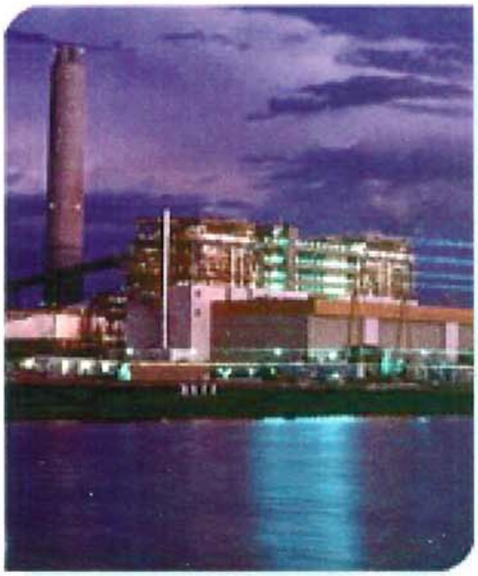
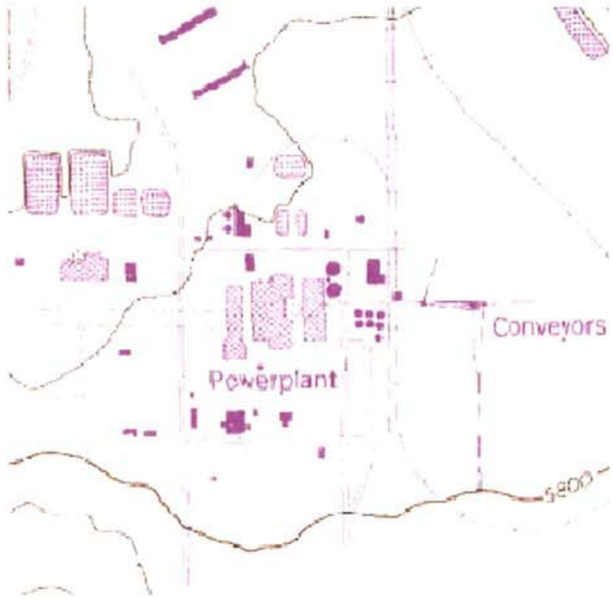
Prepared for:
Salt River Project – Coronado Generating Station
Tempe, AZ





BART Analysis for the Coronado Generating Station Units 1 & 2

ENSR Corporation
February 2008
Document No.: 05830-012-200

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SENT VIA HAND-DELIVERY

February 8, 2008

Ms. Nancy Wrona, Director
Air Quality Division
Arizona Department of Environmental Quality
1110 West Washington Street
Phoenix, Arizona 85007

Re: Coronado Generating Station BART Analysis

Dear Ms. Wrona:

Enclosed are three copies of the Best Available Retrofit Technology (BART) Report for Units 1 and 2 at the Salt River Project (SRP) Coronado Generating Station (CGS). While reviewing this report, please note the following:

- The attached BART report contemplates control equipment modifications at the CGS facility independent of the proposed changes associated with the Significant Permit Revision Application that was submitted to the Arizona Department of Environmental Quality on November 29, 2007. It should be noted that SRP believes that the Significant Permit Revision contains control equipment modifications that exceed BART requirements.

- Modeling conducted for the control options assumes that there would be new, independent stacks for Units 1 and 2 that would each have a stack height of 400 feet, as compared to the existing configuration which has a merged stack that is 500 feet high.

If you have any questions regarding this report, please contact Barbara Sprungl at (602) 236-5374 or me at (602) 236-2968.

Sincerely,

Kevin Wanttaja

Kevin Wanttaja, Manager
Environmental Services

LOC 5-2-8.1

EC 13492.0208

Prepared for:
Salt River Project – Coronado Generating Station
Tempe, AZ

BART Analysis for the Coronado Generating Station Units 1 & 2

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Executive Summary

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 with a combined net power generating capacity of approximately 785 MW. The CGS facility became operational in 1979.

The Clean Air Act's Regional Haze Rule (RHR) contains a requirement for each State to address the Best Available Retrofit Technology (BART) requirements when preparing the State's Regional Haze State Implementation Plan (SIP). This BART Analysis for the CGS was prepared pursuant to 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"). 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) has determined that the CGS is a "BART-eligible source". Based on air dispersion modeling performed by ENSR and reported in this document, CGS is subject to BART. SRP retained ENSR to perform a BART analysis for the two units at CGS. The BART analysis was performed 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 this area.

SO_2 emissions are currently controlled with the use of low-sulfur coal and partial wet flue gas desulfurization (WFGD). CGS proposes to install full wet flue gas desulfurization for SO_2 control. The short-term (30-day) SO_2 emission rate will not exceed 0.08 lb/MMBtu, which is about half of the presumptive limit of 0.15 lb/MMBtu.

NO_x emissions are currently controlled by good combustion practices and overfire air. The baseline peak daily NO_x emissions for Coronado range from about 0.45 to 0.50 lb/MMBtu, which exceeds the BART presumptive limit of 0.23 lb/MMBtu for dry-turbo-fired boilers burning sub-bituminous coal. Therefore, several NO_x controls were considered in this BART analysis for the Coronado Generating Station.

The BART analysis for NO_x was conducted in accordance with the procedures contained in the final BART Guidelines published by the EPA on July 6, 2005. Consistent with the BART Guidelines, the five steps for a case-by-case BART analysis were followed.

- Step 1 – Identify all available control technologies including improvements to existing control equipment or installation of new add-on control equipment.
- Step 2 – Eliminate technically infeasible options considering the commercial availability of the technology, space constraints, operating problems and reliability, and adverse side effects on the rest of the facility.
- Step 3 – Evaluate the control effectiveness of the remaining technologies based on current pollutant concentrations, flue gas properties and composition, control technology performance, etc.
- Step 4 – Evaluate the annual and incremental costs of each feasible option using approved EPA methods, as well as the associated energy and non-air quality environmental impacts.
- Step 5 – Determine the visibility impairment associated with baseline emissions and the visibility improvements provided by the control technologies considered in the engineering analysis.

The alternative NO_X control technologies identified as being technically feasible at CGS include: low NO_X burners (LNB), selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). As an alternative to the SNCR case, an option with one unit controlled with LNB and the other unit controlled with LNB plus SCR was considered, since the plant-wide NO_x emission rate was lower than the SNCR case. All of the NO_x control options beyond LNB were found to result in NO_x emissions averaged over the two units that are lower than the EPA presumptive emission limit for CGS of 0.23 lb/MMBtu.

The modeled BART control options for SO_2 and NO_x were as follows:

Option 1. This option represents baseline conditions.

Option 2. This option involves the treatment of the entire flue gas stream from Units 1 and 2 in the WFGD system to achieve a reduction in the daily SO_2 emission rate to 0.08 lb/MMBtu. This WFGD control is maintained in all of the remaining control options.

Option 3. This option involves the retrofit of advanced combustion controls (ACC), such as LNB, to Units 1 and 2 to control NO_x emissions from both units to 0.320 lb/MMBtu.

Option 4a. This option involves the retrofit of ACC and selective non-catalytic reduction (SNCR) to Units 1 and 2 to control NO_x emissions from both units to 0.224 lb/MMBtu.

Option 4b. This option involves the retrofit of ACC to Unit 1 to control NO_x emissions from this unit to 0.320 lb/MMBtu, and the retrofit of ACC and selective catalytic reduction (SCR) to Unit 2 to control NO_x emissions from these units to 0.08 lb/MMBtu. This option results in a plant-wide NO_x emission rate of 0.20 lb/MMBtu.

Option 5. This option involves the retrofit of ACC and SCR to Units 1 and 2 to control NO_x emissions from both units to 0.08 lb/MMBtu.

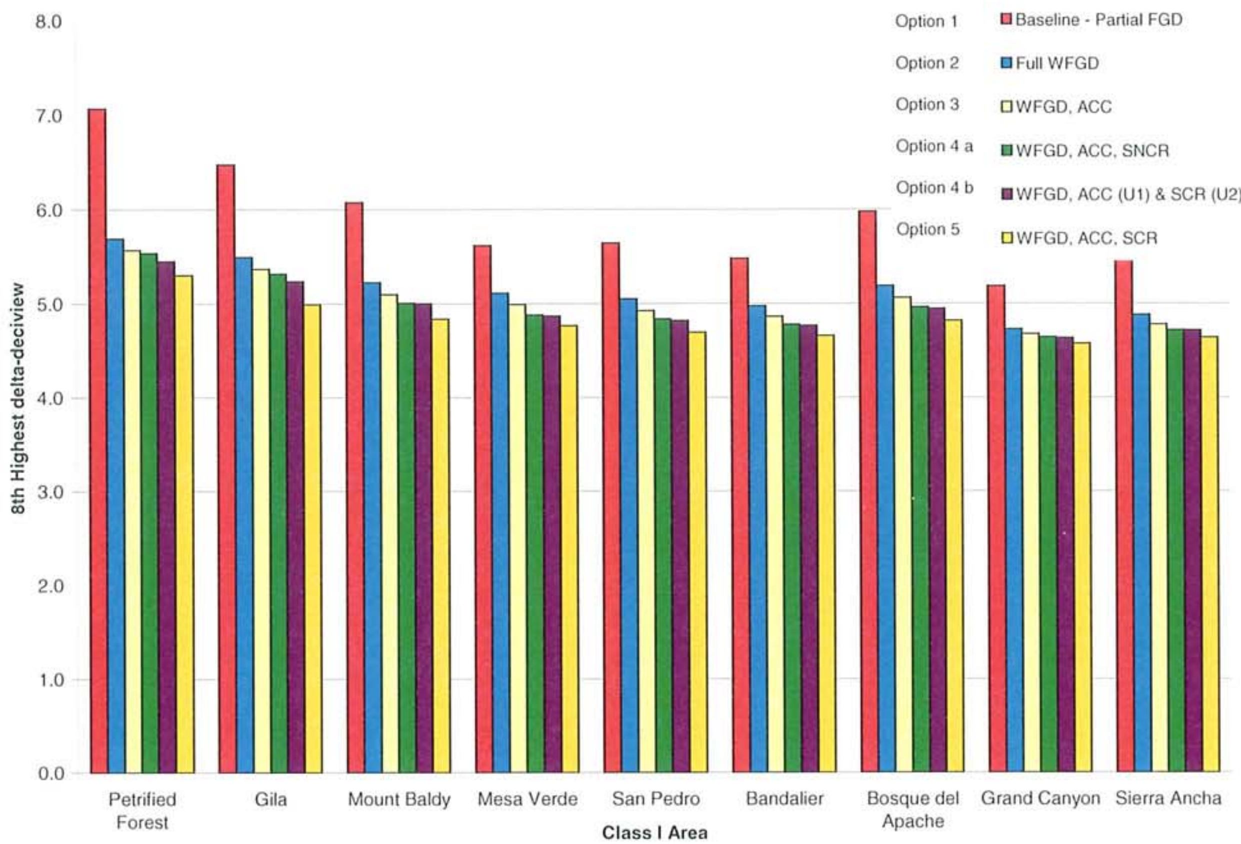
The results of the visibility modeling for the single SO_2 BART control option and the candidate NO_x BART control options are graphically plotted in Figure ES-1. This figure compares the total visibility impairment (expressed in deciviews) for the modeled results with output from the three modeled years averaged for each case and the nine closest Class I areas for ease of review. The modeling indicates that the SO_2 control will provide the largest visibility benefit while the NO_x control options provide relatively small visibility benefits.

The first NO_x control option (control option 3) involves the installation of low NO_X burners (LNB) resulting in a NO_x emission rate not exceeding 0.320 lb/MMBtu. This combustion modification is modeled to produce visibility improvements across the nine closest PSD Class I areas averaging 0.11 deciviews compared to the NO_x control base case (option 2). For comparison, a deciview (dv) change of 1.0 is considered the threshold of humanly perceptible changes in visibility.

The second NO_x control option (option 4a) evaluated selective non-catalytic reduction (SNCR) in addition to LNB. This option produces a NO_x emission rate of 0.224 lb/MMBtu, which is better than the presumptive limit of 0.23 lb/MMBtu. The injection of ammonia, (NH_3) or urea, $(NH_2)_2CO$ into the boiler with this operation lowers NO_x emissions, but produces increased stack emissions of ammonia slip and sulfuric acid mist. These additional fine particulate emissions are expected to at least partially offset the expected visibility benefits from NO_x controls. As expected, the three-year average across the eight parks for the visibility impacts was only slightly improved over the results for control option 3.

As an alternative to control option 4a (referred to as 4b), CGS is considering a hybrid approach that results in lower plant-wide NO_x emissions (0.20 lb/MMBtu) over the SNCR option discussed above: use of LNB on Unit 1 and LNB plus SCR on Unit 2. As expected, this option shows a slight additional benefit from option 4a.

Figure ES--1 8th Highest Regional Haze Deciview (Includes Background Haze and CGS BART Control Case Emissions)



Control Option 5 evaluated LNB plus SCRs for both units. This option presents slight additional visibility benefits, but at a higher incremental cost than any of the previous options.

The associated annual costs, derived from capital expenditures and annual operational and maintenance costs are shown in Tables ES-1 and ES-2 for SO_2 and NO_x, respectively. The modeled visibility improvements and the calculated cost in terms of dollars per deciview are provided in Tables ES-3 and ES-4 for SO_2 and NO_x, respectively.

Table ES-1: Total Capital and Annual Costs Associated with SO_2 Controls Applied to CGS Units 1 and 2

Control Option	Control Technology	Total Capital Cost ($)	Fixed Capital Costs ($/yr)[a]	Annual O&M Costs ($/yr)	Total Annual Costs ($/yr)
1	Baseline	$0	$0	$0	$0
2	Wet FGD	$347,000,000	$32,753,330	$11,600,000	$44,353,330

Table ES-2: Total Capital and Annual Costs Associated with NO_x Controls Applied to CGS Units 1 and 2

Control Option	Control Technology	Total Capital Cost ($)	Fixed Capital Costs ($/yr)[a]	Annual O&M Costs ($/yr)	Total Annual Costs ($/yr)
3	ACC on Units 1-2	$13,000,000	$1,227,070	$0	$1,227,070
4a	ACC/SNCR on Units 1-2	$26,000,000	$2,454,140	$2,200,000	$4,654,140
4b	ACC on Unit 1 & ACC/SCR on Unit 2	$79,000,000	$7,456,810	$1,100,000	$8,556,810
5	ACC/SCR on Units 1-2	$145,000,000	$13,686,550	$3,400,000	$17,086,550

[a] Fixed capital costs based on a CRF of 0.09439, assuming an interest rate of 7% and amortization period of 20 years.
[b] Total capital costs include costs associated with outages required for installation of control equipment.
[c] Annual O&M costs include the lost revenues resulting from ammonia contamination of fly ash from SNCR.

Table ES-3: Annual Costs of SO_2 Controls vs. Visibility Improvements (Average of the Nine Class I Areas)

Option	BART Controls	Annualized Cost for SO_2 Controls ($/year)	8th Highest Average over 3-Year and 9 Class I Area (dv)	Incremental Reduction Relative to Option 1 (dv)	Incremental Cost Effectiveness Relative to Option 1 ($/dv)
Option 1	Baseline	$0	5.91	0.000	$0
Option 2	Wet FGD	$44,353,330	5.17	0.741	$59,847,072

Table ES-4: Annual Costs of NO_x Controls vs. Visibility Improvements (Average of the Nine Class I Areas)

Option	BART Controls	Annualized Cost for NO_x Controls ($/year)	8th Highest Average over 3-Year and 9 Class I Area (dv)	Incremental Reduction Relative to Option 2 (dv)	Incremental Cost Effectiveness Relative to Option 2 ($/dv)
Option 1	Baseline	$0	5.91	0.000	$0
Option 2	Wet FGD	$0	5.17	0.000	$0
Option 3	ACC on Units 1-2	$1,227,070	5.05	0.114	$10,756,782
Option 4a	ACC/SNCR on Units 1-2	$4,654,140	4.97	0.194	$24,017,924
Option 4b	ACC on Unit 1 & ACC/SCR on Unit 2	$8,556,810	4.95	0.221	$38,783,594
Option 5	ACC/SCR on Units 1-2	$17,086,550	4.82	0.343	$49,745,185

Based on the fact that the NO_x controls all result in generally low visibility benefits at excessive costs in terms of incremental visibility improvement in terms of dollars per deciview, ENSR and SRP conclude that control option 2 is BART for CGS.

1.0 Introduction

1.1 Source Description

The BART-affected emission units at the Coronado plant are Units 1 and 2, which came on-line in 1979 and 1980, respectively. Units 1 and 2 are dry-turbo-fired boilers with a net rated output of 395 MW and 390 MW, respectively, for a total of 785 MW. Because the total generation capacity of the two units exceeds 750 MW and each unit's capacity exceeds 200 MW, these units are subject to presumptive BART requirements. Both units burn primarily PRB sub-bituminous coal.

1.2 BART Requirements

Federal regulations under 40 CFR 51, Appendix Y, provide guidance and regulatory authority for conducting a visibility impairment analysis for designated eligible sources. The program requires the application of BART to those existing eligible sources that are believed to cause or contribute to visibility impairment in order to help meet the targets for visibility improvement at designated Class I areas. Both units at the Coronado Generating Station are BART-eligible because they meet the following applicability requirements:

1. The units were "in existence" between August 7, 1962 and August 7, 1977.
2. The sum of the emissions from the affected units is greater than 250 tons/year.
3. CGS is a "fossil-fueled fired steam electric plant of more than 250 MMBtu/hr heat input", and thus is one of the 28 categories of sources identified in the regional haze rule.

The RHR provides that BART-eligible sources that cause or contribute to visibility impairment at a federal Class I area are "subject to BART". The "contribution" threshold for visibility impairment is a 0.5 deciview change. Based on BART exemption modeling conducted for Units 1 and 2, these units are subject to BART review because the predicted visibility impacts with baseline emissions exceed 0.5 delta deciviews in at least one Class I area.

1.3 Sulfur Dioxide Emission Control

Currently, SO_2 emissions are controlled by partial wet FGD. The resulting emission rate ranges from approximately 0.6 to 0.7 lb/MMBtu, which exceeds the BART presumptive limit of 0.15 lb/MMBtu for dry-turbo-fired boilers burning sub-bituminous coal. Therefore, this BART analysis considers BART control options for SO_2.

1.4 Particulate Matter Emission Control

PM_{10} emissions are controlled with hot-side electrostatic precipitators, and the resulting emissions range from 0.01 to 0.03 lb/MMBtu. Current PM_{10} emissions at CGS are considered to represent highly effective emission controls and application of additional particulate controls to CGS would not be expected to produce substantial additional reductions in PM_{10} emissions. Therefore, this BART analysis does not consider BART control options for PM_{10}. BART for PM is considered to be the current control configuration.

1.5 Nitrogen Oxides Emission Control

NO_x emissions are controlled by good combustion practices, and range from approximately 0.4 to 0.5 lb/MMBtu, which exceeds the BART presumptive limit of 0.23 lb/MMBtu for dry-turbo-fired boilers burning sub-bituminous coal. Therefore, this BART analysis considers BART control options for NO_x.

1.6 Report Outline

Section 2 of this report discusses the general CALPUFF modeling approach. It refers to more detailed discussions in appendices attached to this report for meteorological data processing as well as the CALPUFF modeling approach for the visibility impact analysis. A presentation of the baseline emission impacts on the nearby Class I areas for the BART exemption analysis is provided in Section 3. Because this section indicates that the incremental visibility impact of the plant is in excess of the EPA-designated limit of 0.5 delta deciviews for contributing to visibility impairment, a BART engineering analysis was conducted on available NO_x and SO_2 control options, as presented in Section 4. A CALPUFF modeling analysis was conducted for these control options; the results are presented in Section 5. A recommendation for BART controls is presented in Section 6, based upon the information presented in Sections 4 and 5. References are provided in Section 7.

2.0 CALPUFF Modeling Procedures

For the refined CALPUFF modeling, SRP followed the Western Regional Air Partnership (WRAP) common BART modeling protocol with the exception of the model version and a few refinements to CALMET settings. These differences are discussed below in Section 2.2.

2.1 CALMET Processing

The Western Regional Air Partnership (WRAP) has developed six 4-km CALMET meteorological databases for three years (2001-2003). The CALMET modeling domains are strategically designed to cover all potential BART eligible sources within WRAP states and all PSD Class I areas within 300 km of those sources. The extents of the six domains are shown in Figure 3-a through Figure 3-1f of the WRAP common BART modeling protocol, available at http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf. The BART modeling for CGS was done using the Arizona 4-km domain, as shown in Figure 2-1 of this report. The WRAP CALMET meteorological inputs, technical options, and processing steps are described in Sections 2 and 3 of the WRAP protocol.

USGS 3 arc-second Digital Elevation Model (DEM) files were used by WRAP to generate the terrain data at 4-km resolution for input to the six CALMET runs. Likewise, the Composite Theme Grid format (CTG) files using Level I USGS land use categories were used by WRAP to generate the land use data at 4-km resolution for input to the six CALMET runs. See Sections 3.1.1.3 and 3.1.1.4 of the WRAP common BART modeling protocol for more details on the data processing.

Three years of 36-km MM5 data (2001-2003) were used by WRAP to generate the 4-km sub-regional meteorological datasets. Section 2 of the WRAP protocol discusses MM5 data extraction. The BART CALPUFF modeling for CGS was done using the Arizona 4-km CALMET database with application-specific modifications described in Appendix A.

2.2 CALPUFF Modeling Procedures

Coronado used the EPA-approved version of CALPUFF (Version 5.8, Level 070623) that has been posted at http://www.src.com/calpuff/download/download.htm#EPA_VERSION. Although the WRAP BART protocol mentions the use of CALPUFF version 6, the EPA's Office of Air Quality Planning and Standards has clearly stated that the use of a version other than the official EPA version is a non-guideline application that must obtain regional EPA approval on a case-by-case basis. It is clear from the discussion provided in Appendix A that CALPUFF version 6 is not approvable by EPA at this time without a significant effort to show that it is technically superior. To avoid the need for the justification and documentation required to use a non-guideline version of the model, ENSR used the official EPA version.

The area covered by the 4-km WRAP domain for Arizona is shown in Figure 2-1. The BART CALPUFF modeling for Coronado was done using a smaller computational grid within the WRAP domain to provide reasonable computation time and output file size. The computational grid domain is also shown in Figure 2-1. This domain includes seventeen Class I areas within 300 km of the source, plus a 50-km buffer around each Class I area and a 100-km buffer around the source to assure puff recirculation. The receptors used for each of the Class I areas are based on the National Park Service database of Class I receptors.

