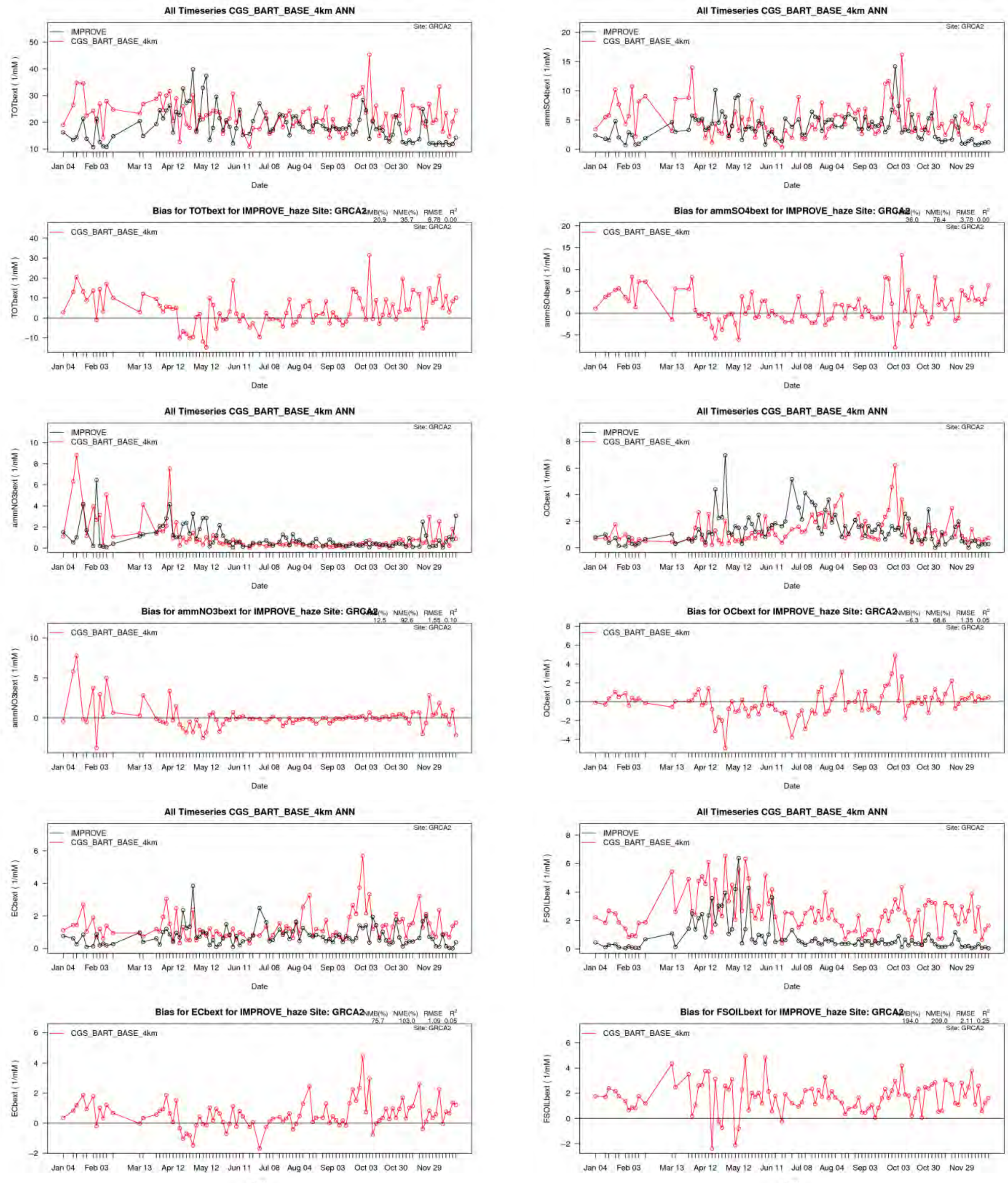


Figure A-13. Predicted and observe 24-hour average visibility extinction (Mm^{-1}) at Grand Canyon (GRCA1) IMPROVE sites for total (top left), AmmSO4 (top right), AmmNO3 (middle left), OA (middle right), EC (bottom left) and SOIL (bottom right).

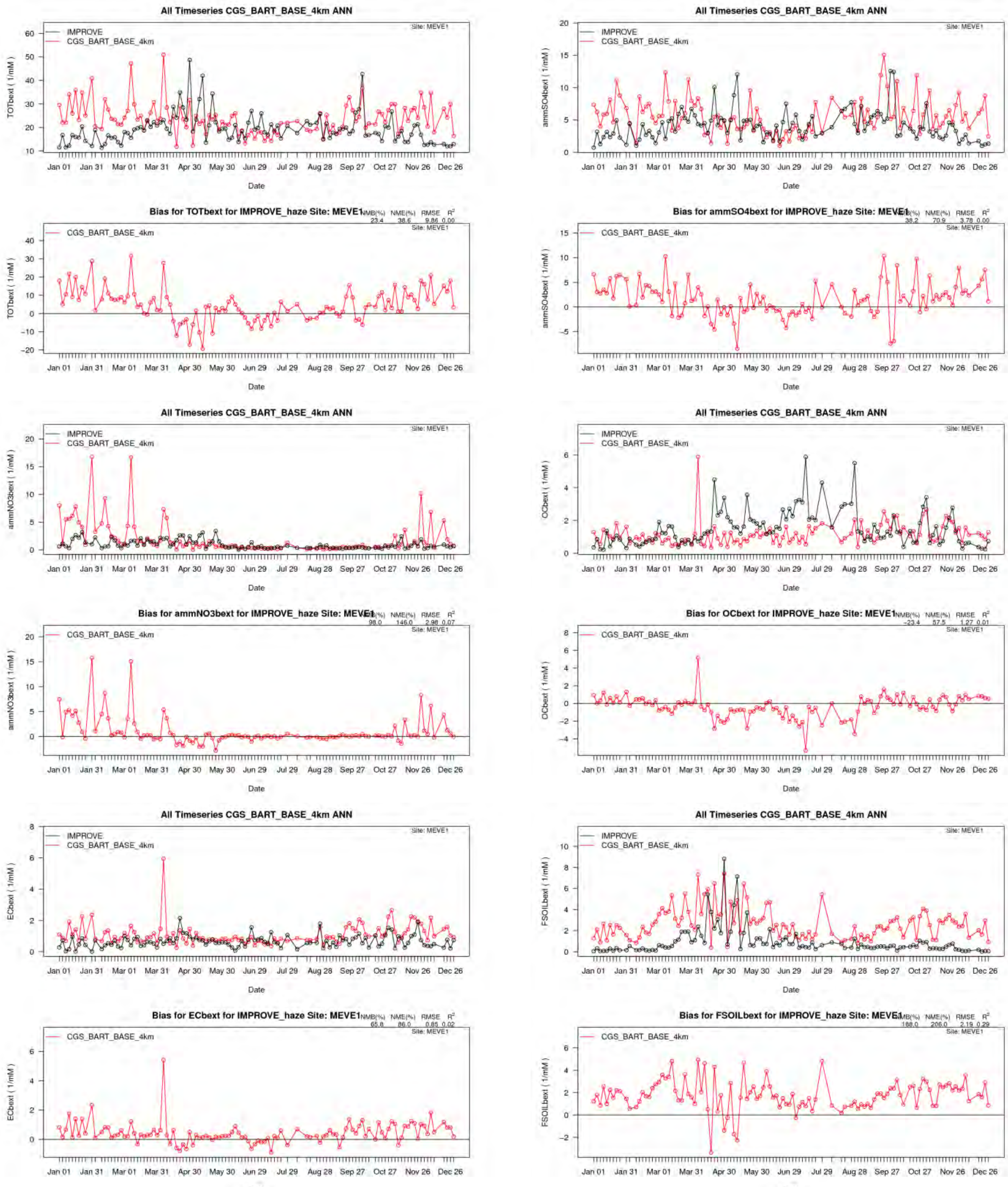


Figure A-14. Predicted and observe 24-hour average visibility extinction (Mm^{-1}) at Mesa Verde (MEVE1) IMPROVE sites for total (top left), AmmSO4 (top right), AmmNO3 (middle left), OA (middle right), EC (bottom left) and SOIL (bottom right).

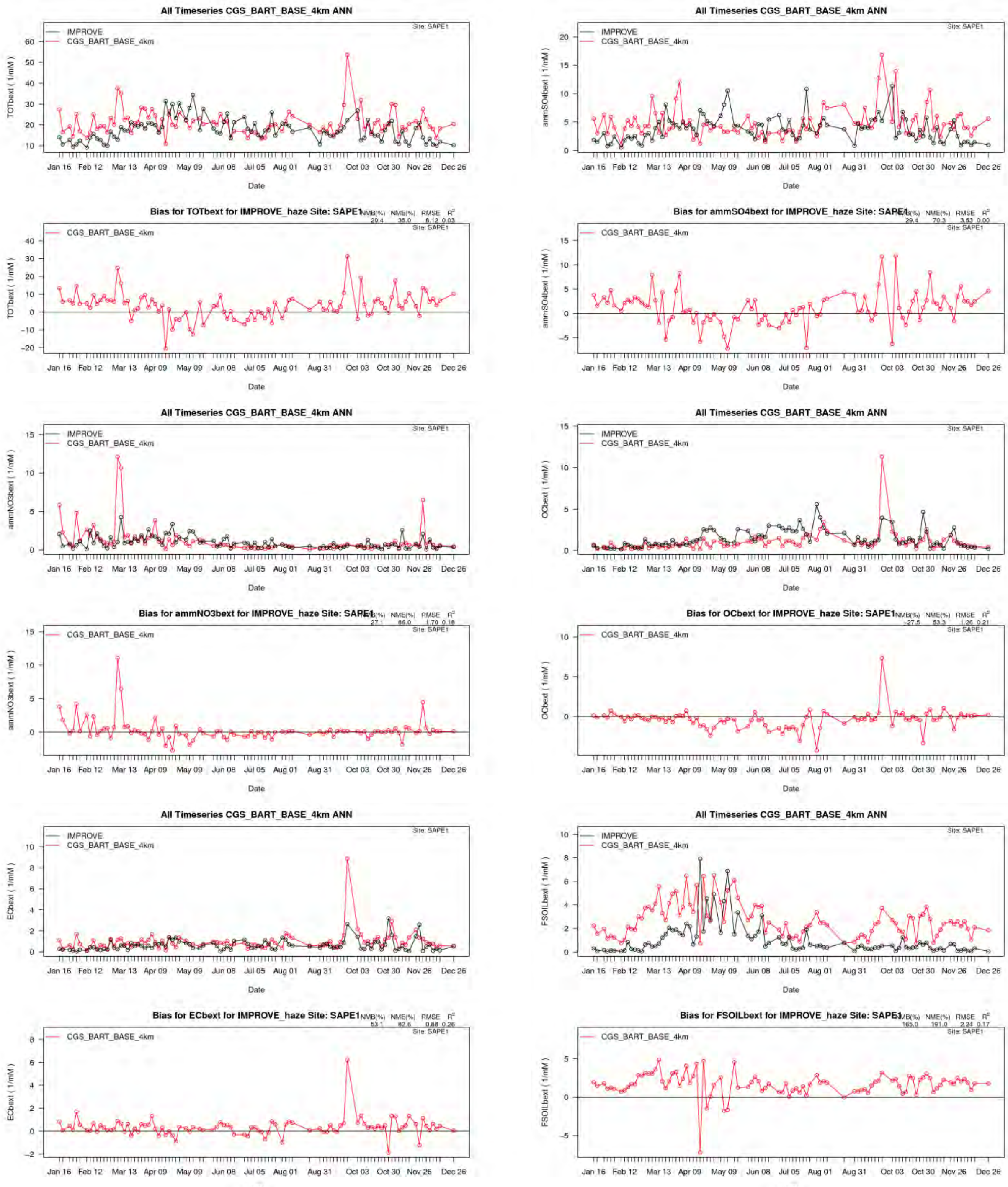


Figure A-15. Predicted and observe 24-hour average visibility extinction (Mm^{-1}) at San Pedro Parks (SAPE1) IMPROVE sites for total (top left), AmmSO4 (top right), AmmNO3 (middle left), OA (middle right), EC (bottom left) and SOIL (bottom right).

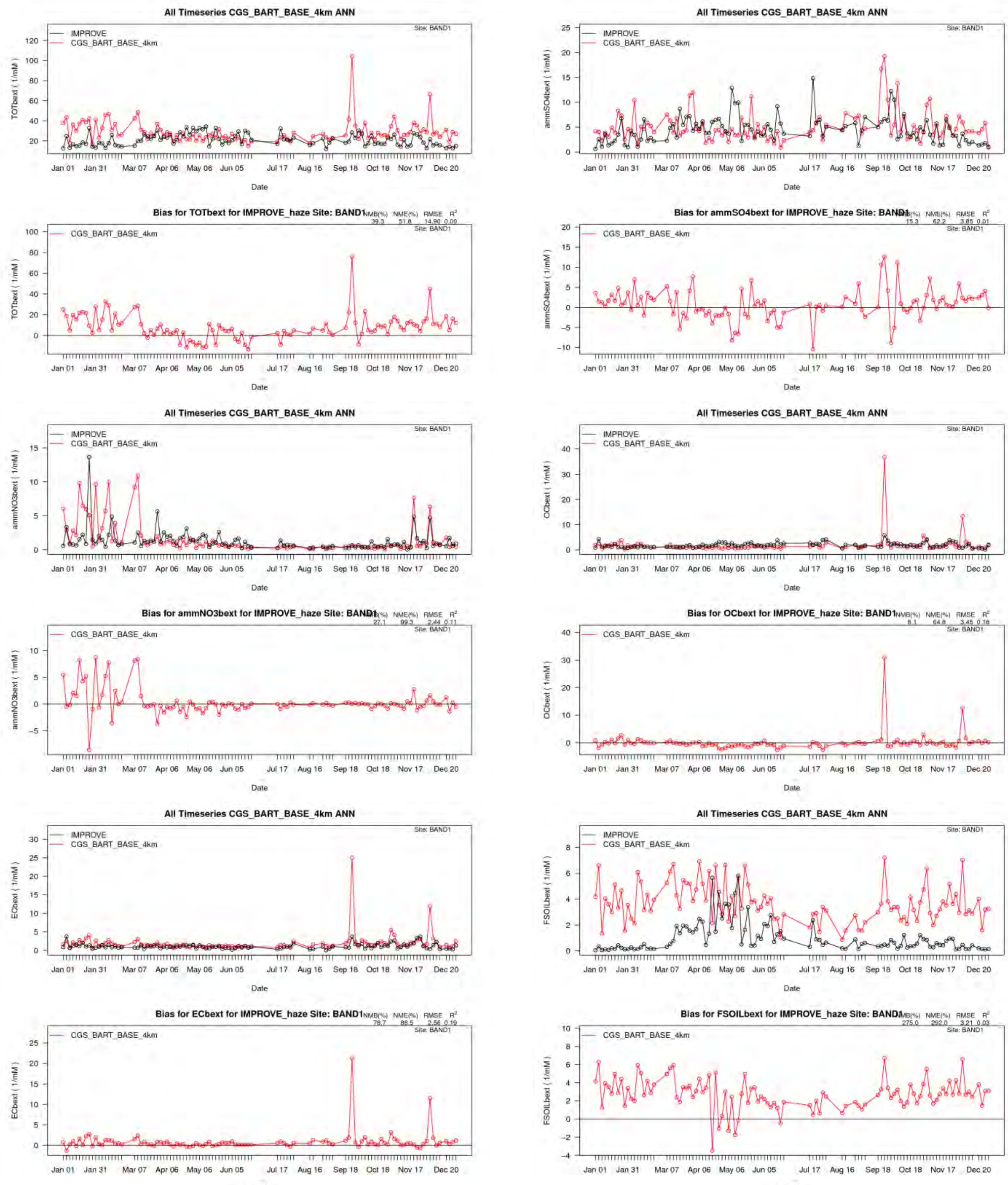


Figure A-16. Predicted and observe 24-hour average visibility extinction (Mm^{-1}) at Bandelier (BAND1) IMPROVE sites for total (top left), AmmSO4 (top right), AmmNO3 (middle left), OA (middle right), EC (bottom left) and SOIL (bottom right).

A.4.4 Visibility Performance Summary

Figure A-17 displays stacked bar charts of annual total extinction at each IMPROVE sites with the stacked bars showing each component. For most sites, the observed and predicted total extinction are similar, although the modeled value tends to be the same or higher than the observed value. Annual AmmSO4 extinction agrees well at all IMPROVE sites. The annual AmmNO3 extinction also agrees well at most sites, although some have an overestimation (e.g., MEVE1) and others an underestimation (e.g., SAGU1). The largest overestimation site is BAND1 whose overestimation is primarily due to overstated extinction due to Soil and coarse mass.

Stacked extinction bar charts by quarter are shown in Figure A-18. This figure clearly shows that the modeled annual extinction overestimation is primarily due to overstated extinction across several species in Q1 and Q4. The model extinction performance in Q2 and Q3 is quite good.

Figure A-19 displays the stacked bar chart performance for extinction averaged across the best 20 percent (B20%) and worst 20 percent (W20%) days at each IMPROVE site. The model overestimates the average observed extinction on the B20% days, with the overestimation bias approximately a factor of 2 at BAND1 (Figure A-19, top). The B20% days extinction overestimation is mainly due to overstated extinction due to AmmSO4, OA, EC, Soil, coarse mass and sometimes AmmNO3.

The model does a better job at reproducing the observed extinction for the W20% days (Figure A-19, bottom). There is a slight underestimation of the extinction due to AmmSO4 and AmmNO3 with larger underestimation of extinction due to coarse mass at some sites (e.g., SYCA1).

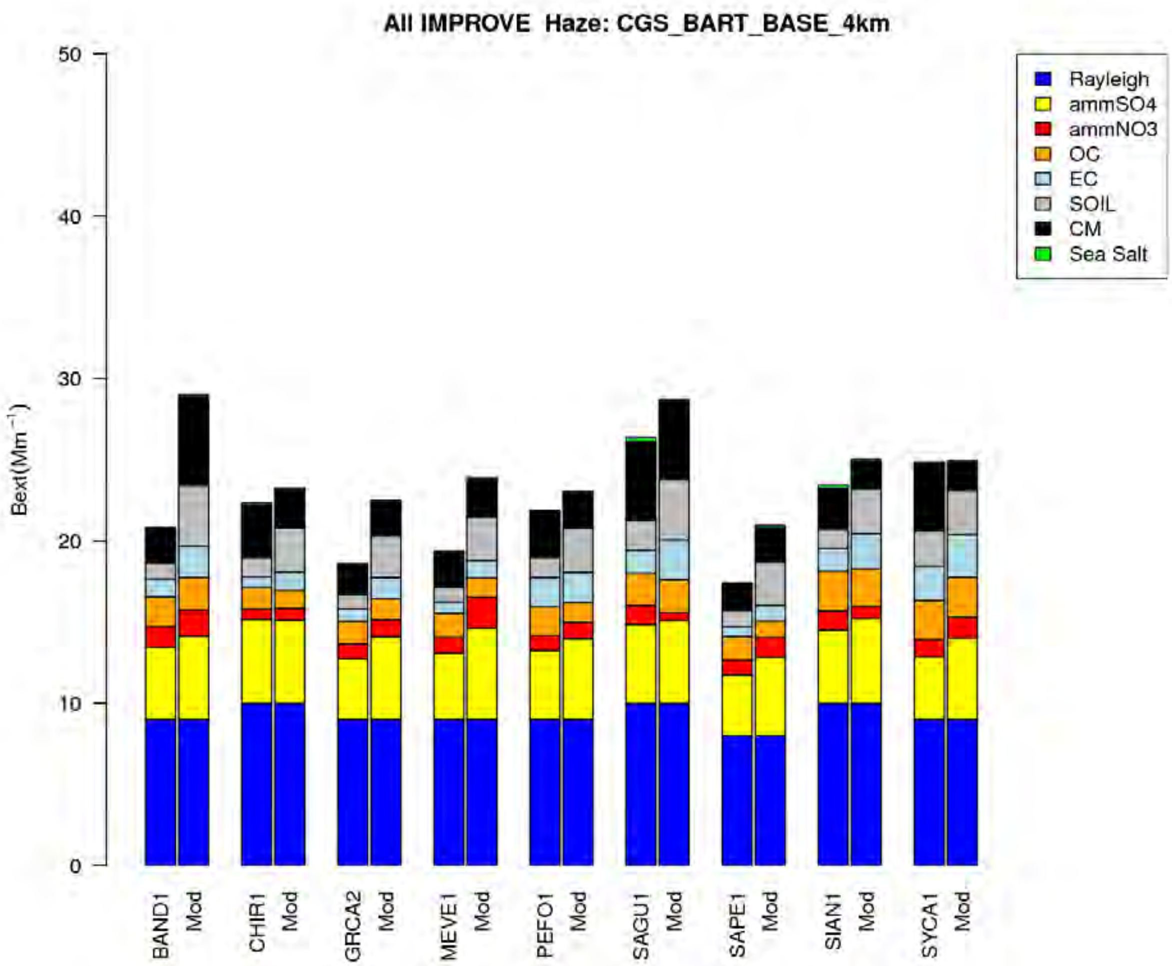


Figure A-17. Predicted and observed annual average total extinction (Mm^{-1}) stacked bar charts.

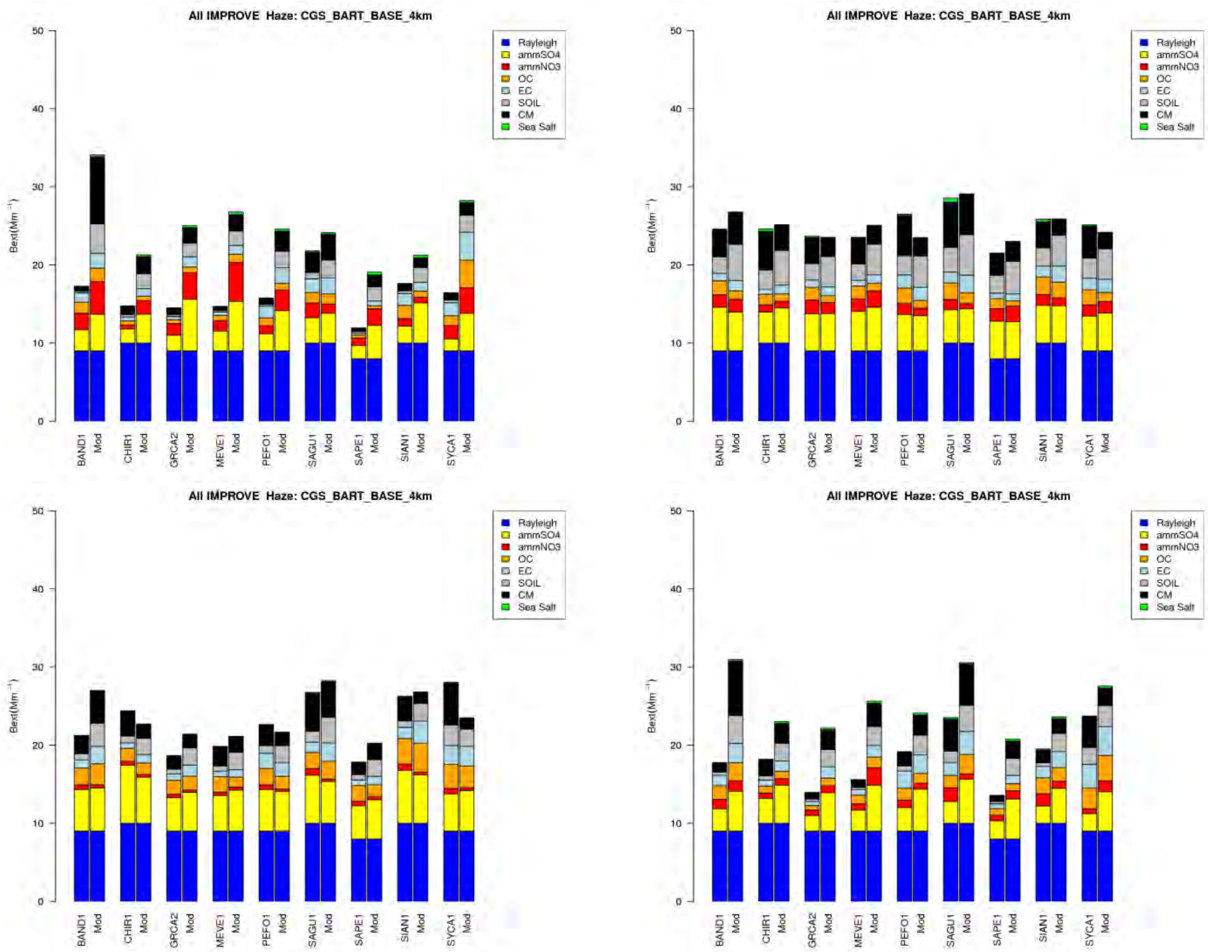


Figure A-18. Predicted and observed seasonal average total extinction (Mm^{-1}) stacked bar charts for Q1 (top left), Q2 (top right), Q3 (bottom left) and Q4 (bottom right)..

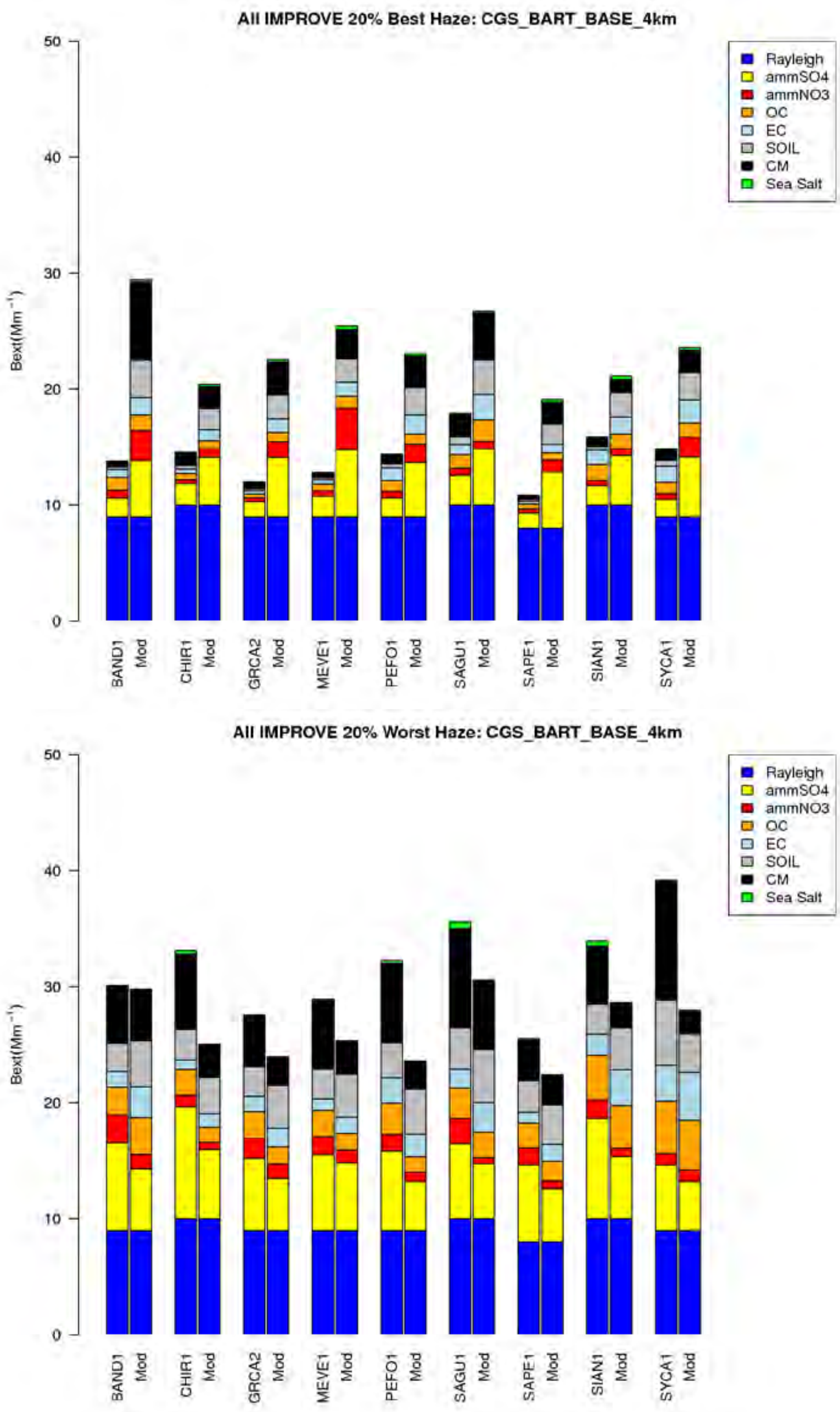


Figure A-19. Predicted and observed extinction for best (top) and worst (bottom) 20 percent days.

A.5 Model Performance Evaluation Conclusions

The CAMx total visibility extinction achieves the PM Performance Goal on an annual basis as well as for 9 of 12 months with the overestimation bias in the winter months being high enough so that it falls between the PM Performance Goals and Criteria. The visibility performance varies geographically, seasonally and by PM species. The visibility performance at IMPROVE sites in the lower two-thirds of the 4 km CGS modeling domain is quite good meeting the most stringent ozone Performance Goals with the visibility performance at IMPROVE sites in the top third of the 4 km domain having an overestimation bias, but still achieves the PM Performance Goals except at the Bandelier (BAND1) IMPROVE whose overestimation bias is due in part to modeled wildfire impacts that are high enough that the PM Performance Criteria is not achieved.

The seasonal visibility model performance shows good performance for the warmer months and an overestimation bias for the cooler months. The monthly visibility model performance achieves the PM Performance Criteria for all months, the PM Performance Goal for 12 months and the ozone Performance Goal for 7 months, the overestimation bias for the three winter months is sufficiently high that the visibility model performance falls between the PM Performance Goal and Criteria.

The ammonium sulfate (AmmSO4) and ammonium nitrate (AmmNO3) visibility performance is fairly good with 9 of 12 months achieving the PM Performance Criteria. AmmSO4 visibility performance also has many months achieving the PM Performance Goal, but the overestimation bias in the three winter months is sufficiently high that the PM Performance Criteria is not achieved. The seasonal variation of the observed AmmNO3 visibility is reproduced well by the model with extremely low values in the warm months and high values in the cooler months with lots of day-to-day variations. The model does not always match the observed day-to-day variations of high and low AmmNO3 events in the cooler months. Visibility performance due to organic aerosol is also fairly good, albeit with a summer underestimation bias. And visibility performance for elemental carbon and soil exhibits an overestimation bias.

The main objective of the CGS Better-than-BART visibility modeling is to evaluate the trade-offs of visibility benefits between reducing CGS's NO_X versus SO_2 emissions. Given that the visibility performance for AmmSO4 and AmmNO3 is fairly good and mostly unbiased with what bias that does occur (slight winter overestimation) being common among AmmSO4 and AmmNO3 and the fact that CAMx incorporates state-of-science sulfate and nitrate formation chemistry algorithms, then the CAMx 2008 12/4 km CGS modeling platform should provide an accurate and reliable database for evaluating the alternative BART modeling scenarios.

Appendix C – BTB Alternatives: Emissions Assessment

C. BTB Alternatives: Emissions Assessment

This appendix presents estimated emissions under uncontrolled and various BART and BTB alternative operating scenarios. The purpose of this analysis is to compare emissions that would result under BART with emissions that would result under the BTB alternatives to determine the relative effectiveness of the various emissions reductions and operational curtailments.

C.1 Emissions Evaluation

In February 2008, SRP provided ADEQ with a BART analysis, including a dispersion modeling analysis, for CGS Units 1 and 2. In its 2011 Regional Haze SIP determination, ADEQ, after reviewing the analysis, determined BART for NOx, SO_2, and PM emissions from the CGS units. In 2012, EPA approved ADEQ's SO_2 and PM BART determinations. However, EPA disapproved ADEQ's NOx BART determination, which ADEQ based on installation and operation of overfire air and low NOx burners ("OFA and LNB") on both CGS units and instead determined that SCR represents NOx BART for each of the two units.

SRP herein proposes a set of alternative operating scenarios that meet BTB criteria. These scenarios incorporate operation at a lower SO_2 emissions rate for both units (three scenarios), a NOx emissions rate below the current permit limit for Unit 1 (one scenario), and seasonal curtailment periods for Unit 1 to minimize visibility impacts. This subsection presents the emissions evaluation for each of the various scenarios, including the proposed BTB scenarios, as listed in Table C-1.

Table C-1. Emissions Associated with Alternative Operations

Scenario	Operating Parameters
2007 Baseline	This scenario assumes 2008 submittal operating conditions
2014 Baseline	This scenario reflects 2008 consent decree (CD) controls[1]
2012 ADEQ BART	This scenario is based on the 2012 ADEQ BART determination
2015 EPA BART Reconsideration	This scenario adjusts the NOx limitation to reflect EPA's BART reconsideration
BTB1, BTB2, BTB3, BTB4	These scenarios assume combinations of BTB alternative operating scenarios that include seasonal curtailment periods for Unit 1

Annual NOx, SO_2, and PM emissions were calculated using the operating parameters in Table C-2. For purposes of comparison, all scenarios were assumed to have the same average heat input rate and the same percentage for the annual (non-curtailed) utilization factor. For the BTB scenarios, utilization factors are based on the proposed seasonal curtailment of Unit 1 operations.

[1] Consent Decree, *United States of America v. Salt River Project Agricultural Improvement and Power District*, Civil Action No. 2:08-cv-1479-JAT, August 12, 2008.

Table C-2. Parameters for Emissions Associated with Alternative Operations

Scenario	Unit	Pollutant	Average EF (lb/MMBtu)	Average Heat Input (MMBtu/hr)	Annual Utilization Rate
2007 Baseline	Unit 1	NOx	0.433	3,986	92%
		SO_2	0.610	3,986	92%
		PM*	0.030	3,986	92%
	Unit 2	NOx	0.466	4,018	97%
		SO_2	0.689	4,018	97%
		PM*	0.030	4,018	97%
2014 Baseline	Unit 1	NOx	0.320	3,986	92%
		SO_2	0.080	3,986	92%
		PM	0.030	3,986	92%
	Unit 2	NOx	0.080	4,018	97%
		SO_2	0.080	4,018	97%
		PM	0.030	4,018	97%
2012 ADEQ BART	Unit 1	NOx	0.320	3,986	92%
		SO_2	0.080	3,986	92%
		PM	0.030	3,986	92%
	Unit 2	NOx	0.320	4,018	97%
		SO_2	0.080	4,018	97%
		PM	0.030	4,018	97%
2015 EPA BART Reconsideration (NOx) and 2012 ADEQ BART (PM/SO_2)	Unit 1	NOx	0.065	3,986	92%
		SO_2	0.080	3,986	92%
		PM	0.030	3,986	92%
	Unit 2	NOx	0.080	4,018	97%
		SO_2	0.080	4,018	97%
		PM	0.030	4,018	97%
BTB1 (Unit 1 curtailment period Nov 1 to Feb 29)	Unit 1	NOx	0.320	3,986	62%
		SO_2	0.080	3,986	62%
		PM	0.030	3,986	62%
	Unit 2	NOx	0.080	4,018	97%
		SO_2	0.080	4,018	97%
		PM	0.030	4,018	97%
BTB2 (Unit 1 curtailment period Nov 11 to Dec 31)	Unit 1	NOx	0.320	3,986	79%
		SO_2	0.070	3,986	79%
		PM	0.030	3,986	79%
	Unit 2	NOx	0.080	4,018	97%
		SO_2	0.070	4,018	97%
		PM	0.030	4,018	97%
BTB3 (Unit 1 curtailment period Nov 21 to Dec 31)	Unit 1	NOx	0.320	3,986	82%
		SO_2	0.050	3,986	82%
		PM	0.030	3,986	82%
	Unit 2	NOx	0.080	4,018	97%
		SO_2	0.050	4,018	97%
		PM	0.030	4,018	97%
BTB4 (Unit 1 curtailment period Nov 21 to Dec 31)	Unit 1	NOx	0.310	3,986	82%
		SO_2	0.060	3,986	82%
		PM	0.030	3,986	82%
	Unit 2	NOx	0.080	4,018	97%
		SO_2	0.060	4,018	97%
		PM	0.030	4,018	97%

**Although 2007 PM rates are calculated using the CD limits, the CD limits became applicable after the installation of flue gas desulfurization systems.*

Average daily heat inputs for CGS Units 1 and 2 were derived from the Clean Air Market Division ("CAMD") heat input data for the period of 2008 to 2010, for operational hours on daily basis.[2] This data set was also used to calculate the annual utilization rate using the hours of operation for each unit and the total number of hours in the period.

The 2007 baseline emission factors for NOx and SO_2 are from ADEQ's 2011 submittal to EPA.[3] PM emission factors and the 2014 baseline emission factors are from the 2008 CD.[4] The 2015 EPA BART reconsideration scenario reflects BART limitations (including proposed NOx limits) for the two units.[5] BTB emission factors are based on the proposed emission rates used in the modeling described in section 3.0 of the application.

C.1.1 Baseline Annual Emissions

Baseline annual emissions for CGS Units 1 and 2, representing 2007 and 2014 emissions rates of NOx, SO_2 and PM, are presented below. The baseline emissions are calculated using the average daily heat input rates and annual utilization for the two units using subbituminous coal calculated from the CAMD data for the period of 2008 to 2010.[6]

C.1.1.1 2007 Baseline Annual Emissions

The 2007 baseline emissions estimates are based on the emissions control systems that were in place at CGS Units 1 and 2 as of that year, as noted in the ADEQ BART submittal, and the operating parameters listed in Table C-2. Emissions factors used here reflect use of hot-side electrostatic precipitators (ESP) and partial wet flue gas desulfurization (FGD).[7]

Table C-3. Estimated 2007 Baseline Emissions for CGS Units 1 and 2

Scenario	Unit	Pollutant	Emissions (tons/year)
2007 Baseline Emissions	Unit 1	NOx	6,955
		SO_2	9,798
		PM	482
	Unit 2	NOx	7,955
		SO_2	11,762
		PM	512
	Combined	NOx	14,910
		SO_2	21,560
		PM	994

[2] Data available at the Clean Air Market Divisions Website: http://ampd.epa.gov/ampd.
[3] "Submittal of Arizona Regional Haze State Implementation Plan Under Section 308 of the Federal Regional Haze Rule," letter with enclosures from Henry Darwin, Director, ADEQ, to Jared Blumenfeld, Regional Administrator, EPA Region 9, February 28, 2011.
[4] Consent Decree, Civil Action No. 2:08-cv-1479-JAT.
[5] 80 Fed. Reg. 17010, March 31, 2015.
[6] Data available at the Clean Air Market Divisions Website: http://ampd.epa.gov/ampd.
[7] "Submittal of Arizona Regional Haze State Implementation Plan Under Section 308 of the Federal Regional Haze Rule," letter with enclosures from Henry Darwin, Director, ADEQ, to Jared Blumenfeld, Regional Administrator, EPA Region 9, February 28, 2011.

C.1.1.2 2014 Baseline Annual Emissions

In 2008, SRP entered into a CD with EPA to settle alleged Clean Air Act violations at CGS. The CD required SRP to invest in improved emissions controls for both CGS units. Emission factors used here reflect:

(a) New wet FGD on both units;
(b) LNB and OFA on both units; and
(c) SCR on Unit 2.[8]

Baseline emissions for 2014 are presented in Table C-4 based on the operating parameters listed in Table C-2.

