Prepared for:
Southern California Edison

BART Determination for the Mohave Generating Station: Natural Gas Firing Options (Revised)

ENSR Corporation
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Executive Summary

The Southern California Edison (SCE) Mohave Generating Station (MGS) has been identified as a Best Available Retrofit Technology (BART)-eligible source by the Nevada Division of Environmental Protection (NDEP). The MGS is located near the southern tip of Clark County, Nevada. The station has two units capable of either coal or natural gas firing, each with a net rated capacity of 790 megawatts. Commercial operation began in 1971. The affected units include two boilers, historically fired with coal, referred to as Units 1 and 2. While these units have generally fired coal, they also have full load natural gas firing capability, or a combination of coal and natural gas firing at full load. The Nevada BART program requires that BART-eligible Electric Generating Units (EGU) that cause or contribute to visibility impairment must perform a site-specific BART determination analysis.

In December 2007, Southern California Edison submitted a BART report (ENSR, 2007) addressing emission control options for coal-fired operation. This analysis included a control technology review and CALPUFF modeling analysis to assess the visibility impact of the candidate BART control options. The BART analysis report documented the control technology options and modeling assessment conducted for the MGS.

The station is currently in a temporary period of non-operation. SCE has identified a prospective buyer for the MGS who has agreed in principle to an operation that involves dedicated natural gas firing and retirement of the coal firing capability for this facility that would be reflected in a revision to Mohave's Class I (Title V) Operating Permit. Therefore, this supplemental BART report for MGS addresses future control options that involve only natural gas firing emission scenarios. Because firing of pipeline-quality natural gas inherently results in minimal SO_2 and PM_{10} emissions, this review of BART controls focuses upon emission options for NO_x.

SCE has been involved in discussions with the NDEP to agree upon a suitably complete list of NO_x BART control options for this prospective future operation of MGS Units 1 and 2. These options include one or more of the following technologies: low-NO_x burners (LNB), overfire air (OFA), selective non-catalytic reduction (SNCR), flue gas recirculation (FGR), in-line selective reduction (SCR), and stand-alone SCR. An agreed-upon set of five feasible BART control options are listed in Table ES-1, along with a summary of the BART analysis.

ENSR used the CALPUFF model with meteorological data from years 2001 through 2003 to assess potential visibility improvements due to the five candidate BART control options at the eleven Class I areas located within 300 kilometers of MGS (they are all more than 100 km from the project site). For each Class I area, ENSR compared the 98th percentile value of the modeling results to the threshold of 0.5 delta-deciview (dv). On an annual basis, the 98th percentile value implies the 8th highest day at each modeled Class I area.

A review of the 5-step BART determination analysis provided in Table ES-1 shows the NO_x emission reductions, annualized costs, other environmental and energy impacts, and visibility improvements expected for each control option relative to the baseline case. Since the Baseline Case reflects implementation of the Consent Decree, which specifies controls that are applicable only for coal-fired units, the costs associated with each gas-fired option are accounted for in this BART analysis.

In its Regional Haze Final Rule Preamble, EPA estimated ranges of cost effectiveness that were used to establish the presumptive limits for NO_x as \$100 to \$1000 per ton of NO_x removed. For NO_x controls, EPA stated that its presumptive NOx "limits…are based on the use of current combustion control technology. Current combustion control technology is generally, but not always, more cost-effective than post-combustion controls such as SCRs." We note that the cost effectiveness of stand-alone SCR is more than \$2,300 per ton of NO_x removed, and the incremental cost effectiveness relative to Option 5 is almost \$11,000 per ton. EPA further stated that they were "…not establishing presumptive limits based on the installation of SCR. Although

States may in specific cases find that the use of SCR is appropriate, we have not determined that SCR is generally cost-effective for BART across unit types."

The data in this report and illustrated in Table ES-1 clearly indicates that the incremental visibility improvement for BART control options more expensive than Option 5 result in only minor visibility improvements at significant cost and other environmental impacts. Consistent with EPA guidance, we select Option 5 (LNB+OFA), an effective combustion control strategy, as BART.

Table ES-1 Summary of BART Analysis for NO_x

	Step 1	Step 2	Step 3	Step 4a	Step 4b	Step 5	
	Identify Control Technologies	**Feasible Control Technology?**	**Evaluate Control Effectiveness for Technically Feasible Control Technologies**	**Calculate Cost Effectiveness for Control Technologies (relative to baseline)**	**Determine Non-Air Quality Environmental and Energy Impacts**	**Evaluate Visibility Impact of Controls vs. baseline (# days > 0.5 delta-dv removed, and average visibility improvement , delta-dv)**	**Identify BART Control Results**
Control Option 1	Low NO_x burners, overfire air, and stand-alone SCR	Yes	97.6% NO_x reduction from coal-fired baseline	Annualized cost = $50,990,000; Marginal cost eff. relative to Option 5 = $11,714/ton	Excess NH_3 emissions; higher energy use for pressure drop; need RMP	# days > 0.5 delta-dv removed = 1346(1), average vis. improvement = 1.11(2) delta-dv	Marginal visibility benefits and high cost
Control Option 2	Low NO_x burners, overfire air, and in-line SCR	Yes	94.1% NO_x reduction from coal-fired baseline	Annualized cost = $47,240,000; Marginal cost eff. relative to Option 5 = $12,992/ton	Excess NH_3 emissions; higher energy use for pressure drop; need RMP	# days > 0.5 delta-dv removed = 1345(1), average vis. improvement = 1.09(2) delta-dv	Marginal visibility benefits and high cost
Control Option 3	Low NO_x burners, overfire air, and flue gas recirculation	Yes	83.5% NO_x reduction from coal-fired baseline	Annualized cost = $33,610,000; Marginal cost eff. relative to Option 5 = $22,806/ton	Increased CO emissions; higher energy use for pressure drop	# days > 0.5 delta-dv removed = 1332(1), average vis. improvement = 1.05(2) delta-dv	Marginal visibility benefits and high cost
Control Option 4	Low NO_x burners, overfire air, and SNCR	Yes	81.1% NO_x reduction from coal-fired baseline	Annualized cost = $20,250,000; Marginal cost eff. relative to Option 5 = $19,968/ton	Excess NH_3 emissions; need RMP	# days > 0.5 delta-dv removed = 1327(1), average vis. improvement = 1.04(2) delta-dv	Marginal visibility benefits and high cost
Control Option 5	Low NO_x burners and overfire air	Yes	76.4% NO_x reduction from coal-fired baseline	Annualized cost = $1,500,000	None	# days > 0.5 delta-dv removed = 1319(1), average vis. improvement = 1.02(2) delta-dv	Selected as BART

(1) Total number of days above 0.5 delta-dv removed over three meteorological years and eleven Class I areas.
(2) Average 8th highest visibility improvement over three meteorological years and eleven Class I areas.

1.0 Introduction

Federal regulations under Title 40 of the Code of Federal Regulations (CFR) Part 51 Appendix Y provide guidance and regulatory authority for conducting a visibility impairment analysis for designated eligible sources. The program requires the application of Best Available Retrofit Technology (BART) to those existing eligible sources in order to help meet the targets for visibility improvement at designated Class I areas. The BART analysis will be reviewed and used by the Nevada Division of Environmental Protection (NDEP) for development of the state's Regional Haze State Implementation Plan (SIP). The NDEP identified the two coal-fired boilers, Units 1 and 2, at Southern California Edison's (SCE) Mohave Generating Station (MGS) as two BART-eligible emission units. The BART rules require that sources that are subject to BART perform a site-specific BART analysis including a control technology review and CALPUFF modeling to assess the visibility impact of the emission units. SCE submitted a BART report (ENSR, 2007) addressing coal-fired control options in December, 2007. This report addressed emission controls required for the facility to continue operating as a coal-fired unit, and these control levels are further discussed in Section 3.

SCE has identified a prospective buyer for the MGS who has agreed in principle to a future operation that involves dedicated natural gas firing, and the retirement of the coal-firing capability for this facility, that would be reflected in a revision to the MGS Class I (Title V) Operating Permit. Therefore, the BART control options in this supplemental BART report for MGS involve only natural gas firing emission scenarios.

This site-specific BART determination analysis includes the following components:

1. A list of demonstrated candidate retrofit controls that may apply.
2. A discussion of technical feasibility for retrofit of each candidate technology to the boilers.
3. A ranking of the control effectiveness of each feasible retrofit technology, or site-specific BART options.
4. An evaluation of the impacts of each site-specific BART option, including:
    - An estimate of the annualized cost for each of the BART options;
    - An analysis of the incremental cost for each option;
    - An evaluation of the impacts on visibility for each of the BART options or combinations of BART options;
    - An evaluation of the non-air quality impacts of each BART option; and
    - An evaluation of the energy impacts of each BART option.
5. An evaluation and justification of the mass emission rates and averaging time in the context of modeled visibility improvements.

The regulation further requires a formal choice of BART based on the above data, including the degree of improvement in visibility (impacts), which may be reasonably anticipated to result from the installation or implementation of the proposed BART. Economic analysis, remaining useful life of the plant, and impacts on facility operation that are a cost consequence of air pollution control equipment may be considered in the final BART decision-making process.

The organization of the remainder of this report is as follows:

- Section 2 discusses baseline emissions.
- Section 3 presents a general discussion of available NO_x emission controls considered for BART.

- Section 4 presents feasible NO_x control options considered for this specific BART analysis and discusses the elements of the first four factors listed above.
- Section 5 discusses meteorological processing procedures for the CALPUFF analysis that was used to determine the modeled visibility improvements associated with each BART control option.
- Section 6 discusses the CALPUFF dispersion modeling procedures for the visibility improvement analysis.
- Section 7 presents the results of the CALPUFF modeling analysis.
- Section 8 summarizes the BART determination analysis and provides a BART selection decision.
- Section 9 contains references.
- Appendix A provides a discussion by the boiler engineering firm, Babcock Power Inc., of NO_x emission control options for this facility.
- Appendix B discusses relevant agency guidance (from EPA Region 9 and the National Park Service) regarding recommendations for CALPUFF system technical options for a BART determination analysis.
- Appendix C discusses the secondary formation of particles from NO_x gaseous emissions and how the CALPUFF model handles this process. The discussion provides recommendations for appropriate modeling procedures for this application.
- Appendix D provides regional haze calculations procedures using the old IMPROVE equation.
- Appendix E provides detailed CALPUFF modeling results and graphic charts using the new IMPROVE equation.
- Appendix F provides detailed CALPUFF modeling results and graphic charts using the old IMPROVE equation.

2.0 Baseline Emissions

2.1 Facility Description

The MGS is located near the southern tip of Clark County, Nevada. The station covers approximately 2,490 acres and is approximately 1 mile west and north of the Colorado River in Laughlin, Nevada. The station is located in Township 32, South Range 66 East MBD&M in Sections 22 and 23 and part of Sections 21, 24, 26, and 27. The plant site is accessible from Nevada State Route 163, Edison Way, and Desert Road. The station is currently in a temporary period of non-operation and will not operate as a coal fired power plant until pollution control equipment is installed. One interested party is in discussion with the plant owners to purchase the asset and return it back to service as only a natural gas-fired plant.

The MGS has two units that have historically been coal-fired (but with natural gas firing capability as well), each rated at 790 megawatts (MW) (net). Commercial operation of Unit 1 and Unit 2 began in 1971. The facility was originally designed and built as a base-load plant, such that the plant was running full time unless its operations were curtailed for maintenance and other permit limitations. The boilers are each equipped with electrostatic precipitators (ESPs) to control PM emissions.

The main EGUs are pulverized coal-fueled, tangentially fired boilers. Low-sulfur, bituminous coal has historically been supplied to the station via pipeline in slurry consisting of approximately 50 percent coal and 50 percent water. The coal has historically been mined by Peabody Coal Company at Black Mesa Mine in northeastern Arizona, then crushed, mixed with water, and transported 273 miles through the pipeline to the station.

2.2 Estimated Emissions for BART Baseline Assessment

The NDEP asked SCE to provide peak 24-hour actual (or calculated) emission rates from the three Regional Haze Rule baseline years of operation that account for "high capacity utilization" during normal operating conditions. For the case of MGS, these conditions would involve coal firing during the years 2001 through 2003. The baseline emissions for each of the evaluated pollutants are presented in Table 2-1.

Table 2-1 Peak Daily Baseline Emissions

Pollutant	Emissions (lb/hr)	
	Unit 1	Unit 2
NO_X	3,731	3,425
SO_2	6,359	6,209
PM_{10}	357	423

The speciation of the baseline PM_{10} emissions required for modeling purposes 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 percent of the filterable PM emissions are filterable PM_{10} and 29 percent 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 percent 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 PM_{10} was determined using the default approach cited in AP-42, Table 1.1-5. For coal-fired boilers equipped with ESPs, total condensable PM_{10} emissions are determined from the relationship "0.1(S) - 0.03" where S is the sulfur content in percent by weight. The inorganic fraction, assumed to consist of primary sulfates, is 80 percent of the condensable PM_{10} and the organic fraction is 20 percent of the condensable PM_{10}.

Table 2-2 presents the stack parameters of the merged flues that were used in the modeling of baseline conditions. Table 2-3 presents the emission rates, including speciation of PM_{10} emissions that were used in the modeling of baseline conditions.

Table 2-2 MGS Baseline Stack Parameters

Parameter	Units	Units 1 & 2
UTM-X (Zone 11, NAD27)	Meters	719,677
UTM-Y (Zone 11, NAD27)	Meters	3,891,454
Stack Height	Meters	152.4
Base Elevation	Meters	216.41
Diameter	Meters	9.91
Gas Exit Velocity	m/s	39.16
Exit Temperature	°K	449.8

Table 2-3 MGS Baseline Emissions Used for Modeling

Unit	Description	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions			Filterable PM10					Condensable PM10			Total PM10
												total	coarse	Fine						
														fine total	fine soil	EC	total	SO4	organic	
		MMBtu/hr	Btu/lb	% wt.	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
1	Bituminous Coal, 790 MW, PC Tangential-Fired, ESP	8,439	8,292	0.460	0.442	3,731	0.754	6,359	0.039	332.00	Max. Daily Emissions (2001-2003)	222.44 (a)	126.16	96.3 (a)	92.72	3.56 (b)	135.02	108.02 (c)	27.00 (d)	357
2	Bituminous Coal, 790 MW, PC Tangential-Fired, ESP	8,439	8,292	0.460	0.406	3,425	0.736	6,209	0.051	430.00	Max. Daily Emissions (2001-2003)	288.10 (a)	163.40	124.7 (a)	120.09	4.61 (b)	135.02	108.02 (c)	27.00 (d)	423

(a) For a dry bottom boiler fired with bituminous coal and equipped with an ESP, total filterable PM10 is 67% of filterable PM and fine filterable PM10 is 29% of filterable PM based on AP-42, Table 1.1-6.
(b) 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.
(c) H2SO4 is 80% of condensable emissions, based on AP-42 Table 1.1-5.
(d) Organics are 20% of condensable emissions, based on AP-42 Table 1.1-5.

3.0 Evaluation of Alternative Control Technologies

The air pollutants produced during natural gas combustion that may cause visibility impairment downwind of the plant include NO_x, SO_2, and PM_{10}. Given the nature of the fuel, conversion of the Mohave units from coal to natural gas firing will dramatically reduce the emissions of all of these pollutants. Because natural gas combustion inherently minimizes SO_2 and PM_{10} emissions and BACT analyses for new projects do not require additional controls for these pollutants, the discussion provided below addresses only NO_x emissions and candidate controls.

3.1 Consent Decree Emissions

The future of the station is governed by a Consent Decree (CD) entered into by the owners of the MGS and is available on the Grand Canyon Trust web site at http://www.grandcanyontrust.org/programs/air/consent.php. The CD requires new opacity and SO_2 emission limits (specified for coal-fired units only), including the installation of low NO_X burner technology to reduce NO_x emissions and installation of a lime spray dryer in combination with a fabric filter baghouse to reduce SO_2 and particulate matter less than 10 microns (PM_{10}) emissions. The addition of air pollution control equipment as required to meet the terms of the CD, if installed, would greatly reduce the visibility impairing pollutants emitted by the plant. These pollutants include NO_x, SO_2, and PM_{10}.

