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BART Analysis for Cholla Unit 3

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January 2008

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Executive Summary

ADEQ
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Executive Summary

Background

In response to the Regional Haze Rule and Best Available Retrofit Technology (BART) regulations and guidelines, CH2M HILL was requested to perform a BART analysis for Arizona Public Service Company (APS) Cholla Unit 3 (hereafter referred to as Cholla 3). APS's Cholla Power Plant includes four electric generating units, with a gross 1,150 megawatts (MW). The gross megawatt capacity ratings are as follows: Unit 1 at 125 MW, Unit 2 and 3 at 300 MW, and Unit 4 at 425 MW. Cholla 3 coal-fired steam electric generating unit utilizes coal as the primary fuel; however, diesel fuel oil is used for warm-up and stabilization.

The BART analysis for Cholla 3 addressed the following criteria pollutants: oxides of nitrogen (NO_x) sulfur dioxide (SO_2), and particulate matter less than 10 microns in aerodynamic diameter (PM_{10}). BART emissions limits must be achieved within five years after the State Implementation Plan (SIP) is approved by the EPA. A compliance date of 2013 was assumed for this analysis.

In completing the BART analysis, technology alternatives were investigated and potential reductions in NO_x, SO_2, and PM_{10} emissions rates were identified. The following technology alternatives were investigated, listed below by pollutant:

NO_x emission controls:

- New/modified state-of-the-art low-NO_x burners (LNB) with separated over-fire air (SOFA) system
- Rotating Opposed Fire Air (ROFA)
- Selective non-catalytic reduction system (SNCR)
- Selective catalytic reduction (SCR) system
- Neural Network Controls (Neural Net)

SO_2 emission controls:

- Dry Flue Gas Desulfurization
- Dry sorbent sodium injection
- Wet Flue Gas Desulfurization

PM_{10} emission controls:

- Electrostatic Precipitator (ESP) enhancements
- Fabric Filter

BART Engineering Analysis

The specific components of a BART engineering analysis are identified in the Code of Federal Regulations (CFR) at 40 CFR 51 Appendix Y, Section IV. The evaluation must include:

1. The identification of available, technically feasible, retrofit control options

2. Consideration of any pollution control equipment in use at the source (which affects the availability of options and their impacts)
3. The costs of compliance with the control options
4. The remaining useful life of the facility
5. The energy and non-air quality environmental impacts of compliance
6. The degree of visibility improvement that may reasonably be anticipated from the use of BART

These components are incorporated into the BART analysis performed by CH2M HILL through the following steps:

Step 1 – Identify All Available Retrofit Control Technologies

Step 2 – Eliminate Technically Infeasible Options

- The identification of available, technically feasible, retrofit control options
- Consideration of any pollution control equipment in use at the source (which affects the applicability of options and their impacts)

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Step 4 – Evaluate Impacts and Document the Results

- The costs of compliance with the control options
- The remaining useful life of the facility
- The energy and non-air quality environmental impacts of compliance

Step 5 – Evaluate Visibility Impacts

- The degree of visibility improvement that may reasonably be anticipated from the use of BART

Separate analyses have been conducted for NO_x, SO_2, and PM_{10} emissions. All costs included in the BART analyses are in 2007 dollars, and costs have not been escalated to the assumed 2013 BART implementation date.

Coal Characteristics

Sources of coal burned at Cholla 3 are McKinley, Lee Ranch, and El Segundo. The McKinley and the Lee Ranch mines are in western New Mexico, near the towns of Gallup and Grants respectively. The El Segundo mine is located adjacent to the Lee Ranch mine.

Some of these coals may be classified as sub-bituminous, while demonstrating characteristics of bituminous coal which influences the level of NO_x emissions from the boiler. Bituminous coals typically have higher nitrogen content than sub-bituminous coals such as those from the PRB, which represent the bulk of sub-bituminous coal use in the U.S. and upon which the presumptive BART limit for sub-bituminous coals was based. This BART analysis has considered the higher nitrogen content and different combustion characteristics of bituminous and sub-bituminous coals planned to be burned at Cholla 3, and has evaluated the effect of these qualities on NO_x formation and achievable emission rates.

Recommendations

NO_x Emission Control

Based on the analysis conducted, new LNB with SOFA can achieve the BART emission level of 0.22 lb/MMBtu, based on the projected significant reduction in NO_x emissions, reasonable control costs, and the advantages of lack of non air quality environmental impacts.

SO_2 Emission Control

Based on the analysis conducted, installation of a wet FGD system can achieve the BART emission level of 0.15 lb/MMBtu for SO_2 emission control.

PM_{10} Emission Control

Based on the analysis conducted, the installation of a fabric filter can achieve the BART emission level of 0.015 lb/MMBtu for PM_{10} emission control.

BART Modeling Analysis

CH2M HILL used the CALPUFF modeling system to assess the visibility impacts of emissions from Cholla 3 at Class I areas. The Class I areas potentially affected are located more than 50 kilometers (with the exception of Petrified Forest National Park), but less than 300 kilometers, from the Cholla Power Plant. Petrified Forest National Park is approximately 39 kilometers from the Cholla Power Plant). The Class I areas include the following:

- Petrified Forest National Park (NP)
- Sierra Ancha Wilderness Area (WA)
- Mazatzal WA
- Mount Baldy WA
- Sycamore Canyon WA
- Pine Mountain WA
- Superstition WA
- Grand Canyon NP
- Gila WA
- Galiuro WA
- Mesa Verde NP
- Capitol Reef NP
- Saguaro NP

Because Cholla 3 will simultaneously control NO_x, SO_2, and PM_{10} emissions, post control visibility modeling scenarios were developed to cover the range of effectiveness for combining the individual NO_x and SO_2 control technologies under evaluation. These modeling scenarios, and the controls assumed, are as follows:

- **Scenario 1**: New LNBs with SOFA system, new wet FGD system, and fabric filter.

- **Scenario 2**: New LNBs with SOFA system and ROFA, new wet FGD system, and fabric filter.
- **Scenario 3**: New LNBs with SOFA system and ROFA and Rotamix, new wet FGD system, and fabric filter.
- **Scenario 4**: New LNBs with SOFA system and SNCR, new wet FGD system, and fabric filter.
- **Scenario 5**: New LNBs with SOFA system and SCR, new wet FGD system, and fabric filter.

Visibility improvements for all emission control scenarios were analyzed, and the results were compared utilizing a Least-Cost Envelope Analysis, as outlined in the draft EPA 1990 New Source Review Workshop Manual (NSR Manual).

Least-Cost Envelope Analysis

EPA has adopted the Least-Cost Envelope Analysis Methodology as an accepted methodology for selecting the most reasonable, cost-effective controls. Incremental cost-effectiveness comparisons focus on annualized cost and emission reduction differences between dominant alternatives. The dominant set of control alternatives is determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for a total emissions reductions for all control alternatives identified in the BART analysis.

To evaluate the impacts of the modeled control scenarios on the thirteen Class I areas, the total annualized cost, cost per deciview (dV) reduction, and cost per reduction in number of days above 0.5 dV were analyzed. This report provides a comparison of the average incremental costs between relevant scenarios for the thirteen Class I areas; the total annualized cost versus number of days above 0.5 dV, and the total annualized cost versus 98th percentile delta-deciview (ΔdV) reduction.

Results of the least-cost analysis for the various NO_x emission control scenarios confirm the selection of Scenario 1 (New LNB with SOFA), based on incremental cost and visibility improvements. All other NO_x control scenarios are excluded on the basis of cost effectiveness.

Just-Noticeable Differences in Atmospheric Haze

Studies have been conducted that demonstrate only dV differences of approximately 1.5 to 2.0 dV or more are perceptible by the human eye (Henry, 2002). Deciview changes of less than 1.5 cannot be distinguished by the average person. Therefore, the modeling analysis results indicate that only minimal, if any, observable visibility improvements at the Class I areas studied would be expected under any of the control scenarios. Thus, the results indicate that even though APS will be spending many millions of dollars at this single unit, and over a billion dollars when considering its entire coal fleet, only minimal discernable visibility improvements may result.

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Acronyms and Abbreviations

ADEQ	Arizona Department of Environmental Quality
APS	Arizona Public Service
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CALDESK	Program to display data and results
CALMET	Meteorological data preprocessing program for CALPUFF
CALPOST	Post-processing program for calculating visibility impacts
CALPUFF	Gaussian puff dispersion model
COFA	close-coupled over-fire air
dV	deciview
ΔdV	delta deciview, change in deciview
ESP	electrostatic precipitator
EPA	United States Environmental Protection Agency
Fuel NO_x	oxidation of fuel bound nitrogen
FGC	flue gas conditioning
FGD	flue gas desulfurization
f(RH)	relative humidity factors
ID	internal diameter
kW	kilowatts
kW-Hr	kilowatt-hour
LAER	lowest achievable emission rate
lb/MMBtu	pounds per million British Thermal Units
LNB	low-NO_x burner
LOI	loss on ignition
MMBtu	Million British Thermal Units
MM5	Mesoscale Meteorological Model, Version 5
MW	megawatts
N_2	nitrogen
NM	National Monument
NO	nitric oxide
NO_x	oxides of nitrogen
NP	National Park

NWS	National Weather Service
OFA	over-fire air
PM_{10}	particulate matter less than 10 microns in aerodynamic diameter
PRB	Powder River Basin
ROFA	Rotating Opposed Fire Air
SCR	selective catalytic reduction system
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction system
SOFA	separated over-fire air
SO_2	sulfur dioxide
SO_3	sulfur trioxide
Thermal NO_x	high temperature fixation of atmospheric nitrogen in combustion air
USGS	U.S. Geological Survey
WA	Wilderness Area

Section 1.0
Introduction

1.0 Introduction

The Clean Air Act established goals for visibility improvement in national parks, wilderness areas, and international parks. Through the 1977 amendments to the Clean Air Act in Section 169A, Congress set a national goal for visibility as "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution." The Amendments required the United States Environmental Protection Agency (EPA) to issue regulations to assure "reasonable progress" toward meeting the national goal. In 1990, Congress again amended the Clean Air Act, providing additional emphasis on regional haze issues.

In 1999, EPA issued comprehensive regulations to improve visibility, or visual air quality, in the 156 national parks and wilderness areas across the country classified as mandatory Class I areas. These regulations include requirements for States to establish goals for improving visibility in national parks and wilderness areas and to develop long-term strategies for reducing emissions of air pollutants that cause visibility impairment.

One of the principal elements of the visibility protection provisions of the Clean Air Act addresses installation of best available retrofit technology, or BART, for certain existing sources placed into operation between 1962 and 1977. The 1999 Regional Haze Rule requires three basic state plan elements related to BART:

- A list of BART-eligible sources (includes sources of air pollutants that are reasonably anticipated to contribute to visibility impairment in a Class I area);
- An analysis of the emission reductions and changes in visibility that would result from "best retrofit" control levels on sources subject to BART; and
- The BART emission limits for each subject source, or an alternative measure such as an emissions trading program for achieving greater reasonable progress in visibility protection than implementation of source-by-source BART controls.

In determining BART, the State can take into account several factors, including the existing control technology in place at the source, the costs of compliance, energy and non-air environmental impacts of compliance, remaining useful life of the source, and the degree of visibility improvement that is reasonably anticipated from the use of such technology (EPA, 1999).

In July 2005, EPA released specific BART guidelines for states to use when determining which facilities were required to install additional controls, and the type of controls that must be used. Under current regulatory deadlines, States, including Arizona, must submit a Regional Haze Rule State Implementation Plan (SIP) amendment that addresses BART implementation by December, 2007. In this plan amendment, States were to identify the facilities that will have to reduce emissions under BART and then set BART emissions limits for those facilities, and/or identify any alternative plan for reducing visibility impairing pollutants that would achieve greater reductions than those realized from BART emissions limits (EPA, 2005).

Using information from the Western Regional Air Partnership and its Regional Modeling Center, the State of Arizona has identified those eligible in-state sources that are required to reduce emissions under BART, and has directed those sources to complete BART analyses to identify potential reductions for emissions of sulfur dioxide (SO2), nitrogen oxides (NOx) and particulate matter less than 10 microns in aerodynamic diameter (PM10) that would be associated with addition of additional or new air pollution controls. This information will be included in the State's SIP that was due in December 2007. At this time, it is expected that Arizona's SIP, when submitted will address reduction of SO2 emissions at BART sources through an alternative measure in the form of a four-state backstop cap-and-trade program. Reduction of NOx and PM10 emissions will be addressed through establishment of BART emissions limits in source operating permits.

The EPA BART guidelines state that the BART emission limits established as a result of BART analyses must be fully implemented within five years of EPA's approval of the SIP. For the purposes of this project, that date is assumed to be 2013.

This report documents the BART analysis that was performed on Cholla 3 on behalf of APS by CH2M HILL. The analysis was performed for the pollutants NO_x, SO_2, and PM_{10}.

Section 2.0 of this report provides a description of the present unit operation, including a discussion of coal sources and characteristics. The BART Engineering Analysis is provided in Section 3.0 by pollutant type. Section 4.0 provides the methodology and results of the BART Modeling Analysis, followed by recommendations in Section 5.0. References are provided in Section 6.0. Appendices include the detailed economic analysis (Appendix A) and the BART modeling protocol (Appendix B).

Section 2.0
Present Unit Operation

2.0 Present Unit Operation

The Cholla Power Plant consists of four electric generating units with a total generating capacity of 1,150 megawatts (MW). The power plant is located approximately 2 miles east of the town of Joseph City on Interstate 40, in Navajo County, Arizona. Cholla 3 is a 300 MW coal-fired steam electric generating unit equipped with a tangentially-fired, dry bottom, boiler manufactured by Combustion Engineering. Current emissions control equipment includes a hot side electrostatic precipitator for particulate matter control. Close-coupled overfire air (COFA) is utilized for NOx control, and there is currently no SO_2 equipment installed. Cholla 3 shares a flue gas exhaust stack with Cholla 2.

Cholla 3 was placed in service in 1980, with a projected remaining life of 40 years or until 2047. This analysis is based on a 20-year life for BART control technologies. Assuming a BART implementation date of 2013, this estimates the technologies will operate until 2033. Table 2-1 lists additional unit information and study assumptions for this analysis.

TABLE 2-1
Unit Operation and Study Assumptions
Cholla 3

General Plant Data	
Site Elevation (feet above MSL)	5,019
Stack Height (feet)[1,3]	550
Stack Exit ID (feet) /Exit Area (sq. ft.)[1,3]	22.8 /408.3
Stack Exit Temperature (°F) [1,3]	253.9
Stack Exit Velocity (ft/sec)[1,3]	97.1
Stack Flow (ACFM)[3]	2.4×10^6
Annual Unit Capacity Factor (%)[2]	86.0
Gross Unit Output (MW)	300
Gross Unit Heat Rate (Btu/kW-Hr)(100% load)[4]	9,763
Boiler Heat Input (MMBtu/Hr)(100% load)[4]	2,929
Type of Boiler	Tangential fired
Boiler Fuel	Coal
Coal Sources	See Table 2-2
Current NO_x Controls	COFA
NO_x Emission Rate (lb/MMBtu)[5]	0.41
Current SO_2 Controls	None
SO_2 Emission Rate (lb/MMBtu) [5]	1.000
Current PM_{10} Controls	Hot-side Electrostatic Precipitator
PM_{10} Emission Rate (lb/MMBtu) [5]	0.015

1 - Based on APS Cholla emission Reduction Project, August 2006
2 – Based on EPA Acid Rain Program 2001-2006
3 – Shared Stack with Unit 2
4 – Technical Support Documentation May 3, 2006
5 – Based on actual emissions, highest 24 hr average emissions during 2001-2003, provided by APS.

For Table 2-1 above, emissions for the years 2001 to 2003 were analyzed to obtain the Cholla 3 emissions.

In the July 2005 EPA BART guidelines, EPA prescribed presumptive BART limits to be achieved at BART-eligible coal fired power plants with a total generating capacity greater than 750 MW. Since the total generating capacity of the Cholla Power Plant is 1150 MW, the presumptive limits apply.

The BART presumptive NO_x limit for dry bottom tangentially-fired boilers burning sub-bituminous coal is 0.15 lb/MMBtu, and the BART presumptive NO_x limit for burning bituminous coal is 0.28 lb/MMBtu. Current sources of coal burned at Cholla 3 are summarized in Table 2-2, and APS is transitioning the coal supply to burn solely El Segundo coal by July 2009. Burning El Segundo coal may result in SO_2 emissions as high as 2.5 lb/MMBtu.

APS is planning to install new LNB with SOFA, a new lime SO_2 scrubber, and a new fabric filter in 2009.

TABLE 2-2
Coal Sources and Characteristics
Cholla 3

							Ultimate Analysis (% dry basis)						
Mines	**Moist. %**	**Ash %**	**Volatile Matter %**	**Fixed Carbon %**	**Btu/lb**	**Sulfur %**	**Carbon**	**Hydrogen**	**Nitrogen**	**Chlorine**	**Sulfur**	**Ash**	**Oxygen**
McKinley Mine, NM	13.90	14.28	32.45	39.90	9911	0.47	65.92	4.58	1.11	0.01	0.55	16.59	11.25
Lee Ranch Mine, NM	15.30	17.80	33.50	33.40	9250	0.90	61.70	4.50	1.00	0.01	1.06	21.00	10.73
El Segundo Mine, NM	17.60	16.80	31.70	33.90	9215	1.10	62.13	4.62	1.00	0.02	1.34	20.48	10.79

Section 3.0
BART Engineering Analysis

3.0 BART Engineering Analysis

3.1 BART Process

The specific components in a BART engineering analysis are identified in the Code of Federal Regulations (CFR) at 40 CFR 51 Appendix Y, Section IV. The evaluation must include:

1. The identification of available, technically feasible, retrofit control options
2. Consideration of any pollution control equipment in use at the source (which affects the availability of options and their impacts)
3. The costs of compliance with the control options
4. The remaining useful life of the facility
5. The energy and non-air quality environmental impacts of compliance, and
6. The degree of visibility improvement which may reasonably be anticipated from the use of BART

These components are incorporated into the BART analysis performed by CH2M HILL through the following steps:

Step 1 – Identify All Available Retrofit Control Technologies

Step 2 – Eliminate Technically Infeasible Options

- The identification of available, technically feasible, retrofit control options
- Consideration of any pollution control equipment in use at the source (which affects the applicability of options and their impacts)

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Step 4 – Evaluate Impacts and Document the Results

- The costs of compliance with the control options
- The remaining useful life of the facility
- The energy and non-air quality environmental impacts of compliance

Step 5 – Evaluate Visibility Impacts

- The degree of visibility improvement which may reasonably be anticipated from installation of BART controls.

In the evaluation, consideration was made of any pollution control equipment in use at the source, the costs of compliance associated with the control options, and the energy and non-air quality environmental impacts of compliance using these existing control devices. As a consequence, controls scenarios included enhancement of existing equipment, as well as addition of new control equipment.

Separate analyses have been conducted for NO_x, SO_2, and PM_{10} emissions. All costs included in the BART analysis are in 2007 dollars, and costs have not been escalated to the assumed 2013 BART implementation date.

Establishing Permit Emission Levels From BART Analysis Results

As an integral part of the BART analysis process, cost and expected emission information was developed for NO_x, SO_2, and PM_{10}. This information is assembled from various sources including emission reduction equipment vendors, APS operating and engineering data, and internal CH2M HILL historical information.

The level of accuracy of the cost estimate can be broadly classified as "Order of Magnitude", which can be categorized as -30/+50%. There are several reasons for the wide range of cost estimates included in the BART analysis. This variability is primarily caused by the difficulty in receiving detailed and accurate information from equipment vendors. Due to the extremely active power industry marketplace, obtaining engineering and construction cost information is severely restricted due to vendor workload. Material and construction labor costs are also widely fluctuating in today's active economy.

The accuracy of expected emissions may also be questionable, and is also attributable to the inability to gain timely and accurate information. This is exemplified by the difficulty in obtaining background information, and the vendor time required to develop accurate emission projections for study purposes as opposed to their response to actual project request for proposals. Also, variance in expected emissions can be dependent upon the pollutant under consideration; i.e., particulate emissions can generally be more accurately predicted than NO_x emissions.

Therefore, when selecting emissions control technologies and establishing emission permitting levels, consideration of variability in cost and expected emissions information has been considered.

3.1.1 BART NO_x Analysis

NO_x formation in coal-fired boilers is a complex process that is dependent on a number of variables, including operating conditions, equipment design, and coal characteristics.

3.1.1.1 Formation of NO_x

During coal combustion, NO_x is formed in three different ways. The dominant source of NO_x formation is the oxidation of fuel-bound nitrogen (fuel NO_x). During combustion, part of the fuel-bound nitrogen is released from the coal with the volatile matter, and part is retained in the solid portion (char). The nitrogen chemically bound in the coal is partially oxidized to nitrogen oxides (NO and NO_2) and partially reduced to molecular nitrogen (N_2). A smaller part of NO_x formation is due to high temperature fixation of atmospheric nitrogen in the combustion air (thermal NO_x). A very small amount of NO_x is called "prompt" NO_x. Prompt NO_x results from an interaction of hydrocarbon radicals, nitrogen, and oxygen.

In a conventional pulverized coal burner, air is introduced with turbulence to promote good mixing of fuel and air, which provides stable combustion. However, not all of the oxygen in the air is used for combustion. Some of the oxygen combines with the fuel nitrogen to form NO_x.