For CALPUFF model technical options, inputs and processing steps, ENSR followed the WRAP common BART protocol with the exception of the model version. Due to the large distance to the nearest Class I area, building downwash effects were not included in the CALPUFF modeling.

WRAP has developed hourly ozone measurement files for three years (2001-2003), available at http://pah.cert.ucr.edu/aqm/308/bart/calpuff/ozone_dat/. Data collection and processing are described in

Section 3.1.2.7 of the WRAP protocol. These ozone data files were used as input to CALPUFF. The monthly ammonia background concentrations selected for use in CALPUFF are discussed in Appendices A and B.

2.3 Natural Conditions and Monthly f(RH) at Class I Areas

Seventeen Class I areas were modeled for the Coronado Generating Station. For these Class I areas, natural background conditions must be established in order to determine a change in natural conditions related to a source's emissions. For the modeling described in this document, ENSR used the natural background light extinctions shown in Table 2-1, modified as noted below with site-specific considerations, and corresponding to the annual average (EPA 2003, Appendix B), consistent with the July 19, 2006 EPA guidance to Region 4 on this issue ("Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations", Joseph W. Paise/ EPA OAQPS to Kay Prince/Branch Chief).

Table 2-1: Annual Average Natural Background Concentrations

Class I Area	Natural Background Concentrations (deciviews)	Natural Background Concentrations (Mm^{-1})
Grand Canyon NP	4.39	5.51
Sycamore Canyon W	4.40	5.53
Mazatzal W	4.35	5.45
Pine Mountain W	4.36	5.47
Sierra Ancha W	4.36	5.47
Superstition W	4.32	5.40
Mount Baldy W	4.39	5.51
Petrified Forest NP	4.41	5.54
Galiuro W	4.32	5.40
Saguaro NM	4.28	5.34
Chiricahua NM	4.36	5.47
Chiricahua W	4.35	5.45
Gila W	4.39	5.51
Bosque del Apache	4.41	5.54
Bandalier NM	4.46	5.62
San Pedro Parks W	4.47	5.64
Mesa Verde NP	4.53	5.73

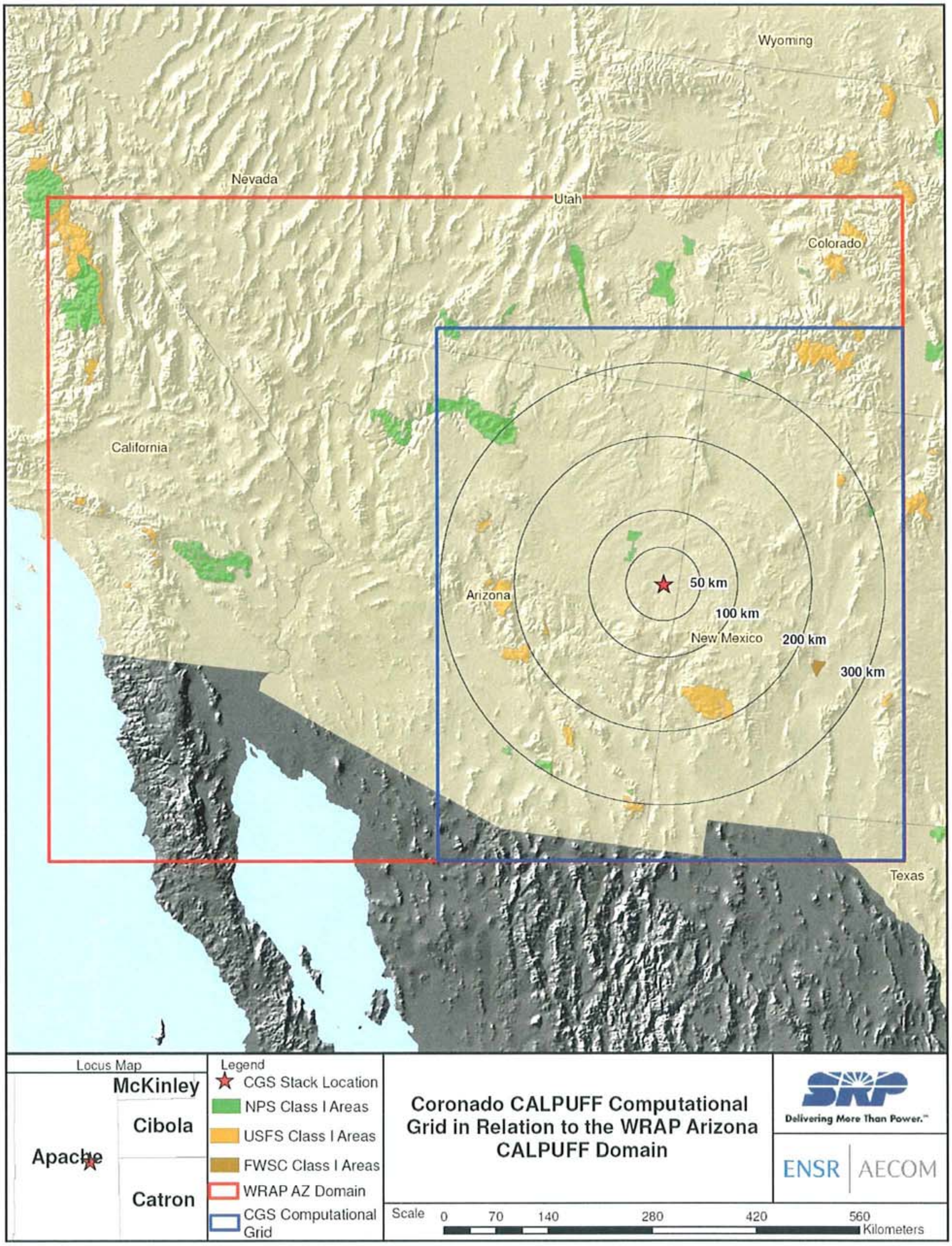
To determine the input to CALPOST, it is first necessary to convert the deciviews to extinction using the equation:

Extinction (Mm^{-1}) = 10 exp(deciviews/10).

For example, for Grand Canyon, 4.39 deciviews is equivalent to an extinction of 5.51 inverse megameters (Mm^{-1}); this extinction excludes the default 10 Mm^{-1} for Rayleigh scattering. This remaining extinction is due to naturally occurring particles, and is held constant for the entire year's simulation. Therefore, the data provided to CALPOST for Grand Canyon would be the total natural background extinction minus 10 (expressed in Mm^{-1}), or 5.51. This is most easily input as a fine soil concentration of 5.51 $\mu g/m^3$ in CALPOST, since the extinction efficiency of soil (PM-fine) is 1.0 and there is no f(RH) component. The concentration entries for all other particle constituents would be set to zero, and the fine soil concentration would be kept the same for each month of the year.

The monthly values for f(RH) that CALPOST needs were taken from "Guidance for Tracking Progress Under the Regional Haze Rule" (EPA, 2003) Appendix A, Table A-3.

Figure 2-1: Coronado CALPUFF Computational Grid in Relation to WRAP Arizona Domain



2.4 Light Extinction and Haze Impact Calculations

The CALPOST postprocessor was used to calculate the impact from the modeled source's primary and secondary particulate matter concentrations on light extinction. The formula that is used is the existing IMPROVE/EPA formula, which is applied to determine a change in light extinction due to increases in the particulate matter component concentrations. Using the notation of CALPOST, the formula is the following:

$$b_{ext} = 3\ f(RH)\ [(NH_4)2SO_4] + 3\ f(RH)\ [NH_4NO_3] + 4[OC] + 1[Soil] + 0.6[Coarse\ Mass] + 10[EC] + b_{Ray}$$

The concentrations, in square brackets, are in $\mu g/m^3$ and b_{ext} is in units of Mm^{-1}. The Rayleigh scattering term (b_{Ray}) has a default value of 10 Mm^{-1}, as recommended in EPA guidance for tracking reasonable progress (EPA, 2003a).

The assessment of visibility impacts at the Class I areas used CALPOST Method 6. Each hour's source-caused extinction is calculated by first using the hygroscopic components of the source-caused concentrations, due to ammonium sulfate and nitrate, and monthly Class I area-specific f(RH) values. The contribution to the total source-caused extinction from ammonium sulfate and nitrate is then added to the other, non-hygroscopic components of the particulate concentration (from coarse and fine soil, secondary organic aerosols, and from elemental carbon) to yield the total hourly source-caused extinction.

3.0 BART Applicability Analysis

3.1 BART-Eligible Requirements

The BART-affected emission units at the Coronado Generating Station are Units 1 and 2. These units are BART eligible because they meet the following requirements:

1. They were "in existence" between 1962 and 1977.

2. The emissions from the combined BART-eligible units are greater than 250 tons/year.

3. It is in one of the 28 categories of sources identified in the Regional Haze Rule.

Due to the fact that the CGS sources are eligible for BART, the next step in the process is to determine whether the BART-eligible baseline emissions contribute to a discernable visibility impact at any Class I area. The contribution threshold is a modeled change in the natural background visibility of 0.5 delta-deciview. This modeling assessment is described in Section 5.

3.2 Existing Control Equipment and Emission Rates

For purposes of determining BART applicability, the SO_2 and NO_x baseline emissions were determined by ENSR using continuous emission monitoring system (CEMS) data compiled in baseline calendar years 2001 through 2003. Filterable PM baseline emissions were also determined by ENSR based on stack test data and CEMS data collected from 2001 through 2003.

For purposes of determining BART applicability, the SO_2 and NO_x baseline emissions were based on the highest calendar day emission rates for each pollutant and the highest daily heat input rate for each individual unit compiled by the CEMS for baseline calendar years 2001 through 2003. The determination of the highest daily emissions did not consider emissions associated with malfunctions, start-up, and shutdown, consistent with the WRAP BART protocol. Filterable PM baseline emissions were based on stack test data for each individual unit over the period of 2001 through 2003 and the highest daily heat input rate for each individual unit during the period 2001 through 2003, as recorded by the CEMS.

Speciation of the particulate matter emissions into filterable and condensable PM components was determined using the following approach:

- Filterable PM was subdivided by size category consistent with the default approach cited in AP-42, Table 1.1-6. For coal-fired boilers equipped with ESPs, 67% of the filterable PM emissions are filterable PM_{10} and 29% of the PM emissions are fine filterable PM_{10} emissions (less than 2.5 microns in size).
- For coal-fired boilers, elemental carbon is expected to be 3.7% of fine PM_{10} based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
- Condensable inorganic PM_{10} emissions, assumed to consist of H_2SO_4, are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers, H_2SO_4 emissions are determined by the following relationship:

$E = (Q)(98.06/64.04)(F1)(F2)$

where: E is the H_2SO_2 emission rate (lb/hr),
Q is the baseline SO_2 emission rate (lb/hr),
F1 is the fuel factor (0.0018 for PRB sub-bituminous coal), and
F2 is the control factor (0.63 for a hot-side ESP, 0.56 for an air pre-heater, and 0.40 for a wet FGD).

- For coal-fired boilers with FGD, the total condensable organic PM_{10} emission factor is 0.004 lb/MMBtu based on AP-42, Table 1.1-5.

Table 3-1 presents the stack parameters of the merged flues that were used in the modeling of baseline conditions. Currently two flues exhaust onto one stack. Table 3-2 then presents the emission rates that were used in the modeling of baseline conditions.

Table 3-1: Coronado Generating Station Baseline Stack Parameters

	Units	Unit 1	Unit 2	Merged Stack
Latitude	Degrees	34.5777	34.5777	34.5777
Longitude	Degrees	-109.2723	-109.2723	-109.2723
Stack Height	Meters	152.4	152.4	152.4
Base Elevation	Meters	1766.7	1766.7	1766.7
Diameter	Meters	5.79	5.79	8.19
Gas Exit Velocity	m/s	27.85	25.45	26.65
Stack Gas Exit Temperature	Deg K	387.6	380.4	384.1

Table 3-2: Coronado Generating Station Baseline Emissions (Option 1)

Facility	Unit	Description	Max. Heat Input [a]		Maximum Fuel Sulfur [b]	Maximum SO2 Emissions [c]			Maximum NOx Emissions [d]			Maximum Filterable PM Emissions		Filterable PM_{10}					Condensable PM_{10}			Total PM_{10}
														total	coarse	Fine: fine total	Fine: fine soil	EC	total	H2SO4	organic	
			MMBtu/day	MMBtu/hr	%	ton/day	lb/hr	lb/MMBtu	ton/day	lb/hr	lb/MMBtu	lb/MMBtu [e]	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Coronado	1	PC, subbituminous coal, dry bottom, wall opposed, hot side ESP, partial wet FGD, 389 MW	130,753	5,448	1.17	39.91	3,326	0.610	28.29	2,358	0.433	0.0260	141.65	94.90 (f)	53.83 (f)	41.08 (f)	39.6 (g)	1.52 (g)	75.45 (h)	9.85 (i)	65.59 (j)	170.4
Coronado	2	PC, subbituminous coal, dry bottom, wall opposed, hot side ESP, partial wet FGD, 384 MW	117,922	4,913	1.17	40.64	3,386	0.689	27.49	2,291	0.466	0.0180	88.44	59.26 (f)	33.61 (f)	25.65 (f)	24.7 (g)	0.95 (g)	68.04 (h)	8.89 (i)	59.16 (j)	127.3

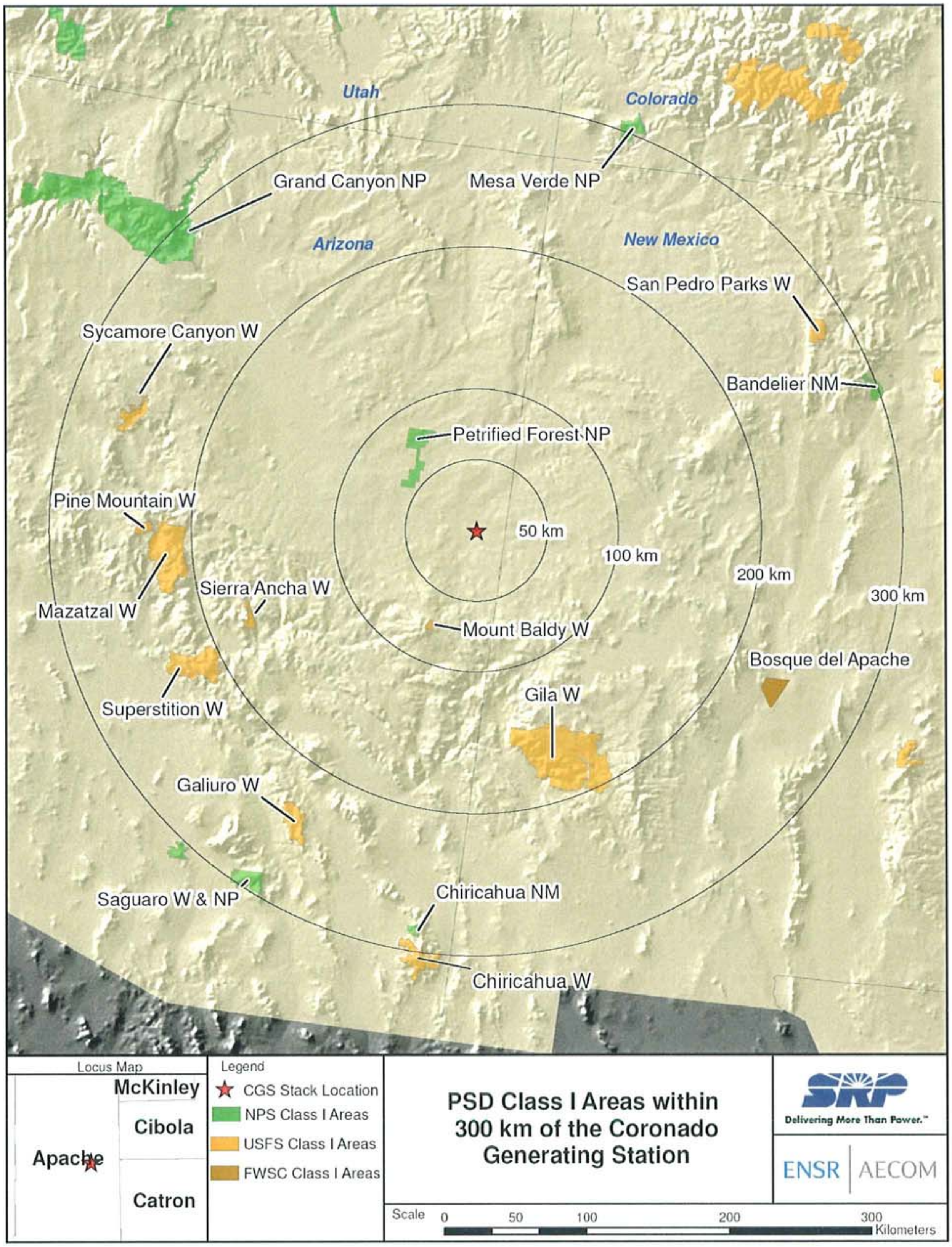
(a) Maximum daily 24 hour actual heat input based on Part 75 monitoring data for the 2001 - 2003 period. Unit 1 based on 4/18/01 and Unit 2 based on 2/26/01 data.
(b) Maximum fuel sulfur is based on daily data for the 2001 to 2003 period. Maximum is 1.17% S with a heating value of 9,546 Btu/lb.
(c) Maximum daily 24 hour actual emissions based on Part 75 monitoring data for the 2001 - 2003 period. Unit 1 based on 3/31/02 and Unit 2 based on 8/16/02 data.
(d) Maximum daily 24 hour actual emissions based on Part 75 monitoring data for the 2001 - 2003 period. Unit 1 based on 10/31/01 and Unit 2 based on 9/3/03 data.
(e) Maximum of 3 Method 17 stack test results for the 2001 to 2003 period.
(f) For a dry bottom boiler with an ESP 67% of filterable PM is PM10 and 29% is fine PM10 (PM2.5) based on AP-42, Table 1.1-6, September 1998.
(g) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(h) Total condensable PM10 is the sum of H2SO4 and organic condensible PM10 emissions.
(i) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants", Electric Power Research Institute, Technical Update, March, 2007. H2SO4 before control equals 0.0018 x %S/100 x 1/9,546 x 1,000,000 x Heat Input x 98.06/32.07. Coal heating value is 9,546 Btu/lb. H2SO4 control is 37% for a hot side ESP, 44% for an air preheater, and 60% for wet FGD. The factor 0.0018 (0.18% oxidation) is for the combustion process. 40% of the flue gas is controlled by wet FGD.
(j) Organic condensable PM10 is 0.20 x (0.1S -0.03) lb/MMBtu without FGD and 0.004 lb/MMBtu with FGD based on AP-42, Table 1.1-5, September 1998. 40% of the flue gas is controlled by wet FGD.

3.3 Affected Class I Areas

The Class I areas located within 300 km of the Coronado Generating Station are listed below and their proximities to the station are shown in Figure 3-1:

1. Bandalier NM
2. Bosque del Apache
3. Chiricahua NM
4. Chiricahua Wilderness
5. Galiuro Wilderness
6. Gila Wilderness
7. Grand Canyon NP
8. Mazatzal Wilderness
9. Mesa Verde National Park
10. Mount Baldy Wilderness
11. Petrified Forest National Park
12. Pine Mountain Wilderness
13. Saguaro Wilderness within Saguaro National Park
14. San Pedro Parks Wilderness
15. Sierra Ancha Wilderness
16. Superstition Wilderness
17. Sycamore Canyon Wilderness

Figure 3-1: Class I Areas within 300 km of the Coronado Generating Station



3.4 Baseline CALPUFF Modeling Results

CALPUFF modeling results of the baseline emissions at seventeen Class I areas are presented in Table 3-1 and graphically plotted in Figure 3-2. Modeling was conducted for all three years of CALMET meteorological data (2001-2003).

For each Class I area and year, Table 3-1 lists the 8th highest delta-deciview and the total 8th highest deciview (source contribution plus the natural background). Figure 3-2 shows the total 8th highest deciview impacts. The figure indicates that the higher visibility impacts generally occur at Petrified Forest National Park and Gila Wilderness. Higher impacts at these Class I areas are due to their proximity to CGS.

EPA recommends in their BART rule that the 98th percentile value of the modeling results should be compared to the threshold of 0.5 deciviews to determine if a source contributes to visibility impairment. This statistic is also recommended for comparing visibility improvements due to BART control options. On an annual basis, this implies the 8th highest day at each modeled Class I area.

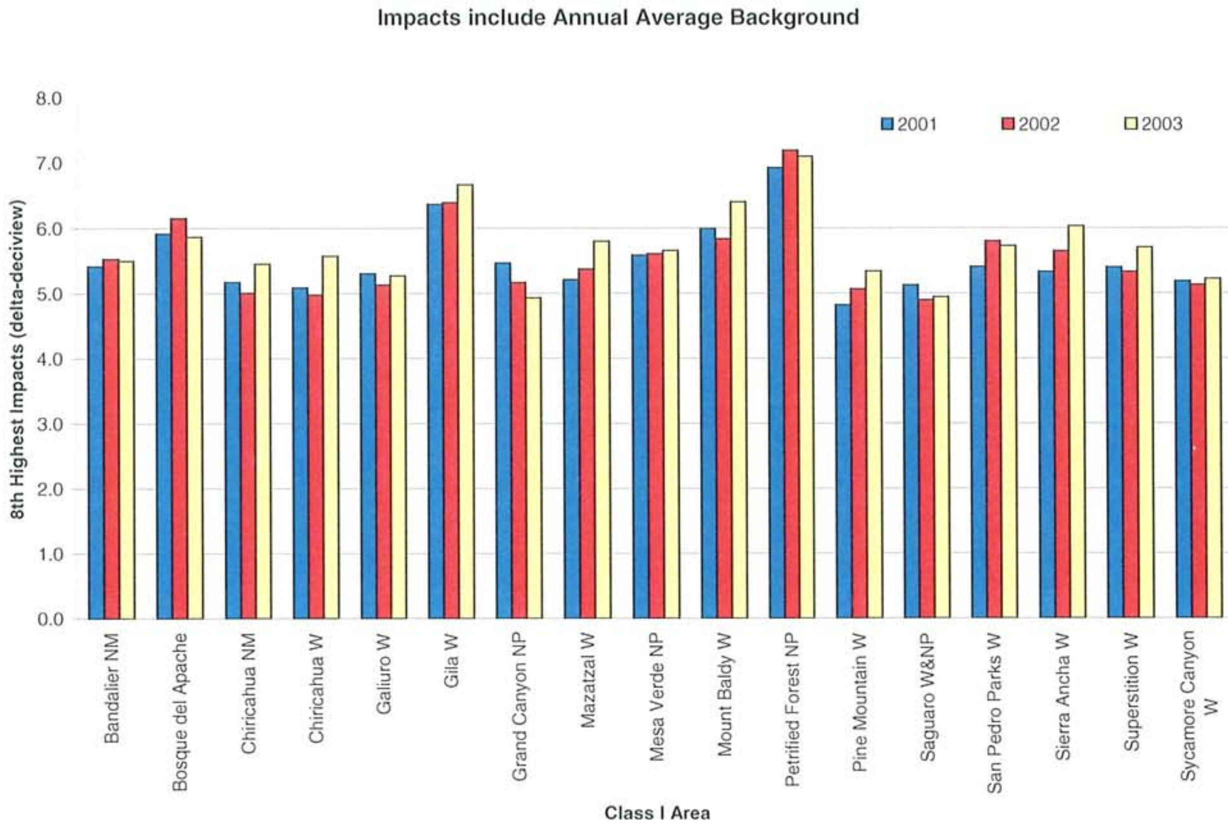
The results of the baseline emissions indicate that the Coronado units have predicted visibility impacts exceeding 0.5 deciviews in at least one Class I area. Therefore, per 40 CFR Part 51, Appendix Y, the CGS is presumed to cause or contribute to visibility impairment and is subject to BART. Candidate BART controls are discussed in Section 4. The results of the visibility improvement modeling for these candidate controls are discussed in Section 5. The final BART recommendations are provided in Section 6.