The CD controls for NO_X, SO_2, and PM_{10} emissions associated with coal-fired units were specified in the December 2007 BART report (ENSR, 2007a), and include the following:

- NO_X – Low NO_X Burners with Over-fired Air (LNB-OFA)
- SO_2 – Lime Spray Dryer (LSD)
- PM_{10} – Fabric Filter (FF). The existing electrostatic precipitator (ESP) would remain in operation upstream of the FF.

Conformance to the Consent Decree directly establishes a mass SO_2 emission rate as listed in Table 3-1 for the units based on coal fuel combustion. In addition, the emission levels summarized in Table 3-1 for NO_x and PM_{10} are contained in SCE's February 7, 2003 Application[1] for the NDEP's Class I-B Minor Revision to the facility Class I Air Quality Operating Permit issued by the NDEP on February 28, 2003, and as revised on May 21, 2003. Also, the emission levels in Table 3-1 were provided in the Revised Title I-B Operating Permit Renewal Application dated July 2007 (ENSR 2007b). Accordingly, the emission rates in Table 3-1 are used in this BART analysis as reference emission levels, that represent the expected level of control associated with the CD for normal operation of the coal-fired units.

[1] SCE's application for a Class I-B minor revision to the Mohave facility Class I Air Quality Operating Permit included a PSD Applicability Determination, which found that PSD was not applicable to the equipment changes required for Mohave to comply with the Consent Decree and continue operation after year 2005. The NO_x and PM_{10} emission rates listed in Table 3-1 are emission rate commitments made by SCE in its February 7, 2008 Application for a Class I-B minor permit revision for Mohave operations to meet the terms of the Consent Decree, and to avoid triggering PSD requirements for NO_x and PM_{10} at the facility. The emission rates for NO_x and PM_{10} in Table 3-1 were designed by Mohave engineers at a level that would not triggering PSD Applicability. Thus, while not listed as permit emission limits in the Mohave Title V (Class I) Operating Permit, the limits for NO_x and PM_{10} serve as an enforceable element of the Class I-B minor revision to the facility Class I Operating Permit issued on February 28, 2003 to avoid triggering PSD applicability.

Table 3-1 Consent Decree Emission Rates

Pollutant	Emission Rates per Unit	
	(lb/MMBtu)	(lb/hr)
NO_X	0.338	2,852.4
PM_{10}	0.025	211.0
SO_2	0.15	1,265.8

In contrast, the emission rates associated with natural gas firing with no new controls on the Mohave units are expected not to exceed about 0.2 lb/MMBtu for NO_x, and about 0.002 lb/MMBtu for SO_2 and PM_{10}. Therefore, the natural gas firing option, even without new controls, represents a very substantial reduction in visibility-affecting emissions. With respect to the Consent Decree requirements, it is important to note that it requires that, "… If the Mohave Generating Station is converted to combust a fuel other than coal, such as natural gas, it shall not emit pollutants in greater amounts than that allowed by paragraph (d) of this section [i.e., the coal-fired emission limits and control equipment specified in the Consent Decree]."[2] Therefore, based on the natural gas-fired emission rates stated above, the proposed conversion of Mohave to a 100% natural gas fired-power plant will result in uncontrolled emissions levels that will yield a substantial reduction in visibility reduction emissions when compared to the Consent Decree Emission Rates listed in Table 3-1. It is important to note that the NO_x controls considered for the five BART Control Options evaluated in this BART evaluation will achieve a reduction in NO_x emission rates (compared with the CD controlled emission levels listed in Table 3-1) ranging from 70% to 97% based on the proposed NO_x emission rates listed in Table 3-2 at Section 3.5 below.

3.2 NO_X Emission Controls for Natural Gas Firing

Nitrogen oxides (NO_x) are formed during the combustion process of natural gas via three distinct mechanisms. The first mechanism, called "thermal" NO_x, refers to the NO_x that is formed through the oxidation of nitrogen that is present in the air supplied to complete the combustion process. Thermal NO_x formation is dependent on temperature, local oxygen concentrations, and residence time in the primary combustion zone. The second mechanism, called "fuel" NO_x, refers to the NO_x that is formed through the oxidation of the nitrogen that is chemically bound in the fuel itself. Given the nature of the fuel, there is no fuel NO_x produced during natural gas combustion. The third mechanism, "prompt" NO_x, refers to the NO_x that is formed within the flame itself from hydrocarbons that react with molecular nitrogen. Prompt NO_x represents a very small portion of the total NO_x generated during natural gas combustion. Understanding basic NO_x formation during the combustion process is important in understanding how NO_x control technologies reduce emissions and how they affect unit operation.

There are basically two techniques that have been used in reducing and controlling NO_x emissions generated by utility boilers combusting fossil fuels: (1) modifications to the combustion process; and (2) use of chemical reagents to reduce NO_x to molecular nitrogen. Modifications to the combustion process are designed to reduce the temperature and available oxygen in the primary combustion zone, thereby reducing the production of thermal NO_x. The post-combustion NO_x controls involve the chemical reaction between the NO_x and ammonia introduced to the flue gas. Both of these control techniques by themselves or in combination have been used throughout the industry with various degrees of success to reduce NO_x emissions.

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[2] See: 40 CFR 52.1488(d)(1). The provisions of the Consent Decree were incorporated into the Nevada Visibility SIP at 40 CFR 52.1488(d).

The control techniques available to further reduce NO_x emissions from natural gas-fired, utility boilers, in top-down order, include:

- Selective catalytic reduction (SCR);
- Selective non-catalytic reduction (SNCR);
- Flue gas recirculation (FGR);
- Over fire air (OFA);
- Low NO_x burners (LNB);
- Burners out of service (BOOS); and
- Low excess air (LEA).

The technical feasibility, effectiveness, and potential impacts of applying these post-combustion and combustion controls to the Mohave units are addressed in the BART analysis. A detailed review of these NO_x control techniques prepared by Babcock Power, Inc. is provided in Appendix A.

3.2.1 Selective Catalytic Reduction

SCR is a post-combustion NO_x control technology that involves a catalyst bed installed between the boiler economizer and combustion air pre-heater in a conventional natural gas-fired boiler. The temperature range of the flue gas at this point is between 600 to 800°F. Ammonia is injected into the flue gas upstream of a precious metal catalyst bed and reduces a portion of the NO_x to molecular nitrogen and water. In-line SCR systems are typically applied to natural gas fired-units. Due to the lower velocities required for the NO_x reduction reaction to take place in the catalyst-laden reactor, the existing ductwork is replaced with larger size ductwork. If there is insufficient space for in-line SCR, a stand-alone SCR may be installed adjacent to the boiler. In either case, application of SCR to a natural gas-fired boiler would increase overall system pressure drop (approximately 6 to 8 inches H_2O) would require the installation of induced draft fans resulting in increased fan power consumption and loss of overall plant efficiency. The power loss resulting from SCR operation would need to be made up by additional power generation from this plant or from other (possibly coal-fired) plants in the region. In addition, the catalyst will oxidize some available SO_2 to SO_3 prior to stack emission, leading to additional visibility-affecting particulate emissions. The formation of sulfates (but not nitrates) with SCR operation is also discussed by EPA at http://www.epa.gov/ttn/catc/dir1/fscr.pdf. The unreacted ammonia will be emitted from the stack as ammonia slip for SCR operation. The Babcock Power Appendix A notes that ammonia slip would be estimated as 2 ppm at 3% oxygen.

SCR systems have been applied to natural gas-fired boilers throughout the country and are considered the most effective control for the removal of NO_X emissions. Depending on the uncontrolled NO_x emission levels, reductions ranging from 75 to 90 percent have been be achieved by this technology on natural gas-fired boilers. Therefore, both stand-alone and in-line SCR are considered technically feasible NO_x control technologies for the Mohave units under the natural gas firing configuration, although the EPA web citation noted above does indicate that SCR retrofits on industrial boilers is “difficult and costly”.

3.2.2 Selective Non-Catalytic Reduction

SNCR is a post-combustion NO_x control technology that involves the injection of ammonia or urea into the flue gases without the presence of a catalyst. SNCR, like SCR, involves the reaction of NO_x with ammonia where a portion of the NO_X is converted to molecular nitrogen and water. Without the use of a catalyst or supplemental fuel injection, the NO_x reduction reaction temperature must be tightly controlled between 1,600 and 2,200°F (between 1,600 and 1,800°F for optimum efficiency). Below 1,600°F, the ammonia will not fully react resulting in unreacted ammonia that is emitted into the atmosphere (referred to as ammonia slip). If the temperature rises above 2,200°F, the ammonia added will be oxidized resulting in an increased levels of NO_x. NO_x removal efficiencies with SNCR, typically from 15 to 30 percent, are lower than SCR, depending on the combustion process. The unreacted ammonia will be emitted from the stack as ammonia slip for SNCR operation. The Babcock Power Appendix A notes that ammonia slip would be estimated as 6 ppm at 3% oxygen. Even with the operational complications noted above, SNCR is still considered a technically feasible NO_x control technology for the Mohave units under the natural gas firing configuration.

3.2.3 Flue gas Recirculation

Flue gas recirculation (FGR) refers to the mixing of the combustion products (flue gas) with combustion air to reduce NO_x emissions. FGR lowers oxygen concentration during the initial stages of combustion, along with combustion temperatures. Because flue gas is inert, it is important that the oxygen concentration of combustion air/flue gas mixture is maintained above 17 percent to ensure that sufficient oxygen is available for the combustion of natural gas to ensure flame stability and to minimize combustible losses (e.g., CO and PM). The flue gas is typically taken from the outlet of the boiler upstream of the air heater and then is mixed with hot combustion air exiting the air heater. The mixture is then transported to the burners (windbox) through the existing combustion air ductwork. The NO_x reduction achieved though the use of FGR depend primarily dependent on the FGR flow rate, excess air levels, burner stoichiometry, and burner/furnace heat release rate. Generally, FGR is effective in reducing thermal NO_x due to the dilution effect on the combustion process and reduction in combustion temperatures. Typically the NO_x reductions that have been achieved using FGR range are on the order of 20 to 50 percent. This NO_x control technique is considered technically feasible to control NO_x emission from the Mohave units under the natural gas firing configuration.

3.2.4 Overfire Air

Overfire air (OFA) involves the use of air injection ports above the main combustion (burner) zone in the upper reaches of the furnace to divert a portion of the combustion air away from the primary combustion zone. The quantity of air that is diverted to the OFA ports typically varies from 5 to 25 percent with the primary objective being to reduce oxygen concentrations and temperatures in the primary combustion zone, thereby reducing NO_x emissions. The air introduced through the OFA ports ensures complete combustion. This technology has been used in combination with other NO_x control techniques, such as LNB and FGR, on hundreds of units throughout the country to provide additional NO_x reduction. The NO_x reductions that have been achieved with OFA ports have ranged from 10 to 30 percent. This NO_x control technique is considered technically feasible to control NO_x emission from the Mohave units under the natural gas firing configuration.

3.2.5 Low NO_x Burners

Low NO_x burners (LNB) are designed to reduce NO_x emissions by controlling the mixing of fuel and air during the initial stages of combustion. The basic concept that forms the basis of the LNB design is to delay the mixing of the fuel and air during the initial stages of the combustion process. This delay is achieved through the physical separation of some of the air from the fuel, or through aerodynamic means by imparting swirl to the air, or both. The production of NO_x is minimized under these conditions since the availability (concentration) of oxygen to react with the liberated organically bound nitrogen is minimized. The Mohave units are tangentially-fired boilers that are characterized by their inherent lower NO_x emissions when compared to wall-fired boilers. In tangentially-fired boilers, the fuel and air are introduced in the corners of the combustion chamber through alternating ports. Consequently, the mixing of fuel and air is delayed resulting in lower temperatures and hence lower NO_x emissions. The use of OFA ports further delays the introduction of air in the combustion zone further reducing NO_x emissions. This NO_x control technique, therefore, is considered technically feasible to further reduce NO_x emission from the Mohave units under the natural gas firing configuration. At a steady-state, 100% rated heat input operation, LNB with OFA achieves the maximum NO_x pounds per hour formation presented in Table 4-6. However, as load changes up or down and during startup and shutdown, the NO_x reduction performance will vary due to variables in combustion air control, but in no case will the maximum NO_x pounds per hour formation listed in Table 4-6 be exceeded.[3].

3.2.6 Burners-Out-of-Service

Burners-out-of-service (BOOS) is a technically proven means of achieving staged combustion reducing burner zone stoichiometry and subsequently NO_x emissions. Staged combustion involves the generation of a fuel-rich zone during the initial stages of the fuel combustion that reduces oxygen concentration and flame temperatures. BOOS operation is accomplished by eliminating fuel flow to selected burners, while maintaining air flow through those burners. The fuel flow to remaining burners is increased to maintain the heat input required to produce the fuel rich atmosphere required for reducing NO_x emissions. The current Mohave units having been designed for pulverized coal firing lend themselves to BOOS as the existing burner corner (tangential) openings are oversized for natural gas. The proposed conversion of the units calls for the use of the excess space as overfire (OFA) ports. This NO_x control technique, therefore, is already inherent in the design of the tangentially-fire boilers to accommodate the dedicated natural gas firing.

3.2.7 Low Excess Air

Operating natural gas fired utility boilers at Low excess air (LEA) operation with natural gas-fired boilers levels has been demonstrated to provide minor improvements in NO_x emissions. This operation reduces the amount of available oxygen in the primary combustion zone, lowering the overall NO_x formation stoichiometry and combustion temperatures. The Mohave units typically will operate at excess air levels ranging from 8 to12 percent by volume. Further reducing excess air levels could have the negative effects of decreasing boiler efficiency and increasing the combustible losses (e.g., CO and PM). This NO_x control technique, therefore, is inherent in the design of the tangentially-fire boilers under the natural gas firing configuration.

3.2.8 Summary of NO_X Control Technical Feasibility

The NO_X control technologies considered technically feasible for application to the Mohave units under the natural gas firing configuration include SCR, SNCR, FGR, LNB, and OFA. The other NO_x control techniques, BOOS and LEA, are inherent in the design of the tangentially-fired boilers under the natural gas firing configuration.

3.3 SO_2 Control

Sulfur dioxide is formed during natural gas combustion by the oxidation of the sulfur in the fuel. The sulfur, in the form of hydrogen sulfide (H_2S) or mercaptans, is added to the fuel as an odorant at a rate of approximately 1.0 pound of H_2S per million cubic feet of natural gas. The conversion of the Mohave units from coal to dedicated natural gas combustion, therefore, will reduce SO_2 emissions from approximately 0.75 lb/MMBtu under baseline conditions to 0.0019 lb/MMBtu under the natural gas firing configuration. This corresponds to a reduction in SO_2 emissions relative to baseline conditions of approximately 99.8 percent. Given these

[3] The NO_x baseline emissions were based on a coal-fueled facility that was economically dispatched as a baseload system resource that would essentially run at full load for all hours available for operation. With the conversion to natural gas only operation, the units will become an economically dispatched system resource delivering energy generally in order of its cost of production as compared to other system resources. Consequently, the units will be considered intermediate and peaking system resources subject to hour-by-hour load changes and potentially multiple weekly starts and shutdowns. As explained in Appendix G, the projected NO_x lb/MMBtu actual performance emission rate will be up to 0.20 lb/MMBtu during operation as MGS will be dispatched as a load following, intermediate and peaking system resource, Mohave will achieve 0.10 lb/MMBtu at full load operation, shown in Table 4-6 and an expected 0.15 lb/MMBtu rolling twelve-month average.

extremely low SO_2 emission levels, there are no technically feasible control technologies that are capable of further reducing SO_2 emissions under the natural gas-firing configuration.

3.4 PM Control

Particulates formed during natural gas combustion are products of incomplete combustion in the form of unburned carbon and condensable organics. Particulate formation may be promoted in the fuel-rich environment associated with staged combustion techniques, such as FGR or LEA. The conversion of the Mohave units from coal to dedicated natural gas combustion will reduce PM_{10} emissions from approximately 0.046 lb/MMBtu under baseline conditions to 0.0077 lb/MMBtu under the natural gas firing configuration. This corresponds to a reduction in PM_{10} emissions relative to baseline conditions of approximately 84.5 percent. Given these extremely low PM_{10} emission levels, there are no technically feasible control technologies that are capable of further reducing PM_{10} emissions under the natural gas-firing configuration.