Coal characteristics directly and significantly affect NO_x emissions from coal combustion. Coal ranking as defined by The American Society for Testing and Materials (ASTM) is a means of classifying coals according to their degree of metamorphism in the natural series, from lignite to sub-bituminous to bituminous and on to anthracite. Lower rank coals, such as the sub-bituminous coals from the PRB, produce lower NO_x emissions than higher rank bituminous coals, due to their higher reactivity and lower nitrogen content. The fixed carbon to volatile matter ratio (fuel ratio), coal oxygen content, and rank are good relative indices of the reactivity of a coal. Lower rank coals release more organically bound nitrogen earlier in the combustion process than do higher rank bituminous coals. When used with low NO_x burners, sub-bituminous coals create a longer time for the kinetics to promote more stable molecular nitrogen, and hence result in lower NO_x emissions.

The primary basis for coal rank classification of lower rank bituminous and all sub-bituminous coals by ASTM is gross calorific value determined on a moist mineral-matter-free basis. In the cases of both high volatile bituminous "C" and sub-bituminous "A" classifications, the gross calorific values on a moist mineral-matter-free basis must be greater than 10,500 Btu/lb and less than 11,500 Btu/lb. In order to classify these types of coals, a characteristic called agglomeration is used. Agglomeration is a distinguishing characteristic that classifies the coals as bituminous rather than sub-bituminous; that is, they are "agglomerating" as compared to "non-agglomerating". Agglomerating as applied to coal is "the property of softening when it is heated to above about 400° C in a non-oxidizing atmosphere, and then appearing as a coherent mass after cooling to room temperature." Because the agglomerating property of coals is the result of particles transforming into a plastic or semi-liquid state when heated, it reflects a change in surface area of the particle. Thus, with the application of heat, agglomerating coals would tend to develop a non-porous surface, while the surface of non-agglomerating coals would become even more porous with combustion. As shown by Figure 3-1, the increased porosity provides more particle surface area, resulting in more favorable combustion conditions. This non-agglomerating property assists in making sub-bituminous coals more amenable to controlling NO_x, by allowing less air to be introduced during the initial ignition portion of the combustion process. Since Cholla 3 may burn a blend of bituminous and marginally ranked sub-bituminous coals, NO_x emissions from combustion of these blended coals will vary depending on the resultant combined coal characteristics.

FIGURE 3-1
Illustration of the Effect of Agglomeration on the Speed of Coal Combustion
Cholla 3

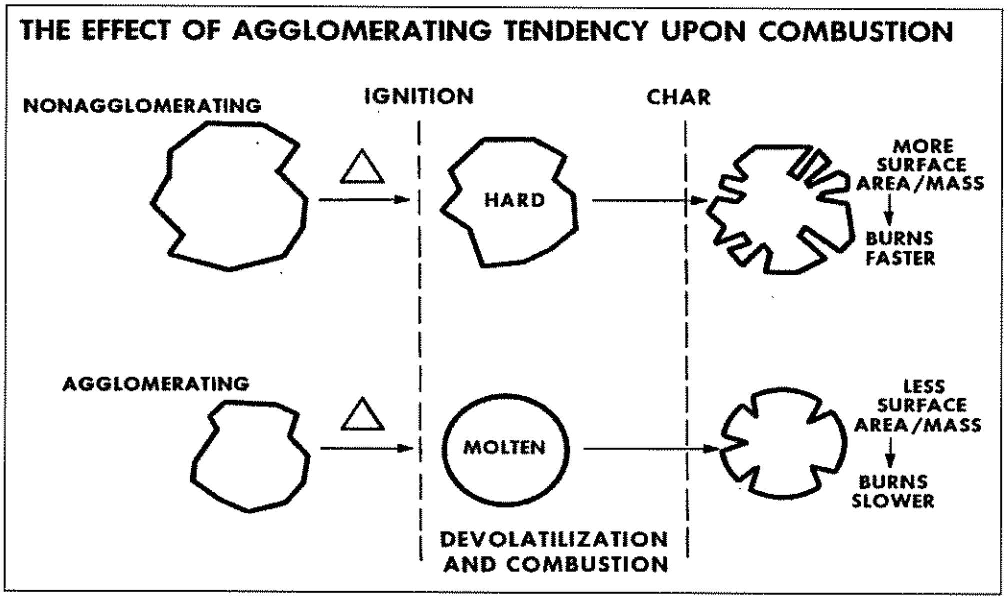


Table 3-1 shows key characteristics of the coals which are currently being burned on Cholla 3 and a "typical" PRB sub-bituminous coal (Antelope) for comparison. APS is currently transitioning to burn only El Segundo coal beginning in 2008.

TABLE 3-1
Key Coal Characteristics
Cholla 3

Site	Btu/Lb	Ash (%)	Sulfur (%)	Nitrogen (%)	Oxygen (%)	Coal Rank
McKinley New Mexico	9911	14.28	0.47	0.96	9.96	Bit
Lee Ranch New Mexico	9250	17.80	0.90	0.85	9.09	Bit/Sub
El Segundo New Mexico	9215	16.80	1.10	0.82	8.86	Bit/Sub
Antelope Wyoming	8800	5.25	0.24	0.78	12.08	Sub

The analyses shown above that were furnished for this report did not indicate whether the coals were agglomerating or non-agglomerating. Since the McKinley coal analysis results in a moist, mineral-matter-free heating value of 11,726 Btu/Lb, it is classified as high volatile C bituminous. The Lee Ranch and El Segundo coals have moist mineral-matter-free values of 11,466 and 11,279, respectively, which require the agglomerating determination in order to classify them.

As shown in Table 3-1, the bituminous coals generally exhibit higher nitrogen content and lower oxygen content than the sub-bituminous PRB coal. The higher nitrogen content is an indication that more nitrogen is available to the combustion process and higher NO_x emissions are likely. Oxygen content can be correlated to the reactivity of the coal, with more reactive coals generally containing higher levels of oxygen. More reactive coals tend to produce lower NO_x emissions, and they are also more conducive to reduction of NO_x emissions through the use of combustion control measures, such as low NO_x burners and over-fire air (OFA). These characteristics indicate that higher NO_x formation is likely with bituminous rather than sub-bituminous coals.

Coal quality characteristics also impact the design and operation of the boiler and associated auxiliary equipment. Minor changes in quality can sometimes be accommodated through operational adjustments or changes to equipment. It is important to note, however, that consistent variations in quality or assumptions of "average" quality for performance projections can be problematic. This is particularly troublesome when dealing with performance issues that are very sensitive to both coal quality and combustion conditions, such as NO_x formation. There is significant variability in the quality of coals burned at Cholla 3.

Several of the coal quality characteristics and their effect on NO_x formation have been previously discussed. There are additional considerations that illustrate the complexity of achieving and maintaining consistent low NO_x emissions with pulverized coal on a shorter term, such as a 30-day rolling average basis.

Good combustion is based on the "three Ts": time, temperature and turbulence. These parameters along with a "design" coal are taken into consideration when designing a boiler and associated firing equipment such as fans, burners, and pulverizers. If a performance requirement such as NO_x emission limits is subsequently changed, conflicts with other performance issues can result.

Cholla 3 is located at an altitude of 5,019 feet above sea level. At this elevation, atmospheric pressure is lower as compared with sea level pressure of 14.7 pounds per square inch. This lower pressure means that less oxygen is available for combustion for each volume of air. In order to provide adequate oxygen to meet the requirements for efficient combustion, larger volumes of air are required. When adjusting air flows and distribution to lower NO_x using low NO_x burners and overfire air (OFA), original boiler design restrictions again limit the modifications that can be made and still achieve satisfactory combustion performance.

Another significant factor in controlling NO_x emissions is the fineness of the coal entering the burners. Fineness is influenced by the Hardgrove Grindability Index (HGI) of the coal. Finer coal particles promote release of volatiles and assist char burnout due to more surface area exposed to air. NO_x reduction with high volatile coals is improved with greater fineness and with proper air staging. The lower rank sub-bituminous coals such as PRB coals are quite friable and easy to grind. Coals with lower HGI values, are more difficult to grind and can contribute to higher NO_x levels. In addition, coal fineness can deteriorate over time periods between pulverizer maintenance and service as pulverizer grinding surfaces wear.

In summary, when all the factors of agglomeration versus non-agglomeration, nitrogen and oxygen content of the coals, and the grindability index are taken into account, this analysis demonstrates that, for the variability of coal supply to be utilized at Cholla 3, the more appropriate presumptive BART limit is 0.28 lb/MMBtu. This limit is referred to here only as a point of reference, and CH2M HILL recommends that this value be used in evaluation of the effectiveness of BART controls applied to Cholla 3. The BART analysis for NO_x emissions from Cholla 3 is further described below.

3.1.1.2 Step 1: Identify All Available Retrofit Control Technologies

The first step of the BART process is to evaluate NO_x control technologies with practical potential for application to Cholla 3, including those control technologies identified as Best Available Control Technology (BACT) or lowest achievable emission rate (LAER) by permitting agencies across the United States. A broad range of information sources have been reviewed in an effort to identify potentially applicable emission control technologies.

Cholla 3 NO_x emissions are currently controlled through the use of COFA system, and a new LNB system will be added. A SOFA upgrade is also planned for Cholla 3.

The following potential NO_x control technology options were considered:

- New/modified state-of-the-art low-NO_x burners (LNB) with SOFA
- Rotating Opposed Fire Air (ROFA)
- Selective non-catalytic reduction system (Rotamix & SNCR)
- Selective catalytic reduction (SCR) system
- Neural Network/Boiler Combustion Control (Neural Net)

3.1.1.3 Step 2: Eliminate Technically Infeasible Options

For Cholla 3, a tangentially-fired boiler burning a blend of bituminous and sub-bituminous rank coals, technical feasibility will primarily be determined by physical constraints, boiler configuration, and on the ability to achieve the regulatory presumptive limit of 0.28 lb NO_x/MMBtu. Cholla 3 currently has an average - NO_x emission rate of 0.410 lb/MMBtu.

For this BART analysis, information pertaining to LNBs, OFA, SNCR, and SCR were based on a combination of vendor information and internal CH2M HILL information. Sources of cost estimates for Cholla 3 are listed below in Table 3-2, which also summarizes the control technology options evaluated in this BART analysis, along with projected NO_x emission rates. All technologies listed can meet the bituminous presumptive BART limit of 0.28 lb/MMBTU, except for the neural net boiler controls.

TABLE 3-2
NO_x Control Technology Emission Rate Ranking
Cholla 3

Technology	Source of Estimated Cost and Emissions	Expected Emission Rate (lb/MMBtu)
Presumptive BART Limit		0.28
New LNB w/SOFA[3]	Foster Wheeler	0.22
ROFA[4]	Mobotec	0.16
ROFA w/Rotamix[4]	Mobotec	0.12

TABLE 3-2
NO_x Control Technology Emission Rate Ranking
Cholla 3

Technology	Source of Estimated Cost and Emissions	Expected Emission Rate (lb/MMBtu)
New LNB w/SOFA & SNCR[2]	Foster Wheeler, CH2M HILL	0.17
New LNB w/SOFA & SCR	Foster Wheeler, CH2M HILL	0.07
Neural Net Controls[1]	NeuCo	0.30

1 - NeuCo provides no guarantees; derived using 15% reduction from average NO_x emissions level.
2 - A 25% removal efficiency was assumed from prior SNCR proposals
3 - Expected emission rate from APS environmental upgrades
4 – Potential guaranteed emission levels

3.1.1.4 Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Preliminary vendor proposals, such as those used to support portions of this BART analysis, may be technically feasible and provide expected or guaranteed emission rates; however, they include inherent uncertainties. These proposals are usually prepared in a limited time frame, may be based on incomplete information, may contain over-optimistic conclusions, and are non-binding. Therefore, emission rate values obtained in such preliminary proposals must be qualified, and it must be recognized that contractual guarantees are established only after more detailed analysis has been completed.

Level of Confidence for Vendor Post-Control NO_x Emissions Estimates. In order to determine the level of NO_x emissions needed to consistently achieve compliance with an established goal, a review of typical NO_x emissions from coal-fired generating units was completed. As a result of this review, it was noted that NO_x emissions can vary significantly around an average emissions level. This variance can be attributed to many reasons, including coal characteristics, unit load, boiler operation including excess air, boiler slagging, burner equipment condition, coal mill fineness, and so forth.

The steps utilized for determining a level of confidence for the vendor expected value are as follows:

1. Establish expected NO_x emissions value from vendor.
2. Evaluate vendor experience and historical basis for meeting expected values.
3. Review and evaluate unit physical and operational characteristics and restrictions. The fewer variations there are in operations, coal supply, etc., the more predictable and less variant the NO_x emissions are.
4. For each technology expected value, there is a corresponding potential for actual NO_x emissions to vary from this expected value. From the vendor information presented, along with anticipated unit operational data, an adjustment to the expected value can be made.

The following subsections describe the NO_x control technologies and the control effectiveness evaluated in this BART analysis.

New LNBs with SOFA System. The mechanism used to lower NO_x with low NO_x burners is to stage the combustion process and provide a fuel rich condition initially; this is so oxygen needed for combustion is not diverted to combine with nitrogen and form NO_x. Fuel-rich conditions favor the conversion of fuel nitrogen to N_2 instead of NO_x. Additional air (OFA) is then introduced upstream or downstream in a lower temperature zone to burn out the char.

Both LNBs and SOFA are considered to be a capital cost, combustion technology retrofit which may require boiler water wall tube replacement. Information provided to CH2M HILL by APS indicates that new LNB and SOFA modifications at Cholla 3 would result in an expected NO_x emission rate of 0.22 lb/MMBtu. This emission rate represents a significant reduction from the current NO_x emission rate, and is below the EPA presumptive NO_x emission rate for bituminous coal of 0.28 lb/MMBtu.

ROFA. Mobotec markets ROFA as an improved second generation OFA system. Mobotec states that "the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles." Rotation is reported to prevent laminar flow and improve gas mixing, so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. Mobotec expects that enhanced mixing will also result in reduction in hot/cold furnace zones, improved heat absorption and boiler efficiency, and lower CO and NO_x emissions.

A typical ROFA installation will have a booster fan(s) to supply the high velocity air to the ROFA boxes. Mobotec proposed one 3,300 Hp fan for Cholla 3 located at grade, which would provide hot air at all boiler loads.

Utilizing ROFA technology, Mobotec offered an estimated NO_x emission rate of 0.16 lb/MMBtu. The operation of existing burners and OFA ports will be analyzed, and OFA ports not planned for use would likely be blocked off. While a typical installation does not require modification to the existing burners, some modification may be necessary. Computational fluid dynamics modeling will determine the quantity and location of new ROFA ports. Mobotec does not typically provide installation services because they believe that the Owner can more cost effectively contract for these services, however they did provide a budgetary price for installation labor. Mobotec provides one onsite construction supervisor during installation and startup.

SNCR. With SNCR, an amine-based reagent such as ammonia, or more commonly urea, is injected into the furnace within a temperature range of 1,600° F to 2,100° F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 40 to 60 percent have been achieved, although 15 to 30 percent is more realistic for most applications. SNCR is typically applied on smaller units. Adequate reagent distribution in the furnaces of large units can be problematic.

Reagent utilization, which is a measure of the efficiency with which the reagent reduces NO_x, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create problems downstream. The ammonia may render fly ash unsaleable, and also react with sulfur to form ammonium bisulphate which can foul heat exchanger surfaces and/or create a visible stack plume. Reagent utilization can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost.

Reductions from higher baseline inlet NO_x concentrations are lower in cost per ton, but result in higher operating costs, due to greater reagent consumption.

Mobotec also provided information for their Rotamix SNCR system for Cholla 3. The expected NO_x emission rate for the Rotamix system, operating in conjunction with ROFA, is 0.12 lb/MMBtu. CH2M HILL utilized previous SNCR vendor proposals to develop cost and NO_x emission estimates.

SCR. SCR works on the same chemical principle as SNCR but SCR uses a catalyst to promote the chemical reaction. Ammonia or urea is injected into the flue-gas stream, where it reduces NO_x to nitrogen and water. Unlike the high temperatures required for SNCR, in SCR the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580° F to 750° F. Due to the catalyst, the SCR process is more efficient than SNCR and results in lower NO_x emissions. The most common type of SCR is the high-dust configuration, where the catalyst is located downstream from the boiler economizer and upstream of the air heater and any particulate control equipment. In this location, the SCR is exposed to the full concentration of fly ash in the flue gas that is leaving the boiler. For Cholla 3 the SCR would be installed before the air heater a high-particulate location. In a full-scale SCR, the flue ducts are routed to a separate large reactor containing the catalyst. With in-duct SCR, the catalyst is located in the existing gas duct, which may be expanded in the area of the catalyst to reduce flue gas flow velocity and increase flue gas residence time. Due to the higher removal rate, a full-scale SCR was used as the basis for analysis at Cholla 3.

As with SNCR, it is generally more cost effective to reduce NO_x emission levels as much as possible through combustion modifications, in order to minimize the catalyst surface area and ammonia requirements of the SCR.

Neural Net Controls/Boiler Combustion Control. Review of neural net and improved boiler combustion control are combined for purposes of this analysis under the potential implementation of neural net boiler control system. Information regarding neural net controls has been previously received from NeuCo, Inc. While NeuCo offers several neural net products, CombustionOpt and SootOpt provide the potential for NO_x reduction. NeuCo stated these products can be utilized on most control systems, and can be effective even in conjunction with other NO_x reduction technologies.

NeuCo predicts that CombustionOpt can reduce NO_x by 15%, and SootOpt can provide an additional 5 to 10%. Since NeuCo does not offer guarantees on this projected emission reduction, a nominal reduction of 15% was assumed for evaluation purposes. The budgetary price for CombustionOpt and SootOpt were $150,000 and $175,000 respectively, with an addition $200,000 cost for a process link to the unit control system.

Since NeuCo does not guarantee NO_x reduction, the estimated emission reduction levels provided can not be considered as reliable projections. Therefore, neural net should be considered as a supplementary or "polishing" technology, but not on a "stand-alone" basis.

3.1.1.5 Step 4: Evaluate Impacts and Document the Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. Installation of new LNBs and SOFA system are not expected to significantly impact the boiler efficiency or forced draft fan power usage. Therefore, these technologies are not expected to have significant energy impacts.

The Mobotec ROFA system requires installation and operation of one 3,300 Hp ROFA fan (2,461 kW total). Fuel Tech provided an estimate of 130 kW of additional auxiliary power, and the same estimate was used for Rotamix. SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase.

Environmental Impacts. With the planned installation of new LNBs and SOFA system, CO emissions are projected to increase significantly to an estimated 0.15 lb/MMBtu (based on a 30-day average). APS completed a CO BACT review for this anticipated increase in CO emissions.

Mobotec generally predicts that CO emissions, and unburned carbon in the ash commonly referred to as LOI (loss on ignition), would be the same or lower than prior levels for the ROFA system.

SNCR and SCR installation could impact the salability and disposal of fly ash due to ammonia levels, and could potentially create a visible stack plume, which may negate other visibility improvements. Other environmental impacts involve the potential public and employee safety hazard associated with the storage of ammonia, especially anhydrous ammonia, and the transportation of the ammonia to the power plant site.

Economic Impacts. A comparison of the technologies on the basis of costs, design control efficiencies, and tons of NO_x removed is summarized in Table 3-3, and the first year control costs are shown in Figure 3-2. The complete Economic Analysis is contained in Appendix A.