Table 3-3: Regional Haze Impacts Due to Baseline Emissions

Class I Area	Annual Average Natural Bkg (dv)	Met Year 2001		Met Year 2002		Met Year 2003	
		8th Highest Δ dv	8th Highest total dv(1)	8th Highest Δ dv	8th Highest total dv(1)	8th Highest Δ dv	8th Highest total dv(1)
Bandalier NM	4.46	1.0	5.4	1.1	5.5	1.0	5.5
Bosque del Apache	4.41	1.5	5.9	1.7	6.1	1.5	5.9
Chiricahua NM	4.36	0.8	5.2	0.6	5.0	1.1	5.5
Chiricahua W	4.35	0.7	5.1	0.6	5.0	1.2	5.6
Galiuro W	4.32	1.0	5.3	0.8	5.1	0.9	5.3
Gila W	4.39	2.0	6.4	2.0	6.4	2.3	6.7
Grand Canyon NP	4.39	1.1	5.5	0.8	5.2	0.5	4.9
Mazatzal W	4.35	0.9	5.2	1.0	5.4	1.4	5.8
Mesa Verde NP	4.53	1.1	5.6	1.1	5.6	1.1	5.7
Mount Baldy W	4.39	1.6	6.0	1.4	5.8	2.0	6.4
Petrified Forest NP	4.41	2.5	6.9	2.8	7.2	2.7	7.1
Pine Mountain W	4.36	0.5	4.8	0.7	5.1	1.0	5.3
Saguaro W&NP	4.28	0.8	5.1	0.6	4.9	0.7	4.9
San Pedro Parks W	4.47	0.9	5.4	1.3	5.8	1.3	5.7
Sierra Ancha W	4.36	1.0	5.3	1.3	5.6	1.7	6.0
Superstition W	4.32	1.1	5.4	1.0	5.3	1.4	5.7
Sycamore Canyon W	4.40	0.8	5.2	0.7	5.1	0.8	5.2

(1) Total regional haze impact that inlcludes CGS contribution and the annual average natural background.

Figure 3-2: 8th Highest Regional Haze Impacts for Each Modeled Year Due to Baseline Emissions



4.0 BART Engineering Analysis

4.1 SO_2 Emissions Controls

BART is being reviewed for SO_2 for Coronado Units 1 and 2. The following section describes the proposed SO_2 technology and the expected effectiveness of such control applied to CGS.

4.1.1 Wet Flue Gas Desulfurization

Wet flue gas desulfurization (WFGD) uses limestone or lime to react with SO_2 from the flue gas. The temperature of the flue gas is reduced to its adiabatic saturation temperature and the SO_2 is removed from the flue gas by reaction with the alkaline medium. SO_2 and other acid gases are absorbed into the scrubbing slurry, which falls into the lower section of the vessel known as the reaction tank. Finely ground limestone and make-up water are added to the reaction tank to neutralize and regenerate the scrubbing slurry.

Limestone scrubbing introduces limestone slurry into the scrubber. The sulfur dioxide is absorbed, neutralized, and partially oxidized to calcium sulfite and calcium sulfate. The overall reactions are shown in the following equations:

$$CaCO_3 + SO_2 + \frac{1}{2} H_2O \rightarrow CaSO_3 \bullet \frac{1}{2} H_2O + CO_2$$

$$CaSO_3 \bullet \frac{1}{2} H_2O + 3/2\ H_2O + \frac{1}{2} O_2 \rightarrow CaSO_4 \bullet 2\ H_2O$$

Lime scrubbing is similar to limestone scrubbing in equipment and process flow, except that lime is a more reactive reagent than limestone. The reactions for lime scrubbing are as follows:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \bullet 1/2\ H_2O + 1/2\ H_2O$$

$$Ca(OH)_2 + SO_2 + 1/2\ O_2 + H_2O \rightarrow CaSO_4 \bullet 2\ H_2O$$

If lime or limestone is used as the reagent for SO_2 removal, additional equipment is needed to prepare the lime/limestone slurry and collecting and dewatering the resultant sludge. Calcium sulfite sludge is difficult to mechanically dewater and is typically stabilized with fly ash for landfilling. Calcium sulfate sludge is stable and is readily mechanically dewatered. To produce calcium sulfate, an air injection blower is needed to supply the oxygen for the second reaction to occur (forced oxidation).

WFGD is the most effective control device available to reduce SO_2 emissions resulting from coal combustion. The alternative SO_2 control technologies, such as spray dryer absorbers and dry sorbent injection, are not capable of achieving SO_2 emissions levels comparable to that achieved by WFGD; therefore, no further controls were considered.

4.1.2 Conclusion

A WFGD system is proposed to be installed to treat the entire flue gas stream from both Units 1 and 2 (this is also assumed for all subsequent NO_x control scenarios). The proposed SO_2 emission rate is 0.08 lb/MMBtu on a 30-day average, which is well below the presumptive limit of 0.15 lb/MMBtu.

4.2 NO_x Emissions Control

Nitrogen oxides (NO_x) formed during the combustion of coal are generally classified as either thermal NO_x or fuel-bound NO_x. Thermal NO_x is formed when elemental nitrogen in the combustion air is oxidized at the high temperatures in the primary combustion zone yielding nitrogen oxide (NO) and nitrogen dioxide (NO_2). The rate of formation of thermal NO_x is a function of residence time and free oxygen, and increases exponentially with peak flame temperatures. Thermal NO_x from coal combustion can be effectively controlled by techniques that limit available oxygen or reduce peak flame temperatures in the primary combustion zone. Fuel-bound NO_x is formed by the oxidation of chemically bound nitrogen in the fuel. The rate of formation of fuel-bound NO_x is primarily a function of the coal nitrogen content, but is affected by gas turbulence and fuel/air mixing.

The following sections describe (1) the technologies for reduction of NO_x from coal fired power plants, (2) the feasibility of applying such controls to CGS, (3) the expected effectiveness of such controls if used at CGS, and (4) the impacts of implementing such controls at CGS.

4.2.1 Identification of Alternative NO_x Controls

The alternative NO_x control technologies available for limiting NO_x emissions from Units 1 and 2 include combustion techniques, such as low-NO_x burners (LNB) and overfire air (OFA), and post-combustion controls, such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). These alternative NO_x control technologies are evaluated below in terms of their application to Units 1 and 2.

4.2.1.1 Advanced Combustion Controls

Advanced combustion controls (ACC), including LNB and OFA, on dry-turbo-fired boilers are designed to control fuel and air mixing to reduce peak flame temperatures resulting in less NO_x formation. Combustion, reduction and burnout are achieved in three stages within a conventional low NO_x burner. In the initial stage, combustion occurs in a fuel rich, oxygen deficient zone where the NO_x is formed. A reducing atmosphere follows where hydrocarbons are formed that react with the already formed NO_x. In the third stage, internal air staging completes the combustion, but may result in additional NO_x formation. This, however, can be minimized by completing the combustion in an air lean environment. Combustion air is separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of nitrogen, rather than NO_x. Primary air (70-90%) is mixed with the fuel producing a relatively low temperature, oxygen deficient, fuel-rich zone thereby reducing the formation of fuel-bound NO_x. Secondary air representing 10-30% of the combustion air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles mounted above the burners. Combustion is completed at this increased flame volume. Hence, the relatively low-temperature secondary-stage limits the production of thermal NO_x.

4.2.1.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction is based on a gas-phase homogeneous reaction that involves the injection of an amine-based compound into the flue gas within an appropriate temperature range for reduction of NO_x. An amine-based compound, such as ammonia, NH_3, or urea, $(NH_2)_2CO$, is used as the NO_x reducing agent in SNCR processes. When ammonia or urea is injected into the flue gas stream, it selectively reduces the NO_x into molecular nitrogen, N_2, and water, H_2O. At stoichiometric conditions, when the adequate residence time is reached, the overall reactions that occur may be characterized by:

Ammonia

$$4NO + 4NH_3 + 0_2 \rightarrow 4N_2 + 6H_20$$

$$2NO_2 + 4NH_3 + 0_2 \rightarrow 3N_2 + 6H_20$$

Urea

$$2(NH_2)_2CO + 4NO + O_2 \rightarrow 4N_2 + 2CO_2 + 4H_2O$$

In an SNCR system, NO_x reduction does not take place in the presence of a catalyst, but rather is driven by the thermal decomposition of ammonia or urea and the subsequent reduction of NO_x. Consequently, the SNCR process operates at higher temperatures than the SCR process. The temperature of the flue gas is critical to the successful reduction of NO_x with SNCR at the point where the reagent is injected. For the ammonia injection process, the necessary temperature range is 1,700 to 1,900°F. The other factors affecting SNCR performance are gas mixing, residence time at operating temperatures, and ammonia slip.

Because oxygen is present in the flue gas, a portion of the ammonia may oxidize at temperatures greater than 2,000°F. Above 2,000°F, the reaction of ammonia oxidation becomes predominant. Nitrogen monoxide is formed as a product of this reaction. As a result, when the flue gas temperature at reagent injection locations is higher than the appropriate temperature window, the SNCR process results in NO_x formation rather than NO_x reduction. At temperatures lower than the required temperature window, the NO_x reduction reaction rates become lower, and unreacted ammonia may slip through and be emitted to the atmosphere.

Similar to SCR, equipment vendors suggest a higher ammonia injection rate than is stoichiometrically required to achieve higher NO_x control efficiencies. The various SNCR vendors typically guarantee ammonia slip of no less than 5 ppm for systems designed for high NO_x performance levels. This excess ammonia may react with SO_3 and water vapor to form ammonium bisulfate and ammonium sulfate. Although no SO_2 is oxidized by the SNCR system, naturally occurring SO_3 concentrations are high enough to be a concern with potentially high ammonia slip rates. Ammonium bisulfate may precipitate out at air heater operating temperatures and can ultimately lead to air heater fouling and plugging. Furthermore, the ammonium salts may condense as the flue gases cool and can lead to increased emissions of both PM_{10} and $PM_{2.5}$. Ammonia slip from SNCR systems occurs either from injection at temperatures too low for effective reaction with NO_x or from over-injection of reagent leading to uneven distribution. Controlling ammonia slip in SNCR systems is difficult as there is no opportunity for effective feedback to control reagent injection. The reagent injection system must be able to place the reagent where it is most effective within the boiler because NO_x distribution varies within the cross section. An injection system that has too few injection control points or fails to inject a uniform amount of ammonia across the entire section of the boiler will almost certainly lead to a poor distribution ratio and high ammonia slip. Distribution of the reagent can be especially difficult in larger coal-fired boilers because of the long injection distance required to cover the relatively large cross-section of the boiler. Multiple layers of reagent injection as well as individual injection zones in the cross-section of each injection level are commonly used to follow the temperature changes caused by boiler load changes.

On small coal-fired units (i.e., less than 200 MW), SNCR has been demonstrated to achieve NO_x reductions ranging from 25 to 50% with acceptable levels of ammonia slip. This variation in NO_x reduction depends on site-specific considerations and the amount of ammonia slip considered acceptable. In practical applications, non-uniformities in velocity and temperature at the reagent injection location can pose operational difficulties because of the inherent sensitivity of the process to these parameters. The physical location of the effective temperature range within the boiler depends on operating factors such as unit load, combustion air distribution, and soot blowing cycles. Generally, these factors require the utilization of multiple injection elevations in full-scale systems. For larger boilers (i.e., greater than 300 MW), there are numerous challenges associated with applying SNCR. In particular, the large physical dimensions pose challenges for injecting and mixing the reagent with the flue gas. Another issue with larger units is the fact that the SNCR temperature window often exists within the convective passes. Demonstrations at the Port Jefferson, Morro Bay and Merrimac Plants have shown that injecting in the convective pass can create high ammonia slip due to limited residence time at the operating temperatures of SNCR.[1,2]

EPRI sponsored a computational fluid dynamics modeling program to evaluate the performance of SNCR on Southern Company Service's Wansley Unit 1 located in Roopville, Georgia. This 880-MW unit is a wall-fired boiler equipped with low-NO_x burners and separated overfire air. The modeling results demonstrated that SNCR has the potential to reduce NO_x emissions by only 22% with an acceptable ammonia slip of 6 ppm. The firing characteristics of the boiler make achieving higher levels of NO_x reduction impractical. The

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[1] Shore, D., et al, "Urea SNCR Demonstration at Long Island Lighting Company's Port Jefferson Station, Unit 3," Proceedings of the EPRI/EPA Joint Symposium on Stationary Combustion NO_x Control, May 1993.
[2] Lin, Chin-I, " Full Scale Tests of SNCR Technology on a Gas-Fired Boiler," EPRI Workshop on NO_x Controls for Utility Boilers, July 1992.

most influential factor is the separated overfire air system, which elevates upper furnace temperatures by causing the combustion process to extend beyond the furnace nose and into the convection section.[3]

4.2.1.3 Selective Catalytic Reduction

Selective catalytic reduction is a process that involves post-combustion removal of NO_x from flue gas utilizing a catalytic reactor. In the SCR process, ammonia injected into the flue gas reacts with nitrogen oxides and oxygen to form nitrogen and water vapor. The SCR process converts NO_x to nitrogen and water by the following general reactions:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction to about 375° to 750°F, depending on the specific catalyst and other contaminants in the flue gas. The factors affecting SCR performance are catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system.

The SCR system is comprised of a number of subsystems, including the SCR reactor, ammonia injection system, and ammonia storage and delivery system. The SCR reactor would be located downstream of the economizer and electrostatic precipitators, and upstream of the air pre-heater. From the ESP outlet, the flue gas would first pass through a low-pressure ammonia/air injection grid designed to provide optimal mixing of ammonia with flue gas. The ammonia treated flue gas would then flow through the catalyst bed and exit to the air pre-heater. The SCR system for a pulverized coal boiler typically uses a fixed bed catalyst in a vertical down-flow, multi-stage reactor.

Reduction catalysts are divided into two groups: base metal, primarily vanadium, platinum, or titanium (lower temperature) and zeolite (higher temperature). Both groups exhibit advantages and disadvantages in terms of operating temperature, ammonia-NO_x ratio, and optimum oxygen concentration. The optimum operating temperature for a vanadium-titanium catalyst system is in the range of 550° to 800°F, which is significantly higher than for platinum catalyst systems. However, the vanadium-titanium catalyst systems begin to break down when continuously operating at temperatures above this range. Operation above the maximum temperature results in oxidation of ammonia to either ammonia sulfate or NO_x, thereby actually increasing NO_x emissions.

To achieve high NO_x control efficiencies, the SCR vendors suggest a higher ammonia injection rate than is stoichiometrically required to react all of NO_x in the combustion gases. This results in emissions of un-reacted ammonia or "ammonia slip." The various SCR vendors typically guarantee ammonia slip of about 2 ppm for systems designed for very high NO_x performance levels. This excess ammonia may react with SO_3 and water vapor to form ammonium bisulfate $(NH_4)HSO_4$ and ammonium sulfate $(NH_4)_2SO_4$. Higher levels of ammonia and SO_2 result in higher levels of ammonium bisulfate and ammonia sulfate. These ammonium salts may condense as the flue gases cool and can lead to increased emissions of both PM_{10} and $PM_{2.5}$. Furthermore, the catalyst promotes the partial oxidation of SO_2 to SO_3, which in turn combines with water thereby increasing the formation of these ammonia salts and potential emissions of PM_{10} and $PM_{2.5}$.

Some SCR installations have experienced significant air pre-heater plugging and corrosion resulting from the deposition of ammonium bisulfate. The plugging and corrosion can cause reduced boiler efficiency, higher flue gas pressure drop, more frequent air pre-heater cleaning and washing, increased boiler downtime, and increased maintenance cost. The primary factors for controlling the formation and deposition

[3] Harmon, A., et al., "Evaluation of SNCR Performance on Large-Scale Coal-Fired Boilers," Institute of Clean Air Companies (ICAC) Forum on Cutting NO_x Emissions, Durham, NC, March, 1998.

of ammonium bisulfate are the level of ammonia, the level of SO_3, the air pre-heater surface temperature profile, the air pre-heater surface material, and the air pre-heater physical configuration. The temperature window for ammonium bisulfate deposition is as wide as 300°F to 425°F. The temperature window for sulfuric acid formation, which is primarily a function of SO_3 concentration, is significantly lower, but must also be evaluated in system design.

The SCR system is subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation generally results from either prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and thus is a permanent condition. Catalyst suppliers typically guarantee a limited lifetime for high performance catalyst systems. Fly ash plugging generally results from excessive fly ash carryover to the catalyst or poor catalyst gas flow design. Gas, ash, and ammonia flow distribution modeling is critical in the design phase. Lessons learned have been incorporated into this process resulting in improved ammonia injection system and catalyst design and performance.

4.2.2 Technical Feasibility of Alternative NO_x Controls

The BART analysis is limited to those technologies having been demonstrated to achieve significant NO_x reduction on units of the same scale and design as Coronado Units 1 and 2. Specifically, the only technologies considered technically feasible for NOx control on Units 1 and 2 are ACC, ACC/SNCR; and ACC/SCR.

4.2.3 Effectiveness of Technically Feasible NO_x Controls

The alternative NO_x control technologies, ACC, SCR and SNCR, have been successfully applied to new utility coal-fired boilers, as well as retrofitted to existing utility coal-fired boilers. The effectiveness of these technologies in reducing NO_x emissions is dependent primarily on the inlet NO_x concentrations, residence time, and operating temperatures. Advanced combustion has been demonstrated to achieve 25% to 35% reduction in uncontrolled NO_x emissions from coal-fired utility boilers. SNCR has been demonstrated to achieve NO_x control efficiencies ranging from 30% to 50% with inlet NO_x concentrations of 300 to 400 ppmvd. If staged combustion is used to reduce inlet NO_x concentrations to less than 250 ppmvd, SNCR is capable of achieving NO_x control efficiencies of only 20 to 40%. Likewise, SCR can achieve NO_x control efficiencies as high as 90% with inlet NO_x concentrations in the range of 300 to 400 ppmvd. If inlet NO_x concentrations are less than 250 ppmvd, SCR can achieve NO_x control efficiencies ranging from only 70 to 80%.

Currently, the maximum NO_x emissions from Units 1 and 2 are typically 0.433 and 0.466 lb/MMBtu, respectively. Based on information provided by equipment vendors, it is estimated that ACC will reduce NO_x emissions to an emission level of approximately 0.320 lb/MMBtu. Based on the inlet NO_x concentrations, it is estimated that the addition of SNCR will reduce NO_x emissions by another 30%, which corresponds to a NO_x emission level of approximately 0.224 lb/MMBtu. SCR is estimated to reduce NO_x emissions by 75%, which corresponds to a NO_x emission level of 0.080 lb/MMBtu. Table 4-1 summarizes the annual NO_x emissions resulting from the application of ACC, SCR and SNCR to Units 1 and 2.

Table 4-1: Annual NO_x Emissions Resulting from NO_x Controls

Control Option	Control Technology	Unit 1 (lb NO_x/MMBtu)	Unit 2 (lb NO_x/MMBtu)
1	Baseline - Partial FGD	0.433	0.466
2	Wet FGD	0.433	0.466
3	WFGD, ACC	0.320	0.320
4a	WFGD, ACC, SNCR	0.224	0.224
4b	WFGD, ACC (Unit 1) & SCR (Unit 2)	0.320	0.080
5	WFGD, ACC, SCR	0.080	0.080

4.2.4 Impacts of Alternative NO_x Controls

The alternative control technologies available to control NO_x emissions from Units 1 and 2 are LNB, SCR and SNCR. This section documents the economic, environmental, and energy impacts associated with applying either SCR or SNCR to Units 1 and 2.

4.2.4.1 Economic Impacts

Table 4-2 summarizes the total capital and annual costs associated with applying LNB, SCR and SNCR to Units 1 and 2. Note that the fixed capital costs were based on a capital recovery factor (CRF) of 0.09439, assuming an interest rate of 7%, and amortization period of 20 years.

Table 4-2: Total Capital and Annual Costs Associated with NO_x Controls Applied to CGS Units 1 and 2

Control Option	Control Technology	Total Capital Cost ($)	Fixed Capital Costs ($/yr)[a]	Annual O&M Costs ($/yr)	Total Annual Costs ($/yr)
3	ACC on Units 1-2	$13,000,000	$1,227,070	$0	$1,227,070
4a	ACC/SNCR on Units 1-2	$26,000,000	$2,454,140	$2,200,000	$4,654,140
4b	ACC on Unit 1 & SCR on Unit 2	$79,000,000	$7,456,810	$1,100,000	$8,556,810
5	ACC/SCR on Units 1-2	$145,000,000	$13,686,550	$3,400,000	$17,086,550

[a] Fixed capital costs based on a CRF of 0.09439, assuming an interest rate of 7% and amortization period of 20 years.

4.2.4.2 Non-Air Quality Environmental Impacts

One of the most significant impacts of retrofitting SCR or SNCR on the facility is the addition of ammonia or urea storage and handling systems. Anhydrous ammonia and aqueous ammonia above 20 percent are considered dangerous to human health. An accidental release of anhydrous ammonia or 20% or greater aqueous ammonia is reportable to local, state and federal agencies. In anticipation of such an incident, the site would need to develop, implement and maintain a Risk Management Plan (RMP) and Process Safety Measures (PSM) Program. Risk communication to the general public typically includes a worst-case analysis with potential impacts possible at up to a mile from the facility. Even the storage of less than 20% anhydrous ammonia is subject to the general duty clause of the RMP Program.