3.5 Effectiveness of the NO_x Control Options

The effectiveness of the technically feasible NO_x control options is based on a review of performance data from operational plants by Babcock Power, Inc. Based on this review, the NO_x emission levels achievable by each control technology applied to the Mohave units under the natural gas firing configuration at maximum rated heat input are summarized in Table 3-2.

Table 3-2 Emissions Control Effectiveness of NO_x Control Options

Option	Description	NO_x Emissions (lb/MMBtu)	Reduction from coal baseline emissions (%)
1	LNB+OFA+SCR (Stand Alone)	0.010[4]	97.6
2	LNB+OFA+SCR (In-Line)	0.025	94.1
3	LNB+OFA+FGR	0.070	83.5
4	LNB+OFA+SNCR	0.080	81.1
5	LNB+OFA	0.100	76.4

3.6 Economic Impacts of the NO_x Control Options

To determine the cost effectiveness of the NO_x control options, the direct capital and annual operating and maintenance costs associated with each control option were estimated by Babcock Power, Inc. The direct equipment and installation capital costs then were adjusted to account for the additional indirect costs incurred by the owner. Typical indirect owner's costs over and above the direct procurement cost of the emissions control equipment include:

- Owner's Engineering: 5%-15%
- Owner's Project Management: 5%-10%

[4] 0.10 lb/MMBtu performance rate represents 100% thermal input NO_x performance. As indicated in Appendix G, NO_x performance will vary from 0.20 lb/MMBtu during startup and shutdown and from 0.07 to 0.15 lb/MMBtu in a range from 25% thermal input to 75% thermal input. Based on economic dispatch expectations, the annual 12-month rolling average NO_x performance should not exceed 0.15 lb/MMBtu, and NO_x production should not exceed 788 lb/hour mass rate used in the CALPUFF modeling discussed below.

- Project Contingency: %5-10%
- Interest During Construction: 5%-10%
- Total Range of Owner's Costs: 20%-45%

For purposes of this analysis, the owner's indirect costs are assumed to be 40% of direct procurement costs consistent with the Utility Air Regulatory Group's report "Capital Cost and Cost Effectiveness: Power Plant Emission Control Technologies."

The annual fixed capital costs then were estimated by means of the capital recovery factor assuming an interest rate of 12 percent and an amortization period of 20 years. While other cost analyses may assume an interest rate as low as 7%, the project proponent notes that in the financial markets for this type of project it would be difficult to attract investors for cost of capital rates below 12%, because the restart of MGS on natural gas and its long term competitiveness are speculative. Although the units are anticipated to have a useful life of at least 20 years (so that useful life is not a factor in the BART analysis), their long-term competitiveness in the electric energy market place is uncertain. In the short term (5 years), it is anticipated that the units will be under contract and therefore the short-term outlook supports restart of the units. However, beyond the initial 5-year period, the market competitiveness of the units is speculative and uncertain. As a result, any investment in emission controls needs to be evaluated on a higher return on investment during the 20-year period. It is the project proponents' judgement that a 12% cost of capital is appropriate for the risks and uncertainties associated with the return of investment on the emission control investments.

The annual NO_x emissions associated with the baseline case and five NO_x control options were based on the maximum hourly NO_x emission rate, the maximum heat input rate, and the annual average capacity factor. The maximum hourly NO_x emission rate for the baseline case and five NO_x control options are provided earlier in the report. The maximum heat input rates for the baseline case and five NO_x control options are 8,439 and 7,880 MMBtu/hr per unit, respectively. The annual average capacity factor is based on historical data compiled by the EPA for the most recent five-year period of full operations from 2001 through 2005. Table 3-3 persents the actual and maximum heat input to both of the units over this five-year period. As shown, the annual average capacity factor for each unit and the entire plant was approximately 68%.

The total annual costs were then determined by adding the annual fixed capital costs and annual O&M costs. The cost effectiveness of the five NO_x control options then was determined by dividing the total annual cost by the NO_x reduction associated with each control option over the baselines case. The Table 3-4 summarizes the capital and annual operating costs, as well as the cost effectiveness, for each of the NO_x control options applied to the Mohave units.

3.7 Environmental Impacts of the NO_x Control Options

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-percent 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 percent 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, or insufficient residence time. These physical limitations may be compensated for by injecting a larger amount of ammonia than stoichiometrically required and essentially achieving the NO_x emissions at the expense of ammonia slip. The ammonia slip associated with SCR is specified by Babcock Power, Inc. in Appendix A to be 2 ppm at 3 percent O_2, while that associated with SNCR is specified to be 6 ppm at 3 percent O_2. This excess ammonia will react with SO_2 and NO_x in the atmosphere to form ammonium salts and hence increased concentrations of both PM_{10} and $PM_{2.5}$.

3.8 Energy Impacts of the NO_x Control Options

Selective catalytic reduction would consume significantly more electrical energy than SNCR. The higher electrical energy consumption for SCR operation 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 an evaporator blower. Likewise, FGR would also consume more electrical energy relative to other staged combustion techniques due to the increased fan static pressure required to overcome the pressure drop across the boiler. The increased emissions of criteria pollutants, possibly from regional coal-fired power plants, required to maintain the MGS current net electrical output capability have not been incorporated into the visibility modeling, so the reviewer should be aware that any reported visibility improvements due to FGR or SCR operation do not consider this negative impact.

Table 3-3 Annual Capacity Factor for Mohave Units 1 and 2[a]

Year	Unit 1 Actual Heat Input (MMBtu/hr)	Unit 1 Maximum Heat Input(b) (MMBtu/hr)	Unit 1 Annual Capacity Factor (%)	Unit 2 Actual Heat Input (MMBtu/hr)	Unit 2 Maximum Heat Input(b) (MMBtu/hr)	Unit 2 Annual Capacity Factor (%)	Plant Annual Capacity Factor (%)
2001	50,043,926	73,925,640	67.69%	50,510,546	73,925,640	68.33%	68.01%
2002	46,715,511	73,925,640	63.19%	52,315,381	73,925,640	70.77%	66.98%
2003	48,035,296	73,925,640	64.98%	45,356,271	73,925,640	61.35%	63.17%
2004	51,440,496	73,925,640	69.58%	52,615,179	73,925,640	71.17%	70.38%
2005	53,811,649	73,925,640	72.79%	51,216,847	73,925,640	69.28%	71.04%
Average	50,009,376	73,925,640	67.65%	50,402,845	73,925,640	68.18%	67.91%

(a) The historical heat input based on data compiled in the EPA Clean Air Market Website at http://www.epa.gov/airmarkets/trading/buying.html.

(b) Maximum annual heat input based on maximum hourly heat input of 8,439 MMBtu/hr and conitnuous operation for 8,760 hr/yr.

Table 3-4 Cost Effectiveness of NO_x Control Options

Option	Description	Capital Cost[a] (10^6 \$)	Annual Fixed Capital Cost[b] (10^6 \$)	Annual Operating Cost (10^6 \$)	Total Annual Cost (10^6 \$)	Annual Emissions[c] (tpy)	Annual Emissions Reduction (tpy)	Cost Effectiveness (\$/ton)	Marginal Cost Effectiveness (\$/ton)
1	LNB+OFA+SCR (Stand Alone)	291.20	38.99	12.00	50.99	469	16,522	$3,086	$11,714
2	LNB+OFA+SCR (In-Line)	263.20	35.24	12.00	47.24	1,173	15,818	$2,986	$12,992
3	LNB+OFA+FGR	221.20	29.61	4.00	33.61	3,286	13,705	$2,453	$22,806
4	LNB+OFA+SNCR	95.20	12.75	7.50	20.25	3,755	13,236	$1,530	$19,968
5	LNB+OFA	11.20	1.50	0.00	1.50	4,694	12,297	$122	N.A.
Baseline	Coal-Firing	0.00	0.00	0.00	0.00	16,991	0	N.A.	N.A.

(a) The capital costs include indirect owners costs assumed to be 40% of the direct procurement costs.

(b) The annual fixed capital costs are based on a capital recovery factor of 0.13388 assuming an interest rate of 12% and amortization period of 20 years.

(c) The annual emissions are based on an annual average capacity factor of 68% for both units as reported in the EPA Clean Air Market Website.

4.0 Future Emissions for BART Control Options

4.1 Modeled Stack Parameters

The NO_x control options available for the Mohave units under the natural gas firing configuration that are considered in the visibility modeling analysis are:

- Option 1: LNB, OFA and stand-alone SCR;
- Option 2: LNB, OFA and in-line SCR;
- Option 3: LNB, OFA and FGR;
- Option 4: LNB, OFA and SNCR; and
- Option 5: LNB and OFA.

The design and performance data for these five NO_x control options were developed by Babcock Power, Inc. as detailed in Appendix A.

4.2 Estimated Emissions

The conversion of the Mohave units from coal to natural gas firing will dramatically reduce the emissions of PM_{10}, SO_2, and NO_x. SO2 emissions were based on a material balance assuming an H_2S concentration of 1.0 lb per million cubic feet of natural gas. The PM_{10} emissions and speciation were determined using the following approach:

- PM_{10} emissions were based on the default approach cited in AP-42, Table 1.4-2. For natural gas-fired boilers, filterable PM_{10} emissions are based on the emission factor of 1.9 lb/10^6 scf, while condensable PM_{10} emissions are based on the emission factor of 5.7 lb/10^6 scf of natural gas.
- For natural gas-fired boilers, elemental carbon is expected to be 6.7 percent 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 2008. For natural-fired boilers equipped with SCR, H_2SO_4 emissions are determined as follows:

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

  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 (0.01 for natural gas),
  S2 is the SCR catalyst SO_2 oxidation rate (0.03 for natural gas)
  F2 is the control factor (assumed to be 1.0 given the extremely low SO_2 emissions)

  Note that the inorganic PM_{10} emissions are assumed to consist entirely of H_2SO_4. NO_x emissions formed during combustion are predominantly in the form of NO due to the fuel lean mixture associated with natural gas combustion. Because NO is only slightly water soluble, it does not readily dissolve in water droplets available in the combustion process, thus minimizing the formation of nitric acid and hence nitrates.

The stack parameters for Units 1 and 2 under natural gas firing conditions are presented in Table 4-1. The NO_X, SO_2, and PM_{10} emissions under the five BART control options then are summarized in Tables 4-2 through 4-6, respectively. As indicated in Appendix G, the maximum NO_x emission rate occurs at maximum load conditions, which is the case being modeled for the various BART options.

Table 4-1 MGS Natural Gas Firing Stack Parameters

	Units	Units 1 & 2
UTM-X (Zone 11, NAD27)	Meters	719,677
UTM-Y (Zone 11, NAD27)	Meters	3,891,454
Stack Height	Meters	152.4
Base Elevation	Meters	216.41
Diameter	Meters	9.91
Gas Exit Velocity	m/s	27.81
Exit Temperature	°K	395.4

Table 4-2 MGS BART Option 1 Emissions

Unit	Description	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions			Filterable PM10					Condensable PM10			Total PM10	NH3 Slip
												total	coarse	Fine			total	SO4	organic		
														fine total	fine soil	EC					
		MMBtu/hr	Btu/scf	gr/10^6 scf	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
1	Natural Gas, 790 MW, Tangential-Fired, LNB, OFA, Stand-Alone SCR & ESP	7,880	1,000	7,000	0.010	78.80	0.0019	14.81	0.0019	14.97	Maximum Daily Emissions	14.97 (a)	0.00	14.97 (a)	13.97	1.00 (b)	45.60 (a)	0.91 (c)	44.69	60.57	7.07 (d)
2	Natural Gas, 790 MW, Tangential-Fired, LNB, OFA, Stand-Alone SCR & ESP	7,880	1,000	7,000	0.010	78.80	0.0019	14.81	0.0019	14.97	Maximum Daily Emissions	14.97 (a)	0.00	14.97 (a)	13.97	1.00 (b)	45.60 (a)	0.91 (c)	44.69	60.57	7.07 (d)

(a) The PM and SO2 emissions are based on the emission factors (assuming 1.0 lb of H2S per million cubic feet of natural gas) cited in Section 1.4, Natural Gas Combustion, of "Compilation of Air Pollutant Emission Factors," EPA Document No. AP-42, September 1998.
(b) Elemental carbon is 6.7% of fine PM based on the best estimate for electric utility natural gas 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.
(c) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2008. For natural gas-fired boilers, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1+S2)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr), F1 is the fuel factor (0.01 for natural gas), and S2 is the SO2 oxidation in SCR (0.03 for natural gas). Given the extemely low uncontrolled SO2 emissions, F2, the control factor, is assumed to be 1.0.
(d) The ammonia slip resulting from SCR is assumed to be a typical value of 0.75% at 6% O2 per EPRI 2008.

Table 4-3 MGS BART Option 2 Emissions

Unit	Description	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions			Filterable PM10					Condensable PM10			Total PM10	NH3 Slip
												total	coarse	Fine			total	SO4	organic		
														fine total	fine soil	EC					
		MMBtu/hr	Btu/scf	gr/10^6 scf	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
1	Natural Gas, 790 MW, Tangential-Fired, LNB, OFA, In-Line SCR & ESP	7,880	1,000	7,000	0.025	197.00	0.0019	14.81	0.0019	14.97	Maximum Daily Emissions	14.97 (a)	0.00	14.97 (a)	13.97	1.00 (b)	45.60 (a)	0.91 (c)	44.69	60.57	7.07 (d)
2	Natural Gas, 790 MW, Tangential-Fired, LNB, OFA, In-Line SCR & ESP	7,880	1,000	7,000	0.025	197.00	0.0019	14.81	0.0019	14.97	Maximum Daily Emissions	14.97 (a)	0.00	14.97 (a)	13.97	1.00 (b)	45.60 (a)	0.91 (c)	44.69	60.57	7.07 (d)

(a) The PM and SO2 emissions are based on the emission factors (assuming 1.0 lb of H2S per million cubic feet of natural gas) cited in Section 1.4, Natural Gas Combustion, of "Compilation of Air Pollutant Emission Factors," EPA Document No. AP-42, September 1998.
(b) Elemental carbon is 6.7% of fine PM based on the best estimate for electric utility natural gas 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.
(c) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2008. For natural gas-fired boilers, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1+S2)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr), F1 is the fuel factor (0.01 for natural gas), and S2 is the SO2 oxidation in SCR (0.03 for natural gas). Given the extemely low uncontrolled SO2 emissions, F2, the control factor, is assumed to be 1.0.
(d) The ammonia slip resulting from SCR is assumed to be a typical value of 2% at 3% O2 per Babcock Power.

Table 4-4 MGS BART Option 3 Emissions

Unit	Description	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions			Filterable PM10					Condensable PM10			Total PM10	NH3 Slip
												total	coarse	Fine			total	SO4	organic		
														fine total	fine soil	EC					
		MMBtu/hr	Btu/scf	gr/10^6 scf	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
1	Natural Gas, 790 MW, Tangential-Fired, LNB, OFA, FGR & ESP	7,880	1,000	7,000	0.070	551.60	0.0019	14.81	0.0019	14.97	Maximum Daily Emissions	14.97 (a)	0.00	14.97 (a)	13.97	1.00 (b)	44.92 (a)	0.23 (c)	44.69	59.89	0.00
2	Natural Gas, 790 MW, Tangential-Fired, LNB, OFA, FGR & ESP	7,880	1,000	7,000	0.070	551.60	0.0019	14.81	0.0019	14.97	Maximum Daily Emissions	14.97 (a)	0.00	14.97 (a)	13.97	1.00 (b)	44.92 (a)	0.23 (c)	44.69	59.89	0.00

(a) The PM and SO2 emissions are based on the emission factors (assuming 1.0 lb of H2S per million cubic feet of natural gas) cited in Section 1.4, Natural Gas Combustion, of "Compilation of Air Pollutant Emission Factors," EPA Document No. AP-42, September 1998.
(b) Elemental carbon is 6.7% of fine PM based on the best estimate for electric utility natural gas 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.
(c) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2008. For natural gas-fired boilers, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr) and F1 is the fuel factor (0.01 for natural gas). Given the extemely low uncontrolled SO2 emissions, F2, the control factor, is assumed to be 1.0.