Table C-4. Estimated 2014 Baseline Emissions for CGS Units 1 and 2

Scenario	Unit	Pollutant	Emissions (tons/year)
2014 Baseline Emissions	Unit 1	NOx	5,140
		SO_2	1,285
		PM	482
	Unit 2	NOx	1,366
		SO_2	1,366
		PM	512
	Combined	NOx	6,506
		SO_2	2,651
		PM	994

C.1.2 BART Controlled Emissions

BART-level controlled emissions are presented in this subsection. This includes the 2012 ADEQ BART determinations for NOx, SO_2 and PM emissions and EPA's 2015 BART reconsideration determination for NOx for the CGS units. The BART controlled emissions are calculated using the same average heat input rates and annual utilization for the two units as the baseline operation.

C.1.2.1 2012 ADEQ BART Controlled Annual Emissions

ADEQ determined that use of LNB and OFA was BART for NOx, wet FGD was BART for SO_2, and hot-side ESP was BART for PM for the CGS units. ADEQ also concluded that use of SCR for the CGS units would not be cost effective. The ADEQ-determined BART emission rates are used here to calculate the 2012 ADEQ BART emissions presented in Table C-5.

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[8] *United States v. Salt River Project Agricultural Improvement and Power District*, Civil Action No. 2:08-cv-1479-JAT (D. Ariz.), August 12, 2008.

Table C-5. 2012 ADEQ BART Emissions for CGS Units 1 and 2

Scenario	Unit	Pollutant	Emissions (tons/year)
2012 ADEQ BART Emissions	Unit 1	NOx	5,140
		SO_2	1,285
		PM	482
	Unit 2	NOx	5,463
		SO_2	1,366
		PM	512
	Combined	NOx	10,603
		SO_2	2,651
		PM	994

C.1.2.2 EPA BART Controlled Annual Emissions

EPA issued a NOx BART FIP for the CGS units in 2012. At the same time, EPA approved the PM and SO_2 BART SIP rates finalized by ADEQ. EPA determined that use of SCR was cost-effective for the CGS units for NOx emission control. In response to a petition from SRP, in 2015, EPA issued a proposed reconsideration of the 2012 BART determination for NOx and proposed to revise the NOx emission limits for both units. Table C-6 presents the annual emissions calculated using the 2012 PM and SO_2 approved BART SIP emission rates and EPA's 2015 proposed NOx BART emissions rates.

Table C-6. 2012/2015 EPA BART Emissions for CGS Units 1 and 2

Scenario	Unit	Pollutant	Emissions (tons/year)
2015 EPA BART Reconsideration (NOx) and ADEQ BART (SO_2 and PM)	Unit 1	NOx	1,044
		SO_2	1,285
		PM	482
	Unit 2	NOx	1,366
		SO_2	1,366
		PM	512
	Combined	NOx	2,410
		SO_2	2,651
		PM	994

C.1.2.3 CGS Alternative Controlled Emissions

This subsection presents SRP's BTB alternative operating scenarios and estimated annual emissions. These values are presented here for comparison purposes.

SRP is proposing four BTB alternative control options for the CGS units. SRP's proposed BART alternative options for the CGS units are based on operation at lower SO_2 emissions rates for both units (three scenarios), a NOx emissions rate below the current permit limit for Unit 1 (one scenario), and seasonal curtailment periods for Unit 1. The four alternatives are presented in Table C-7.

Table C-7. BTB Alternative Operating Scenarios

Scenario	Unit 1 (lb/MMBtu)		Unit 2 SO_2 (lb/MMBtu)	Additional Operating Requirement
	NOx	SO_2		
BTB1	0.320	0.080	0.080	Nov 1-Feb 29
BTB2	0.320	0.070	0.070	Nov 11-Dec 31
BTB3	0.320	0.050	0.050	Nov 21-Dec 31
BTB4	0.310	0.060	0.060	Nov 21-Dec 31

The unit- and pollutant-specific BTB alternative operating scenario annual emission rates are provided in Table C-8, using the emission factors from Table C-7. These emission factors were also used for purposes of the modeling scenarios described in Appendix B. The BTB alternative operating scenario emissions are calculated using the same average heat input rates and annual utilization for the two units as the baseline operation. For Unit 1, the number of days in the seasonal curtailment period was divided by the total number of days in a year to calculate the percent downtime within the calendar year. Future utilization was calculated by multiplying the past annual utilization by the percent uptime for the unit, as listed in Table C-2.

Table C-8. BTB Emissions for CGS Units 1 and 2

Scenario	Unit	Pollutant	Emissions (tons/year)
BTB1, (Unit 1 curtailment period Nov 1 to Feb 29)	Unit 1	NOx	3,464
		SO_2	866
		PM	325
	Unit 2	NOx	1,366
		SO_2	1,366
		PM	512
	Combined	NOx	4,829
		SO_2	2,232
		PM	837
BTB2, (Unit 1 curtailment period Nov 11 to Dec 31)	Unit 1	NOx	4,414
		SO_2	965
		PM	414
	Unit 2	NOx	1,366
		SO_2	1,195
		PM	512
	Combined	NOx	5,779
		SO_2	2,160
		PM	926
BTB3, (Unit 1 curtailment period Nov 21 to Dec 31)	Unit 1	NOx	4,581
		SO_2	716
		PM	429
	Unit 2	NOx	1,366
		SO_2	854
		PM	512
	Combined	NOx	5,947
		SO_2	1,569
		PM	942
BTB4, (Unit 1 curtailment period Nov 21 to Dec 31)	Unit 1	NOx	4,438
		SO_2	859
		PM	429
	Unit 2	NOx	1,366
		SO_2	1,024
		PM	512
	Combined	NOx	5,804
		SO_2	1,883
		PM	942

C.1.3 Annual Emissions Comparison

Annual emissions under the different operating scenarios listed in Table C-7 are compared in this subsection to understand how emissions changed between the 2007 and 2014 modeling scenarios and to evaluate the emissions reductions due to the alternative controls scenarios. Table C-9 presents a comparison of the total emissions for each pollutant for each of the scenarios for the CGS units.

Table C-9. Controlled Combined Annual Emissions (TPY)

Operating Scenarios	NOx	SO_2	PM
2007 Baseline	14,910	21,560	994
2014 Baseline	6,506	2,651	994
2012 ADEQ BART	10,603	2,651	994
2015 EPA BART Reconsideration (NOx) and 2012 ADEQ BART (SO_2 and PM)	2,410	2,651	994
BTB1	4,829	2,232	837
BTB2	5,779	2,160	926
BTB3	5,947	1,569	942
BTB4	5,804	1,883	942

Table C-10 presents a comparison of controlled emissions for the CGS units with the 2014 and 2007 baseline emissions.

Table C-10. Controlled Annual Emissions Comparison with Baseline

Scenario Comparison	NOx (TPY)	SO_2 (TPY)	PM (TPY)
2014 Baseline to 2007 Baseline	-8,404	-18,909	0
2012 ADEQ BART to 2007 Baseline	-4,307	-18,909	0
2015 EPA BART Reconsideration (NOx)/2012 ADEQ BART (PM and SO_2) to 2014 Baseline	-4,096	0	0
BTB1 to 2014 Baseline	-1676	-419	-157
BTB2 to 2014 Baseline	-726	-490	-68
BTB3 to 2014 Baseline	-559	-1081	-52
BTB4 to 2014 Baseline	-702	-767	-52

The 2014 baseline case to 2007 baseline case resulted in 56% NOx reductions and 88% SO_2 reductions due to CD controls implemented in the 2009-2014 period. As previously explained, the following controls were installed under the CD:

(a) Wet scrubbers on both CGS units (2011/2012);
(b) LNB and OFA on both units (2009/2011); and
(c) SCR on Unit 2 (2014).

Table C-11 compares the emissions reductions for the BTB scenarios and EPA's BART determination with the same 2014 baseline. For comparison purposes, a common 2014 baseline was used in this review. The BTB alternative operating scenarios involve seasonal curtailment periods for Unit 1, which result in substantial concomitant reductions in SO_2 and PM emissions.

Table C-11. Comparison of Reductions Associated with EPA's BART Determination and BTB Alternative Operating Scenarios with 2014 Baseline for CGS Units

Scenario Comparison	NOx	SO_2	PM
2015 EPA BART Reconsideration (NOx)/2012 ADEQ BART (PM and SO_2) to 2014 Baseline	63%	0%	0%
BTB1 to 2014 Baseline	26%	16%	16%
BTB2 to 2014 Baseline	11%	18%	7%
BTB3 to 2014 Baseline	9%	41%	5%
BTB4 to 2014 Baseline	11%	29%	5%

Although the NOx reductions from the BTB alternative operating scenarios would be less than the 63% reduction under EPA's BART Reconsideration, each of these scenarios would produce significant SO_2 and PM emissions reductions. SO_2 emissions reductions from the CGS units would range from 16% to 41%, and PM emissions reductions would range from 5% to 16%. This is because, under the BTB alternatives, SRP would reduce SO_2 emissions from both of the CGS units through (1) annual operation at a lower emissions rate and/or (2) seasonal curtailment of CGS Unit 1. In addition, under the BTB scenarios, SRP would reduce PM emissions from both units through seasonal curtailment of CGS Unit 1.

For the seasonal curtailment periods for Unit 1, SRP proposes periods ranging from 40 days to 120 days to minimize visibility impacts based on the modeling demonstration included in Appendix B.

As these data show, SRP's BTB alternatives provide significant reductions in emissions of NOx, SO_2, and PM as compared to the 2014 baseline. Furthermore, the reductions in NOx and SO_2 emissions under the BTB alternatives would be surplus to the emission reductions resulting from measures adopted to meet the requirements of the Clean Air Act, as of the baseline date of the SIP.

C.2 Visibility Evaluation

The BTB alternative operating scenarios proposed by SRP reflect large reductions in emissions from the 2007 baseline and improvements over ADEQ's 2012 BART determination for both CGS units. The relative contribution of NOx, SO_2, and PM emissions reductions to visibility improvement is an important factor for determining whether the BTB alternative operating scenarios are better than EPA's reconsidered BART determination.

In its 2013 Regional Haze SIP revision to address some of the deficiencies identified by EPA, ADEQ presented a revised 2008 emissions inventory for the state.[9] Statewide emissions of NOx and SO_2 calculated by ADEQ are presented inTable C-12.

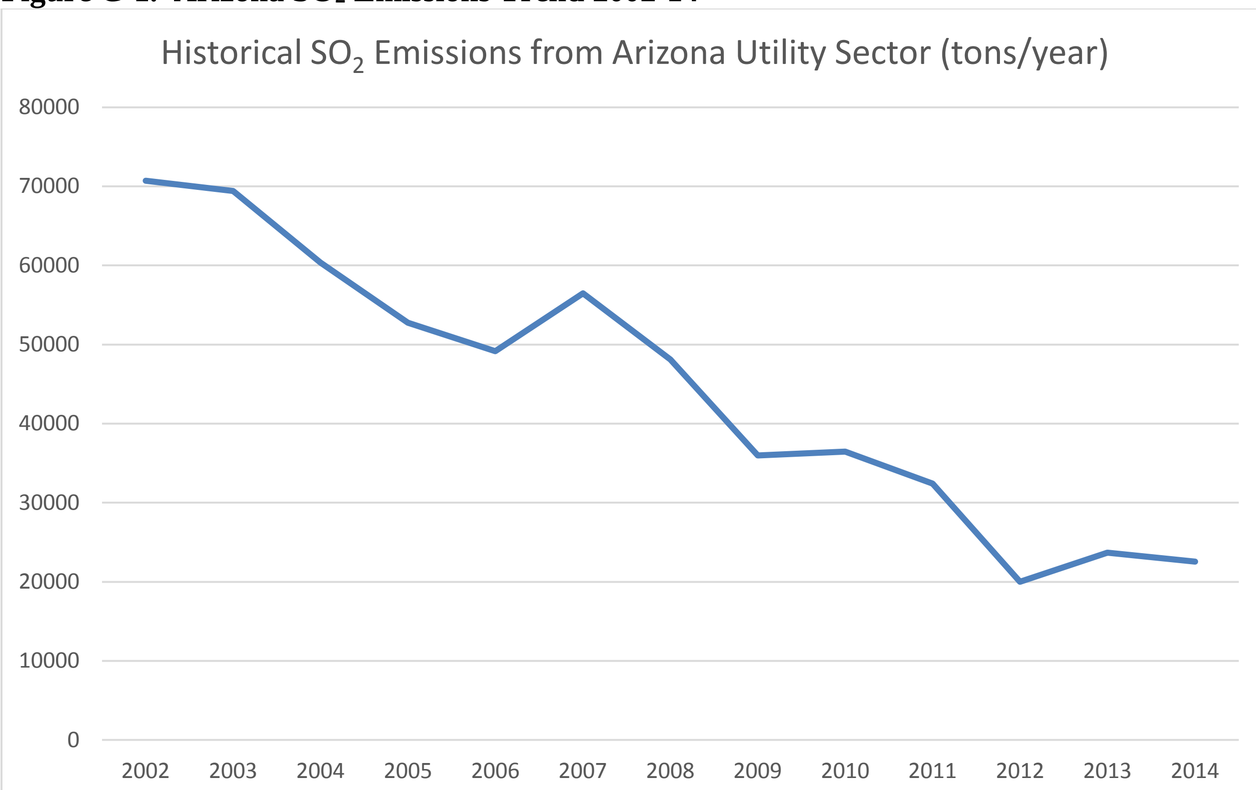
[9] "Arizona State Implementation Plan Revision: Regional Haze Under Section 308 of the Federal Regional Haze Rule," Arizona Department of Environmental Quality (ADEQ), 2013.

Table C-12. Statewide Emissions Inventory for 2008

	NOx	SO_2
Statewide Emissions (tons/year)	290,344	84,784
Point Sources Contribution to Emissions	21%	93%

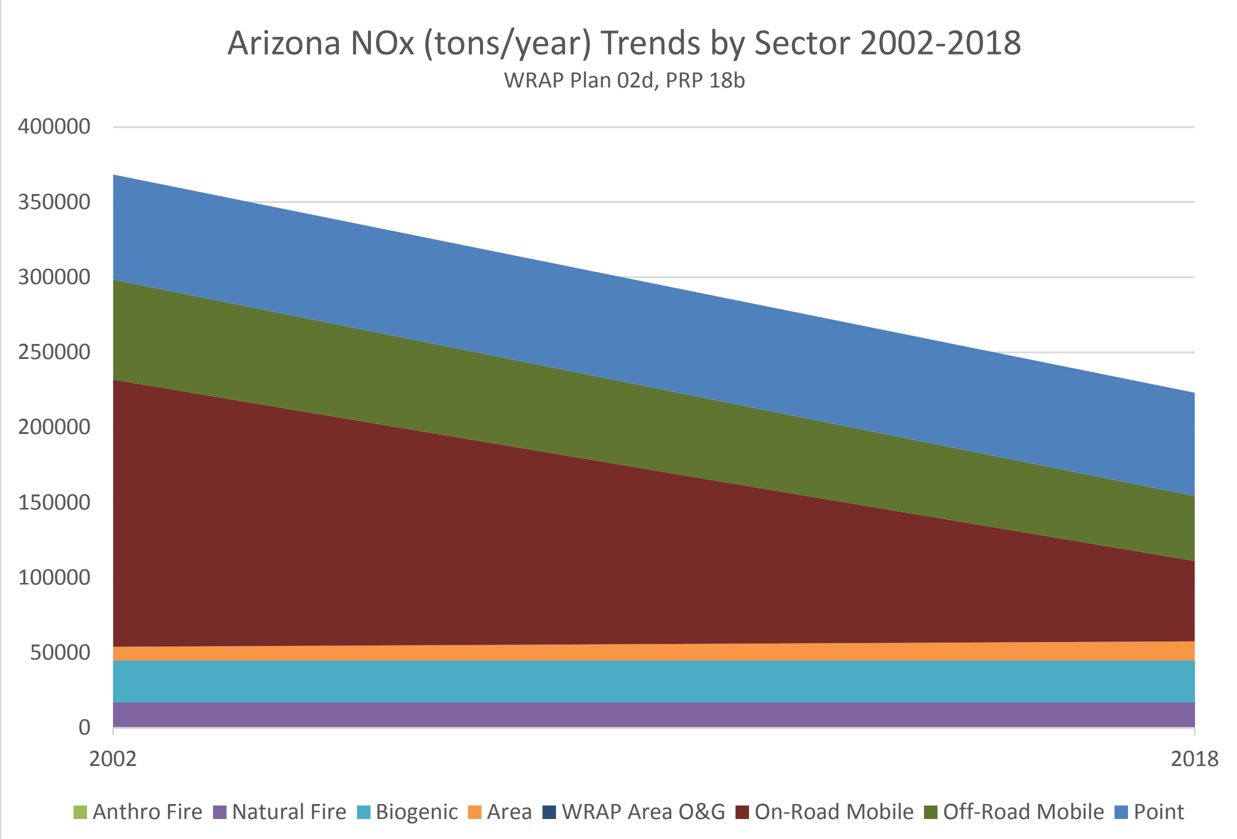
Historically, large reductions in SO_2 emissions from the utility sector have occurred in Arizona, as shown in Figure C-1.[10] While significant SO_2 emissions reductions have been targeted in Arizona's Regional Haze SIP for stationary sources, large reductions in overall NOx emissions from all sources are also projected. Figure C-2 presents large reductions in NOx emissions from mobile sources in the state.[11]

Figure C-1. Arizona SO_2 Emissions Trend 2002-14



[10] Air Markets Program Data, All Programs for Arizona, http://ampd.epa.gov/ampd/. Arizona's RH SIP addressed SO_2 emissions through installation of emissions controls, shutdowns, and fuel switches at the affected sources.
[11] WRAP Plan 02d and PRP 18b inventory (PRP 18a mobile) http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx.

Figure C-2. Arizona NOx Emissions Trend 2002-18



ADEQ discussed the relative contribution of statewide NOx and SO_2 emissions to visibility impairment in the BART alternative Technical Support Document for the Apache Generating Station.[12] As shown in Table C-12, ADEQ estimated statewide NOx emissions as more than 3.4 times the SO_2 emissions. However, visibility extinction (mM^{-1}) due to SO_2-attributed ammonium sulfate averaged 3.4, 3.5, and 3.8 times the magnitude of NOx-attributed ammonium nitrate visibility extinction for the 20% best days, 20% worst days, and all days, respectively. This is based on the average visibility extinction from the IMPROVE monitoring data for the period between 2000 and 2010 for the Class I areas impacted by the emissions from the CGS units presented in Appendix D.[13] Speciated annual average light extinction at the three Class I areas that are closest to the CGS units are presented in Figure C-3, Figure C-4, and Figure C-5.[14]

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[12] "AEPCO Apache Generating Station BART Alternative Control Review Technical Support Document," ADEQ, April 15, 2014.

[13] Data obtained from: http://vista.cira.colostate.edu/improve/Data/IMPROVE/summary_data.htm.

[14] http://views.cira.colostate.edu/fed/DataWizard/Default.aspx. Data legend for figures is as follows: ammSO4f_bext = Ammonium sulfate concentration; ammNO3f_bext = Ammonium nitrate concentration; ECf_bext = Light absorbing carbon concentration; CM_bext = Coarse mass light extinction; OMCf_bext = Organic mass concentration; SeaSalt_bext = Sea Salt concentration; and SOILf_bext = Fine soil concentration.

Figure C-3. Speciated Annual Average Light Extinction at Petrified Forest National Park

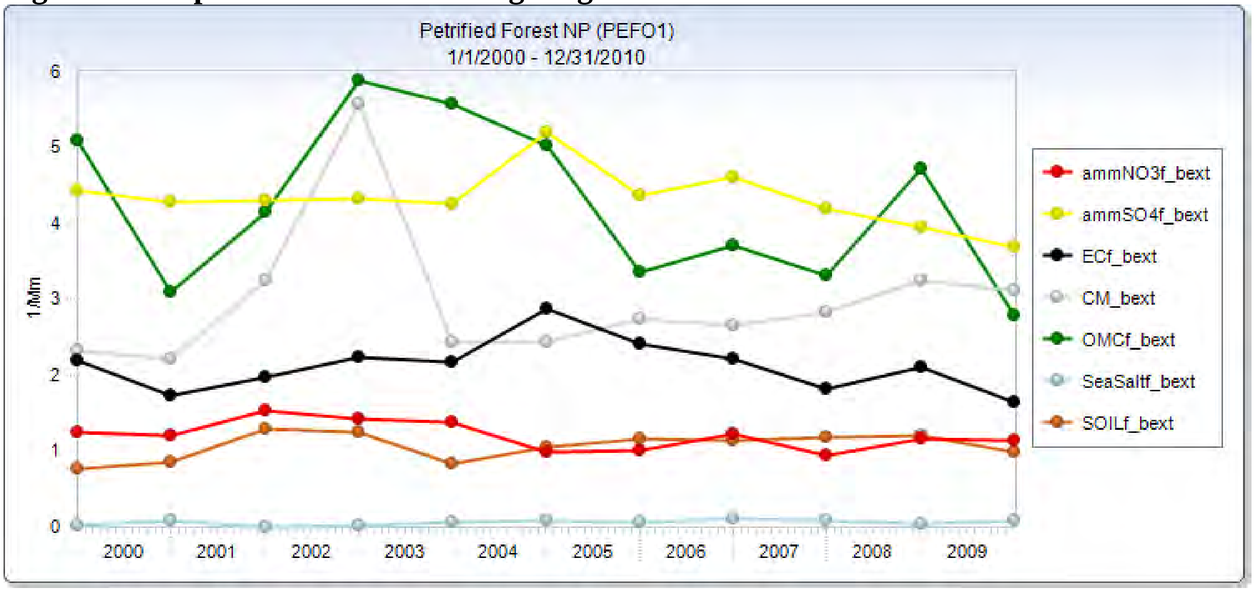


Figure C-4. Speciated Annual Average Light Extinction at Mount Baldy Wilderness

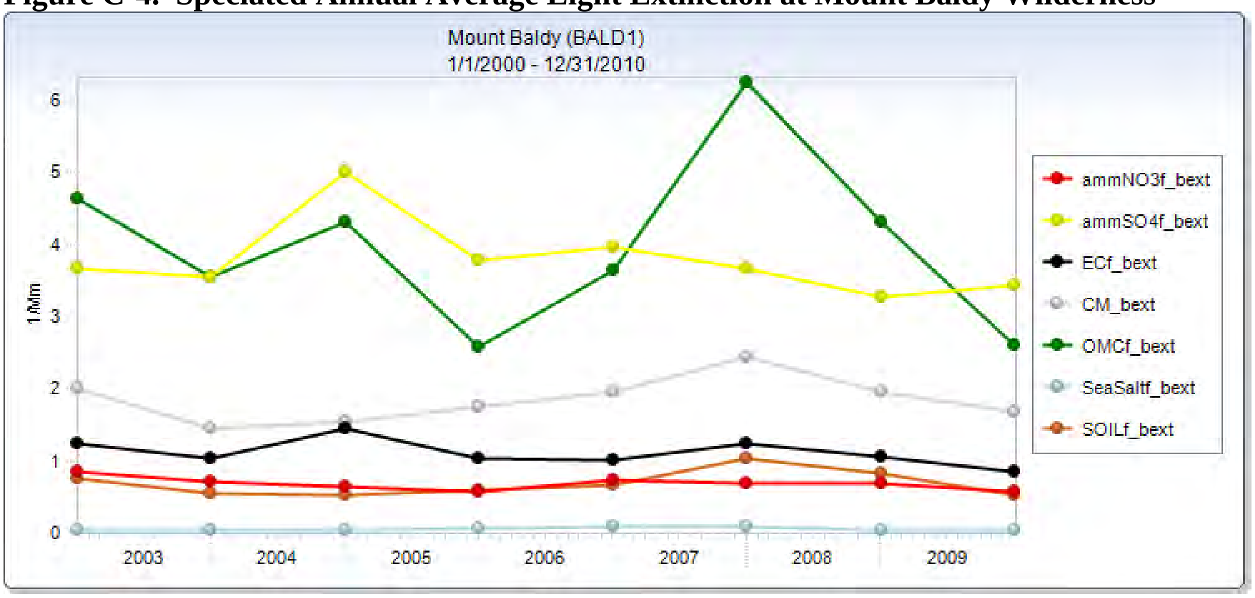
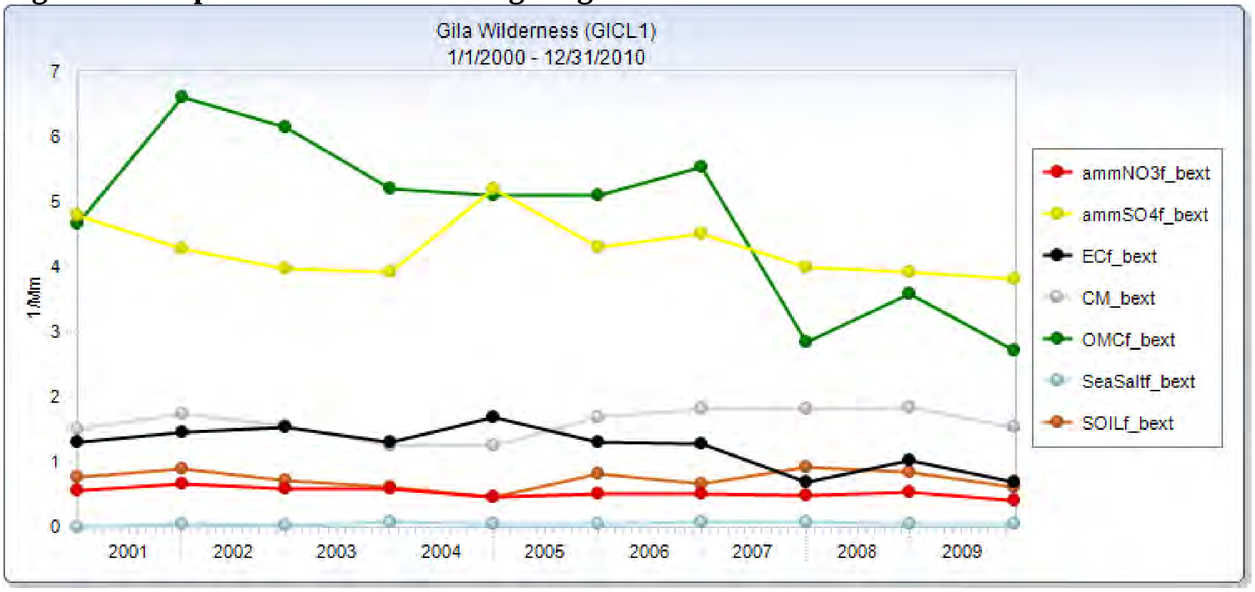


Figure C-5. Speciated Annual Average Light Extinction at Gila Wilderness Area



Ultimately, the visibility monitoring data for the CGS-affected Class I areas show that SO_2 emissions reductions produce greater Class I area visibility improvements than do NOx emissions reductions. The BTB alternative operating scenarios proposed by SRP would realize a greater degree of visibility improvement than other control scenarios presented here due to significant reductions in SO_2 emissions under the BTB alternative operating scenarios.

Appendix D – Average Annual Visibility Extinction 2000 to 2010

D. Average Annual Ammonium Sulfate and Ammonium Nitrate Extinction (Mm^{-1}) Measured at all CGS Affected Class I Areas from 2000 to 2010

Ammonium Sulfate Extinction (Mm^{-1})													
Best 20% Days													
Class I Area	ID	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
Bandalier NM	BAND1	2.4	2.9	2.5	2.0	2.4	2.0	2.5	2.4	1.7	1.9	1.8	2.2
Chiricahua NM, Chiricahua Wild, Galiuro Wild	CHIR1	2.5	2.2	2.5	2.2	2.1	2.4	2.3	2.0	1.7	2.3	2.0	2.2
Gila Wild	GICL1		2.3	1.8	1.4	1.9	2.0	1.9	1.6	1.3	1.8	1.6	1.8
Grand Canyon NP	GRCA2	1.7		1.5	1.2	1.4	1.6	1.8	1.6	1.2	1.6	1.3	1.5
Mazatzal Wild, Pine Mountain Wild	IKBA1		2.5	2.2	1.8	2.4	2.1	2.5	1.9	1.5	1.8	1.8	2.1
Mesa Verde NP	MEVE1	2.3	2.7	2.5	2.1	2.3	2.0	2.3	2.1	1.8	2.2	1.8	2.2
Mount Baldy Wild	BALD1		2.1	1.4	1.4	1.7	1.7	1.7	1.4	1.2	1.9	1.7	1.6
Petrified Forest NP	PEFO1	2.2	2.4	2.3	2.1	2.2	2.3	2.4	2.3	1.6	2.1	1.9	2.2
Saguaro NP	SAGU1			3.0	2.3	2.7	3.5	3.4	2.3	2.0	2.6	2.0	2.6
San Pedro Parks Wild	SAPE1		1.9	1.4	1.4	1.6	1.3	1.9	1.4	1.2	1.5	1.2	1.5
Sierra Ancha Wild	SIAN1		2.3	2.3	1.8	2.3	2.0	2.3	1.8	1.6	1.7	2.2	2.0
Superstition Wild	TONT1		3.1	3.1	2.3	2.6	2.8	3.0	2.3	2.5	2.3	2.3	2.6
Sycamore Canyon Wild	SYCA1		2.4	2.0	1.8	2.0	2.6	2.4	1.7	1.6	2.1	1.9	2.1
Average Extinction		2.2	2.4	2.2	1.8	2.1	2.2	2.3	1.9	1.6	2.0	1.8	2.0

Ammonium Sulfate Extinction (Mm^{-1})													
Worst 20% Days													
Class I Area	ID	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
Bandalier NM	BAND1	7.6	7.5	7.1	7.1	5.4	10.6	7.7	8.4	7.3	7.9	5.2	7.4
Chiricahua NM, Chiricahua Wild, Galiuro Wild	CHIR1	8.7	8.5	7.8	8.6	7.0	10.6	8.3	10.7	9.0	7.0	7.9	8.6
Gila Wild	GICL1		8.3	6.4	6.9	5.8	10.1	7.9	8.8	7.0	6.4	7.3	7.5
Grand Canyon NP	GRCA2	6.3		5.1	4.7	5.4	7.4	5.6	5.7	6.4	4.1	4.8	5.5
Mazatzal Wild, Pine Mountain Wild	IKBA1		6.3	7.4	6.2	6.1	9.1	6.9	8.1	7.6	5.7	5.7	6.9
Mesa Verde NP	MEVE1	6.6	7.3	5.5	5.9	7.0	7.6	6.2	6.5	6.3	4.9	4.3	6.2
Mount Baldy Wild	BALD1		6.8	6.5	5.9	5.5	9.2	6.0	6.8	5.1	5.3	5.8	6.3
Petrified Forest NP	PEFO1	6.8	6.8	6.4	6.8	6.5	8.9	6.1	7.9	6.4	6.5	5.2	6.7
Saguaro NP	SAGU1			8.3	7.8	6.1	10.6	6.6	7.9	6.1	5.7	7.0	7.3
San Pedro Parks Wild	SAPE1		6.5	6.0	5.3	5.3	9.1	6.3	7.4	6.3	4.7	4.5	6.1
Sierra Ancha Wild	SIAN1		6.4	7.1	6.3	5.8	9.5	5.6	8.0	7.4	5.2	6.0	6.7
Superstition Wild	TONT1		7.0	7.5	6.9	7.3	11.0	8.1	9.0	7.9	6.5	7.2	7.8
Sycamore Canyon Wild	SYCA1		4.9	4.9	4.9	5.2	8.2	5.0	4.9	6.3	4.0	4.0	5.2
Average Extinction		7.2	6.9	6.6	6.4	6.0	9.4	6.6	7.7	6.9	5.7	5.8	6.8

Ammonium Sulfate Extinction (Mm^{-1})													
All Days													
Class I Area	ID	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
Bandalier NM	BAND1	5.0	4.9	4.6	4.4	4.0	5.3	4.5	4.9	4.4	4.2	3.5	4.5
Chiricahua NM, Chiricahua Wild, Galiuro Wild	CHIR1	5.6	5.1	5.3	5.1	4.6	5.7	5.0	5.4	4.9	4.5	4.4	5.1
Gila Wild	GICL1		4.8	4.3	4.0	3.9	5.2	4.3	4.5	4.0	3.9	3.8	4.3
Grand Canyon NP	GRCA2	3.8		3.3	3.1	3.5	4.5	3.7	3.8	3.8	3.4	3.2	3.6
Mazatzal Wild, Pine Mountain Wild	IKBA1		4.7	4.3	4.1	4.5	5.1	4.7	4.9	4.6	3.9	3.8	4.5
Mesa Verde NP	MEVE1	4.5	5.2	4.1	4.1	4.3	4.7	4.3	4.2	4.1	3.6	3.6	4.2
Mount Baldy Wild	BALD1		4.2	3.8	3.7	3.6	5.0	3.8	4.0	3.7	3.3	3.4	3.9
Petrified Forest NP	PEFO1	4.4	4.3	4.3	4.3	4.3	5.2	4.4	4.6	4.2	3.9	3.7	4.3
Saguaro NP	SAGU1			5.2	5.2	4.5	6.1	5.1	5.1	4.4	4.1	4.3	4.9
San Pedro Parks Wild	SAPE1		4.1	3.7	3.5	3.6	4.7	3.7	3.9	3.8	3.1	3.1	3.7
Sierra Ancha Wild	SIAN1		6.4	7.1	6.3	5.8	9.5	5.6	8.0	7.4	5.2	6.0	6.7
Superstition Wild	TONT1		4.4	4.2	4.0	4.0	5.3	4.4	4.6	4.4	3.8	3.8	4.3
Sycamore Canyon Wild	SYCA1		4.2	3.9	3.8	4.1	5.4	4.2	4.2	4.3	3.6	3.5	4.1
Average Extinction		4.7	4.8	4.5	4.3	4.2	5.5	4.4	4.8	4.5	3.9	3.9	4.5

Ammonium Nitrate Extinction (Mm^{-1})													
Best 20% Days													
Class I Area	ID	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
Bandalier NM	BAND1	0.8	0.6	0.8	0.8	0.7	0.6	0.5	0.6	0.7	0.4	0.5	0.6
Chiricahua NM, Chiricahua Wild, Galiuro Wild	CHIR1	0.5	0.6	0.6	0.5	0.6	0.5	0.4	0.4	0.3	0.4	0.4	0.5
Gila Wild	GICL1		0.4	0.3	0.2	0.4	0.3	0.3	0.2	0.2	0.2	0.3	0.3
Grand Canyon NP	GRCA2	0.5		0.5	0.4	0.4	0.4	0.3	0.5	0.3	0.6	0.3	0.4
Mazatzal Wild, Pine Mountain Wild	IKBA1		1.1	0.9	0.8	0.6	0.8	1.0	0.8	0.6	0.4	0.5	0.8
Mesa Verde NP	MEVE1	0.8	0.7	1.0	1.0	0.8	0.6	0.6	0.6	0.6	0.6	0.6	0.7
Mount Baldy Wild	BALD1		0.6	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.5	0.4
Petrified Forest NP	PEFO1	0.7	1.0	0.9	0.7	0.8	0.6	0.7	0.6	0.6	0.6	0.7	0.7
Saguaro NP	SAGU1			0.8	1.2	0.9	1.0	0.8	0.8	0.7	0.6	0.7	0.8
San Pedro Parks Wild	SAPE1		0.5	0.4	0.4	0.4	0.4	0.3	0.4	0.4	0.4	0.4	0.4
Sierra Ancha Wild	SIAN1		0.9	0.8	0.8	0.9	0.4	0.4	0.5	0.5	0.4	0.8	0.6
Superstition Wild	TONT1		1.2	0.9	1.1	0.6	0.7	0.5	0.8	1.0	0.5	0.9	0.8
Sycamore Canyon Wild	SYCA1		1.2	0.9	0.7	0.7	1.0	0.8	0.8	0.6	0.9	1.3	0.9
Average Extinction		0.6	0.8	0.7	0.7	0.6	0.6	0.5	0.6	0.5	0.5	0.6	0.6

Ammonium Nitrate Extinction (Mm^{-1})													
Worst 20% Days													
Class I Area	ID	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
Bandalier NM	BAND1	2.8	2.2	2.6	2.8	2.2	1.4	2.1	4.1	2.3	2.0	1.6	2.4
Chiricahua NM, Chiricahua Wild, Galiuro Wild	CHIR1	1.1	0.9	1.9	1.5	1.4	1.0	1.7	1.1	1.1	1.4	1.2	1.3
Gila Wild	GICL1		0.6	1.0	1.1	0.9	0.6	0.7	0.9	0.8	0.9	0.7	0.8
Grand Canyon NP	GRCA2	2.4		2.1	2.0	2.3	1.3	2.1	2.0	1.6	1.8	1.7	1.9
Mazatzal Wild, Pine Mountain Wild	IKBA1		2.2	3.1	3.6	5.2	1.4	3.4	2.7	2.2	2.0	1.9	2.8
Mesa Verde NP	MEVE1	1.7	1.9	3.5	2.5	2.0	1.5	1.6	3.1	1.3	2.4	2.4	2.2
Mount Baldy Wild	BALD1		0.9	1.2	1.4	1.0	0.7	0.9	1.3	0.8	1.2	0.8	1.0
Petrified Forest NP	PEFO1	1.8	1.3	2.2	1.7	2.2	1.3	1.5	1.7	1.4	1.7	1.8	1.7
Saguaro NP	SAGU1			6.4	6.7	4.2	2.0	3.1	3.0	2.7	2.2	3.7	3.8
San Pedro Parks Wild	SAPE1		1.5	1.8	1.6	1.3	1.3	1.3	1.0	1.3	1.0	1.1	1.3
Sierra Ancha Wild	SIAN1		1.9	2.3	2.2	2.2	1.5	1.9	2.2	1.6	1.9	1.4	1.9
Superstition Wild	TONT1		2.9	3.2	3.1	3.0	1.8	3.2	2.7	2.7	2.1	1.6	2.6
Sycamore Canyon Wild	SYCA1		1.1	1.8	2.2	3.0	1.2	1.0	1.6	1.1	1.9	1.4	1.6
Average Extinction		2.0	1.6	2.5	2.5	2.4	1.3	1.9	2.1	1.6	1.7	1.6	1.9

Ammonium Nitrate Extinction (Mm^{-1})													
All Days													
Class I Area	ID	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
Bandalier NM	BAND1	1.6	1.4	1.6	1.4	1.4	1.0	1.1	1.6	1.2	1.1	0.9	1.3
Chiricahua NM, Chiricahua Wild, Galiuro Wild	CHIR1	0.9	0.7	1.2	0.9	0.9	0.8	0.9	0.9	0.6	0.7	0.7	0.8
Gila Wild	GICL1		0.6	0.7	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.4	0.5
Grand Canyon NP	GRCA2	1.3		1.1	1.1	1.1	0.9	1.0	1.3	0.9	1.1	1.0	1.1
Mazatzal Wild, Pine Mountain Wild	IKBA1		1.9	1.8	1.9	2.2	1.2	1.6	1.7	1.4	1.2	1.1	1.6
Mesa Verde NP	MEVE1	1.1	1.2	1.9	1.6	1.2	1.0	0.9	1.5	1.0	1.2	1.2	1.3
Mount Baldy Wild	BALD1		0.8	0.9	0.9	0.7	0.7	0.6	0.7	0.7	0.7	0.6	0.7
Petrified Forest NP	PEFO1	1.3	1.2	1.5	1.4	1.4	1.0	1.0	1.2	0.9	1.2	1.1	1.2
Saguaro NP	SAGU1			2.4	2.4	1.9	1.5	1.7	1.6	1.5	1.3	1.6	1.8
San Pedro Parks Wild	SAPE1		1.0	1.1	0.9	1.0	0.8	0.8	0.9	0.9	0.8	0.8	0.9
Sierra Ancha Wild	SIAN1		1.4	1.6	1.5	1.4	1.0	1.1	1.2	1.1	1.0	0.9	1.2
Superstition Wild	TONT1		1.9	1.8	1.8	1.6	1.3	1.6	1.6	1.5	1.2	1.0	1.5
Sycamore Canyon Wild	SYCA1		1.5	1.6	1.6	1.7	1.2	1.3	1.5	1.2	1.3	1.2	1.4
Average Extinction		1.2	1.2	1.5	1.4	1.3	1.0	1.1	1.3	1.0	1.0	1.0	1.2

Appendix E – SCR Installation: Emissions Calculations

E. SCR Installation: Emissions Calculations

As one of the final compliance options, SRP is requesting authorization to install an SCR system for control of NOx emissions from CGS Unit 1. This appendix presents emissions increase calculations pertaining to the installation of an SCR system.