Theoretically, one mole of ammonia will react with one mole of NO_x, forming elemental nitrogen and water in both SCR and SNCR. In reality, not all the injected reagent will react due to imperfect mixing, uneven temperature distribution, and insufficient residence time. These physical limitations may be compensated for by injecting a larger amount of ammonia than stoichiometrically required and essentially achieving lower NO_x emissions at the expense of ammonia slip. Typically, the ammonia slip associated with SCR is approximately 2 ppm at 6% O_2, while that associated with SNCR is approximately 5 ppm at 6% O_2. This excess ammonia may react with SO_3 or H_2SO_4 in the flue to form ammonium bisulfate $(NH_4)HSO_4$ and ammonium sulfate $(NH_4)_2SO_4$. These ammonium salts may condense as the flue gases cool and can lead to increased emissions of both PM_{10} and $PM_{2.5}$. In SCR systems, the catalyst promotes the partial oxidation of SO_2 to SO_3, which in turn increases the formation of ammonium bisulfate and ammonium sulfate. The enhanced formation of the ammonia salts further increases the potential emissions of PM_{10} and $PM_{2.5}$.

Ammonia associated with fly ash has the potential to present several problems with the disposal and/or the use of the fly ash. Once the fly ash is exposed to the SNCR process, there will be a significant quantity of soluble salts associated with the fly ash. These salts are expected to be NH_4HSO_4 and $(NH_4)_2SO_4$. Ash buyers have expressed concerns about the presence of ammonia on ash. The issues appear to be perception and odor, rather than actual impacts on product quality (e.g., when used for concrete). The level of concern may be regional in nature (i.e., less concern in a non-freezing climate) and the ultimate market for the ash (i.e., commercial versus residential use). The tendency of fly ash to adsorb ammonia is a function of many factors in addition to the amount of ammonia slip. Ash characteristics such as pH, alkali mineral content, and volatile sulfur and chlorine content help to determine whether or not ammonia will be adsorbed readily by the fly ash. Elevated pH will definitely cause ammonia release to the air and resulting odor. In most applications, properly designed SNCR systems will keep the ammonia slip levels low enough so that the salability of the ash should be unaffected.

Dry disposal can cause the leachate and/or runoff water to contain increased concentrations of ammonia. If and when these salts are contacted with water, they will most likely be dissolved and the resulting aqueous concentration of nitrogen-containing compounds can increase in the waters associated with the ash.

Table 4-3 summarizes the non-air quality environmental impacts associated with the proposed BART control options.

4.2.4.3 Energy Impacts

Selective catalytic reduction would consume significantly more electrical energy than SNCR. The higher electrical energy consumption for SCR relative to SNCR primarily is due to the power required for the increased fan static pressure required to overcome the pressure drop across the catalyst bed, as well as for pumps and evaporator blower. Assuming a pressure drop of 14 inches W.G. across the catalyst bed, SCR applied to all three units would consume approximately 7,300 kWh more electrical power than SNCR (approaching 1% of the total power generation of the CGS). The increased emissions of criteria pollutants required to maintain the net electrical output have not been incorporated into the visibility modeling, but the reviewer should be aware that any reported visibility improvements due to SCR operation do not consider this negative impact.

Table 4-3: Summary of Non-Air Quality Environmental Impacts

Control Alternative	Summary of Non-Air Quality Environmental Impacts
WFGD	• Increased water consumption resulting from additional water requirements of scrubbing entire flue gas stream. • Increased solid waste generation resulting from additional calcium salts requiring disposal.
ACC	• Potential to increase in loss of ignition (LOI) of flyash, which could reduce recycling sales. • Slight increase in CO_2 emissions/kwh associated with reduced boiler efficiency. • Potential for incomplete combustion and increased CO emissions. • Potential for increased corrosion and more frequent replacement of furnace waterwall tubes.
SNCR	• Addition of ammonia or urea storage and handling systems. • Anhydrous ammonia and aqueous ammonia above 20 percent are considered dangerous to human health and accidental releases are reportable to local, state and federal agencies. • The site must develop, implement and maintain a Risk Management Plan (RMP) and Process Safety Measures (PSM) Program. • Excess ammonia injected into the boiler reacts with SO_3 or H_2SO_4 in the flue to form ammonium bisulfate $(NH_4)HSO_4$ and ammonium sulfate $(NH_4)_2SO_4$.

Control Alternative	Summary of Non-Air Quality Environmental Impacts
	• Sulfuric acid in the flue gas can cause various power plant operating and maintenance problems. Condensation of sulfuric acid has a significant detrimental effect on downstream equipment, including fouling and corrosion of heat transfer surfaces in the air pre-heater. • Increased emissions of ammonium salts that negatively affect plume visibility. • Increased formation of SO_3 mist (sulfur trioxide), which negatively impacts plume visibility. • Ammonia associated with flyash has the potential to present several problems with the disposal and/or the use of the fly ash. • Dry disposal of flyash can cause leachate and/or runoff water to contain increased concentrations of ammonia and/or nitrogen-containing compounds.
SCR	• Addition of ammonia handling systems. • Anhydrous ammonia and aqueous ammonia above 20 percent are considered dangerous to human health and accidental releases are reportable to local, state and federal agencies. • The site must develop, implement and maintain a Risk Management Plan (RMP) and Process Safety Measures (PSM) Program. • Excess ammonia injected into the boiler reacts with SO_3 or H_2SO_4 to form ammonium bisulfate $(NH_4)HSO_4$ and ammonium sulfate $(NH_4)_2SO_4$. • Increased formation of SO_3 mist (sulfur trioxide), which negatively impacts plume visibility.
SCR Continued	• Disposal of spent catalyst containing heavy metals such as vanadium, tungsten or molybdenum. • Increase in CO_2 emissions from power required for the increased fan static pressure required to overcome the pressure drop across the catalyst bed, as well as for pumps and evaporator blower.

4.2.4.4 Remaining Useful Life

As discussed previously, a 20-year amortization period was used for purposes of the BART analysis for CGS.

4.3 Future Emissions and Stack Parameters

To assess the effectiveness of the alternative SO_2 and NO_x control technologies in reducing visibility impairment attributable to Units 1 and 2, we developed stack and emission parameters for the following control options:

- Option 1. This option represents baseline conditions and involves partial FGD.
- Option 2. This option involves the treatment of the entire flue gas stream from Units 1 and 2 in the wet FGD system to control SO_2 emissions from both units to 0.08 lb/MMBtu. Full wet FGD control is maintained in all of the remaining control options.
- Option 3. This option involves the retrofit of advanced combustion controls (ACC), such as LNB/OFA, to Units 1 and 2 to control NO_x emissions from both units to 0.320 lb/MMBtu.
- Option 4a. This option involves the retrofit of ACC and selective non-catalytic reduction (SNCR) to Units 1 and 2 to control NO_x emissions from both units to 0.224 lb/MMBtu.

- Option 4b. This option involves the retrofit of ACC to Unit 1 to control NO_x emissions from this unit to 0.320 lb/MMBtu, and the retrofit of ACC and selective catalytic reduction (SCR) to Unit 2 to control NO_x emissions from these units to 0.08 lb/MMBtu.
- Option 5. This option involves the retrofit of ACC and SCR to Units 1 and 2 to control NO_x emissions from both units to 0.08 lb/MMBtu.

The alternative control technologies will not only affect PM, SO_2 and NO_x emission levels from Units 1 and 2, but will also affect the emissions and speciation of PM_{10}. The PM_{10} emissions and speciation were determined using the following approach:

- Filterable PM was subdivided by size category consistent with the default approach cited in AP-42, Table 1.1-6. For coal-fired boilers equipped with ESPs, 67% of the filterable PM emissions are filterable PM_{10} and 29% of the PM emissions are fine filterable PM_{10} emissions (less than 2.5 microns in size).
- For coal-fired boilers, elemental carbon is expected to be 3.7% of fine PM_{10} based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
- Condensable inorganic PM_{10} emissions, assumed to consist of H_2SO_4, are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers equipped with SCR, H_2SO_4 emissions are determined by the following relationship:

  $$E = (Q)(98.06/64.04)(F1+S2)(F2)$$

  where: E is the H_2SO_2 emission rate (lb/hr),
  Q is the baseline SO_2 emission rate (lb/hr),
  F1 is the fuel factor (0.0018 for western bituminous coal),
  S2 is the SCR catalyst SO_2 oxidation rate (0.01 for PRB coal), and
  F2 is the control factor (0.63 for a hot-side ESP, 0.56 for an air pre-heater, and 0.60 for wet FGD).

  Note that, for units not equipped with SCR, the factor, S2, is eliminated from the above relationship.
- For coal-fired boilers with FGD, the total condensable organic PM_{10} emission factor is 0.004 lb/MMBtu based on AP-42, Table 1.1-5.

The stack parameters for Units 1 and 2 under Control Options 2 through 5 are presented in Table 4-4. The NO_x, SO_2, and PM_{10} emissions from Units 1 and 2 under the five control options are then summarized in Tables 4-5, 4-6, 4-7, 4-8, and 4-9, respectively.

Table 4-4: Future Stack Parameters

	Units	Unit 1	Unit 2
Latitude	Degrees	34.57890	34.5765
Longitude	Degrees	-109.2716	-109.2715
Stack Height	Meters	121.92	121.92
Base Elevation	Meters	1766.3	1767.5
Diameter	Meters	7.47	7.47
Gas Exit Velocity	m/s	18.27	18.27
Stack Gas Exit Temperature	deg K	329.3	329.3

Table 4-5: Coronado Generating Station with Full WFGD (Option 2)

Facility	Unit	Description	Max. Heat Input (a)		Fuel Sulfur (b)	Maximum SO2 Emissions (c)		Maximum NOx Emissions (d)		Maximum Filterable PM Emissions		Filterable PM_{10}					Condensable PM_{10}			Total PM_{10}
												total	coarse	Fine			total	H2SO4	organic	
														fine total	fine soil	EC				
			MMBtu/day	MMBtu/hr	%	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu (e)	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Coronado	1	PC, subbiituminous coal, dry bottom, wall opposed, hot side ESP, wet FGD, 389 MW	130,753	5,448	0.436	0.080	435.8	0.433	2,358	0.0260	141.65	94.90 (f)	53.83 (f)	41.08 (f)	39.6 (g)	1.52 (g)	23.88 (h)	2.08 (i)	21.79 (j)	118.8
Coronado	2	PC, subbiituminous coal, dry bottom, wall opposed, hot side ESP, wet FGD,384 MW	117,922	4,913	0.436	0.080	393.1	0.466	2,291	0.0180	88.44	59.26 (f)	33.61 (f)	25.65 (f)	24.7 (g)	0.95 (g)	21.53 (h)	1.88 (i)	19.65 (j)	80.8

(a) Maximum daily/24 hour actual heat input based on Part 75 monitoring data for the 2001 - 2003 period. Unit 1 based on 4/18/01 and Unit 2 based on 2/26/01 data.
(b) Fuel sulfur is average based on PRB coal, 80% Jacobs Ranch, 20% Spring Creek. Average heating value is 8,850 Btu/lb.
(c) Based on maximum heat input rate, fuel sulfur, fuel heating value, 100% conversion of S to SO2 and 95% control by wet FGD.
(d) Maximum daily/24 hour actual emissions based on Part 75 monitoring data for the 2001 - 2003 period. Unit 1 based on 10/31/01 and Unit 2 based on 9/3/03 data.
(e) Maximum of 3 Method 17 stack test results for the 2001 to 2003 period.
(f) For a dry bottom boiler with an ESP 67% of filterable PM is PM10 and 29% is fine PM10 (PM2.5) based on AP-42, Table 1.1-6, September 1998.
(g) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(h) Total condensable PM10 is the sum of H2SO4 and organic condensible PM10 emissions.
(i) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants", Electric Power Research Institute, Technical Update, March, 2007. H2SO4 before control equals 0.0018 x %S/100 x 1/8,850 x 1,000,000 x Heat Input x 98.06/32.07. Coal heating value is 8,850 Btu/lb. H2SO4 control is 37% for a hot side ESP, 44% for an air preheater, and 60% for wet FGD. The factor 0.0018 (0.18% oxidation) is for the combustion process. 100% of the flue gas is controlled by wet FGD.
(j) Organic condensable PM10 is 0.004 lb/MMBtu with FGD based on AP-42, Table 1.1-5, September 1998. 100% of the flue gas is controlled by wet FGD.

Table 4-6: Coronado Generating Station with WFGD and ACC (Option 3)

Facility	Unit	Description	Max. Heat Input [a]		Fuel Sulfur [b]	Maximum SO2 Emissions [c]		Maximum NOx Emissions [d]		Maximum Filterable PM Emissions		Filterable PM_{10}					Condensable PM_{10}			Total PM_{10}
												total	coarse	Fine			total	H2SO4	organic	
														fine total	fine soil	EC				
			MMBtu/day	MMBtu/hr	%	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu [e]	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Coronado	1	PC, subbiituminous coal, dry bottom, wall opposed, advanced combustion controls, hot side ESP, wet FGD, 389 MW	130,753	5,448	0.436	0.080	435.8	0.320	1,743	0.0260	141.65	94.90 (f)	53.83 (f)	41.08 (f)	39.6 (g)	1.52 (g)	23.88 (h)	2.08 (i)	21.79 (j)	118.78
Coronado	2	PC, subbiituminous coal, dry bottom, wall opposed, advanced combustion controls, hot side ESP, wet FGD,384 MW	117,922	4,913	0.436	0.080	393.1	0.320	1,572	0.0180	88.44	59.26 (f)	33.61 (f)	25.65 (f)	24.7 (g)	0.95 (g)	21.53 (h)	1.88 (i)	19.65 (j)	80.79

(a) Maximum daily/24 hour actual heat input based on Part 75 monitoring data for the 2001 - 2003 period. Unit 1 based on 4/18/01 and Unit 2 based on 2/26/01 data.
(b) Fuel sulfur is average based on PRB coal, 80% Jacobs Ranch, 20% Spring Creek. Average heating value is 8,850 Btu/lb.
(c) Based on maximum heat input rate, fuel sulfur, fuel heating value, 100% conversion of S to SO2 and 95% control by wet FGD.
(d) Based on maximum heat input rate and advanced combustion controls to limit emissions to 0.320 lb/MMBtu.
(e) Maximum of 3 Method 17 stack test results for the 2001 to 2003 period.
(f) For a dry bottom boiler with an ESP 67% of filterable PM is PM10 and 29% is fine PM10 (PM2.5) based on AP-42, Table 1.1-6, September 1998.
(g) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(h) Total condensable PM10 is the sum of H2SO4 and organic condensible PM10 emissions.
(i) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants", Electric Power Research Institute, Technical Update, March, 2007. H2SO4 before control equals 0.0018 x %S/100 x 1/8,850 x 1,000,000 x Heat Input x 98.06/32.07. Coal heating value is 8,850 Btu/lb. H2SO4 control is 37% for a hot side ESP, 44% for an air preheater, and 60% for wet FGD. The factor 0.0018 (0.18% oxidation) is for the combustion process. 100% of the flue gas is controlled by wet FGD.
(j) Organic condensable PM10 is 0.004 lb/MMBtu with FGD based on AP-42, Table 1.1-5, September 1998. 100% of the flue gas is controlled by wet FGD.

Table 4-7: Coronado Generating Station with WFGD, ACC and SNCR (Option 4a)

Facility	Unit	Description	Max. Heat Input [a]		Fuel Sulfur [b]	Maximum SO2 Emissions [c]		Maximum NOx Emissions [d]		Maximum Filterable PM Emissions		Filterable PM_{10}					Condensable PM_{10}			Total PM_{10}	NH3 Slip
												total	coarse	Fine: fine total	Fine: fine soil	Fine: EC	total	H2SO4	organic		
			MMBtu/day	MMBtu/hr	%	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu [e]	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Coronado	1	PC, subbituminous coal, dry bottom, wall opposed, advanced combustion controls, SNCR, hot side ESP, wet FGD, 389 MW	130,753	5,448	0.436	0.080	435.8	0.224	1,220	0.0260	141.65	94.90 (f)	53.83 (f)	41.08 (f)	39.6 (g)	1.52 (g)	23.88 (h)	2.08 (i)	21.79 (j)	118.78	16.47
Coronado	2	PC, subbituminous coal, dry bottom, wall opposed, advanced combustion controls, SNCR, hot side ESP, wet FGD, 384 MW	117,922	4,913	0.436	0.080	393.1	0.224	1,101	0.0180	88.44	59.26 (f)	33.61 (f)	25.65 (f)	24.7 (g)	0.95 (g)	21.53 (h)	1.88 (i)	19.65 (j)	80.79	14.86

(a) Maximum daily/24 hour actual heat input based on Part 75 monitoring data for the 2001 - 2003 period. Unit 1 based on 4/18/01 and Unit 2 based on 2/26/01 data.
(b) Fuel sulfur is average based on PRB coal, 80% Jacobs Ranch, 20% Spring Creek. Average heating value is 8,850 Btu/lb.
(c) Based on maximum heat input rate, fuel sulfur, fuel heating value, 100% conversion of S to SO2 and 95% control by wet FGD.
(d) Based on maximum heat input rate, advanced combustion controls and SNCR on Units 1 and 2 to limit emissions to 0.224 lb/MMBtu.
(e) Maximum of 3 Method 17 stack test results for the 2001 to 2003 period.
(f) For a dry bottom boiler with an ESP 67% of filterable PM is PM10 and 29% is fine PM10 (PM2.5) based on AP-42, Table 1.1-6, September 1998.
(g) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(h) Total condensable PM10 is the sum of H2SO4 and organic condensible PM10 emissions.
(i) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants", Electric Power Research Institute, Technical Update, March, 2007. H2SO4, before control, equals 0.0018 x %S/100 x 1/8,850 x 1,000,000 x Heat Input x 98.06/32.07. Coal heating value is 8,850 Btu/lb. H2SO4 control is 37% for a hot side ESP, 44% for an air preheater, and 60% for wet FGD. The factor 0.0018 (0.18% oxidation) is for the combustion process. 100% of the flue gas is controlled by wet FGD.
(j) Organic condensable PM10 is 0.004 lb/MMBtu with FGD based on AP-42, Table 1.1-5, September 1998. 100% of the flue gas is controlled by wet FGD.
(k) Ammonia slip from the SNCR is 5ppm at 6% oxygen.

Table 4-8: Coronado Generating Station with WFGD and ACC on Unit 1 and WFGD, ACC and SCR on Unit 2 (Option 4b)

Facility	Unit	Description	Max. Heat Input [a]		Fuel Sulfur [b]	Maximum SO2 Emissions [c]		Maximum NOx Emissions [d]		Maximum Filterable PM Emissions		Filterable PM_{10}					Condensable PM_{10}			Total PM_{10}	NH3 Slip
												total	coarse	Fine			total	H2SO4	organic		
														fine total	fine soil	EC					
			MMBtu/day	MMBtu/hr	%	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu [e]	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Coronado	1	PC, subbituminous coal, dry bottom, wall opposed, advanced combustion controls, hot side ESP, wet FGD, 389 MW	130,753	5,448	0.436	0.080	435.8	0.32	1,743	0.0260	141.65	94.90 (f)	53.83 (f)	41.08 (f)	39.6 (g)	1.52 (g)	23.88 (h)	2.08 (i)	21.79 (j)	118.78	0
Coronado	2	PC, subbituminous coal, dry bottom, wall opposed, advanced combustion controls, hot side ESP, SCR, wet FGD, 384 MW	117,922	4,913	0.436	0.080	393.1	0.08	393	0.0180	88.44	59.26 (f)	33.61 (f)	25.65 (f)	24.7 (g)	0.95 (g)	38.11 (h)	18.46 (i)	19.65 (j)	97.37	5.94 (k)

(a) Maximum daily/24 hour actual heat input based on Part 75 monitoring data for the 2001 - 2003 period. Unit 1 based on 4/18/01 and Unit 2 based on 2/26/01 data.
(b) Fuel sulfur is average based on PRB coal, 80% Jacobs Ranch, 20% Spring Creek. Average heating value is 8,850 Btu/lb.
(c) Based on maximum heat input rate, fuel sulfur, fuel heating value, 100% conversion of S to SO2 and 95% control by wet FGD.
(d) Based on maximum heat input rate, advanced combustion controls on Unit 1 to limit emissions to 0.320 lb/MMBtu and SCR on Unit 2 to limit emissions to 0.080 lb/MMBtu.
(e) Maximum of 3 Method 17 stack test results for the 2001 to 2003 period.
(f) For a dry bottom boiler with an ESP 67% of filterable PM is PM10 and 29% is fine PM10 (PM2.5) based on AP-42, Table 1.1-6, September 1998.
(g) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.

(h) Total condensable PM10 is the sum of H2SO4 and organic condensible PM10 emissions.

(i) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants", Electric Power Research Institute, Technical Update, March, 2007. H2SO4, before control, equals 0.0018 x %S/100 x 1/8,850 x 1,000,000 x Heat Input x 98.06/32.07 + 0.0100 x %S/100 x 1/8,850 x 1,000,000 x Heat Input x 98.06/32.07. H2SO4 control is 37% for a hot side ESP (H2SO4 from combustion only), 44% for an air preheater, and 60% for wet FGD. The factor 0.0018 (0.18% oxidation) is for the combustion process and 0.0100 (1.00% oxidation) is for the SCR. 100% of the flue gas is controlled by wet FGD.

(j) Organic condensable PM10 is 0.004 lb/MMBtu with FGD based on AP-42, Table 1.1-5, September 1998. 100% of the flue gas is controlled by wet FGD.
(k) Ammonia slip from the SNCR is 2 ppm at 6% oxygen based on EPRI 2007.