Table 4-5 MGS BART Option 4 Emissions

Unit	Description	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions			Filterable PM10					Condensable PM10			Total PM10	NH3 Slip
												total	coarse	Fine			total	SO4	organic		
														fine total	fine soil	EC					
		MMBtu/hr	Btu/scf	gr/10^6 scf	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
1	Natural Gas, 790 MW, Tangential-Fired, LNB, OFA, SNCR & ESP	7,880	1,000	7,000	0.080	630.40	0.0019	14.81	0.0019	14.97	Maximum Daily Emissions	14.97 (a)	0.00	14.97 (a)	13.97	1.00 (b)	44.92 (a)	0.23 (c)	44.69	59.89	21.20 (d)
2	Natural Gas, 790 MW, Tangential-Fired, LNB, OFA, SNCR & ESP	7,880	1,000	7,000	0.080	630.40	0.0019	14.81	0.0019	14.97	Maximum Daily Emissions	14.97 (a)	0.00	14.97 (a)	13.97	1.00 (b)	44.92 (a)	0.23 (c)	44.69	59.89	21.20 (d)

(a) The PM and SO2 emissions are based on the emission factors (assuming 1.0 lb of H2S per million cubic feet of natural gas) cited in Section 1.4, Natural Gas Combustion, of "Compilation of Air Pollutant Emission Factors," EPA Document No. AP-42, September 1998.
(b) Elemental carbon is 6.7% of fine PM based on the best estimate for electric utility natural gas 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.
(c) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2008. For natural gas-fired boilers, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr) and F1 is the fuel factor (0.01 for natural gas). Given the extemely low uncontrolled SO2 emissions, F2, the control factor, is assumed to be 1.0.
(d) The ammonia slip resulting from SNCR is assumed to be a typical value of 5.0% at 3% O2 per Babcock Power.

Table 4-6 MGS BART Option 5 Emissions[5]

Unit	Description	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions			Filterable PM10					Condensable PM10			Total PM10	NH3 Slip
												total	coarse	Fine			total	SO4	organic		
														fine total	fine soil	EC					
		MMBtu/hr	Btu/scf	gr/10^6 scf	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
1	Natural Gas, 790 MW, Tangential-Fired, LNB, OFA, & ESP	7,880	1,000	7,000	0.100	788.00	0.0019	14.81	0.0019	14.97	Maximum Daily Emissions	14.97 (a)	0.00	14.97 (a)	13.97	1.00 (b)	44.92 (a)	0.23 (c)	44.69	59.89	0.00
2	Natural Gas, 790 MW, Tangential-Fired, LNB, OFA, & ESP	7,880	1,000	7,000	0.100	788.00	0.0019	14.81	0.0019	14.97	Maximum Daily Emissions	14.97 (a)	0.00	14.97 (a)	13.97	1.00 (b)	44.92 (a)	0.23 (c)	44.69	59.89	0.00

(a) The PM and SO2 emissions are based on the emission factors (assuming 1.0 lb of H2S per million cubic feet of natural gas) cited in Section 1.4, Natural Gas Combustion, of "Compilation of Air Pollutant Emission Factors," EPA Document No. AP-42, September 1998.
(b) Elemental carbon is 6.7% of fine PM based on the best estimate for electric utility natural gas 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.
(c) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2008. For natural gas-fired boilers, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr) and F1 is the fuel factor (0.01 for natural gas). Given the extemely low uncontrolled SO2 emissions, F2, the control factor, is assumed to be 1.0.

[5] The 0.10 lb/MMBtu emission rate presented in Table 4-6 is based on maximum thermal input NO_x emissions. See Appendix G for an explanation of the operation of MGS on 100% natural gas fuel and at various load levels that would be expected for a load-following, intermediate and peaking generation system resource serving the Southern California load control area. Such an operation will cause the actual NO_x emission performance rate to be as high as 0.15 lb/MMBtu when averaged over any significant operating time period. The existing ESP structure will remain in place, serving only as a duct for the flue gas.

5.0 Visibility Modeling: CALMET Processing Procedures

For the CALPUFF modeling, SCE 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.

5.1 WRAP CALMET Database

The WRAP has developed six separate 4-kilometer (km) CALMET meteorological databases for 3 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 MGS was done using the Arizona 4-km domain, as shown in Figure 5-1 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 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 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 MGS was done using the Arizona 4-km CALMET database with application-specific modifications described in Section 5.2.

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 only R1, R2, and RMAX1, and the model version. These differences are illustrated in Figures 5-1 through 5-3 and listed in Table 5-1, and are further discussed below. Figure 5-1 shows the CALMET/CALPUFF modeling domain established by the WRAP for Arizona.

5.2 Enhancements to the WRAP CALMET Database

ENSR suggested two modifications/enhancements to the 4-km Arizona CALMET WRAP database. They are as follows:

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 5-2 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 R1MAX = 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, shown in Appendix B, along with other relevant agency recommendations). 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.

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 5-3. 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 the better performance in the wind field depiction associated with the smaller values.

When rerunning CALMET, ENSR used the "official" EPA-approved version of CALPUFF modeling system CALMET Version 5.8 instead of Version 6.211 that was used by WRAP, available at http://www.src.com/calpuff/download/download.htm#EPA_VERSION.

In accordance with recent CALPUFF modeling guidance from the EPA Region IX and National Park Service, the ENSR CALMET modeling also used the technical options listed below.

- Include upper air soundings in a Step 2 analysis; the WRAP BART protocol does not include these observations. Figure 5-1 shows upper air and surface station locations.
- Set NOOBS = 0, to use both surface and upper air observations.
- Set IEXTRP = -4, to extrapolate surface wind observations to the upper layers using similarity theory, and ignore layer 1 from the upper air soundings.
- Set ITPROG = 1, to use surface station temperature and the MM5 for upper air temperature interpolation.

Figure 5-1 Location of Surface and Upper Air Stations used for Arizona CALMET Domain

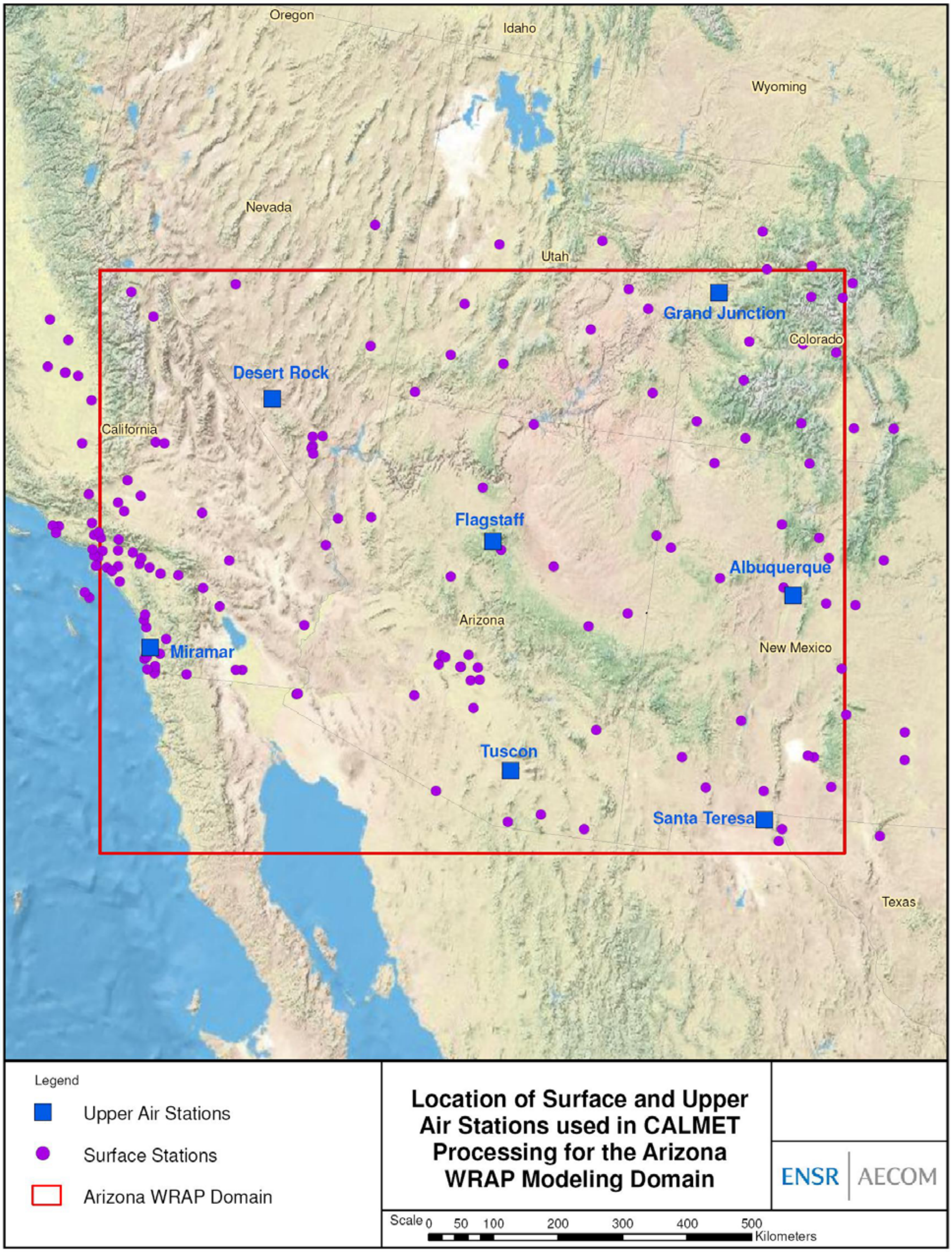


Figure 5-2 CALMET Wind Fields with WRAP Settings

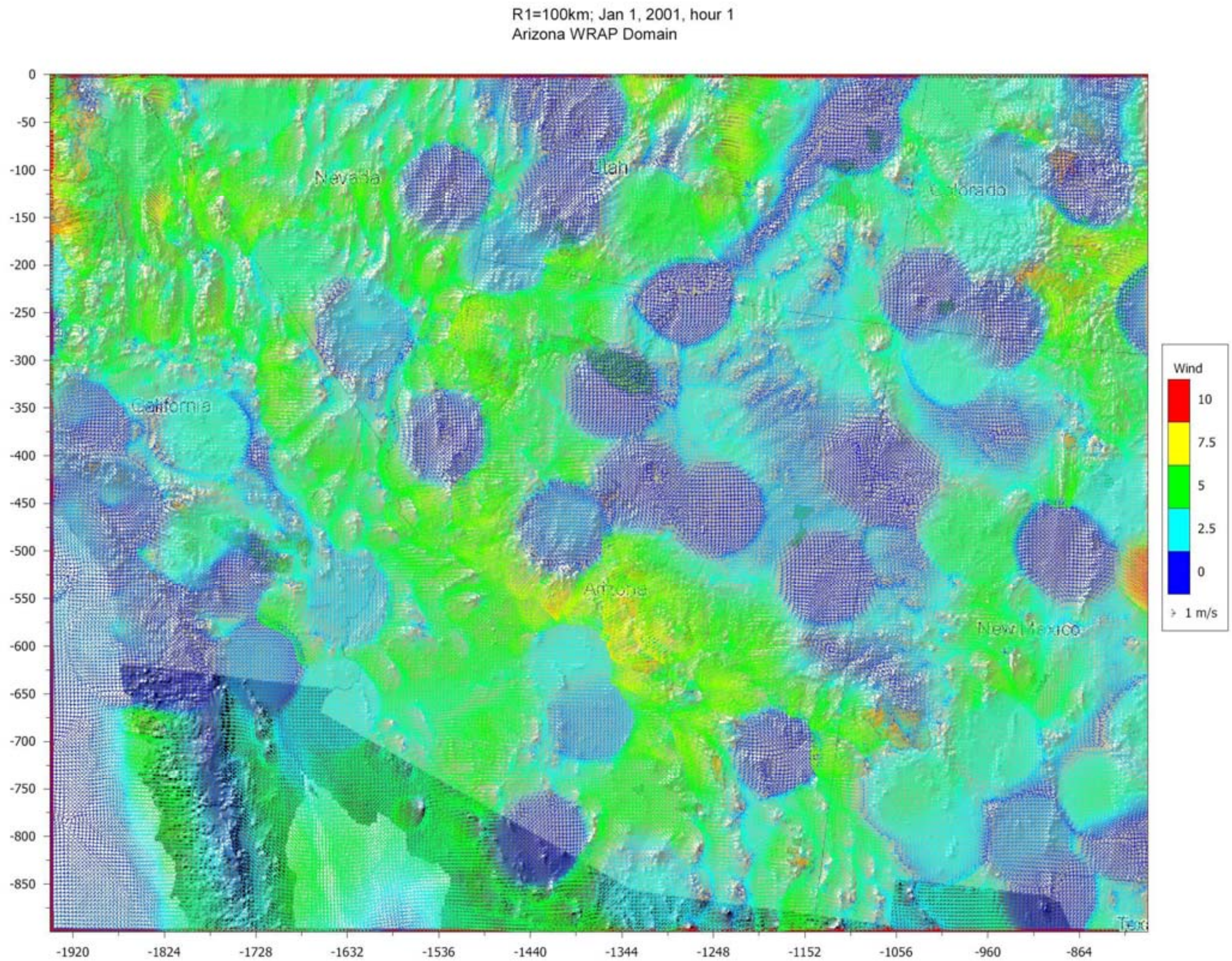
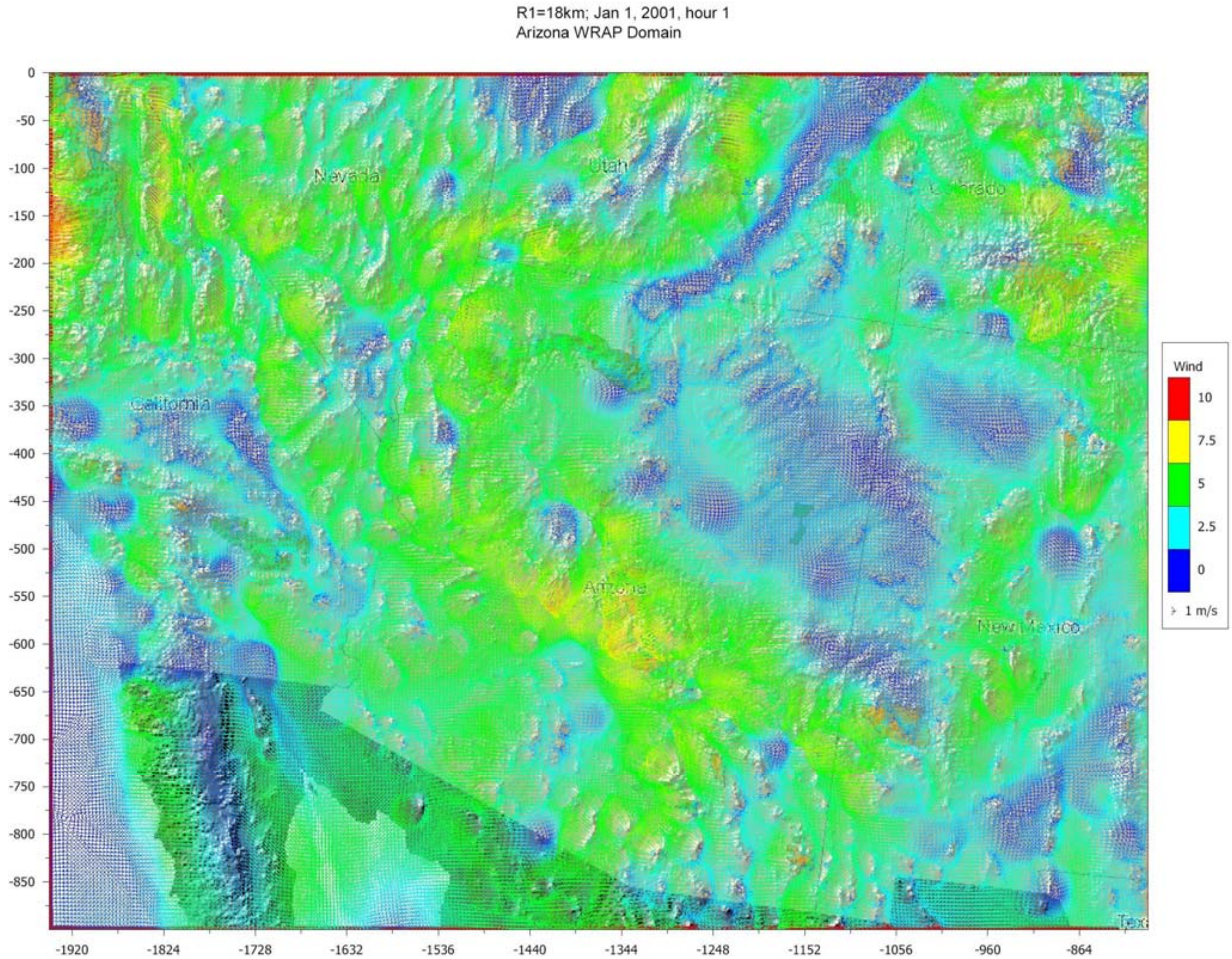


Figure 5-3 CALMET Wind Fields with ENSR Settings



6.0 Visibility Modeling: CALPUFF Procedures

This section provides a summary of the modeling procedures that were used for the refined CALPUFF analysis for the MGS.