E.1 Baseline Actual Emissions

CGS Unit 1 is an existing electric utility steam generating unit. In accordance with A.A.C. R18-2-401(2), SRP has preliminarily selected calendar years 2013-2014 (a consecutive 24-month period within the five year period preceding the project) for establishing the baseline actual emissions ("BAE") for Unit 1. Table E-1 presents BAE for Unit 1 for NSR pollutants affected by the proposed SCR Project.

Table E-1. Baseline Actual Emissions for Unit 1 in Tons per Year

	NOx	PM*	PM10	PM2.5	H_2SO_4
Unit 1	4,986.8	132.8	171.4	171.4	6.7
Selected Baseline Period	2013-2014				
**PM emissions do not include condensable fraction.*					

NOx emissions rates are from the continuous emissions monitoring system ("CEMS") data for Unit 1. PM includes only the filterable fraction and is based on a stack test conducted in March 2015. PM10 and PM2.5 include both filterable and condensable fractions and are also based on the March 2015 stack test (all of the filter catch was assumed to be less than 2.5 µm mean aerodynamic diameter). H_2SO_4 rates are also based on a stack test conducted in March 2015.

The SCR Project does not result in any additional fugitive emissions from CGS Unit 1. Emissions during startup, shutdown, and malfunctions will also remain unchanged. SRP used the best data available for the affected unit to establish BAE in tons per year.

E.2 Projected Actual Emissions

In accordance with A.A.C. R18-2-401(20), SRP projected future utilization of Unit 1 in the ten year period after the implementation of the SCR Project.[15] The projected utilization and projected net generation for Unit 1 are higher than the baseline values. This affects emissions of all pollutants. However, the higher capacity factor and net generation are unrelated to the SCR

[15] Potential to emit of PM10, PM2.5, H_2SO_4 for Unit 1 will increase as a result of the SCR Project. Therefore, a 10-year projection is required.

Project and could have been accommodated during the baseline period.[16] Accordingly, this section presents a detailed analysis for pollutants the emission rate of which may be affected by the proposed SCR Project; namely, NOx, PM, PM10, PM2.5, and H_2SO_4.[17] SRP projected a 91.3% capacity factor for Unit 1, on a heat input basis, in the projection period. Table E-2 presents projected actual emissions ("PAE") for Unit 1.

Table E-2. Projected Actual Emissions for Unit 1 in Tons per Year

	Units	NOx	PM	PM10	PM2.5	H_2SO_4
Unit 1 Emission Factors	lb/MMBtu	0.065	0.009	0.033	0.033	0.005
Unit 1 PAE	tons/year	1,226.6	169.8	622.7	622.7	94.4

PAE for Unit 1 is calculated based on maximum projected heat input (based on the projected utilization rate) and emission factors as noted here. The NOx emission rate for Unit 1 after the SCR Project is based on the BART reconsideration proposal from March 2015. The PM filterable rate is based on the maximum projected emission rate. PM10, PM2.5, and H_2SO_4 emissions are based on the proposed Best Available Control Technology ("BACT") limits as discussed in Appendix F.[18]

E.3 Excluded Emissions

A.A.C. R18-2-401(20)(b)(iv) requires an owner or operator to exclude the portion of an existing unit's emissions that the unit could have accommodated during the baseline period and are unrelated to the project. During the 2013-2014 BAE period, the average capacity factor for Unit 1 was 81.3%, on a heat input basis. SRP's projected capacity factor for Unit 1 is 91.3%, on a heat input basis. As noted previously, the higher utilization rate and associated generation and emissions are unrelated to the SCR Project and could have been accommodated in the baseline period. Therefore, the emissions associated with the difference between the projected Unit 1 utilization and the baseline utilization should be excluded, as they are attributable to projected growth in electricity demand. Table E-3 presents excluded emissions ("EE") for Unit 1.

Table E-3. Excluded Emissions for Unit 1 in Tons per Year

	Units	PM	PM10	PM2.5	H_2SO_4
Unit 1 Emission Factors	lb/MMBtu	0.009	0.028	0.028	0.0004
Unrelated Emissions that Unit 1 Could Have Accommodated	tons/year	169.8	535.9	535.9	7.5
Unit 1 BAE	tons/year	132.8	171.4	171.4	6.7
Unit 1 Excluded Emissions	tons/year	37.0	364.5	364.5	0.8

[16] The term "capacity factor" used throughout this document is calculated using the heat input to the unit (in place of gross or net generation) compared to the maximum heat input to the unit for the specific timeframe.
[17] No detailed analysis is needed for other pollutants, because the proposed SCR Project cannot result in an emissions increase for those pollutants.
[18] Both PM10 and PM2.5 projected emission factors include the filterable and condensable fractions.

The PM filterable emissions rate is based on the maximum projected emission rate. The SCR Project related increase in condensable and H_2SO_4 emissions is calculated as 0.0046 lb/MMBtu. For PM10 and PM2.5 emission factors, 0.0046 lb/MMBtu is the nonexcludable portion related to the SCR Project. Therefore, this is subtracted from the projected PM10 and PM2.5 rate of 0.033 lb/MMBtu, resulting in an excluded emission factor of 0.028 lb/MMBtu for PM10 and PM2.5. The H_2SO_4 emission rate is based on a March 2015 stack test (without the use of SCR).

E.4 Project Emissions Increase

Project emissions increases ("PEI") are calculated in accordance with A.A.C. R18-2-402(D)(3) for projects that involve only existing emissions units by subtracting BAE and EE from PAE. Table E-4 presents the PEI for the SCR Project for Unit 1.

Table E-4. Project Emissions Increases for Unit 1 in Tons per Year

Pollutant	Baseline Actual Emissions	Projected Actual Emissions	Excluded Emissions	Project Emissions Increases	Significant Emission Rate
NOx	4,986.8	1,226.6	N/A	-3,760.2	40
PM	132.8	169.8	37.1	0.00	25
PM10	171.4	622.7	364.5	86.8	15
PM2.5	171.4	622.7	364.5	86.8	10
H_2SO_4	6.7	94.4	0.8	86.8	7

As shown in the table above, the SCR Project is expected to result in increases in emissions of PM10, PM2.5, and H_2SO_4 that are significant. Therefore, the SCR Project is a major modification for these regulated NSR pollutants and subject to PSD review under A.A.C. R18-2-406 and -407.

E.5 Emissions Rates for Dispersion Modeling

Short term increases in emissions of PM10 and PM2.5 were evaluated using dispersion modeling, as required in A.A.C. R18-2-406(A)(5) under PSD review, and discussed in Appendix G of this application.

Table E-5 presents the short term emissions rates calculations for the SCR Project at Unit 1.

Table E-5. Unit 1 SCR Project Short Term Emissions Increases for Dispersion Modeling

Unit 1 maximum heat input	4,719	MMBtu/hour
Unit 1 average heat input during 2013-2014	4,129	MMBtu/hour
Pre-project PM10/PM2.5 emission factor *From March 2015 stack test*	0.0102	lb/MMBtu
Pre-project PM10/PM2.5 emission rate (heat input during 2013-2014)	42.16	lb/hour
Post-project PM10/PM2.5 emission factor* *Proposed BACT rate*	0.033	lb/MMBtu
Post-project PM10/PM2.5 emission rate	155.73	lb/hour
Increase in PM10/PM2.5 emission rate	113.61	lb/hour
**PM10/PM2.5 emission factor includes both filterable and condensable fraction.*		

Salt River Project
Coronado Generating Station
Unit 1 - Actual to Projected Actual Emissions Increases

	Unit 1 Emissions (tons/year)			
Pollutant	Baseline Actual Emissions	Projected Actual Emissions	Excludable Emissions	Project Emissions Increases
NOx	4,986.79	1,226.61		0.00
PM	132.78	169.84	37.06	0.00
PM10	171.44	622.74	364.50	86.81
PM2.5	171.44	622.74	364.50	86.81
H2SO4	6.72	94.35	0.83	86.81

Salt River Project
Coronado Generating Station
Unit 1 - Baseline Actual Emissions

Year	Heat Input (MMBtu/year)	NOx (tons/year)	PM (tons/year)	PM10 (tons/year)	PM2.5 (tons/year)	H2SO4 (tons/year)
2011	32,704,699	5,013.57	129.18	166.79	166.79	6.54
2012	30,709,815	4,596.01	121.30	156.62	156.62	6.14
2013	33,429,869	5,024.41	132.05	170.49	170.49	6.69
2014	33,801,888	4,949.17	133.52	172.39	172.39	6.76

NOx - Reported by CEMS

PM - Filterable PM from the 2015 test

PM10 & PM2.5 - Filterable and condensable PM from 2015 test. Filter catch below 2.5 size

H2SO4 - from the 2015 test

Selected Baseline Period and Emissions

BAE (tons/year)					
	NOx	PM	PM10	PM2.5	H2SO4
Unit 1	4,986.79	132.78	171.44	171.44	6.72
Selected Period	2013-14	2013-14	2013-14	2013-14	2013-14

Baseline capacity factor 81.3%

Salt River Project
Coronado Generating Station
Unit 1 - Projected Actual Emissions

Unit 1 Capacity	430.00	MW
Heat Input	4,719	MMBtu/hr
Heat Input	41,338,440	MMBtu/year
Capacity Factor	91.3%	

	Units	NOx	PM	PM10	PM2.5	H2SO4
Unit 1 Emission Factors	lb/MMBtu	0.065	0.009	0.033	0.033	0.005
	References	1	2	3	3	4
Unit 1 PAE	tons/year	1,226.61	169.84	622.74	622.74	94.35
Unit 1 short term rate	lb/hr	306.74	42.47	155.73	155.73	23.60

References

1 - NOx rate from BART Reconsideration published on March 31, 2015

2 - PM filterable rate from Unit 2 applicability calculations

3 - PM Rate + 0.02 lb/MMBtu condensable rate from AP-42 Table 1.1-5, Coal Combustion PC Boiler (9/98) + H2SO4 Rate

4 - H2SO4 rate as BACT limit of 0.005 lb/MMBtu

Salt River Project
Coronado Generating Station
Unit 1 - Excludable Emissions

Unit 1 Capacity	456.00	MW
Heat Input	4,719	MMBtu/hr
Heat Input	41,338,440	MMBtu/year
Capacity Factor	91.3%	

	Units	PM	PM10	PM2.5	H2SO4
Unit 1 Emission Factors	lb/MMBtu	0.009	0.028	0.028	0.0004
	References	1	2	2	3
Unit 1 Could Have Accommodated Emissions	tons/year	169.84	535.94	535.94	7.55
Unit 1 BAE	tons/year	132.78	171.44	171.44	6.72
Unit 1 Excludable Emissions	tons/year	37.06	364.50	364.50	0.83

References

1 - PM filterable rate from Unit 2 applicability calculations

2 - PM10 and PM2.5 emission factor from PAE - H2SO4 increase of 0.0046 (0.005-0.0004) lb/MMBtu as non-excludable portion

3 - H2SO4 rate from Unit 1 test from March 11, 2015

Appendix F – SCR Installation: BACT Analyses for H_2SO_4 and PM10/PM2.5

F. SCR Installation: BACT Analyses for H_2SO_4 and PM10/PM2.5

The SCR Project is subject to preconstruction PSD review, including the best available control technology ("BACT") requirement under A.A.C. R18-2-406(A)(2), with respect to three regulated NSR pollutants: H_2SO_4, PM10, and PM2.5. This appendix presents the detailed BACT analyses for the Unit 1 SCR Project.

F.1 BACT Methodology

This section presents the methodology used for determining BACT for H_2SO_4, PM10, PM2.5 emissions resulting from the Unit 1 SCR project.

F.1.1 General

The term "best available control technology" is defined in the ADEQ regulations as follows:

> "Best available control technology" (BACT) means an emission limitation, including a visible emissions standard, based on the maximum degree of reduction for each air regulated NSR pollutant which would be emitted from any proposed major source or major modification, taking into account energy, environmental, and economic impact and other costs, determined by the Director in accordance with R18-2-406(A)(4) to be achievable for such source or modification. (A.A.C. R18-2-101.21)

The regulations also include the following general requirements for the determination of BACT:

> BACT shall be determined on a case-by-case basis and may constitute application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment, clean fuels, or innovative fuel combustion techniques, for control of such pollutant. In no event shall such application of BACT result in emissions of any pollutant, which would exceed the emissions allowed by any applicable new source performance standard or national emission standard for hazardous air pollutants under Articles 9 and 11 of this Chapter or by the applicable implementation plan. If the Director determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means which achieve equivalent results. (A.A.C. R18-2-406(A)(4))

The EPA's interpretive policies relating to BACT analyses are set forth in several informal guidance documents. Most notable among these are the following:

- "Guidelines for Determining Best Available Control Technology (BACT)," December 1978.
- "Prevention of Significant Deterioration Workshop Manual," October 1980.
- "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting." Draft. October 1990.

Consistent with prior ADEQ BACT determinations, the BACT analyses presented in this appendix use what has been termed a "top-down" procedure. This procedure requires consideration of the most stringent control technologies available, and a reasoned justification, considering energy, environmental and economic impacts and other costs, of any decision to require less than the maximum degree of reduction in emissions.

The framework for the top-down BACT analysis procedure comprises five key steps, as discussed in detail below. The five-step procedure mirrors the analytical framework set forth in the draft 1990 EPA guidance document, but does not necessarily adhere to the prescriptive process described in that document. Strict adherence to the detailed top-down BACT analysis process described in that draft document would unnecessarily restrict ADEQ's judgment and discretion in weighing various factors before making case-by-case BACT determinations. Rather, the analyses presented herein were prepared with recognition of the fact that, as outlined in the 1978 and 1980 EPA guidance documents, ADEQ has broad flexibility in applying its judgment and discretion in making BACT determinations.

Step 1 - Identify all control options. The process is performed on a unit-by-unit and pollutant-by-pollutant basis and begins with the identification of available control technologies and techniques. For BACT purposes, "available" control options are those technologies and techniques, or combinations of technologies and techniques, with a practical potential for application to the subject emissions units and pollutants. These may include fuel cleaning or treatment, inherently lower polluting processes, and end of pipe control devices. All identified control options that are not inconsistent with the fundamental purpose and basic design of the proposed facility are listed in this step. Those control options that are identified as being technically infeasible or as having unreasonable energy, economic or environmental impacts or other unacceptable costs are eliminated in subsequent steps.

Step 2 - Eliminate technically infeasible control options. In this step, the technical feasibility of identified control options is evaluated with respect to source-specific factors. Technically feasible control options are those that have been demonstrated to function efficiently on identical or similar processes. In general, if a control option has been demonstrated to function efficiently on the same type of emissions unit, or another unit with similar exhaust streams, the control option is presumed to be technically feasible. For presumably technically feasible control options, demonstrations of technical infeasibility must show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the control option from being employed successfully on the subject emissions unit. Technical feasibility need not be addressed for control options that are less effective than the control option proposed as BACT by the permit applicant.

Step 3 - Characterize control effectiveness of technically feasible control options. For each control option that is not eliminated in Step 2, the overall control effectiveness for the pollutant under review is characterized. The control option with the highest overall effectiveness is the "top" control option. If the top control option is proposed by the permit applicant as BACT, no evaluation is required under Step 4, and the procedure moves to Step 5. Otherwise, the top control option and other identified control options that are more effective than that proposed by the permit applicant must be evaluated in Step 4. A control option that can be designed and operated at two or more levels of control effectiveness may be presented and evaluated as two or more distinct control options (i.e., an option for each control effectiveness level).

Step 4 - Evaluate more effective control options. If any identified and technically feasible control options are more effective than that proposed by the permit applicant as BACT, rejection of those more effective control options must be justified based on the evaluation conducted in this step. For each control option that is more effective than the option ultimately selected as BACT, the rationale for rejection must be documented for the public record. Energy, environmental, and economic impacts and other costs of the more effective control options, including both beneficial and adverse (i.e., positive and negative) impacts, are listed and considered.

Step 5 - Establish BACT. Finally, the most effective control technology not rejected in Step 4 is proposed as BACT. To complete the BACT process, an enforceable emission limit representing BACT must be included in the PSD permit.

F.1.2 Prohibition on Source or Project Redefinition

Because the definition of BACT includes the phrase, "achievable for such source or modification," the BACT requirement does not provide for consideration of any emission limit that would necessitate redefinition of the fundamental purpose or basic design of the proposed facility or project. For the SCR Project at CGS Unit 1, this includes the following:

- Use of the existing dry-turbo-fired boiler;
- Continued use of the existing low-NOx burners and overfire air, which is required by the Consent Decree[19] entered into between SRP and the United States and which also forms the basis for EPA's NOx BART determination for Unit 1;
- Continued use of the existing HESP and WFGD system, which is required by the Consent Decree and which also forms the basis for ADEQ's SO_2 and PM BART determinations for Unit 1;
- Use of Powder River Basin sub-bituminous coal or western bituminous coal as the boiler's primary fuel, which is the basis for EPA's and ADEQ's BART determinations for Unit 1;
- Installation of an SCR system with sufficient catalyst volume and activity level to meet the NOx emission limit of 0.065 lb/MMBtu, based on a rolling

[19] Consent Decree, United States of America v. Salt River Project Agricultural Improvement And Power District, Civil Action No. 2:08-cv-1479-JAT, August 12, 2008.

30-boiler-operating-day average, as established by EPA in the BART FIP; and

- Use of ultra-low activity SCR catalyst as part of the SCR design for Unit 1.

Any potentially available control options that would be inconsistent with the above are considered off limits for this analysis and are not identified in Step 1. For example, one potentially available control option in the BACT analysis for H_2SO_4 emissions would be continued operation of the Unit 1 boiler without SCR. However, although this strategy represents an inherently lower polluting process with respect to H_2SO_4 emissions, and therefore falls within the definition of BACT generally, this strategy is not considered achievable for CGS Unit 1 because EPA has issued a FIP requiring the use of SCR to control NOx emissions from this unit.

F.2 H_2SO_4 BACT Analysis

The majority of the fuel sulfur combusted in a coal-fired boiler leaves the boiler as sulfur dioxide (SO_2). During combustion, a small percentage of the fuel sulfur is further oxidized from SO_2 to sulfur trioxide (SO_3). The oxidation of SO_2 to SO_3 will be increased further by the SCR catalyst used for NOx control.

A fraction of the SO_3 in the flue gas stream reacts with water vapor to form sulfuric acid (H_2SO_4). The flue gas temperature decreases as it passes through the air heater and pollution control systems. When the flue gas temperature drops below the acid dew point, a fraction of the gaseous H_2SO_4 condenses into an aerosol. Thus, the resulting emissions include three related constituents: gaseous SO_3, gaseous H_2SO_4, and aerosol H_2SO_4. The total emissions rate for the regulated NSR pollutant named "sulfuric acid mist" comprises the sum of the emissions rates for these three constituents, reported as H_2SO_4.[20]

Guidance documents and technical papers regarding H_2SO_4 emissions from coal-fired electric generating units have H_2SO_4 emission concentrations covering a wide range from 0.03 to 14 parts per million volume (ppmv) at 3 percent oxygen.[21] For example, an EPA document recommends using a H_2SO_4 emission concentration of 3 – 7 ppmv for coal with a sulfur content of 0.5 percent or less, and a concentration of 14 ppmv for coal with a sulfur content of 1.0 percent.[22] EPA's AP-42 document states that about 0.7 percent of fuel sulfur is emitted as SO_3.[23]

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[20] The use of the phrase "sulfuric acid mist" as the name of the regulated NSR pollutant is an unfortunate and potentially misleading misnomer. *See*, 40 CFR §§ 60.81(b) and 60.83(a), establishing "sulfuric acid mist" as a regulated pollutant under Clean Air Act § 111(b) and defining this pollutant as the parameter measured by EPA Reference Method 8 and reported as H_2SO_4; *see, also*, EPA Reference Method 8 in appendix A-4 to 40 CFR part 60, requiring that SO_3 and H_2SO_4 be measured and reported together as H_2SO_4.

[21] All ppmv (parts per million by volume) values are at 3 percent oxygen unless specified otherwise.

[22] *Guidance for Reporting Sulfuric Acid (acid aerosols including mists, vapors, gas, fog, and other airborne forms of any particle size), Emergency Planning and Community Right-to-Know Act*, Report EPA-745-R-97-007.

[23] *Compilation of Air Pollutant Emission Factors,* AP 42, 5th Edition, Table 1.1-3 (9/98 update).

For CGS Unit 1, a coal sulfur content of 1.6 pounds of SO_2 per million Btu (lb SO_2/MMBtu) would result in an H_2SO_4 emission rate of 0.017 lb/MMBtu or 6 ppm.[24]

The Electric Power Research Institute (EPRI) Report, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants* estimates SO_3 formation to be in the range 0.3 to 0.6 percent of the flue gas SO_2 concentration.[25] The much lower conversion rates are generally applicable to western subbituminous coals with alkaline fly ash. The range in H_2SO_4 emissions for conversion rates of 0.2% and 1.6% would be equal to 0.0032 to 0.0256 lb/MMBtu for a coal with a potential combustion concentration of 1.6 lb SO_2/MMBtu.

The above H_2SO_4 emission rates represent the concentration at the boiler exit. Other factors affect the H_2SO_4 emission rate exiting the stack. Factors that can increase emissions of H_2SO_4 include SCR and flue gas conditioning using SO_3. Factors reducing emissions of H_2SO_4 include particulate matter removal devices, air heater deposition, reagent injection, flue gas conditioning using ammonia, ammonia slip from the SCR, coal ash alkalinity, and FGD systems. CGS Unit 1 currently burns approximately 60 to 100 percent Powder River Basin (PRB) coal with a highly alkaline fly ash and has a hot-side ESP, conventional air heater, and WFGD system. The project under consideration would add an SCR system to the unit which would increase H_2SO_4 emissions. With the addition of the SCR system, it is estimated that the post-SCR H_2SO_4 emission rates would range from 0.003 lb/MMBtu to 0.019 lb/MMBtu, depending on the formation of SO_3 by the boiler for various coals, an SCR SO_2-to-SO_3 conversion rate of 0.5 percent, and the reductions afforded by the hot-side ESP, air heater, and WFGD system.

F.2.1 STEP 1. Identify All Potential Control Technologies

Table F-1 summarizes the review of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database identifying the H_2SO_4 permit limits and associated PM/SO_2 and H_2SO_4 controls. Until about ten years ago, the only control options identified in the RBLC database for the control of H_2SO_4 from coal-fired boilers were the same controls used for controlling particulate matter and SO_2. These systems included wet or dry flue gas desulfurization (WFGD or DFGD) systems, and electrostatic precipitators (ESP) or fabric filters (FF) used for PM control. H_2SO_4 is controlled in both WFGD and DFGD systems through mechanisms similar to SO_2 control. Sulfuric acid also tends to adsorb onto fly ash particles as the flue gas cools and is collected by the PM controls.

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[24] Based on the CGS emission limit of 0.08 lb SO_2/MMBtu and 95% control efficiency, maximum coal sulfur level is 1.6 lb SO_2/MMBtu. This results in the following H_2SO_4 emissions rate:
0.017 lb H_2SO_4/MMBtu = 1.6 lb SO_2/MMBtu * 0.7%/100 *98 MW H_2SO_4 / 64 MW SO_2.
[25] *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants*, Version 2012, EPRI Technical Report. p. 3-2.

Table F-1. H_2SO_4 BACT Controls and Limits for PC Fired Electric Generating Units

Company – Facility- Unit	RBLC ID or State	Permit Date	Capacity MW	Primary Fuel	SO_2 lb/MMBtu	H_2SO_4 lb/MMBtu	H_2SO_4 and SO_2 Controls[b]	SCR Controls[b]
Existing Units								
Pacificorp Energy- Jim Bridger Unit 3	WY-0073	6/17/13	561 a	Subbituminous	0.155 Annual d	0.004	ESP/WFGD	No
Pacificorp Energy- Jim Bridger Unit 4	WY-0073	6/17/13	561 a	Subbituminous	0.142 Annual d	0.004	ESP/WFGD	No
Salt River Project- Coronado Unit 2	AZ-0050	1/22/09	411 a	Coal	0.08 30-day c	0.012	ESP/WFGD & ULA SCR	Yes
Pacificorp- Naughton Unit 1	WY-0069	5/20/09	163 a	Coal	0.113 Annual d	0.004 g	FGC/ESP /WFGD	No
Pacificorp- Naughton Unit 2	WY-0069	5/20/09	218 a	Coal	0.0118 Annual d	0.004 g	FGC/ESP /WFGD	No
Constellation Power- Brandon Shores Units 1 & 2	MD-0038	6/2/07	710	Coal	0.114 & 0.103 Annual d	0.027	SI/FF	Yes
Kansas City P&L Iatan Unit 1	MO-0071	1/27/06	728 a	Coal	0.1 30-day	0.0055 c	FF/WFGD	Yes
Detroit Edison- Monroe Units 1-4	MI-0399	12/21/10	820 a	Coal	0.107 24-hour	0.005	ESP/WFGD	Yes
John W Turk Power Plant	AR-0094	11/5/08	600	Power River Basin Coal	0.08 30-day	0.0042	DFGD/FF	Yes
Duke Energy - Cliffside Unit 6 d	NC	Jan-08	800	Bituminous Coal	0.15 30-day c	0.005 c	SDA/FF/WFG D	Yes
Basin Electric Power- Dry Fork Station	WY-0064	10/15/07	385 net	Coal	0.07 12-month	0.0025	CDS/FF	Yes
Kansas City Power & Light Iatan Gen. Station Unit 2	MO-0071	8/3/07 d	850	Powder River Basin Coal	0.09 30-day	0.0055 c	FF/ WFGD	Yes
Dallman Power Plant Unit 4	IL-0107	8/10/06	250	Coal	0.2 30-day c	0.005	FF/WFGD/ WESP d	Yes
Louisville Gas and Electric Trimble County Unit 2	KY	Jan-06	750	Bituminous Coal & Petroleum Coke	0.11 24-hour c	0.0038 c	FF/WFGD/ WESP	Yes

Company – Facility- Unit	RBLC ID or State	Permit Date	Capacity MW	Primary Fuel	SO_2 lb/MMBtu	H_2SO_4 lb/MMBtu	H_2SO_4 and SO_2 Controls[b]	SCR Controls[b]
TXU Corporation – Oak Grove Units 1 & 2	TX	Jul-05	2 x 860	Texas Lignite	0.192 30-day c	0.0122 c	FF/WFGD	Yes
Public Service Company Comanche Station Unit 3	CO-0057	7/5/05	750	Subbituminous Coal	0.10 30-day c	0.0042 c	DFGD/FF	Yes
Newmont Nevada Energy TS Power Plant	NV-0036	5/5/05	200	Powder River Basin Coal	0.09 24-hour	0.001 (calculated) e	DFGD/FF	Yes
Prairie State Generating Co. Lively Grove, Illinois	IL	Apr-05	750	Illinois Coal	0.182 30-day c	0.005 c	ESP/WFGD/ WESP	Yes
Omaha Public Power District Nebraska City Station Unit 2	NE-0031	3/9/05	660	Subbituminous Coal	0.163 24-hour	0.0042	DFGD/FF	Yes
Sandy Creek Energy - Sandy Creek Energy Station	TX-0499	Mar-05	800	Powder River Basin Coal	0.12 30-day	0.0037	DFGD/FF	Yes
City Utilities of Springfield Southwest Station Unit 2	MO-0060	12-15-04	275	Powder River Basin Coal	0.095 30-day	0.00018 c	DFGD/FF	Yes
Wisconsin Public Service Corp. - Weston Unit 4	WI-0228	10-19-04	530	Powder River Basin Coal	0.1 30-day	0.005	DFGD/FF	Yes
Cancelled Units								
Tenaska Trail	TX-0585	12/30/10	900	Subbituminous	0.06 30-day	0.0037	FF/WFGD	Yes
Sand Sage Power Holcomb Unit 2	KS	12/16/10	660	Powder River Basin Coal	0.060 – 0.085 30-day c	0.0037 c	DFGD/FF	Yes
Coleto Creek- Unit 2	TX-0554	5/3/10	750	Power River Basin Coal	0.06 30-day	0.004	SDA/FF	Yes
Karn Weadock Generating Complex	MI-0389	12/29/09	930	Power River Basin Coal	0.06 30-day	0.004	HLI/FF/WFGD	Yes
American Municipal Power Generating Station Units 1 & 2	OH-0310	2/8/09	~500MW each	Coal	0.15 30-day	0.0075	FF/WFGD/ WESP	Yes
Associated Electric Company- Norborne Unit 1	MO-0071	2/22/08	780	Power River Basin Coal	0.065 30-day c 0.05 Annual c	0.0038 c	DFGD/FF	Yes

Company – Facility- Unit	RBLC ID or State	Permit Date	Capacity MW	Primary Fuel	SO_2 lb/MMBtu	H_2SO_4 lb/MMBtu	H_2SO_4 and SO_2 Controls[b]	SCR Controls[b]
Western Farmers Electric Coop - Hugo Unit 2	OK-0118	2/9/07	750	Subbituminous	0.065 30-day	0.0037	FF/ WFGD	Yes
Thoroughbred Generating Co. Thoroughbred Station	KY	Apr-06	750	Bituminous Coal	0.167 30-day c	0.0049 c	ESP or FF/WFGD/ WESP	Yes
Louisiana Generating Big Cajun II Unit 4	LA-0176	8/22/05	675	Powder River Basin Coal	0.1 annual	0.0013 (calculated) f	FF or ESP/ WFGD	Yes
Intermountain Power Service Corp. Intermountain Unit 3	UT-0065	10/15/04	950	Coal	0.09 30-day	0.0044	FF/ WFGD	Yes

Footnotes

a From environmental directory of U.S, Power Plants 1991, Edison Electric Institute.

b FF means fabric filter baghouse; ESP means (dry) electrostatic precipitator; WESP means wet electrostatic precipitator; WFGD means wet flue gas desulfurization; DFGD means dry flue gas desulfurization; SDA means spray dryer absorber; SI means sorbent injection; HLI means hydrated lime injection; CDS means circulating dry scrubber, FGC means flue gas conditioning, SCR means selective catalytic reduction for NOx control, ULA SCR means ultra-low activity SCR.

c From permit either because not in RBLC or RBLC is incorrect.

d From Acid Rain data base for 2013.

e Not permit limits. Calculated using RBLC pounds per hour limit divided by heat input (MMBtu/hr).

f From permit. Not a permit limit. Calculated: 38.7 tpy * 2000 lb/ton / 8760 hrs/yr / 6566 MMBtu/hr.

g. From Notice of Violation (NOV) to Pacificorp Energy, January 3, 2013. Stack test results showed H_2SO_4 emissions of 0.01 lb/MMBtu for Units 1 & 2. http://deq.state.wy.us/out/downloads/AQ_Enforcement/AQ%20NOV%201.3.13.pdf.

However, within the last ten years several new pulverized coal (PC) units burning moderate to high sulfur coals were permitted with the use of wet electrostatic precipitators (WESP) and reagent injection systems for H_2SO_4 control. Reagent injection systems for H_2SO_4 control identified in Table F-1 include: sorbent injection (SI), spray dryer absorber (SDA), and hydrated lime injection (HLI).[26] These systems use lime as the sorbent. Sodium based alkaline sorbents are used, particularly for existing PC fired utility boilers. These systems use trona, sodium carbonate, etc. One commercial reagent injection technology using sodium based reagents (sodium carbonate and sodium bi-sulfide solutions) has been applied at over 30 coal-fired utility boilers representing over 17,000 megawatts (MW) of electric generating capacity.[27]

Another technology identified in Table F-1 for the control of H_2SO_4 is the use of ultra-low activity (ULA) SCR. Catalysts used in SCR systems can be formulated in ways that reduce the oxidation of SO_2 to SO_3. Oxidation rates for SCR catalysts range from 0.3 percent to 3 percent.[28] For example, the CGS Unit 2 SCR catalyst oxidation rate is guaranteed ≤ 0.5 percent. As noted above, SRP intends to include ULA SCR catalyst as part of the SCR design for CGS Unit 1.

As discussed previously, the amount of H_2SO_4 generated is a function of combustion gas SO_2 concentration. Although not identified in the RBLC database review, H_2SO_4 formation can be reduced by firing lower sulfur content coals. Based on general knowledge of ways to reduce fuel sulfur content, the following control options are potentially applicable for the control of H_2SO_4 emissions:

- Coal switching- burning 100% very low sulfur coals (i.e., Powder River Basin (PRB) coal);
- Coal washing- reducing coal ash and sulfur content; and
- Coal processing- mixing the coal with chemicals that break the sulfur away from the coal molecules.

In summary, the following control technologies can potentially be used to reduce H_2SO_4 emissions in addition to the existing CGS Unit 1 control systems (PRB coal, hot-side ESP and WFGD):

- Coal Switching, Washing and Processing
- Flue Gas Conditioning
- Reagent/Sorbent Injection Systems
  - Calcium-based reagent injection
  - Sodium-based reagent injection
  - Hydrated lime injection
- Wet Electrostatic Precipitation

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[26] The circulating dry scrubber (CDS) system is a form of DFGD. Like DFGD, CDS is used primarily for the control of SO_2.
[27] SBS Technology™: http://www.aecomprocesstechnologies.com/wp-content/uploads/2014/10/SBS-brochure-10_01_2014.pdf.
[28] Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Version 2012, EPRI Technical Report 1023790. Page 4-7. Activity is measured/guaranteed based on the percent of SO_2 being oxidized to SO_3.

The installation of a reagent injection system followed by a polishing FF would require a major retrofit cost for installation of the FF in the existing flue gas path after the air heaters and before the WFGD. This option is a major retrofit application having capital and operating costs much greater than the installation of a WESP or other types of reagent injection systems and would be no more efficient for purposes of controlling H_2SO_4 emissions. Because of the higher cost and lack of additional benefit, use of FF is not considered further in this analysis.

F.2.2 STEP 2. Identify Technically Feasible Control Technologies

As discussed in Step 1, H_2SO_4 emissions may be controlled to varying degrees using PM and FGD control systems and low sulfur coals. CGS Unit 1 is already well controlled for PM, SO_2, and H_2SO_4 by the following systems in place: 60 to 100% PRB coal, hot-side ESP, WFGD. As discussed previously, the use of ultra-low activity SCR catalyst is an inherent part of the proposed project. Additional H_2SO_4 controls that are potentially applicable include:

- Coal Switching, Washing and Processing;
- Flue Gas Conditioning;
- Reagent/Sorbent Injection; and
- Wet Electrostatic Precipitation.

The following discussion identifies which of these control options are technically feasible and available.

F.2.2.1 Coal Switching, Washing and Processing

Fuel switching to a lower sulfur coal can be one option for reducing emissions of H_2SO_4. CGS Unit 1 currently fires sub-bituminous blends, but has historically burned bituminous and sub-bituminous coals, and may continue to do so in the future. Western bituminous coal has sulfur concentrations ranging from 1.0 to 1.5 percent with a heating value range of 9,200 to 12,000 British thermal unit (Btu) per pound. Sub-bituminous/PRB coal has sulfur concentrations below 0.5 percent with a heating value range of 8,000 to 8,600 Btu per pound. Switching to 100 percent PRB subbituminous coal could potentially reduce boiler SO_3 emissions. Currently, CGS Unit 1 burns 60 to 100 percent PRB coal. The decision on what coals and the amount of coals to burn has very complex technical and economic issues that include, in addition to the coal cost on a dollar per Btu basis, capability of the boiler to burn 100 percent PRB coal for long periods of time (furnace slagging/fouling, pulverized capacity, etc.), delivery reliability (PRB coals are shipped from Wyoming as opposed to the western bituminous coals which are found near the plant), and balance of plant impacts (ash disposal costs, FGD operating costs, etc.). Due to the lower heating value of PRB coal, the quantity of coal required at CGS Unit 1 will also go up by at least 15 to 40%. The reliability of PRB deliveries is a legitimate and significant concern. In order to minimize potential issues associated with dependable fuel delivery and to ensure economical long-term supply of fuel, CGS must keep the option to use western bituminous coals. Thus switching to 100% PRB subbituminous coal is not considered an available H_2SO_4 control option.

Coal washing, or beneficiation, is one pre-combustion method that has been used to reduce impurities in the coal (i.e., ash and sulfur). In general coal washing is accomplished by separating and removing inorganic impurities from organic coal particles. With washing of coal, rocks including sulfur bearing pyrites are removed, and a significant amount of coal is also lost. For economic reasons, coal washing occurs at the mine in order to reduce the cost of shipping the waste rock and to provide a disposal area for the waste rock. To date, no commercial coal washing plants have been built to wash western coals. This is because the sulfur contained in western coals, besides being low, is not found in the inorganic form, and as such not removable using conventional coal washing techniques. Research to date has demonstrated that washing western coals is technically infeasible and/or cost ineffective. Therefore, washing coal as a strategy to reduce H_2SO_4 emissions is not considered an available control option.

As is the case for most western coals, the sulfur in the coals burned by CGS Unit 1 is chemically connected to the coal's carbon molecules instead of existing as separate particles (i.e., pyritic form). This type of sulfur is called "organic sulfur," and washing won't remove that sulfur. Several processes have been tested that mix the coal with chemicals that break the sulfur away from the coal molecules. However, these processes have proven to be too expensive.[29] Scientists are still working to reduce the cost of these chemical cleaning processes which have not been demonstrated commercially. Therefore, coal processing as a strategy to reduce H_2SO_4 emissions is not considered an available control option.

F.2.2.2 Flue Gas Conditioning

Flue gas conditioning refers to the addition of water or chemicals to the flue gas in order to modify properties of fly ash or other particulate matter and thus improve the collection efficiency of the ESP or WFGD. It is most frequently used to upgrade existing ESPs. A conditioning agent may influence the ESP collection efficiency through one or more of the following mechanisms: 1) adsorbing on the surface of fly ash to reduce surface resistivity, 2) adsorbing on the fly ash to change the adhesion and cohesion properties of the ash, 3) increasing ultrafine particle concentrations for space charge enhancement, 4) increasing the electrical breakdown strength of the flue gas, 5) increasing the mean particle size, and 6) changing the acid dew point in the flue gas.[30]

Many chemicals and water have been used as conditioning agents at power plants or have been studied in the laboratory as potential conditioning agents. Of the commercially used conditioning agents, the most common are SO_3 and ammonia (NH_3). To a lesser extent is the use of ammonium compounds (sulfamic acid, $(NH_4)_2SO_4$, etc.), organic amines (triethylamine, trimethylamine, etc.), dry alkali compounds (Na_2SO_4 and Na_2CO_2), and humidification (injection of water). The injection of sulfur trioxide or ammonium compounds increase the amount of SO_3 in the flue gas and as a result are not technically feasible controls for SO_3. The effect of injecting organic amines for the control of H_2SO_4 is unknown. Humidification adds water upstream of the WFGD to slowly cool the flue gas below its acid dew point and thereby condense large acid droplets. The WFGD more effectively captures larger acid droplets. However, humidification upstream of the WFGD may cause fly ash dropout in the ductwork resulting in corrosion or choking of equipment near the WFGD inlet. This process has not been demonstrated on coal-fired boilers equipped with WFGD. Therefore, humidification is not considered a technically

[29] http://www.fossil.energy.gov/education/energylessons/coal/coal_cct2.html.