Table 4-9: Coronado Generating Station with WFGD, ACC and SCR (Option 5)

Facility	Unit	Description	Max. Heat Input [(a)]		Fuel Sulfur [(b)]	Maximum SO2 Emissions [(c)]		Maximum NOx Emissions [(d)]		Maximum Filterable PM Emissions		Filterable PM_{10}					Condensible PM_{10}			Total PM_{10}	NH3 Slip
												total	coarse	Fine			total	H2SO4	organic		
														fine total	fine soil	EC					
			MMBtu/day	MMBtu/hr	%	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu [(e)]	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Coronado	1	PC, subbituminous coal, dry bottom, wall opposed, advanced combustion controls, hot side ESP, SCR wet FGD, 389 MW	130,753	5,448	0.436	0.080	435.8	0.08	436	0.0260	141.65	94.90 (f)	53.83 (f)	41.08 (f)	39.6 (g)	1.52 (g)	42.26 (h)	20.47 (i)	21.79 (j)	137.16	6.59 (k)
Coronado	2	PC, subbituminous coal, dry bottom, wall opposed, advanced combustion controls, hot side ESP, SCR, wet FGD, 384 MW	117,922	4,913	0.436	0.080	393.1	0.08	393	0.0180	88.44	59.26 (f)	33.61 (f)	25.65 (f)	24.7 (g)	0.95 (g)	38.11 (h)	18.46 (i)	19.65 (j)	97.37	5.94 (k)

(a) Maximum daily/24 hour actual heat input based on Part 75 monitoring data for the 2001 - 2003 period. Unit 1 based on 4/18/01 and Unit 2 based on 2/26/01 data.
(b) Fuel sulfur is average based on PRB coal, 80% Jacobs Ranch, 20% Spring Creek. Average heating value is 8,850 Btu/lb.
(c) Based on maximum heat input rate, fuel sulfur, fuel heating value, 100% conversion of S to SO2 and 95% control by wet FGD.
(d) Based on maximum heat input rate, SCR on Units 1 and 2 to limit emissions to 0.80 lb/MMBtu.
(e) Maximum of 3 Method 17 stack test results for the 2001 to 2003 period.
(f) For a dry bottom boiler with an ESP 67% of filterable PM is PM10 and 29% is fine PM10 (PM2.5) based on AP-42, Table 1.1-6, September 1998.
(g) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(h) Total condensable PM10 is the sum of H2SO4 and organic condensible PM10 emissions.
(i) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants", Electric Power Research Institute, Technical Update, March, 2007. H2SO4, before control, equals 0.0018 x %S/100 x 1/8,850 x 1,000,000 x Heat Input x 98.06/32.07 + 0.0100 x %S/100 x 1/8,850 x 1,000,000 x Heat Input x 98.06/32.07. H2SO4 control is 37% for a hot side ESP (H2SO4 from combustion only), 44% for an air preheater, and 60% for wet FGD. The factor 0.0018 (0.18% oxidation) is for the combustion process and 0.0100 (1.00% oxidation) is for the SCR. 100% of the flue gas is controlled by wet FGD.
(j) Organic condensable PM10 is 0.004 lb/MMBtu with FGD based on AP-42, Table 1.1-5, September 1998. 100% of the flue gas is controlled by wet FGD.
(k) Ammonia slip from the SCR is 2 ppm at 6% oxygen based on EPRI 2007.

5.0 BART Control Options Modeling Analysis

This section provides a summary of the modeled visibility improvement as a result of installing BART control options on Coronado Units 1 and 2.

5.1 Modeled Control Scenarios

Four BART control scenarios were modeled for each meteorological year (2001-2003) and for all 17 Class I areas within 300 km. To summarize the impacts for the nearest Class I areas in several directions from the plant, we report average impacts over the closest 9 areas in some of the summary statistics. Emission rates that were used in modeling the four BART control options are listed in Tables 4-5 through 4-9. These control scenarios are more fully discussed in Section 4 and they are as follows:

Option 2: Full WFGD on Units 1 and 2.

Option 3: WFGD and advanced combustion controls (ACC) on Units 1 and 2.

Option 4a: WFGD, ACC, and SNCR on Units 1 and 2.

Option 4b: WFGD, ACC on Unit 1 and WFGD, ACC, and SCR on Unit 2.

Option 5: WFGD, ACC, and SCR on Units 1 and 2.

5.2 CALPUFF Modeling Results for Control Options

The results of the BART control options modeling are presented in Tables 5-1 and 5-2 and graphically plotted in Figure 5-1. Table 5-1 is an overall summary of the predicted visibility changes due to installation of the candidate BART controls on the CGS units averaged over the nine closest Class I areas and the three modeled years. Table 5-2 shows detailed regional haze impacts of the BART control options for each modeled Class I area and meteorological year. Results for each candidate BART control option are discussed in more detail below.

Option 2: The modeling results indicate that SO_2 controls will provide the largest visibility benefit. The averaged regional haze impacts may improve visibility by about 0.74 delta-dv (relative to the baseline case) with the installation of full WFGD controls. For comparison, a deciview (dv) change of 1.0 is considered the threshold of humanly-perceived changes in visual air quality. These controls result in a SO_2 emission rate that is below the presumptive limit.

Option 3: The first NO_x control option involves the installation of low NO_X burners (LNB). Modeling results show that this combustion modification would produce visibility improvements across the nine parks averaging 0.11 deciviews compared to the NO_x control base case (option 2, which includes SO_2 controls).

Option 4a: The second NO_x control option evaluated selective non-catalytic reduction (SNCR) in addition to LNB. This option produces a NO_x emission rate of 0.224 lb/MMBtu, which is better than the presumptive limit of 0.23 lb/MMBtu. The injection of ammonia (NH_3) or urea ($(NH_2)_2CO$) into the boiler with this operation lowers NO_x emissions, but produces increased stack emissions of ammonia salts and sulfuric acid mist. These additional fine particulate emissions are expected to at least partially offset the expected visibility benefits from NO_x controls. As expected, the three-year average across the eight parks for the visibility impacts was minimally improved (0.08 delta-dv or 2%) over the results for control option 3.

Option 4b: As an alternative to control option 4b, CGS is considering a hybrid approach that results in lower plant-wide NO_x emissions (0.20 lb/MMBtu) over the SNCR option discussed above. As expected, this option shows only a slight benefit (0.03 delta-dv or 1%) from option 4a.

Option 5: This control option evaluated LNB plus SCRs for both units. This option presents slightly additional visibility benefits (0.12 delta-dv or 2%), but at a much higher incremental cost than any of the previous options.

Table 5-1: Regional Haze Benefit of BART Controls

Class I Area	Option	BART Controls	2001	2002	2003	2001-2003 Ave	Benefit of Controls from Baseline, delta-dv	Percent Improvement from Previous Control Option
			8th Highest total dv Δ B_{ext} (1)					
Average of 9 Class I Areas (2)	Option 1	Baseline - Partial FGD	5.82	5.92	5.98	5.91	**0.00**	0
	Option 2	Full WFGD	5.19	5.19	5.06	5.15	**0.76**	13%
	Option 3	WFGD, ACC	5.07	5.08	4.96	5.04	**0.87**	2%
	Option 4a	WFGD, ACC, SNCR	4.98	5.00	4.91	4.96	**0.95**	1%
	Option 4b	WFGD, ACC (U1) & SCR (U2)	4.95	4.96	4.89	4.94	**0.97**	1%
	Option 5	WFGD, ACC, SCR	4.81	4.82	4.79	4.81	**1.10**	3%

(1) Total regional haze impact (CGS contribution plus natural background).

(2) Nine Class I areas are: Grand Canyon, Petrified Forest, Gila, Mount Baldy, Sierra Ancha, Bosque del Apache, San Pedro, Mesa Verde, and Bandelier.

Figure 5-1: 8th Highest Regional Haze Total Impacts Averaged Over 3 Years for Baseline and BART Control Case Emissions

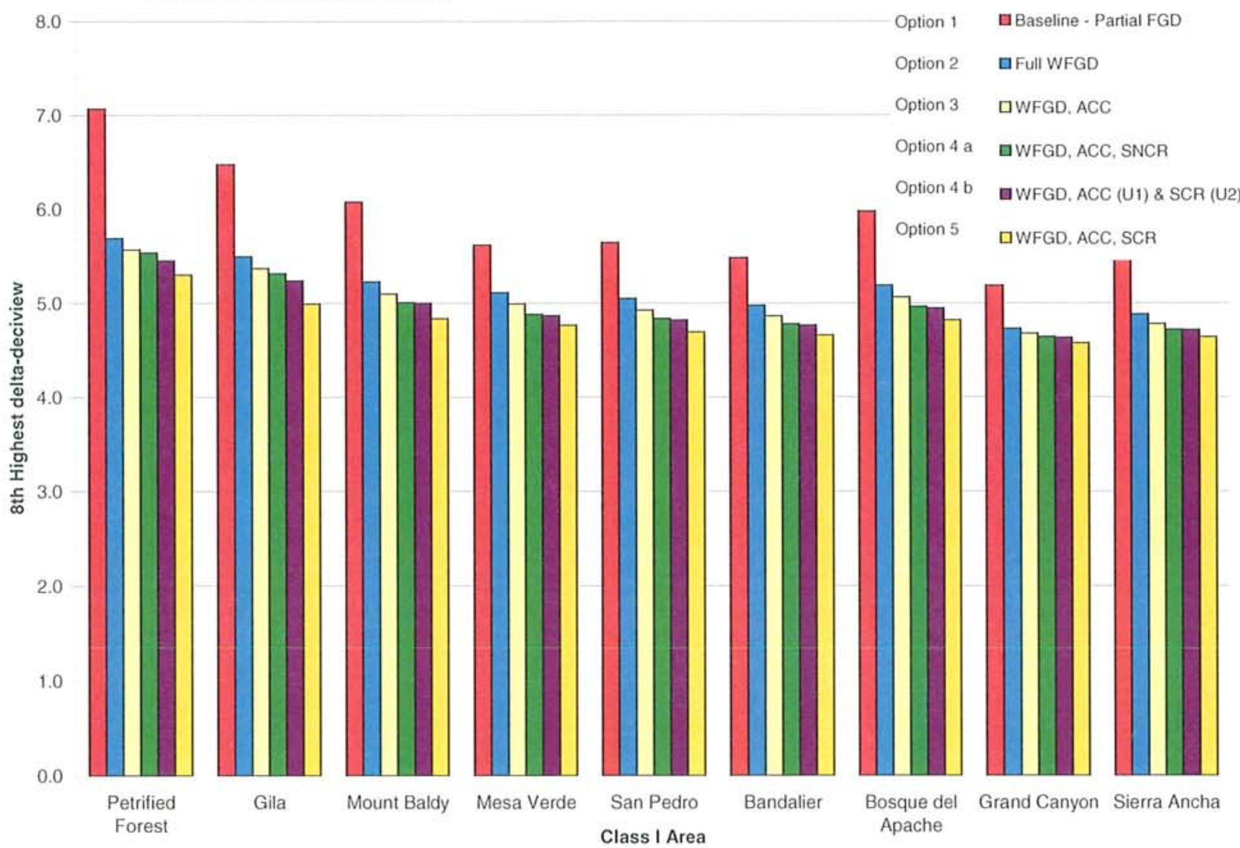


Table 5-2: Regional Haze Results of BART Controls for Each Year and Class I Areas

Class I Area	Case	BART Controls	Annual Average Natural Bkg (dv)	Met Year 2001		Met Year 2002		Met Year 2003		2001-2003 Ave	
				8th Highest dv Δ B_{ext}	8th Highest total dv[1]	8th Highest dv Δ B_{ext}	8th Highest total dv[1]	8th Highest dv Δ B_{ext}	8th Highest total dv[1]	8th Highest Δ dv	8th Highest total dv[1]
Petrified Forest	Option 1	Baseline - Partial FGD	4.41	2.51	6.92	2.78	7.19	2.68	7.09	2.66	7.07
	Option 2	Full WFGD	4.41	1.50	5.91	1.32	5.73	1.02	5.43	1.28	5.69
	Option 3	WFGD, ACC	4.41	1.36	5.77	1.21	5.62	0.91	5.32	1.16	5.57
	Option 4a	WFGD, ACC, SNCR	4.41	1.25	5.66	1.21	5.62	0.92	5.33	1.12	5.53
	Option 4b	WFGD, ACC (U1) & SCR (U2)	4.41	1.19	5.60	1.11	5.52	0.83	5.24	1.04	5.45
	Option 5	WFGD, ACC, SCR	4.41	1.03	5.44	0.93	5.34	0.71	5.12	0.89	5.30
Gila	Option 1	Baseline - Partial FGD	4.39	1.97	6.36	2.00	6.39	2.27	6.66	2.08	6.47
	Option 2	Full WFGD	4.39	1.04	5.43	1.26	5.65	1.01	5.40	1.10	5.49
	Option 3	WFGD, ACC	4.39	0.91	5.30	1.13	5.52	0.90	5.29	0.98	5.37
	Option 4a	WFGD, ACC, SNCR	4.39	0.85	5.24	1.04	5.43	0.89	5.28	0.93	5.32
	Option 4b	WFGD, ACC (U1) & SCR (U2)	4.39	0.78	5.17	0.95	5.34	0.80	5.19	0.84	5.23
	Option 5	WFGD, ACC, SCR	4.39	0.53	4.92	0.65	5.04	0.63	5.02	0.60	4.99
Mount Baldy	Option 1	Baseline - Partial FGD	4.39	1.60	5.99	1.44	5.83	2.01	6.40	1.68	6.07
	Option 2	Full WFGD	4.39	0.80	5.19	0.88	5.27	0.82	5.21	0.84	5.23
	Option 3	WFGD, ACC	4.39	0.68	5.07	0.73	5.12	0.72	5.11	0.71	5.10
	Option 4a	WFGD, ACC, SNCR	4.39	0.57	4.96	0.64	5.03	0.64	5.03	0.61	5.00
	Option 4b	WFGD, ACC (U1) & SCR (U2)	4.39	0.56	4.95	0.61	5.00	0.65	5.04	0.61	5.00
	Option 5	WFGD, ACC, SCR	4.39	0.42	4.81	0.39	4.78	0.53	4.92	0.45	4.84
Mesa Verde	Option 1	Baseline - Partial FGD	4.53	1.06	5.59	1.07	5.60	1.12	5.65	1.09	5.62
	Option 2	Full WFGD	4.53	0.69	5.22	0.53	5.06	0.52	5.05	0.58	5.11
	Option 3	WFGD, ACC	4.53	0.56	5.09	0.43	4.96	0.40	4.93	0.46	4.99
	Option 4a	WFGD, ACC, SNCR	4.53	0.42	4.95	0.33	4.86	0.30	4.83	0.35	4.88
	Option 4b	WFGD, ACC (U1) & SCR (U2)	4.53	0.40	4.93	0.32	4.85	0.29	4.82	0.33	4.86
	Option 5	WFGD, ACC, SCR	4.53	0.22	4.75	0.28	4.81	0.21	4.74	0.23	4.76
San Pedro	Option 1	Baseline - Partial FGD	4.47	0.94	5.41	1.33	5.80	1.25	5.72	1.17	5.64
	Option 2	Full WFGD	4.47	0.47	4.94	0.67	5.14	0.60	5.07	0.58	5.05
	Option 3	WFGD, ACC	4.47	0.37	4.84	0.54	5.01	0.45	4.92	0.45	4.92
	Option 4a	WFGD, ACC, SNCR	4.47	0.29	4.76	0.44	4.91	0.37	4.84	0.36	4.83
	Option 4b	WFGD, ACC (U1) & SCR (U2)	4.47	0.28	4.75	0.42	4.89	0.35	4.82	0.35	4.82
	Option 5	WFGD, ACC, SCR	4.47	0.18	4.65	0.26	4.73	0.23	4.70	0.22	4.69
Bandalier	Option 1	Baseline - Partial FGD	4.46	0.96	5.42	1.07	5.53	1.04	5.50	1.02	5.48
	Option 2	Full WFGD	4.46	0.40	4.86	0.60	5.06	0.54	5.00	0.51	4.97
	Option 3	WFGD, ACC	4.46	0.31	4.77	0.48	4.94	0.42	4.88	0.40	4.86
	Option 4a	WFGD, ACC, SNCR	4.46	0.26	4.72	0.37	4.83	0.32	4.78	0.32	4.78
	Option 4b	WFGD, ACC (U1) & SCR (U2)	4.46	0.26	4.72	0.35	4.81	0.31	4.77	0.30	4.76
	Option 5	WFGD, ACC, SCR	4.46	0.18	4.64	0.21	4.67	0.21	4.67	0.20	4.66
Bosque del Apache	Option 1	Baseline - Partial FGD	4.41	1.51	5.92	1.74	6.15	1.46	5.87	1.57	5.98
	Option 2	Full WFGD	4.41	0.93	5.34	0.75	5.16	0.65	5.06	0.78	5.19
	Option 3	WFGD, ACC	4.41	0.71	5.12	0.68	5.09	0.58	4.99	0.65	5.06
	Option 4a	WFGD, ACC, SNCR	4.41	0.57	4.98	0.57	4.98	0.51	4.92	0.55	4.96
	Option 4b	WFGD, ACC (U1) & SCR (U2)	4.41	0.55	4.96	0.55	4.96	0.50	4.91	0.53	4.94
	Option 5	WFGD, ACC, SCR	4.41	0.40	4.81	0.45	4.86	0.38	4.79	0.41	4.82
Grand Canyon	Option 1	Baseline - Partial FGD	4.39	1.07	5.46	0.77	5.16	0.54	4.93	0.80	5.19
	Option 2	Full WFGD	4.39	0.59	4.98	0.24	4.63	0.19	4.58	0.34	4.73
	Option 3	WFGD, ACC	4.39	0.52	4.91	0.19	4.58	0.15	4.54	0.29	4.68
	Option 4a	WFGD, ACC, SNCR	4.39	0.47	4.86	0.16	4.55	0.13	4.52	0.25	4.64
	Option 4b	WFGD, ACC (U1) & SCR (U2)	4.39	0.44	4.83	0.15	4.54	0.13	4.52	0.24	4.63
	Option 5	WFGD, ACC, SCR	4.39	0.30	4.69	0.13	4.52	0.12	4.51	0.18	4.57
Sierra Ancha	Option 1	Baseline - Partial FGD	4.36	0.97	5.33	1.28	5.64	1.67	6.03	1.31	5.67
	Option 2	Full WFGD	4.36	0.49	4.85	0.65	5.01	0.41	4.77	0.52	4.88
	Option 3	WFGD, ACC	4.36	0.40	4.76	0.51	4.87	0.34	4.70	0.42	4.78
	Option 4a	WFGD, ACC, SNCR	4.36	0.34	4.70	0.42	4.78	0.32	4.68	0.36	4.72
	Option 4b	WFGD, ACC (U1) & SCR (U2)	4.36	0.33	4.69	0.40	4.76	0.32	4.68	0.35	4.71
	Option 5	WFGD, ACC, SCR	4.36	0.24	4.60	0.30	4.66	0.29	4.65	0.28	4.64
Average of 9 Class I Areas	Option 1	Baseline - Partial FGD	4.42	1.40	5.82	1.50	5.92	1.56	5.98	1.49	5.91
	Option 2	Full WFGD	4.42	0.77	5.19	0.77	5.19	0.64	5.06	0.73	5.15
	Option 3	WFGD, ACC	4.42	0.65	5.07	0.65	5.08	0.54	4.96	0.61	5.04
	Option 4a	WFGD, ACC, SNCR	4.42	0.56	4.98	0.57	5.00	0.49	4.91	0.54	4.96
	Option 4b	WFGD, ACC (U1) & SCR (U2)	4.42	0.53	4.95	0.54	4.96	0.46	4.89	0.51	4.94
	Option 5	WFGD, ACC, SCR	4.42	0.39	4.81	0.40	4.82	0.37	4.79	0.38	4.81

(1) Total regional haze impact includes CGS contribution and the annual average natural background.

5.3 Cost of BART Control Options

Table 5-3 summarizes the annualized control cost that is the product of the $/ton removed. The table also shows visibility improvement relative to the baseline scenario and cost effectiveness of SO_2 controls in terms of cost per deciview. These controls result in a SO_2 emission rate that is below the presumptive limit.

Table 5-4 shows visibility improvement and cost effectiveness of NO_x controls combined in terms of cost per deciview. The visibility results in the tables are based on the average of the three years and the nine closest modeled Class I areas. The visibility improvements and associated costs are presented relative to Option 2 (NO_x control baseline), rather than the overall baseline case because only NO_x emissions change from Option 2 to Option 3, 4, and 5. SO_2 and PM_{10} emissions remain unchanged.

Figure 5-2 shows a graph of visibility improvements as a function of the cost for Options 3, 4, and 5. BART options associated with incremental improvements in visibility relative to a previous control option are connected with a blue line. The NO_x controls all result in generally small visibility benefits.

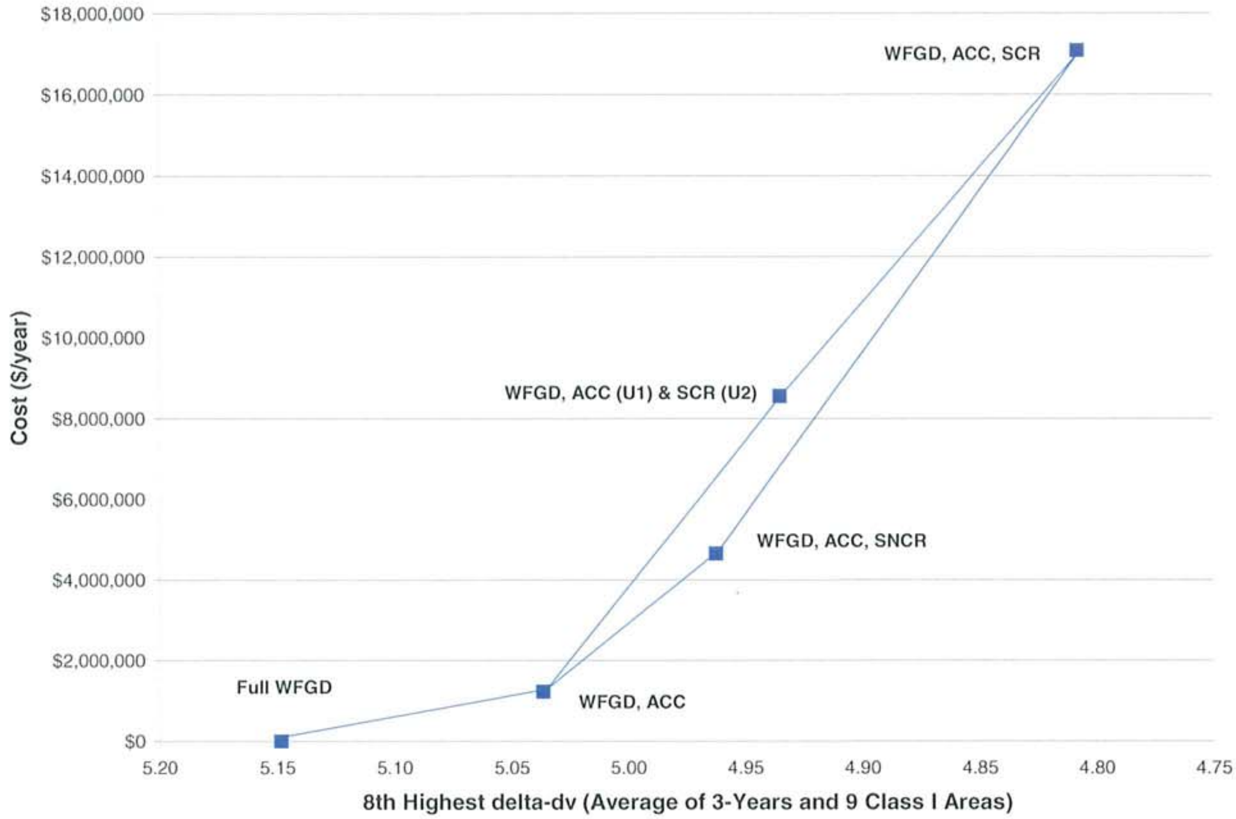
Table 5-3: Annual Costs of SO_2 Controls vs. Visibility Improvements (Average of the Nine Class I Areas)

Option	BART Controls	Annualized Cost for SO_2 Controls ($/year)	8th Highest Average over 3-Year and 9 Class I Area (dv)	Incremental Reduction Relative to Option 1 (dv)	Incremental Cost Effectiveness Relative to Option 1 ($/dv)
Option 1	Baseline	$0	5.91	0.000	$0
Option 2	WFGD	$44,353,330	5.17	0.741	$59,847,072

Table 5-4: Annual Costs of NO_x Controls vs. Visibility Improvements (Average of the Nine Class I Areas)

Option	BART Controls	Annualized Cost for NO_x Controls ($/year)	8th Highest Average over 3-Year and 9 Class I Area (dv)	Incremental Reduction Relative to Option 2 (dv)	Incremental Cost Effectiveness Relative to Option 2 ($/dv)
Option 1	Baseline	$0	5.91	0.000	$0
Option 2	WFGD	$0	5.17	0.000	$0
Option 3	WFGD and ACC on Units 1-2	$1,227,070	5.05	0.114	$10,756,782
Option 4a	WFGD and ACC/ SNCR on Units 1-2	$4,654,140	4.97	0.194	$24,017,924
Option 4b	WFGD and ACC on Unit 1 & WFGD and ACC/SCR on Unit 2	$8,556,810	4.95	0.221	$38,783,594
Option 5	WFGD and ACC/SCR on Units 1-2	$17,086,550	4.82	0.343	$49,745,185

Figure 5-2: Annual Cost of NO_x Controls vs. Visibility Improvements



6.0 BART Recommendations

ENSR and SRP conclude that full WFGD on both units (control option 2) is the Best Available Retrofit Technology alternative for the Coronado Generating Station based on the expected incremental visibility improvement, the cost of compliance, energy impacts, and other non-air quality environmental impacts. This control option results in a SO_2 emission rate of 0.08 lb/MMBtu, which is well below the presumptive limit of 0.15 lb/MMBtu. NO_x controls are not recommended as part of the BART alternative due to the excessive cost associated with minimal visibility improvement.