6.1 CALPUFF Modeling Procedures

SCE and ENSR 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. 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.

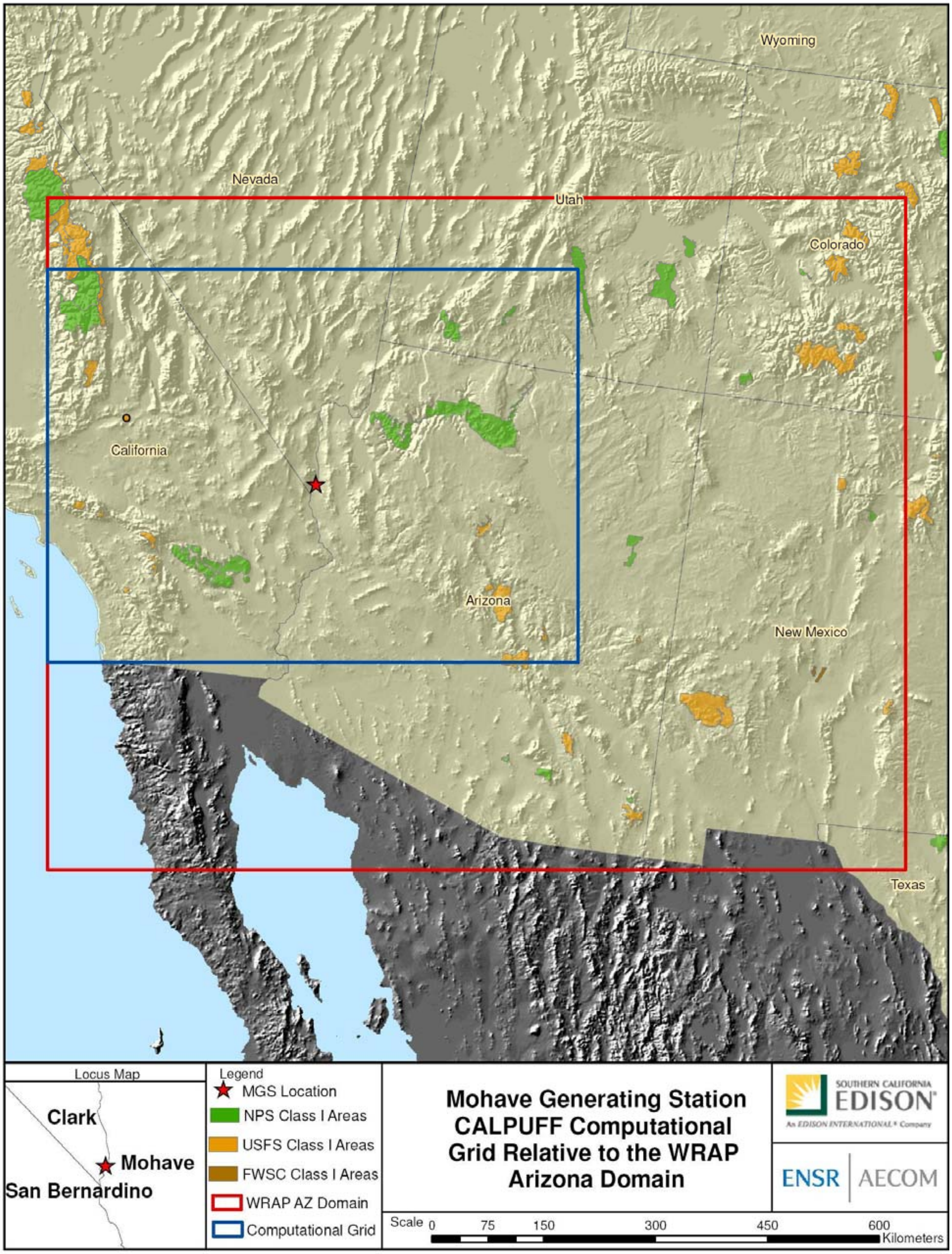
The area covered by the 4-km WRAP domain for Arizona is shown in Figure 5-1. The BART CALPUFF modeling for MGS was done using a smaller computational grid within the WRAP domain to minimize computation time and output file size. The computational grid domain is shown in Figure 6-1. This domain includes 11 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 long 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 3 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. Ammonia background concentrations selected for use in CALPUFF are discussed in Appendix C.

As suggested by NDEP, ENSR applied both the new and old IMPROVE equations to report regional haze results for the baseline case and the five BART options using Excel spreadsheets for western US Class I areas, as supplied by Dr. Ivar Tombach. The new IMPROVE calculation system (described in Appendix D) incorporates the equation for determining light extinction from particulate concentration estimates. The old IMPROVE algorithm does not incorporate the effects of site-specific Rayleigh scattering and naturally occurring sea salt on background visibility, but the new algorithm does account for this effect. We provide the results using the new IMPROVE equation in Appendix E and with the old IMPROVE equation in Appendix F.

Figure 6-1 MGS CALPUFF Computational Grid Relative to the WRAP Arizona Domain



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

There are 11 Class I areas to be modeled for the MGS BART analysis. 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 Annual Average Natural Concentrations, listed in Table 6-1 and the monthly f(RH) values recommended by EPA (EPA 2003a,b). For each Class I area, the natural conditions and the f(RH) values to be used are consistent with the Arizona WRAP modeling.

Table 6-1 Annual Average Natural Concentrations of Aerosol Components (μg/m^3)

Ammonium Sulfate	0.12
Ammonium Nitrate	0.10
Organic Carbon	0.47
Elemental Carbon	0.02
Soil	0.5
Coarse Mass	3.0

6.3 Light Extinction and Haze Impact Calculations

The CALPOST postprocessor was used for the calculation of 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 μg/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 elemental carbon) to yield the total hourly source-caused extinction.

7.0 CALPUFF Visibility Modeling Results

This section provides a summary of the modeled visibility improvement on affected Class I areas as a result of installing BART control options on MGS.

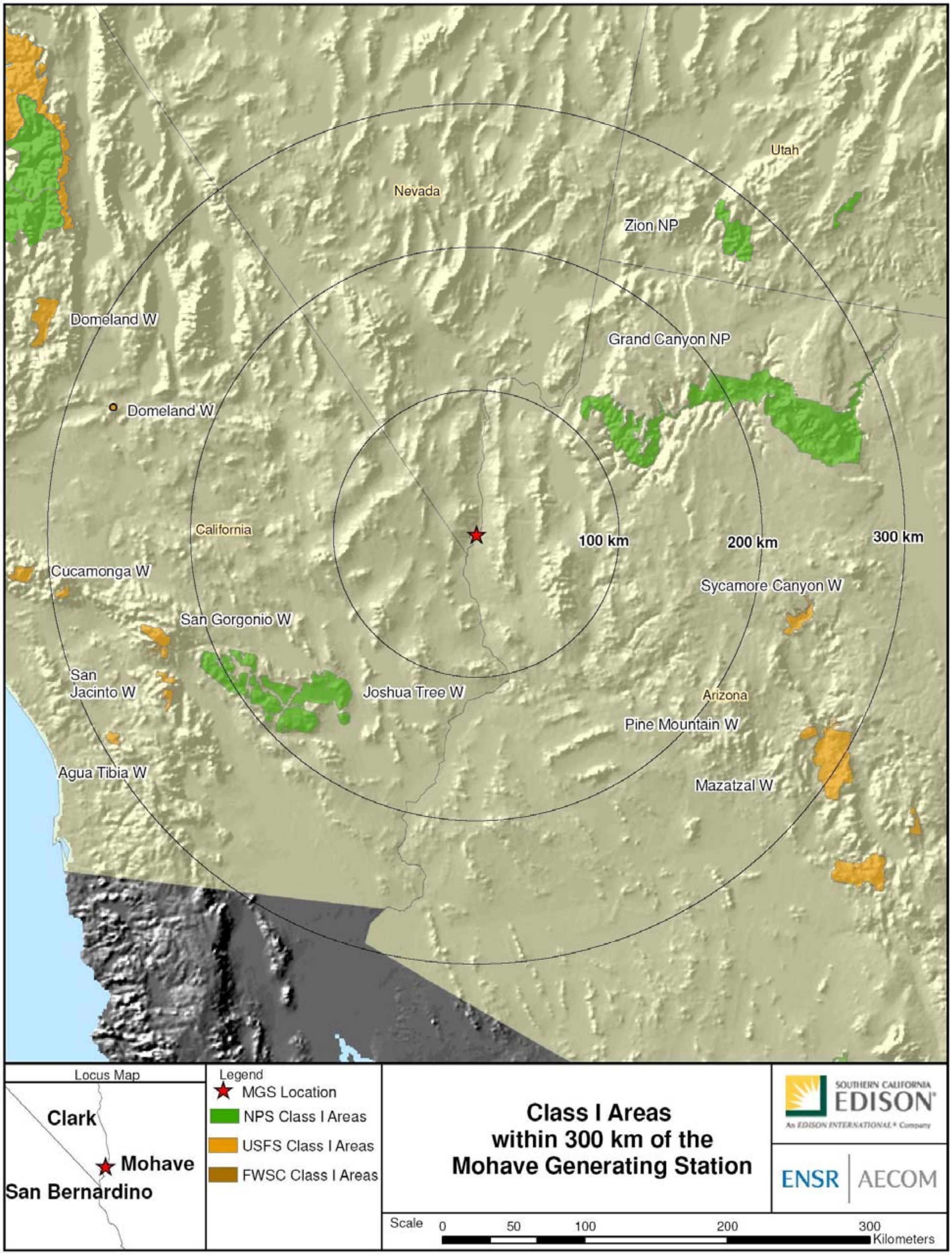
7.1 Affected Class I Areas

Class I areas within 300 km of the facility are shown in Figure 7-1 and include the following 11 Class I areas:

1. Grand Canyon National Park
2. Sycamore Canyon Wilderness
3. Mazatzal Wilderness
4. Pine Mountain Wilderness
5. Zion National Park
6. Joshua Tree National Monument
7. Agua Tibia Wilderness
8. San Jacinto Wilderness
9. San Gorgonio Wilderness
10. Cucamonga Wilderness
11. Domeland Wilderness

Note that Domeland Wilderness is located approximately 320 km from the MGS; however, the NPS receptor file indicates that there is at least one receptor within the 300 km the of the MGS. Therefore, Domeland Wilderness was included in the regional haze modeling.

Figure 7-1 Class I Areas within 300 km of the Mohave Generating Station



7.2 Baseline CALPUFF Modeling Results

CALPUFF modeling results of the baseline emissions at 11 Class I areas are presented in Table 7-1 and graphically plotted in Figure 7-2. (The old IMPROVE equation results can be found in Table F-1 and Figure F-1, respectively). Modeling was conducted for all three years of CALMET meteorological data (2001-2003). The results are reported below using the new IMPROVE equation and the old IMPROVE equation results are presented in Appendix F, which lists the tables and figures in the main report that are counterparts in the appendix.

For each Class I area and year, Table 7-1 lists the 8th highest delta-deciview impact. Figure 7-2 shows the 8th highest deciview impacts. The figure indicates that the higher visibility impacts generally occur at Grand Canyon National Park and Joshua Tree National Monument. Higher impacts at these Class I areas occur due to their proximity to MGS.

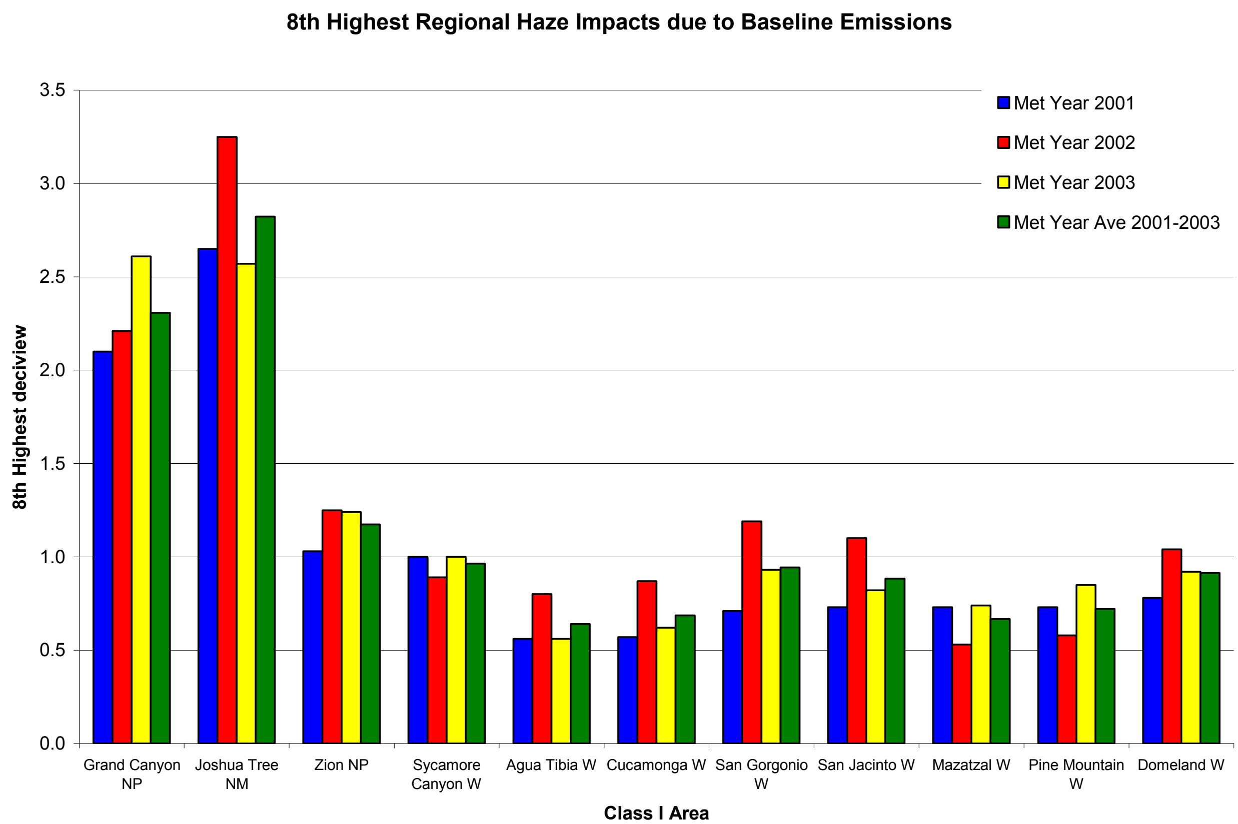
EPA recommends in its BART Guidelines that the 98th percentile value of the modeling results should be compared to the threshold of 0.5 deciviews to determine if a source contributes to visibility impairment. The Guidelines also recommend using the 98th-percentile statistic for comparing visibility improvements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

The results of the baseline emissions analysis indicate that the Mohave 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 MGS is presumed to be subject to BART because its emissions may reasonably be anticipated to cause or contribute to visibility impairment at a relevant Class I area. Candidate BART controls are discussed in Section 3. The results of the visibility improvement modeling for these candidate controls are discussed in Section 7.3.