TABLE 3-3
NO_x Control Cost Comparison
Cholla 3

Factor	LNB w/SOFA[1]	ROFA	ROFA w/ Rotamix	LNB w/SOFA & SNCR	LNB w/SOFA & SCR
Major Materials and Design Costs	$2.1 Million	$4.4 Million	$6.1 Million	$6.6 Million	$32.1 Million
Total Installed Capital Costs	$5.4 Million	$11.9 Million	$18.6 Million	$17 Million	$82.8 Million
Total First Year Fixed & Variable O&M Costs	$0.1 Million	$1.1 Million	$1.5 Million	$0.5 Million	$1.7 Million
Total First Year Annualized Cost	$0.6 Million	$2.2 Million	$3.3 Million	$2.2 Million	$9.6 Million
Power Consumption (MW)	---	2.46	2.46	0.3	1.5
Annual Power Usage (1000 MW-Hr/Yr)	---	18.5	18.5	2.3	11.3
NO_x Design Control Efficiency	46.3%	61%	70.7%	58.5%	82.9%

TABLE 3-3
NO_x Control Cost Comparison
Cholla 3

Factor	LNB w/SOFA[1]	ROFA	ROFA w/ Rotamix	LNB w/SOFA & SNCR	LNB w/SOFA & SCR
NO_x Removed per Year (Tons)	2,096	2,758	3,200	2,648	3,751
First Year Average Control Cost ($/Ton of NO_x Removed)	303	813	1,034	814	2,551
Incremental Control Cost ($/Ton of NO_x Removed)	303	784	2,413	2,758	11,350

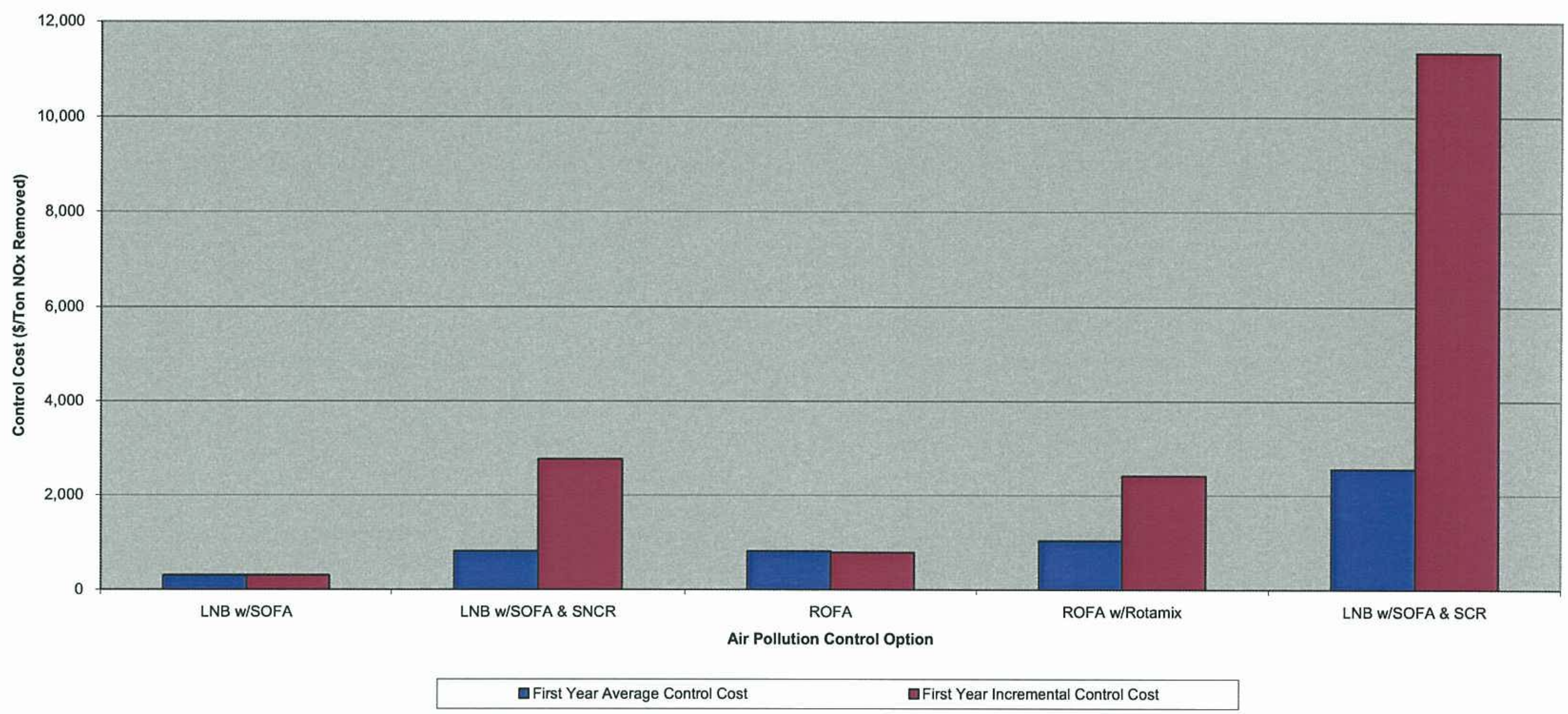
1 – Since installation of LNB is part of the APS environmental upgrades this option is assumed to have zero cost

Preliminary BART Selection. The 4-step evaluation indicates new LNBs with SOFA would represent BART for Cholla 3 based on its significant reduction in NO_x emissions, reasonable control cost, and no additional power requirements or environmental impacts. New LNB w/SOFA meets the target EPA presumptive limit of 0.28 lb/MMBtu for bituminous coal.

3.1.1.6 Step 5: Evaluate Visibility Impacts

Please see Sections 4.0 (BART Modeling Analysis) and 5.0 (Preliminary Assessment and Recommendations).

FIGURE 3-2
First Year Control Cost for NOx Air Pollution Control Options
Cholla 3



3.1.2 BART SO_2 Analysis

SO_2 forms in the boiler during the combustion process from the oxidation of the sulfur present in the coal, and is primarily dependent on coal sulfur content. Cholla 3 currently does not have an SO_2 removal system in operation; however a new wet lime scrubber system is planned in 2009. The BART analysis for SO_2 emissions on Cholla 3 is described below.

3.1.2.1 Step 1: Identify All Available Retrofit Control Technologies

A broad range of information sources were reviewed, in an effort to identify potentially applicable emission control technologies for SO_2 at Cholla 3. This included control technologies identified as BACT or LAER by permitting agencies across the United States.

The following SO_2 control technology options were considered:

- Dry sorbent Injection with existing ESP or new fabric filter
- Dry FGD with existing ESP or new fabric filter
- Wet lime FGD

3.1.2.2 Step 2: Eliminate Technically Infeasible Options

Technical feasibility will primarily be based on the regulatory presumptive limit of 95 percent reduction in SO_2 emissions, or 0.15 lb/MMBtu. Assuming an uncontrolled SO_2 emission level of 2.5 lb/MMBtu, a reduction efficiency of 94 percent would be required to achieve outlet SO_2 emissions of 0.15 lb/MMBtu.

Dry FGD System. The lime spray dryer typically injects lime slurry in the top of the absorber vessel with a rapidly rotating atomizer wheel. The rapid speed of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas. The SO_2 in the flue gas reacts with the calcium in the lime slurry to form dry calcium sulfate particles. At Cholla 3 this dry particulate matter would be injected upstream of the particulate control device and collected along with the fly ash. A lime spray dryer system typically produces a dry waste product suitable for landfill disposal.

A dry FGD system is estimated to achieve 90 percent SO_2 removal. This would result in a controlled SO_2 meeting the target emission rate of 0.25 lb/MMBtu target, based on an uncontrolled SO_2 emissions rate of 2.5 lb/MMBtu. Therefore, this technology option would not meet the targeted guideline SO_2 emissions of 0.15 lb/MMBtu.

Dry Sodium Sorbent Injection. Dry duct injection of sodium materials such as sodium carbonate or sodium bicarbonate can be utilized to remove moderate levels of SO_2 from flue gas at a reasonably low capital cost ($50-100/kW). The sorbent is injected into the flue gas downstream of the air heater, typically at approximately 300°F, and the reacted and unreacted sorbent material and fly ash would be collected in the fabric filter or electrostatic precipitator. Maximum SO_2 removal efficiency for this technology is approximately 75 percent, which would not result achieving the guideline target of 0.15 lb/MMBtu SO_2 emissions. A visible brown NO_2 plume at higher SO_2 removal rates and/or larger stack diameters is a potential limitation of the dry sodium injection technology. Therefore, the dry sodium sorbent injection technology is not considered a viable SO_2 reduction option for this analysis.

New Wet Lime Scrubber. A typical wet lime scrubber consists of SO_2-laden flue gas entering a scrubber vessel where it is sprayed with water/calcium slurry. The calcium reacts to form calcium sulfite or sulfate, and is then either removed and disposed as scrubber waste or reclaimed as gypsum. Wet lime scrubbers are capable of very high SO_2 removal efficiencies, with a 95 percent removal efficiency assumed for this BART analysis. Based on the uncontrolled SO_2 emissions of 2.5 lb/MMBtu, a new wet lime scrubber can achieve the target outlet SO_2 emissions of 0.15 lb/MMBtu. Table 3-5 summarizes the control technology options evaluated in this BART analysis, along with projected SO_2 emission rates. Only dry FGD and new lime wet scrubber technology options can consistently meet or exceed the SO_2 removal efficiency required to achieve the guideline target. Therefore, only these two alternatives are considered technically feasible for purposes of this analysis.

TABLE 3-4
SO_2 Control Technology Emission Rate Ranking
Cholla 3

Technology	Projected Emission Rate (lb/MMBtu)	Estimated SO_2 Removal Efficiency (%)
BART Presumptive Limit Guideline	0.15	N/A
Dry FGD/Lime Spray Dryer	0.25	90
Wet Lime FGD	0.15	94

3.1.2.3 Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

When evaluating the control effectiveness of SO_2 reduction technologies, each option can be compared against benchmarks of performance. One such benchmark is the presumptive BART emission limit, which is used in this study as a guideline. As indicated previously, the BART presumptive limit for SO_2 on a BART-eligible coal burning unit is 95 percent removal, or 0.15 lb/MMBtu. The Wet Lime FGD alternative can achieve the 0.15 lb/MMBtu guideline listed above.

3.2.2.4 Step 4: Evaluate Impacts and Document the Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. The new FGD system will require additional power consumption. (NOTE: CH2M HILL still needs to provide specific information on power needs.)

Environmental Impacts. There will additional scrubber waste disposal costs, reagent usage, and power consumption with the wet lime FGD systems. It will also require additional make-up water.

Economic Impacts. Capital cost information for the wet Lime FGD alternative was estimated from CH2M HILL in-house information. This cost information is summarized in Table 3-4. A comparison of the technologies on the basis of costs, design control efficiencies, and tons of

SO_2 removed is summarized in Tables 3-6 and 3-7, with the first-year control costs in Figures 3-3 and 3-4. The complete Economic Analysis is contained in Appendix A.

TABLE 3-5
SO2 Wet Limestone FGD Costs
Cholla 3

Factor	Wet Limestone FGD
Major Materials and Design Costs	\$26 Million
Total Installed Capital Costs	\$67.1 Million
Total First Year Fixed & Variable O&M Costs	\$2.4 Million
Total First Year Annualized Cost	\$8.8 Million
Additional Power Consumption (MW)	0.4
Additional Annual Power Usage (1000 MW-Hr/Yr)	3.0
Incremental PM Design Control Efficiency	85%
Incremental Tons PM Removed per Year	9,378
First Year Average Control Cost ($/Ton of PM Removed)	936
Incremental Control Cost ($/Ton of PM Removed)	936

Preliminary Selection. Based upon the technical and economic analysis above, a wet lime FGD system can meet the guideline of 0.15 lb/MMBtu, and is therefore BART.

3.1.2.5 Step 5: Evaluate Visibility Impacts

Please see Sections 4.0 (BART Modeling Analysis) and 5.0 (Preliminary Assessment and Recommendations).

3.1.3 BART PM10 Analysis

Cholla 3 is currently equipped with a hot-side electrostatic precipitator for primary PM_{10} control, and a fabric filter is planned to be installed in 2009. Current PM_{10} emissions on Cholla 3 are approximately 0.015 lb/MMBtu, and the fabric filter will result in emissions estimated at 0.015 lb/MMBtu

The BART analysis for PM_{10} emissions at Cholla 3 is described below. For the modeling analysis in Sections 4.0 and 5.0, PM_{10} and $PM_{2.5}$ are used as indicators of PM emissions.

3.1.3.1 Step 1: Identify All Available Retrofit Control Technologies

Two retrofit control technologies have been identified for additional PM control:

- ESP upgrade or replacement
- Fabric Filter

3.1.3.2 Step 2: Eliminate Technically Infeasible Options

ESP. While a replacement electrostatic precipitator may be capable of achieving a 0.015 lb/MMBtu target, operational variations may not result in consistent compliance with this emissions rate. Any ESP upgrade or gas conditioning would also result in a PM_{10} removal system which is less reliable in achieving the 0.015 lb/MMBtu than a fabric filter. Therefore this option is not considered technically attractive.

Fabric Filter. A pulse jet fabric filter could be installed as a replacement for the existing hot-side ESP on Cholla 3. This fabric filter would be sized for approximately 3.5 or 4:1 Air to Cloth (A/C) ratio (actual cubic feet per minute of flue gas/square feet of fabric). An A/C ratio of 4:1 was used for this analysis. Fabric filters have been proven to provide highly effective and consistent particulate emissions reduction, with outlet emissions of approximately 0.015 lb/MMBtu. The hot-side ESP will be removed from service with this replacement fabric filter option.

3.1.3.3 Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

The existing hot-side ESP at Cholla 3 is achieving a controlled PM emission rate of approximately 0.015 lb/MMBtu. Adding a replacement fabric filter, or new ESP, PM_{10} emissions are expected to be approximately 0.015 lb/MMBtu.

The PM_{10} control technology emission rates are summarized in Table 3-6, with the PM_{10} emissions rates shown for both a replacement fabric filter and ESP.

TABLE 3-6
PM_{10} Control Technology Emission Rates
Cholla 3

Control Technology	Expected PM_{10} Emission Rate (Lb/MMBtu)
Electrostatic Precipitator	>0.015
Fabric Filter	0.015

3.1.3.4 Step 4: Evaluate Impacts and Document the Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. Energy is required to overcome the additional pressure drop from the fabric filter replacement and associated ductwork. Therefore, fan upgrades may be required to overcome the additional pressure drop. An estimated 6 to 8 inches H_2O additional total system pressure drop for the replacement fabric filter may be experienced.

Environmental Impacts. There are no negative environmental impacts from the addition of an ESP replacement or modification, or a fabric filter.

Economic Impacts. A listing of the costs and PM_{10} removed for a fabric filter is shown in Table 3-7. Capital cost information was used from previous CH2M HILL equipment estimates for the replacement fabric filter. Since an ESP is not capable of achieving reliable PM_{10} reduction comparable to a fabric filter, costs for an ESP are not shown.

TABLE 3-7
PM_{10} Fabric Filter Costs
Cholla 3

Factor	Fabric Filter Replacement
Major Materials and Design Costs	$32.9 Million
Total Installed Capital Costs	$84.8 Million
Total First Year Fixed & Variable O&M Costs	$1.3 Million
Total First Year Annualized Cost	$9.4 Million
Additional Power Consumption (MW)	0.4
Additional Annual Power Usage (1000 MW-Hr/Yr)	3.0
Incremental PM Design Control Efficiency	0.7%
Incremental Tons PM Removed per Year	1
First Year Average Control Cost ($/Ton of PM Removed)	8,522,807
Incremental Control Cost ($/Ton of PM Removed)	8,522,807

Preliminary BART Selection. The 4-step evaluation indicates installation of a replacement fabric filter represents BART for Cholla 3. This option has a high control cost, but APS plans to install a fabric filter. Based on this plan and the knowledge that a fabric filter will result in a significant reduction in PM emissions and have no non-air quality environmental impacts, this option is selected as BART.

3.1.3.5 Step 5: Evaluate Visibility Impacts

Please see Section 4.0, BART Modeling Analysis.

Section 4.0
BART Modeling Analysis

4.0 BART Modeling Analysis

4.1 Introduction

This section presents the dispersion modeling methods and results for estimating the degree of visibility improvement from BART control technology options for the Cholla 3.

To a large extent, the modeling followed the methodology outlined in the WRAP protocol for performing BART analyses (WRAP, 2006). Any proposed deviations from that methodology are documented in this report.

4.2 Model Selection

CH2M HILL used the EPA-required CALPUFF modeling system to assess the visibility impacts at Class I areas. CALPUFF is a multi-layer, multi-species non-steady-state puff dispersion model that simulates the effects of time- and space-varying meteorological conditions on pollution transport, transformation, and removal. BART guidance says, "CALPUFF is the best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment and is currently the only EPA-approved model for use in estimating single source pollutant concentrations resulting from the long range transport of pollutants."

The CALPUFF modeling system includes the meteorological data preprocessing program for CALPUFF (CALMET) with algorithms for chemical transformation and deposition, and a post processor capable of calculating concentrations, visibility impacts, and deposition (CALPOST). The CALPUFF modeling system was applied in a full, refined mode.

CH2M HILL used the latest version (Version 6) of the CALPUFF modeling system preprocessors and models in lieu of the EPA-approved versions (Version 5). The FLM and others have noted that the EPA-approved Version 5 contained errors and that a newer version should be used. Consequently, it was decided to use the latest (as of April 2006) version of the CALPUFF modeling system (available at www.src.com):

- CALMET Version 6.211 Level 060414
- CALPUFF Version 6.112 Level 060412

CALMET, CALPUFF, CALPOST, and POSTUTIL were recompiled with the Lahey/Fujitsu Fortran 95 Compiler (Release 7.10.02) to accommodate the large CALMET domain. The recompiled processors were tested against the test case results provided with the source code (TRC, 2007), and the difference between the results was 0.03 percent.

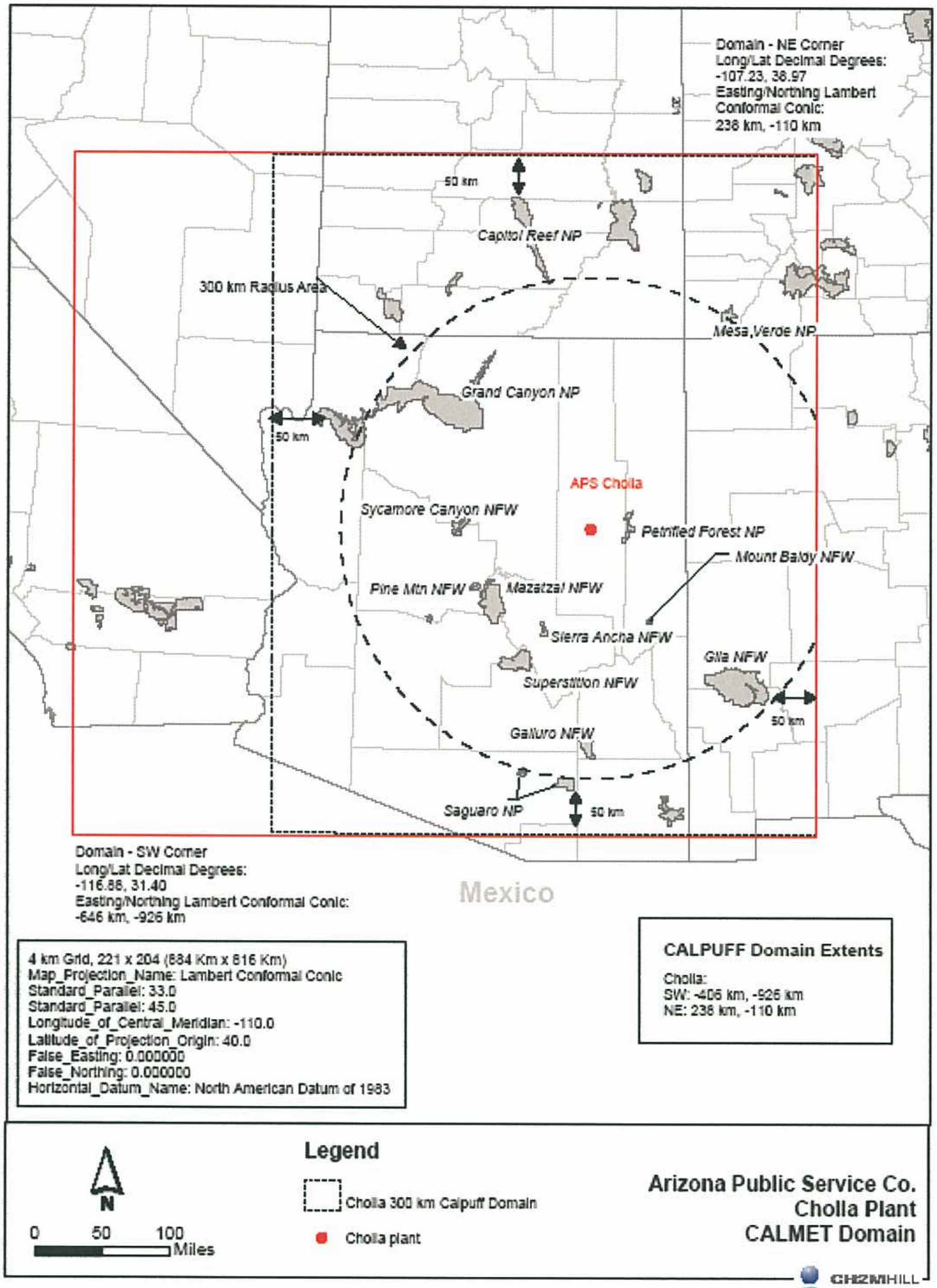
4.3 CALMET Methodology

4.3.1 Dimensions of the Modeling Domain

CH2M HILL-defined domains for Mesoscale Meteorological Model, Version 5 (MM5), CALMET, and CALPUFF that were slightly different than those established for the Arizona BART modeling in WRAP (2006). In addition, the CALMET and CALPUFF Lambert Conformal Conic (LCC) map projection used in this analysis is based on a central meridian of 110° W rather than 97° W. This puts the central meridian near the center of the domain.

CH2M HILL used the CALMET model to generate three-dimensional wind fields and other meteorological parameters suitable for use by the CALPUFF model. A CALMET modeling domain has been defined to allow for at least a 50-kilometers buffer around all Class I areas within 300 kilometers of the Cholla Power Plant. Grid resolution for this domain was 4 kilometers. Figure 4-1 shows the extent of the modeling domain.

FIGURE 4-1
CALPUFF and CALMET Modeling Domains



The technical options recommended in WRAP (2006) were used for CALMET. Vertical resolution of the wind field included 11 layers, with vertical cell face heights as follows (in meters):

- 0, 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, 5000

Also, following WRAP (2006), ZIMAX were set to 4,500 meters based on the Colorado Department of Health and Environment (CDPHE) analyses of soundings for summer ozone events in the Denver area (CDPHE, 2005). The CDPHE analysis suggests mixing heights in the Denver area are often well above the CALMET default value of 3,000 meters during the summer. For example, on some summer days, ozone levels are elevated to 6,000 meters mean sea level or beyond during some meteorological regimes, including some regimes associated with high-ozone episodes. It is assumed that, as in Denver, mixing heights in excess of the 3,000 meters AGL CALMET default maximum would occur in the domain used for this analysis.

Table 4-1 lists the key user-specified options.

TABLE 4-1
User-Specified CALMET Options

Description	CALMET Input Parameter	Value
	CALMET Input Group 2	
Map projection	PMAP	LCC
Grid spacing	DGRIDKM	4
Number vertical layers	NZ	11
Top of lowest layer (meters)		20
Top of highest layer (meters)		5,000
	CALMET Input Group 4	
Observation mode	NOOBS	1
	CALMET Input Group 5	
Extrapolation of surface wind observations	IEXTRP	4
Prognostic or MM-FDDA data switch	IPROG	14
Max surface over-land extrapolation radius (kilometers)	RMAX1	50
Max aloft over-land extrapolations radius (kilometers)	RMAX2	50
Radius of influence of terrain features (kilometers)	TERRAD	10
Relative weight at surface of Step 1 field and obs	R1	25
Relative weight aloft of Step 1 field and obs	R2	25
	CALMET Input Group 6	
Maximum over-land mixing height (meters)	ZIMAX	4,500

4.3.2 CALMET Input Data

CH2M HILL ran the CALMET model to produce 3 years of analysis: 2001, 2002, and 2003. CH2M HILL used MM5 data as the basis for the CALMET wind fields. The horizontal resolution of the MM5 data is 36 kilometers.