[30] United States Environmental Protection Agency document EPA/600/S7-85/005, Project Summary Flue Gas Conditioning.

feasible H_2SO_4 control option. Ammonia and dry alkali injection are discussed in the following subsection.

F.2.2.3 Reagent/Sorbent Injection

Reagent/sorbent injection systems use chemicals such as ammonia, sodium bisulfite ($NaHSO_3$) or lime (CaO) to react with SO_3 to form sulfate byproducts. Most of the reagent injection technologies react with SO_3 or H_2SO_4 to form a solid particle which is then collected by downstream particulate control systems or WFGD systems.

One sorbent injection system injects a solution of sodium bisulfite upstream in the flue gas. This reagent reduces SO_3 to SO_2 so that the sulfur dioxide may be collected in the WFGD system. Sulfur trioxide is removed according to the following general equation:

$$SO_3 + NaHSO_3 \rightarrow NaHSO_4 + SO_2$$

Reagent injection with NH_3 has achieved SO_3 reductions greater than 90 percent.[31]

In Table F-1, Brandon Shores Units 1 and 2 (MD-0038), Duke Cliffside Unit 6 (North Carolina), and Karn Weadock (MI-0389) are identified PC units permitted to use alkaline sorbent injection for H_2SO_4 control. The Duke Cliffside unit fires a medium sulfur bituminous coal and has a H_2SO_4 BACT emission limit of 0.005 lb/MMBtu (equal to 1.7 ppmv). The Brandon Shores units are capable of firing low, medium and high sulfur coals[32] and have a H_2SO_4 BACT emission limit of 0.027 lb/MMBtu (equal to 9.1 ppmv). Construction on the Karn Weadock units was cancelled.

One major factor with the application of some reagent injection technologies is the injection must be before a PM control device. Most coal-fired utility boilers have cold side ESPs or fabric filters. As a result, the injection of reagent will be ahead of the PM control device. However, as is the case with CGS Unit 1, some boilers are equipped with hot-side ESPs. In order to control the H_2SO_4 generated by the installation of the SCR system, the reagent injection would have to be before the WFGD system. As a result, the solid byproducts of the reagent injection system would have to be captured by the CGS Unit 1 WFGD system.

All of the reagent injection technologies increase the amount of PM in the flue gas; some more than others. Reagent injection technologies that inject a solid reactant (lime, sodium bicarbonate, etc.) increase the PM loading due to the solids injected. However, the solids injected are relatively large, greater than 10 µm, and would be removed to some extent by downstream PM controls or FGD systems. Although the injected solids would be removed to some extent by the WFGD system, the injected solids would result in solids deposits in the downstream equipment

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[31] Wet ESP vs. Sorbent Injection for SO_3 Control, Carl V. Weilert, Burns & McDonnell Engineering Company, 9400 Ward Parkway, Kansas City, MO 64114.

[32] On March 1, 2010, Constellation Energy announced completion of the Brandon Shores air quality control systems (AQCS) project. Perhaps the most distinctive design requirement was for the AQCS to treat flue gases from coal that has a sulfur content ranging from 0.4% to 4.0%. http://www.powermag.com/top-plantbrandon-shores-generating-station-pasadena-maryland.

and ductwork, and could cause operating issues with the WFGD system chemistry. Proper operation of the WFGD system is dependent on maintaining good process chemistry, and the introduction of an alkaline reagent could affect the operation and performance of the WFGD system.

Reagent injection technologies that inject a gas or liquid reactant increase the PM loadings due to the reaction product (ammonium sulfates, $NaHSO_4$, etc.). These solids are fine particulates, less than 2.5 µm, and are not easily removed by WFGD systems. Typically, WFGD systems only remove 50 to 60 percent of PM less than 10 µm.[33] However, one reagent injection vendor stated that the SBS™ reagent particulate capture across the WFGD systems has ranged from 98-99.8%, with the lower removal on an 1980's vintage wet scrubber and the higher removal on a modern high-efficiency wet scrubber design.[34]

F.2.2.4 Wet Electrostatic Precipitators

The principle of operation of a WESP is similar to a dry ESP. Particulate matter in the flue gas is exposed to an electric field which induces a charge on the particle which is then drawn to an oppositely charged collection electrode. However, in a WESP, the flue gas is cooled near or below the dew point and consequently PM may be present as either solid or liquid particles. In recent PC boiler applications of WESP technology, the WESP is placed downstream of a WFGD for the control of sulfuric acid mist. In this type of application, the flue gas temperature is below the H_2SO_4 and water saturation temperatures as it passes through the WESP. As such, water droplets and other condensable materials in the flue gas stream are charged and collected by the ESP plates. Filterable particulate matter, not previously collected by the WFGD system or entrained from the WFGD system, will also be collected in the WESP. The collection electrodes are either continuously or periodically flushed with water to remove collected materials. For large flue gas flow applications, plate type WESPs are most commonly used. Recently membrane-type WESPs have been commercially demonstrated at industrial scale and have been pilot tested on coal/coke-fired boiler flue gas. Each of these types is discussed below.

Conventional WESP

Conventional WESPs have been reported to provide significant control of filterable (solid and liquid) PM. The EPA Air Pollution Control Technology Fact Sheet for conventional WESPs[35] reports filterable PM2.5 control efficiencies of 90.0 to 99.2 percent for various industrial applications, although it does not list utility boilers among the typical industrial applications. The fact sheet does not specify whether it is referring to total (including condensables) or filterable PM, but filterable emissions are implied. A report of WESP improvements undertaken at the

[33] Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Version 2012, EPRI Technical Report 1023790. Table 4-5.

[34] Email from Sterling Gray (URS) sent Tuesday, April 08, 2014 4:41 PM to Thomas Emmel (RTP Environmental); Subject: RE: SBS Technology Application Questions.

[35] EPA-452/F-03-030, "Wet Electrostatic Precipitator (ESP) – Wire-Plate Type."

AES Deepwater cogeneration plant to reduce visible emissions[36] provides measured control efficiencies for both filterable and condensed PM. It was reported that "…the WESP also removed filterable flyash on the order of 90%". The AES Deepwater facility test report concludes that 90 percent control of H_2SO_4 is "achievable." The investigators' primary interest was the reduction of H_2SO_4 which was contributing to unacceptable visible emissions. One can assume, however, that the control efficiency for all condensed acid gases would similarly be near 90 percent or better. A Wheelabrator technical paper reported H_2SO_4 emissions control efficiencies of between 65 and 88 percent.[37]

Membrane WESP

Membrane WESPs use the same electrostatic principles used in conventional WESPs, but they utilize polypropylene membranes rather than steel plates as collection surfaces. The membrane collectors are made of corrosion-resistant fibers. Capillary action between the fibers maintains an even distribution of water throughout the membrane. In addition to flushing collected particles, the water acts as the charge-carrying electrode. These attributes of membrane WESPs avoid issues with plate-type WESPs such as: field disruptions that occur due to spraying (misting) of water, and formation of dry spots (channeling) that causes collector surface corrosion and reduced collector efficiency. Pilot test data from the DOE Utility Pilot Unit at First Energy's Bruce Mansfield Plant, Shippingport, PA indicate that a membrane WESP is somewhat more effective at collecting H_2SO_4 as SO_3 than a steel plate WESP.[38] Table F-2 summarizes the study results.

Table F-2. H_2SO_4 Emissions Evaluation for Metal-Plate and Membrane WESP

Parameter	Metal Plate Wet ESP		Membrane Wet ESP	
Comparative ESP Gas Velocities	Low Velocity	Moderate Velocity	Low Velocity	Moderate Velocity
H_2SO_4 Reduction %	88	65	93	71

To date, commercial installations of membrane WESP units have only been on industrial facilities, with no utility applications.[39]

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[36] "Performance Evaluation of Wet Electrostatic Precipitator at AES Deepwater," Ron Triscori, *et al*., June 2007, see http://www.babcock.com/library/pdf/BR-1796.pdf.

[37] "SO_3 Control and Wet ESP Technology," James "Buzz" Reynolds, Wheelabrator Air Pollution Control Inc., published in the Proceedings of the 2006 Environmental Controls Conference, U.S. Department of Energy, National Energy Technology Laboratory; see http://www.netl.doe.gov/publications/proceedings /06/ecc/pdfs/Reynolds_Summary.pdf.

[38] "MEMBRANE WESP – A Lower Cost Technology to Reduce PM2.5, SO_3 & HG^{+2} Emissions," John Caine and Hardik Shah, Southern Environmental, Inc., published technical paper for 2006 Air & Waste Management Association; see http://www.southernenvironmental.com/_pdf/Membrane%20WESP_Paper.pdf & sales brochure: http://www.southernenvironmental.com/_pdf/membraneWESPbrochure.pdf.

[39] May 9, 2014 telephone conversation between Tom Emmel RTP Environmental Associates, Inc. and Hardik Shah, Southern Environmental, Inc.

WESP Performance Summary

WESPs are expected to be effective in controlling H_2SO_4 emissions at saturated flue gas conditions. Units/plants permitted with WESPs include: We Energies' Elm Road Generating Station Units 1 & 2 (Wisconsin), American Municipal Power Generating Station Units 1 & 2 (Ohio), Prairie State Generating Company (Illinois), Thoroughbred Generating Station (Kentucky), Dallman Unit 4 (Illinois), and LG&E's Trimble County Unit 2 (Kentucky). These units have permitted emission limits ranging between 0.0038 and 0.01 lb/MMBtu.[40] We Energies' Elm Road Generating Station Units 1 & 2, Prairie State Generating Company Units 1 and 2, and Dallman Unit 4 are operational.

When used in conjunction with WFGD systems and high sulfur fuels, WESPs are very effective at reducing sulfuric acid mist. However, WESP systems have only been required for PC fired boilers firing high percentages of medium to high sulfur bituminous coals or petroleum coke and equipped with WFGD systems for SO_2 control. In these medium to high sulfur fuel applications, H_2SO_4 concentrations leaving the WFGD system may be as high as 10 to 40 ppm, or 0.03 to 0.12 lb/MMBtu. WESP control efficiencies when applied to boiler flue gases with high concentrations of H_2SO_4 are on the order of 90 percent.[41]

While the use of a WESP system is technically feasible for application at the CGS Unit 1, there are no WESP demonstrations that indicate the use of WESP on units that fire a significant percentage of subbituminous coal would reduce emissions by a quantifiable amount below the levels which can be achieved without a WESP system. Recent stack testing at CGS Unit 2, which was retrofit with an SCR system in 2014, measured H_2SO_4 emissions as 0.002 lb/MMBtu without the application of any H_2SO_4 controls.[42] This H_2SO_4 level is lower than most of the H_2SO_4 permit limits in the RBLC database. Between the existing units and operational new units identified in Table F-1, only NV-0036 and MO-0060 have H_2SO_4 permit limits below 0.002 lb/MMBtu. Both of these units burn western subbituminous coals and are equipped with DFGD/FF for SO_2 and PM control. It is unknown at this time how effective a WESP would be at reducing H_2SO_4 emissions when the inlet H_2SO_4 concentration is very low.

F.2.3 STEP 3. Rank the Technically Feasible Control Technologies

Based on the Step 2 analysis, the following H_2SO_4 controls are considered technically feasible and available: reagent injection and WESP. Table F-1 is a summary of the H_2SO_4 emission limits for PC boilers based on the EPA's RBLC database, and a review of other recently permitted sources. For units permitted with WESPs that are operational, H_2SO_4 emission limits representing BACT range from 0.005 lb/MMBtu (Dallman Unit 4 and Prairie State Units 1 & 2)

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[40] We Energies' Elm Road Generating Station Units 1 & 2 (Wisconsin) is the only permit not shown as it was permitted more than 10 years ago.

[41] Wet ESP vs. Sorbent Injection for SO_3 Control, Carl V. Weilert, Burns & McDonnell Engineering Company, 9400 Ward Parkway, Kansas City, MO 64114.

[42] Information from a single stack test does not account for the variability in emissions of H_2SO_4 from the CGS units.

to 0.01 lb/MMBtu (We Energies' Elm Road Generating Station Units 1 & 2).[43] For operational units permitted with reagent injection technologies (SI and SDA) in Table F-1, H_2SO_4 emission limits representing BACT range from 0.005 lb/MMBtu (Duke Energy's Cliffside Unit 6) to 0.027 lb/MMBtu (Brandon Shores Units 1 & 2). Currently, CGS Unit 2 has a H_2SO_4 emissions limit of 0.006 lb/MMBtu without any specific H_2SO_4 emission controls (WESP or reagent injection).[44] Recent stack testing at CGS Unit 2, which was retrofit with an SCR system in 2014, measured H_2SO_4 emissions as 0.002 lb/MMBtu without the application of any H_2SO_4 controls.[45] Since CGS Units 1 and 2 are similar units, except that Unit 2 is equipped with SCR, it is assumed for baseline purposes that the emissions from CGS Unit 1 will be similar to the CGS Unit 2 permit limit after the installation of SCR on CGS Unit 1. Although undemonstrated on coal-fired boilers firing low-sulfur, alkaline ash coals, such as PRB coals burned by CGS Unit 1, it is assumed that the application of WESP or reagent injection can lower H_2SO_4 emissions to 0.0005 lb/MMBtu. This H_2SO_4 emission rate is based on conservatively assuming two and half (2.5) times the recent CGS unit 2 H_2SO_4 testing result controlled by 90 percent by the application of WESP or reagent injection technology.[46]

F.2.4 STEP 4. Evaluate the Most Effective Controls

Based on the Step 3 discussion, for this analysis, the maximum achievable emission reduction is based on reducing H_2SO_4 emission from 0.005 lb/MMBtu (1.7 ppm) down to 0.0005 lb/MMBtu (0.17 ppm) using either a WESP or reagent injection. The following subsections identify the BACT impacts (environmental, economic and energy) of WESP and reagent injection technologies. The results will show that the application of a WESP or reagent injection is not cost effective as BACT for the Coronado Unit 1 application.

F.2.4.1 Wet Electrostatic Precipitators

Table F-3 presents the environmental, economic and energy impacts for reducing H_2SO_4 emissions by 90 percent using a WESP, and the results are discussed in the following subsections.

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[43] A permit limit is not demonstrated until the unit is in operation and a compliance test demonstrates compliance with the limit. It is assumed that operational units have demonstrated compliance with the applicable emissions limits. As such, these units are the focus of the analysis.
[44] Page 42 of the TV Permit Renewal Number 52639, SRP – Coronado Generating Station, December 6, 2011.
[45] Information from a single stack test does not account for the variability in emissions of H_2SO_4 from the CGS units.
[46] 0.0005 lb/MMBtu = 0.002 lb/MMBtu from stack test x 2.5 conservancy factor x 1 – 90% control/100.

Table F-3. Summary of H_2SO_4 BACT Impacts for Wet ESP Addition after WFGD System

Parameter	WFGD-Baseline	WFGD Plus WESP
Boiler Heat Input, MMBtu/hour (HHV)	4,719	
Flue Gas From FGD, scfm	939,868	
Unit Gross Generation, kW	456,000	
Controlled Emission Rate, lb/MMBtu	0.005	0.0005
Potential H_2SO_4 Emissions, tons per year	103	10
WESP Total Capital Requirement, $	n/a	$29,112,000
Capital Recovery Factor (CRF)	n/a	0.0944
Annual Capital Cost, $/yr	n/a	$2,748,000
Annual O&M Cost, $/yr	n/a	$5,487,000
Total Annual Cost, $/yr	n/a	$8,235,000
Ton Reduced, tons per year	n/a	93
Cost per Incremental Ton Reduced, $ per ton	n/a	$88,500

Environmental Impacts

The primary environmental impact of adding the WESPs after the WFGD is the reduction in total H_2SO_4 emissions from 0.005 to 0.0005 lb/MMBtu assuming a 90% control efficiency. The addition of a WESP would reduce potential H_2SO_4 emissions from 103 tons per year to 10 tons per year, resulting in a reduction in total H_2SO_4 emissions of 93 tons per year. In addition emissions of PM2.5 would be reduced by approximately 80 percent. On the negative side, an acid waste water stream is generated which will require additional processing before disposal of the wet solids and the waste water stream.

Economic Impacts

The addition of a WESP after the WFGD system would have a significant economic impact (Unit is equipped with ESP and WFGD that are considered the baseline for the analysis). The capital costs of retrofitting a WESP on top of the current WFGD system is estimated at $29.1 million based on a cost of $26.5 dollars per wet standard cubic feet of flue gas.[47] This equates to $64 per kilowatt, which is consistent with the costs reported by others for retrofit installations.[48]

The total annual cost of $8.2 million per year is based on:

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[47] EPA-452/F-03-030, "Wet Electrostatic Precipitator (ESP) – Wire-Plate Type." Capital cost range of 20 to 40 dollars per scfm; used $20 per scfm escalated from 2002 dollars to 2015 dollars using CPI-U: U.S. city average cost index. http://www.economagic.com/em-cgi/data.exe/blscu/CUUR0000AA0.

[48] One vendor has indicated that the total installed cost of a vertical flow WESP integrated into the top of a retrofit FGD absorber tower will range from $20/kW to $40/kW, depending on the design SO_3 collection efficiency. The cost of the external horizontal flow WESP at Dakota Gasification has been reported to be approximately $90/kW. Wet ESP vs. Sorbent Injection for SO_3 Control, Carl V. Weilert, Burns & McDonnell Engineering Company, 9400 Ward Parkway, Kansas City, MO 64114.

- A capital recovery factor of 0.0944 (20-year life and 7 percent societal cost of money per U.S. EPA guidance), and
- Annual operating and maintenance cost of $5 per standard cubic feet a minute (scfm) of flue gas.[49]

From Table F-3, the incremental cost effectiveness of adding a WESP to the existing WFGD outlet duct work is greater than $88,000 per ton of H_2SO_4 reduced. This is a very high cost of control demonstrating that the addition of a WESP is not cost effective as BACT.

Energy Impacts

The primary energy impacts of the WESP technology would be increased electrical demand for operation of the WESP and additional ID fan power requirements for the increase in pressure drop.

F.2.4.2 Reagent Injection

Pilot scale and full-scale testing and commercial operation have confirmed that up to 90% or greater SO_3 control efficiency is possible with several different sorbents, including ammonia and SBS™.[50] Control efficiency performance with other sorbents is somewhat lower at 70 to 90%. Table F-4 presents the environmental, economic and energy impacts for reducing H_2SO_4 emissions by 70 and 90 percent using reagent injection technologies. The environmental, economic, and energy impacts are discussed in the following subsections.

Table F-4. Summary of H_2SO_4 BACT Impacts for Reagent Injection

Parameter	WFGD-Baseline	Reagent Injection at 90% Control	Reagent Injection at 70% Control
Boiler Heat Input, MMBtu/hour (HHV)	4,719		
Flue Gas From FGD, scfm	1,097,387		
Unit Gross Generation, kW	456,000		
Controlled Emission Rate, lb/MMBtu	0.005	0.0005	0.0015
Potential H_2SO_4 Emissions, tons per year	103	10	31
Total Capital Requirement, $	n/a	$6,840,000	$6,840,000
Capital Recovery Factor (CRF)	n/a	0.0944	0.0944
Annual Capital Cost, $/yr	n/a	$646,000	$646,000
Annual O&M Cost, $/yr	n/a	$46,000	$35,000
Incremental Total Annual Cost, $/yr	n/a	$692,000	$681,000
Incremental Ton Reduced, tons per year	0	93	72
Incremental Cost Effectiveness, $ per ton	n/a	$7,440	$9,414

Environmental Impacts

[49] Air Pollution Control Technology Fact Sheet EPA-452/F-03-030; low end of the range for operating and maintenance cost for wire-plate type WESP.

[50] Wet ESP vs. Sorbent Injection for SO_3 Control, Carl V. Weilert, Burns & McDonnell Engineering Company, 9400 Ward Parkway, Kansas City, MO 64114. Page 6.

The primary environmental impact of reagent injection is the reduction in H_2SO_4 emissions from 0.005 lb/MMBtu to 0.0015 lb/MMBtu for 70% control, and to 0.0005 lb/MMBtu for 90% control. Reagent injection would reduce H_2SO_4 emissions by 72 tons for 70% control and 93 tons for 90% control. On the negative side, with reagent injection systems there will be a small increase in plant solid waste and a potential increase in PM emissions from the WFGD stack.

Additionally, as discussed above, the use of reagent injection systems to control H_2SO_4 emissions will result in an increase in PM2.5. The CGS Unit 1 WFGD may capture 50 to 60 percent of the PM2.5, with the remainder being emitted from the WFGD stack. This collateral increase in PM2.5 along with the undemonstrated status of reagent injection on boilers firing low-sulfur, alkaline ash coals makes the use of reagent injection systems infeasible as BACT for technical and environmental impact reasons for CGS Unit 1.

Economic Impacts

The addition of a reagent injection system before the WFGD system would have a negative economic impact (Unit is equipped with ESP and WFGD that are considered the baseline for the analysis). The capital costs of retrofitting a reagent injection system before the WFGD system is estimated at $6.8 million based on an average cost of $15 per kilowatt.[51] The total annual cost of approximately $0.68 million per year is based on:

- A capital recovery factor of 0.0944 (20-year life and 7 percent societal cost of money per U.S. EPA guidance); and
- Annual operating and maintenance cost of $600 per ton of SO_3 removed.[52]

From Table F-4, the incremental cost effectiveness of adding a reagent injection system before the exiting WFGD is greater than $7,400 per ton of H_2SO_4 reduced. This is a high cost of control and is not economically feasible as BACT.

Energy Impacts

The application of a retrofit reagent injection would result in a small increase in power requirements for the injection system pumps (for liquids injection) or air compressors (for solids injection).

F.2.5 STEP 5. Proposed Sulfuric Acid Mist BACT Determination

Based on the Step 4 analysis, the application of WESP technology and reagent injection technology are not BACT. Either of these control options would have significant, adverse economic impacts and would provide negligible, beneficial environmental impacts, as reflected in the calculated cost effectiveness values of >$88,000 per ton of H_2SO_4 removed and >$7,000 per ton of H_2SO_4 removed, respectively. Additionally, WESP and reagent injection technologies have not been commercially demonstrated to achieve 70% to 90% control for the very low H_2SO_4 emissions expected from firing low-sulfur western coals, use of hot-side ESP, use of ultra-low activity SCR catalyst, and use of WFGD.

[51] "SBS Injection™ Technology: SO_3 Control for the Power Industry," URS Corporation, 2012.
[52] Ibid.

Therefore, SRP proposes an emission limit of 0.005 pounds per MMBtu heat input as BACT for H_2SO_4 emissions from CGS Unit 1. Compliance with this limit will be determined using EPA Conditional Test Method 13, based on the average of three test runs of at least two hours each. This limit reflects the use of low-sulfur western coals and ultra-low activity SCR catalyst and continuous performance of the existing boiler, HESP, and WFGD system in accordance with good air pollution control practice.

F.3 PM10 & PM2.5 BACT Analysis

Flue gas emitted from large, coal-fired boilers, such as CGS Unit 1, contains particulate matter. Particulate matter is from inorganic material in the coal, organic material from the incomplete combustion of the coal organic matter, and condensed organic and inorganic compounds in the flue gas that are not captured by the pollution control devices for solid matter. From well controlled boilers such as CGS Unit 1, the particulate matter emitted is essentially all less than 2.5 µm (PM2.5); thus, the PM10 and PM2.5 emission rates are identical, and the filterable PM10 and PM2.5 emission rates are identical to the filterable PM emission rate. In addition, because CGS Unit 1 is equipped with a WFGD system and its exhaust gases are saturated with water, there is no reference method that can be applied to determine whether any fraction of the filterable PM emissions from this unit is made up of particles having a mean aerodynamic diameter less than 10 µm or 2.5 µm. The EPA test method for PM10 and PM2.5 emissions is Reference Method 201A. Paragraph 1.5 of this method states the following:

> Limitations. You cannot use this method to measure emissions in which water droplets are present because the size separation of the water droplets may not be representative of the dry particle size released into the air. To measure filterable PM10 and PM2.5 in emissions where water droplets are known to exist, we recommend that you use Method 5 of appendix A-3 to part 60.

As a result, the following discussion will focus on the control of PM2.5, but the resulting emission limit will be expressed as total particulate matter, with the filterable fraction measured using Reference Method 5.

In the preamble to the NSR regulations for PM2.5, EPA states that "fine particles in the atmosphere are made up of a complex mixture of components. Common constituents include sulfate (SO_4); nitrate (NO_3); ammonium; elemental carbon; a great variety of organic compounds; and inorganic material (including metals, dust, sea salt and other trace elements) generally referred to as 'crustal' material, although it may contain material from other sources." EPA further states that "*Primary* particles are emitted directly into the air as a solid or liquid particle (e.g., elemental carbon from diesel engines or fire activities, or condensable organic particles from gasoline engines). *Secondary* particles (e.g., sulfate and nitrate) form in the atmosphere as a result of various chemical reactions."[53]

[53] 73 FR 28321, May 16 2008.

Primary PM2.5 Emissions
Primary PM2.5 emissions from CGS Unit 1 can be broken into two components with distinct physical and chemical properties in the boiler flue gas stream. Filterable PM2.5 consists of particulate matter less than 2.5 µm in size that is collected on an appropriate filter in a stack sampling train. Condensable PM2.5 is defined by EPA as "material that is vapor phase at stack conditions, but which condenses and/or reacts upon cooling or dilution in the ambient air to form solid or liquid particulate matter immediately after discharge from the stack. Note that all condensable particulate matter is assumed to be in the PM2.5 size fraction."[54]

Secondary PM2.5 Emissions
EPA has identified several gases as potential precursors of PM2.5 and requires consideration of each in NSR permitting as follows:

- Sulfur dioxide (SO_2) – treated as a precursor in all areas;
- Nitrogen oxides (NOx) – presumed to be a precursor in all areas unless state or EPA rebuts presumption;
- Volatile Organic Compounds (VOC) – not regulated as a precursor unless state or EPA provides a demonstration that VOCs are a significant contributor to ambient PM2.5 concentrations; and
- Ammonia (NH_3) – not regulated as a precursor, but can be regulated case-by-case in non-attainment areas.

In the *Federal Register*, EPA acknowledges that three of the four listed potential precursor pollutants are criteria pollutants that are already regulated and typically subject to limits in an NSR permitting review. Therefore, regulation of these pollutants as precursors for PM2.5 "is not expected to add a major burden to regulated sources."[55] The proposed SCR Project will not result in any increases in these regulated precursors emissions from CGS Unit 1. The area in which CGS is located is designated in attainment, and therefore ammonia may not be regulated as a precursor here. As a result, secondary PM2.5 emissions are not addressed herein.

F.3.1 STEP 1. Identify All Potential Control Technologies

Table F-5 summarizes the permit limits and PM and acid gas control technologies identified through the RBLC database search and the review of permits for existing and new coal-fired boilers not found in the RBLC database. Primary filterable PM controls include ESPs and FFs. Acid gas controls include wet and dry FGD. Condensed acid gas controls include reagent injection (HLI- hydrated lime injection, and SDA-spray dryer absorber) and WESP technologies.

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[54] 40 CFR §51.50.
[55] 73 FR 28321, May 16 2008.

Table F-5. PM10/PM2.5 BACT Controls and Limits for PC Fired Electric Generating Units

Company – Facility- Unit	RBLC ID or State	Permit Date	Capacity MW	Primary Fuel	PM2.5 lb/MMBtu	Other PM lb/MMBtu [b]	PM and SO_2 Controls [c]	SCR Controls [c]
Existing Units								
Limestone Electric Generating Station Units 1 & 2	TX-0700	12/20/2013	900 each	Lignite	0.03 TPM2.5	0.03 TPM10	ESP/WFGD	No
Pacificorp Energy- Jim Bridger Unit 3	WY-0073	6/17/13	561 a	Subbituminous	0.0205 TPM2.5	0.0418 TPM10	ESP/WFGD	No
Pacificorp Energy- Jim Bridger Unit 4	WY-0073	6/17/13	561 a	Subbituminous	0.018 TPM2.5	0.0397 TPM10	ESP/WFGD	No
Salt River Project- Coronado Unit 2	AZ-0050	1/22/09	411 a	Coal	None d	0.03 FPM10	ESP/WFGD	Yes
Duke- Crystal River Units 4 & 5	FL-0295	5/18/07	760	Coal	None d	0.03 FPM10	ESP/WFGD	Yes
Kansas City P&L Iatan Unit 1	MO-0071	1/27/06	728 a	Coal	None d 0.0244 TPM10 e	0.0244 TPM10	FF/WFGD	Yes
Detroit Edison- Monroe Units 1-4	MI-0399	12/21/10	820 a	Coal	None 0.024 TPM10 e	0.011 FPM 0.024 TPM10	ESP/WFGD	Yes
Operational New Units								
John W Turk Power Plant (operational)	AR-0094	11/5/08	600	Power River Basin Coal	None 0.025 TPM10 e	0.012 FPM10 0.025 TPM10	DFGD/FF	Yes
Duke Energy - Cliffside Unit 6 d (operational)	NC	Jan-08	800	Bituminous Coal	None d 0.018 TPM10 e	0.012 FPM10 0.018 TPM10	SDA/FF/WFGD	Yes
Basin Electric Power- Dry Fork Station (operational)	WY-0064	10/15/07	385 net	Coal	None	0.012 FPM10	CDS/FF	Yes

Company – Facility- Unit	RBLC ID or State	Permit Date	Capacity MW	Primary Fuel	PM2.5 lb/MMBtu	Other PM lb/MMBtu [b]	PM and SO_2 Controls [c]	SCR Controls [c]
Kansas City Power & Light Iatan Gen. Station Unit 2 (operational)	MO-0071	8/3/07 d	850	Powder River Basin Coal	None d 0.0236 TPM10 e	0.014 FPM10 d 0.0236 TPM10 d	FF/ WFGD	Yes
Dallman Power Plant Unit 4 (operational)	IL-0107	8/10/06	250	Coal	None d 0.035 TPM e	0.012 PM d 0.035 TPM	FF/WFGD/ WESP d	Yes
Public Service Company Comanche Station Unit 3 (operational)	CO-0057	7/5/05	750	Subbituminous Coal	None d 0.022 TPM e	0.020 TPM10 d 0.022 TPM d	DFGD/FF	Yes
Newmont Nevada Energy TS Power Plant (operational)	NV-0036	5/5/05	200	Powder River Basin Coal	None d	0.012 FPM10	DFGD/FF	Yes
Prairie State Generating Co. Lively Grove, Illinois	IL	Apr-05	750	Illinois Coal		0.018-0.035 TPM10 d f	ESP/WFGD/ WESP	Yes
Omaha Public Power District Nebraska City Station Unit 2 (operational)	NE-0031	3/9/05	660	Subbituminous Coal	None d 0.018 TPM e	0.018 TPM	DFGD/FF	Yes
Sandy Creek Energy - Sandy Creek Energy Station (operational)	TX-0499	Mar-05	800	Powder River Basin Coal	None d 0.040 TPM10 e	0.015 FPM10 0.040 TPM10 d	DFGD/FF	Yes
City Utilities of Springfield Southwest Station Unit 2 d (operational)	MO-0060	12-15-04	275	Powder River Basin Coal	None d	0.018 FPM10 d	DFGD/FF	Yes
Wisconsin Public Service Corp. - Weston Unit 4 (operational)	WI-0228	10-19-04	530	Powder River Basin Coal	None d 0.02 TPM e	0.018 TPM10 d 0.02 TPM d	DFGD/FF	Yes
Cancelled New Units								

Company – Facility- Unit	RBLC ID or State	Permit Date	Capacity MW	Primary Fuel	PM2.5 lb/MMBtu	Other PM lb/MMBtu [b]	PM and SO_2 Controls [c]	SCR Controls [c]
Coleto Creek- Unit 2 (cancelled)	TX-0554	5/3/10	750	Power River Basin Coal	None d 0.025 TPM e	0.012 FPM10 0.025 TPM	SDA/FF	Yes
Tanaska Trail (cancelled)	TX-0585	12/30/10	900	Subbituminous	None d 0.025 TPM10 e	0.012 FPM10 0.025 TPM10 d	FF/WFGD	Yes
Karn Weadock Generating Complex (cancelled)	MI-0389	12/29/09	930	Power River Basin Coal	None TPM10 e	0.011 FPM 0.024 TPM10	HLI/FF/WFGD	Yes
American Municipal Power Generating Station Units 1 & 2 (cancelled)	OH-0310	2/8/09	~500MW each	Coal	None d 0.025 TPM10 e	0.015 FPM10 d 0.025 TPM10 d	FF/WFGD/ WESP	Yes
Associated Electric Company-Norborne Unit 1 (cancelled)	MO-0071	2/22/08	780	Power River Basin Coal	None d 0.018 TPM10 e	0.012 FPM10 d 0.018 TPM10	DFGD/FF	Yes
Western Farmers Electric Coop - Hugo Unit 2 (cancelled)	OK-0118	2/9/07	750	Subbituminous	None d 0.025 TPM10 e	0.015 FPM10 0.025 TPM10 d	FF/ WFGD	Yes
Louisiana Generating Big Cajun II Unit 4 (cancelled)	LA-0176	8/22/05	675	Powder River Basin Coal	None d	0.015 FPM10 d	FF or ESP/ WFGD	Yes
Sand Sage Power Holcomb Unit 2 (cancelled)	KS	Jun-05	660	Powder River Basin Coal	0.012 FPM d	0.012 FPM10 d	DFGD/FF	Yes
Intermountain Power Service Corp. Intermountain Unit 3 (cancelled)	UT-0065	10/15/04	950	Coal	None d	0.012 FPM10	FF/ WFGD	Yes

Footnotes

a From environmental directory of U.S, Power Plants 1991, Edison Electric Institute.

b TPM10 assumed to include filterable and condensable fractions; FPM10 includes only filterable fraction.
c FF means fabric filter baghouse; ESP means (dry) electrostatic precipitator; WFGD means wet flue gas desulfurization; DFGD means dry flue gas desulfurization; SDA means spray dryer absorber; CDS means circulating dry scrubber, SCR means selective catalytic reduction for NOx control.
d From permit either because not in RBLC or RBLC is incorrect.
e Assumed that TPM and TPM10 equals to TPM2.5.
f A lower limit (as low as 0.018 lb/million Btu) may be set based on a reevaluation of the above limit based upon actual PM10 emissions.

A single piece of emissions control equipment often controls multiple pollutants, and multiple pieces of pollution control equipment work together to control emissions of various pollutants to certain levels. For these reasons, it is necessary to evaluate the control equipment system as a whole. The following discussion of potential PM2.5 control options will focus on control options that can enhance the removal of PM2.5 beyond the proposed BACT for H_2SO_4: hot-side ESP and WFGD.

Hot-side ESPs have excellent filterable PM removal capabilities and poor vapor-phase acid gas removal capabilities. WFGD systems have excellent vapor-phase acid gas removal capabilities, and poor filterable PM control capabilities. Table F-6 presents a description of PM BACT control technologies identified in Table F-5, which are potentially transferable to CGS Unit 1 to improve the control of PM2.5.

Table F-6. Typical Control Technologies for Total PM

Control Technology	Primary PM2.5 Component Controlled
Project Controls also BACT for H_2SO_4	
Hot side ESP	Filterable particulate
Wet Flue Gas Desulfurization (WFGD)	Vapor phase acid gases and some filterable and condensed particulate
Additional Compatible Controls	
Fabric Filter (FF)	Filterable and condensed particulate and vapor phase acid gases if capturing alkaline ash or if alkaline sorbent is injected
Wet Electrostatic Precipitator (WESP)	Filterable and condensed particulate
Reagent Injection – Solid type – Liquid type – Gaseous Type	Vapor phase acid gases

As Table F-6 shows, there are a number of additional controls that can be applied at CGS Unit 1 to enhance the removal of additional PM2.5. The addition of a FF downstream of the air heater would reduce filterable and condensed PM2.5. The FF would also reduce vapor-phase acid gas, such as H_2SO_4, hydrogen chloride, and hydrogen fluoride, if the coal fly ash is alkaline, which it is for CGS Unit 1 because of the high percentage of PRB coal fired. Also, the injection of alkaline solids (e.g., lime) before the FF would enhance the removal of vapor-phase acid gas. Other additional control options effective at removing filterable and condensable PM2.5 include the use of a WESP and the use of reagent injection. Both of these controls were discussed in the section addressing control of H_2SO_4 emissions (refer to Section F.2).

F.3.2 STEP 2. Identify Technically Feasible Control Technologies

As noted above, filterable and condensable PM2.5 and vapor-phase condensable gases are controlled to varying degrees using particulate matter and acid gas control systems. As identified in Step 1, filterable (solid and liquid) and condensable (acid gases) controls are considered to address PM2.5 emissions. CGS Unit 1 PM2.5 emissions may be further reduced through the application of FF, WESP, or reagent injection technologies. The use of these controls for PM2.5 specifically at CGS Unit 1 is discussed below.

F.3.2.1 Fabric Filter

Fabric filters separate dry particles from the boiler flue gas by filtering the flue gas through fabric filters or "bags." The components of a FF include the fabric bags, a tube sheet to support the bags, a gas-tight enclosure, a mechanism to clean accumulated PM from the bags, and a hopper to collect accumulated particulate. Particulate matter in the flue gas enters the FF and passes through the bags. As the flue gas flows through the filter fabric, a layer of PM, called the "filter cake", builds up on the fabric. The primary filtering media is actually the filter cake rather than the fabric itself. At coal-fired power plants, FFs are used as the primary PM control device. Typical FF configurations at coal-fired power plants include downstream of the units air heaters or downstream of a spray dryer vessel if the FF is also being used as a component of a dry FGD system. Fabric filters are not used downstream of a wet FGD system due to the moisture (condensed water) content in the flue gas, which will wet and rapidly plug the fabric filters.

Fabric filters have several advantages when used for PM control from coal-fired boilers, including:

- High particulate matter control efficiencies;
- Relatively constant outlet grain loading over the entire boiler load range; and
- Simple operation and maintenance.

Fabric filters have superior PM2.5 reduction performance relative to dry ESPs for coal-fired boiler applications. The primary disadvantage of fabric filter baghouses is the relatively high pressure drop across the baghouse as compared to a dry ESP and the resulting increased fan power requirements.

For CGS Unit 1, the primary PM control device is the hot-side ESP. There are two potential options for improving the reduction of filterable PM using FFs for CGS Unit 1. One option is the installation of a FF downstream of the air heater and before the WFGD. Another option is the conversion of the exiting ESP to a combined ESP/FF system; also known as the COHPAC system.[56] Both of these options are major retrofit applications having capital and operating costs much greater than the installation of a WESP. Additionally, due to the high temperatures at the location of the hot-side ESP, the COHPAC technology is not technically feasible because bag filters are not available for temperatures greater than 500 °F. At higher temperatures than 500 °F, ceramic filters are required, which have higher costs and space requirements than conventional FFs. As a result of the high costs associated with retrofit of fabric or ceramic filters at CGS Unit 1, these technologies are considered economically unreasonable as BACT for PM2.5. It will be shown in Step 4 that even the lower cost WESP option is not BACT due to unreasonable

[56] COHPAC™ is an EPRI licensed technology which is centered around the combination of an ESP with a high air-to-cloth ratio fabric filter. The fabric filter is located in a separate casing downstream of the ESP (known as COHPAC I) or within the existing ESP's casing by replacing one or more fields of collecting plates with fabric filter modules (COHPAC II).

economic impacts in relation to the negligible, beneficial environmental impacts that would result.