Table 7-1 Regional Haze Impacts Due to Baseline Emissions

Class I Area	Met Year 2001				Met Year 2002				Met Year 2003				2001-2003 Ave
	Days above 0.5 Δ dv	Days above 1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	Days above 0.5 Δ dv	Days above 1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	Days above 0.5 Δ dv	Days above 1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	8th Highest Δ dv
Grand Canyon NP	153	74	3.75	2.10	159	78	3.94	2.21	191	105	5.11	2.61	2.31
Joshua Tree NM	72	63	4.62	2.65	87	61	6.36	3.25	78	47	3.52	2.57	2.82
Zion NP	57	10	1.84	1.03	61	12	1.85	1.25	70	16	2.35	1.24	1.17
Sycamore Canyon W	25	7	1.73	1.00	31	5	2.44	0.89	47	7	2.16	1.00	0.96
Agua Tibia W	9	1	1.65	0.56	12	5	2.56	0.80	10	0	0.99	0.56	0.64
Cucamonga W	8	1	1.38	0.57	17	4	3.03	0.87	12	3	1.68	0.62	0.69
San Gorgonio W	15	4	1.54	0.71	22	10	4.17	1.19	15	4	1.52	0.93	0.94
San Jacinto W	15	3	1.30	0.73	22	9	3.73	1.10	19	5	1.32	0.82	0.88
Mazatzal W	18	2	1.70	0.73	9	2	1.65	0.53	22	6	1.64	0.74	0.67
Pine Mountain W	17	3	1.80	0.73	10	2	1.71	0.58	20	4	1.33	0.85	0.72
Domeland W	12	2	1.72	0.78	19	9	2.07	1.04	12	6	2.19	0.92	0.91

Figure 7-2 8th Highest Regional Haze Impacts for Each Modeled Year Due to Baseline Emissions



7.3 CALPUFF Modeling Results for BART Control Options

Five BART control options were modeled for each meteorological year (2001-2003) and for eleven Class I areas to determine the predicted visibility improvement for these candidate controls. The results presented in this section are based on the new IMPROVE equation, while the old IMPROVE equation results are presented in Appendix F.

The 3-year average results of the BART control options modeling are presented in Table 7-2 and graphically plotted in Figure 7-3. Figures E-1 through E-5 shows the same statistic for each meteorological year. (The old IMPROVE equation results can be found in Table F-2 and graphically shown in Figures F-2 through F-8). Table 7-2 shows the 8th highest visibility results averaged over three modeled years and corresponding visibility improvements relative to the baseline case. The table also summarizes the total number of days over three years above the 0.5 delta-dv and the number of days above the 0.5 delta-dv that were reduced relative to the baseline case.

Emission rates that were used in modeling the five BART control options are listed in Tables 4-2 through 4-6. These control scenarios, which are more fully discussed in Section 3, are:

- BART Option 1: LNB+OFA+SCR (Stand Alone)
- BART Option 2: LNB+OFA+SCR (In-Line)
- BART Option 3: LNB+OFA+FGR

- BART Option 4: LNB+OFA+SNCR
- BART Option 5: LNB+OFA

Results for each candidate BART control option are discussed in more detail below. The results discussion focuses on Joshua Tree Nation Park and Grand Canyon National Park because of their proximity to the MGS.

BART Option 1: The modeling results indicate that the LNB+OFA+SCR (Stand-Alone) controls will provide the largest visibility benefit, although not substantially more than the other BART options. The visibility (average 8^{th} highest days) is predicted to improve by 2.65 and 2.14 delta-dv relative to the baseline case at Joshua Tree NP and Grand Canyon NP, respectively. (This metric is used to characterize visibility improvement for the other BART options as well.) The BART Option 1 would result in a predicted reduction of 1346 days above 0.5 delta-dv over three years and the 11 Class I areas considered in this analysis. Note that these modeling results do not account for other power generation required to make up for the parasitic losses due to the SCR operational requirements. However, this control option would create new emissions of primary sulfates (H_2SO_4) and excess ammonia.

BART Option 2: The modeling results for the LNB+OFA+SCR (In-Line) controls are very similar to BART Option 1 and show that the visibility is predicted to improve by 2.61 and 2.10 delta-dv relative to the baseline case at Joshua Tree NP and Grand Canyon NP, respectively. The BART Option 2 would result in a predicted reduction of 1345 days above 0.5 delta-dv over three years and at the 11 modeled Class I areas. This control option is also subject to the same parasitic power requirements as Option 1.

BART Option 3: Addition of FGR to LNB and OFA is predicted to improve visibility by 2.46 and 2.01 delta-dv relative to the baseline case at Joshua Tree NP and Grand Canyon NP, respectively. The BART Option 3 would result in a predicted reduction of 1332 days above 0.5 delta-dv over three years and at the 11 modeled Class I areas.

BART Option 4: Addition of SNCR with LNB+OFA is predicted to improve visibility by 2.43 and 1.98 delta-dv relative to the baseline case at Joshua Tree NP and Grand Canyon NP, respectively. This BART option would result in a predicted reduction of 1327 days above 0.5 delta-dv over three years and at the 11 modeled Class I areas.

BART Option 5: A combination of LNB+OFA emission controls is predicted to improve visibility by 2.36 and 1.94 delta-dv relative to the baseline case at Joshua Tree NP and Grand Canyon NP, respectively, and would lead to a reduction of 1319 days above 0.5 delta-dv over three years and at the 11 modeled Class I areas.

It is noteworthy that the average 98^{th} percentile daily impact over the three years modeled results in a visibility impact less than 0.5 delta-dv at all Class I areas for all of the BART control options, even Option 5 (using the new IMPROVE equation). Therefore, all of these options result in an imperceptible visibility impact.

Figure 7-4 shows the total number of days above 0.5 delta-dv removed as a result of the BART NO_x controls and Figure 7-5 shows the breakdown of the days above 0.5 delta-dv removed at the highly impacted Class I areas as well as at the California Class I areas and non-California Class I areas. (Figures F-9 and F-10 graphically show the results using the old IMPROVE equation). Note that if the full height of the bars in Figure 7-4 were plotted, the heights of the bars would be virtually the same, indicating a very small difference in improvement from the baseline case to each of these BART control options involving the number of days removed for delta-dv above 0.5.

Table 7-2 Regional Haze Results of Modeled BART Options

Class I Area	BART Option	BART Controls	2001-2003 Ave		2001-2003 Total	
			8th Highest Δ dv	Change from Baseline, dv	# of Days above 0.5 Δ dv	# of Days above 0.5 Δ dv Reduced Relative to Baseline
Grand Canyon N	-	Baseline	2.31	0.00	503	0
	1	LNB+OFA+SCR (Stand Alone)	0.17	2.14	0	503
	2	LNB+OFA+SCR (In-Line)	0.20	2.10	1	502
	3	LNB+OFA+FGR	0.30	2.01	6	497
	4	LNB+OFA+SNCR	0.32	1.98	8	495
	5	LNB+OFA	0.36	1.94	8	495
Joshua Tree NM	-	Baseline	2.82	0.00	237	0
	1	LNB+OFA+SCR (Stand Alone)	0.17	2.65	0	237
	2	LNB+OFA+SCR (In-Line)	0.21	2.61	0	237
	3	LNB+OFA+FGR	0.36	2.46	8	229
	4	LNB+OFA+SNCR	0.39	2.43	11	226
	5	LNB+OFA	0.46	2.36	19	218
Zion NP	-	Baseline	1.17	0.00	188	0
	1	LNB+OFA+SCR (Stand Alone)	0.05	1.13	0	188
	2	LNB+OFA+SCR (In-Line)	0.05	1.12	0	188
	3	LNB+OFA+FGR	0.10	1.07	0	188
	4	LNB+OFA+SNCR	0.11	1.06	0	188
	5	LNB+OFA	0.13	1.04	0	188
Sycamore Canyon W	-	Baseline	0.96	0.00	103	0
	1	LNB+OFA+SCR (Stand Alone)	0.02	0.94	0	103
	2	LNB+OFA+SCR (In-Line)	0.03	0.93	0	103
	3	LNB+OFA+FGR	0.06	0.91	0	103
	4	LNB+OFA+SNCR	0.07	0.90	0	103
	5	LNB+OFA	0.08	0.89	0	103
Agua Tibia W	-	Baseline	0.64	0.00	31	0
	1	LNB+OFA+SCR (Stand Alone)	0.02	0.62	0	31
	2	LNB+OFA+SCR (In-Line)	0.02	0.62	0	31
	3	LNB+OFA+FGR	0.04	0.60	0	31
	4	LNB+OFA+SNCR	0.04	0.60	0	31
	5	LNB+OFA	0.05	0.59	0	31
Cucamonga W	-	Baseline	0.69	0.00	37	0
	1	LNB+OFA+SCR (Stand Alone)	0.02	0.67	0	37
	2	LNB+OFA+SCR (In-Line)	0.02	0.67	0	37
	3	LNB+OFA+FGR	0.05	0.64	0	37
	4	LNB+OFA+SNCR	0.05	0.64	0	37
	5	LNB+OFA	0.06	0.63	0	37

Table 7-2 Regional Haze Results of Modeled BART Options

Class I Area	BART Option	BART Controls	2001-2003 Ave: 8th Highest Δ dv	2001-2003 Ave: Change from Baseline, dv	2001-2003 Total: # of Days above 0.5 Δ dv	2001-2003 Total: # of Days above 0.5 Δ dv Reduced Relative to Baseline
San Gorgonio W	-	Baseline	0.94	0.00	52	0
	1	LNB+OFA+SCR (Stand Alone)	0.03	0.92	0	52
	2	LNB+OFA+SCR (In-Line)	0.03	0.91	0	52
	3	LNB+OFA+FGR	0.06	0.88	0	52
	4	LNB+OFA+SNCR	0.06	0.88	0	52
	5	LNB+OFA	0.08	0.87	0	52
San Jacinto W	-	Baseline	0.88	0.00	56	0
	1	LNB+OFA+SCR (Stand Alone)	0.03	0.85	0	56
	2	LNB+OFA+SCR (In-Line)	0.04	0.84	0	56
	3	LNB+OFA+FGR	0.07	0.82	0	56
	4	LNB+OFA+SNCR	0.07	0.81	0	56
	5	LNB+OFA	0.08	0.80	0	56
Mazatzal W	-	Baseline	0.67	0.00	49	0
	1	LNB+OFA+SCR (Stand Alone)	0.02	0.65	0	49
	2	LNB+OFA+SCR (In-Line)	0.02	0.65	0	49
	3	LNB+OFA+FGR	0.03	0.63	0	49
	4	LNB+OFA+SNCR	0.03	0.63	0	49
	5	LNB+OFA	0.04	0.63	0	49
Pine Mountain W	-	Baseline	0.72	0.00	47	0
	1	LNB+OFA+SCR (Stand Alone)	0.02	0.70	0	47
	2	LNB+OFA+SCR (In-Line)	0.02	0.70	0	47
	3	LNB+OFA+FGR	0.03	0.69	0	47
	4	LNB+OFA+SNCR	0.03	0.69	0	47
	5	LNB+OFA	0.04	0.68	0	47
Domeland W	-	Baseline	0.91	0.00	43	0
	1	LNB+OFA+SCR (Stand Alone)	0.02	0.89	0	43
	2	LNB+OFA+SCR (In-Line)	0.03	0.88	0	43
	3	LNB+OFA+FGR	0.05	0.86	0	43
	4	LNB+OFA+SNCR	0.05	0.86	0	43
	5	LNB+OFA	0.06	0.85	0	43
11 Class I Areas	-	Baseline	1.16	0.00	1346	0
	1	LNB+OFA+SCR (Stand Alone)	0.05	1.11	0	1346
	2	LNB+OFA+SCR (In-Line)	0.06	1.09	1	1345
	3	LNB+OFA+FGR	0.10	1.05	14	1332
	4	LNB+OFA+SNCR	0.11	1.04	19	1327
	5	LNB+OFA	0.13	1.03	27	1319

Figure 7-3 8^{th} Highest Visibility Impacts due to Five NO_x Control Options

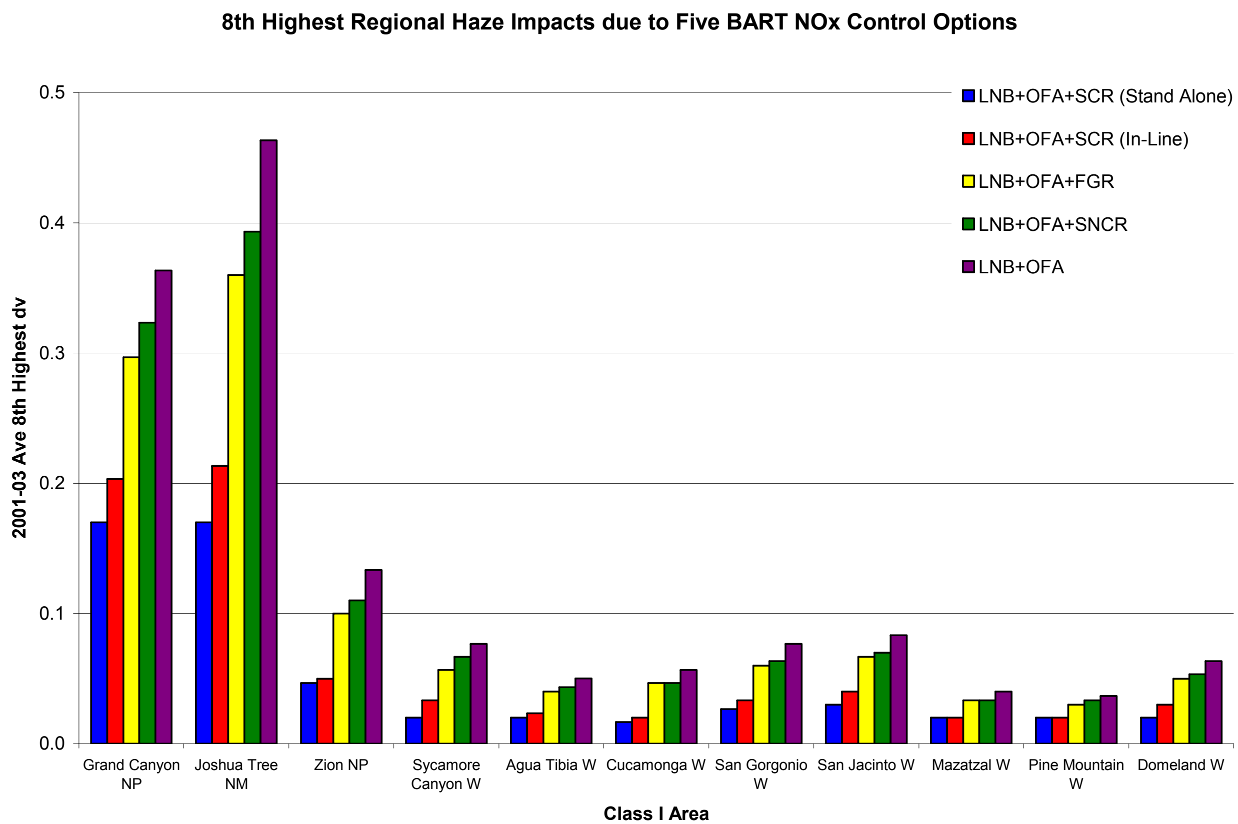


Figure 7-4 Total Number of Days Removed Above 0.5 delta-dv Relative to the Baseline Case