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Appendix A

CALMET/CALPUFF Processing Refinements

CALMET meteorological inputs, technical options, and processing steps used in this BART analysis were identical to those specified in the WRAP common BART modeling protocol with the exception of R1, R2, RMAX1, and the model version. These differences are illustrated in Figures A-1 through A-3, are listed in Table A-1, and are further discussed below. Figure A-1 shows the CALMET/CALPUFF modeling domain established by the WRAP for Arizona.

Figure A-1: WRAP CALMET Modeling Domain for Arizona

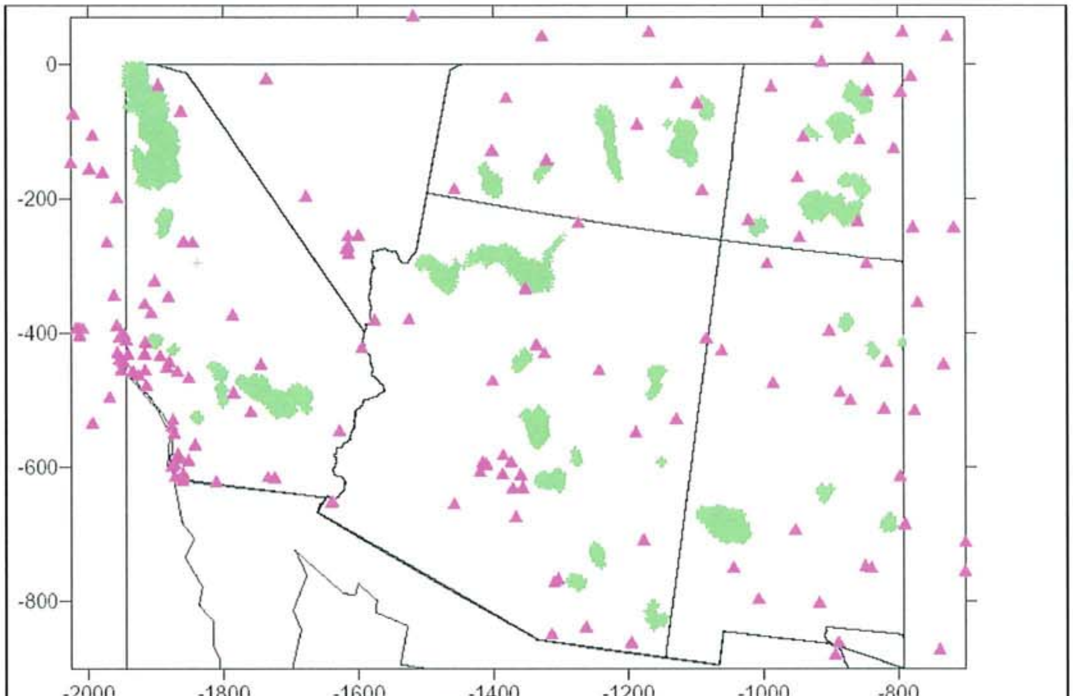


Figure 3-1a. Proposed CALMET/CALPUFF modeling domain, Class I area receptors (green) and observed surface meteorological sites for Arizona.

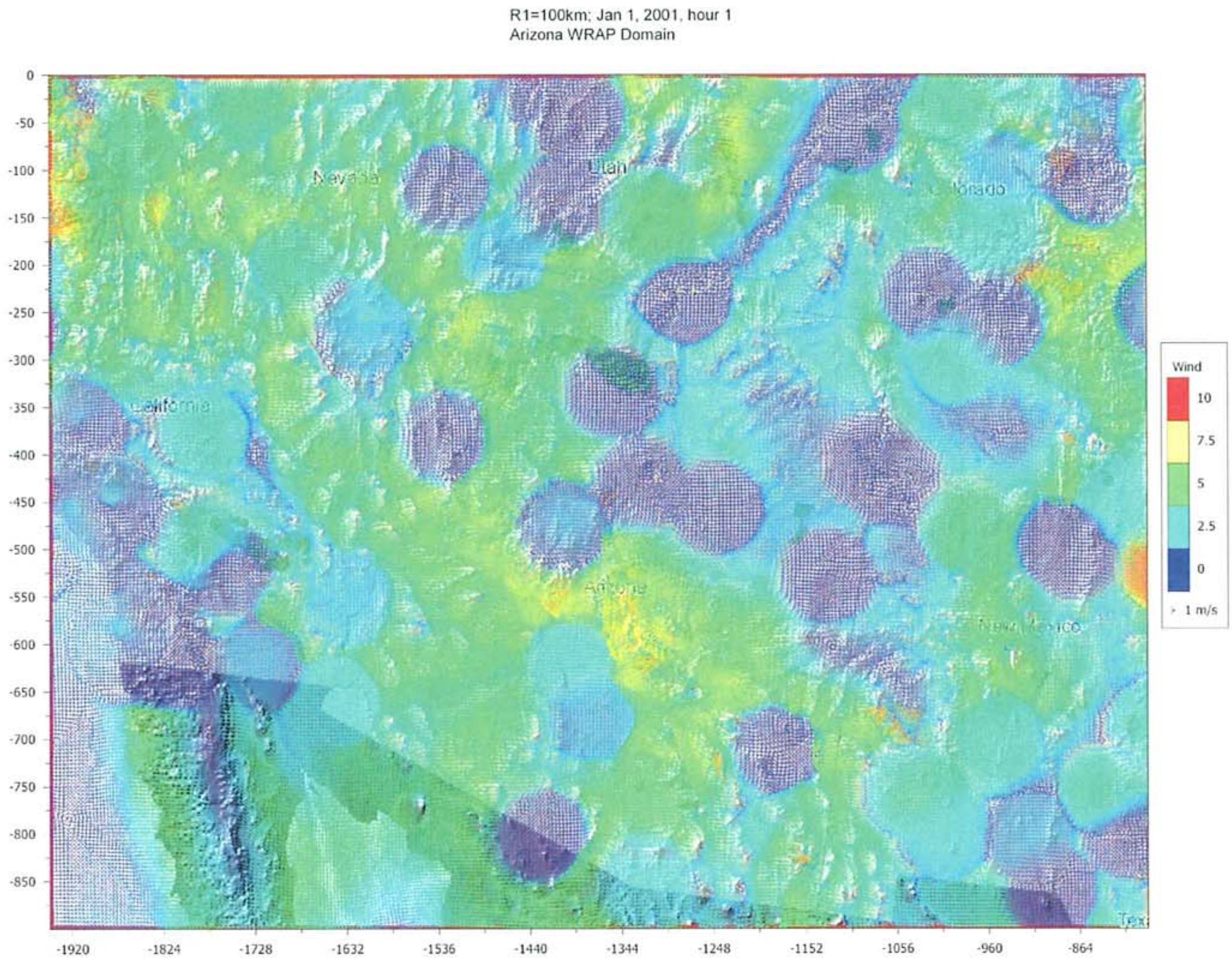
Enhancements to the WRAP CALMET Database

ENSR made two refinements to the 4-km Arizona CALMET WRAP database. They are discussed in more detail below.

1. Weighting Factors for Modifying the Step 1 Wind Field

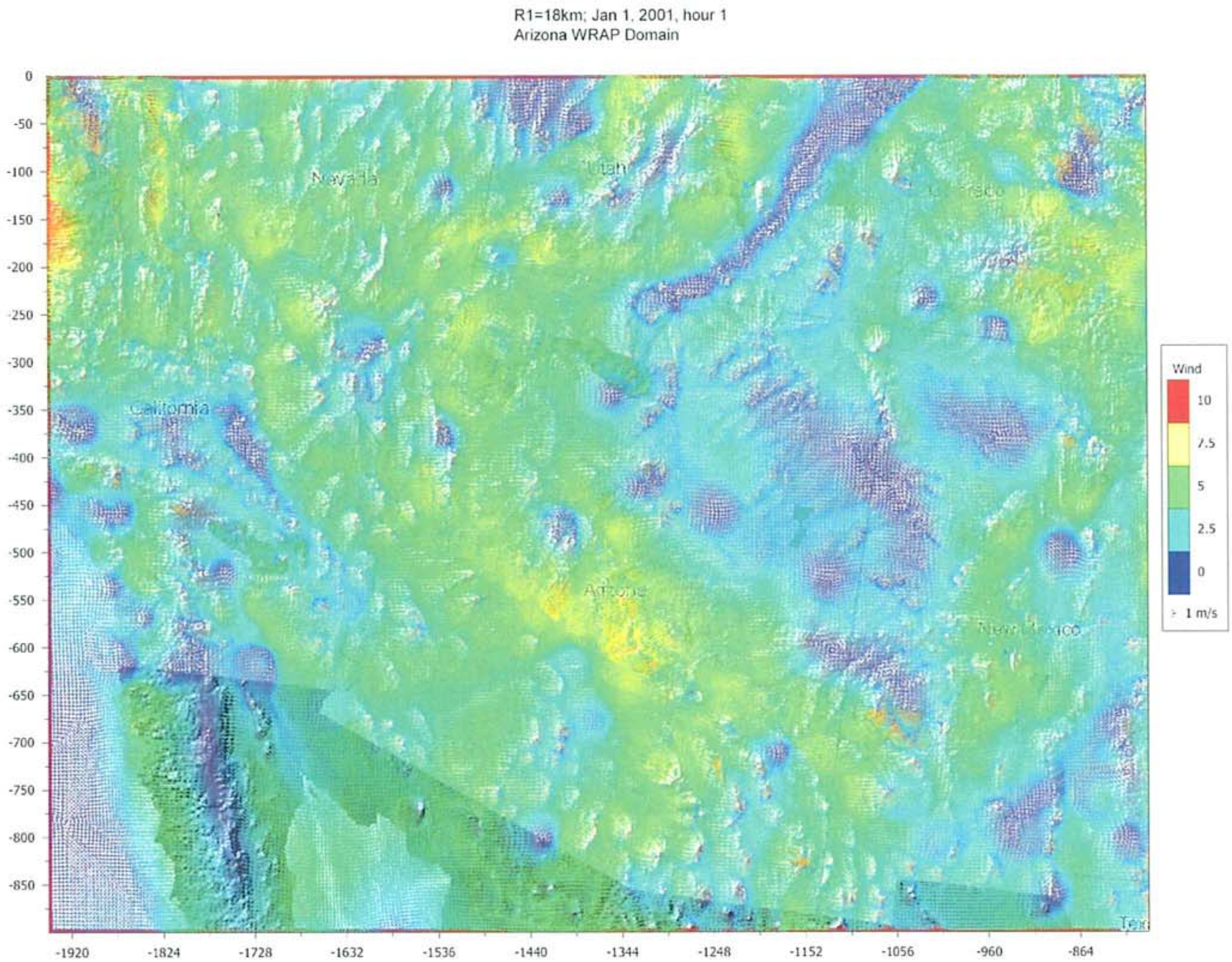
The 4-km Arizona CALMET database has been produced by ENSR using the downloaded CALMET inputs from the WRAP website http://pah.cert.ucr.edu/aqm/308/bart/calpuff/calmet_inputs/az/. ENSR initially ran CALMET with the setting suggested in the WRAP BART modeling protocol. As part of ENSR's internal quality assurance procedure, we displayed and examined the 4-km Arizona WRAP CALMET wind fields in the visualization software CALDESK. Figure A-2 graphically shows wind fields with the WRAP settings for a typical hour. Arrows represent wind direction and wind speed for that hour at 10 meter height. Circular areas in these figures with common winds and abrupt transitions at the edge of the circles indicate a radius of influence of surface stations, R1, which was set to 100 km, as suggested in the WRAP BART protocol. The R1 value was coupled with an R1MAX of 50 km so that the influence of the surface stations is established out to 50 km and then it abruptly ends beyond that distance. Setting R1 and R1MAX to such high values is not recommended by the model developer and Federal Land Managers, especially with MM5 data resolution of 36 km with areas of complex terrain. Typically, R1 is set to a fairly small value, generally not exceeding half of the MM5 data resolution (18 km), according to recent guidance on multiple PSD projects involving CALPUFF modeling in the WRAP region from John Notar of the National Park Service (personal correspondence between John Notar of the NPS and Bob Paine of ENSR). A large R1 value results in wind fields surrounding surface stations that overwrite the MM5 wind fields, which do have terrain influences incorporated into them. In many instances, the extended extrapolation of the surface station data with an abrupt transition at 50 km produces opposing wind directions in adjacent grid squares at the 50 km distance.

Figure A-2: CALMET Windfields with WRAP Settings



To avoid this problematic wind field result, ENSR used a smaller R1 value of 18 km and R1MAX value of 30 km. The resulting wind fields for the same hour and height are depicted in Figure A-3. The adjusted R1 and R1MAX values blend the surface observations into the MM5 observations much better, creating a more uniform wind field throughout the domain. Therefore, ENSR used the smaller R1 and R1MAX values to be more consistent with FLM guidance and due to better performance in the wind field depiction associated with the smaller values.

Figure A-3: CALMET Windfields with ENSR Settings



2. Official EPA CALPUFF Version

When rerunning CALMET, ENSR used the latest EPA-approved version of the CALPUFF modeling system CALMET (Version 5.8, Level 070623) instead of Version 6.211, which was used by WRAP, available at http://www.src.com/calpuff/download/download.htm#EPA_VERSION. CALPUFF version 6 is basically equivalent to the VISTAS version of CALPUFF, Version 5.756. At the time of the WRAP BART protocol development process, the VISTAS version and Version 6 were generally acknowledged to be the latest and best versions available. However, EPA's deliberate attempt to review the nature of the changes between the previous official version (5.711a) and the VISTAS version (and Version 6) uncovered a number of issues that were of concern to EPA. These issues were discussed in a presentation by Mr. Dennis Atkinson of EPA's Office of Air Quality Planning and Standards at the 2007 Annual Modelers Workshop (see http://www.cleanairinfo.com/regionalstatelocalmodelingworkshop/agenda.htm; "CALPUFF_status_update.pdf"). The basic issues of concern with the VISTAS version (and equivalent Version 6) are as follows:

- There were unexplained and unresolved large differences between Versions 5.711a and 5.756.
- Incomplete model documentation has been a problem with the last model users guides now 7 years old.

- The VISTAS code changes went beyond just fixing coding errors in Version 5.711a, contrary to what TRC, the model developer, asserted.
- EPA's annotated in-code documentation identified several categories of changes, including:
  - Bug fixes;
  - Non-optional technical enhancements;
  - Optional technical enhancements;
  - Non-technical enhancements;
  - Enhancement adjustments; and
  - Coordinate conversion fixes.
- EPA had serious technical concerns regarding how the optional technical enhancements (e.g., for mixing height) were implemented in CALMET.

The new approved Version 5.8 disables some of the VISTAS "optional technical enhancements". Therefore, use of Version 5.756 or Version 6 of CALPUFF would appear to be inconsistent with the current EPA approved version. Default values of technical options specified in the newly approved version are adopted by ENSR.

Table A-1: CALMET Options Comparison

Variable	Description	WRAP Value	ENSR Value
RMAX1	Maximum radius of influence over land in the surface layer	50	30
R1	Relative weighting of the first-guess field and observations in the surface layer	100	18
R2	Relative weighting of the first-guess field and observations in the layers aloft	200	20

3. Background Ammonia Values

The POSTUTIL utility program was used to repartition HNO_3 and NO_3 using appropriate ammonia background values that were recently approved by the Federal Land Managers for the nearby Toquop Energy Project (TEP) PSD permit application (northwest of Mesquite, Nevada) and for the Desert Rock Energy Facility PSD permit application (Navajo Nation, NM). These background ammonia values are based upon direct measurements (some in the Grand Canyon) as well as seasonal considerations. In general, it is important to note that the likely over-prediction by CALPUFF of nitrates in winter as noted by Morris et al. (2005) can be partially addressed by using a monthly variation of background ammonia concentrations. The default value of 1.0 ppb for arid lands as referenced in the IWAQM Phase 2 document is valid at 20 deg C, but the same document cites a strong dependence with ambient temperature, with variations of a factor of 3-4. This same dependence is seen at the CASTNET monitor at Bondville, Illinois (see page 5 at http://www.ladco.org/tech/monitoring/docs_gifs/NH3proposal-revised3.pdf). In addition, a study of light-affecting particles in SW Wyoming indicated that nitrates were over-predicted by a factor of 3 for a constant ammonia concentration of 1.0 ppb, and by a factor of 2 for an ammonia concentration of 0.5 ppb (see slide 57 at http://www.air.dnr.state.ga.us/airpermit/psd/dockets/longleaf/facilitydocs/050711_CALPUFF_eval.pdf). Since there are no large sources of ammonia due to agricultural activities near the Class I areas being analyzed (see Figure 1 in http://www.ladco.org/tech/monitoring/docs_gifs/ammonia_role_midwest_haze.pdf), it is appropriate to introduce a monthly varying ammonia background concentration to the CALPUFF modeling. Table A-2 lists the values that were used in CALPUFF and have been agreed to by the National Park Service for TEP and DREF and other PSD submittals. Note that these values were used only for modeling the baseline and BART Options 1 and 2 emissions. A refined set of ammonia background values was developed for modeling BART Options 3, 4, and 5, and is further discussed in Appendix B. These proposed values are consistent with the CMAQ modeled values provided in Appendix A of www.vistas-sesarm.org/BART/CMAQ2002_evaluation_Dec31_2005.pdf.

Table A-2: Ambient Ammonia Background Concentration

Month	Ambient Ammonia Background Concentration (ppb)
January – February	0.2
March – April	0.5
May – September	1.0
October – November	0.5
December	0.2

Appendix B

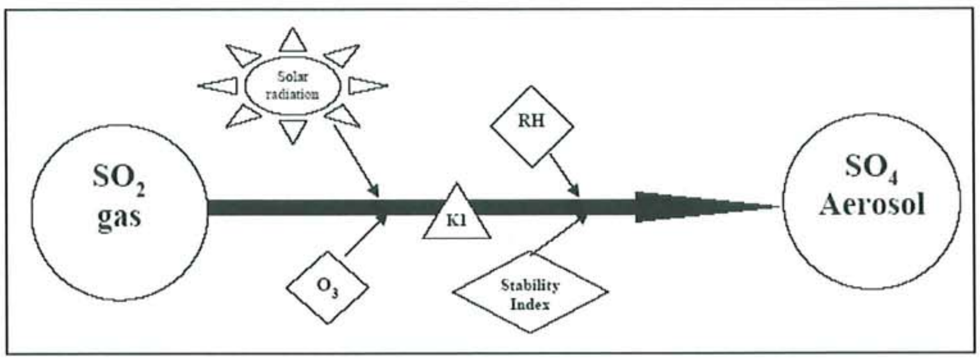
Factors Influencing NO_x Emissions Effects on Visibility

Secondary pollutants such as nitrates and sulfates are significant contributors to the visibility extinction in Class I areas. The CALPUFF model was used to determine the effect of these pollutants on Class I areas associated with BART control options. CALPUFF uses the EPA-approved MESOPUFF II chemical reaction mechanism to convert SO_2 and NO_x emissions to secondary sulfates and nitrates. The discussion below describes how the secondary pollutants are formed and the factors affecting their formation.

Formation of Sulfates

The rate of transformation of gaseous SO_2 to ammonium sulfate $(NH_4)_2SO_4$ aerosol is dependent upon solar radiation, ambient ozone concentration, atmospheric stability, and relative humidity, as shown in Figure B-1 (taken from the CALPUFF users guide, 2000). Homogeneous gas phase reaction is the dominant SO_2 oxidation pathway during clear, dry conditions (Calvert et al., 1978). CALPUFF assumes that the sulfate reacts preferentially with ammonia (NH_3) to form ammonium sulfate and that any remaining ammonia is available to form ammonium nitrate (NH_4NO_3).