For 2001, CH2M HILL used MM5 data at 36-kilometers resolution that were obtained from the contractor (Alpine Geophysics) who developed the nationwide data for the EPA. For 2002, CH2M HILL used 36-kilometers MM5 data obtained from Alpine Geophysics, originally developed for the WRAP. Data for 2003 (also from Alpine Geophysics), at 36-kilometers resolution, were developed by the Wisconsin Department of Natural Resources, the Illinois Environmental Protection Agency, and the Lake Michigan Air Directors Consortium (Midwest RPO).

The MM5 data were used as input to CALMET as the "initial guess" wind field. The initial guess field was adjusted by CALMET for local terrain and land use effects to generate a Step 1 wind field, and then further refined using local surface observations to create a final Step 2 wind field.

Surface data for 2001 through 2003 were obtained from the National Climatic Data Center. CH2M HILL processed data for all stations from the National Weather Service's (NWS) Automated Surface Observing System (ASOS) network that are in the domain. The surface data were obtained in abbreviated DATSAV3 format. A conversion routine available from the TRC website was used to convert the DATSAV3 files to CD 144 format for input to the SMERGE preprocessor and CALMET.

Land use and terrain data were obtained from the U.S. Geological Survey (USGS). Land use data were obtained in Composite Theme Grid format from the USGS, and the Level I USGS land use categories were mapped into the 14 primary CALMET land use categories. Surface properties, such as albedo, Bowen ratio, roughness length, and leaf area index, were computed from the land use values. Terrain data were taken from USGS 1 degree Digital Elevation Model data, which are primarily derived from USGS 1:250,000 scale topographic maps. Missing land use data were filled with a value that is appropriate for the missing area.

Precipitation data were ordered from the National Climatic Data Center. All available data in fixed-length, TD-3240 format were ordered for the modeling domain. The list of available stations and stations that have collected complete data varies by year, but CH2M HILL processed all available stations/data within the domain for each year. Precipitation data were prepared with the PXTRACT/PMERGE processors in preparation for use within CALMET.

Following the methodology recommended in WRAP (2006), no observed upper-air meteorological observations were used as they are redundant to the MM5 data and may introduce spurious artifacts in the wind fields. In the development of the MM5 data, the twice daily upper-air meteorological observations were used as input with the MM5 model. The MM5 estimates were nudged to the upper-air observations as part of the Four Dimensional Data Assimilation. This results in higher temporal (hourly versus. 12 hour) and spatial (36 kilometers versus ~300 kilometers) resolution for the upper-air meteorology in the MM5 field. These MM5 data are more dynamically balanced than those contained in the upper-air observations. Therefore, the use of the upper-air observations with CALMET is not needed, and in fact, will upset the dynamic balance of the meteorological fields potentially producing spurious vertical velocities.

4.3.3 Validation of CALMET Wind Field

CH2M HILL used the CALDESK (program to display data and results) data display and analysis system (v2.97, Enviromodeling Ltda.) to view plots of wind vectors and other meteorological parameters to evaluate the CALMET wind fields. CH2M HILL observed weather conditions, as depicted in surface and upper-air weather maps from the National Oceanic and Atmospheric Administration Central Library U.S. Daily Weather Maps Project (http://docs.lib.noaa.gov/ rescue/ dwm/ data_rescue_daily_weather_maps.html), to compare to the CALDESK displays.

4.4 CALPUFF Methodology

4.4.1 CALPUFF Modeling

CH2M HILL ran the CALPUFF model with the meteorological output from CALMET over the CALPUFF modeling domain (Figure 4-1). The CALPUFF model was used to predict visibility impacts for the pre-control (baseline) scenario for comparison to the predicted impacts for post-control scenarios.

Background Ozone and Ammonia

Hourly values of background ozone concentrations were used by CALPUFF for the calculation of SO_2 and NO_X transformation with the MESOPUFF II chemical transformation scheme. CH2M HILL used the hourly ozone data generated for the WRAP BART analysis for 2001, 2002, and 2003.

For periods of missing hourly ozone data, the chemical transformation relied on a monthly default value of 80 parts per billion. For background ammonia the following monthly values were used:

Dec – Mar: 0.2 parts per billion (ppb)
Apr – May: 0.5 ppb
Jun – Sep: 1.0 ppb
Oct – Nov: 0.5 ppb

Stack Parameters

The baseline stack parameters for the baseline and post-control scenarios were supplied by APS staff. The parameters used in the WRAP analysis appeared to be related to natural gas combustion so it was necessary to replace these with more applicable values. The same stack data were used for all scenarios since none of the emission controls related to these scenarios would significantly affect the exhaust exit flows or temperatures.

Pre-Control Emission Rates

Pre-control emission rates reflect normal maximum capacity 24-hour emissions that may occur under the source's current permit. The emission rates reflect actual emissions under normal operating conditions. As described by the EPA in the Regional Haze Regulations and Guidelines for BART Determinations; Final Rule (40 CFR Part 51; July 6, 2005, pg 39129):

> *"The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high-capacity utilization. We do not generally recommend that emissions reflecting periods of start-up, shutdown, and malfunction be used..."*

CH2M HILL used available CEM data to determine the baseline emission rates. Data reflect operations from 2001 through 2006.

Emissions were modeled for the following species:

- Sulfur dioxide (SO_2)
- Oxides of nitrogen (NO_x)
- Coarse particulate (diameter greater than $PM_{2.5}$ and less than or equal to PM_{10})
- Fine particulate (diameter less than or equal to $PM_{2.5}$)
- Elemental carbon (EC)
- Organic aerosols (SOA)
- Sulfates (SO_4)

Post-control Emission Rates

Post-control emission rates reflected the effects of the emissions control scenario under consideration. Modeled pollutants were the same as listed for the pre-control scenario.

Modeling Process

The CALPUFF modeling for the control technology options followed this sequence:

- Model WRAP-RMC parameters to verify results
- Model pre-control (baseline) emissions
- Determine the degree of visibility improvement
- Model other control scenarios if applicable
- Determine the degree of visibility improvement
- Factor visibility results into BART five-step evaluation

4.4.2 Receptor Grids and Coordinate Conversion

The TRC COORDS program was used to convert the latitude/longitude coordinates to LCC map coordinates for the meteorological stations and source locations. The USGS conversion program PROJ (version 4.4.6) was used to convert the National Park Service (NPS) receptor location data from latitude/longitude to LCC.

For the Class I areas that are within 300 kilometers of the Cholla Power Plant, discrete receptors for the CALPUFF modeling were taken from the National Park Service database for Class I area modeling receptors. The entire area of each Class I area that is within or intersects the 300-kilometers circle (Figure 4-1) were included in the modeling analysis. The following lists the Class I areas that were modeled for the Cholla facility:

- Capitol Reef NP (care)
- Galiuro Wilderness (gali)
- Gila Wilderness (gila)
- Grand Canyon NP (grca)
- Mazatzal Wilderness (maza)
- Mesa Verde NP (meve)
- Mount Baldy Wilderness (moba)
- Petrified Forest NP (pefo)
- Pine Mountain Wilderness (pimo)
- Saguaro NP (sagu)
- Sierra Ancha Wilderness (sian)
- Superstition Wilderness (supe)
- Sycamore Canyon WA (syca)

4.5 Visibility Post-processing

4.5.1 CALPOST

The CALPOST processor was used to determine 24-hour average visibility results. Output is specified in deciview (dV) units.

Calculations of light extinction were made for each pollutant modeled. The sum of all extinction values was used to calculate the delta-dv (ΔdV) change relative to natural background. The following default extinction coefficients for each species, as shown below, were used:

- Ammonium sulfate 3.0
- Ammonium nitrate 3.0
- PM coarse (PM_{10}) 0.6
- PM fine ($PM_{2.5}$) 1.0
- Organic carbon 4.0
- Elemental carbon 10.0

CALPOST Visibility Method 6 (MVISBK=6) was used for the determination of visibility impacts. Monthly average relative humidity factors (f[RH]) were used in the light extinction calculations to account for the hygroscopic characteristic of sulfate and nitrate particles. Monthly f(RH) values, from the WRAP_RMC BART modeling, were used in CALPOST for the particular Class I area being modeled.

The natural background conditions used in the post-processing to determine the change in visual range background—or ΔdV—represent the average natural background concentration for western Class I areas.

Table 4-2 lists the annual average species concentrations from the EPA Guidance.

TABLE 4-2
Average Natural Levels of Aerosol Components

Aerosol Component	Average Natural Concentration (μg/m³) for Western Class I Areas
Ammonium Sulfate	0.12
Ammonium Nitrate	0.10
Organic Carbon	0.47
Elemental Carbon	0.02
Soil	0.50
Coarse Mass	3.0

Taken from Table 2-1 of Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule. EPA-454/B-03-005, September 2003.

4.6 Results

Input and output files for the CALMET/CALPUFF modeling and post-processing will be provided in electronic format to the Arizona Department of Environmental Quality (ADEQ). Larger files, such as binary files generated by CALMET, have not been included on the submitted disks, but any omitted files will be provided electronically upon request.

4.6.1 BART Least-Cost Analysis

The results and comparisons of the CALPUFF modeling for the baseline emission rates and those for the alternative emission control scenarios are provided in Section 5.

Section 5.0
Preliminary Assessment and Recommendations

5.0 Preliminary Assessment and Recommendations

5.1 Preliminary Recommended BART Controls

As a result of the completed technical and economic evaluations, and consideration of the modeling analysis for Cholla 3, the preliminary recommended BART controls for NO_x, SO_2, and PM_{10} are as follows:

- The most cost-effective emissions control scenario for NO_x includes new LNB with SOFA.
- Installation of a replacement fabric filter for PM_{10} emission control is recommended.
- Installation of a wet FGD system for SO_2 removal is also recommended.

The above NO_x recommendation is identified as Scenario 1 for the modeling analysis described in Section 4.0. Visibility improvements for all emission control scenarios were analyzed, and the results are compared below, using a least-cost envelope, as outlined in the draft EPA *New Source Review Workshop Manual* (1990).

5.2 Analysis Baseline and Scenarios

Table 5-1 compares the six emission control scenarios with expected emission levels.

TABLE 5-1
Emission Control Scenarios
Cholla 3

Case	Description	Expected NO_x Emission (lb/MMBtu)	Expected SO_2 Emissions (lb/MMBtu)	Expected PM_{10} Emissions (lb/MMBtu)
Baseline		0.410	1.000	0.015
Scenario 1	New LNB with SOFA	0.220	0.150	0.015
Scenario 2	ROFA	0.160	0.150	0.015
Scenario 3	ROFA with Rotamix	0.120	0.150	0.015
Scenario 4	New LNB with SOFA & SNCR	0.170	0.150	0.015
Scenario 5	New LNB with SOFA & SCR	0.070	0.150	0.015

The ranking of the different NO_x emission control scenarios based on annual costs, from lowest to highest cost, is presented on Table 5-2.

TABLE 5-2
Ranking of NO_x Control Scenarios by Cost
Cholla 3

Rank	Scenario	Description	Total Annual Cost
1	Scenario 1	New LNB with SOFA	$635,403
2	Scenario 4	New LNB with SOFA & SNCR	$2,156,692
3	Scenario 2	ROFA	$2,243,202
4	Scenario 3	ROFA with Rotamix	$3,307,972
5	Scenario 5	New LNB with SOFA & SCR	$9,569,062

The Baseline of this BART analysis was defined as the level of NO_x and PM_{10} emission control that would be representative of future operations without the additional cost and level of control associated with the scenarios. Figures 5-1 through 5-4 compare the modeled contribution to visual range reduction for each Class I area for the Baseline and each NO_x emission control scenario.

Of the thirteen Class I areas included in this analysis, results from the analysis for four of these areas are presented in this section. These four areas were selected because they represented the maximum Baseline impacts. The results for the remaining nine areas are presented in Appendix C. The four selected areas include:

- Capitol Reef NP (care)
- Grand Canyon NP (grca)
- Petrified Forest NP (pefo)
- Sycamore Canyon WA (syca)

The following figures show the maximum impacts for each emission control scenario at these Class I areas.

FIGURE 5-1
NO_x Control Scenarios—Maximum Contributions to Visual Range Reduction at Capitol Reef NP
Cholla 3

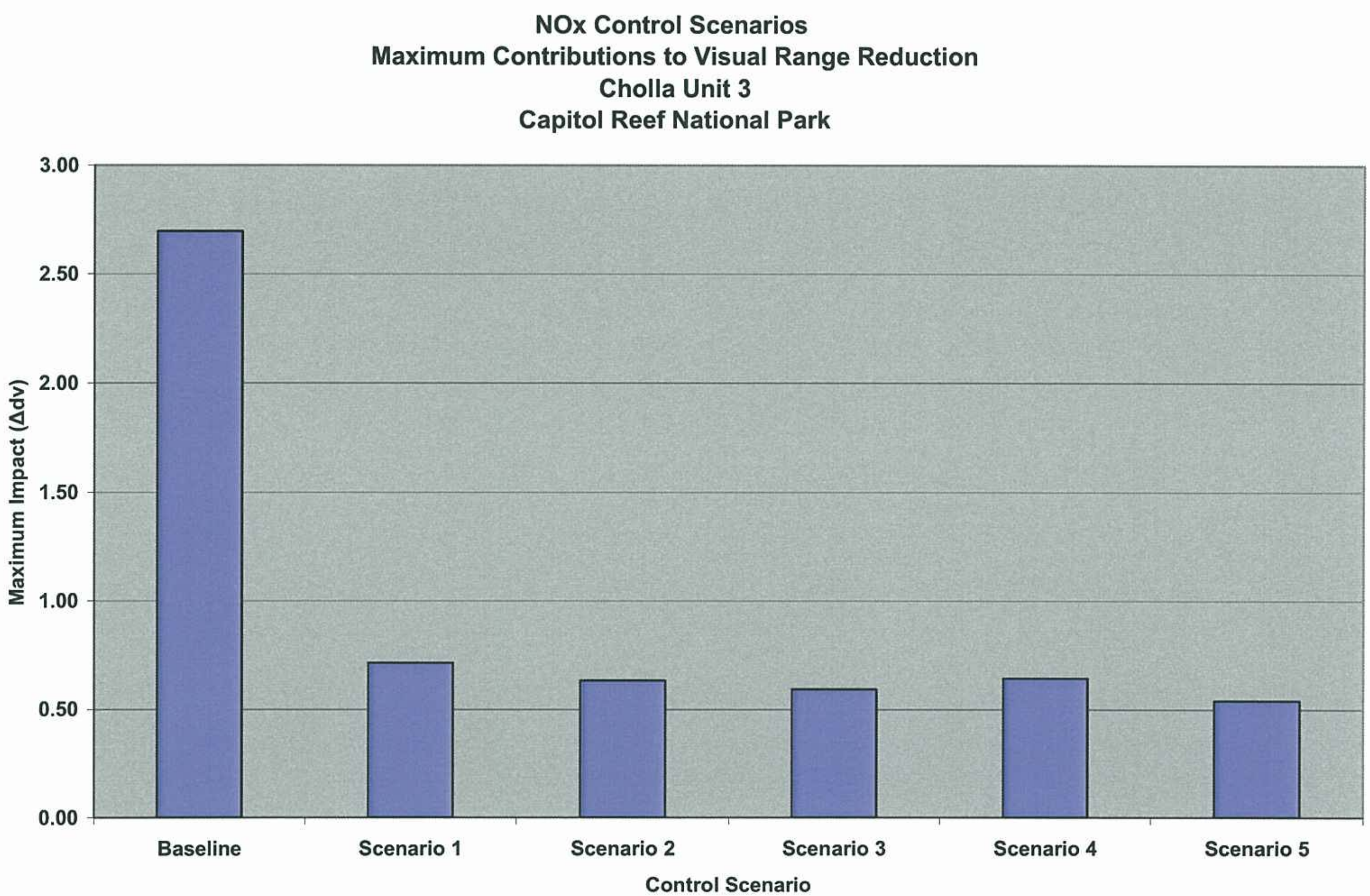


FIGURE 5-2
NO_x Control Scenarios—Maximum Contributions to Visual Range Reduction at Grand Canyon NP
Cholla 3

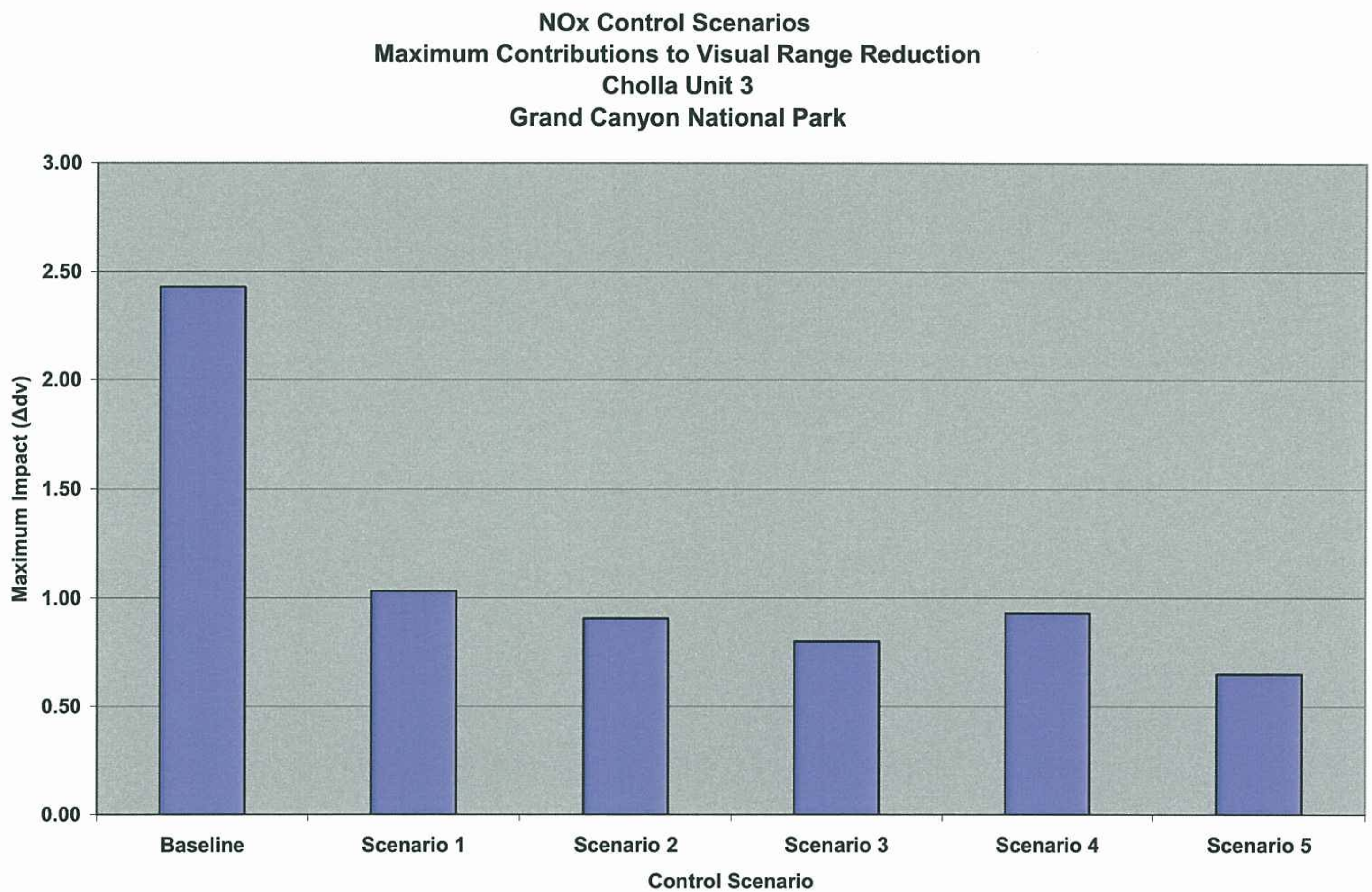


FIGURE 5-3
NO_x Control Scenarios—Maximum Contributions to Visual Range Reduction at Petrified Forest NP
Cholla 3