F.3.2.2 Wet ESP

As discussed previously, WESPs are not used as the primary particulate control device for coal-fired PC boilers, but are used as a tertiary particulate control device downstream of a wet FGD system. WESPs require that the flue gas be at or near moisture saturation to prevent evaporation of moisture from the wet collection surfaces. For large flue gas flow applications, plate type WESPs are most commonly used. Recently, membrane WESPs have been commercially demonstrated at industrial scale and have been pilot tested on coal-fired PC boiler flue gas. Table F-7 summarizes the study results of a membrane WESP as compared to a metal plate WESP.[57]

Table F-7. PM2.5 Emissions Evaluation for Metal-Plate and Membrane WESP

Parameter	Metal Plate Wet ESP		Membrane Wet ESP	
Comparative ESP Gas Velocities	Low Velocity	Moderate Velocity	Low Velocity	Moderate Velocity
PM Reduction %	93	70	96	80

Based on these data, SRP concludes that a WESP can remove approximately 70 to 90 percent of the H_2SO_4 and fine PM (filterable and condensable).

F.3.2.3 Reagent Injection

Reagent injection systems are described previously under the H_2SO_4 BACT (refer to Section F.2). In addition to removing H_2SO_4, reagent injection systems using alkaline reagents also remove hydrogen fluoride (HF) and hydrogen chloride (HCl), both of which contribute to PM2.5 emissions. However, reagent injection systems do not reduce filterable PM2.5, as do FFs, dry ESPs, FGDs and WESPs. Additionally, as previously discussed, all of the reagent injection technologies would increase the amount of filterable PM in the CGS Unit 1 flue gas. From a PM2.5 emission control basis on CGS Unit 1, this increase cannot be completely controlled by the WFGD system, and as a result, reagent injection without the use of a FF before the CGS Unit 1 WFGD is rejected as being technically infeasible for the control of PM2.5.

F.3.3 STEP 3. Rank the Technically Feasible Control Technologies

WESP technology and FF technology, with or without reagent injection, are considered technically feasible for application on CGS Unit 1 for the reduction of PM2.5. The WESP technology would be installed after the existing WFGD system and before the wet stack. The FF technology would be installed before the existing WFGD. The retrofit difficulty and costs for the FF technology would be significantly greater than for the WESP technology. The expected achievable emission rates for both the WESP technology and FF technology would be 0.0066 lb/MMBtu for condensable and filterable PM2.5.[58] Note the estimated controlled emission rate

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[57] "MEMBRANE WESP – A Lower Cost Technology to Reduce PM2.5, SO_3 & HG^{+2} Emissions," John Caine and Hardik Shah, Southern Environmental, Inc., published technical paper for 2006 Air & Waste Management Association; see http://www.southernenvironmental.com/_pdf/Membrane%20WESP_Paper.pdf & sales brochure: http://www.southernenvironmental.com/_pdf/membraneWESPbrochure.pdf.
[58] Based on an 80 percent reduction in PM2.5 from an emission rate of 0.033 lb/MMBtu.

of 0.0066 lb/MMBtu is much lower than permitted emission limits, but is consistent with the WESP test data presented in Step 2 for the low velocity tests.

F.3.4 STEP 4. Evaluate the Most Effective Controls

Because the cost of the FF technology would be much greater than the WESP technology with the same achievable emission rate, only the WESP technology will be addressed in Step 4. Based on the Step 3 discussion, the highest level of total PM2.5 control for CGS Unit 1 is the use of a WESP (assuming on average 80% control efficiency). As such, the following impact analysis is presented evaluating the incremental impacts of a WESP versus the unit's current controls using ESP/WFGD. Please note that there is limited data available demonstrating the potential reduction of PM2.5 emissions from the use of a WESP as a polishing system for CGS Unit 1 type boilers fired with low-sulfur, high-alkaline coals, which have very low H_2SO_4, HF, and HCl emissions. Table F-8 presents the economic impacts for reducing PM2.5 emissions. The results, along with the environmental and energy impacts are discussed in the following subsections.

Table F-8. Summary of PM2.5 BACT Impacts for a WESP

Parameter	Baseline	WESP
Boiler Heat Input, MMBtu/hour (HHV)	4,719	
Unit Gross Generation, kW	410,000	
Controlled Emission Rate, lb/MMBtu	0.033	0.0066
Potential PM Emissions, tons per year	682	136
WESP Total Capital Requirement, $	n/a	$29,112,000
Capital Recovery Factor (CRF)	n/a	0.0944
Annual Capital Cost, $/yr	n/a	$2,748,000
Annual O&M Cost, $/yr	n/a	$5,487,000
Incremental Total Annual Cost, $/yr	n/a	$8,235,000
Incremental Ton Reduced, tons per year	0	546
Cost per Incremental Ton Reduced, $ per ton	n/a	$15,092

F.3.4.1 Environmental Impacts

The primary environmental impact of adding the WESP after the WFGD is the reduction in total PM2.5 emissions from 0.033 to 0.0066 lb/MMBtu. The addition of a WESP would reduce potential PM2.5 emissions from 682 tons per year at 0.033 lb/MMBtu to 136 tons per year at 0.0066 lb/MMBtu, resulting in an incremental reduction in total PM2.5 emissions of 546 tons per year. On the negative side, an acid waste water stream is generated which will require additional processing before disposal of the wet solids and the waste water stream.

F.3.4.2 Economic Impacts

The addition of a WESP after the WFGD system would have a significant economic impact. The capital costs of retrofitting a WESP on top of the current WFGD system is estimated at $29.1

million based on a cost of $26.5 dollars per wet standard cubic feet of flue gas.[59] This equates to $64 per kilowatt which is consistent with the costs reported by others for retrofit installations.[60] The total annual cost of $8.2 million per year is based on:

- A capital recovery factor of 0.0944 (20-year life and 7 percent societal cost of money per U.S. EPA guidance); and
- Annual operating and maintenance cost of $5 per standard cubic feet a minute (scfm).[61]

From Table F-8, the incremental cost effectiveness of adding a WESP to the existing WFGD outlet duct work is greater than $15,000 per ton of PM2.5 reduced. This is a very high cost of control demonstrating that the addition of a WESP is not cost effective as BACT.

F.3.4.3 Energy Impacts

The primary energy impacts of the WESP technology would be increased electrical demand for operation of the WESP and additional ID fan power requirements for the increase in pressure drop.

F.3.5 STEP 5. Proposed PM10 and PM2.5 BACT Determination

Based on the Step 4 analysis, the application of WESP technology is not BACT. This control option would have significant, adverse economic impacts and would provide negligible, beneficial environmental impacts, as reflected in the calculated cost effectiveness value of more than $15,000 per ton of PM10/PM2.5 removed.

Therefore, SRP proposes an emission limit of 0.033 pounds per MMBtu heat input as BACT for PM10/PM2.5 (filterable and condensable) emissions from CGS Unit 1.[62] Compliance with this limit will be determined using EPA Reference Methods 5 and 202, based on the average of three test runs of at least two hours each. This limit reflects the use of low-sulfur western coals and ultra-low activity SCR catalyst, and continuous performance of the existing boiler, HESP, and WFGD system in accordance with good air pollution control practice.

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[59] EPA-452/F-03-030, "Wet Electrostatic Precipitator (ESP) – Wire-Plate Type." Capital cost range of $20 to $40 per scfm; used $20 per scfm escalated from 2002 dollars to 2015 dollars using CPI-U: U.S. city average cost index. http://www.economagic.com/em-cgi/data.exe/blscu/CUUR0000AA0.

[60] One vendor has indicated that the total installed cost of a vertical flow WESP integrated into the top of a retrofit FGD absorber tower will range from $20/kW to $40/kW, depending on the design SO_3 collection efficiency. The cost of the external horizontal flow WESP at Dakota Gasification has been reported to be approximately $90/kW. Wet ESP vs. Sorbent Injection for SO3 Control, Carl V. Weilert, Burns & McDonnell Engineering Company, 9400 Ward Parkway, Kansas City, MO 64114.

[61] Air Pollution Control Technology Fact Sheet EPA-452/F-03-030; low end of the range for operating and maintenance cost for wire-plate type WESP.

[62] The proposed PM10/PM2.5 limit includes both filterable and condensable fractions. Whereas, the Unit 1 PM limit in the Title V permit 52639 of 0.030 lb/MMBtu only applies to the filterable particulate matter emissions.

Appendix G – SCR Installation: PSD Air Impact Analysis

Appendix G

AIR DISPERSION MODELING ANALYSIS FOR THE PROPOSED MODIFICATIONS TO THE SRP CORONADO GENERATING STATION

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1.0 INTRODUCTION

This document presents the results of the air quality dispersion modeling analysis conducted for the proposed modifications to the Salt River Project Agricultural Improvement and Power District's (“SRP”) Coronado Generating Station (“CGS”) in Apache County, Arizona. The modifications include installation of Selective Catalytic Reduction (“SCR”) to reduce emissions of nitrogen oxides on Unit 1 (“SCR Project” or “project”). The SCR system is being proposed for Unit 1 as one of the compliance options to meet Best Available Retrofit Technology (“BART”) requirements.

The analysis evaluated emissions of the pollutants regulated under the Prevention of Significant Deterioration (“PSD”) program codified at Title 18, Chapter 2, § R18-2-406 of the Arizona Administrative Code (A.A.C.) for which emissions will increase in excess of the PSD significant emission rates (SERs). For the SCR Project, the pollutants evaluated included particulate matter with an aerodynamic diameter of less than 10 microns (PM10) and particulate matter with an aerodynamic diameter of less than 2.5 microns (PM2.5). Sulfuric acid mist (H_2SO_4) emissions will also exceed the SER; however, since there are no ambient standards for H_2SO_4, this pollutant was not included in the modeling analysis. The analysis was conducted to ensure that the proposed SCR Project will not cause or contribute to air pollution in violation of a National Ambient Air Quality Standard (NAAQS) or increment.

The analysis demonstrates that the SCR Project will result in impacts less than the PSD significant impact levels (SILs) for PM10. Therefore, no additional modeling to assess compliance with the NAAQS or PSD increments was warranted for PM10. However, impacts of the PM2.5 emissions increase were shown to exceed the SILs. Additional modeling to assess compliance with the NAAQS and increments demonstrates that the proposed SCR Project will not result in concentrations in excess of either standard.

There are 17 Class I areas located within 300 kilometers (km) of CGS. Each Class I area is located in excess of 50 km from the facility. The Federal Land Manager's emissions divided by distance screening (Q/D) was used to assess the potential for the facility modifications to affect a Class I Air Quality Related Value (AQRV). The resultant

Q/D value for each Class I area was determined to be less than 10, so a detailed Class I AQRV impacts assessment was not warranted. The maximum, daily short-term emissions increase and 365 days per year were used to calculate the emissions increase. Modeling also demonstrates that the proposed SCR Project will not result in ambient concentrations in excess of the PM10 Class I SILs at any Class I area. However, impacts of the PM2.5 emissions increase were shown to exceed the Class I SILs. Additional analysis to assess impacts from the proposed SCR Project at the Class I areas were performed confirming non-significant impacts.

A separate Class II visibility assessment was not conducted for the change as the SCR Project under consideration is intended solely for the purpose of ensuring compliance with visibility requirements. In addition, there are no wilderness areas, parks, or integral vistas within 50 km of the project that warrant a discrete plume analysis for visibility impacts.

The analysis conforms with the modeling procedures outlined in the U.S. Environmental Protection Agency's (EPA) Guideline on Air Quality Models[1] (Guideline), the Arizona Department of Environmental Quality's (ADEQ) Air Dispersion Modeling Guidelines for Arizona Air Quality Permits,[2] and associated EPA modeling policy and guidance.

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[1] Guidelines on Air Quality Models, (Revised). Appendix W of 40 CFR Part 51, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina. November 9, 2005.

[2] Air Dispersion Modeling Guidelines for Arizona Air Quality Permits, Air Quality Permit Section, Arizona Department of Environmental Quality, September 23, 2013.

2.0 PROJECT DESCRIPTION

The SCR Project comprises of installation of an SCR system on Unit 1 at CGS. The proposed Project will result in increases in emissions of PM10 and PM2.5 that are in excess of PSD SERs for which NAAQS and increments exist. The regulated NSR pollutants whose emissions increases exceed the SERs, and are therefore subject to PSD review, were evaluated in the modeling analysis.

3.0 SITE DESCRIPTION

CGS consists of two 4,719 MMBtu/hr coal-fired units and associated coal preparation and handling equipment. The facility is located approximately seven miles northeast of St. Johns, in Apache County, Arizona (Township 14 North, Range 29 East). The approximate Universal Transverse Mercator (UTM) coordinates of the facility are 658,400 meters east and 3,827,700 meters north (UTM Zone 12, NAD 83). The facility is approximately 1770 m (5800 ft) above mean sea level. Figure 1 shows the general location of the facility. Figure 2 shows the specific facility location on a 7.5-minute U.S. Geological Survey (USGS) topographic map. Apache County is classified as attainment or unclassified for all criteria pollutants.

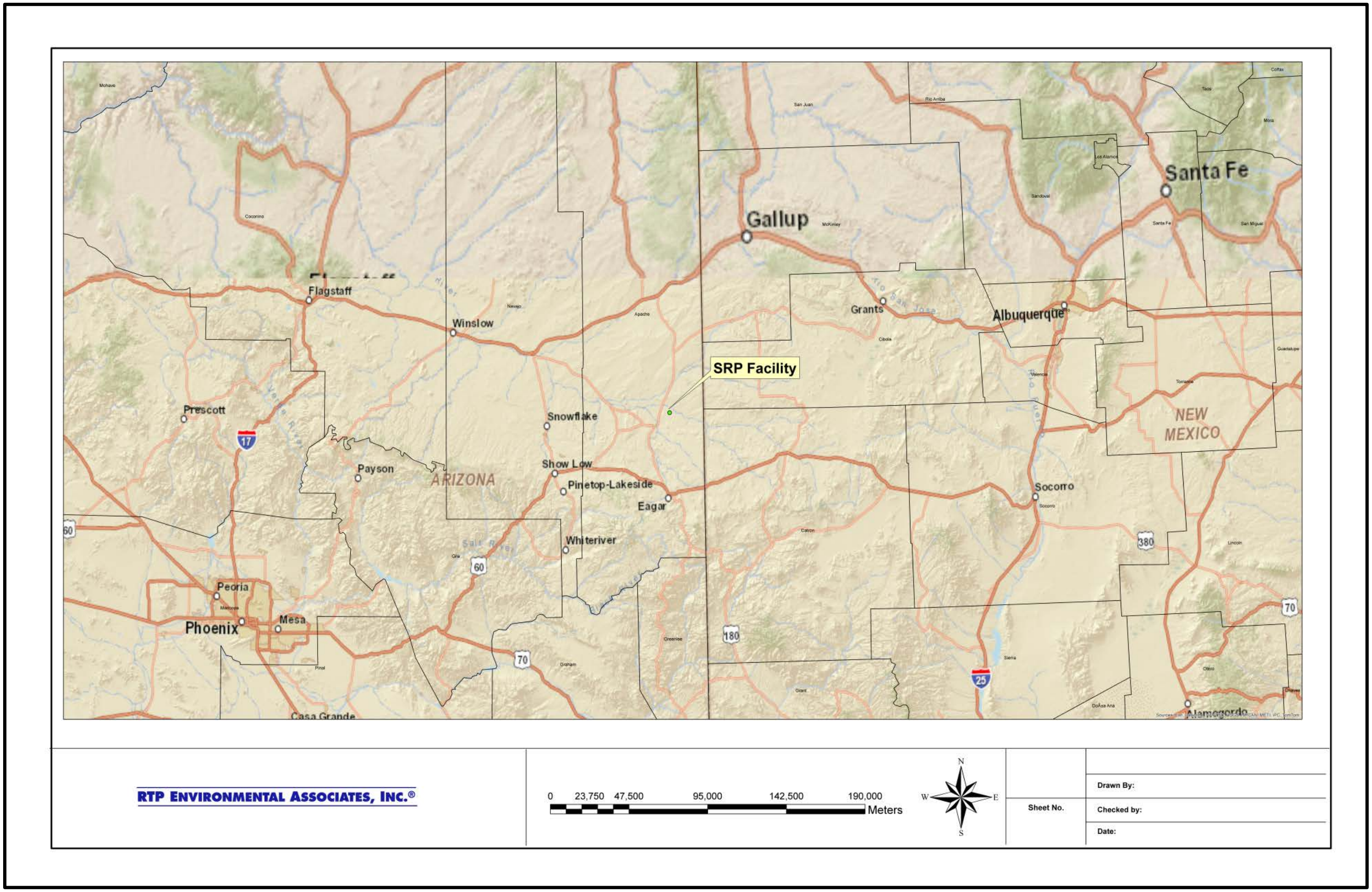

Figure 1. General Location of CGS

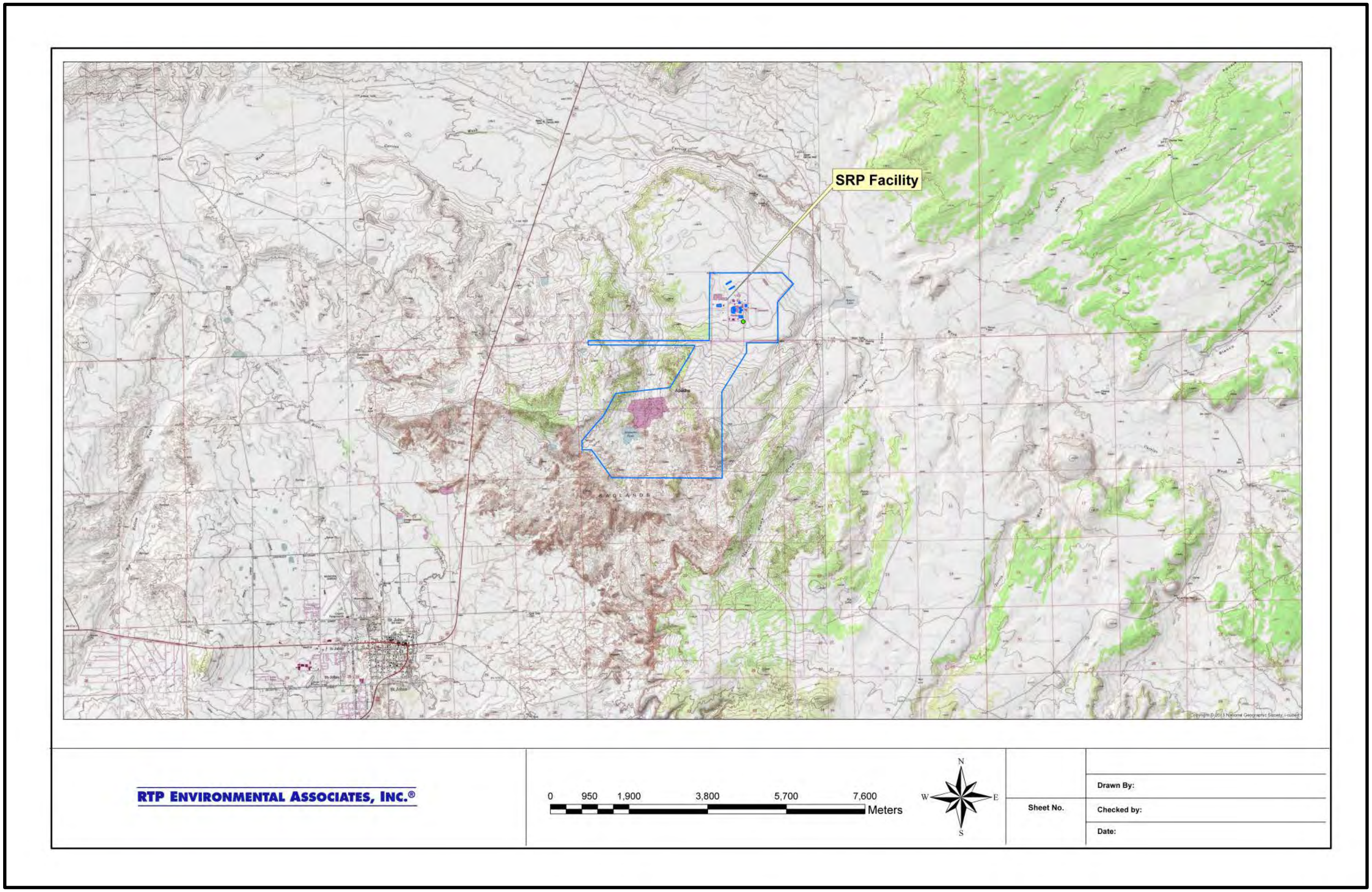

Figure 2. Specific Location of CGS

4.0 MODEL SELECTION AND MODEL INPUT

4.1 Model Selection

The latest version of the AMS/EPA Regulatory Model (AERMOD, Version 15181) was used to conduct the dispersion modeling anlayses. AERMOD is a Gaussian plume dispersion model that is based on planetary boundary layer principles for characterizing atmospheric stability. The model evaluates the non-Gaussian vertical behavior of plumes during convective conditions with the probability density function and the superposition of several Gaussian plumes. AERMOD is a modeling system with three components: AERMAP is the terrain preprocessor program, AERMET is the meteorological data preprocessor and AERMOD includes the dispersion modeling algorithms.

AERMOD is the most appropriate model for calculating ambient concentrations near the facility based on the model's ability to incorporate multiple sources and source types. The model can also account for convective updrafts and downdrafts and meteorological data throughout the plume depth. The model also provides parameters required for use with up to date planetary boundary layer parameterization. The model also has the ability to incorporate building wake effects and to calculate concentrations within the cavity recirculation zone. All model options were selected as recommended in the Guideline.

Oris Solution's BEEST Graphical User Interface (GUI) was used to run AERMOD. The GUI uses an altered version of the AERMOD code to allow for flexibility in the file naming convention. The dispersion algorithms of AERMOD were not altered. Therefore, there was no need for a model equivalency evaluation pursuant to Section 3.2 of 40 CFR 51, Appendix W.

The EPA-approved version of the CALPUFF model (Version 5.8) was used to assess pollutant concentrations for comparison to the Class I SILs. RTP employed the 2001-

2003 CALMET dataset developed by ENVIRON for the Western Regional Air Partnership to perform BART analyses in Arizona.

4.2 AERMOD Model Control Options and Land Use

AERMOD was run in the regulatory default mode for all pollutants. The default rural dispersion coefficients in the model were used. This is supported by the Land Use Procedure consistent with subsection 7.2.3(c) of the Guideline and Section 5.1 of the AERMOD Implementation Guide.

The USGS 2006 National Land Cover Data (NLCD) within 3 km of the facility were converted to Auer 1978 land use types and evaluated.[3] It was determined that the land use in the vicinity of the facility is predominantly rural (Figure 3). Only the red and dark red areas (land use classifications codes 23 and 24) in the figure are classified as urban by Auer. The potential for urban heat island affects, which are regional in character, was considered and determined not to be of concern due to land use characterstics of the site.

4.3 Source Data

Source Characterization

All modeling input data, including the modeled parameters for affected equipment, can be found in Attachment A to this report.

[3] Auer, Jr., A.H. "Correlation of Land Use and Cover with Meteorological Anomalies." Journal of Applied Meteorology, 17:636-643, 1978.

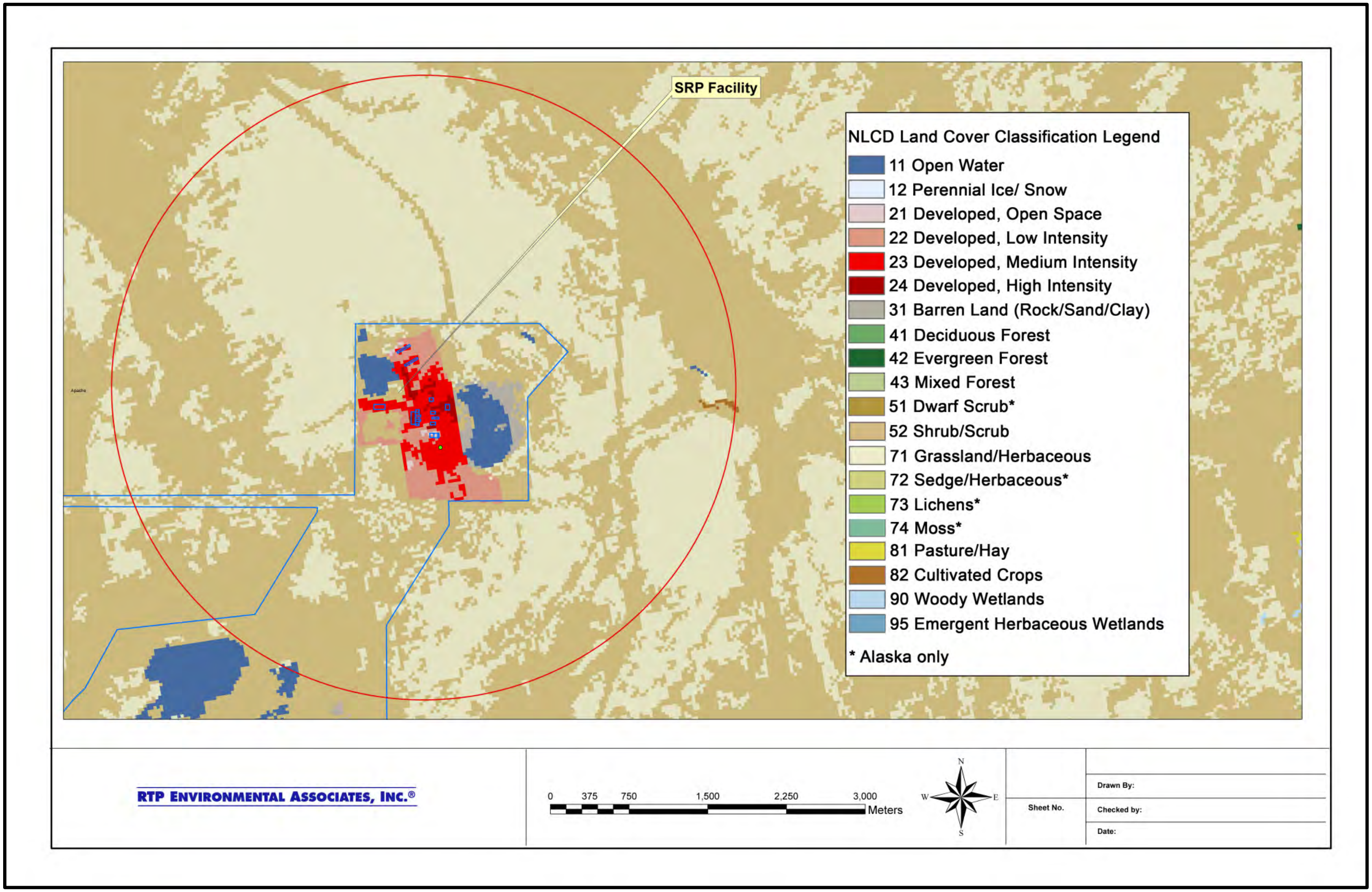

Figure 3. Land Use within Three Kilometers (3km Radius Shown)

Point Sources

The boilers vent to stacks with well defined openings. These units were modeled as point sources in AERMOD. The cooling towers and emergency engines were also modeled as point sources. Fugitive emissions (i.e., stockpiles, roads, etc.) also required evaluation.

Fugitive Emissions

The fugitive emissions were modeled as either area or volume sources. Emissions from storage piles were modeled as area sources. The area sources were modeled as multi-sided polygons with shapes that closely approximate the layout of the piles. The modeled heights represent half the height of each pile. Dumping and bulldozing emissions were added to the corresponding piles. The roads and material handling operations were modeled as volume sources. The initial dispersion coefficients (sigma y and sigma z) were obtained from the PSD Modeling analysis conducted for the facility in 2008.[4] The report from this modeling study states that the volume source parameters were derived as follows:

> "With the exception of the ash burial source, other material handling sources (including coal, ash, and lime handling) were modeled as volume sources within AERMOD. The emissions from the road were modeled as a series of volume sources. Volume source parameters for the roads were taken in part from the USEPA document, Modeling Fugitive Dust Impacts from Surface Coal Mining Operations – Phase II Model Evaluation Protocol (USEPA, 1994). The source height of the road volume sources are a weighted average of the truck heights based on traffic, as based on the statement from the USEPA document that the maximum mass flux from haul road dust plumes occurs at that height. Initial vertical dispersion terms were calculated based on the release height of the volume source for the road volumes. The initial horizontal dispersion terms were

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[4] "Revised Air Quality Dispersion Modeling Report for the Salt River Project Coronado Generation Station Significant Permit Revision Application," ENSR Corporation, July 2008.

calculated in accordance with recommendations in the User's Guide For The AMS/EPA Regulatory Model AERMOD (USEPA, 2004). Initial dimensions for the volume sources were determined from Table 3-1 in the AERMOD User's Guide using the factor for a line source represented by separated volume sources. As recommended in the AERMOD guidance, an elongated source could be represented as a string of separated volumes if the separation distance does not exceed twice the width of the line source. The width of the roads determined the separation of the volume sources. Using the guidance from Table 3-1 in the ISC User's Guide, the initial horizontal dispersion term is the separation distance divided by 2.15."

Good Engineering Practice Stack Height Analysis

A Good Engineering Practice (GEP) stack height evaluation was conducted to determine appropriate building dimensions to include in the model. Procedures to be used were in accordance with those described in the EPA Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations-Revised)[5]. GEP formula stack height, as defined in A.A.C §R18-2-332 of the ADEQ Regulations, is expressed as GEP = H_b + 1.5L, where H_b is the building height and L is the lesser of the building height or maximum projected width. Building/structure locations and dimensions were obtained from the 2008 PSD modeling conducted for CGS. This modeling included the structures associated with the SCR installed on Unit 2. The structure locations and heights were input into the EPA's Building Profile Input Program (BPIP-PRIME) computer program to calculate the direction-specific building dimensions needed for AERMOD. A 3-dimensional rendering of the facility is shown in Figure 4.

[5] Guideline for Determination of Good Engineering Practice Stack Height (Technical Support Document for Stack Height Regulations (Revised). EPA-450/4-80-023R, U.S. Environmental Protection Agency, June 1985.

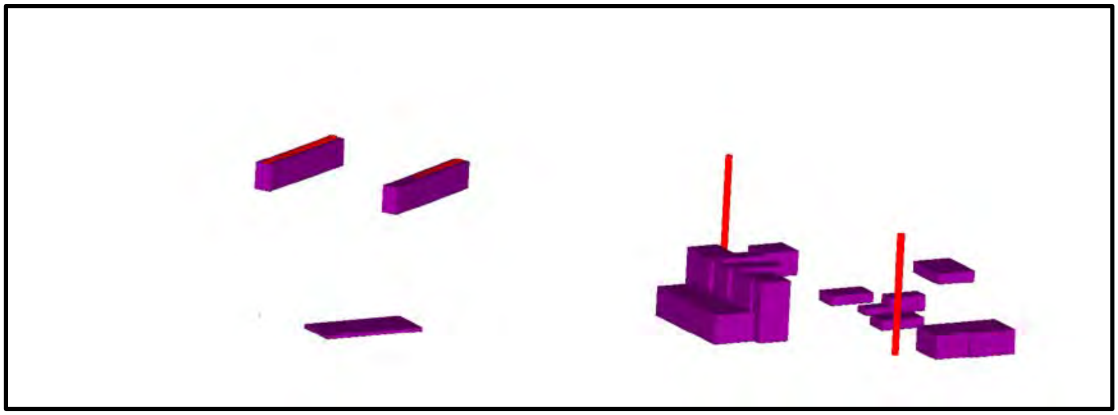

Figure 4. Three Dimensional Rendering of CGS
(View from the SW)

4.4 Monitored Background Data

Ambient, background pollutant concentrations are needed to establish a representative background concentration to complete the NAAQS portion of the *Source Impact Analysis* required by A.A.C. R18-2-406. The background concentrations are added to the modeled concentrations to assess NAAQS compliance. Ambient pollutant concentrations are also needed to fulfill the *Air Quality Analysis* requirement of A.A.C. R18-2-407.

Pursuant to A.A.C. R18-2-407(H), the requirements for ambient monitoring data may be waived if projected increases in ambient concentrations due to the project are less than the Significant Monitoring Concentrations (SMCs). As shown in Section 6, the SCR Project would qualify for such a waiver with respect to PM10 and PM2.5 because the maximum modeled impacts are less than the SMCs. However, in light of the decision of the D.C. Circuit Court of Appeals *Sierra Club v. EPA*,[6] SRP has elected not to request such a waiver and has elected to propose the use of existing representative ambient data in lieu of preconstruction monitoring data.

[6] *Sierra Club v. EPA*, No. 10-1413, 2013 WL 216018 (Jan. 22, 2013).

There are few, existing ambient monitors within 100 miles of the facility. However, data exists which can be used to fulfill the ambient monitoring requirements. Existing monitoring data were evaluated in relation to the criteria provided in EPA's Ambient Monitoring Guidelines[7] as being representative of the CGS site and proposed for use in both the Source Impact Analysis and the Air Quality Analysis requirements.

RTP has used the most recent available, PM2.5 annual and 24-hour design values published by the US EPA for Coconino County (2011-2013). This county is the closest county to Apache for which a design value has been calculated.[8] For PM10, SRP calculated the average of the maximum monitored value from 2012-2014 from AQS Monitor #4-021-3002 in Apache Junction. This value was used to establish the representative background PM10 24-hr concentration. The background data used are presented in Table 1. The existing monitoring data satisfy the criteria provided in the Ambient Monitoring Guidelines as being representative of the CGS site.

Monitor Location

The Coconino and Apache Junction monitoring locations are each approximately 150 miles west and southwest, respectively, of CGS. Measurements from these monitors provide an adequate representation of air quality in the vicinity of the CGS site.

Table 1. PM10 and PM2.5 Background Concentrations

Pollutant	Averaging Time	Design Value (µg/m^3)	Monitor Site Location
PM10	24-hour	101	Apache Junction
PM2.5	24-hour	12.0	Coconino Co. Design Value
	Annual	5.3	

7 Ambient Monitor Guidelines for Prevention of Significant Deterioration, EPA-450/4-87-007, USEPA, May 1987.

8 See: http://www.epa.gov/airtrends/values.html.

Data Quality

The existing ambient monitors were established and air quality data were collected as part of EPA's ambient air quality monitoring network. Federal regulations at 40 CFR Part 58, Appendix A, require that these data meet quality assurance ("QA") requirements. The existing ambient air quality data also meet the data quality requirements of Section 2.4.2 of the Monitoring Guidelines. The QA requirements for monitoring criteria pollutants at PSD sites are very similar to the QA requirements for monitoring sites for NAAQS compliance. The data presented in Section 4.4 meet the data quality criterion.

Currentness of Data

The Monitoring Guidelines suggest that air quality monitoring data used to meet PSD data requirements should be "collected in the 3-year period preceding the permit application."[9] The data presented herein are current and meet this criterion.

Relevant EPA Decisions

Recent actions by U.S. EPA, including permit approvals by Regional Offices and decisions by the Environmental Appeals Board, support reliance on regional monitors to fulfill the PSD ambient air quality monitoring requirements for PM10 and PM2.5 in the SRP application. Several relevant actions are summarized below, beginning with the final PSD permit decision recently issued by U.S. EPA for Energy Answers Arecibo, LLC ("EA"). In that matter, the agency stated:

> EA provided EPA with monitoring data for all criteria pollutants subject to PSD even though those pollutants were less than the Significant Monitoring Concentrations in 40 C.F.R. 52.21(i)(5)(i)…. Energy Answers requested approval to use existing data for all of the criteria pollutants instead of obtaining

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[9] Monitoring Guidelines at p. 9.

> new, site-specific monitoring data in May and September 2011. EPA approved this request based on the fact that representative existing ambient monitoring data was provided. The existing data that is available was collected at sites that have higher concentrations than Arecibo since they are located in more industrial areas, such as Catano, Barceloneta, and San Juan (see Response to Comment 3 in this section for further details).
>
> *
>
> *
>
> [The Monitoring Guidelines document] allows the use of monitors in other geographical areas provided they are representative. In this case, the monitors are located in more industrialized area so they represent a conservative estimate. EPA allowed the use of these monitors for background in this case since these monitors measure more than the "natural, minor or major distant sources" in Arecibo (Guideline on Air Quality Models section 8.) They also measure concentrations from other large sources.[10]

The decision by U.S. EPA to approve the use of existing, representative monitoring data from regional monitors in the EA permit review was made notwithstanding the fact that complex terrain exists within 3 miles (5 km) of the EA project site.[11] These regional monitors are located in industrialized areas and are outside the project's maximum impact area – more than 43 miles (70 km) from the EA project site in the case of the San Juan monitoring data used for PM10 and CO. Moreover, none of the data from the regional monitors were gathered in the year preceding the submittal of the permit application; the NO_2 and SO_2 data were collected by EA outside the three-year time window suggested by the Monitoring Guidelines. U.S. EPA's decision with respect to EA supports SRP's reliance upon data from the selected off-site monitoring locations; the data relied upon by SRP are arguably more representative and more current than the data accepted by the agency in the EA matter.

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[10] Responses to Public Comments on the Clean Air Act Prevention of Significant Deterioration of Air Quality Draft Permit for Energy Answers Arecibo, LLC. U.S. EPA Region 2. June 2013. Pages 92-94.

[11] PSD Air Quality Modeling Analysis (Revised PM10/PM2.5 Analysis). Energy Answers Arecibo, LLC. Revised October 2011.

The EA permit decision is consistent with long-standing EPA policy that, with respect to approval of representative, existing ambient monitoring data from regional monitors, “the guidelines are very broad and leave much to the discretion of the permitting authority.”[12] Notably, EA was the first PSD permit approval from U.S. EPA since the decision in *Sierra Club v. EPA*, vacating the SMC, making the approach in the EA permit review especially informative. The agency’s determination in the EA matter confirms that the court’s decision in *Sierra Club v. EPA* cannot be read to narrow the agency’s broad discretion on this PSD requirement. Over the 25 years since U.S. EPA issued the Monitoring Guidelines, the agency has consistently used its discretion to accept existing, representative ambient air quality data in permit decisions and formal administrative decisions.

ADEQ has broad discretion to accept the monitoring data provided for PM10 and PM2.5 in SRP’s permit application. The off-site data relied upon by SRP to fulfill the ambient air quality monitoring requirement for this PSD application satisfies the criteria outlined in EPA’s Monitoring Guidelines (*data quality, currentness of the data, and location of the monitors),* and represents the ambient air quality in the area of SRP’s SCR Project. Representative, existing data provided for PM10 and PM2.5 fulfill the pre-construction data requirement.

4.5 Receptor Data

Modeled receptors were placed in all areas considered as "ambient air" pursuant to 40 CFR § 50.1(e) and A.A.C. R18-2-101. Ambient air is defined as that portion of the atmosphere, external to buildings, to which the general public has access.

The receptor grid used in the significant impacts analysis consisted of several Cartesian grids and receptors spaced at 25 m intervals along the facility fenceline (or process area

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[12] In the Matter of Hibbing Taconite Co., PSD Appeal No. 87-3, 2 E.A.D. 838 (Adm’r 1989).

boundary) (Figure 5). The receptor spacing is shown in Table 2. The receptor grid was designed such that maximum facility impacts fall within the 50 or 100 m spacing of receptors.