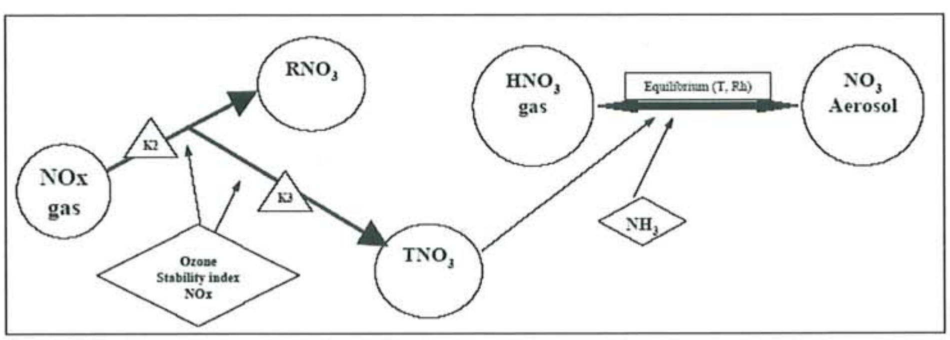
Figure B-1: MESOPUFF II SO_2 Oxidation



Formation of Nitrates

The oxidation of NO_x to nitric acid (HNO_3) depends on the NO_x concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure B-2 (from the CALPUFF users guide).

Figure B-2 MESOPUFF II NO_x Oxidation

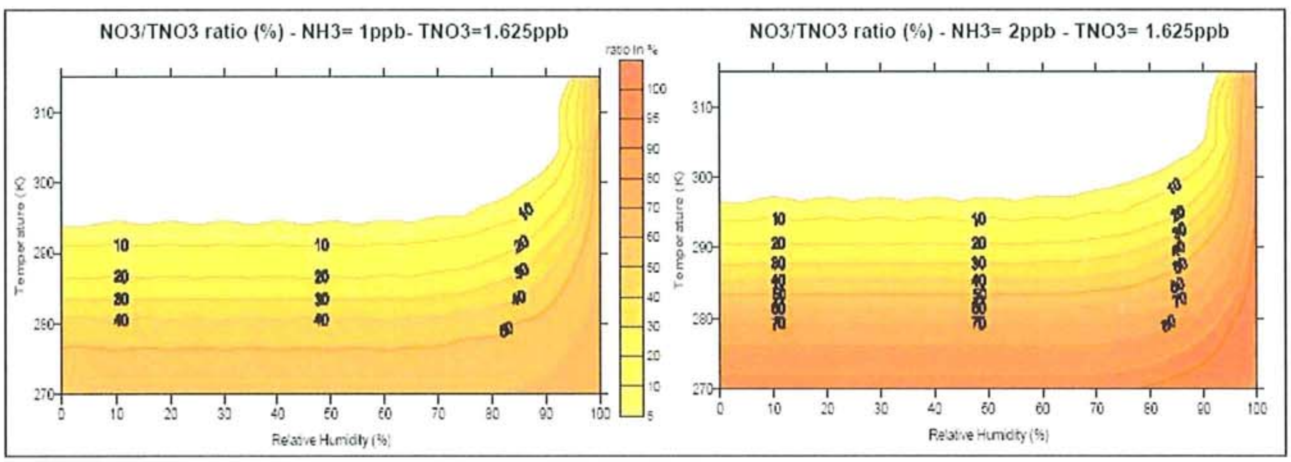


In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into each species according to the equilibrium relationship between gaseous HNO_3 and NO_3 aerosol. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate strongly depends on availability of NH_3 to form ammonium nitrate, as shown in Figure B-3 (from CALPUFF courses given by TRC). The figure on the left shows that with 1 ppb of available ammonia and fixed temperature and humidity (for example, 275 deg K and 80% humidity), only 50% of the total nitrate forms particulate matter. When the available ammonia is increased to 2 ppb, as shown in the figure on the right, as much as 80% of the total nitrate is in the particulate form. Figure B-3 also shows that colder temperatures and higher relative humidity significantly favor nitrate formation and vice versa. A summary of the conditions affecting nitrate formation are listed below:

- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed.
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium nitrate is formed.
- Sulfate preferentially scavenges ammonia over nitrates. In areas where sulfate concentrations are high and ambient ammonia concentrations are low, there is less ammonia available to react with nitrate, and therefore less ammonium nitrate is formed.

For this BART analysis, the effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various NO_x control options. For parts of the country where sulfate concentrations are relatively high and ammonia emissions are quite low, the atmosphere is likely to be in an ammonia-limited regime relative to nitrate formation. Therefore, NO_x emission controls are not very effective in improving regional haze, especially if there is very little ambient ammonia available.

Figure B-3: NO_3/HNO_3 Equilibrium Dependency on Temperature and Humidity



Refined Ambient Ammonia Background Concentrations

As discussed above, the formation of nitrate is highly sensitive to the availability of ammonia to form ammonium nitrate. Ammonium nitrate is a visibility-degrading pollutant. For the purpose of evaluating NO_x emission control options, the ambient ammonia background concentrations were refined to factor in excess ammonia emission increases associated with SNCR and SCR operations. Moreover, the installation of SCR creates primary sulfate emissions (H_2SO_4) that are also visibility-degrading.

Excess ammonia emissions associated with SNCR and SCR operations were modeled in CALPUFF to determine the maximum 24-hour ammonia concentration at the Petrified Forest National Park as well as the other Class I areas. Predicted excess ammonia concentrations associated with SNCR and SCR operation are listed in Table B-1. For simplicity in post-processing, the predicted values of additional ambient ammonia concentrations were allocated to several values representing typical values covering the range of the CALPUFF predictions.

The resultant ammonia concentrations for the peak daily impact at the Class I areas (corresponding to a peak regional haze event) produced in μg/m^3 were converted to ppb and then added to the monthly ambient background values, as shown in Table B-1. Then POSTUTIL program (CALPUFF post-processor) was used to re-compute regional haze impacts with the adjusted ammonia background at each Class I area.

Table B-1: Refined Ambient Ammonia Background Concentration

Note that color-coded NH_3 values were averaged and then added to the monthly ambient NH_3 concentrations

Class I Area	Option 4a	Option 4b	Option 5
	SNCR on Units 1&2	SCR on Unit 2	SCR on Units 1&2
	ppb	ppb	ppb
These NH_3 values were predicted at each Class I area			
Bandalier NM	0.01	0.00	0.00
Bosque del Apache	0.02	0.00	0.01
Chiricahua NM	0.01	0.00	0.00
Chiricahua W	0.01	0.00	0.00
Galiuro W	0.01	0.00	0.00
Gila W	0.04	0.01	0.02
Grand Canyon NP	0.01	0.00	0.01
Mazatzal W	0.02	0.00	0.01
Mesa Verde NP	0.01	0.00	0.00
Mount Baldy W	0.03	0.00	0.01
Petrified Forest NP	0.08	0.02	0.03
Pine Mountain W	0.01	0.00	0.01
Saguaro W&NP	0.01	0.00	0.00
San Pedro Parks W	0.01	0.00	0.01
Sierra Ancha W	0.02	0.00	0.01
Superstition W	0.01	0.00	0.00
Sycamore Canyon W	0.01	0.00	0.00
Color-coded NH_3 values were averaged and then added to the monthly ambient NH_3 concentrations			
Gila W	0.06	0.01	0.02
Petrified Forest NP			
Bandalier NM			
Bosque del Apache			
Chiricahua NM			
Chiricahua W			
Galiuro W			
Grand Canyon NP			
Mazatzal W			
Mesa Verde NP	0.01	-	0.01
Mount Baldy W			
Pine Mountain W			
Saguaro W&NP			
San Pedro Parks W			
Sierra Ancha W			
Superstition W			
Sycamore Canyon W			
Excess NH_3 Emission Rate (lb/hr)	31.33	5.94	12.53

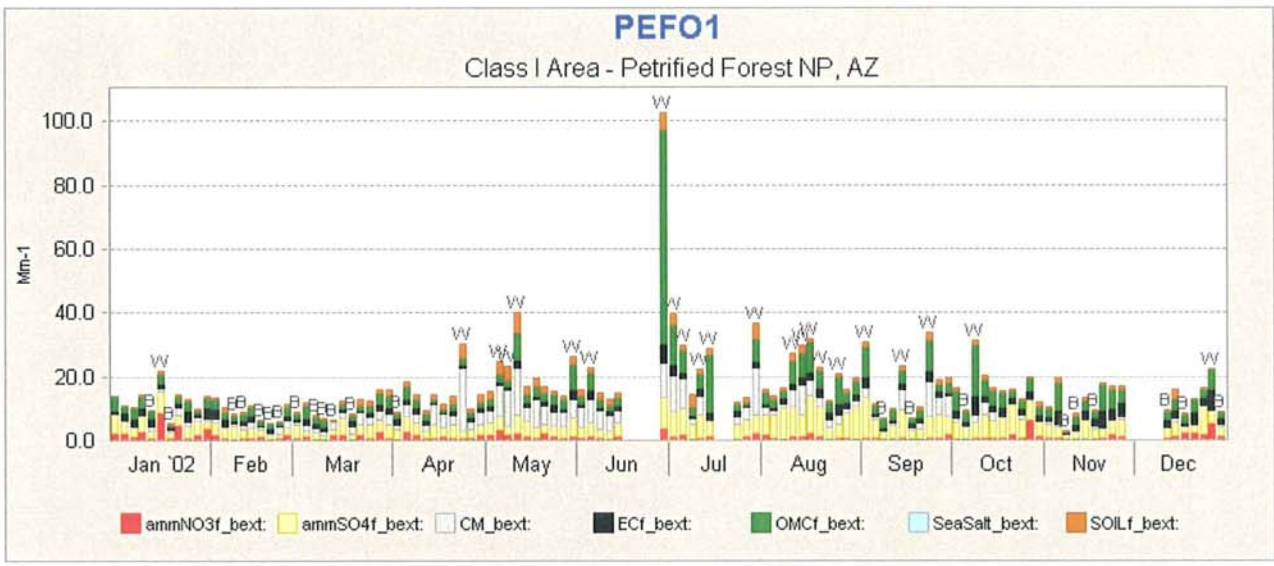
Appendix C

Review of Data from the IMPROVE Monitoring Network

The Visibility Information Exchange Web System (VIEWS) is an online database of air quality data designed to understand the effects of air pollution on visibility and to support the Regional Haze Rule enacted by the USEPA to reduce regional haze and improve visibility in national parks and wilderness areas (http://vista.cira.colostate.edu/views/).

The VIEWS database contains an annual summary of Class I area-specific charts of visibility-degrading pollutants. Bar charts depict the seasonal pattern of pollution and pie charts show the average composition for the 20% best and 20% worst pollution days. An example of a bar and pie chart for Petrified Forest National Park is shown in Figure C-1. Bar and pie charts for the closest nine Class I areas for year 2002 are presented in this appendix. Year 2002 was chosen because it is the year for which WRAP has established the baseline emissions inventory.

Figure C-1: Plot of Measured Visibility-Degrading Pollutants in Petrified Forest NP, Year 2002



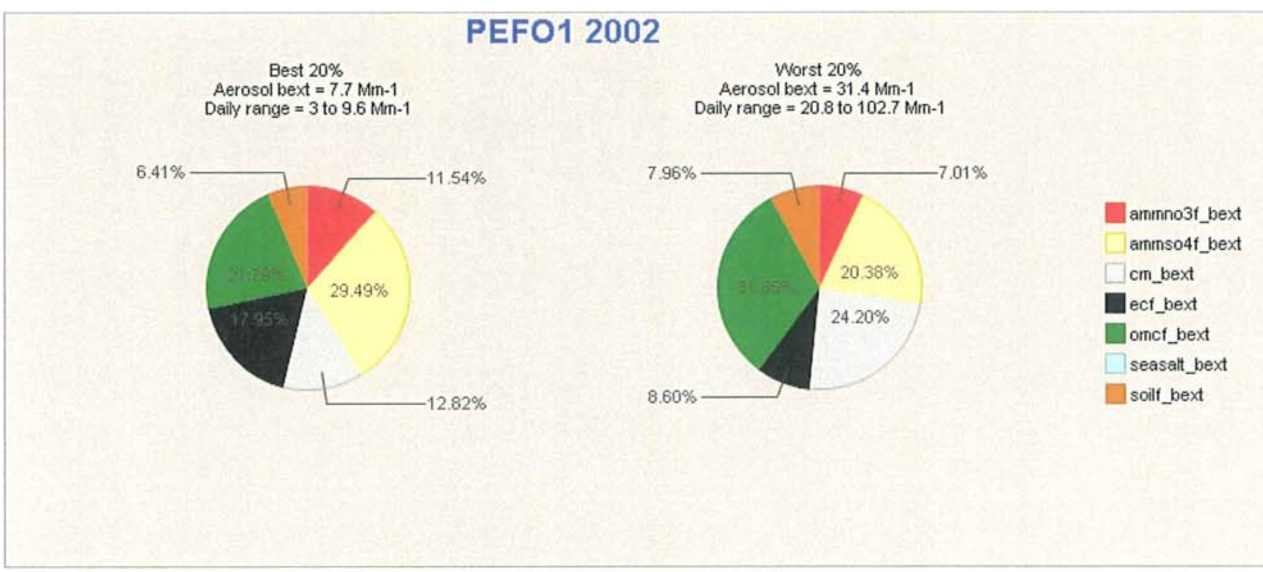
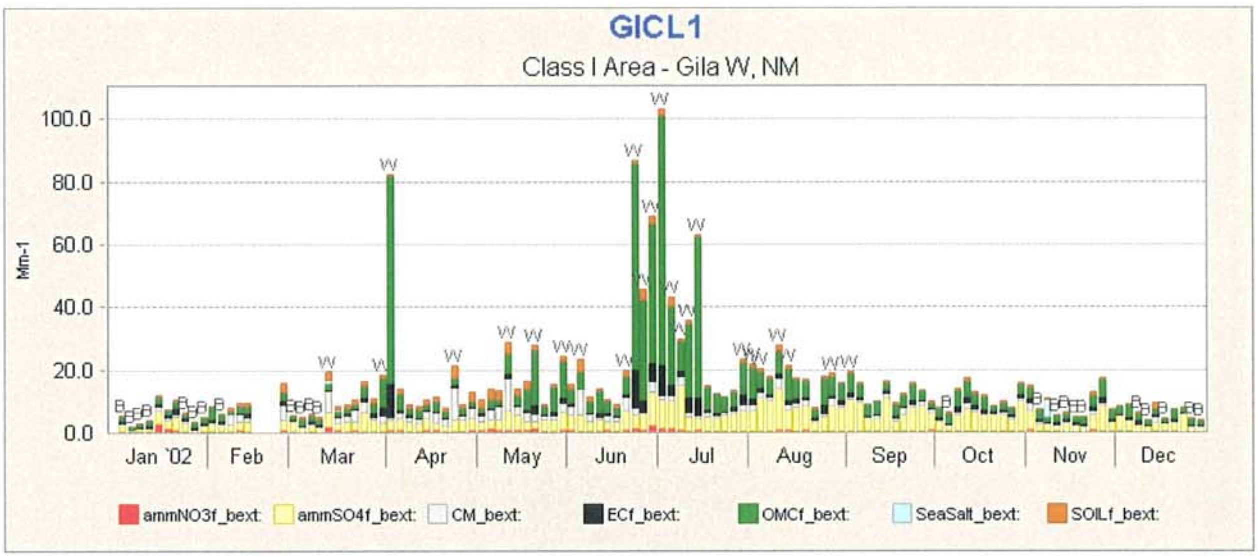


Figure C-1 is typical of the composition of visibility-affecting particulate that is shown in the plots for other Class I areas provided below. The figure shows that, for 2002, organic aerosols (probably associated with forest fires for peak impacts) contributed about 32% and coarse particulate matter (due to wind-blown dust) contributed about 24% on the worst 20% days to the visibility extinction at Petrified Forest National Park. On the other hand, ammonium nitrate contributed only 7% and ammonium sulfate contributed 21% to the visibility extinction at the park.

It is important to note that the nitrate impacts were virtually nonexistent during the warm period of April-October (during the period of heaviest park visitation), while sulfate impacts were generally present throughout the entire year. In fact, very few of the worst 20% days (marked with a "W") have substantial nitrate contributions. Therefore, reduction of NO_x emissions would do very little to improve the visibility for this set of days that is specifically targeted by the Regional Haze Rule. On the other hand, several of the 20% worst days have some sulfate component, which would be increased by certain NO_x controls, such as SCR, due to the collateral increases in sulfate and ammonia emissions associated with these controls. This overall pattern is generally present in all of the nearby Class I areas, as can be seen in the composition plots shown below.

Figure C-2: Plot of Measured Visibility-Degrading Pollutants in Gila W, Year 2002



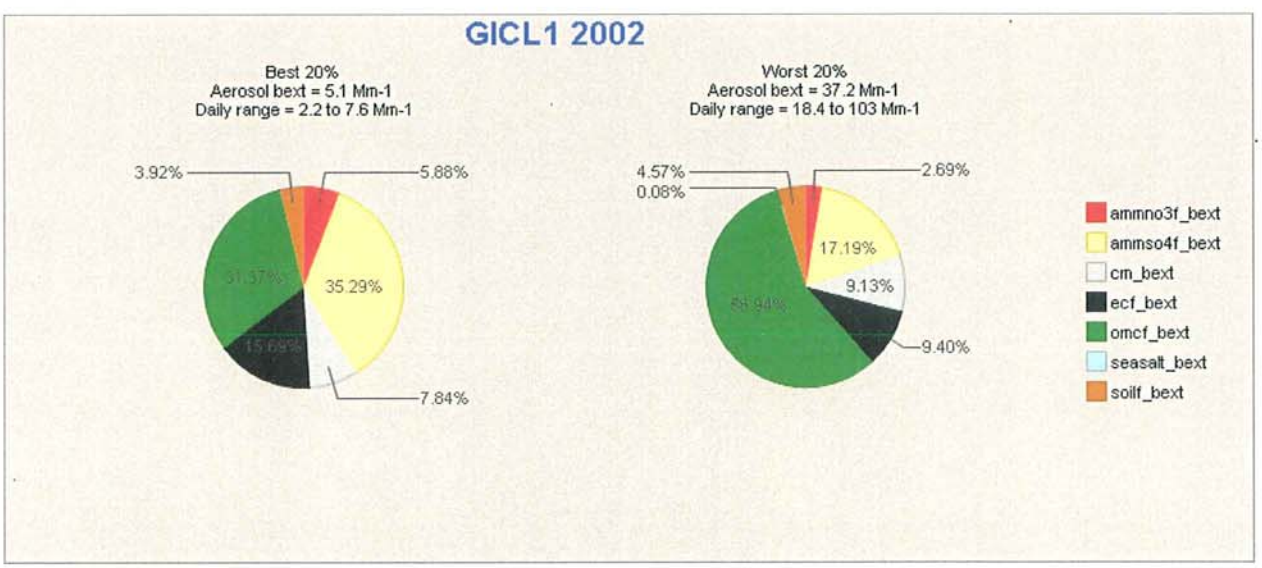
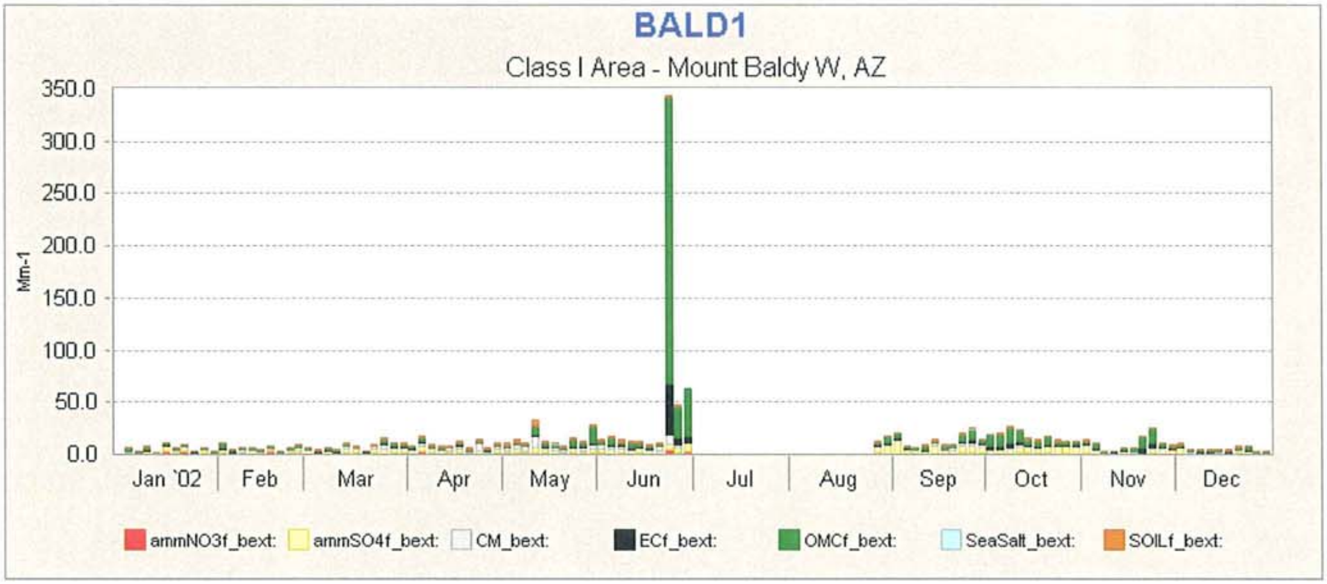
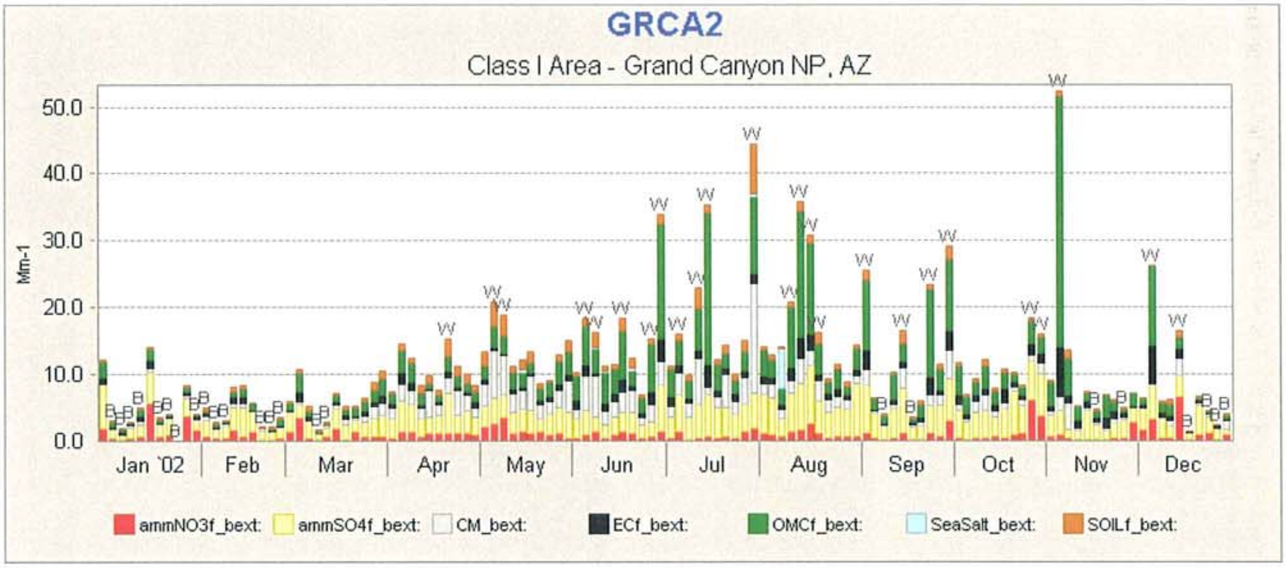


Figure C-3: Plot of Measured Visibility-Degrading Pollutants in Mount Baldy W, Year 2002



Pie chart for Mount Baldy is not available.