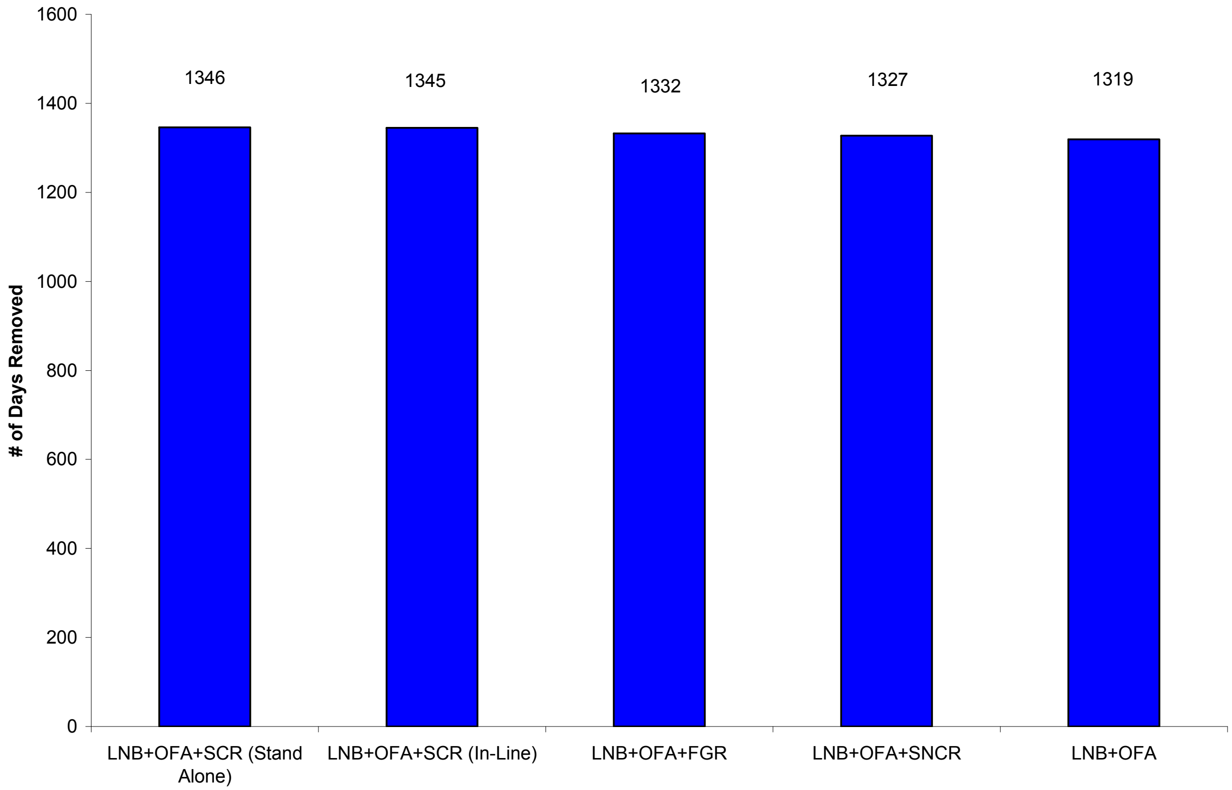
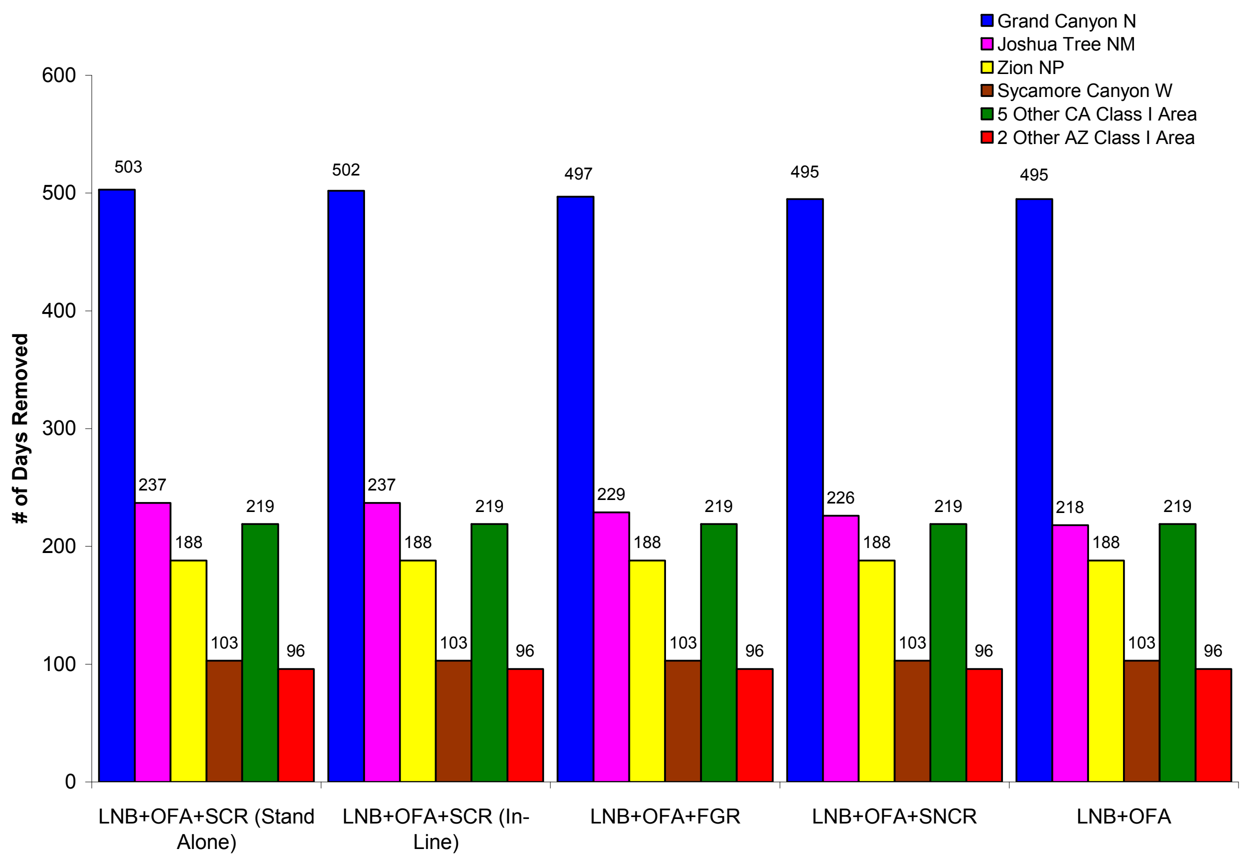


Figure 7-5 Number of Days Removed at Each Class I Area Above 0.5 delta-dv Relative to the Baseline Case



8.0 Final BART Determination

8.1 Evaluation of BART Control Options

To assess the relative visibility benefits of the candidate BART options, we provide plots showing the visibility improvements as a function of costs for the two closest Class I areas in Figure 8-1, as well as all of the other California Class I areas in Figure 8-2 and the other non-California Class I areas in Figure 8-3. The separate figures (8-1 through 8-3) are provided to assist the reader's interpretation of the results. Similar figures are graphically plotted using the old IMPROVE equation results in Figures F-11 through F-13. It is apparent from Figures 8-2 and 8-3 that these other Class I areas show very low visibility impacts from all of the BART control options. The results for the Grand Canyon and Joshua Tree National Parks in Figure 8-1 indicate only modest visibility gains at great cost relative to BART Control Option 5 for the other BART control options.

It is clear from all of these figures that a large visibility improvement is attained by the restriction of fuel to natural gas and the installation of LNB and OFA. The remaining, more expensive BART control options provide some modest improvements, but at significant cost. All BART control options result in average 98th percentile impacts below the contribution to perceptible haze threshold of 0.5 delta-dv.

We also provide Figure 8-4 that plots the annual NO_x emissions reduction as a function of annual costs for each control options as shown in Table 3-3.

A summary of findings for each of the BART control options is presented below.

<u>BART Control Option 1: LNB + OFA + Stand-Alone SCR</u>

This option has the lowest NO_x emissions, but since nitrates are not the most important visibility-impairing particle species, the visibility improvement (expressed in terms of change in the average 98th percentile day over three years modeled) relative to that of BART Option 5 is only 0.20 delta-dv at the Grand Canyon NP and 0.29 delta-dv at Joshua Tree NP (and less at the other Class I areas). The number of days of 0.5 delta-dv reduced from the base case is nearly the same for all Class I areas.

In its Regional Haze Final Rule Preamble, EPA estimated ranges of cost effectiveness that were used to establish the presumptive limits for NO_x as $100 to $1000 per ton of NO_x removed. For NO_x controls, EPA stated that its presumptive NOx "limits…are based on the use of current combustion control technology. Current combustion control technology is generally, but not always, more cost-effective than post-combustion controls such as SCRs." Note from Table 3-4 that the cost effectiveness of stand-alone SCR is in excess of $2,400 per ton of NO_x removed, and the incremental cost effectiveness relative to Option 5 is over $11,700 per ton. EPA further stated that they were "not establishing presumptive limits based on the installation of SCR. Although States may in specific cases find that the use of SCR is appropriate, we have not determined that SCR is generally cost-effective for BART across unit types." As shown in the figures in this section, the NO_x control technologies analyzed for MGS are generally consistent with EPA's guidance. The combustion control technologies are significantly more cost effective than post-combustion controls, such as SCR. It is also worth noting that the imposition of SCR, on top of the retirement of the coal-firing capability and the other capital equipment improvements proposed could possibly require an investment in excess of what the prospective owners would be able to support. If MGS is not re-activated as a natural gas-fired plant, then the required electrical generation of several hundred megawatts from possibly more visibility-impairing pollutant sources would have the potential to adversely affect the Nevada Regional Haze Rule State Implementation Plan (SIP) outlook for meeting the 2018 milestone. Other factors that contribute to the rejection of this option as BART are:

- The need to transport ammonia supplies to the plant, with the attendant hazardous air pollutant risks and additional vehicular traffic; and
- The parasitic power loss to run the SCR equipment that will need to be made up elsewhere.

Therefore, Option 1 is rejected as BART for MGS.

BART Control Option 2: LNB + OFA + In-Line SCR

This option has the somewhat higher NO_x emissions than those of BART Option 1, and the costs are slightly less. Otherwise, the issues for this option are similar to that of Option 1. The visibility improvement relative to that of BART Option 5 is only 0.16 delta-dv at the Grand Canyon NP and 0.18 delta-dv at Joshua Tree NP (and less at the other Class I areas). The number of days of 0.5 delta-dv reduced from the base case is nearly the same for all Class I areas.

Note from Table 3-3 that the cost effectiveness of in-line SCR is in excess of $2,300 per ton of NO_x removed, and the incremental cost effectiveness relative to Option 5 is about $13,000 per ton. The conclusions for this BART control option are basically similar to that for Option 1, and this option is rejected as BART.

BART Control Option 3: LNB + OFA + FGR

This option has notably higher NO_x emissions than those of BART Options 1 and 2, and the costs are somewhat less. Otherwise, the issues for this option are similar to those of Options 1 and 2, except for no requirement for ammonia injection. The visibility improvement relative to that of BART Option 5 is essentially zero delta-dv at the Grand Canyon NP and only 0.10 delta-dv at Joshua Tree NP (and less at the other Class I areas). The number of days of 0.5 delta-dv reduced from the base case is nearly the same for all Class I areas.

Note from Table 3-3 that the cost effectiveness of this option is in excess of $1,800 per ton of NO_x removed, and the incremental cost effectiveness relative to Option 5 is about $22,800 per ton. This option also may result in increased CO emissions. The conclusions for this BART control option are basically similar to those for Options 1 and 2, and this option is rejected as BART.

BART Control Option 4: LNB + OFA + SNCR

This option has higher NO_x emissions than the previous BART options 1 and 2, and the costs are somewhat less. Otherwise, the issues for this option are similar to those of Options 1 and 2, with a feature of considerably higher ammonia slip. The visibility improvement relative to that of BART Option 5 is only 0.04 delta-dv at the Grand Canyon NP and 0.07 delta-dv at Joshua Tree NP (and less at the other Class I areas). The number of days of 0.5 delta-dv reduced from the base case is nearly the same for all Class I areas.

Note from Table 3-3 that the cost effectiveness of this option is more than $1,100 per ton of NO_x removed, and the incremental cost effectiveness relative to Option 5 is about $20,000 per ton. This option requires ammonia deliveries and storage, and the attendant complications. The conclusions for this BART control option are basically similar to those of the previous options, and Option 4 is rejected as BART.

BART Control Option 5: LNB + OFA

This option has higher NO_x emissions than those of the other BART options, but the costs are comparatively quite low. The CALPUFF visibility modeling results presented in Sections 5.0 - 7.0 was performed based on the maximum expected 788 lbs NO_x per hour for each Mohave generating unit, consistent with Table 4.6, in Section 4.0. This option also results in visibility impacts at all 11 Class I areas within 300 Km of MGS that are below the contribution to the perceptible limit (0.5 delta-dv). The number of days of 0.5 delta-dv reduced from the base case is nearly the same for all Class I areas.

Note from Table 3-3 that the annualized cost for this option is less than $100 per ton of NO_x removed. This option represents the combustion controls cited by EPA as cost-effective for NO_x BART, and accordingly is selected as BART.

8.2 Conclusions

Table 8-1 presents an overall summary of the BART determination. The data in Figures 8-1 and 8-2 clearly indicate that the incremental visibility improvement for BART control options other than Option 5 result in only minor visibility improvements at significant cost and other negative environmental impacts. Consistent with EPA guidance noted in Section 8.1, we select Option 5, an effective combustion control strategy, as BART.

Consistent with the CALPUFF modeling demonstrating significant visibility improvements for affected Class I areas from BART Control Option 5, we select a NO_x BART Emissions Limit of 788 lbs/hour for each Mohave Generating Unit. In addition, consistent with the controlled NO_x performance of Mohave as a 100% natural gas generating facility,[6] we select a NO_x BART Emission Rate of 0.15 lb/MMBtu, and we select a 12-month rolling average as the method for determining compliance with both the lb/hour and lb/MMBtu BART Emission Limits.

[6] See a detailed discussion in Appendix G regarding Mohave's NOx reduction performance as a 100% natural gas fueled generating facility serving the Southern California load control area as a load following, intermediate and peaking system generation resource

Figure 8-1 Annual Cost of NO_x Controls vs. Visibility Improvements at the Closest Class I Areas

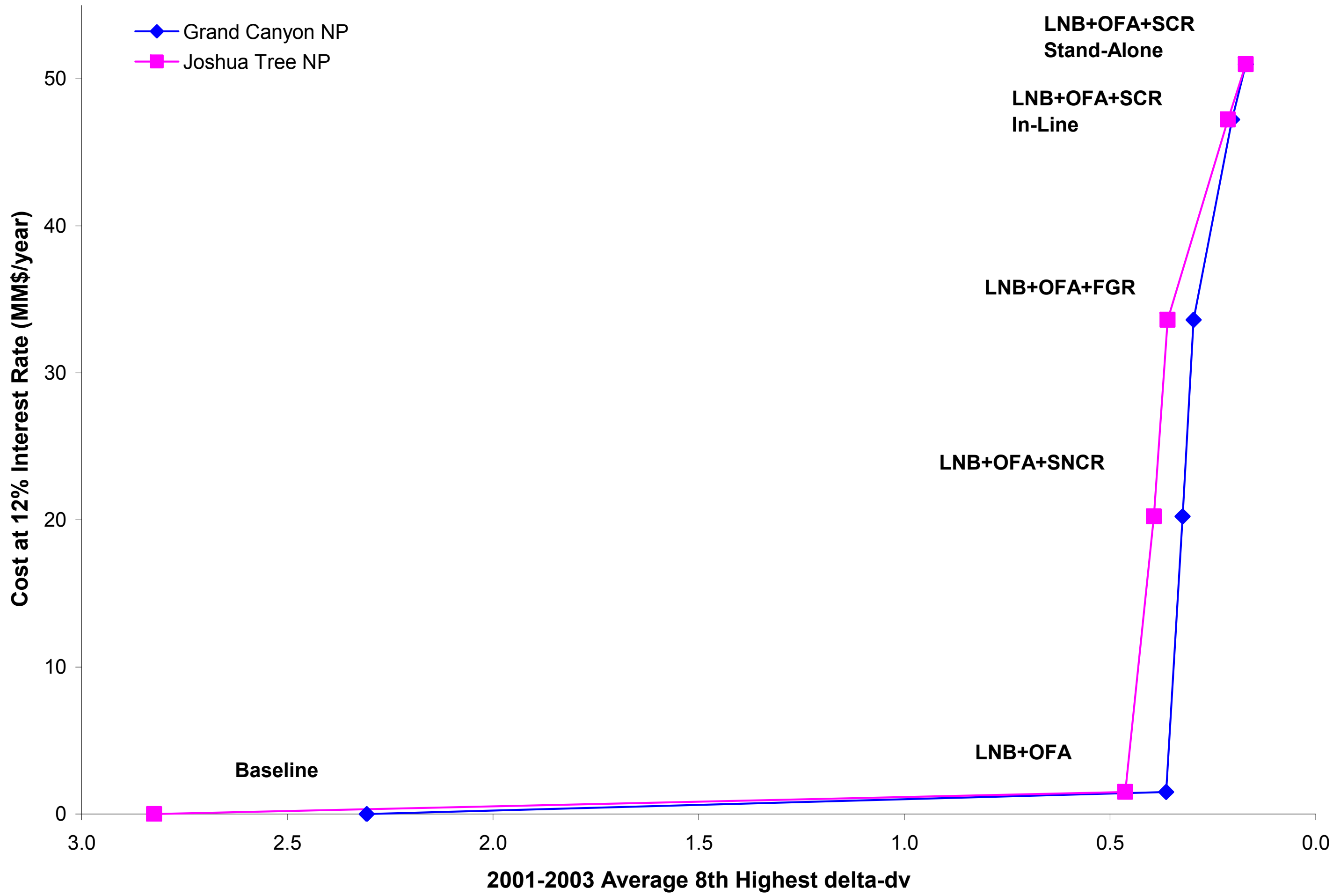


Figure 8-2 Annual Cost of NO_x Controls vs. Visibility Improvements at the Other California Class I Areas