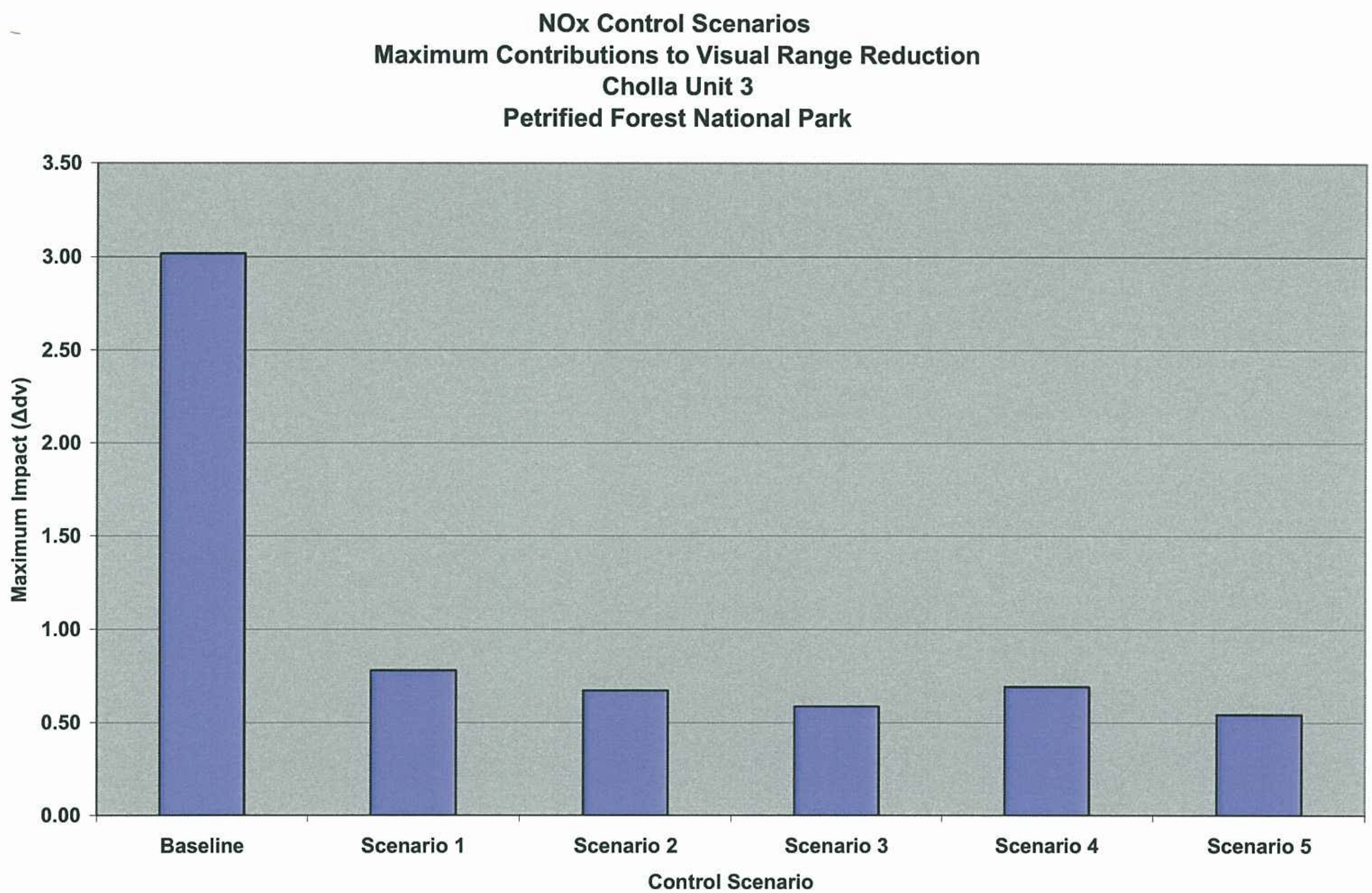
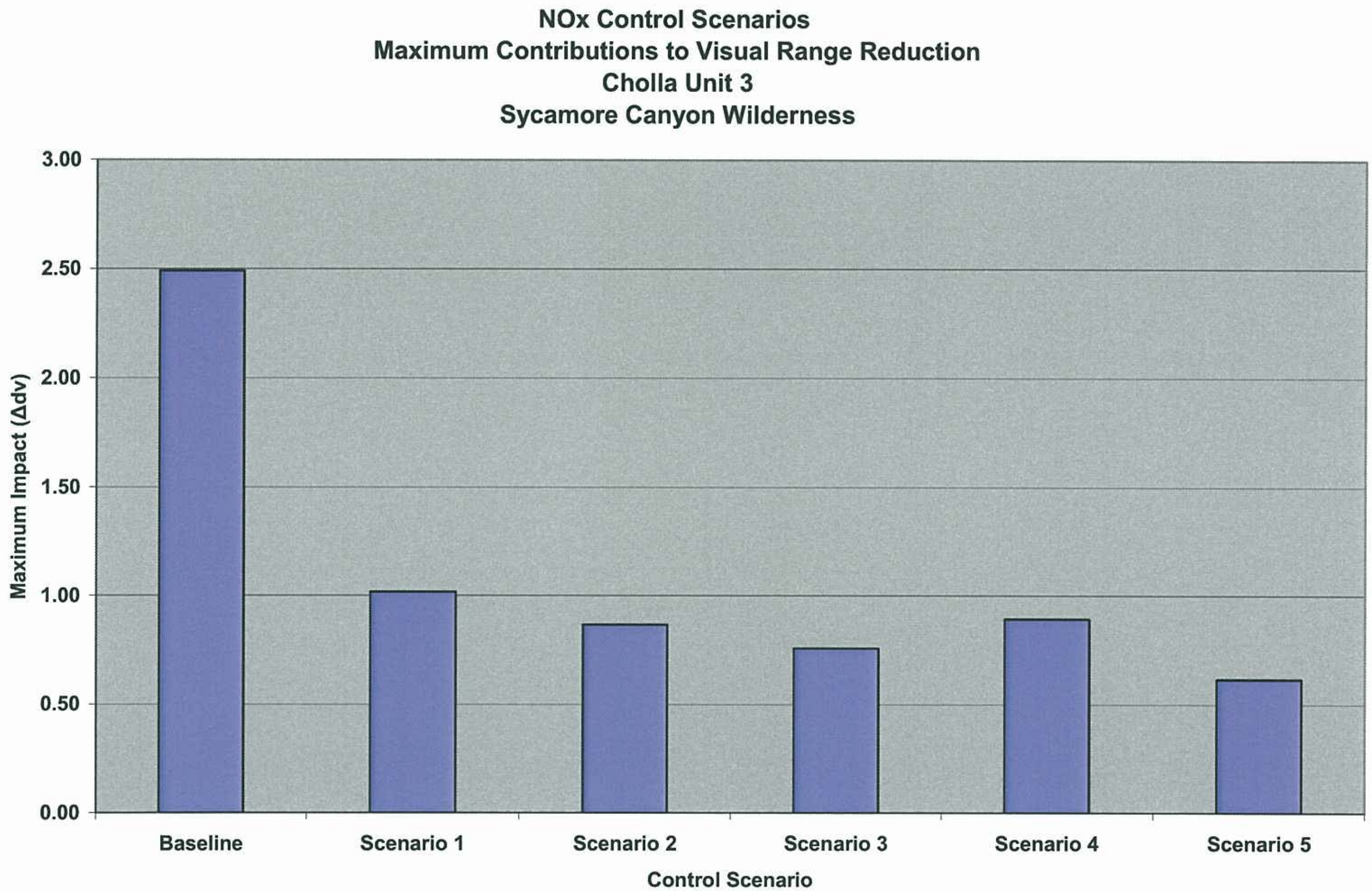


FIGURE 5-4
NO_x Control Scenarios—Maximum Contributions to Visual Range Reduction at Sycamore Canyon WA
Cholla 3



5.3 Least-Cost Envelope Analysis

The total annualized cost, cost per ΔdV reduction, and cost per reduction in number of days above 0.5 ΔdV for each of the NO_x emission control scenarios and each of the selected Class I areas are listed in Tables 5-3 through 5-6. Only costs for NO_x control scenarios are shown. A comparison of the incremental costs between relevant scenarios is shown in Tables 5-7 through 5-8. The total annualized cost versus number of days above 0.5 ΔdV, and the total annualized cost versus 98^{th} percentile ΔdV reduction are shown in Figures 5-5 through 5-12 for the four Class I areas.

5.3.1 Analysis Methodology

On page B-41 of the *New Source Review Workshop Manual* (EPA, 1990), the EPA states that,

> *"Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between dominant alternatives. Dominant set of control alternatives are determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for a total emissions reductions for all control alternatives identified in the BACT analysis..."*

An analysis of incremental cost effectiveness has been conducted. This analysis was performed in the following manner. Control scenarios are selected from points that fall on the least-cost envelope curves (Figures 5-5 through 5-12). The incremental cost effectiveness data, expressed per day and per ΔdV, represents a comparison of the different scenarios, and is summarized in Tables 5-7 through 5-10 for each of the Class I areas. Then the most reasonable smooth curve of least-cost control option scenarios is plotted for each analysis.

TABLE 5-3
NO_x Control Scenario Results for Capitol Reef NP
Cholla 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98^{th} Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		21	0.000	0.000	0.000	0.000
1	New LNB with SOFA	1	0.523	0.635	0.032	1.215
2	ROFA	1	0.562	2.243	0.112	3.991
3	ROFA with Rotamix	1	0.581	3.308	0.165	5.694
4	New LNB with SOFA & SNCR	1	0.557	2.157	0.108	3.872
5	New LNB with SOFA & SCR	1	0.605	9.569	0.478	15.817

TABLE 5-4
NO_x Control Scenario Results for Grand Canyon NP
Cholla 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/ Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		25	0.000	0.000	0.000	0.000
1	New LNB with SOFA	7	0.677	0.635	0.035	0.939
2	ROFA	5	0.700	2.243	0.112	3.205
3	ROFA with Rotamix	3	0.716	3.308	0.150	4.620
4	New LNB with SOFA & SNCR	5	0.696	2.157	0.108	3.099
5	New LNB with SOFA & SCR	1	0.749	9.569	0.399	12.776

TABLE 5-5
NO_x Control Scenario Results for Petrified Forest NP
Cholla 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/ Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		140	0.000	0.000	0.000	0.000
1	New LNB with SOFA	5	1.154	0.635	0.005	0.551
2	ROFA	4	1.197	2.243	0.016	1.874
3	ROFA with Rotamix	3	1.226	3.308	0.024	2.698
4	New LNB with SOFA & SNCR	4	1.192	2.157	0.016	1.809
5	New LNB with SOFA & SCR	1	1.258	9.569	0.069	7.607

TABLE 5-6
NO_x Control Scenario Results for Sycamore Canyon WA
Cholla 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98^{th} Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		24	0.000	0.000	0.000	0.000
1	New LNB with SOFA	1	0.586	0.635	0.028	1.084
2	ROFA	1	0.602	2.243	0.098	3.726
3	ROFA with Rotamix	1	0.621	3.308	0.144	5.327
4	New LNB with SOFA & SNCR	1	0.602	2.157	0.094	3.583
5	New LNB with SOFA & SCR	1	0.644	9.569	0.416	14.859

TABLE 5-7
Capitol Reef NP NO_x Control Scenario Incremental Analysis Data
Cholla 3

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	20	0.523	0.635	0.032	1.215
Scenario 2 vs. Scenario 1	0	0.039	1.608	NA	41.226
Scenario 3 vs. Scenario 2	0	0.019	1.065	NA	56.041
Scenario 5 vs. Scenario 3	0	0.024	6.261	NA	260.878

TABLE 5-8
Grand Canyon NP NO_x Control Scenario Incremental Analysis Data
Cholla 3

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	18	0.677	0.635	0.035	0.939
Scenario 3 vs. Scenario 1	2	0.016	1.065	0.532	66.548
Scenario 5 vs. Scenario 3	2	0.033	6.261	3.131	189.730

TABLE 5-9
Petrified Forest NP NO_x Control Scenario Incremental Analysis Data
Cholla 3

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	135	1.154	0.635	0.005	0.551
Scenario 3 vs. Scenario 1	1	0.029	1.065	1.065	36.716
Scenario 5 vs. Scenario 3	2	0.032	6.261	3.131	195.659

TABLE 5-10
Sycamore Canyon WA NO_x Control Scenario Incremental Analysis Data
Cholla 3

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	23	0.586	0.635	0.028	1.084
Scenario 3 vs. Scenario 1	0	0.019	1.065	NA	56.040
Scenario 5 vs. Scenario 3	0	0.023	6.261	NA	272.221

FIGURE 5-5
NO_x Control Scenarios – Least-Cost Envelope Capitol Reef NP—Days Reduction
Cholla 3

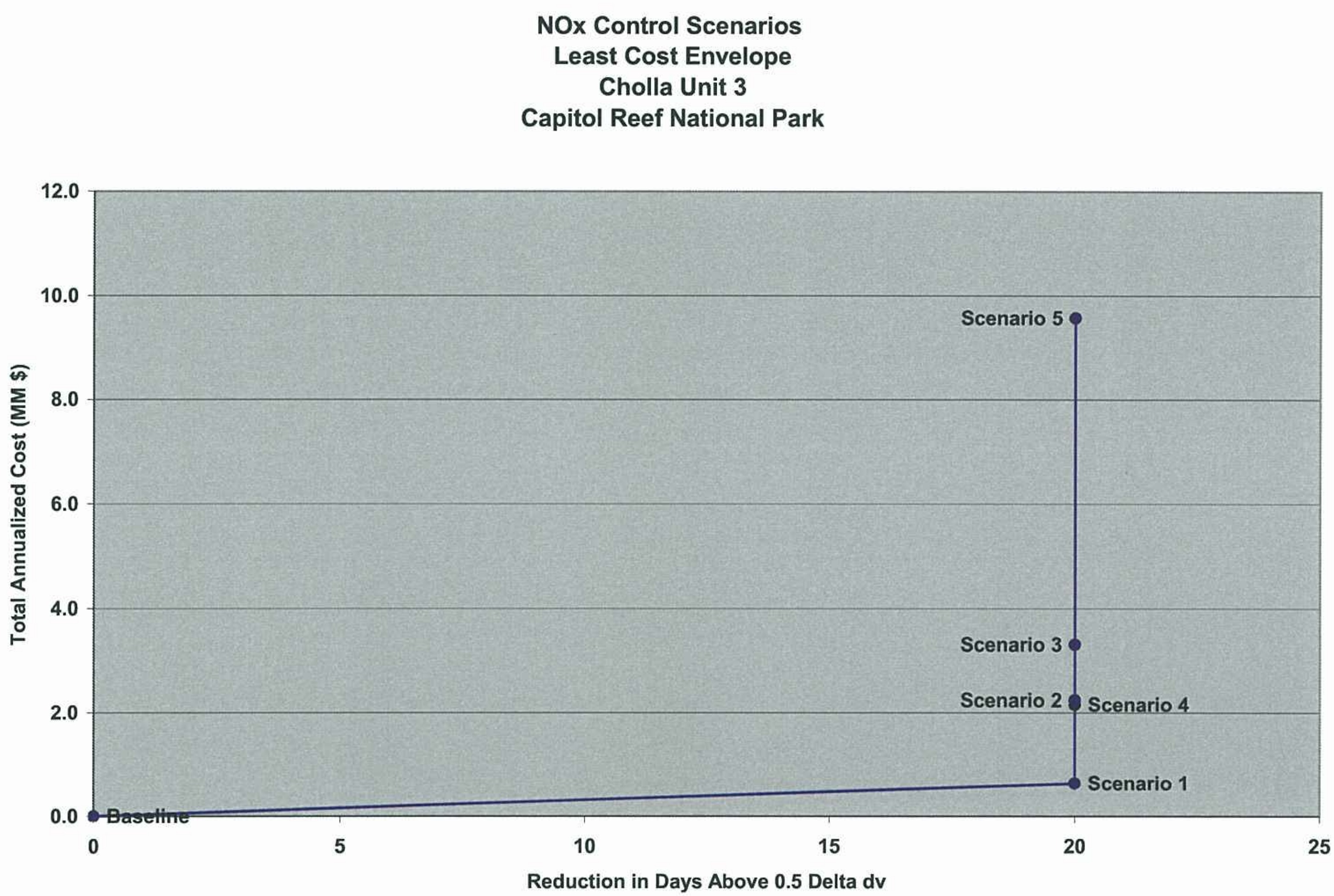


FIGURE 5-6
NO_x Control Scenarios—Least-Cost Envelope Capitol Reef NP—98th Percentile Reduction
Cholla 3

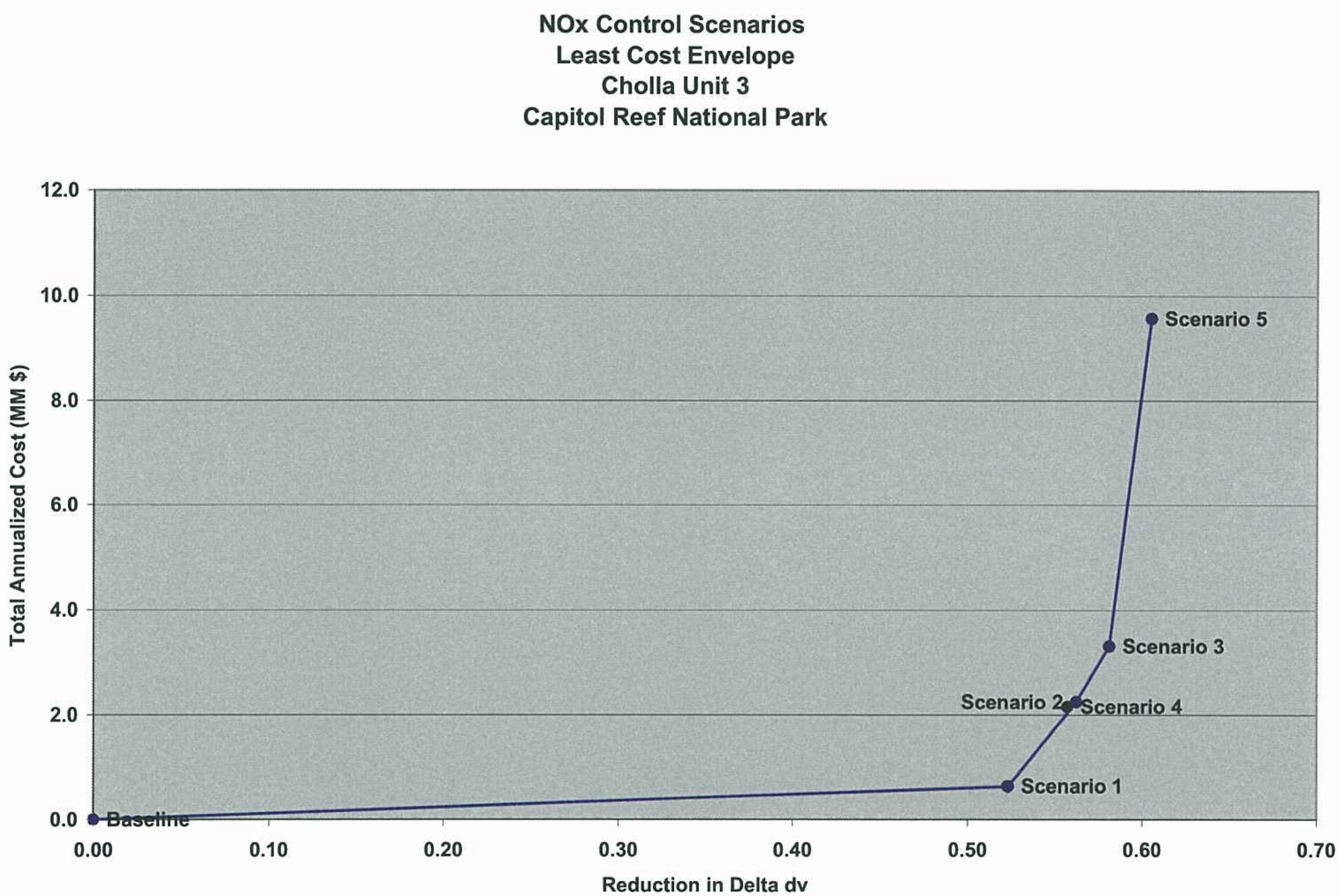


FIGURE 5-7
NO_x Control Scenarios—Least-Cost Envelope Grand Canyon NP—Days Reduction
Cholla 3

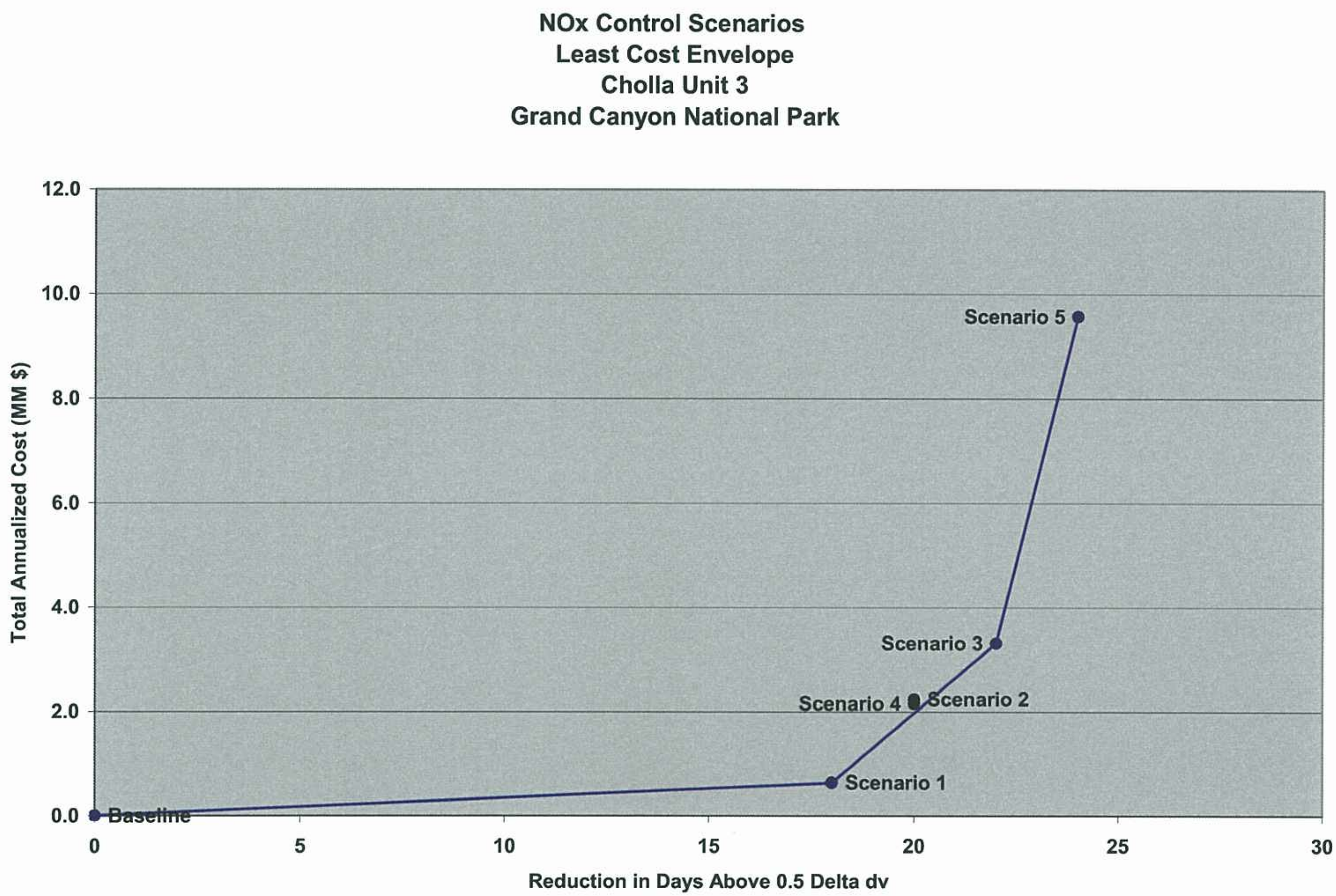


FIGURE 5-8
NO_x Control Scenarios—Least-Cost Envelope Grand Canyon NP—98th Percentile Reduction
Cholla 3