Figure C-4: Plot of Measured Visibility-Degrading Pollutants in Grand Canyon NP, Year 2002



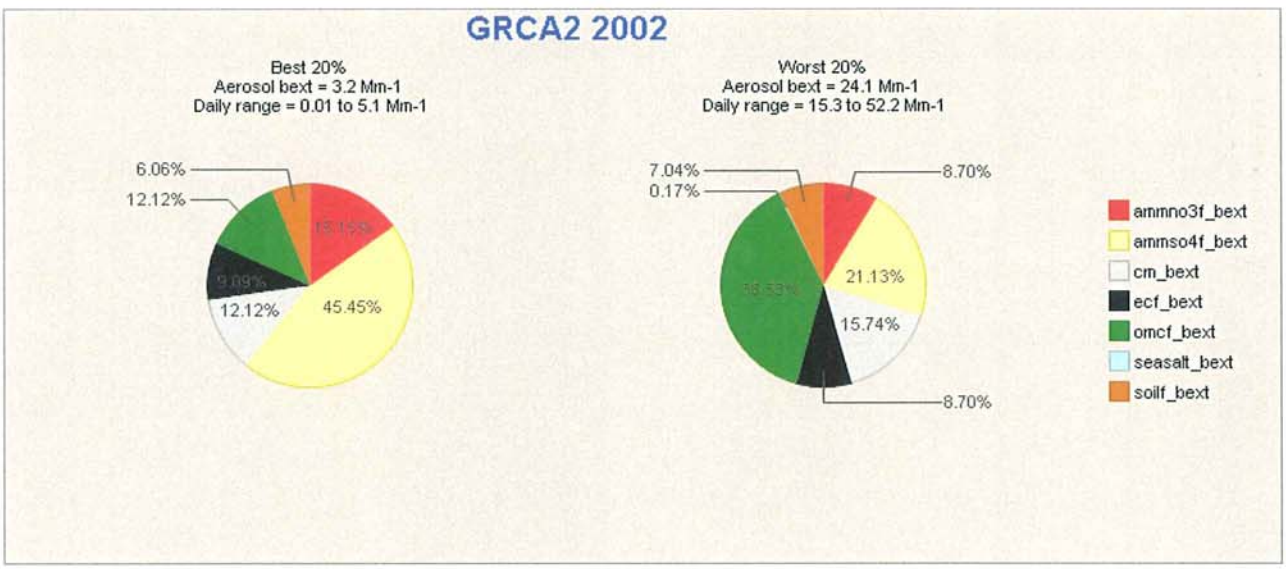
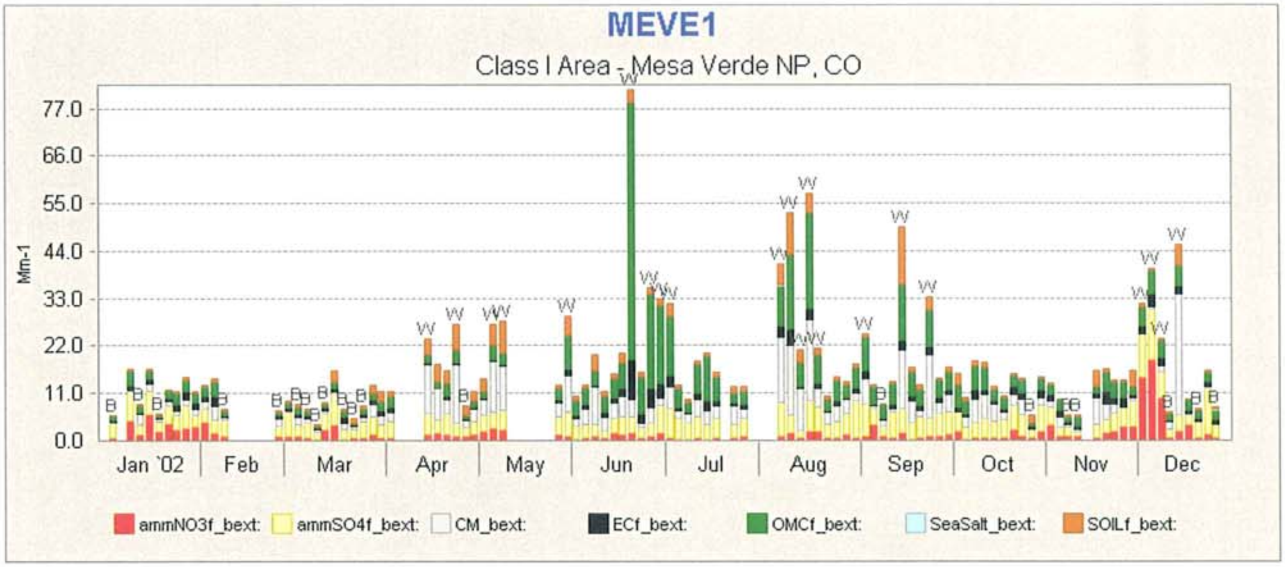


Figure C-6 Plot of Measured Visibility-Degrading Pollutants in Mesa Verde NP, Year 2002



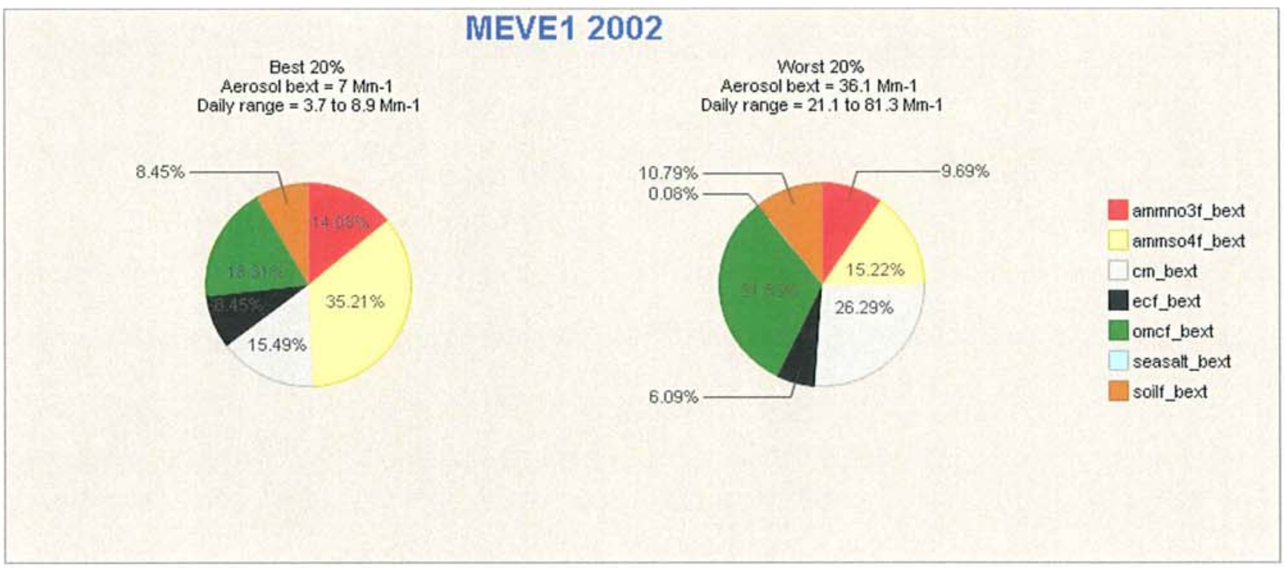
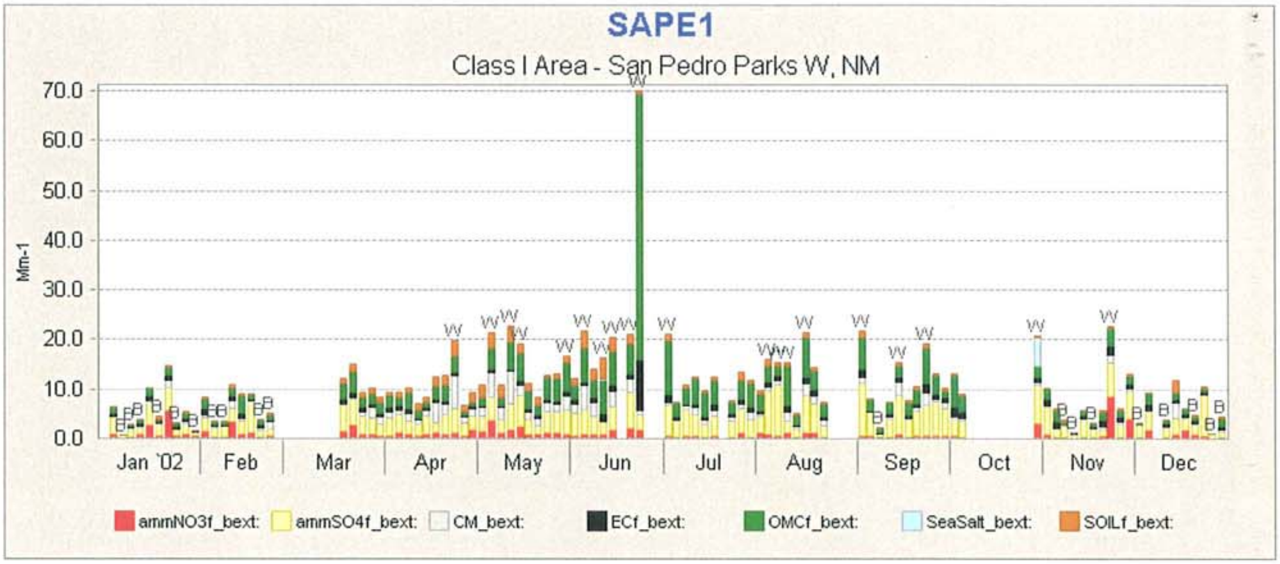


Figure C-7: Plot of Measured Visibility-Degrading Pollutants in San Pedro W, Year 2002



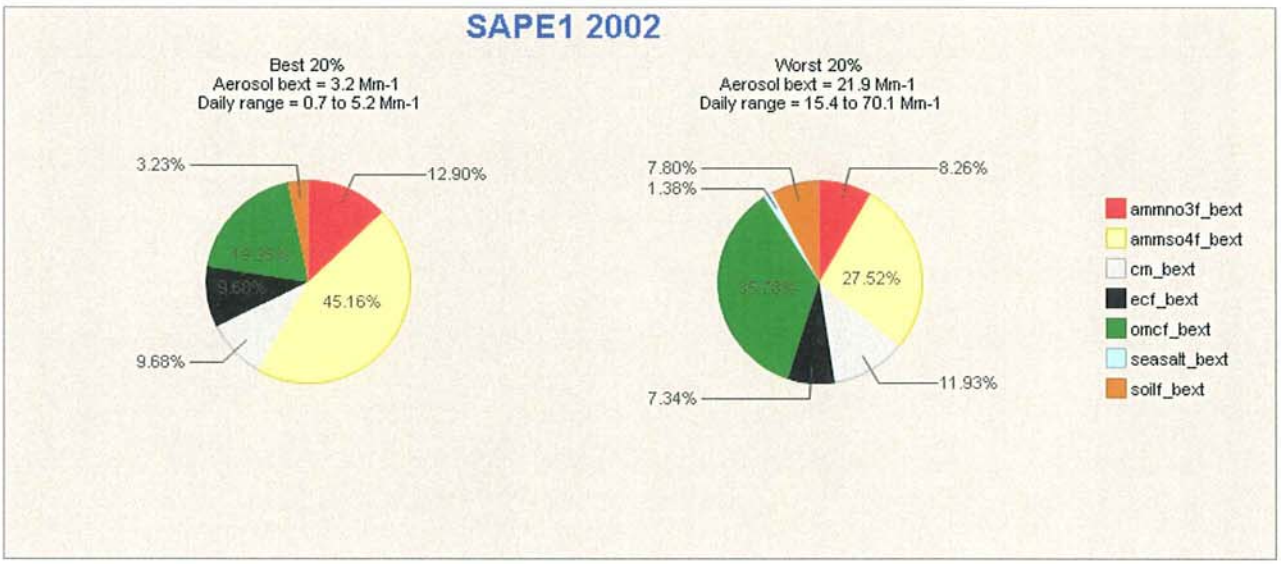
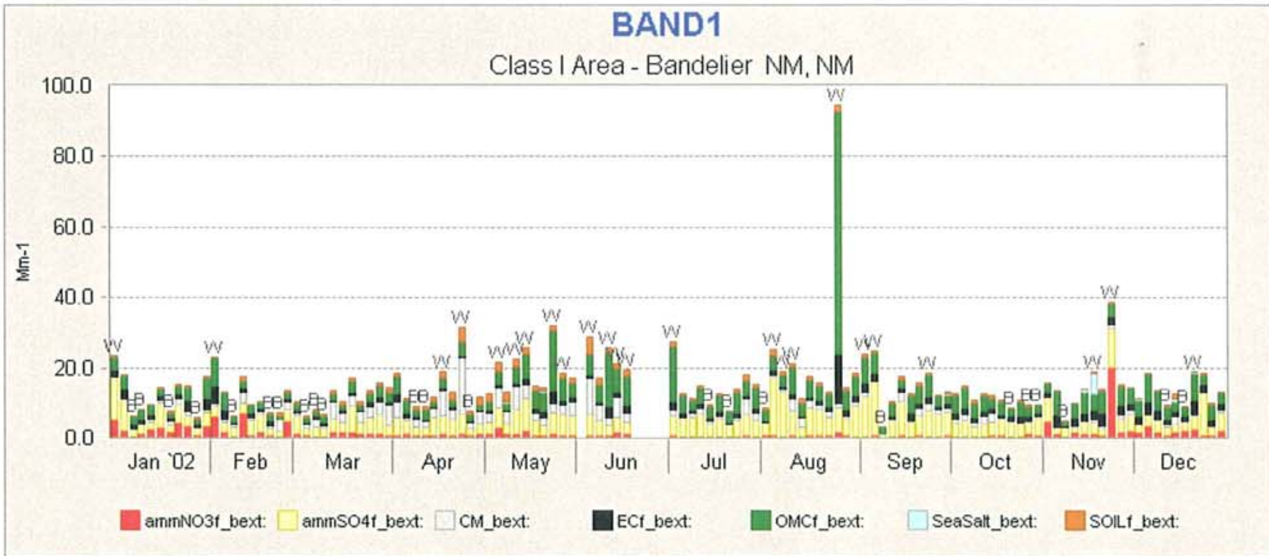


Figure C-8: Plot of Measured Visibility-Degrading Pollutants in Bandelier NM, Year 2002



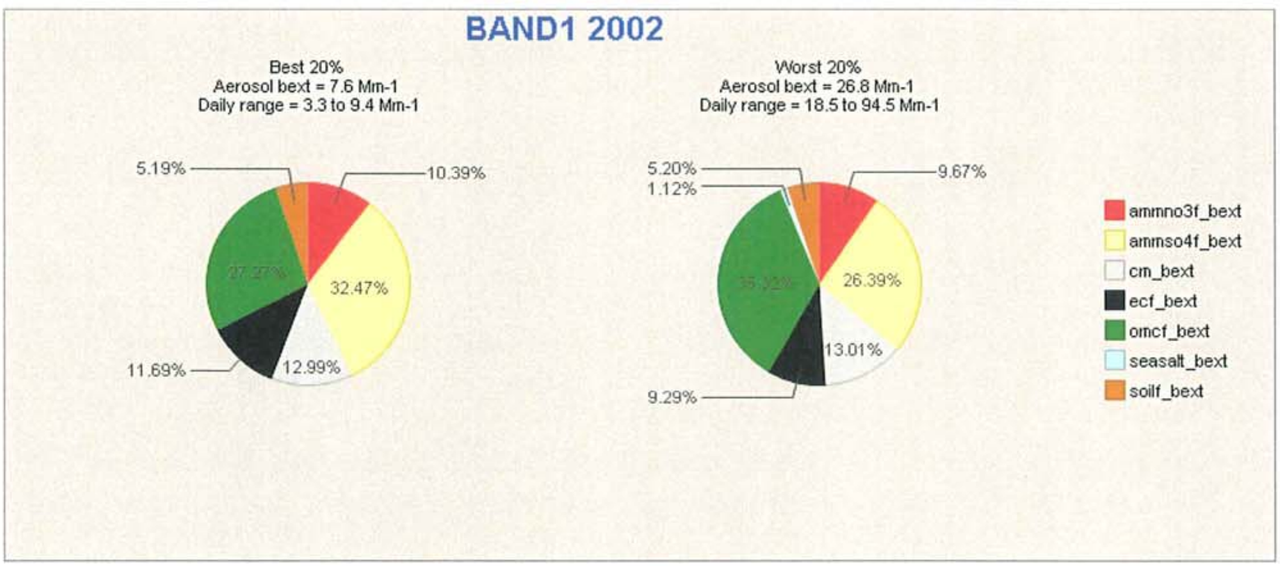
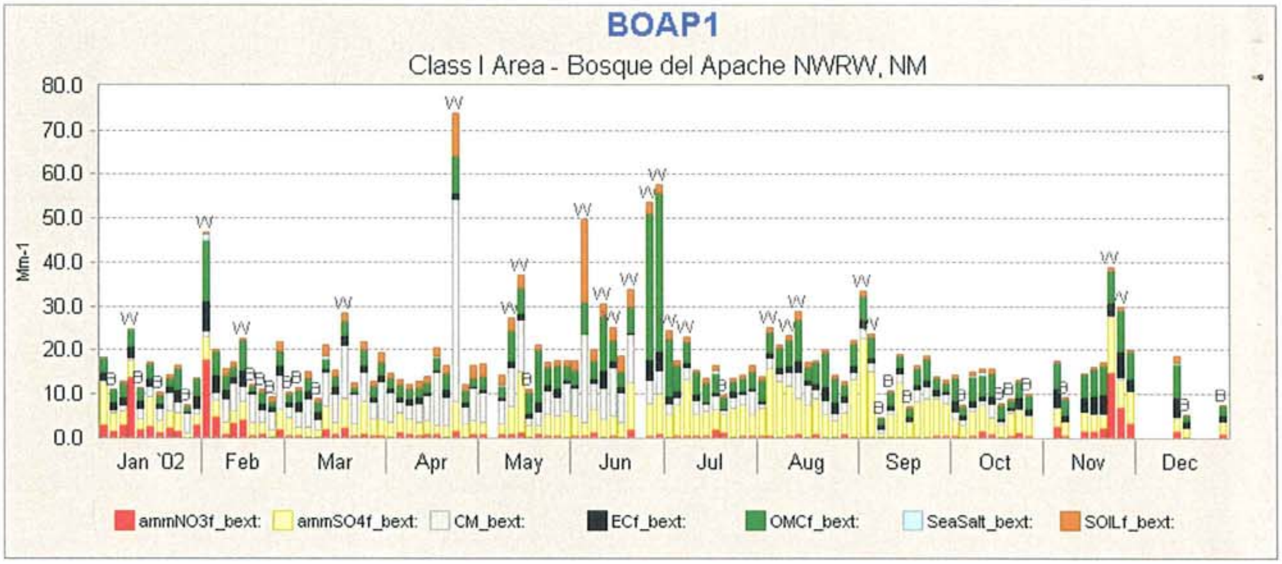


Figure C-9: Plot of Measured Visibility-Degrading Pollutants in Bosque del Apache, Year 2002



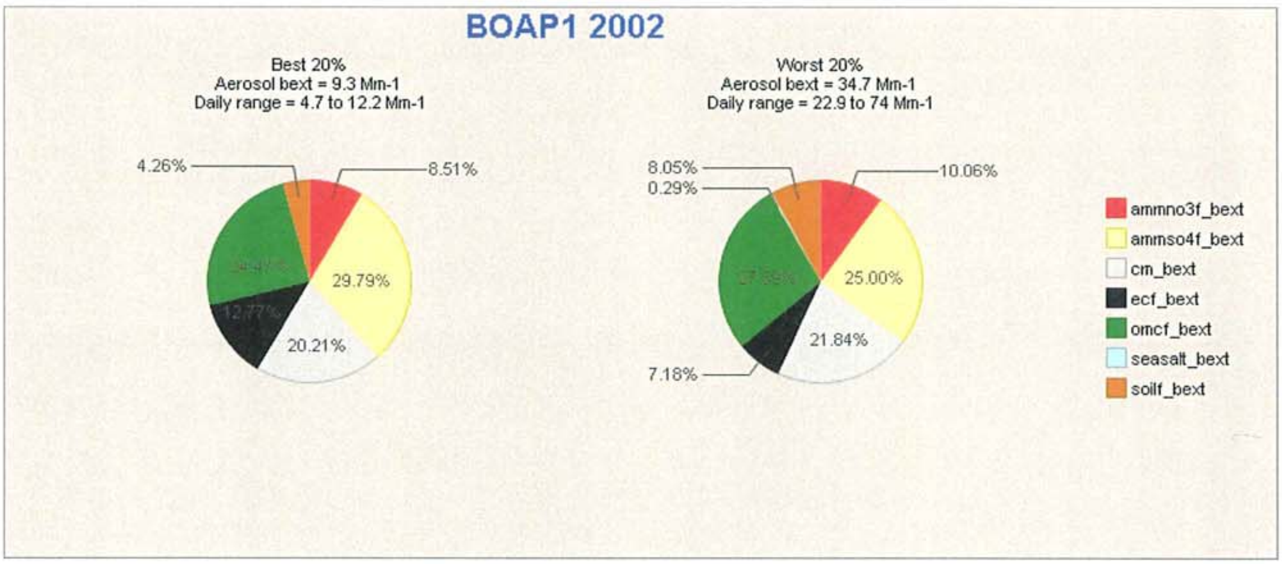


Figure C-10: Plot of Measured Visibility-Degrading Pollutants in Sierra Ancha, Year 2002