Table 2. Receptor Grid Spacing

Receptor Spacing (m)	Distance from Facility Fence (m)
50	1,000
100	3,000
500	10,000
1,000	50,000

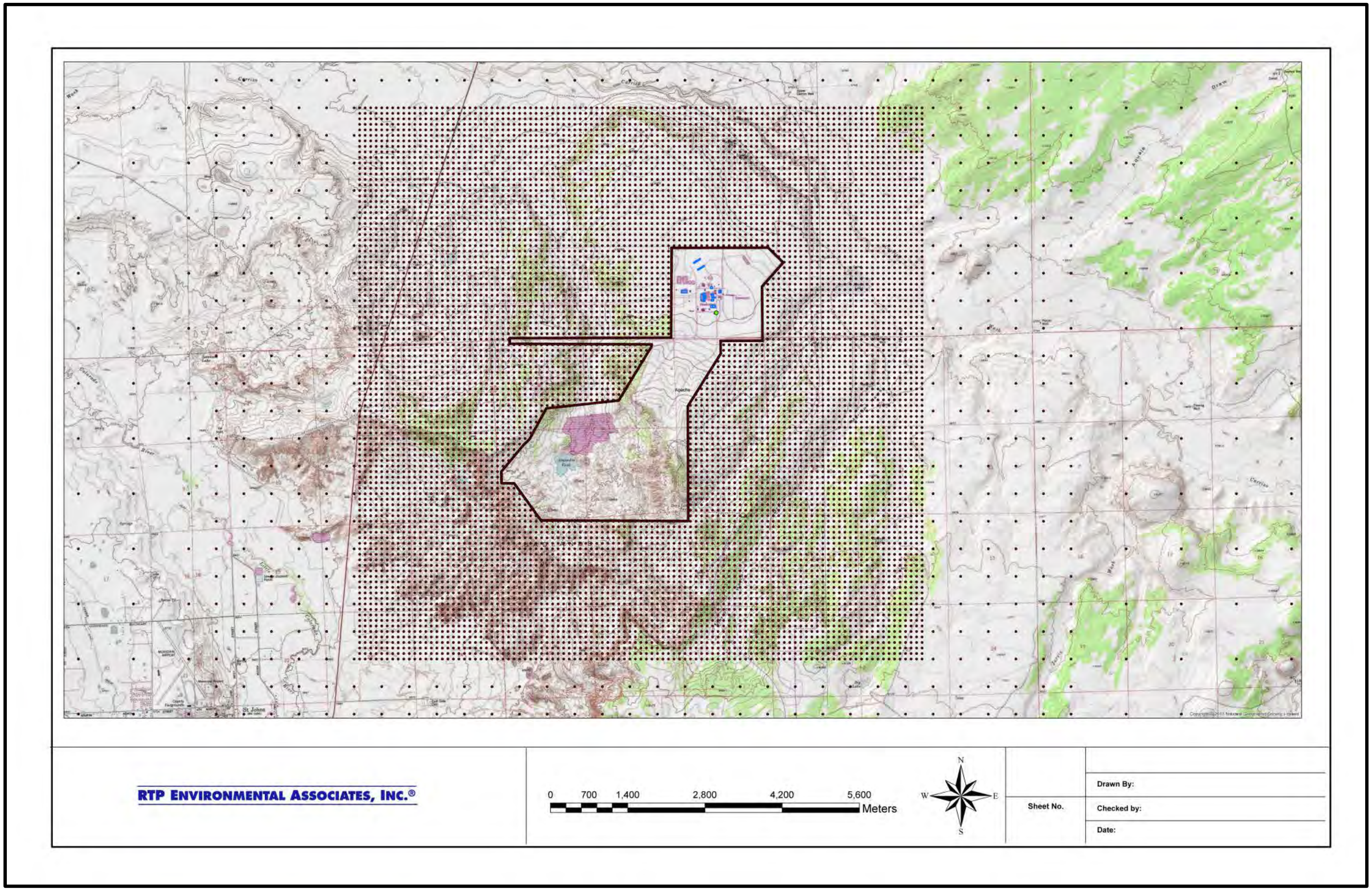

Figure 5. SRP Facility Near-field Receptor Grid

The receptor grid used in the NAAQS and increment analysis was limited to those receptors that were shown to have a significant impact.

The CGS site is located in eastern Arizona. There is terrain in the vicinity of the facility which exceeds stack top elevation. Receptor elevations and hill height scale factors were calculated with AERMAP (11103). The elevation data were obtained from the USGS 1 arc second National Elevation Data (NED) obtained from the USGS. Locations were based upon a NAD83, UTM Zone 12 projection.

4.6 <u>Meteorological Data</u>

The 2010-2014, 5-year sequential hourly surface meteorological data collected at the National Weather Service (NWS) station at the St. John's airport in Apache County (WBAN No. 93027) and upper air data from the Albuquerque International Airport in New Mexico (WBAN No. 23050) were used in the analysis. The St. John's airport is located approximately 7 miles southwest of CGS. Meteorological data collected at this station are representative of the conditions at CGS. The data were processed into a “model-ready” format using the latest version of AERMET (version 15181).

The AERMET meteorological processor requires estimates of the following surface characteristics: surface roughness length, albedo, and Bowen ratio. The surface roughness length is related to the height of obstacles to the wind flow. It is the height above the surface where the average wind speed is zero. The smoother the surface, the lower the roughness length. The surface roughness length influences the surface shear stress and is an important factor in calculating mechanical turbulence and stability. The albedo is the fraction of the total incident solar radiation reflected by the surface back to space without absorption. The Bowen ratio is an indicator of surface moisture and is the ratio of the sensible heat flux to the latent heat flux. The albedo and Bowen ratio are used for determining the planetary boundary layer parameters for convective conditions due to the surface sensible heat flux.

Estimates of the surface characteristics were made using EPA's AERSURFACE program (Version 13016). A 1 km search radius was employed at the location of the meteorological tower. Twelve sectors of 30 degrees each and seasonal resolution were used in the AERSURFACE analysis. In addition, inputs were selected for an airport site, arid region, average surface moisture condition, and no continuous snow cover during the winter.

The use of NWS meteorological data for dispersion modeling can often lead to a high incidence of calms and variable wind conditions if the data are collected by Automated Surface Observing Stations (ASOS), as are in use at most NWS stations since the mid-1990's. A calm wind is defined as a wind speed less than 3 knots and is assigned a value of 0 knots. In addition, variable wind observations may include wind speeds up to 6 knots, but the wind direction is reported as missing if the wind direction varies more than 60 degrees during the 2-minute averaging period for the observation. The AERMOD model currently cannot simulate dispersion under calm or missing wind conditions. To reduce the number of calms and missing winds in the surface data, archived 1-minute winds for the ASOS stations were used to calculate hourly average wind speed and directions, which were used to supplement the standard archive of hourly observed winds processed in AERMET. The EPA AERMINUTE program (Version 14327) was used for these calculations.

EPA's guidance to assess compliance with the 90 percent completeness criterion was followed. According to EPA-454/R-99-005, "Meteorological Monitoring Guidance for Regulatory Modeling Applications", the meteorological data must be 90 percent complete in order to be acceptable for use in regulatory dispersion modeling. The data from the St. John's station were evaluated with Stage 1 of AERMET, by quarter, to assess compliance with the 90% completeness criterion. No data substitution was employed. The results are shown in Table 3. As shown, the data meet the 90 percent requirement for each monitored parameter for each quarter.

A wind rose of the 5-year meteorological dataset is provided in Figure 6.

Table 3. Results of 90% Completeness Evaluation

		% Data Accepted		
Year	**Quarter**	**Temperature**	**Direction**	**Speed**
2010	Q1	100.0	97.1	100.0
	Q2	100.0	95.2	100.0
	Q3	100.0	94.1	100.0
	Q4	100.0	96.2	99.9
2011	Q1	98.9	97.6	100.0
	Q2	99.9	96.4	99.9
	Q3	100.0	93.0	100.0
	Q4	99.9	96.9	99.9
2012	Q1	100.0	96.1	99.7
	Q2	100.0	95.3	100.0
	Q3	100.0	94.3	100.0
	Q4	100.0	96.9	100.0
2013	Q1	100.0	96.3	99.9
	Q2	100.0	94.9	100.0
	Q3	99.9	94.1	99.9
	Q4	100.0	95.6	99.8
2014	Q1	100.0	95.6	99.4
	Q2	100.0	93.9	99.0
	Q3	99.9	91.1	99.2
	Q4	100.0	95.9	99.9
	Min	**98.9**	**91.1**	**99.0**

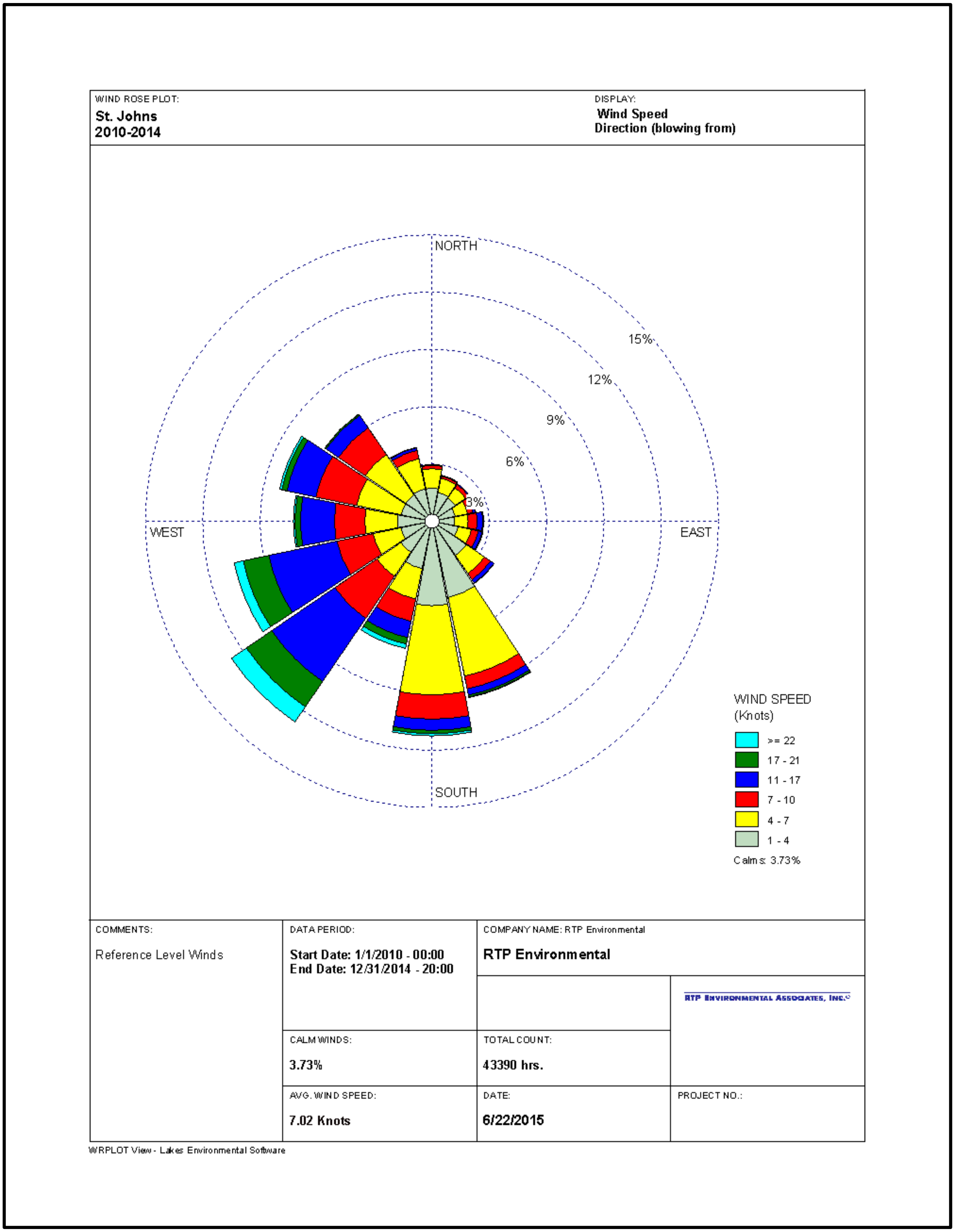

Figure 6. St. John's 2010-2014 Windrose

4.7 CALPUFF Technical Settings

CALPUFF was run using the FLM-approved default parameters where available. These options generally follow EPA's Guideline on Air Quality Models (40 CFR 51, Appendix W) and the IWAQM Phase 2 guidance. The regulatory default switch was used (MREG = 1). Building downwash was not considered given the distance between CGS and the Class I areas of concern.

The ENVIRON WRAP CALMET files employ a 4km grid with 288 grid cells in the easting and 225 grid cells in the northing. RTP employed the following computational grid settings, which insures a 50 km buffer past all Class I areas:

- Lower left corner of grid (IBCOMP of 95.9, JBCOMP of 2.5); and
- Upper right corner of grid (IECOMP of 288, JECOMP of 179.9).

The Class I area receptors modeled were obtained from the NPS. Lambert-Conformal Conic (LCC) Coordinates were used with an origin of 49.0N and 97.0W and Standard Parallels of 33.0N and 45.0N, consistent with the CALMET modeling domain.

The modeling domain and Class I receptors are shown in Figure 7.

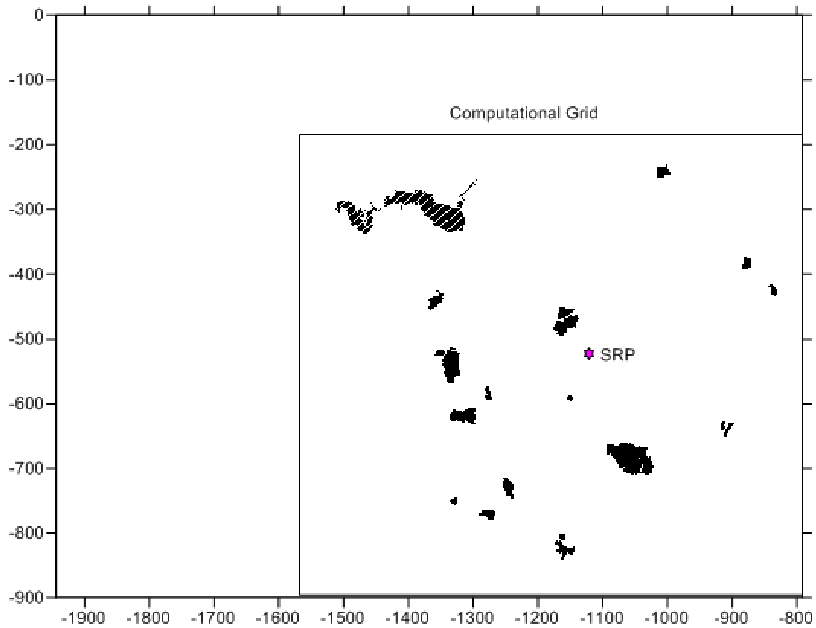

Figure 7. CALPUFF Modeling Domain and Class I Areas

5.0 MODELING METHODOLOGY

5.1 Pollutants Subject to Review

PM10 and PM2.5 emissions were evaluated as these are the regulated NSR pollutants whose emissions increases exceed the PSD SERs and are therefore subject to PSD review. Sulfuric acid mist emissions will also be emitted in excess of the SER; however, this pollutant was not modeled since there are no ambient standards to compare the results to.

5.2 Load/Operating Conditions and Facility Design

The boiler emissions and stack parameters vary with operating load. Therefore a load screening analysis was conducted to determine the operating load that results in the highest modeled impacts. The boiler flow rate and emissions are linearly related to load. Three load conditions were evaluated: 100%, 75%, and 50%.

5.3 Significant Impact Analysis

The criteria pollutant air quality analysis was conducted in two phases: an initial or significant impact analysis, and a refined phase including an increment analysis and a NAAQS analysis. In the significant impacts analysis, the modeled maximum impacts were determined for PM10 and PM2.5. Five years of meteorology were modeled. These impacts determine the net change in air quality resulting from the proposed modification. Maximum modeled PM10 concentrations were compared to the significance levels. For PM2.5, the 5-year average of the 24-hr and annual impacts were compared to the SILs.

Pollutants with impacts that exceed the significant impact levels, as listed in Table 4, were included in both the NAAQS and increment analyses. In these latter analyses, impacts from CGS were added to concentrations modeled from other nearby sources, plus a regional background concentration. The resultant total concentration was compared to the NAAQS. The modeled concentrations from CGS and other increment consuming sources were compared directly to the increments without addition of a background to determine compliance.

Table 4. PSD Class II Significant Impact Levels

Pollutant	Averaging Time	PSD Class II Significant Impact Levels (μg/m^3)[a]
PM2.5	24-hour	1.2
	Annual	0.3
PM10	24-hour	5.0
	Annual	1.0

[a] The significance levels are codified at A.A.C. R18-2-401.

5.4 NAAQS Analysis

Following the determination of significant impacts, a refined air quality analysis was conducted (to determine compliance with the NAAQS). The refined analysis was conducted to determine compliance with the NAAQS only for pollutants modeled as having significant impacts in the initial analysis. Only the actual receptors showing a significant impact were evaluated in assessing compliance with the NAAQS. Each source's potential emission rate was used. Five years of meteorology were again modeled.

Nearby Source Inventory

Off-site sources were included in the NAAQS analysis. A 50 km radius was added to the maximum distance to a significant impact to define the screening area. An inventory of the major sources that are located within the screening area was obtained from ADEQ and the New Mexico Environment Department.

NAAQS Compliance Assessment

Appropriate ambient background concentrations were then added to the modeled concentrations to evaluate NAAQS compliance. The maximum modeled annual impacts were added to the maximum monitored values used to assess compliance with the annual standards. The 98th percentile maximum daily PM2.5 modeled values were added to the background monitor value. The federal NAAQS are shown in Table 5.

Table 5. National Ambient Air Quality Standards

Pollutant	Averaging Time	Ambient Air Quality Standards (μg/m^3)[a]	
		Primary	Secondary
PM2.5	24-hour	35	35
	Annual	12	12
PM10	24-hour	188	--

[a] 40 CFR part 50.

5.5 Class II PSD Increment Analysis

The Class II increment consumption analysis included emissions from all proposed increment consuming sources. Compliance with the PSD increments was based on the cumulative impacts of CGS and other increment consuming sources identified in the nearby source emissions inventory. Only the actual receptors showing a significant impact were evaluated in assessing compliance with the increments. Potential emissions were conservatively used as an alternate to actual emissions when actual emissions were not available. The resultant impacts were compared to the PSD Class II increment levels. The highest modeled annual averages were used for evaluating compliance with the annual increments and the high-second-high values were used for the evaluation of compliance with the short-term increments. The PSD Class II increments are shown in Table 6.

Table 6. PSD Increments

Pollutant	Averaging Time	PSD Increments (µg/m^3)	
		Class II	Class I
PM2.5	24-hour	9	2
	Annual	4	1
PM10	24-hour	30	8
	Annual	17	4

5.6 Secondary PM2.5 Analyses

In May 2014, EPA issued its final guidance for assessing primary and secondary formed fine particulate matter (PM2.5) in a NAAQS and increment compliance demonstration under PSD.[13] EPA outlines four cases for assessing the primary and secondary PM2.5 impacts. The appropriate case to use depends on the magnitude of direct PM2.5 emissions and precursor NO_2 and SO_2 emissions. Case 2 is applicable to the SCR Project as direct PM2.5 emissions increases exceed 10 tons per year; however, precursor NOx and SO_2 emissions increases do not exceed 40 tons per year. In this case, a PM2.5 compliance demonstration is required for the direct PM2.5 emissions based on approved dispersion modeling techniques. The potential impact of the precursor emissions need not be evaluated.

[13] Guidance for PM2.5 Permit Modeling, EPA-454/B-14-001, May 2014.

6.0 MODELING RESULTS

Attachment B to this report provides the model summary output. AERMOD input and output files, including the BPIP-PRIME files, are included on the enclosed CD.

6.1 Boiler Load Analysis Results

The results of the load analysis are presented in Table 7. As shown, the 100% load scenario was found to generate the highest impacts. Therefore the 100% load case was used in the remainder of the modeling analysis.

6.2 Significant Impact Analysis Results

The Class II significant impact analysis results are also presented in Table 7. (The SCR Project is expected to result in significant impacts only for PM2.5.) Therefore, a cumulative NAAQS and increment analysis was conducted for PM2.5.

6.3 NAAQS Analysis Results

Following the determination of significant impacts, an analysis was conducted to assess compliance with the PM2.5 NAAQS. The results of the NAAQS analysis are presented in Table 8. As shown, the model demonstrates compliance with the NAAQS.

6.4 Class II Increment Analysis Results

The minor source baseline date has not been triggered in the Northern Arizona Interstate Air Quality Control Region, which covers Apache County. The proposed changes to Unit 1 are the only activities that consume PM2.5 increment. Therefore, the modeling results from the significant impacts analysis were conservatively used to evaluate increment. As shown in Table 9, the SCR Project will not cause or contribute to a violation of the PSD increments.

6.5 Model Input and Output Files

The modeling input and output files are provided on the attached CD. Model summary results are presented in Attachment B to this report. The summary results list the model file names associated with each phase of the analysis.

Table 7. Boiler Load and Class II Significant Impact Analysis Results

Pollutant	Averaging Period	Boiler Load Condition	Maximum Modeled Impact (μg/m³)	PSD Significant Class II Impact Level (μg/m³)	Significant Monitoring Concentration (μg/m³)	Maximum Distance to Significant Impact (km)
PM2.5	24-hr	100%	1.42	1.2	10	1.8
		75%	1.25	1.2	10	1.4
		50%	1.01	1.2	10	N/A
	Annual	100%	0.32	0.3	N/A	1.2
		75%	0.28	0.3	N/A	N/A
		50%	0.23	0.3	N/A	N/A
PM10	24-hr	100%	1.61	5.0	10	N/A
		75%	1.44	5.0	10	N/A
		50%	1.23	5.0	10	N/A
	Annual	100%	0.35	1.0	N/A	N/A
		75%	0.31	1.0	N/A	N/A
		50%	0.25	1.0	N/A	N/A

Please note that on January 22, 2013, the US Court of Appeals for the District of Columbia Circuit Court granted a request from the EPA to vacate and remand the $PM_{2.5}$ SILs. EPA has stated that as long as the difference between the background monitored $PM_{2.5}$ value and the NAAQS is greater than the SIL, the SIL can still be used in evaluating significance (see the March 3, 2013, "Draft Guidance for PM2.5 Permit Modeling"). As shown in Table 8 below, the difference between the NAAQS and the background values are greater than the $PM_{2.5}$ Class II SILs.

Table 8. NAAQS Analysis Results

Pollutant	Averaging Period	Modeled Concentration (µg/m^3)	Background Concentration (µg/m^3)	Total Concentration (µg/m^3)	Standard (µg/m^3)
PM2.5	24-hour	10.49	12.0	22.96	35
	Annual	4.04	5.3	9.34	12

Table 9. PSD Class II Increment Analysis Results

Pollutant	Averaging Period	Modeled Concentration (µg/m^3)	Standard (µg/m^3)
PM2.5	24-hour	1.42	9
	Annual	0.32	4

7.0 CLASS II VISIBILITY ANALYSIS

The CAA Amendments of 1977 require evaluation of new and modified emission sources to determine potential impacts on visibility. A class II visibility assessment was not conducted for the SCR Project as the modification under consideration is solely for the purpose of ensuring compliance with visibility requirements. In addition, no wilderness areas, parks, or integral vistas within 50 km of the project site were identified that warrant a discrete plume analysis for visibility impacts. The VISCREEN discrete plume model, which is typically used for local plume visibility impacts, does not account for the visibility effects of secondary nitrate compounds. The visibility impacts associated with such compounds will be substantially reduced as a result of the SCR Project.

8.0 CLASS I AREA IMPACTS

8.1 Class I AQRV Analysis

There are 17 Class I areas located within 300 km of CGS (see Figure 8).[14] Each Class I area is located at a distance of 50 km or more from CGS. The Federal Land Manager's (FLM) Q/D (maximum daily emissions in tons per year divided by distance in kilometers) method has been used to determine the potential for adverse Class I impacts for each Class I area (Table 10). No quantitative Class I Air Quality Related Values (AQRV) evaluation is typically required for the Class I areas with calculated Q/D values below 10. Based upon the proposed PM10, PM2.5 and H_2SO_4 emissions increase from the SCR Project of 113.61 lb/hr (there is no SO_2 or NOx increase), an emission rate of 497.6 tons per year is calculated based on continuous operation. The resultant Q/D values for each Class I area are shown in Table 10.

[14] Class I areas are pristine areas (e.g., National Parks and Wilderness Areas) that have been designated by Congress and are afforded a greater degree of air quality protection. All other areas are designated as Class II areas.

Table 10. Calculated Q/D Values for Each Class I Area

Class I	Map ID	Minimum Distance (km)	Maximum Distance (km)	Q/D
Chiricahua Wilderness	chir	292	318	1.70
Chiricahua NM	chir	281	288	1.77
Galiuro	gali	232	254	2.14
Saguaro	sagu	285	314	1.75
Gila	gila	142	205	3.50
Superstition Wilderness	supe	200	240	2.49
Mazatzal Wilderness	maza	206	232	2.42
Sierra Ancha Wilderness	sian	168	177	2.96
Mt. Baldy Wilderness	mobo	71	79	7.01
Sycamore Canyon	syca	247	266	2.01
Petrified Forest	pefo	50	87	9.95
Pine Mountain	pimo	229	242	2.17
Grand Canyon	grca	278	242	1.79
San Pedro Parks	sape	271	287	1.84
Bandelier	band	294	304	1.69
Bosque del Apache	bosq	229	244	2.17
Mesa Verde	meve	294	316	1.69

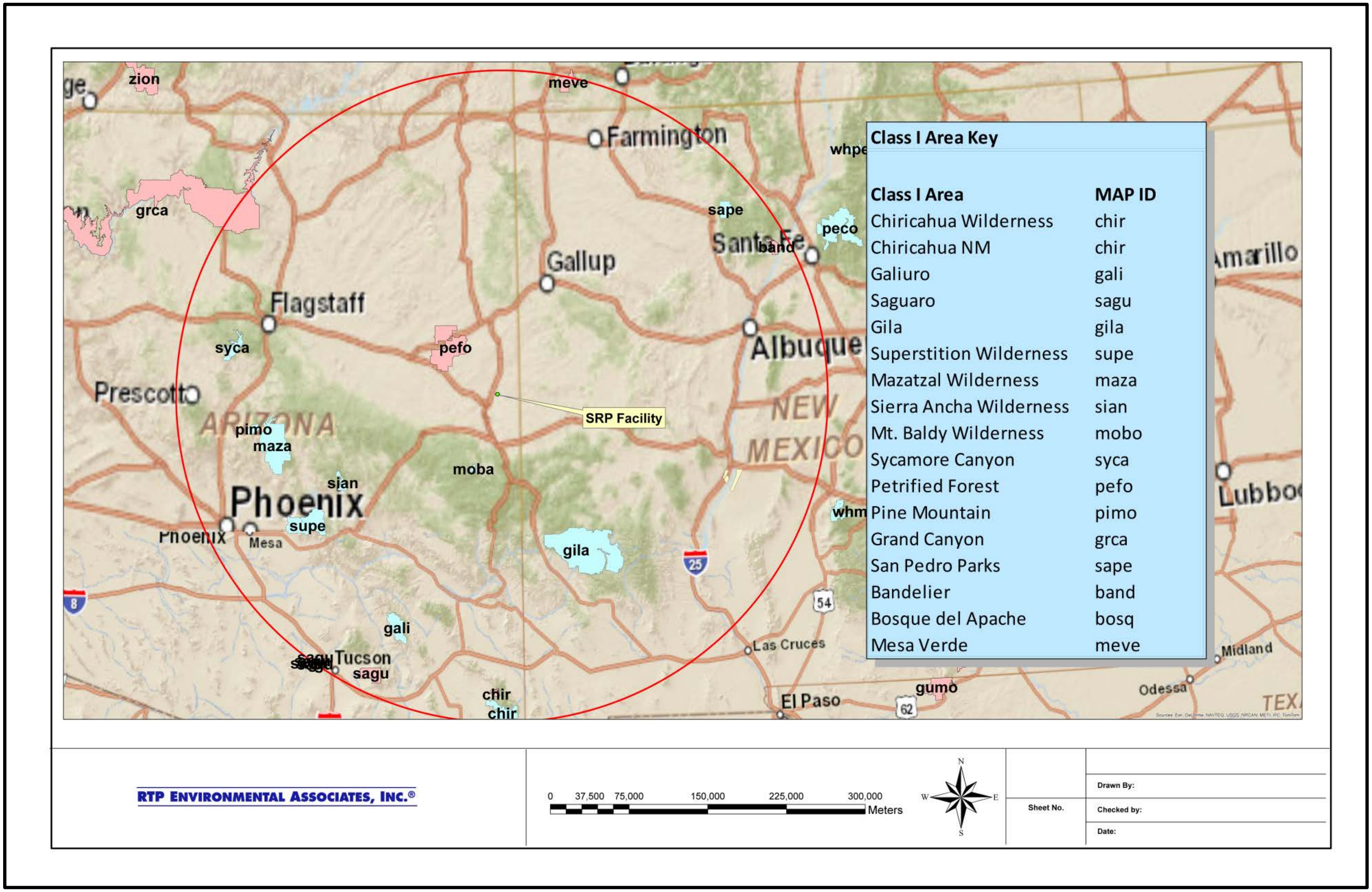

Figure 8. Class I Areas Located within Three Hundred Kilometers of CGS (300km radius shown)

Since all Q/D values are less than 10, no Class I AQRV analysis was conducted.

8.2 Class I Significant Impacts Analysis

The air quality impacts at each Class I area within 300 km was initially determined using AERMOD, as currently recommended by EPA in its proposed revisions to Appendix W. (Note that EPA has proposed to remove CALPUFF as a preferred model. Therefore, AERMOD was initially used to ascertain the potential for Class I impacts. - See the July 29, 2015 Federal Register at page 45349). A 360 degree arc of receptors spaced at 5 degree intervals, located at a distance of 50 km from CGS, was modeled with AERMOD. Three elevations were modeled for each receptor. The elevations were set equal to the minimum, maximum, and average elevation over all of the 17 Class I areas. The model results were compared to the proposed Class I significant impact levels (Table 11).[15] As shown, all impacts are less than the Class I SILs except for the 24-hr PM2.5 impact. There are only four receptors in AERMOD that showed a concentration in excess of the proposed PM2.5 24-hr Class I SIL. Closer inspection of these receptors show that only two of the four receptors are located on an arc that is located on a direction between CGS and a Class I area (Figure 9). The Class I areas located on these arcs (San Pedro Parks Wilderness Area and Bosque del Apache) are a minimum of 220 km from CGS. As the impacts at the 50 km ring are an overly conservative estimate of the concentrations at the more distant Class I area and because the 24-hour PM2.5 impacts at a distance of 50 km are only 14% above the SIL, impacts at the Class I areas are expected to be insignificant.

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[15] See 61 FR 38249 (July 23, 1996) for the proposed Class I SILs.

CALPUFF was run for these two Class I areas to verify that the proposed 24-hour Class I SILs would not be exceeded. The CALPUFF results are shown in Table 12. As shown, the proposed facility modifications result in concentrations below the proposed Class I SILs and therefore will not threaten the 24-hr PM2.5 Class I increment. The model summary output is provided in Attachment B. The modeling files are on the enclosed CD.

Table 11. Class I Significant Impact Analysis Results (AERMOD)

Pollutant	Averaging Period	Maximum Modeled Impact (μg/m³)	Proposed Class I Significant Impact Level (μg/m³)	% Class I SIL
PM2.5	24-hr	0.08	0.07	114%
	Annual	0.01	0.06	20%
PM10	24-hr	0.14	0.30	46%
	Annual	0.01	0.20	6%

Please note that on January 22, 2013, the US Court of Appeals for the District of Columbia Circuit Court granted a request from the EPA to vacate and remand the $PM_{2.5}$ SILs. EPA has stated that as long as the difference between the background monitored $PM_{2.5}$ value and the NAAQS is greater than the SIL, the SIL can still be used in evaluating significance (see the March 3, 2013, "Draft Guidance for PM2.5 Permit Modeling"). As shown in Table 8 above, the difference between the NAAQS and the background values are greater than the $PM_{2.5}$ Class I SILs.

Table 12. 24-Hour PM2.5 Class I Significant Impact Analysis Results (CALPUFF)

Class I Area	Year	Maximum Modeled Impact (μg/m³)	Proposed Class I Significant Impact Level (μg/m³)	% Class I SIL
San Pedro Parks	2001	2.86E-02	0.07	41%
	2002	3.06E-02	0.07	44%
	2003	3.26E-02	0.07	47%
Bosque del Apache	2001	5.10E-02	0.07	73%
	2002	4.60E-02	0.07	66%
	2003	4.24E-02	0.07	61%

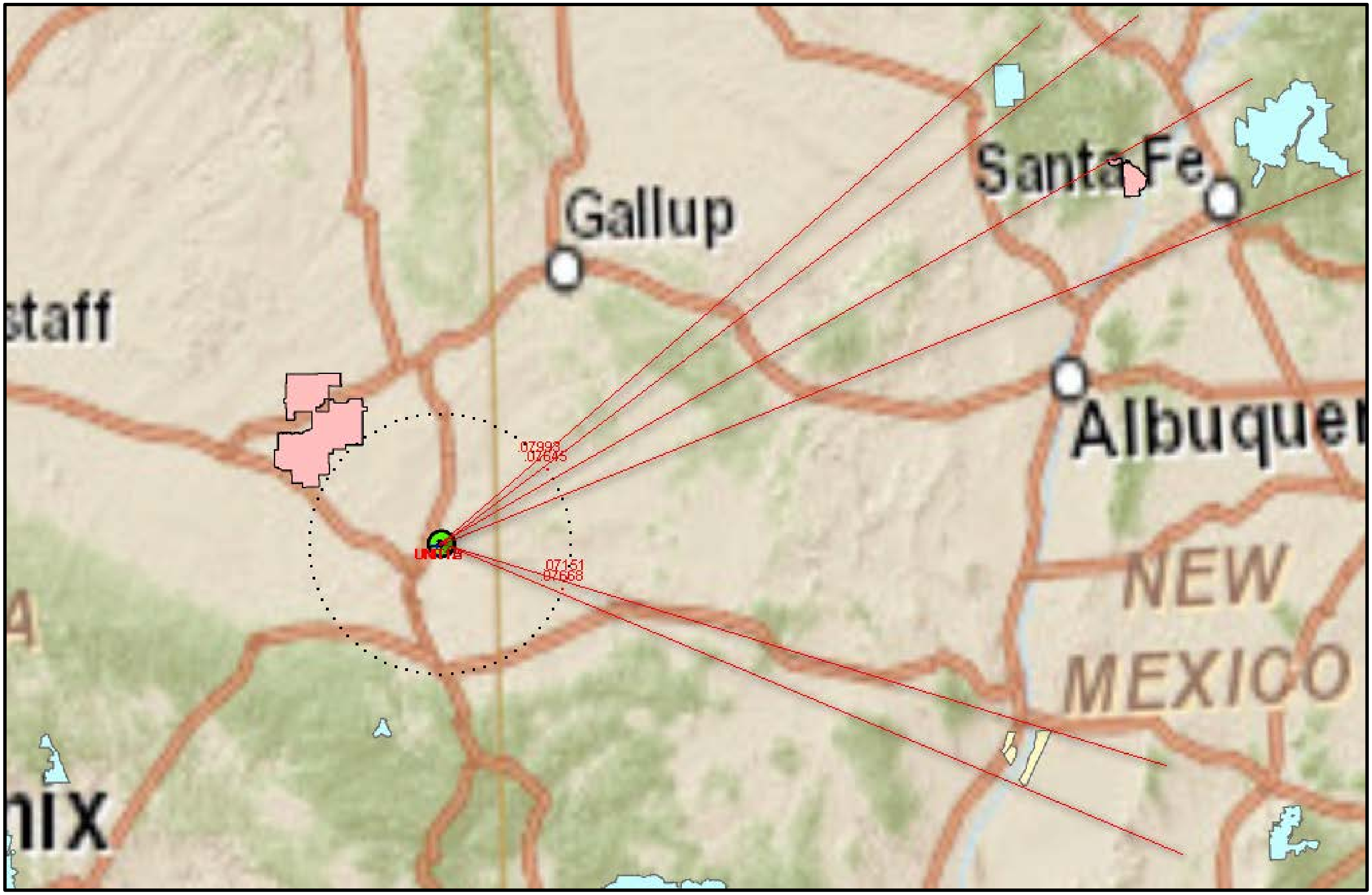

Figure 9. AERMOD Impacts in Excess of the Proposed Class I SILS and the Class I Areas Potentially Impacted

Attachment A – Model Input Data

SRP Coronado Modeling
NAD83, Zone 12
Point Sources

Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Stack Height (ft)	Temp. (F)	Exit Velocity (ft/sec)	Stack Diameter (ft)	Potential Emissions (lb/hr) PM10	Potential Emissions (lb/hr) PM25	Emission Increase (lb/hr) PM10	Emission Increase (lb/hr) PM25
UNIT1a	Unit 1 (100% load)	658427.440	3827741.060	5793.6	400.0	133.0	59.1	24.24	155.73	155.73	113.61	113.61
UNIT1b	Unit 1 (75% load)	658427.440	3827741.060	5793.6	400.0	133.0	44.3	24.24	116.80	116.80	85.21	85.21
UNIT1c	Unit 1 (50% load)	658427.440	3827741.060	5793.6	400.0	133.0	29.5	24.24	77.86	77.86	56.80	56.80
UNIT2	Unit 2	658437.800	3827408.070	5798.9	400.0	133.0	59.1	24.28	251.99	251.99	0.00	0.00
CTS_1	S. Cooling Tower Cell 1	658233.580	3828064.400	5788.7	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTS_2	S. Cooling Tower Cell 2	658242.080	3828069.900	5789.0	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTS_3	S. Cooling Tower Cell 3	658249.940	3828074.750	5789.2	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTS_4	S. Cooling Tower Cell 4	658258.440	3828079.400	5789.4	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTS_5	S. Cooling Tower Cell 5	658267.150	3828084.690	5789.6	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTS_6	S. Cooling Tower Cell 6	658275.650	3828090.190	5789.9	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTS_7	S. Cooling Tower Cell 7	658283.940	3828094.620	5790.2	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTS_8	S. Cooling Tower Cell 8	658292.220	3828099.480	5790.5	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTS_9	S. Cooling Tower Cell 9	658300.720	3828104.980	5790.8	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTS_10	S. Cooling Tower Cell 10	658309.010	3828109.460	5791.1	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTS_11	S. Cooling Tower Cell 11	658317.510	3828114.530	5791.4	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTS_12	S. Cooling Tower Cell 12	658326.010	3828119.610	5791.8	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTS_13	S. Cooling Tower Cell 13	658334.510	3828125.110	5792.0	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTS_14	S. Cooling Tower Cell 14	658343.010	3828129.970	5792.1	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_1	N. Cooling Tower Cell 1	658160.720	3828187.980	5787.1	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_2	N. Cooling Tower Cell 2	658168.970	3828193.230	5787.3	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_3	N. Cooling Tower Cell 3	658177.220	3828198.480	5787.5	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_4	N. Cooling Tower Cell 4	658185.900	3828203.520	5787.7	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_5	N. Cooling Tower Cell 5	658194.150	3828208.770	5787.9	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_6	N. Cooling Tower Cell 6	658202.610	3828213.380	5788.2	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_7	N. Cooling Tower Cell 7	658211.070	3828218.630	5788.6	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_8	N. Cooling Tower Cell 8	658219.110	3828223.180	5788.9	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_9	N. Cooling Tower Cell 9	658227.790	3828228.380	5789.2	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_10	N. Cooling Tower Cell 10	658236.250	3828233.150	5789.4	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_11	N. Cooling Tower Cell 11	658244.710	3828238.140	5789.5	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_12	N. Cooling Tower Cell 12	658253.180	3828242.910	5789.6	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_13	N. Cooling Tower Cell 13	658261.430	3828248.110	5789.8	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
CTN_14	N. Cooling Tower Cell 14	658269.680	3828253.310	5790.0	90.5	100.0	24.6	30.00	0.64	0.64	0.00	0.00
EFIREPMP	Fire Water Pump	657913.820	3827748.650	5785.1	9.5	847.6	207.4	0.33	0.59	0.59	0.00	0.00
AUXBOIL	Auxillary Boiler	658365.740	3827628.380	5795.2	200.0	718.0	50.0	6.00	2.53	1.71	0.00	0.00
BOOSTER	Booster Pump	658360.160	3827642.730	5794.9	14.0	847.6	207.4	0.63	0.56	0.56	0.00	0.00
DGEN	Diesel Genearator	658356.740	3827642.770	5794.9	15.0	726.3	207.4	0.63	0.66	0.66	0.00	0.00