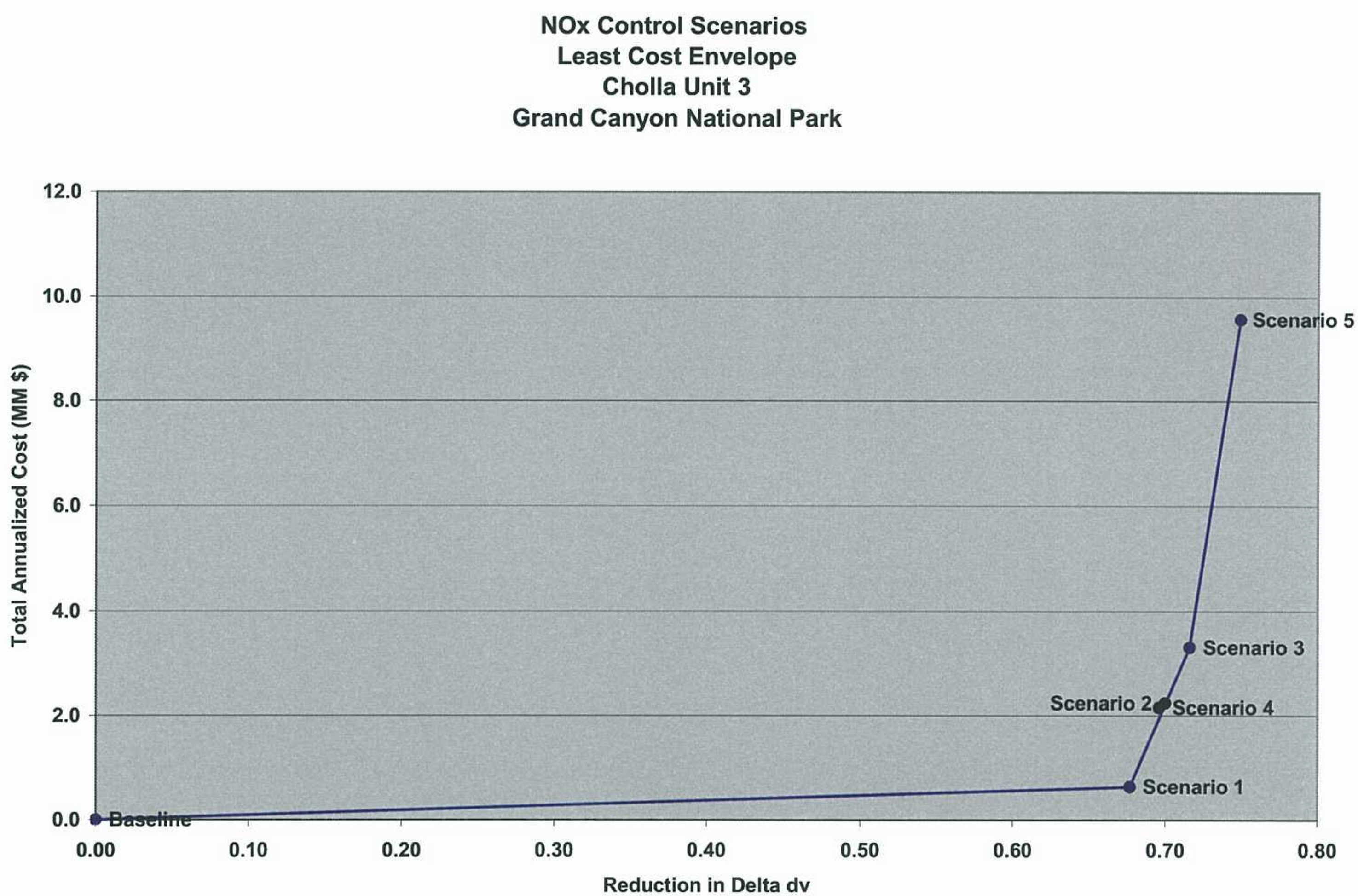


FIGURE 5-9
NO_x Control Scenarios—Least-Cost Envelope Petrified Forest NP—Days Reduction
Cholla 3

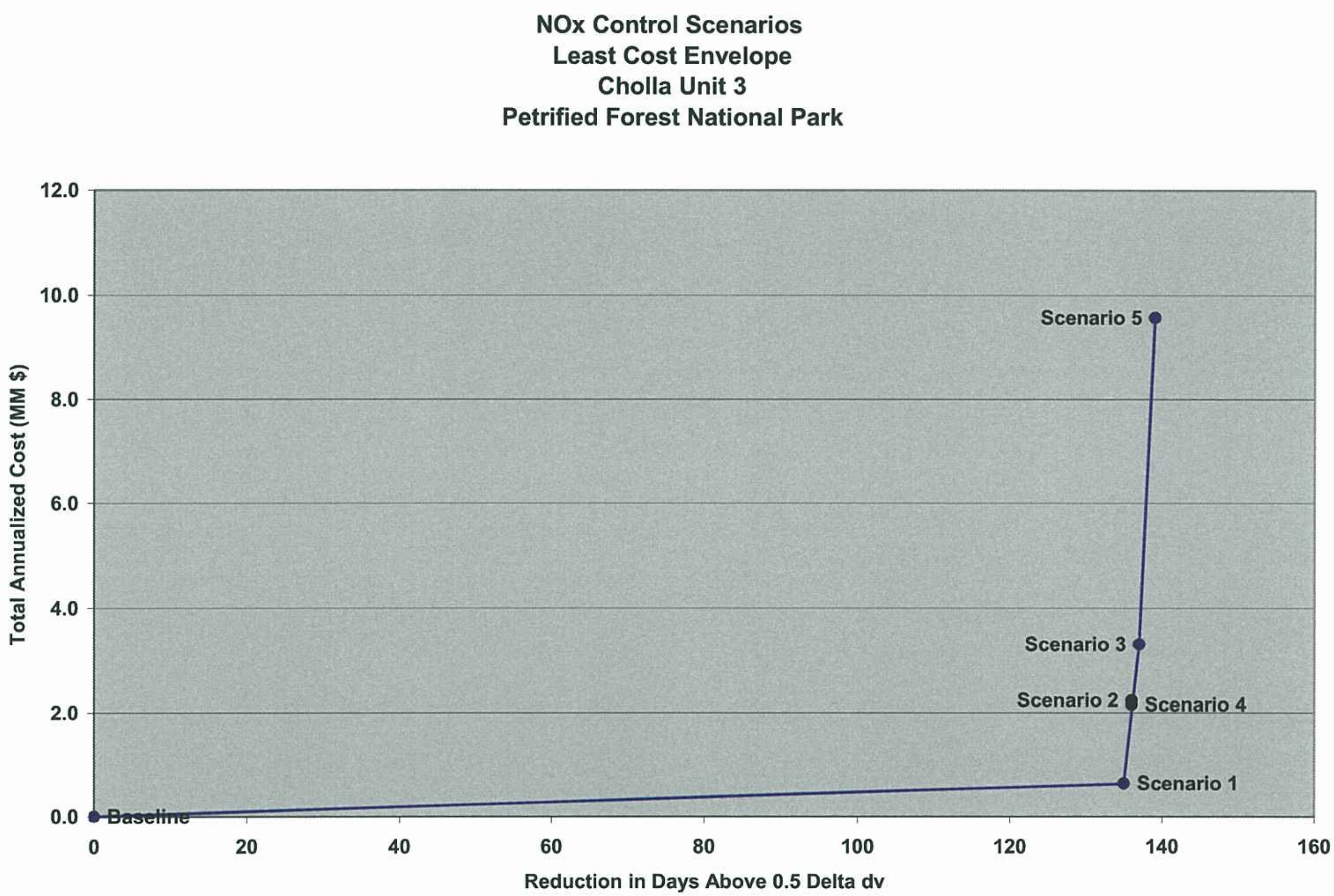


FIGURE 5-10
NO_x Control Scenarios—Least-Cost Envelope Petrified Forest NP—98th Percentile Reduction
Cholla 3

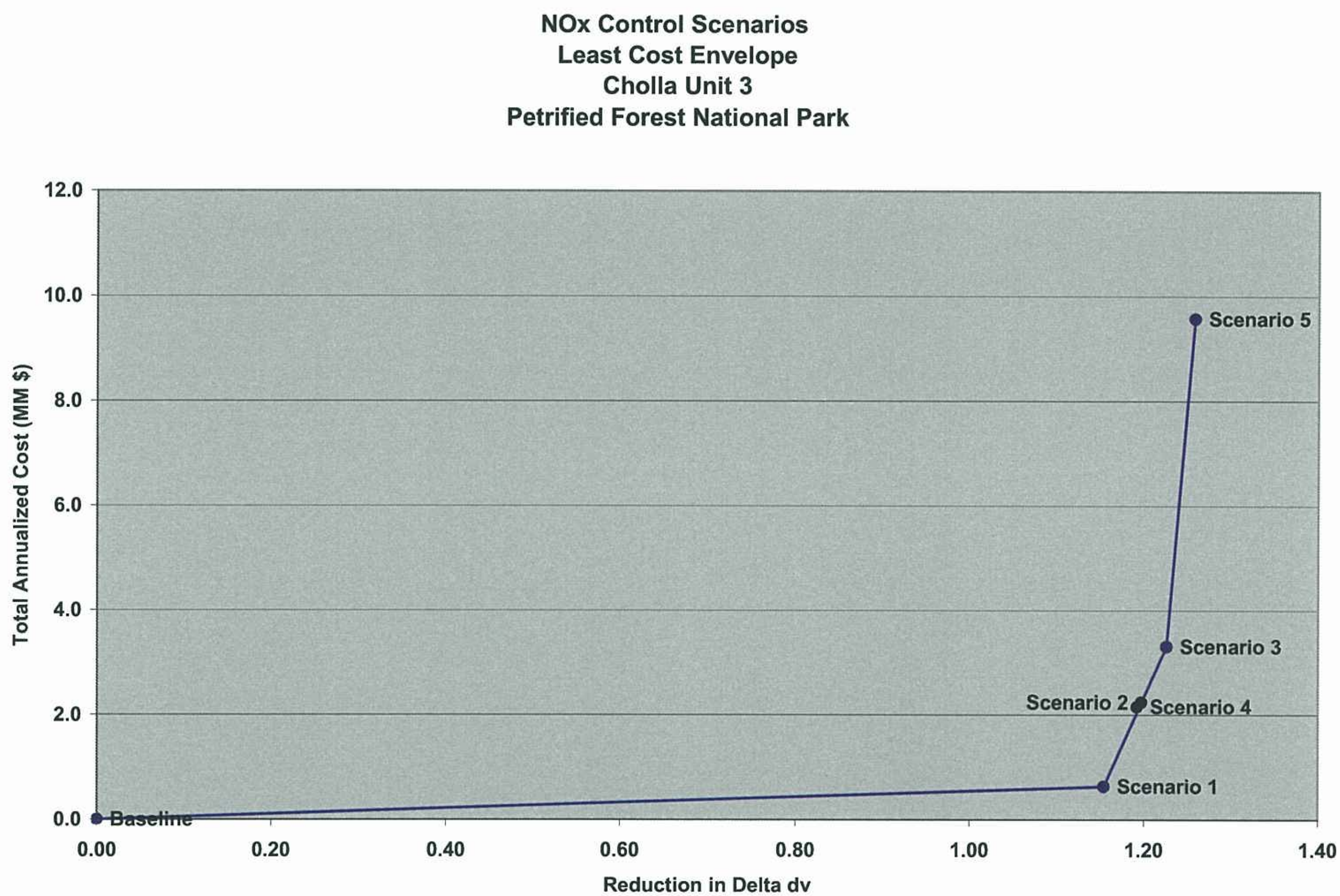


FIGURE 5-11
NO_x Control Scenarios—Least-Cost Envelope Sycamore Canyon WA—Days Reduction
Cholla 3

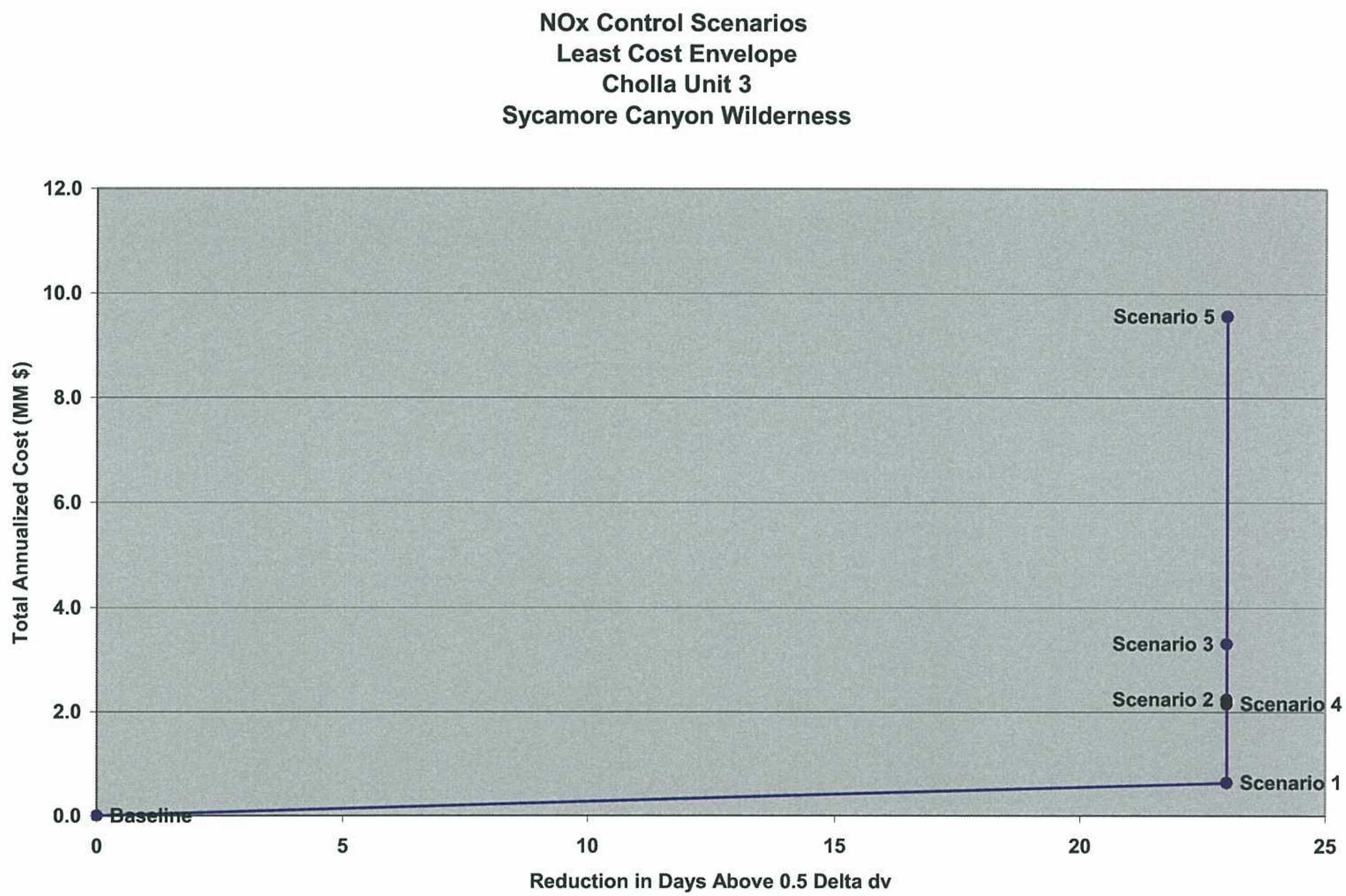
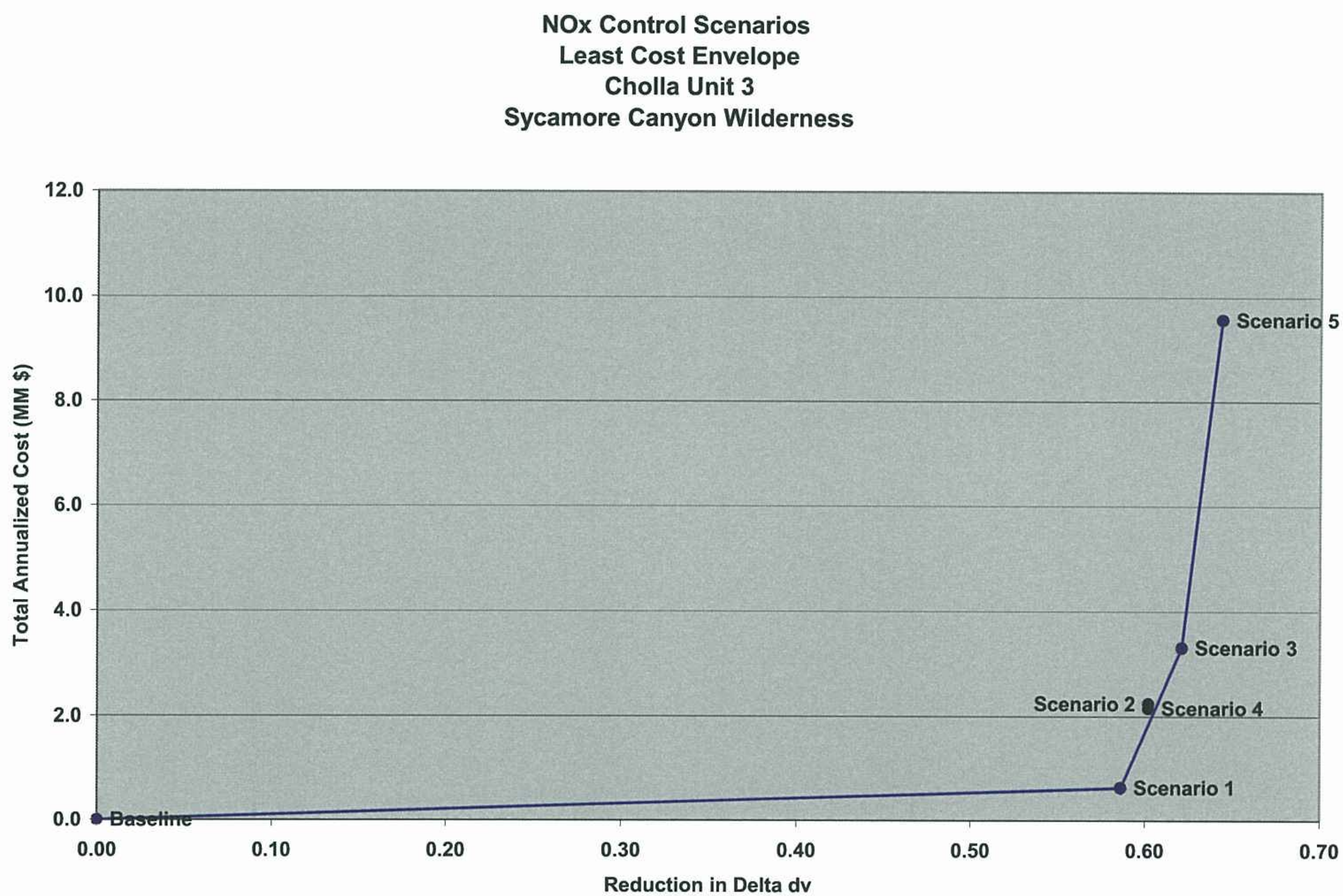


FIGURE 5-12
NO_x Control Scenarios—Least-Cost Envelope Sycamore Canyon WA—98th Percentile Reduction
Cholla 3



5.3.2 Analysis Results

Results of the least-cost analysis for the various NO_x emission control scenarios, shown in Tables 5-3 through 5-10 and Figures 5-5 through 5-12, confirm the selection of Scenario 1 (New LNB with SOFA), based on incremental cost and visibility improvements. All other NO_x control scenarios are excluded on the basis of cost effectiveness.

Analysis of the NO_x results for the four Class I areas in Tables 5-3 through 5-10 and Figures 5-5 through 5-12 illustrates the conclusions stated above. For the Grand Canyon NP, the incremental cost differential for Scenario 1 compared to Baseline is reasonable at \$939,000 per ΔdV. The incremental cost effectiveness between Scenario 3 (ROFA with Rotamix) and Scenario 1 shows a significant increase (\$66,548,000 per ΔdV). The incremental cost effectiveness of Scenarios 2 (ROFA) and Scenario 4 (New LNB with SOFA & SNCR) relative to Scenario 1 are similar to that of Scenario 3. The incremental cost effectiveness of Scenarios 5 (New LNB with SOFA & SCR) relative to Scenario 1 is quite high (\$189,730,000 per ΔdV).