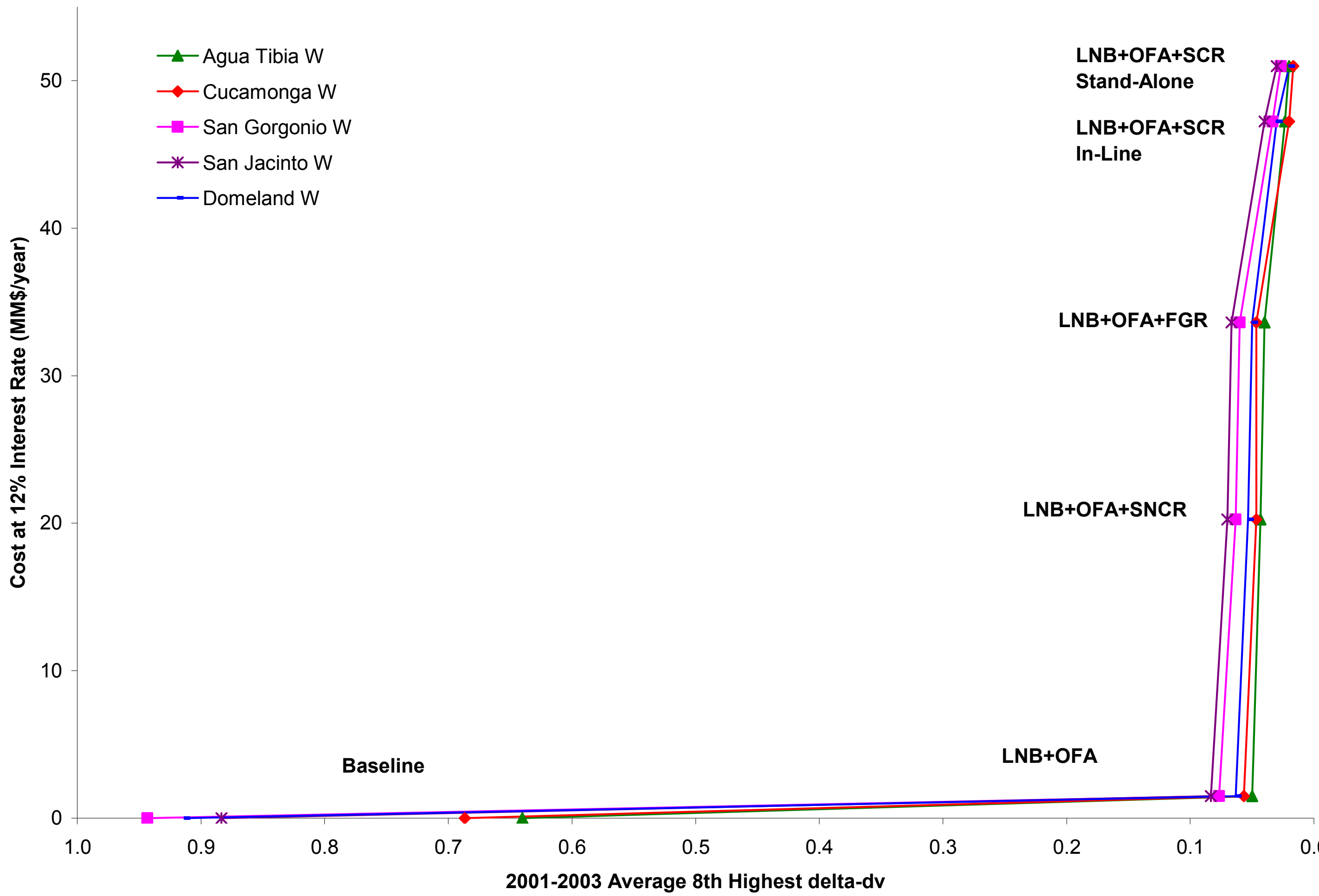


Figure 8-3 Annual Cost of NO_x Controls vs. Visibility Improvements at the Other Non-California Class I Areas

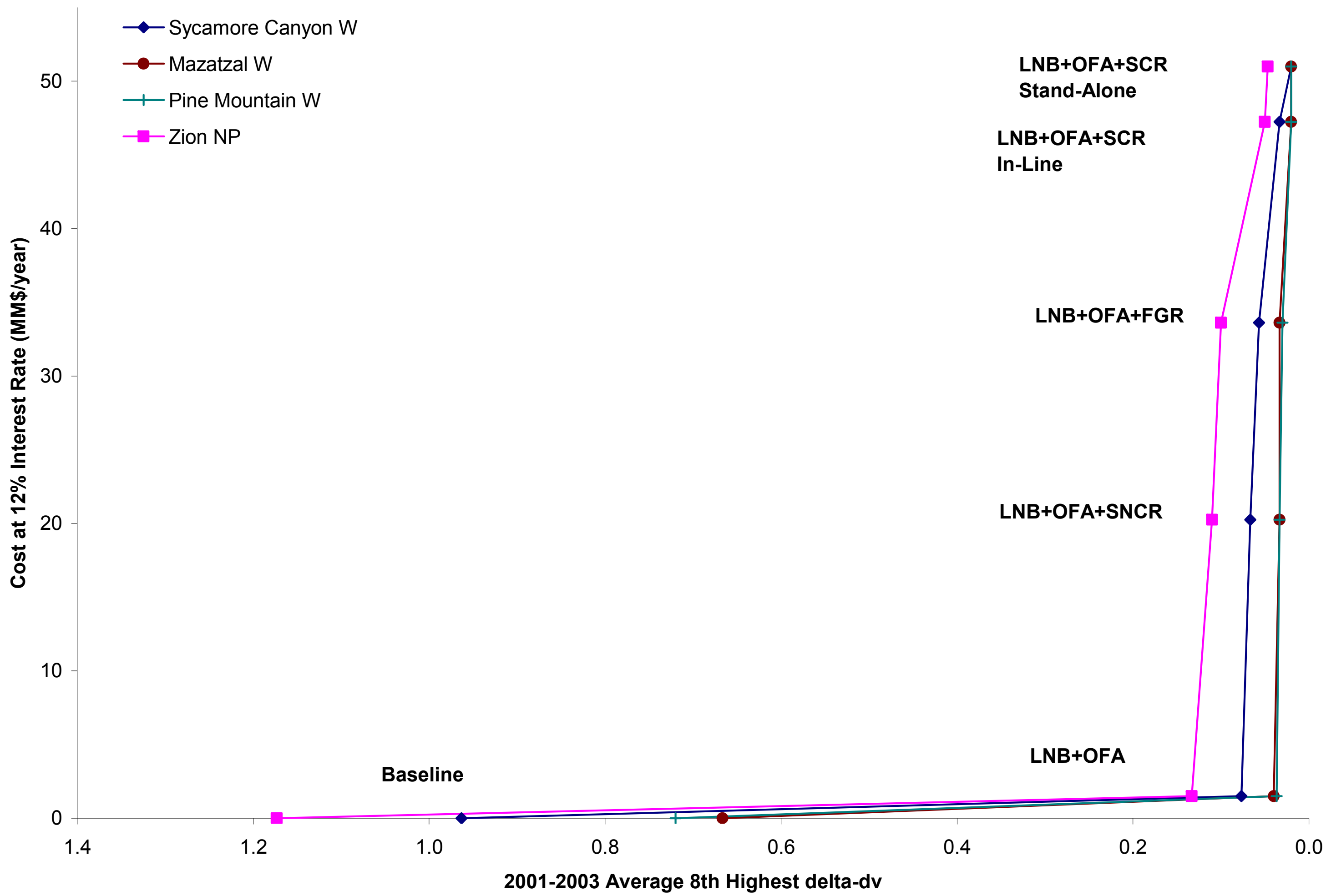


Figure 8-4 NO_x Control Options Cost Effectiveness

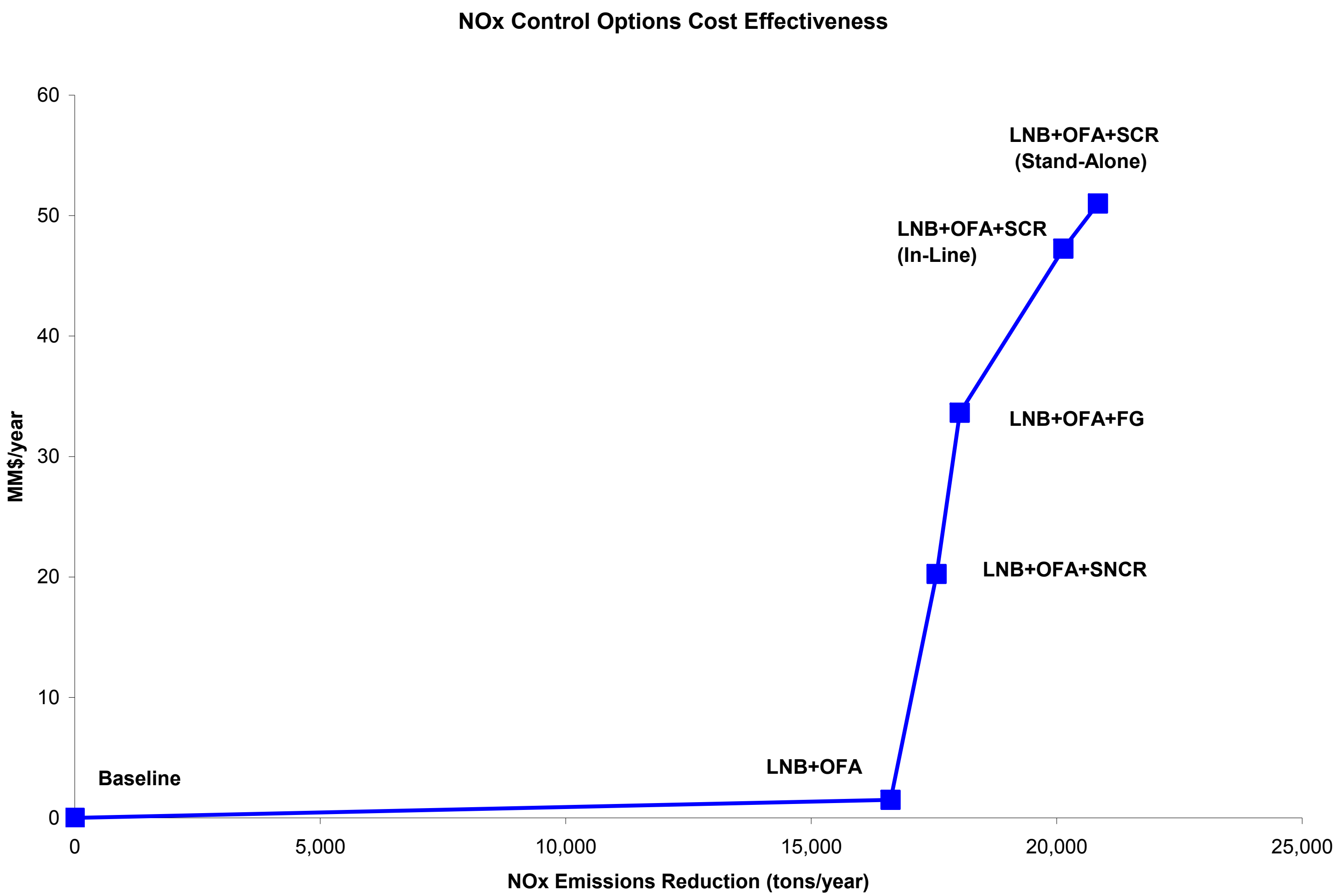


Table 8-1 Summary for BART Analysis for NO_x

	Step 1	Step 2	Step 3	Step 4a	Step 4b	Step 5	
	Identify Control Technologies	**Feasible Control Technology?**	**Evaluate Control Effectiveness for Technically Feasible Control Technologies**	**Calculate Cost Effectiveness for Control Technologies (relative to baseline)**	**Determine Non-Air Quality Environmental and Energy Impacts**	**Evaluate Visibility Impact of Controls vs. baseline (# days > 0.5 delta-dv removed, and average visibility improvement , delta-dv)**	**Identify BART Control**
Control Option 1	Low NO_x burners, overfire air, and stand-alone SCR	Yes	97.6% NO_x reduction from coal-fired baseline	Annualized cost = \$50,990,000; Marginal cost eff. relative to Option 5 = \$11,714/ton	Excess NH_3 emissions; higher energy use for pressure drop; need RMP	# days > 0.5 delta-dv removed = 1346(1), average vis. improvement = 1.11(2) delta-dv	Marginal visibility benefits and high cost
Control Option 2	Low NO_x burners, overfire air, and in-line SCR	Yes	94.1% NO_x reduction from coal-fired baseline	Annualized cost = \$47,240,000; Marginal cost eff. relative to Option 5 = \$12,992/ton	Excess NH_3 emissions; higher energy use for pressure drop; need RMP	# days > 0.5 delta-dv removed = 1345(1), average vis. improvement = 1.09(2) delta-dv	Marginal visibility benefits and high cost
Control Option 3	Low NO_x burners, overfire air, and flue gas recirculation	Yes	83.5% NO_x reduction from coal-fired baseline	Annualized cost = \$33,610,000; Marginal cost eff. relative to Option 5 = \$22,806/ton	Increased CO emissions; higher energy use for pressure drop	# days > 0.5 delta-dv removed = 1332(1), average vis. improvement = 1.05(2) delta-dv	Marginal visibility benefits and high cost
Control Option 4	Low NO_x burners, overfire air, and SNCR	Yes	81.1% NO_x reduction from coal-fired baseline	Annualized cost = \$20,250,000; Marginal cost eff. relative to Option 5 = \$19,968/ton	Excess NH_3 emissions; need RMP	# days > 0.5 delta-dv removed = 1327(1), average vis. improvement = 1.04(2) delta-dv	Marginal visibility benefits and high cost
Control Option 5	Low NO_x burners and overfire air	Yes	76.4% NO_x reduction from coal-fired baseline	Annualized cost = \$1,500,000	None	# days > 0.5 delta-dv removed = 1319(1), average vis. improvement = 1.02(2) delta-dv	Selected as BART

(1) Total number of days above 0.5 delta-dv removed over three meteorological years and eleven Class I areas.
(2) Average 8th highest visibility improvement over three meteorological years and eleven Class I areas.

9.0 References

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Appendix A

NO_x BART Review for the Mohave Generating Station

Appendix B

Guidance on CALMET Settings

Appendix C

Factors Influencing NO_x Emissions Effects on Visibility

Appendix D

Re-Calculating CALPOST Visibility Outputs with the New IMPROVE Algorithm

Appendix E

CALPUFF Modeling Results and Graphic Charts using the New IMPROVE Equation

Appendix F

CALPUFF Modeling Results and Graphic Charts using the Old IMPROVE Equation

Appendix G

Projected NO_x Emissions on Natural Gas Over Mohave's Future Operating Range Based on 2005 Actual Reporting for the Mohave Generating Station