Area Sources (Potential to Emit)

Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Release Height (ft)	Easterly Length (ft)	Northerly Length (ft)	Angle from North	Initial Vert. Dimension (ft)	PM10 (lb/hr)	PM25 (lb/hr)
F10	New Limestone Pile	658596.660	3827319.690	5800.3	10.0	142.0	142.0	0.0	0.00	1.27E-01	4.35E-02
COAL_A	Coal Pile	659018.680	3827603.710	5799.6	15.0	300.0	200.0	180.0	0.00	4.96E-02	1.81E-02
FLYASH	Flyash Pile	657384.590	3824119.110	5899.7	10.0	932.5	933.0	0.0	0.00	16.35	6.540
COAL_B	Coal Pile	658876.970	3827146.750	5803.7	15.0	195.5	850.0	0.0	0.00	1.37E-01	5.00E-02

Volume Sources (Potential to Emit)

Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Release Height (ft)	Init. Horizontal Dimension (ft)	Initial Vert. Dimension (ft)	PM10 (lb/hr)	PM25 (lb/hr)
F9	Limestone Unloading	658661.140	3827380.080	5800.0	3.3	8.0	0.033	4.36E-01	1.37E-01
EP12	Limestone Handling Transfer Tower	658661.520	3827478.820	5799.0	40.0	0.2	18.602	6.43E-02	6.43E-02
EP13	Limestone Handling Transfer Tower TT	658558.920	3827477.660	5798.6	50.0	0.2	23.261	6.43E-02	6.43E-02
EP14	New Limestone Storage Silo	658544.940	3827374.740	5799.7	40.0	0.1	37.205	4.29E-02	4.29E-02
EP15	Limestone Storage Silo	658539.420	3827559.880	5797.3	70.0	0.3	24.180	3.00E-01	3.00E-01
EP20	Ash Surge Bin U1	658345.810	3827623.690	5795.1	50.0	0.1	93.012	8.57E-02	8.57E-02
EP21	Ash Storage Silo U1	658303.670	3827653.850	5794.3	100.0	0.1	44.193	8.57E-02	8.57E-02
EP22	Pin Mixer U1	658303.670	3827653.850	5794.3	14.0	0.7	44.193	1.64E-02	5.14E-03
EP23	Ash Blower Building U1	658303.590	3827658.350	5794.3	14.0	0.2	44.193	1.71E-01	1.71E-01
EP28	Ash Surge Bin U2	658345.810	3827502.690	5796.8	50.0	0.1	93.012	8.57E-02	8.57E-02
EP29	Ash Storage Silo U2	658361.090	3827424.300	5798.3	100.0	0.1	44.193	8.57E-02	8.57E-02
EP30	Pin Mixer U2	658361.090	3827424.300	5798.3	14.0	0.7	44.193	1.64E-02	5.14E-03
EP31	Ash Blower Building U2	658361.090	3827429.300	5798.2	14.0	0.2	44.193	1.71E-01	1.71E-01
UNLOAD	Rotary Car Dumper	658685.460	3827600.900	5798.0	6.6	16.9	23.261	3.19E-02	1.00E-02
DC2	Coal Crusher House	658730.090	3827574.300	5798.6	78.0	0.2	18.602	1.39E+00	1.39E+00
DC3	Coal Transfer Area U1	658378.520	3827582.100	5795.8	157.0	0.8	305.184	1.54E+00	1.54E+00
DC4	Coal Transfer Area U2	658378.520	3827574.340	5795.9	181.0	0.8	305.184	1.03E+00	1.03E+00
DC5A	Coal Silo 1	658374.220	3827581.690	5795.7	155.0	0.8	305.184	1.71E-01	1.71E-01
DC5B	Coal Silo 2	658374.220	3827577.690	5795.8	155.0	0.8	305.184	1.71E-01	1.71E-01
DC5C	Coal Silo 3	658374.220	3827573.690	5795.8	155.0	0.8	305.184	1.71E-01	1.71E-01
DC5D	Coal Silo 4	658374.220	3827541.690	5796.3	155.0	0.8	305.184	1.71E-01	1.71E-01
DC5E	Coal Silo 5	658374.220	3827537.690	5796.4	155.0	0.8	305.184	1.71E-01	1.71E-01
DC5F	Coal Silo 6	658374.220	3827533.690	5796.5	155.0	0.8	305.184	1.71E-01	1.71E-01
DC6	Coal Sample Building	658860.210	3827588.240	5799.0	70.0	0.8	32.579	1.29E+00	1.29E+00
DC7A	Fly Ash Bin Vent 1	658607.090	3827560.430	5797.7	70.0	0.8	32.579	2.04E-01	2.04E-01
DC7B	Fly Ash Bin Vent 2	658622.940	3827560.430	5797.8	70.0	0.8	32.579	2.04E-01	2.04E-01
DC8	Fly Ash Receiving Silo	658664.300	3827542.650	5798.3	6.0	0.8	32.579	1.29E+00	1.29E+00
DC9	Limestone Ball Mill	658532.130	3827560.490	5797.2	70.0	0.8	30.217	6.00E-01	6.00E-01
DC10	Soda Ash	658350.710	3827784.150	5793.1	75.0	0.8	32.579	2.57E-02	2.57E-02
DC11	Lime Storage Silo	658355.030	3827773.160	5793.2	75.0	0.8	32.579	2.57E-02	2.57E-02
STACKER	Coal Stacker	658906.020	3827169.460	5803.0	79.0	7.6	13.714	7.97E-02	2.51E-02
L0004782	Ash Haul Road Segment 1	657680.720	3824295.810	5916.8	6.6	36.4	3.051	8.48E-02	8.36E-03
L0004783	Ash Haul Road Segment 2	657684.090	3824319.430	5916.4	6.6	36.4	3.051	8.48E-02	8.36E-03
L0004784	Ash Haul Road Segment 3	657687.460	3824343.040	5918.1	6.6	36.4	3.051	8.48E-02	8.36E-03
L0004785	Ash Haul Road Segment 4	657689.510	3824375.350	5919.9	6.6	49.5	3.051	8.48E-02	8.36E-03
L0004786	Ash Haul Road Segment 5	657690.320	3824407.770	5923.8	6.6	49.5	3.051	8.48E-02	8.36E-03
L0004787	Ash Haul Road Segment 6	657691.140	3824440.180	5928.8	6.6	49.5	3.051	8.48E-02	8.36E-03
L0004788	Ash Haul Road Segment 7	657675.950	3824478.060	5942.6	6.6	64.0	3.051	8.48E-02	8.36E-03
L0004789	Ash Haul Road Segment 8	657655.260	3824514.560	5940.4	6.6	64.0	3.051	8.48E-02	8.36E-03
L0004790	Ash Haul Road Segment 9	657635.840	3824542.150	5940.4	6.6	51.6	3.051	8.48E-02	8.36E-03
L0004791	Ash Haul Road Segment 10	657615.150	3824568.900	5941.0	6.6	51.6	3.051	8.48E-02	8.36E-03
L0004792	Ash Haul Road Segment 11	657594.460	3824595.650	5930.9	6.6	51.6	3.051	8.48E-02	8.36E-03
L0004793	Ash Haul Road Segment 12	657573.770	3824622.400	5920.1	6.6	51.6	3.051	8.48E-02	8.36E-03
L0004794	Ash Haul Road Segment 13	657559.630	3824654.210	5904.1	6.6	53.8	3.051	8.48E-02	8.36E-03
L0004795	Ash Haul Road Segment 14	657548.670	3824687.710	5908.2	6.6	53.8	3.051	8.48E-02	8.36E-03
L0004796	Ash Haul Road Segment 15	657537.720	3824721.210	5913.1	6.6	53.8	3.051	8.48E-02	8.36E-03
L0004797	Ash Haul Road Segment 16	657526.770	3824754.710	5922.8	6.6	53.8	3.051	8.48E-02	8.36E-03
L0004798	Ash Haul Road Segment 17	657522.890	3824791.890	5919.7	6.6	57.5	3.051	8.48E-02	8.36E-03
L0004799	Ash Haul Road Segment 18	657522.090	3824829.600	5918.2	6.6	57.5	3.051	8.48E-02	8.36E-03
L0004800	Ash Haul Road Segment 19	657521.290	3824867.310	5911.4	6.6	57.5	3.051	8.48E-02	8.36E-03
L0004801	Ash Haul Road Segment 20	657520.480	3824905.020	5909.4	6.6	57.5	3.051	8.48E-02	8.36E-03
L0004802	Ash Haul Road Segment 21	657519.680	3824942.720	5909.7	6.6	57.5	3.051	8.48E-02	8.36E-03
L0004803	Ash Haul Road Segment 22	657518.880	3824980.430	5920.6	6.6	57.5	3.051	8.48E-02	8.36E-03
L0004804	Ash Haul Road Segment 23	657524.330	3825016.510	5911.4	6.6	56.0	3.051	8.48E-02	8.36E-03
L0004805	Ash Haul Road Segment 24	657532.320	3825052.330	5905.2	6.6	56.0	3.051	8.48E-02	8.36E-03
L0004806	Ash Haul Road Segment 25	657540.310	3825088.150	5917.7	6.6	56.0	3.051	8.48E-02	8.36E-03
L0004807	Ash Haul Road Segment 26	657548.310	3825123.970	5923.7	6.6	56.0	3.051	8.48E-02	8.36E-03
L0004808	Ash Haul Road Segment 27	657556.300	3825159.790	5921.0	6.6	56.0	3.051	8.48E-02	8.36E-03
L0004809	Ash Haul Road Segment 28	657564.290	3825195.610	5916.5	6.6	56.0	3.051	8.48E-02	8.36E-03
L0004810	Ash Haul Road Segment 29	657572.280	3825231.440	5919.8	6.6	56.0	3.051	8.48E-02	8.36E-03
L0004811	Ash Haul Road Segment 30	657588.750	3825268.320	5922.4	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004812	Ash Haul Road Segment 31	657607.920	3825304.210	5923.9	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004813	Ash Haul Road Segment 32	657627.080	3825340.100	5926.8	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004814	Ash Haul Road Segment 33	657646.240	3825375.990	5926.1	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004815	Ash Haul Road Segment 34	657665.410	3825411.890	5923.7	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004816	Ash Haul Road Segment 35	657684.570	3825447.780	5921.4	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004817	Ash Haul Road Segment 36	657703.740	3825483.670	5919.9	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004818	Ash Haul Road Segment 37	657722.900	3825519.560	5918.1	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004819	Ash Haul Road Segment 38	657742.060	3825555.450	5915.8	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004820	Ash Haul Road Segment 39	657761.230	3825591.340	5913.5	6.6	62.1	3.051	8.48E-02	8.36E-03

Volume Sources (Potential to Emit)

Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Release Height (ft)	Init. Horizontal Dimension (ft)	Initial Vert. Dimension (ft)	PM10 (lb/hr)	PM25 (lb/hr)
L0004821	Ash Haul Road Segment 40	657780.390	3825627.230	5911.1	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004822	Ash Haul Road Segment 41	657799.560	3825663.120	5908.7	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004823	Ash Haul Road Segment 42	657818.720	3825699.010	5905.9	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004824	Ash Haul Road Segment 43	657837.890	3825734.900	5904.4	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004825	Ash Haul Road Segment 44	657857.050	3825770.790	5903.0	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004826	Ash Haul Road Segment 45	657876.210	3825806.680	5900.6	6.6	62.1	3.051	8.48E-02	8.36E-03
L0004827	Ash Haul Road Segment 46	657895.670	3825841.700	5897.7	6.6	61.1	3.051	8.48E-02	8.36E-03
L0004828	Ash Haul Road Segment 47	657915.340	3825876.590	5894.6	6.6	61.1	3.051	8.48E-02	8.36E-03
L0004829	Ash Haul Road Segment 48	657935.020	3825911.490	5891.7	6.6	61.1	3.051	8.48E-02	8.36E-03
L0004830	Ash Haul Road Segment 49	657954.690	3825946.380	5889.7	6.6	61.1	3.051	8.48E-02	8.36E-03
L0004831	Ash Haul Road Segment 50	657974.360	3825981.280	5887.1	6.6	61.1	3.051	8.48E-02	8.36E-03
L0004832	Ash Haul Road Segment 51	657994.030	3826016.170	5884.4	6.6	61.1	3.051	8.48E-02	8.36E-03
L0004833	Ash Haul Road Segment 52	658013.700	3826051.070	5881.4	6.6	61.1	3.051	8.48E-02	8.36E-03
L0004834	Ash Haul Road Segment 53	658033.380	3826085.970	5877.8	6.6	61.1	3.051	8.48E-02	8.36E-03
L0004835	Ash Haul Road Segment 54	658053.050	3826120.860	5874.8	6.6	61.1	3.051	8.48E-02	8.36E-03
L0004836	Ash Haul Road Segment 55	658072.720	3826155.760	5870.9	6.6	61.1	3.051	8.48E-02	8.36E-03
L0004837	Ash Haul Road Segment 56	658092.390	3826190.650	5864.5	6.6	61.1	3.051	8.48E-02	8.36E-03
L0004838	Ash Haul Road Segment 57	658112.060	3826225.550	5860.9	6.6	61.1	3.051	8.48E-02	8.36E-03
L0004839	Ash Haul Road Segment 58	658133.180	3826251.950	5859.1	6.6	51.9	3.051	8.48E-02	8.36E-03
L0004840	Ash Haul Road Segment 59	658156.310	3826276.890	5856.2	6.6	51.9	3.051	8.48E-02	8.36E-03
L0004841	Ash Haul Road Segment 60	658179.430	3826301.830	5853.1	6.6	51.9	3.051	8.48E-02	8.36E-03
L0004842	Ash Haul Road Segment 61	658202.560	3826326.760	5850.4	6.6	51.9	3.051	8.48E-02	8.36E-03
L0004843	Ash Haul Road Segment 62	658233.470	3826343.790	5848.0	6.6	55.0	3.051	8.48E-02	8.36E-03
L0004844	Ash Haul Road Segment 63	658267.060	3826356.890	5845.6	6.6	55.0	3.051	8.48E-02	8.36E-03
L0004845	Ash Haul Road Segment 64	658300.650	3826369.990	5842.8	6.6	55.0	3.051	8.48E-02	8.36E-03
L0004846	Ash Haul Road Segment 65	658334.230	3826383.090	5839.9	6.6	55.0	3.051	8.48E-02	8.36E-03
L0004847	Ash Haul Road Segment 66	658367.820	3826396.190	5836.8	6.6	55.0	3.051	8.48E-02	8.36E-03
L0004848	Ash Haul Road Segment 67	658401.850	3826414.870	5833.4	6.6	59.4	3.051	8.48E-02	8.36E-03
L0004849	Ash Haul Road Segment 68	658435.040	3826435.240	5831.2	6.6	59.4	3.051	8.48E-02	8.36E-03
L0004850	Ash Haul Road Segment 69	658456.980	3826453.580	5829.6	6.6	43.9	3.051	8.48E-02	8.36E-03
L0004851	Ash Haul Road Segment 70	658477.420	3826473.830	5827.7	6.6	43.9	3.051	8.48E-02	8.36E-03
L0004852	Ash Haul Road Segment 71	658497.860	3826494.080	5825.5	6.6	43.9	3.051	8.48E-02	8.36E-03
L0004853	Ash Haul Road Segment 72	658527.680	3826534.870	5822.4	6.6	61.7	3.051	8.48E-02	8.36E-03
L0004854	Ash Haul Road Segment 73	658549.590	3826568.870	5820.9	6.6	61.7	3.051	8.48E-02	8.36E-03
L0004855	Ash Haul Road Segment 74	658562.010	3826606.700	5819.3	6.6	61.5	3.051	8.48E-02	8.36E-03
L0004856	Ash Haul Road Segment 75	658571.080	3826645.950	5816.4	6.6	61.5	3.051	8.48E-02	8.36E-03
L0004857	Ash Haul Road Segment 76	658573.450	3826678.740	5814.3	6.6	50.5	3.051	8.48E-02	8.36E-03
L0004858	Ash Haul Road Segment 77	658573.440	3826711.810	5813.0	6.6	50.5	3.051	8.48E-02	8.36E-03
L0004859	Ash Haul Road Segment 78	658573.420	3826744.870	5812.0	6.6	50.5	3.051	8.48E-02	8.36E-03
L0004860	Ash Haul Road Segment 79	658573.410	3826777.930	5811.1	6.6	50.5	3.051	8.48E-02	8.36E-03
L0004861	Access Road Segment 1	658555.780	3826789.460	5810.8	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004862	Access Road Segment 2	658513.390	3826789.100	5810.9	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004863	Access Road Segment 3	658470.990	3826788.750	5811.2	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004864	Access Road Segment 4	658428.590	3826788.390	5811.8	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004865	Access Road Segment 5	658386.190	3826788.030	5812.4	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004866	Access Road Segment 6	658343.800	3826787.680	5813.5	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004867	Access Road Segment 7	658301.400	3826787.320	5814.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004868	Access Road Segment 8	658259.000	3826786.960	5816.2	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004869	Access Road Segment 9	658216.600	3826786.600	5817.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004870	Access Road Segment 10	658174.210	3826786.250	5819.1	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004871	Access Road Segment 11	658131.810	3826785.890	5820.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004872	Access Road Segment 12	658089.410	3826785.530	5821.8	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004873	Access Road Segment 13	658047.010	3826785.180	5823.2	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004874	Access Road Segment 14	658004.620	3826784.820	5825.2	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004875	Access Road Segment 15	657962.220	3826784.460	5827.4	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004876	Access Road Segment 16	657919.820	3826784.100	5829.5	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004877	Access Road Segment 17	657877.420	3826783.750	5830.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004878	Access Road Segment 18	657835.030	3826783.390	5831.1	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004879	Access Road Segment 19	657792.630	3826783.030	5832.2	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004880	Access Road Segment 20	657750.230	3826782.680	5834.4	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004881	Access Road Segment 21	657707.840	3826782.320	5835.8	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004882	Access Road Segment 22	657665.440	3826781.960	5838.2	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004883	Access Road Segment 23	657623.040	3826781.600	5840.5	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004884	Access Road Segment 24	657580.640	3826781.250	5841.1	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004885	Access Road Segment 25	657538.250	3826780.890	5841.8	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004886	Access Road Segment 26	657495.850	3826780.530	5842.1	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004887	Access Road Segment 27	657453.450	3826780.180	5842.6	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004888	Access Road Segment 28	657411.050	3826779.820	5842.8	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004889	Access Road Segment 29	657368.660	3826779.460	5837.0	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004890	Access Road Segment 30	657326.260	3826779.100	5828.1	6.6	64.7	3.051	3.16E-02	3.08E-03

Volume Sources (Potential to Emit)

Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Release Height (ft)	Init. Horizontal Dimension (ft)	Initial Vert. Dimension (ft)	PM10 (lb/hr)	PM25 (lb/hr)
L0004891	Access Road Segment 31	657283.860	3826778.750	5822.2	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004892	Access Road Segment 32	657241.460	3826778.390	5817.0	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004893	Access Road Segment 33	657199.070	3826778.030	5813.0	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004894	Access Road Segment 34	657156.670	3826777.680	5808.8	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004895	Access Road Segment 35	657114.270	3826777.320	5806.3	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004896	Access Road Segment 36	657071.870	3826776.960	5804.6	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004897	Access Road Segment 37	657029.480	3826776.600	5803.6	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004898	Access Road Segment 38	656987.080	3826776.250	5806.4	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004899	Access Road Segment 39	656944.680	3826775.890	5805.1	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004900	Access Road Segment 40	656902.280	3826775.530	5798.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004901	Access Road Segment 41	656859.890	3826775.180	5792.0	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004902	Access Road Segment 42	656817.490	3826774.820	5788.3	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004903	Access Road Segment 43	656775.090	3826774.460	5784.5	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004904	Access Road Segment 44	656732.690	3826774.100	5779.1	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004905	Access Road Segment 45	656690.300	3826773.750	5766.0	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004906	Access Road Segment 46	656647.900	3826773.390	5761.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004907	Access Road Segment 47	656605.500	3826773.030	5759.9	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004908	Access Road Segment 48	656563.100	3826772.680	5757.6	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004909	Access Road Segment 49	656520.710	3826772.320	5755.6	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004910	Access Road Segment 50	656478.310	3826771.960	5753.0	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004911	Access Road Segment 51	656435.910	3826771.600	5749.3	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004912	Access Road Segment 52	656393.520	3826771.250	5746.5	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004913	Access Road Segment 53	656351.120	3826770.890	5749.5	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004914	Access Road Segment 54	656308.720	3826770.530	5751.2	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004915	Access Road Segment 55	656266.320	3826770.180	5755.2	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004916	Access Road Segment 56	656223.930	3826769.820	5762.0	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004917	Access Road Segment 57	656181.530	3826769.460	5770.4	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004918	Access Road Segment 58	656139.130	3826769.100	5783.2	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004919	Access Road Segment 59	656096.730	3826768.750	5792.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004920	Access Road Segment 60	656054.340	3826768.390	5802.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004921	Access Road Segment 61	656011.940	3826768.030	5805.1	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004922	Access Road Segment 62	655969.540	3826767.680	5805.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004923	Access Road Segment 63	655927.140	3826767.320	5804.5	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004924	Access Road Segment 64	655884.750	3826766.960	5804.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004925	Access Road Segment 65	655842.350	3826766.600	5806.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004926	Access Road Segment 66	655799.950	3826766.250	5810.9	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004927	Access Road Segment 67	655757.550	3826765.890	5815.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004928	Access Road Segment 68	655715.160	3826765.530	5817.8	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004929	Access Road Segment 69	655672.760	3826765.180	5819.5	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004930	Access Road Segment 70	655630.360	3826764.820	5822.4	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004931	Access Road Segment 71	655587.960	3826764.460	5825.5	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004932	Access Road Segment 72	655545.570	3826764.100	5826.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004933	Access Road Segment 73	655503.170	3826763.750	5827.7	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004934	Access Road Segment 74	655460.770	3826763.390	5828.1	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004935	Access Road Segment 75	655418.370	3826763.030	5828.1	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004936	Access Road Segment 76	655375.980	3826762.680	5828.8	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004937	Access Road Segment 77	655333.580	3826762.320	5829.6	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004938	Access Road Segment 78	655291.180	3826761.960	5830.6	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004939	Access Road Segment 79	655248.780	3826761.600	5828.1	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004940	Access Road Segment 80	655206.390	3826761.250	5823.6	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004941	Access Road Segment 81	655163.990	3826760.890	5813.4	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004942	Access Road Segment 82	655121.590	3826760.530	5807.5	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004943	Access Road Segment 83	655079.200	3826760.180	5799.3	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004944	Access Road Segment 84	655036.800	3826759.820	5792.8	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004945	Access Road Segment 85	654994.400	3826759.460	5787.1	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004946	Access Road Segment 86	654952.000	3826759.100	5781.8	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004947	Access Road Segment 87	654909.610	3826758.750	5779.3	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004948	Access Road Segment 88	654867.210	3826758.390	5777.4	6.6	64.7	3.051	3.16E-02	3.08E-03
L0004949	Unpaved Road No. 2 Seg. 1	658572.460	3826820.850	5810.1	6.6	60.5	3.051	1.22E-01	1.19E-02
L0004950	Unpaved Road No. 2 Seg. 2	658572.210	3826860.510	5809.4	6.6	60.5	3.051	1.22E-01	1.19E-02
L0004951	Unpaved Road No. 2 Seg. 3	658571.950	3826900.180	5808.5	6.6	60.5	3.051	1.22E-01	1.19E-02
L0004952	Unpaved Road No. 2 Seg. 4	658571.690	3826939.850	5807.3	6.6	60.5	3.051	1.22E-01	1.19E-02
L0004953	Unpaved Road No. 2 Seg. 5	658571.440	3826979.510	5806.2	6.6	60.5	3.051	1.22E-01	1.19E-02
L0004954	Unpaved Road No. 2 Seg. 6	658571.180	3827019.180	5805.3	6.6	60.5	3.051	1.22E-01	1.19E-02
L0004955	Unpaved Road No. 2 Seg. 7	658570.920	3827058.850	5804.5	6.6	60.5	3.051	1.22E-01	1.19E-02
L0004956	Unpaved Road No. 2 Seg. 8	658570.670	3827098.510	5803.6	6.6	60.5	3.051	1.22E-01	1.19E-02
L0004957	Unpaved Road No. 2 Seg. 9	658570.410	3827138.180	5802.8	6.6	60.5	3.051	1.22E-01	1.19E-02
L0004709	Limestone Delivery Seg. 1	658578.520	3827408.910	5799.4	6.6	42.4	3.051	1.21E-02	1.18E-03
L0004710	Limestone Delivery Seg. 2	658606.160	3827405.940	5799.4	6.6	42.4	3.051	1.21E-02	1.18E-03
L0004711	Limestone Delivery Seg. 3	658636.350	3827395.920	5799.7	6.6	49.1	3.051	1.21E-02	1.18E-03

Volume Sources (Potential to Emit)

Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Release Height (ft)	Init. Horizontal Dimension (ft)	Initial Vert. Dimension (ft)	PM10 (lb/hr)	PM25 (lb/hr)
L0004712	Limestone Delivery Seg. 4	658653.620	3827367.670	5800.1	6.6	54.4	3.051	1.21E-02	1.18E-03
L0004713	Limestone Delivery Seg. 5	658658.450	3827333.400	5800.5	6.6	53.1	3.051	1.21E-02	1.18E-03
L0004714	Limestone Delivery Seg. 6	658650.650	3827294.470	5800.9	6.6	61.4	3.051	1.21E-02	1.18E-03
L0004715	Limestone Delivery Seg. 7	658634.730	3827260.800	5801.3	6.6	57.1	3.051	1.21E-02	1.18E-03
L0004716	Limestone Delivery Seg. 8	658616.780	3827227.990	5801.6	6.6	57.1	3.051	1.21E-02	1.18E-03
L0004717	Limestone Delivery Seg. 9	658598.830	3827195.180	5802.0	6.6	57.1	3.051	1.21E-02	1.18E-03
L0004718	Limestone Delivery Seg. 10	658580.880	3827162.370	5802.5	6.6	57.1	3.051	1.21E-02	1.18E-03
L0004958	Unpaved Road No. 3 Seg. 1	658569.460	3827161.420	5802.5	6.6	54.3	3.051	9.06E-02	8.92E-03
L0004959	Unpaved Road No. 3 Seg. 2	658569.030	3827197.010	5801.9	6.6	54.3	3.051	9.06E-02	8.92E-03
L0004960	Unpaved Road No. 3 Seg. 3	658568.590	3827232.590	5801.4	6.6	54.3	3.051	9.06E-02	8.92E-03
L0004961	Unpaved Road No. 3 Seg. 4	658568.160	3827268.180	5800.9	6.6	54.3	3.051	9.06E-02	8.92E-03
L0004962	Unpaved Road No. 4 Seg. 1	658567.160	3827290.920	5800.6	6.6	54.8	3.051	7.00E-02	6.89E-03
L0004963	Unpaved Road No. 4 Seg. 2	658566.760	3827326.840	5800.2	6.6	54.8	3.051	7.00E-02	6.89E-03
L0004964	Unpaved Road No. 4 Seg. 3	658566.360	3827362.760	5799.9	6.6	54.8	3.051	7.00E-02	6.89E-03
L0004965	Unpaved Road No. 4 Seg. 4	658565.960	3827398.680	5799.5	6.6	54.8	3.051	7.00E-02	6.89E-03
L0004966	Unit 2 Bottom Ash Seg. 1	658403.530	3827278.240	5800.1	6.6	57.1	3.051	8.00E-03	7.89E-04
L0004967	Unit 2 Bottom Ash Seg. 2	658366.130	3827278.030	5800.1	6.6	57.1	3.051	8.00E-03	7.89E-04
L0004968	Unit 2 Bottom Ash Seg. 3	658328.730	3827277.820	5800.2	6.6	57.1	3.051	8.00E-03	7.89E-04
L0004969	Unit 2 Bottom Ash Seg. 4	658291.340	3827277.610	5800.4	6.6	57.1	3.051	8.00E-03	7.89E-04
L0004970	Unit 2 Bottom Ash Seg. 5	658281.930	3827304.820	5800.1	6.6	57.8	3.051	8.00E-03	7.89E-04
L0004971	Unit 2 Bottom Ash Seg. 6	658283.620	3827342.690	5799.5	6.6	57.8	3.051	8.00E-03	7.89E-04
L0004972	Unit 2 Bottom Ash Seg. 7	658285.310	3827380.570	5798.9	6.6	57.8	3.051	8.00E-03	7.89E-04
L0004973	Unit 2 Bottom Ash Seg. 8	658286.990	3827418.440	5798.1	6.6	57.8	3.051	8.00E-03	7.89E-04
L0004974	Unit 2 Bottom Ash Seg. 9	658318.320	3827428.860	5798.0	6.6	63.3	3.051	8.00E-03	7.89E-04
L0004975	Unit 2 Bottom Ash Seg. 10	658359.800	3827428.610	5798.3	6.6	63.3	3.051	8.00E-03	7.89E-04
L0004976	Unit 2 Bottom Ash Seg. 11	658401.280	3827428.360	5798.3	6.6	63.3	3.051	8.00E-03	7.89E-04
L0004977	Unit 2 Bottom Ash Seg. 12	658412.410	3827403.360	5798.8	6.6	54.3	3.051	8.00E-03	7.89E-04
L0004978	Unit 2 Bottom Ash Seg. 13	658413.130	3827367.790	5799.2	6.6	54.3	3.051	8.00E-03	7.89E-04
L0004979	Unit 2 Bottom Ash Seg. 14	658413.840	3827332.230	5799.6	6.6	54.3	3.051	8.00E-03	7.89E-04
L0004980	Unit 2 Bottom Ash Seg. 15	658414.560	3827296.670	5799.9	6.6	54.3	3.051	8.00E-03	7.89E-04
L0004981	Unpaved Road No. 6 Seg. 1	658567.180	3827420.670	5799.2	6.6	43.5	3.051	4.95E-02	4.88E-03
L0004982	Unpaved Road No. 6 Seg. 2	658566.900	3827449.180	5798.9	6.6	43.5	3.051	4.95E-02	4.88E-03
L0004983	Unpaved Road No. 6 Seg. 3	658566.630	3827477.680	5798.6	6.6	43.5	3.051	4.95E-02	4.88E-03
L0004984	Unpaved Road No. 7 Seg. 1	658566.380	3827498.920	5798.3	6.6	60.3	3.051	3.95E-02	3.89E-03
L0004985	Unpaved Road No. 7 Seg. 2	658566.780	3827538.430	5797.8	6.6	60.3	3.051	3.95E-02	3.89E-03
L0004986	Unpaved Road No. 7 Seg. 3	658567.170	3827577.930	5797.2	6.6	60.3	3.051	3.95E-02	3.89E-03
L0004987	Fly Ash Pickup Seg. 1	658577.900	3827588.550	5797.1	6.6	43.0	3.051	2.04E-02	2.02E-03
L0004988	Fly Ash Pickup Seg. 2	658606.100	3827588.550	5797.2	6.6	43.0	3.051	2.04E-02	2.02E-03
L0004989	Fly Ash Pickup Seg. 3	658616.890	3827565.920	5797.7	6.6	50.8	3.051	2.04E-02	2.02E-03
L0004990	Fly Ash Pickup Seg. 4	658617.140	3827532.670	5798.2	6.6	50.8	3.051	2.04E-02	2.02E-03
L0004991	Fly Ash Pickup Seg. 5	658617.390	3827499.420	5798.6	6.6	50.8	3.051	2.04E-02	2.02E-03
L0004992	Fly Ash Pickup Seg. 6	658602.210	3827488.800	5798.6	6.6	39.5	3.051	2.04E-02	2.02E-03
L0004993	Fly Ash Pickup Seg. 7	658576.340	3827488.800	5798.5	6.6	39.5	3.051	2.04E-02	2.02E-03
L0004994	Unpaved Road No. 8 Seg. 1	658568.030	3827601.420	5796.9	6.6	48.5	3.051	1.42E-02	1.40E-03
L0004995	Unpaved Road No. 8 Seg. 2	658568.030	3827633.170	5796.3	6.6	48.5	3.051	1.42E-02	1.40E-03
L0004996	Unpaved Road No. 8 Seg. 3	658568.030	3827664.930	5795.8	6.6	48.5	3.051	1.42E-02	1.40E-03
L0004997	Unpaved Road No. 8 Seg. 4	658568.030	3827696.680	5795.6	6.6	48.5	3.051	1.42E-02	1.40E-03
L0004759	Unpaved Road	658577.900	3827712.050	5795.4	6.6	59.2	3.051	1.31E-03	1.28E-04
L0004760	Unpaved Road	658616.680	3827712.050	5796.1	6.6	59.2	3.051	1.31E-03	1.28E-04
L0004761	Unpaved Road	658655.470	3827712.050	5796.4	6.6	59.2	3.051	1.31E-03	1.28E-04
L0004998	Unpaved Road	658555.910	3827711.710	5795.1	6.6	52.5	3.051	1.38E-02	1.37E-03
L0004999	Unpaved Road	658521.550	3827710.590	5794.8	6.6	52.5	3.051	1.38E-02	1.37E-03
L0005000	Unpaved Road	658487.180	3827709.480	5794.5	6.6	52.5	3.051	1.38E-02	1.37E-03
L0005001	Unpaved Road	658452.810	3827708.370	5794.3	6.6	52.5	3.051	1.38E-02	1.37E-03
L0005002	Unpaved Road	658418.450	3827707.260	5794.1	6.6	52.5	3.051	1.38E-02	1.37E-03
L0005003	Unpaved Road	658384.080	3827706.140	5794.2	6.6	52.5	3.051	1.38E-02	1.37E-03
L0005004	Unpaved Road	658361.350	3827706.320	5794.2	6.6	62.2	3.051	6.73E-03	6.64E-04
L0005005	Unpaved Road	658320.620	3827705.430	5794.0	6.6	62.2	3.051	6.73E-03	6.64E-04
L0005006	Unpaved Road	658279.900	3827704.530	5793.5	6.6	62.2	3.051	6.73E-03	6.64E-04
L0005007	Unpaved Road	658269.280	3827687.050	5793.5	6.6	42.6	3.051	6.73E-03	6.64E-04
L0005008	Unpaved Road	658269.280	3827659.170	5793.8	6.6	42.6	3.051	6.73E-03	6.64E-04
L0005009	Unpaved Road	658293.390	3827648.780	5794.2	6.6	53.0	3.051	6.73E-03	6.64E-04
L0005010	Unpaved Road	658328.120	3827649.120	5794.6	6.6	53.0	3.051	6.73E-03	6.64E-04
L0005011	Unpaved Road	658362.850	3827649.450	5794.8	6.6	53.0	3.051	6.73E-03	6.64E-04
L0005012	Unpaved Road	658373.230	3827667.060	5794.7	6.6	42.9	3.051	6.73E-03	6.64E-04
L0005013	Unpaved Road	658372.860	3827695.180	5794.3	6.6	42.9	3.051	6.73E-03	6.64E-04
L0005014	Unpaved Rd Bottom Ash Seg. 1	658554.970	3827282.070	5800.7	6.6	64.7	3.051	1.01E-02	1.00E-03
L0005015	Unpaved Rd Bottom Ash Seg. 2	658512.610	3827281.140	5800.7	6.6	64.7	3.051	1.01E-02	1.00E-03
L0005016	Unpaved Rd Bottom Ash Seg. 3	658470.250	3827280.210	5800.4	6.6	64.7	3.051	1.01E-02	1.00E-03
L0005017	Unpaved Rd Bottom Ash Seg. 4	658427.900	3827279.280	5800.1	6.6	64.7	3.051	1.01E-02	1.00E-03

Area Cir Sources (Potential to Emit)

Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Release Height (ft)	Radius of Circle (ft)	Number of Vertices	Initial Vert. Dimension (ft)	PM10 (lb/hr)	PM2.5 (lb/hr)
F32	Existing Limestone Pile	658534.430	3827477.450	5798.5	20.0	48.0	20.0	0.0	1.71E-02	6.85E-03

CALPUFF Input

Model Source Description	Model Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/sec)	Temp. (K)	Sigma Y (m)	Sigma Z (m)	Momentum Flux	PMF (lb/hr)
Unit 1		-1119.912	-523.844	121.95	1766.34	7.39	18.02	329.26	0	0	1	*113.61*

Notes:

LCC Origin: 40.0N, 97.0W, Standard Parallels: 33.0N, 45.0N. Datum: NWS-84.

PMFine (PMF) or "soil" = PM < 2.5 um in diameter.

PMCoarse (PMC) = PM between 2.5 and 10 um in diameter.

EC = elemental carbon

SOA = secondary organic aerosols

Off-Site Source Inventory

Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Stack Height (ft)	Temp. (F)	Exit Velocity (ft/sec)	Stack Diameter (ft)	PM10 (lb/hr)
Offsite1	Springerville Unit 1	668893.610	3799013.270	6983.1	500.0	173.0	144.4	20.0	454.6
Offsite2	Springerville Unit 2	668801.610	3799012.000	6983.1	500.0	187.0	166.3	20.0	290.3
Offsite3	Springerville Unit 3	668647.290	3799008.100	6983.1	495.0	193.0	157.1	20.0	58.4
Offsite4	Springerville Unit 3	668647.290	3799008.100	6983.1	500.0	189.0	156.1	20.0	127.4
Offsite5	Eker Brothers (NM)	728008.000	3808827.000	6917.7	8.0	1000.0	106.9	0.5	1.1
Offsite6	Derrick Construction (NM)	692000.000	3743994.000	6980.5	50.0	70.0	10.0	0.0	7.8
Offsite7	Pioneer Industries (NM)	696294.000	3747831.000	6806.4	24.9	795.0	106.9	1.0	43.3

Springerville stack locations refined based upon aerial photos.