For Scenario 1 compared to the Baseline, the incremental cost for reduction of days with ΔdV values greater than 0.5 dV is reasonable at \$35,000 per day. As with the deciview improvements, the costs for reduced days of impacts for the other control scenarios are much higher.

Therefore, because of the significant improvements related to Scenario 1, Scenario 1 represents BART for Cholla 3.

5.4 Recommendations

5.4.1 NO_x Emission Control

Based on the analysis conducted, new LNB with SOFA can achieve the BART emission level of 0.22 lb/MMBtu, based on the projected significant reduction in NO_x emissions, reasonable control costs, and the advantages of lack of non air quality environmental impacts.

5.4.2 SO_2 Emission Control

Based on the analysis conducted, installation of a wet FGD system can achieve the BART emission level of 0.15 lb/MMBtu for SO_2 emission control.

5.4.3 PM_{10} Emission Control

Based on the analysis conducted, the installation of a fabric filter can achieve the BART emission level of 0.015 lb/MMBtu for PM_{10} emission control.

5.5 Just-Noticeable Differences in Atmospheric Haze

Studies have been conducted that demonstrate only dV differences of approximately 1.5 to 2.0 dV or more are perceptible by the human eye. Deciview changes of less than 1.5 cannot be distinguished by the average person. Therefore, the modeling analysis results indicate that only minimal, if any, observable visibility improvements at the Class I areas studied would be expected under any of the scenarios. Thus the results indicate that even though many millions of dollars will be spent, only minimal, if any, noticeable visibility improvements may result.

Finally, it should be noted that none of the data were corrected for natural obscuration where water in various forms (fog, clouds, snow, or rain) or other naturally caused aerosols obscure the atmosphere. During the period of 2001 through 2003, there were several mega-wildfires that lasted for many days and could have had a significant impact of background visibility in these Class I areas. If natural obscuration were to reduce the reduction in visibility impacts modeled for the Cholla 3 facility, the effect would be to increase the costs per ΔdV reduction that are presented in this report.

Section 6.0
References

6.0 References

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Appendix A
Economic Analysis

APPENDIX A

Economic Analysis

ECONOMIC ANALYSIS SUMMARY

Cholla Unit 3 — **Boiler Design:** **Tangential Fired**

Parameter	Current Operation	NOx Control					SO2 Control	PM Control
		LNB w/SOFA	LNB w/SOFA & SNCR	ROFA	ROFA w/Rotamix	LNB w/SOFA & SCR	New Wet Limestone FGD	Fabric Filter
Case	1	2	3	4	5	6	7	8
NOx Emission Control System	LNB w/COFA	LNB w/SOFA	LNB w/SOFA & SNCR	ROFA	ROFA w/Rotamix	LNB w/SOFA & SCR	----	---
SO2 Emission Control System	None	---	---	---	---	---	New Wet Limestone FGD	---
PM Emission Control System	ESP	---	---	---	---	---	---	Fabric Filter
TOTAL INSTALLED CAPITAL COST ($)	**0**	**5,418,000**	**17,028,000**	**11,947,815**	**18,644,758**	**82,818,000**	**67,080,000**	**84,817,500**
FIRST YEAR O&M COST ($)								
Operating Labor ($)	0	30,000	60,000	45,000	60,000	75,000	150,000	120,000
Maintenance Material ($)	0	60,000	120,000	90,000	120,000	150,000	300,000	240,000
Maintenance Labor ($)	0	30,000	60,000	45,000	60,000	75,000	150,000	120,000
Administrative Labor ($)	0	0	0	0	0	0	0	0
TOTAL FIXED O&M COST	**0**	**120,000**	**240,000**	**180,000**	**240,000**	**300,000**	**600,000**	**480,000**
Makeup Water Cost	0	0	0	0	0	0	109,989	0
Reagent Cost	0	0	183,852	0	367,704	375,746	979,200	0
SCR Catalyst / FF Bag Cost	0	0	0	0	0	450,000	0	704,000
Waste Disposal Cost	0	0	0	0	0	0	556,402	0
Electric Power Cost	0	0	113,004	926,633	926,633	565,020	150,672	150,672
TOTAL VARIABLE O&M COST	**0**	**0**	**296,856**	**926,633**	**1,294,336**	**1,390,766**	**1,796,263**	**854,672**
TOTAL FIRST YEAR O&M COST	**0**	**120,000**	**536,856**	**1,106,633**	**1,534,336**	**1,690,766**	**2,396,263**	**1,334,672**
FIRST YEAR DEBT SERVICE ($)	0	515,403	1,619,837	1,136,570	1,773,635	7,878,296	6,381,174	8,068,504
TOTAL FIRST YEAR COST ($)	**0**	**635,403**	**2,156,692**	**2,243,202**	**3,307,972**	**9,569,062**	**8,777,437**	**9,403,176**
Power Consumption (MW)	**0.0**	**0.0**	**0.3**	**2.5**	**2.5**	**1.5**	**0.4**	**0.4**
Annual Power Usage (kW-Hr/Yr)	**0.0**	**0.0**	**2.3**	**18.5**	**18.5**	**11.3**	**3.0**	**3.0**
CONTROL COST ($/Ton Removed)								
NOx Removal Rate (%)	**0.0%**	**46.3%**	**58.5%**	**61.0%**	**70.7%**	**82.9%**	**0.0%**	**0.0%**
NOx Removed (Tons/Yr)	**0**	**2,096**	**2,648**	**2,758**	**3,200**	**3,751**	**0**	**0**
First Year Average Control Cost ($/Ton NOx Rem.)	**0**	**303**	**814**	**813**	**1,034**	**2,551**	**0**	**0**
Incremental Control Cost ($/Ton NOx Removed)	**Base**	**303**	**2,758**	**784**	**2,413**	**11,350**	**0**	**0**
Case Comparison		2-1	3-2	4-3	5-4	6-5		
SO2 Removal Rate (%)	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**85.0%**	**0.0%**
SO2 Removed (Tons/Yr)	**0**	**0**	**0**	**0**	**0**	**0**	**9,378**	**0**
First Year Average Control Cost ($/Ton SO2 Rem.)	**0**	**0**	**0**	**0**	**0**	**0**	**936**	**0**
Incremental Control Cost ($/Ton SO2 Removed)	**Base**	**0**	**0**	**0**	**0**	**0**	**936**	**0**
Case Comparison							7-1	
PM Removal Rate (%)	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.66%**
PM Removed (Tons/Yr)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**
First Year Average Control Cost ($/Ton PM Rem.)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**8,522,807**
Incremental Control Cost ($/Ton PM Removed)	**Base**	**0**	**0**	**0**	**0**	**0**	**0**	**8,522,807**
Case Comparison								8-1
PRESENT WORTH COST ($)	**0**	**6,884,142**	**23,587,225**	**25,468,492**	**37,391,055**	**103,475,525**	**96,357,186**	**101,124,327**

SO2 and PM efficiencies shown are only incremental

INPUT CALCULATIONS

Cholla Unit 3 — **Boiler Design:** Tangential Fired

Parameter	Current Operation	LNB w/SOFA	LNB w/SOFA & SNCR	ROFA	ROFA w/Rotamix	LNB w/SOFA & SCR	New Wet Limestone FGD	Fabric Filter	Comments
		NOx Control					SO2 Control	PM Control	
Case	1	2	3	4	5	6	7	8	
NOx Emission Control System	LNB w/COFA	LNB w/SOFA	LNB w/SOFA & SNCR	ROFA	ROFA w/Rotamix	LNB w/SOFA & SCR	----	---	
SO2 Emission Control System	None	---	---	---	---	---	New Wet Limestone FGD	---	
PM Emission Control System	ESP	---	---	---	---	---	---	Fabric Filter	
Unit Design and Coal Characteristics									
Type of Unit	PC	PC	PC	PC	PC	PC	PC	PC	
Net Power Output (kW)	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	
Net Plant Heat Rate (Btu/kW-Hr)	9,763	9,763	9,763	9,763	9,763	9,763	9,763	9,763	
Boiler Fuel	El Segundo	El Segundo	El Segundo	El Segundo	El Segundo	El Segundo	El Segundo	El Segundo	
Coal Heating Value (Btu/Lb)	9,215	9,215	9,215	9,215	9,215	9,215	9,215	9,215	
Coal Sulfur Content (wt.%)	1.10%	1.10%	1.10%	1.10%	1.10%	1.10%	1.10%	1.10%	
Coal Ash Content (wt.%)	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	16.80%	
Boiler Heat Input, each (MMBtu/Hr)	2,929	2,929	2,929	2,929	2,929	2,929	2,929	2,929	
Coal Flow Rate (Lb/Hr)	317,851	317,851	317,851	317,851	317,851	317,851	317,851	317,851	
(Ton/Yr)	1,197,282	1,197,282	1,197,282	1,197,282	1,197,282	1,197,282	1,197,282	1,197,282	
(MMBtu/Yr)	22,065,914	22,065,914	22,065,914	22,065,914	22,065,914	22,065,914	22,065,914	22,065,914	
Emissions									
Uncontrolled SO2 (Lb/Hr)	2,929	2,929	2,929	2,929	2,929	2,929	2,929	2,929	
(Lb/MMBtu)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
(Lb Moles/Hr)	45.72	45.72	45.72	45.72	45.72	45.72	45.72	45.72	
(Tons/Yr)	11,033	11,033	11,033	11,033	11,033	11,033	11,033	11,033	
SO2 Removal Rate (%)	0%	0.0%	0.0%	0.0%	0.0%	0.0%	85.0%	0.0%	
(Lb/Hr)	0	0	0	0	0	0	2,490	0	
(Ton/Yr)	0	0	0	0	0	0	9,378	0	
SO2 Emission Rate (Lb/Hr)	2,929	2,929	2,929	2,929	2,929	2,929	439	2,929	
(Lb/MMBtu)	1.00	1.00	1.00	1.00	1.00	1.00	0.15	1.00	
(Ton/Yr)	11,033	11,033	11,033	11,033	11,033	11,033	1,655	11,033	
Uncontrolled NOx (Lb/Hr)	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	
(Lb/MMBtu)	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	
(Lb Moles/Hr)	40.02	40.02	40.02	40.02	40.02	40.02	40.02	40.02	
(Tons/Yr)	4,524	4,524	4,524	4,524	4,524	4,524	4,524	4,524	
NOx Removal Rate (%)	0.0%	46.3%	58.5%	61.0%	70.7%	82.9%	0.0%	0.0%	
(Lb/Hr)	0	557	703	732	849	996	0	0	
(Lb Moles/Hr)	0.00	18.54	23.42	24.40	28.30	33.18	0.00	0.00	
(Ton/Yr)	0	2,096	2,648	2,758	3,200	3,751	0	0	
NOx Emission Rate (Lb/Hr)	1,201	644	498	469	351	205	1,201	1,201	
(Lb/MMBtu)	0.41	0.22	0.17	0.16	0.12	0.07	0.41	0.41	
(Ton/Yr)	4,524	2,427	1,876	1,765	1,324	772	4,524	4,524	
Uncontrolled Fly Ash (Lb/Hr)	42,719	44	44	44	44	44	44	44	
(Lb/MMBtu)	0.02	0.015	0.015	0.015	0.015	0.015	0.015	0.015	
(Lb Moles/Hr)	1,423.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	
(Tons/Yr)	160,915	167	167	167	167	167	167	167	
Fly Ash Removal Rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.66%	
(Lb/Hr)	42,675	0	0	0	0	0	0	0	
(Ton/Yr)	160,748	0	0	0	0	0	0	1	
Fly Ash Emission Rate (Lb/Hr)	44	44	44	44	44	44	44	44	
(Lb/MMBtu)	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	
(Ton/Yr)	167	167	167	167	167	167	167	165	
General Plant Data									
Annual Operation (Hours/Year)	7,534	7,534	7,534	7,534	7,534	7,534	7,534	7,534	
Annual On-Site Power Plant Capacity Factor	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	
Economic Factors									
Interest Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	
Discount Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	
Plant Economic Life (Years)	20	20	20	20	20	20	20	20	
Installed Capital Costs									
NOx Emission Control System ($2007)	0	5,418,000	17,028,000	11,947,815	18,644,758	82,818,000	0	0	
SO2 Emission Control System ($2007)	0	0	0	0	0	0	67,080,000	0	
PM Emission Control System ($2007)	0	0	0	0	0	0	0	84,817,500	
Total Emission Control Systems ($2007)	0	5,418,000	17,028,000	11,947,815	18,644,758	82,818,000	67,080,000	84,817,500	
NOx Emission Control System ($/kW)	0	18	57	40	62	276	0	0	
SO2 Emission Control System ($/kW)	0	0	0	0	0	0	224	0	
PM Emission Control System ($/kW)	0	0	0	0	0	0	0	283	
Total Emission Control Systems ($/kW)	0	18	57	40	62	276	224	283	
Total Fixed Operating & Maintenance Costs									
Operating Labor ($)	0	30,000	60,000	45,000	60,000	75,000	150,000	120,000	
Maintenance Material ($)	0	60,000	120,000	90,000	120,000	150,000	300,000	240,000	
Maintenance Labor ($)	0	30,000	60,000	45,000	60,000	75,000	150,000	120,000	
Administrative Labor ($)	0	0	0	0	0	0	0	0	
Total Fixed O&M Cost ($)	0	120,000	240,000	180,000	240,000	300,000	600,000	480,000	
Annual Fixed O&M Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Water Cost									
Makeup Water Usage (Gpm)	0	0	0	0	0	0	200	0	
Unit Price ($/1000 Gallons)	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	
First Year Water Cost ($)	0	0	0	0	0	0	109,989	0	
Annual Water Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Reagent Cost	None	None	Urea	None	Urea	Anhydrous NH3	Lime	None	
Unit Cost ($/Ton)	0.00	0.00	370	0.00	370	400	91.25	0.00	
($/Lb)	0.000	0.000	0.185	0.000	0.185	0.200	0.046	0.000	
Molar Stoichiometry	0.00	0.00	0.45	0.00	0.45	1.00	1.00	0.00	
Reagent Purity (Wt.%)	100%	100%	100%	100%	100%	100%	90%	90%	
Reagent Usage (Lb/Hr)	0	0	132	0	264	249	2,849	0	
First Year Reagent Cost ($)	0	0	183,852	0	367,704	375,746	979,200	0	
Annual Reagent Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
SCR Catalyst / FF Bag Replacement Cost						SCR Catalyst			
Annual SCR Catalyst (m3) / No. FF Bags/No. Rolls	0	0	0	0	0	150	0	1,600	
SCR Catalyst ($/m3) / Bag Cost ($/ea.) / Roll Cost ($/ea.)	3,000	3,000	3,000	3,000	3,000	3,000	3,000	440	
First Year SCR Catalyst / Bag Replace. Cost ($)	0	0	0	0	0	450,000	0	704,000	
Annual SCR Catalyst / Bag Cost Esc. Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
FGD Waste Disposal Cost									
FGD Solid Waste Disposal Rate, Dry (Lb/Hr)	0	0	0	0	0	0	6,070	0	
FGD Waste Disposal Unit Cost ($/Dry Ton)	24.33	24.33	24.33	24.33	24.33	24.33	24.33	24.33	
First Year FGD Waste Disposal Cost ($)	0	0	0	0	0	0	556,402	0	
Annual Waste Disposal Cost Esc. Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Auxiliary Power Cost									
Auxiliary Power Requirement (% of Plant Output)	0.00%	0.00%	0.10%	0.82%	0.82%	0.50%	0.13%	0.13%	
(MW)	0.00	0.00	0.30	2.46	2.46	1.50	0.40	0.40	
Unit Cost ($2007/MW-Hr)	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	
First Year Auxiliary Power Cost ($)	0	0	113,004	926,633	926,633	565,020	150,672	150,672	
Annual Power Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	

CAPITAL COST

Cholla Unit 3

Parameter	NOx Control										SO2 Control		PM Control	
	LNB w/SOFA		LNB w/SOFA & SNCR		ROFA		ROFA w/Rotamix		LNB w/SOFA & SCR		New Wet Limestone FGD		Fabric Filter	
Case	2		3		4		5		6		7		8	
NOx Emission Control System	LNB w/SOFA		LNB w/SOFA & SNCR		ROFA		ROFA w/Rotamix		LNB w/SOFA & SCR		---		---	
SO2 Emission Control System	---		---		---		---		---		New Wet Limestone FGD		---	
PM Emission Control System	---		---		---		---		---		---		Fabric Filter	
CAPITAL COST COMPONENT	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost
LNB w/OFA or ROFA		LNB		LNB		ROFA		ROFA		LNB				
Major Materials Design and Supply	Vendor	$2,100,000	Vendor	$2,100,000	Vendor	$4,350,986	Vendor	$4,350,986	Vendor	$2,100,000	Vendor	$0	Vendor	$0
Construction	50.0%	$1,050,000	50.0%	$1,050,000	Vendor	$2,027,567	Vendor	$2,027,567	50.0%	$1,050,000	50.0%	$0	50.0%	$0
Balance of Plant	50.0%	$1,050,000	50.0%	$1,050,000	30.0%	$1,305,296	30.0%	$1,305,296	50.0%	$1,050,000	50.0%	$0	50.0%	$0
Electrical (Allowance)	5.0%	$105,000	5.0%	$105,000	30.0%	$1,305,296	30.0%	$1,305,296	5.0%	$105,000	5.0%	$0	5.0%	$0
Owner's Costs	10.0%	$210,000	10.0%	$210,000	10.0%	$435,099	10.0%	$435,099	10.0%	$210,000	10.0%	$0	10.0%	$0
Surcharge	16.0%	$336,000	16.0%	$336,000	16.0%	$696,158	16.0%	$696,158	16.0%	$336,000	16.0%	$0	16.0%	$0
AFUDC	12.0%	$252,000	12.0%	$252,000	12.0%	$522,118	12.0%	$522,118	12.0%	$252,000	12.0%	$0	12.0%	$0
Subtotal		$5,103,000		$5,103,000		$10,642,519		$10,642,519		$5,103,000		$0		$0
Contingency	15.0%	$315,000	15.0%	$315,000	30.0%	$1,305,296	30.0%	$1,305,296	15.0%	$315,000	15.0%	$0	15.0%	$0
Total Capital Cost for LNB w/OFA or ROFA		$5,418,000		$5,418,000		$11,947,815		$11,947,815		$5,418,000		$0		$0
SNCR or SCR or Rotamix				SNCR				Rotamix		SCR				
Major Materials Design and Supply	Vendor	$0	Vendor	$4,500,000	Vendor	$0	Vendor	$1,790,817	Vendor	$30,000,000	Vendor	$0	Vendor	$0
Construction	50.0%	$0	50.0%	$2,250,000	50.0%	$0	Vendor	$2,703,422	50.0%	$15,000,000	50.0%	$0	50.0%	$0
Balance of Plant	50.0%	$0	50.0%	$2,250,000	50.0%	$0	50.0%	$895,409	50.0%	$15,000,000	50.0%	$0	50.0%	$0
Electrical (Allowance)	5.0%	$0	5.0%	$225,000	5.0%	$0	5.0%	$89,541	5.0%	$1,500,000	5.0%	$0	5.0%	$0
Owner's Costs	10.0%	$0	10.0%	$450,000	10.0%	$0	10.0%	$179,082	10.0%	$3,000,000	10.0%	$0	10.0%	$0
Surcharge	16.0%	$0	16.0%	$720,000	16.0%	$0	16.0%	$286,531	16.0%	$4,800,000	16.0%	$0	16.0%	$0
AFUDC	12.0%	$0	12.0%	$540,000	12.0%	$0	12.0%	$214,898	12.0%	$3,600,000	12.0%	$0	12.0%	$0
Subtotal		$0		$10,935,000		$0		$6,159,699		$72,900,000		$0		$0
Contingency	15.0%	$0	15.0%	$675,000	15.0%	$0	30.0%	$537,245	15.0%	$4,500,000	15.0%	$0	15.0%	$0
Total Capital Cost for SNCR or SCR or Rotamix		$0		$11,610,000		$0		$6,696,944		$77,400,000		$0		$0
Dry or Wet FGD, FGC or Fabric Filter														
Major Materials Design and Supply	Vendor	$0	Vendor	$0	Vendor	$0	Vendor	$0	Vendor	$0	Vendor	$26,000,000	Vendor	$32,875,000
Construction	50.0%	$0	50.0%	$0	50.0%	$0	50.0%	$0	50.0%	$0	50.0%	$13,000,000	50.0%	$16,437,500
Balance of Plant	50.0%	$0	50.0%	$0	50.0%	$0	50.0%	$0	50.0%	$0	50.0%	$13,000,000	50.0%	$16,437,500
Electrical (Allowance)	5.0%	$0	5.0%	$0	5.0%	$0	5.0%	$0	5.0%	$0	5.0%	$1,300,000	5.0%	$1,643,750
Owner's Costs	10.0%	$0	10.0%	$0	10.0%	$0	10.0%	$0	10.0%	$0	10.0%	$2,600,000	10.0%	$3,287,500
Surcharge	16.0%	$0	16.0%	$0	16.0%	$0	16.0%	$0	16.0%	$0	16.0%	$4,160,000	16.0%	$5,260,000
AFUDC	12.0%	$0	12.0%	$0	12.0%	$0	12.0%	$0	12.0%	$0	12.0%	$3,120,000	12.0%	$3,945,000
Subtotal		$0		$0		$0		$0		$0		$63,180,000		$79,886,250
Contingency	15.0%	$0	15.0%	$0	15.0%	$0	15.0%	$0	15.0%	$0	15.0%	$3,900,000	15.0%	$4,931,250
Total Capital Cost for Dry/Wet FGD, FGC or FF		$0		$0		$0		$0		$0		$67,080,000		$84,817,500

Appendix B
BART Protocol

APPENDIX B

BART Protocol

Modeling Protocol for BART Control Technology Improvement Modeling Analyses for the APS Cholla Power Plant

Prepared for

APS®

Prepared by

CH2MHILL

October 2007

Contents

Tables

Figures

SECTION 1.0

Introduction

This document presents a modeling protocol for estimating the degree of visibility improvement from Best Available Retrofit Technology (BART) control technology options for the Arizona Public Service Company (APS) Cholla Power Plant Units 2, 3, and 4. The Arizona Department of Environmental Quality (ADEQ) has identified that these three boiler units at the Cholla Power Plant are BART eligible and must perform a BART analysis.