Attachment B – Model Summary Output

SRP Coronado Boiler Load and Class II SIL Analysis Results (11-25-15)

Model	File	Pollutant	Average	Group	Rank	Conc/Dep	East (X)	North (Y)	Elev	Hill	Flag	Time	Met File	Sources	Groups	Receptors
AERMOD 15181	Coronado SIL_2014_PM10.SUM	PM10	24-HR	UNIT1A	1ST	1.61281	659500	3828600	1755.63	1755.63	0	14051924	STJALB-14.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2012_PM10.SUM	PM10	24-HR	UNIT1A	1ST	1.58592	657200	3827500	1764.42	1764.42	0	12091324	STJALB-12.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2010_PM10.SUM	PM10	24-HR	UNIT1A	1ST	1.52333	659200	3828500	1758.75	1758.75	0	10070324	STJALB-10.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2011_PM10.SUM	PM10	24-HR	UNIT1A	1ST	1.49515	659400.8	3827289.9	1769.86	1769.86	0	11062024	STJALB-11.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2013_PM10.SUM	PM10	24-HR	UNIT1A	1ST	1.44207	659401.2	3827240.8	1770.09	1770.09	0	13060724	STJALB-13.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2012_PM10.SUM	PM10	24-HR	UNIT1B	1ST	1.4431	657200	3827500	1764.42	1764.42	0	12091324	STJALB-12.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2014_PM10.SUM	PM10	24-HR	UNIT1B	1ST	1.42805	659311.8	3828461.5	1759.17	1759.17	0	14051924	STJALB-14.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2010_PM10.SUM	PM10	24-HR	UNIT1B	1ST	1.36337	659200	3828500	1758.75	1758.75	0	10070324	STJALB-10.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2011_PM10.SUM	PM10	24-HR	UNIT1B	1ST	1.28366	659000	3828900	1754.02	1754.02	0	11052924	STJALB-11.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2013_PM10.SUM	PM10	24-HR	UNIT1B	1ST	1.23625	659403.4	3826970.5	1771.43	1771.43	0	13060824	STJALB-13.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2012_PM10.SUM	PM10	24-HR	UNIT1C	1ST	1.22697	657400	3827600	1763.74	1763.74	0	12091324	STJALB-12.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2014_PM10.SUM	PM10	24-HR	UNIT1C	1ST	1.16957	659287.1	3828461.4	1759.19	1759.19	0	14051924	STJALB-14.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2010_PM10.SUM	PM10	24-HR	UNIT1C	1ST	1.13028	659163.7	3828461.3	1759.46	1759.46	0	10070324	STJALB-10.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2011_PM10.SUM	PM10	24-HR	UNIT1C	1ST	1.06248	658900	3828700	1761.88	1761.88	0	11052924	STJALB-11.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2013_PM10.SUM	PM10	24-HR	UNIT1C	1ST	1.01474	657400	3827500	1764.4	1764.4	0	13051124	STJALB-13.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2012_PM10.SUM	PM10	ANNUAL	UNIT1A	1ST	0.35283	659400.4	3827339.1	1769.67	1769.67	0	1 YEARS	STJALB-12.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2011_PM10.SUM	PM10	ANNUAL	UNIT1A	1ST	0.34472	659401	3827265.4	1769.98	1769.98	0	1 YEARS	STJALB-11.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2014_PM10.SUM	PM10	ANNUAL	UNIT1A	1ST	0.32654	659401.2	3827240.8	1770.09	1770.09	0	1 YEARS	STJALB-14.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2010_PM10.SUM	PM10	ANNUAL	UNIT1A	1ST	0.30165	659400.6	3827314.5	1769.75	1769.75	0	1 YEARS	STJALB-10.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2013_PM10.SUM	PM10	ANNUAL	UNIT1A	1ST	0.29526	659400.4	3827339.1	1769.67	1769.67	0	1 YEARS	STJALB-13.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2012_PM10.SUM	PM10	ANNUAL	UNIT1B	1ST	0.30706	659400.4	3827339.1	1769.67	1769.67	0	1 YEARS	STJALB-12.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2011_PM10.SUM	PM10	ANNUAL	UNIT1B	1ST	0.30039	659400.8	3827289.9	1769.86	1769.86	0	1 YEARS	STJALB-11.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2014_PM10.SUM	PM10	ANNUAL	UNIT1B	1ST	0.28525	659401	3827265.4	1769.98	1769.98	0	1 YEARS	STJALB-14.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2010_PM10.SUM	PM10	ANNUAL	UNIT1B	1ST	0.26744	659361.1	3828461.6	1758.92	1758.92	0	1 YEARS	STJALB-10.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2013_PM10.SUM	PM10	ANNUAL	UNIT1B	1ST	0.26186	659400.2	3827363.6	1769.57	1769.57	0	1 YEARS	STJALB-13.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2012_PM10.SUM	PM10	ANNUAL	UNIT1C	1ST	0.24871	659400.2	3827363.6	1769.57	1769.57	0	1 YEARS	STJALB-12.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2011_PM10.SUM	PM10	ANNUAL	UNIT1C	1ST	0.2436	659400.8	3827289.9	1769.86	1769.86	0	1 YEARS	STJALB-11.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2014_PM10.SUM	PM10	ANNUAL	UNIT1C	1ST	0.23154	659400.8	3827289.9	1769.86	1769.86	0	1 YEARS	STJALB-14.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2010_PM10.SUM	PM10	ANNUAL	UNIT1C	1ST	0.22144	659336.4	3828461.5	1759.07	1759.07	0	1 YEARS	STJALB-10.SFC	3	3	14097
AERMOD 15181	Coronado SIL_2013_PM10.SUM	PM10	ANNUAL	UNIT1C	1ST	0.21788	659400	3827388.2	1769.46	1769.46	0	1 YEARS	STJALB-13.SFC	3	3	14097
AERMOD 15181	Coronado SIL_5yrs_PM25.SUM	PM25	1ST-HIGHEST 24-HR	UNIT1A	1ST	1.42361	659400	3828500	1757.78	1757.78	0	5 YEARS	STJALB-1014.SFC	3	3	14097
AERMOD 15181	Coronado SIL_5yrs_PM25.SUM	PM25	1ST-HIGHEST 24-HR	UNIT1B	1ST	1.24681	659336.4	3828461.5	1759.07	1759.07	0	5 YEARS	STJALB-1014.SFC	3	3	14097
AERMOD 15181	Coronado SIL_5yrs_PM25.SUM	PM25	1ST-HIGHEST 24-HR	UNIT1C	1ST	1.00811	659336.4	3828461.5	1759.07	1759.07	0	5 YEARS	STJALB-1014.SFC	3	3	14097
AERMOD 15181	Coronado SIL_5yrs_PM25.SUM	PM25	ANNUAL	UNIT1A	1ST	0.32339	659400.8	3827289.9	1769.86	1769.86	0	5 YEARS	STJALB-1014.SFC	3	3	14097
AERMOD 15181	Coronado SIL_5yrs_PM25.SUM	PM25	ANNUAL	UNIT1B	1ST	0.28291	659400.6	3827314.5	1769.75	1769.75	0	5 YEARS	STJALB-1014.SFC	3	3	14097
AERMOD 15181	Coronado SIL_5yrs_PM25.SUM	PM25	ANNUAL	UNIT1C	1ST	0.23066	659400.4	3827339.1	1769.67	1769.67	0	5 YEARS	STJALB-1014.SFC	3	3	14097

SRP Coronado Boiler Load and Class II SIL Analysis Results (11-25-15)

Pollutant	Average	Group	Rank	Model Conc.	Background	Total	Standard	%Standard
PM25	1ST-HIGHEST 24-HR	UNIT1A	1ST	1.42	NA	1.4	1.2	119%
PM25	1ST-HIGHEST 24-HR	UNIT1B	1ST	1.25	NA	1.2	1.2	104%
PM25	1ST-HIGHEST 24-HR	UNIT1C	1ST	1.01	NA	1.0	1.2	84%
PM25	ANNUAL	UNIT1A	1ST	0.32	NA	0.3	0.3	108%
PM25	ANNUAL	UNIT1B	1ST	0.28	NA	0.3	0.3	94%
PM25	ANNUAL	UNIT1C	1ST	0.23	NA	0.2	0.3	77%
PM10	24-HR	UNIT1A	1ST	1.61	NA	1.6	5	32%
PM10	24-HR	UNIT1B	1ST	1.44	NA	1.4	5	29%
PM10	24-HR	UNIT1C	1ST	1.23	NA	1.2	5	25%
PM10	ANNUAL	UNIT1A	1ST	0.35	NA	0.4	1	35%
PM10	ANNUAL	UNIT1B	1ST	0.31	NA	0.3	1	31%
PM10	ANNUAL	UNIT1C	1ST	0.25	NA	0.2	1	25%

Note 1: "UNIT1A" = Unit No. 1 at 100% Load, "UNIT1B" = Unit No. 1 at 75% Load, and "UNIT1C" = Unit 1 at 50% Load.

Note 2: The 100% load case results in the highest modeled concentrations. This load condition was therefore used in the NAAQS and increment evaluation.

SRP Coronado PM2.5 NAAQS and Increment Analysis Results (11-24-15)

Model	File	Pollutant	Average	Group	Rank	Conc/Dep	East (X)	North (Y)	Elev	Hill	Flag	Time	Met File	Sources	Groups	Receptors
AERMOD 15181	Coronado NAAQS_5yrs_PM25.SUM	PM25	ANNUAL	ALL	1ST	4.04091	659397	3827756.8	1768.71	1768.71	0	5 YEARS	STJALB-1014.SFC	326	1	185
AERMOD 15181	Coronado NAAQS_5yrs_PM25.SUM	PM25	8TH-HIGHEST 24-HR	ALL	1ST	10.96074	659400	3827500	1768.91	1768.91	0	5 YEARS	STJALB-1014.SFC	326	1	185

SRP Coronado PM2.5 NAAQS and Increment Analysis Results (11-24-15)

Pollutant	Average	Group	Rank	Modeled Conc.	Background	Total	Standard	% Standard	Analysis
PM25	8TH-HIGHEST 24-HR	ALL	1ST	10.96	12.0	22.96	35	66%	NAAQS
PM25	ANNUAL	ALL	1ST	4.04	5.3	9.34	12	78%	NAAQS
PM25	1ST-HIGHEST 24-HR	ALL	1ST	1.42	NA	1.42	9	16%	Increment
PM25	ANNUAL	ALL	1ST	0.32	NA	0.32	4	8%	Increment

Note 1: Background PM2.5 values are from the EPA's design value database for Coconino County, which is the closest county to Apache with PM2.5 monitor data. The closest PM2.5 monitor is AQS #04-001-1235 approximately 130km north of the Coronado site in Apache County. The design values at this monitor are less than the EPA's design value for Coconino Co.

Note 2: SRP is the only PM2.5 increment consuming source. Therefore the maximum impacts from the SIL analysis were conservatively used to represent increment consumption.

SRP Coronado Class I SIL Analysis Results, 50km Ring Receptors (11-24-15)

Model	File	Pollutant	Average	Group	Rank	Conc/Dep	East (X)	North (Y)	Elev	Hill	Flag	Time	Met File	Sources	Groups	Receptors
AERMOD 15181	Coronado Class I SIL_2010_PM10.SUM	PM10	24-HR	UNIT1A	1ST	0.13742	705412.07	3810640.1	1800	1800	0	10020324	STJALB-10.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2012_PM10.SUM	PM10	24-HR	UNIT1A	1ST	0.10241	667109.85	3778500.7	1800	1800	0	12123124	STJALB-12.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2014_PM10.SUM	PM10	24-HR	UNIT1A	1ST	0.08598	623072.1	3863096.4	1800	1800	0	14081024	STJALB-14.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2011_PM10.SUM	PM10	24-HR	UNIT1A	1ST	0.08443	696729.66	3859880.4	1800	1800	0	11080724	STJALB-11.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2013_PM10.SUM	PM10	24-HR	UNIT1A	1ST	0.08353	699385.04	3856419.9	1800	1800	0	13021024	STJALB-13.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2010_PM10.SUM	PM10	24-HR	UNIT1B	1ST	0.10996	705412.07	3810640.1	1800	1800	0	10020324	STJALB-10.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2012_PM10.SUM	PM10	24-HR	UNIT1B	1ST	0.08113	667109.85	3778500.7	1800	1800	0	12123124	STJALB-12.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2014_PM10.SUM	PM10	24-HR	UNIT1B	1ST	0.0703	623072.1	3863096.4	1800	1800	0	14081024	STJALB-14.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2011_PM10.SUM	PM10	24-HR	UNIT1B	1ST	0.06877	654069.65	3877550.8	1800	1800	0	11083024	STJALB-11.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2013_PM10.SUM	PM10	24-HR	UNIT1B	1ST	0.06749	699385.04	3856419.9	1800	1800	0	13021024	STJALB-13.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2010_PM10.SUM	PM10	24-HR	UNIT1C	1ST	0.07948	705412.07	3810640.1	1800	1800	0	10020324	STJALB-10.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2011_PM10.SUM	PM10	24-HR	UNIT1C	1ST	0.05919	654069.65	3877550.8	1800	1800	0	11083024	STJALB-11.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2012_PM10.SUM	PM10	24-HR	UNIT1C	1ST	0.05766	667109.85	3778500.7	1800	1800	0	12123124	STJALB-12.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2014_PM10.SUM	PM10	24-HR	UNIT1C	1ST	0.05446	623072.1	3863096.4	1800	1800	0	14081024	STJALB-14.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2013_PM10.SUM	PM10	24-HR	UNIT1C	1ST	0.0486	699385.04	3856419.9	1800	1800	0	13021024	STJALB-13.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2010_PM10.SUM	PM10	ANNUAL	UNIT1A	1ST	0.01242	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-10.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2012_PM10.SUM	PM10	ANNUAL	UNIT1A	1ST	0.0124	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-12.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2014_PM10.SUM	PM10	ANNUAL	UNIT1A	1ST	0.01226	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-14.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2011_PM10.SUM	PM10	ANNUAL	UNIT1A	1ST	0.01136	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-11.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2013_PM10.SUM	PM10	ANNUAL	UNIT1A	1ST	0.01032	699385.04	3856419.9	1800	1800	0	1 YEARS	STJALB-13.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2010_PM10.SUM	PM10	ANNUAL	UNIT1B	1ST	0.00999	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-10.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2012_PM10.SUM	PM10	ANNUAL	UNIT1B	1ST	0.00998	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-12.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2014_PM10.SUM	PM10	ANNUAL	UNIT1B	1ST	0.00979	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-14.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2011_PM10.SUM	PM10	ANNUAL	UNIT1B	1ST	0.00911	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-11.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2013_PM10.SUM	PM10	ANNUAL	UNIT1B	1ST	0.00832	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-13.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2010_PM10.SUM	PM10	ANNUAL	UNIT1C	1ST	0.00733	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-10.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2012_PM10.SUM	PM10	ANNUAL	UNIT1C	1ST	0.00729	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-12.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2014_PM10.SUM	PM10	ANNUAL	UNIT1C	1ST	0.00709	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-14.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2011_PM10.SUM	PM10	ANNUAL	UNIT1C	1ST	0.00664	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-11.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_2013_PM10.SUM	PM10	ANNUAL	UNIT1C	1ST	0.00616	696729.66	3859880.4	1800	1800	0	1 YEARS	STJALB-13.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_5yrs_PM25.SUM	PM25	1ST-HIGHEST 24-HR	UNIT1A	1ST	0.07993	696729.66	3859880.4	1800	1800	0	5 YEARS	STJALB-1014.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_5yrs_PM25.SUM	PM25	1ST-HIGHEST 24-HR	UNIT1B	1ST	0.06444	696729.66	3859880.4	1800	1800	0	5 YEARS	STJALB-1014.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_5yrs_PM25.SUM	PM25	1ST-HIGHEST 24-HR	UNIT1C	1ST	0.04942	705412.07	3810640.1	1800	1800	0	5 YEARS	STJALB-1014.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_5yrs_PM25.SUM	PM25	ANNUAL	UNIT1A	1ST	0.01175	696729.66	3859880.4	1800	1800	0	5 YEARS	STJALB-1014.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_5yrs_PM25.SUM	PM25	ANNUAL	UNIT1B	1ST	0.00944	696729.66	3859880.4	1800	1800	0	5 YEARS	STJALB-1014.SFC	3	3	216
AERMOD 15181	Coronado Class I SIL_5yrs_PM25.SUM	PM25	ANNUAL	UNIT1C	1ST	0.0069	696729.66	3859880.4	1800	1800	0	5 YEARS	STJALB-1014.SFC	3	3	216

SRP Coronado Class I SIL Analysis Results, 50km Ring Receptors (11-24-15)

Pollutant	Average	Group	Rank	Model Conc.	Background	Total	Standard	%Standard
PM25	1ST-HIGHEST 24-HR	UNIT1A	1ST	0.080	NA	0.080	0.07	114%
PM25	1ST-HIGHEST 24-HR	UNIT1B	1ST	0.064	NA	0.06	0.07	92%
PM25	1ST-HIGHEST 24-HR	UNIT1C	1ST	0.049	NA	0.05	0.07	71%
PM25	ANNUAL	UNIT1A	1ST	0.012	NA	0.01	0.06	20%
PM25	ANNUAL	UNIT1B	1ST	0.009	NA	0.01	0.06	16%
PM25	ANNUAL	UNIT1C	1ST	0.007	NA	0.01	0.06	12%
PM10	24-HR	UNIT1A	1ST	0.137	NA	0.14	0.3	46%
PM10	24-HR	UNIT1B	1ST	0.110	NA	0.11	0.3	37%
PM10	24-HR	UNIT1C	1ST	0.079	NA	0.08	0.3	26%
PM10	ANNUAL	UNIT1A	1ST	0.012	NA	0.01	0.2	6%
PM10	ANNUAL	UNIT1B	1ST	0.010	NA	0.01	0.2	5%
PM10	ANNUAL	UNIT1C	1ST	0.007	NA	0.01	0.2	4%

Note 1: "UNIT1A" = Unit No. 1 at 100% Load, "UNIT1B" = Unit No. 1 at 75% Load, and "UNIT1C" = Unit 1 at 50% Load.

SRP Coronado CALPUFF Model Results

Class I Area	Parameter	Averaging Time	Meteorological Year Modeled	Modeled Value	Standard	% Standard
San Pedro Parks	PM2.5 Concentration	24-hour	2001	2.86E-02	0.07	41%
			2002	3.06E-02	0.07	44%
			2003	3.26E-02	0.07	47%
Bosque del Apache	PM2.5 Concentration	24-hour	2001	5.10E-02	0.07	73%
			2002	4.60E-02	0.07	66%
			2003	4.24E-02	0.07	61%

Appendix H – SCR Installation: Soils, Vegetation, and Growth Analysis

H. SCR Installation: Soils, Vegetation, and Growth Analysis

In accordance with A.A.C. R18-2-407(I)(1), this appendix includes analyses of impairment to soils and vegetation that would occur as a result of the SCR Project. The analysis described in the following subsections demonstrates that no significant impairment to soils or vegetation will occur due to increases in PM10, PM2.5, and H_2SO_4 emissions resulting from the SCR Project. Visibility impacts are discussed in Appendix G.

H.1 Effects on Soil

H.1.1 Soil Survey

Over 98,000 acres (150 square miles) surrounding the site of the proposed SCR Project were evaluated for the soils analysis using the U.S. Department of Agriculture Natural Resource Conservation Service Web Soil Survey application. The area evaluated encompasses the central part of Apache County.[63] As presented in Table H-1, the primary soil type in this area is Clovis loamy sand at 23 percent of the total acreage in the study. Other types of soil in significant quantities around the facility include Tours clay loam, Clovis-Palma, Jocity sandy clay loam and Navajo clay. Approximately 17 percent of the land in the study is considered Badland, eroded, or rough broken. The pH of these soils ranged from 8.0 to 8.4.

Table H-1. Major Soil Types in Study Area

Map Unit Name	Acres	Percent of Total	pH
Clovis loamy sand, 0 to 8 percent slopes	22,635	23	8.0
Tours clay loam	15,278	16	8.2
Clovis-Palma association, undulating	12,124	12	8.0
Badland	6,877	7	-
Eroded land	6,803	7	-
Jocity sandy clay loam	6,070	6	8.3
Navajo clay	4,455	5	8.3
Rough broken land	2,834	3	-
Hubert gravelly loam, 2 to 15 percent slopes, eroded	2,813	3	8.2
Millett gravelly sandy loam, 8 to 30 percent slopes	2,567	3	8.4
Loamy alluvial land	2,524	3	8.2

[63] U.S. Department of Agriculture, Natural Resource Conservation Service, Custom Soil Resource Report for Apache County, Arizona, Central Part, April 24, 2015.

The U.S. Department of Agriculture considers less than three (3) percent of this land to be prime farmland if irrigated. No areas within this study are considered farmland of unique importance. All of these soil types are identified as having somewhat or very limited use for recreational activities, such as camping, paths and trails, picnic areas, and playgrounds. No areas are identified as having unlimited recreational value.

H.1.2 Pollutant Impacts on Soils

Current literature contains little information on impairment or other direct effects on soils due to air pollution, and RTP did not identify as part of this analysis any studies in which potential pollutant effects on the soils specific to the project area were evaluated. This is consistent with EPA's findings on this topic:

> In contrast to the amount of published information on the effects of atmospheric pollutants on plants and animals, very little has been reported on their effects on soils. Research on trace elements in soils, often the same elements as atmospheric pollutants, has been directed to notable deficiencies or excesses that limit agricultural crop production. When the amount of an atmospheric pollutant entering a soil system is sufficiently small, the natural ecosystem can adapt to these small changes in much the same way as the ecosystem adapts to the natural weathering processes that occur in all soils. Cultural practices (e.g., liming, fertilization, use of insecticides and herbicides) add elements and modify a soil system more than a small amount of deposited atmospheric pollutant can The secondary effects of the pollutant appear to impact the soil system more adversely than the addition of the pollutant itself to the soil. For instance, damaging or killing vegetative cover could lead to increased solar radiation, increased soil temperatures, and moisture stress. Increased runoff and erosion add to the problem. The indirect action of the pollutant, through changes to the stability of the system, thus may be more significant than the direct effects on soil invertebrates and soil microorganisms. However the lack of long-term historical data on both the type and amount of atmospheric pollutants as well as the lack of baseline data on soils has made difficult the task of determining the effect of pollutants on soils by monitoring changes associated with exposure to pollutants. A limited number of studies have been carried out on trace element contamination in soils. Plant and animal communities appear to be affected before noticeable accumulations occur in the soils. Thus, the approach used here in which the soil acts as an intermediary in the transfer of deposited trace elements to plants appears reasonable as a first attempt at identifying the air quality related values associated with soils.[64]

The degree to which soils are altered by the deposition of sulfuric acid mist is dependent on the buffering capacity of the soil. A lowering of the soil pH to below 4.0 could cause a leaching of base cations or elevated levels of zinc and aluminum.[65]

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[64] Smith, A.E., and J.B. Levenson. *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals* (EPA-450/2-81-078). U.S. EPA, Office of Air Quality Planning and Standards. Research Triangle Park, NC. December 1980. Pp. 17-19.

[65] Impacts of Coal-Fired Power Plants on Fish, Wildlife, and their Habitats; Biological Services Program, March 1978.

Because deposition of H_2SO_4 into soils in the survey area could occur as a result of emissions increases from the SCR Project, it is reasonable to consider whether some marginal acidification of the soils might occur as a result of this project. As discussed, the soils in the survey area are alkaline (*i.e.*, pH greater than 7.0), meaning that some degree of acidification can be readily tolerated and may in fact be desirable. Based on these facts, RTP has concluded that the SCR Project will not cause unacceptable impairment to soils.

H.2 Effects on Vegetation

Pursuant to A.A.C. R18-2-407(I)(1), this analysis is limited to vegetation having significant commercial or recreational value. This analysis of impacts to vegetation encompasses the central part of Apache County. This study area exceeds the scope suggested by EPA guidance, which is limited to the area within the impact area of the proposed facility (10 km).[66]

H.2.1 Vegetation Survey

Table H-2 lists the commercially significant vegetation in the study area. As shown, less than 0.1 percent of the land included in the study area is used for harvested crops. Of this total, approximately 50 percent is used for alfalfa hay and 50 percent is used for vegetables.[67] No vegetation of recreational value was identified in the study area.

H.2.2 Identification of Pollutants of Concern

As discussed below, there are substantial scientific data characterizing the effects of air pollution on certain crops (e.g., common wheat), whereas there are limited data available for other crops. Air pollutants can affect crops through two principal means:

- Direct phytotoxic effects from air concentrations of pollutants; and
- Indirect phytotoxic effects due to deposition of pollutants in soils in which the crops are growing.

Direct Phytotoxic Effects
Particulate matter deposited on above ground plant parts may exert physical and/or chemical effects. Coating of foliar surfaces may cause such physical effects as abrasion, reduced gas exchange, increased temperature, reduced photosynthesis and eventual yellowing and tissue dessication.[68]

[66] See, e.g., *Prevention of Significant Deterioration Workshop Manual* (EPA-450/2-80-081), Oct. 1980, at page I-D-6, expressly limiting the soils and vegetation impairment analysis to the "impact area". See also the same document at page I-C-12, defining the impact area as a "circular area whose radius is equal to the greatest distance from the source to which approved dispersion modeling shows the proposed emissions will have a significant impact."
[67] http://www.agcensus.usda.gov/Publications/2012/Full_Report/Census_by_State/.
[68] Air Quality Criteria for Particulate Matter and Sulfur Oxides, Volume III, EPA-600/8-82-029c.

Table H-2. Land Use for Commercially Significant Vegetation in Study Area[1,2]

Vegetation	Harvested Acreage
Alfalfa Hay	2,125
Wheat for grain	(D)
Dry Beans	9
Upland Cotton	-
Vegetables	2,207
Corn for Grain	-
Total Harvested Cropland	(D)
Total Land Area of Vegetation Study[4]	7,166,413

[1]http://www.agcensus.usda.gov/Publications/2012/Full_Report/Census_by_State/.
[2]Data presented as harvested acres. Crops with greater than 10,000 harvested acres considered by this analysis. Data presented for the entirety of Apache County to represent survey area.
[3](D) Denotes estimates are either too small to warrant publication or not published to avoid disclosure of individual operations per http://www.agcensus.usda.gov/Publications/2012/Full_Report/Census_by_State/
[4]http://www.indexmundi.com/facts/united-states/quick-facts/all-states/land-area#map.

Studies of the effects of chemicals in particulate matter deposited on foliage have found little or no effects on foliar processes unless exposure levels were significantly higher than typically would be experienced in the ambient environment.[69] Sulfuric acid mist is both a pollutant individually subject to PSD review and a component of particulate matter (PM10/PM2.5) emissions. In an EPA review of the effects of sulfuric acid mist on vegetation, one study showed that sulfuric acid aerosols at concentrations up to 170,300 $\mu g/m^3$ settled on dry leaves without causing injury, but when the leaf surface was wet, a spotted type of injury developed.[70]

Indirect Effects

The particulate matter emissions from the CGS may contain trace quantities of arsenic, fluoride, nickel, lead, mercury, and manganese, which have been found to adversely affect plants.[71] However, because the SCR Project will not cause increases in emissions of these contaminants, it is considered unlikely that these emissions will result in significant impairment to vegetation.

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[69] Ecological effects of particulate matter, Grantz et.al., Environment International 29 (2003) 213-239.
[70] Effects of Sulfur Oxides in the Atmosphere on Vegetation; Revised Chapter 5 for Air Quality Criteria for Sulfur Oxides, U.S. EPA, 1973.
[71]Smith, A.E., and J.B. Levenson. *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA-450/2-81-078).* U.S. EPA, Office of Air Quality Planning and Standards. Research Triangle Park, NC. December 1980. P. 17.

H.2.3 Determination of Effects Concentrations

Direct Phytotoxic Effects
As is customary for this type of analysis, the assessment relied heavily on the screening criteria in the EPA report, *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals*.[72] This document establishes the air pollutant concentrations that are generally viewed by EPA to be protective of soils and vegetation having significant commercial or recreational value, including agricultural crops, based on a broad review of pertinent scientific literature. Screening values for PM and H_2SO_4, however, are not available. Therefore, RTP relied heavily on the secondary NAAQS,[73] which are established by EPA at levels that are protective of the public welfare, including agriculture.

Indirect Deposition Effects
Two general approaches have been used in establishing deposition rate limits and soil concentration limits: a) preventing accumulation of pollutants in soils; and b) maximizing the capacity of soils to assimilate, attenuate, and detoxify pollutants. The first approach is based on the premise that soil can be used without any undue restriction if it is maintained free of contamination; if pollutants are artificially introduced and are allowed to accumulate in the soil, then, over the long term, the potential uses of the soil may become limited. The second approach is based on the premise that soils have a capacity to detoxify pollutants. This approach has been applied by EPA and by the World Health Organization.[74]

H.2.4 Results

Based on the results of the air quality impacts analysis, the maximum predicted ambient $PM_{2.5}$ concentrations due to emissions from the proposed SCR Project are 10.46 $\mu g/m^3$ (24-hour average) and 3.86 $\mu g/m^3$ (annual average). When added to the background concentration in the area, these impacts are below the secondary NAAQS of 35 $\mu g/m^3$ (24-hour average) and 15 $\mu g/m^3$ (annual average),[75] respectively.

H.3 Conclusion

Based on the effects analysis described herein, RTP concludes that emissions from the SCR Project are not expected to result in significant impairment to soils, crops, or plant species of concern, within the vicinity of the project site. For each pollutant of concern, the predicted ambient concentration or the predicted deposition rate is well below the secondary NAAQS and the minimum screening values established by EPA. Nothing in the scientific literature identified during this review indicates that the secondary NAAQS and minimum EPA screening values are

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[72] Smith, A.E., and J.B. Levenson. *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA-450/2-81-078).* U.S. EPA, Office of Air Quality Planning and Standards. Research Triangle Park, NC. December 1980.
[73] See, 40 CFR part 50.
[74] A.C. Chang, et al. *Developing Human Health-related Chemical Guidelines for Reclaimed Water and Sewage Sludge Applications in Agriculture.* World Health Organization. Copenhagen, Denmark. May 2002. pp. 19-41.
[75] 40 CFR §§ 50.6 and 50.7.

not protective of any identified crops, and the predicted ambient concentration and deposition rate are less than the screening values established by other governmental authorities.

H.4 Visibility Analysis

Visibility impacts from the SCR Project are discussed in detail in Appendix G.

Appendix I – Unit 1 Shutdown: Revisions to EPA's BART Control Effectiveness Determination

I. Unit 1 Shutdown: Revisions to EPA's BART Control Effectiveness Determination

As one of the final compliance options, SRP is proposing an earlier retirement date for CGS Unit 1 than had been assumed in previous BART evaluations. Specifically, SRP would permanently cease operation of Unit 1 on December 31, 2029, reducing the remaining useful life ("RUL") of the unit to only 12 years. This appendix presents details of a BART control technology assessment that addresses this change.

I.1 BART Cost Estimate Basis

The SRP BART cost estimates presented here are generally consistent with those used by EPA to estimate costs using IPM. The cost estimate bases are presented in Table I-1, including SRP's comments regarding values used in this cost analysis that differ from those used by EPA in IPM. For purposes of the proposed revised BART limit that is the subject of this revised BART control analysis, SRP is proposing to retire Unit 1 no later than December 31, 2029 (reflecting an expected 12-year unit life after the FIP effectiveness date of December 2017). Other independent factors (e.g., the final CAA § 111(d) CPP rulemaking) may also influence the expected date of retirement of Unit 1.[76]

[76] 80 Fed. Reg. 64,662 (Oct. 23, 2015).

Table I-1. BART Cost Analysis Bases for CGS Unit 1

PARAMETER	UNITS	SRP'S ASSUMPTIONS	COMMENTS
Gross Output	MWg	431	EPA used 410.9. SRP's value based on 18 months (2011-12) of data. SRP used an average for both CGS U1 and U2 of 431 MW (Gross).
Gross Heat Rate	Btu/kWh	9,087	EPA used 10,503; net heat rate. SRP's value based on 18 months (2011-12) of data for gross heat rate. SRP used an average for both CGS U1 and U2 of 9,087 (Gross).
Capacity Factor	%	81.0	Based on heat input to the unit
NO_X Rate	lb/MMBtu	0.320	EPA in the BART SIP used 0.303 lb NOx/MMBtu. SRP is using Consent Decree emission rate, which is a 30-day rolling average limit.
Heat Input	MMBtu/hr	3,916	EPA used 4,316. SRP's value based on above MWg and Btu/kWh based on 18 month (2011-12) data.
NO_X Removal Efficiency	Fraction	0.80	Value based on controlled emission rate of 0.065 lb NOx/MMBtu.
Ammonia Cost	$/ton	752	EPA used 400. SRP's value based on actual plant value for anhydrous ammonia based on the operation of SCR on Unit 2.
Catalyst Cost	$/m^3	8,000	
Steam Costs	$/klb	4.00	
Operating Labor Rate	$/hr	75	EPA used 60. SRP's value based on actual plant value based on the operation of SCR on Unit 2.
Amortization Period	Years	12	EPA used 20. SRP's value based on shutdown of unit in 2029.
Capital Recovery Factor	%	12.59%	EPA used 9.44. SRP's value based on shutdown of unit in 2029.
Property Taxes & Insurance	%	1.20%	

I.1.1 Capital Costs

Capital costs for the CGS Unit 1 SCR system were developed by S&L and SRP, based in part on the actual cost of installation of an SCR system on CGS Unit 2 in 2014. As presented in Table I-2, the estimated capital cost for the SCR retrofit on CGS Unit 1 is $112,788,000.[77]

The use of SCR unavoidably contributes to production of sulfur trioxide (SO_3), the precursor of sulfuric acid. Emissions of sulfuric acid have received considerable attention in recent years with the broader application of SCR to coal-fired power plants. Several notable incidents have been witnessed where an increase in sulfuric acid emissions was attributed to the addition of an SCR system to an existing coal-fired power plant. Typically, the SO_2 oxidation rate from SCR catalysts can range from as low as 0.3% of flue gas SO_2 content to 3% for low sulfur, highly alkaline coals (e.g., Powder River Basin coals).

[77] CGS SCR cost estimate from SRP, as of the fourth quarter of 2014.

Table I-2. SRP's Capital Cost Estimate

DESCRIPTION	COST $
Project Permitting and Development	2,000,000
Owner's Consulting Engineer	2,500,000
Balance-of-Plant Equip. Engineering and Design	3,500,000
OEM Engineering, Material, and Equipment	22,500,000
Structural Steel Supply	3,300,000
Induced Draft Fan Modification	1,656,000
Pegging Steam System	1,878,000
Construction Services	61,750,000
Digital Control System Integration	704,000
Start-up & Commissioning Services	2,500,000
Owner's Project Support Costs	10,000,000
Training	500,000
TOTAL	112,788,000

For the reasons described above, installation of an SCR system would be expected to result in a significant increase in emissions of sulfuric acid mist. For purposes of this evaluation of control cost effectiveness, consistent with the analyses performed by EPA and its contractors, SRP has assumed no capital costs will be incurred in conjunction with mitigation of this increase in sulfuric acid emissions.

I.1.2 Annual Costs

Annual costs for the retrofit of an SCR system include fixed operating and maintenance costs, variable operating and maintenance costs, annualized capital costs, and property and insurance costs. The annual costs for SCR are developed using the IPM methodology/equations. For purposes of this evaluation of control cost effectiveness, consistent with the analyses performed by EPA and its contractors, SRP has conservatively assumed no operating costs will be incurred in conjunction with mitigation of the increase in sulfuric acid emissions that would result from SCR system installation. Table I-3 presents the annual costs for the SCR system.

Table I-3. Annual Costs Calculations for SCR on CGS Unit 1

VARIABLE	UNITS	EQUATIONS	CGS Unit 1
Fixed and Variable O&M Cost Estimate			
Fixed O&M Operating Costs	$/kW-yr	= 0.5 x 2,080 x [V] / ([A] x 1,000)	0.18
Fixed O&M Maintenance Costs	$/kW-yr	= 200,000 / ([A] x 1,000)	0.70
Total Fixed O&M Costs (FOM)	$/kW-yr		0.88
Variable O&M Costs for ammonia[78]	$/MWh	= [M] x [R] / ([A] x 2,000)	0.61
Variable O&M Costs for catalyst	$/MWh		0.35
Variable O&M Costs for steam	$/MWh	= [N] x [U] / ([A] x 1,000)	0.01
Total Variable O&M Costs (VOM)	$/MWh		0.97
Annualized Costs			
Annual O&M Costs	$	= ([FOM] x [A] x 1,000) + ([VOM] x [A] x 8,760 x [D])	3,332,209
Annualized Capital Costs	$	= [CECC] x ([CRF] + [AA])	15,553,689
Total Annual Costs	$		18,885,898

Where:
A is unit size, MWg.
V is operating labor rate, $/hr.
M is ammonia rate, lb/hr.
R is ammonia cost, $/ton.
N is steam required, lb/hr.
U is steam cost, $/klb.
D is capacity factor, fraction (%/100)
CECC is Capital, Egr, & Const Costs Subtotal, $.
CRF is capital recovery factor, fraction (%/100).
AA is Property Taxes & Insurance, fraction (%/100).

I.2 Cost Effectiveness

The BART Guidelines require that cost effectiveness be calculated in terms of annualized dollars per ton of pollutant removed, or $/ton. In its final rule promulgating the NOx BART FIP for CGS, EPA stated that it is sufficient to analyze the cost effectiveness of potential BART controls using $/ton, in conjunction with an assessment of the modeled visibility benefits of the BART control.[79] For purposes of this evaluation of control cost effectiveness, consistent with the analyses performed by EPA and its contractors, SRP has assumed no controls will be installed in order to mitigate the increase in sulfuric acid emissions that would result from SCR installation.

Table I-4 presents the SCR annual cost of control per ton of NOx removed.

[78] M in lb/hr divided by 2000 to convert lb/hr to tons/hr.
[79] 77 FR 72512, December 5, 2012.

Table I-4. Cost Effectiveness for SCR on CGS Unit 1

VARIABLE	UNITS	VALUES
Baseline NOx Rate		
NOx Emission Rate	lb/mmBtu	0.320
NOx Emission Rate	lb/hr	1,253
Annual NOx Emissions	tons/yr	4,446
Controlled NOx Rate		
Controlled NOx Emission Rate	lb/mmBtu	0.065
NOx Emission Rate	lb/hr	255
Annual NOx Emissions	tons/yr	903
Delta Tons of NOx Removed	tons/yr	3,543
Annualized Control Costs	$/yr	18,885,898
Annual Cost per Ton NOx Removed	$/ton	5,330

SRP estimates the cost effectiveness of SCR for NOx control as greater than $5,300 per ton of NOx removed. EPA's calculations using the IPM capital and annual cost estimates for CGS Unit 1 resulted in a NOx cost effectiveness value of approximately $2,500 per ton of NOx removed. This value is significantly lower than SRP's estimated cost effectiveness primarily due to the difference in capital costs, and the capital recovery factor ("CRF") used due to the assumption in SRP's analysis of early retirement of CGS Unit 1. These results are presented in Table I-5 below.

Table I-5. BART Alternative Results for CGS Unit 1

VARIABLE	EPA 20-year RUL	SRP 12-year RUL
Capital, Egr, & Const Costs Subtotal, $	64,962,439	112,788,000
Amortization Period, years	20	12
Capital Recovery Factor, %	9.44	12.59
Annual O&M Costs, $/year	2,516,338	3,332,209
Annualized Capital Costs, $/year	6,911,544	15,553,689
Total Annual Costs, $/year	9,427,881	18,885,898
Delta Tons of NOx Removed, tons/year	3,721	3,543
Annual Cost per Ton NOx Removed	2,534	5,330

I.3 Conclusions

Based on a retirement date of no later than December 31, 2029 (i.e., an expected 12-year unit life after the effectiveness date of the FIP), the analysis confirms that the use of SCR is not cost effective as BART for Unit 1.

Appendix J – Application Completeness Checklist

J. Application Completeness Checklist

SECTION 4.0 - APPLICATION ADMINISTRATIVE COMPLETENESS CHECKLIST

	REQUIREMENT	MEETS REQUIREMENTS			COMMENT
		YES	NO	N/A	
1	Has the standard application form been completed?	X			
2	Has the responsible official signed the standard application form?	X			
3	Has a process description been provided?	X			
4	Are the facility's emissions documented with all appropriate supporting information?	X			
5	Is the facility subject to Minor NSR requirements? If the answer is "YES", answer 6a, 6b and 6c as applicable. If the answer is "NO", skip to 7.	X			
6.a	If the facility chooses to implement RACT, is the RACT determination included for the affected pollutants for all affected emission units?		X		BACT determination
6.b	If the facility chooses to demonstrate compliance with NAAQS by screen modeling, is the modeling analysis included?	X			
6.c	If refined modeling has been conducted, is a comprehensive modeling report along with all modeling files included?	X			
7	Does the application include an equipment list with the type, name, make, model, serial number, maximum rated capacity, and date of manufacture?		X		To be determined
8	Does the application include an identification and description of Pollution Controls? (if applicable)	X			
9	For any application component claimed as confidential, are the requirements of A.R.S. 49-432 and A.A.C. R18-2-305 addressed?			X	
10	For any current non-compliance issue, is a compliance schedule attached?			X	
11	For minor permit revision that will make a modification upon submittal of application, has a suggested draft permit been attached?			X	
12	For major sources, have all applicable requirements been identified?	X			
13	For major sources, has a CAM applicability analysis been provided? For CAM applicable units, have CAM plans been provided?	X			
14	For major sources subject to requirements under Article 4 of the A.A.C., have all necessary New Source Review analyses identified in the application been presented?	X			