This protocol outlines the proposed approach for the modeling analysis for the Cholla Power Plant. To a large extent, this protocol follows the methodology outlined in the Western Regional Air Partnership (WRAP) protocol for performing BART analyses (WRAP 2006). Any proposed deviations from that methodology are documented in this protocol. Section 2.0 describes the modeling system (CALPUFF) that will be used for the analyses. Sections 3.0 and 4.0 describe the proposed methodology for the CALMET meteorological model and the CALPUFF model, respectively. Section 5.0 presents a summary of the proposed approach for the CALPOST post-processor and Section 6.0 presents a brief description of the final report format for submittal to ADEQ. Section 7.0 contains a list of references cited in the protocol document.

SECTION 2.0

Model Selection

CH2M HILL will use the CALPUFF modeling system to assess the visibility impacts at Class I areas. Workgroups that represent the interests of the Federal Land Managers (FLM) recommend that an analysis of Class I area air quality and air quality related values (AQRVs) be performed for major sources located more than 50 km from these areas (USEPA 1998). The CALPUFF model is the only model recommended by EPA for these types of regulatory analyses.

The CALPUFF modeling system includes the CALMET meteorological model, a Gaussian puff dispersion model (CALPUFF) with algorithms for chemical transformation and deposition, and a post processor capable of calculating concentrations, visibility impacts, and deposition (CALPOST). The CALPUFF modeling system will be applied in a full, refined mode.

CH2M HILL will use the latest version (Version 6) of the CALPUFF modeling system preprocessors and models in lieu of the EPA-approved versions (Version 5). The Federal Land Managers (FLMs) and others have noted that the EPA-approved Version 5 contained errors and that a newer version should be used. In addition, Version 6 was used in the Subject-To-BART (exemption) modeling analysis conducting by the WRAP Regional Modeling Center. Consequently, it was decided to use the latest (as of April, 2007) version of the CALPUFF modeling system (available at www.src.com):

- CALMET Version 6.211 Level 060414
- CALPUFF Version 6.112 Level 060412

SECTION 3.0

CALMET Methodology

3.1 Dimensions of the Modeling Domain

CH2M HILL will define domains for Mesoscale Model data (MM5), CALMET, and CALPUFF that will be slightly different than those established for the Arizona BART modeling in WRAP 2006. In addition, the CALMET and CALPUFF Lambert Conformal Conic (LCC) map projection will be based on a central meridian of 110 W rather than 97 W. This will put the central meridian near the center of the domain.

CH2M HILL will use the CALMET model to generate three-dimensional wind fields and other meteorological parameters suitable for use by the CALPUFF model. A CALMET modeling domain has been defined to allow for at least a 50-km buffer around all Class I areas within 300 km of the Cholla Power Plant. Grid resolution for this domain will be 4-km. Figure 3-1 shows the extent of the proposed modeling domain.

The technical options recommended in WRAP 2006 will be used for CALMET. Vertical resolution of the wind field will include eleven layers, with vertical cell face heights as follows (in meters):

- 0, 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, 5000

Also, following WRAP 2006, the maximum over-land mixing height (ZIMAX) will be set to 4500 meters based on the Colorado Department of Health and Environment (CDPHE) analyses of soundings for summer ozone events in the Denver area (CDPHE, 2005). The CDPHE analysis suggests mixing heights in the Denver area are often well above the CALMET default value of 3000 meters during the summer. For example, on some summer days, ozone levels are elevated all the way to 6000 meters MSL or beyond during some meteorological regimes, including some regimes associated with high ozone episodes. It is assumed that, like in Denver, mixing heights in excess of the 3,000 m AGL CALMET default maximum would occur in the domains considered for this analysis.

For the APS analysis, we propose to modify IEXTRP, R1, R2, RMAX1, and RMAX2 from the values in WRAP 2006. WRAP 2006 has R1 and R2 values that are larger than the RMAX1 and RMAX2 values. This means at the RMAX distances, the surface stations are weighted *greater* than the MM5 data. Defining the parameters in this way causes a noticeable boundary in the wind field at the RMAX distances. This effect is known as *crop circling* in the wind field because there is a well defined circle around the meteorological data station in the processed wind vector map, where there is a discrepancy between the surface station data and the MM5 data.

Crop circles in the wind field may result in inaccurate results from the CALPUFF modeling because the wind field may be either shifting the plume transport too greatly between individual time steps, or may push the plume back to the original cell in a small time step.

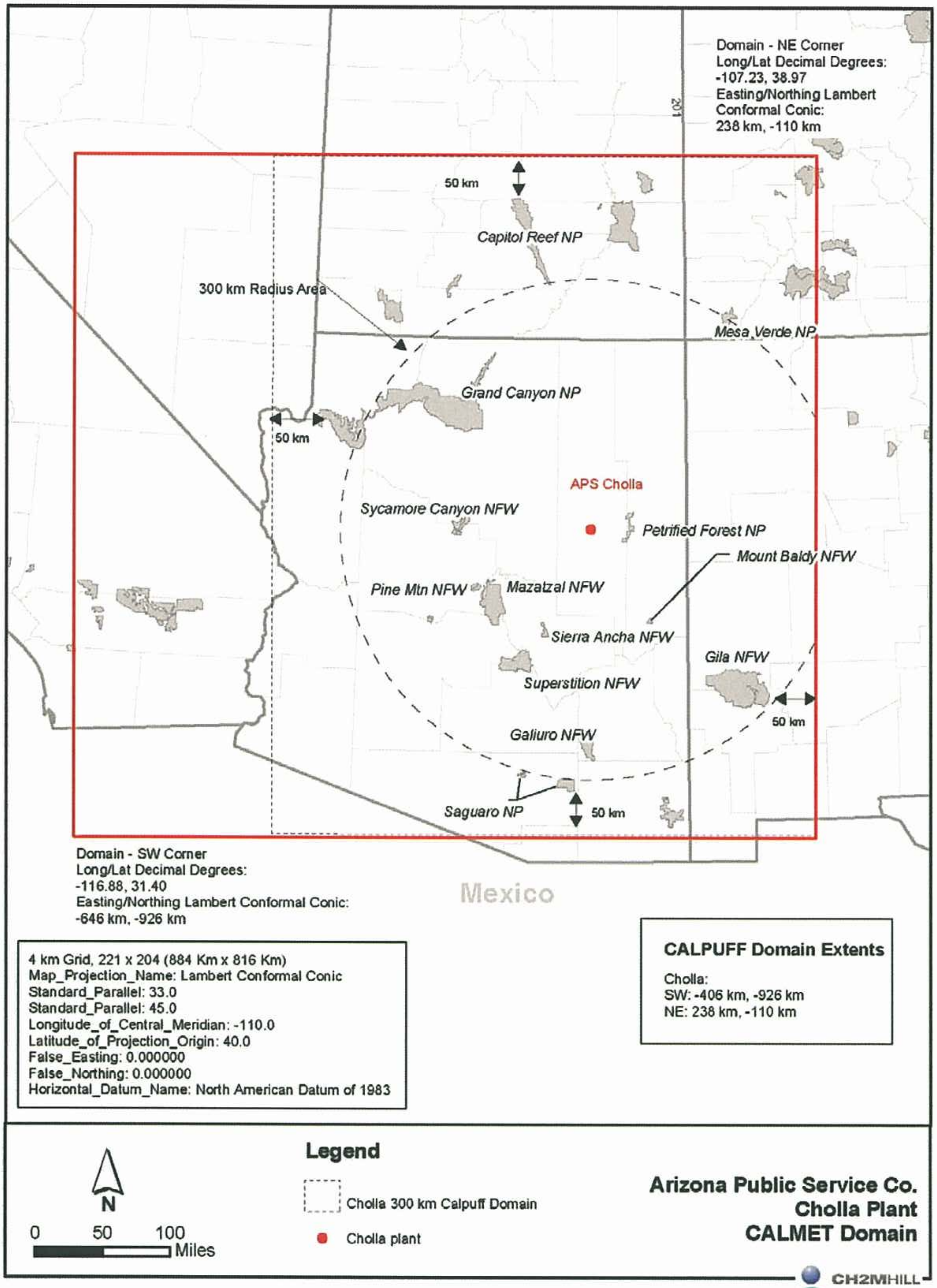

FIGURE 3-1
CALMET and CALPUFF Domains

To alleviate this problem, it is proposed that the R1, R2, RMAX1, and RMAX2 values be modified to allow better smoothing in the wind field.

In addition, by using an IEXTRP value of 1, the WRAP CALMET processing prevents the surface stations from influencing the meteorological data above the surface layer. We are proposing to use an IEXTRP value of 4 (the CALMET default value) which allows some influence of the surface data on the layers above the surface.

Table 3-1 lists the key user-specified CALMET options.

TABLE 3-1
User-Specified CALMET Options

Description	CALMET Input Parameter	Value
	CALMET Input Group 2	
Map projection	PMAP	Lambert Conformal (LCC)
Grid spacing	DGRIDKM	4
Number vertical layers	NZ	11
Top of lowest layer (m)		20
Top of highest layer (m)		5000
	CALMET Input Group 4	
Observation mode	NOOBS	1
	CALMET Input Group 5	
Prognostic or MM-FDDA data switch	IPROG	14
Max surface over-land extrapolation radius (km)	RMAX1	50
Max aloft over-land extrapolations radius (km)	RMAX2	50
Radius of influence of terrain features (km)	TERRAD	10
Relative weight at surface of Step 1 field and obs (km)	R1	25
Relative weight aloft of Step 1 field and obs (km)	R2	25
Extrapolation of surface wind observations to upper layers	IEXTRP	4
	CALMET Input Group 6	
Maximum over-land mixing height (m)	ZIMAX	4500

3.2 CALMET Input Data

CH2M HILL will run the CALMET model to produce three years of analysis: 2001, 2002, and 2003. CH2M HILL will use MM5 data as the basis for the CALMET wind fields. The horizontal resolution of the MM5 data is 36-km.

For 2001, CH2M HILL will use MM5 data at 36-km resolution that were obtained from the contractor (Alpine Geophysics) who developed the nationwide data for the EPA. For 2002, CH2M HILL will use 36-km MM5 data obtained from Alpine Geophysics, originally developed for WRAP. Data to be used for 2003 (also from Alpine Geophysics), at 36-km resolution, were developed by the Wisconsin Department of Natural Resources, the Illinois Environmental Protection Agency, and the Lake Michigan Air Directors Consortium (Midwest RPO).

The MM5 data will be used as input to CALMET as the "initial guess" wind field. The initial guess field will be adjusted by CALMET for local terrain and land use effects to generate a Step 1 wind field, and then further refined using local surface observations to create a final Step 2 wind field.

Surface data for 2001-2003 will be obtained from the National Climatic Data Center (NCDC). CH2M HILL will process data for all stations from the National Weather Service's (NWS) Automated Surface Observing System (ASOS) network that are in the domain. The surface data will be obtained in abbreviated DATSAV3 format. A conversion routine available from the TRC website will be used to convert the DATSAV3 files to CD-144 format for input to the SMERGE preprocessor and CALMET.

Land use and terrain data will be obtained from the U.S. Geological Survey (USGS). Land use data will be obtained in Composite Theme Grid (CTG) format from the USGS, and the Level I USGS land use categories will be mapped into the 14 primary CALMET land use categories. Surface properties such as albedo, Bowen ratio, roughness length, and leaf area index will be computed from the land use values. Terrain data will be taken from USGS 1-degree Digital Elevation Model (DEM) data, which are primarily derived from USGS 1:250,000 scale topographic maps. Missing land use data will be filled with a value that is appropriate for the missing area.

Precipitation data will be ordered from the National Climatic Data Center (NCDC). All available data in fixed-length, TD-3240 format will be ordered for the modeling domain. The list of available stations and stations that have collected complete data varies by year, but CH2M HILL will process all available stations/data within the domain for each year. Precipitation data will be prepared with the PXTRACT/PMERGE processors in preparation for use within CALMET.

Following the methodology recommended in WRAP 2006, no observed upper-air meteorological observations will be used as they are redundant to the MM5 data, and may introduce spurious artifacts in the wind fields. In the development of the MM5 data, the twice daily upper-air meteorological observations are used as input with the MM5 model. The MM5 estimates are nudged to the upper-air observations as part of the Four Dimensional Data Assimilation (FDDA). This results in higher temporal (hourly vs. 12-hour) and spatial (36 km vs. ~300 km) resolution for the upper-air meteorology in the MM5 field.

These MM5 data are more dynamically balanced than those contained in the upper-air observations. Therefore the use of the upper-air observations with CALMET is not needed, and, in fact, will upset the dynamic balance of the meteorological fields potentially producing spurious vertical velocities.

3.3 Validation of CALMET Wind Field

CH2M HILL will use the CalDESK data display and analysis system (v2.97, Enviromodeling Ltd.) to view plots of wind vectors and other meteorological parameters to evaluate the CALMET wind fields. We will use observed weather conditions, as depicted in surface and upper-air weather maps from the National Oceanic and Atmospheric Administration (NOAA) Central Library U.S. Daily Weather Maps Project (http://docs.lib.noaa.gov/rescue/dwm/data_rescue_daily_weather_maps.html), to compare to the CalDESK displays.

SECTION 4.0

CALPUFF Methodology

4.1 CALPUFF Modeling

CH2M HILL will drive the CALPUFF model with the meteorological output from CALMET over the CALPUFF modeling domain (Figure 3-1). The CALPUFF model will be used to predict visibility impacts for the pre-control (baseline) scenario for comparison to the predicted impacts for post-control scenarios.

4.1.1 Background Ozone and Ammonia

Hourly values of background ozone concentrations will be used by CALPUFF for the calculation of SO_2 and NO_X transformation with the MESOPUFF II chemical transformation scheme. CH2M HILL will use the hourly ozone data generated for the WRAP BART analysis for 2001, 2002, and 2003.

For periods of missing hourly ozone data, the chemical transformation will rely on a monthly default value of 80 ppb. Background ammonia will be set to 1 ppb as recommended in WRAP 2006.

4.1.2 Stack Parameters

The baseline stack parameters will be the same as those used in the WRAP-RMC exemption modeling unless more representative data are available. Post-control stack parameters will reflect any anticipated changes from operation of the control technology alternatives that are being evaluated.

4.1.3 Pre-Control Emission Rates

Pre-control emission rates will reflect normal maximum capacity 24-hour emissions that may occur under the source's current permit. The emission rates will reflect actual emissions under normal operating conditions. As described by the EPA in the *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule* (40 CFR Part 51; July 6, 2005, pg 39129):

> *The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high-capacity utilization. We do not generally recommend that emissions reflecting periods of start-up, shutdown, and malfunction be used…*

CH2M HILL will use available CEM data to determine the baseline 24-hour emission rates. Data will reflect operations from 2001 through 2003.

Although the Wrap Exemption Modeling evaluated emissions of NO_X, SO_2, and $PM_{2.5}$, particulate matter speciation data from the USEPA or National Park Service are proposed for this analysis (USEPA 2007, NPS 2007). Therefore emissions will be modeled for the following species:

- Sulfur dioxide (SO_2)
- Nitrogen oxides (NO_x)
- Coarse particulate ($PM_{2.5}$ < diameter ≤ PM_{10})
- Fine particulate (diameter ≤ $PM_{2.5}$)
- Elemental carbon (EC)
- Organic aerosols (SOA)
- Sulfates (SO_4)

4.1.4 Post Control Emission Rates

Post-control emission rates will reflect the effects of the emissions control scenario under consideration. Modeled pollutants will be the same as listed for the pre-control scenario.

4.1.5 Modeling Process

The CALPUFF modeling for the control technology options will follow this sequence:

- Model pre-control (baseline) emissions
- Determine the degree of visibility improvement
- Model other control scenarios if applicable
- Determine the degree of visibility improvement
- Factor visibility results into BART "5-step" evaluation

4.2 Receptor Grids and Coordinate Conversion

The TRC COORDS program will be used to convert the latitude/ longitude coordinates to LCC coordinates for the meteorological stations and source locations. The USGS conversion program PROJ (version 4.4.6) will be used to convert the National Park Service (NPS) receptor location data from latitude/longitude to LCC.

For the Class I areas that are within 300 km of the Cholla Power Plant, discrete receptors for the CALPUFF modeling will be taken from the NPS database for Class I area modeling receptors. The entire area of each Class I area that is within or intersects the 300 km circle (Figure 3-1) will be included in the modeling analysis. The following lists the Class I areas that will be modeled for the Cholla Power Plant:

- Capitol Reef National Park
- Galiuro Wilderness
- Saguaro National Park
- Gila Wilderness
- Superstition Wilderness
- Mount Baldy Wilderness
- Sierra Ancha Wilderness
- Mazatzal Wilderness
- Grand Canyon National Park
- Mesa Verde National Park

- Petrified Forest National Park
- Pine Mountain Wilderness
- Sycamore Canyon Wilderness

SECTION 5.0

Visibility Post-processing

5.1 CALPOST

The CALPOST processor will be used to determine 24-hour average visibility results. Output will be specified in deciview (dv) units.

Calculations of light extinction will be made for each pollutant modeled. The sum of all extinction values will be used to calculate the delta-dv change relative to natural background. Default extinction coefficients for each species, as shown below, will be used.

- Ammonium sulfate 3.0
- Ammonium nitrate 3.0
- PM coarse (PM_{10}) 0.6
- PM fine ($PM_{2.5}$) 1.0
- Organic carbon 4.0
- Elemental carbon 10.0

CALPOST visibility Method 6 (MVISBK=6) will be used for the determination of visibility impacts. Monthly average relative humidity factors [f(RH)] will be used in the light extinction calculations to account for the hygroscopic characteristic of sulfate and nitrate particles. Monthly f(RH) values will be the same as the Class I area specific values used in the WRAP-RMC BART modeling.

The natural background conditions as a reference for determination of the delta-dv change will represent the average natural concentration for western Class I areas. Table 5-1 lists the annual average species concentrations from the EPA Guidance.

TABLE 5-1
Average Natural Levels of Aerosol Components

Aerosol Component	Average Natural Concentration ($\mu g/m^3$) for Western Class I Areas
Ammonium Sulfate	0.12
Ammonium Nitrate	0.10
Organic Carbon	0.47
Elemental Carbon	0.02
Soil	0.50
Coarse Mass	3.0

Note: Taken from Table 2-1 of Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule.

SECTION 6.0

Presentation of Results

The results for a given year of meteorology, each emission control scenario, and each Class I area will be presented as the maximum Δdv and 98th percentile Δdv over the 3-year period, as well as the maximum number of days per year that the maximum Δdv exceeds 0.5 Δdv.

For the BART analysis, the model results for each emission control scenario will be compared to those for the baseline scenario. Incremental differences between increasing levels of control will also be evaluated.

The methodology and results of the CALPUFF modeling analyses will be presented in a technical report for each unit that is subject to BART. Input and output files for the CALMET/CALPUFF modeling and post-processing will be provided in electronic format to the ADEQ. Larger files such as binary files generated by CALMET will not be included on the submitted disks, but any omitted files will be provided electronically upon request.

SECTION 7.0

References

Western Regional Air Partnership (WRAP) 2006. Draft Final Modeling Protocol, CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States. Western Regional Air Partnership, Air Quality Modeling Forum, Regional Modeling Center, August 15, 2006.

Colorado Department of Public Health and Environment (CDPHE) 2005. CALMET/CALPUFF BART Protocol for Class I Federal Area Individual Source Attribution Visibility Impairment Modeling Analysis. Colorado Department of Public Health and Environment, Air Pollution Control Division, Denver, Colorado. October 24.

National Park Service (NPS) 2007. Nature & Science, Air, Permits, Particulate Matter Speciation. http://www2.nature.nps.gov/air/Permits/ect/ectCoalFiredBoiler.cfm. Accessed 7/13/2007.

US Environmental Protection Agency (USEPA) 2003a. Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule. USEPA. EPA-454/B-03-005. September 2003.

USEPA 2003b. Guidance for Tracking Progress under the Regional Haze Rule. USEPA. EPA-454/B-03-004. September 2003.

USEPA 1998. Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts. U.S. Environmental Protection Agency, Air Quality Modeling Group (MD-14), Research Triangle Park, North Carolina; National Park Service, Air Resources Division, Denver, Colorado; USDA Forest Service, Air Program, Fort Collins, Colorado; and U.S. Fish and Wildlife Service, Air Quality Branch Denver, Colorado. December, 1998.

USEPA 2007. AP 42, Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. USEPA Technology Transfer Network Clearinghouse for Inventories & Emissions Factors, Emissions Factors & AP 42. http://www.epa.gov/ttn/chief/ap42/index.html. Accessed 7/20/2007.

Appendix C
Additional BART
Modeling Results

APPENDIX C

Additional BART Modeling Results

FIGURE C-1
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Gila Wilderness
Cholla 3

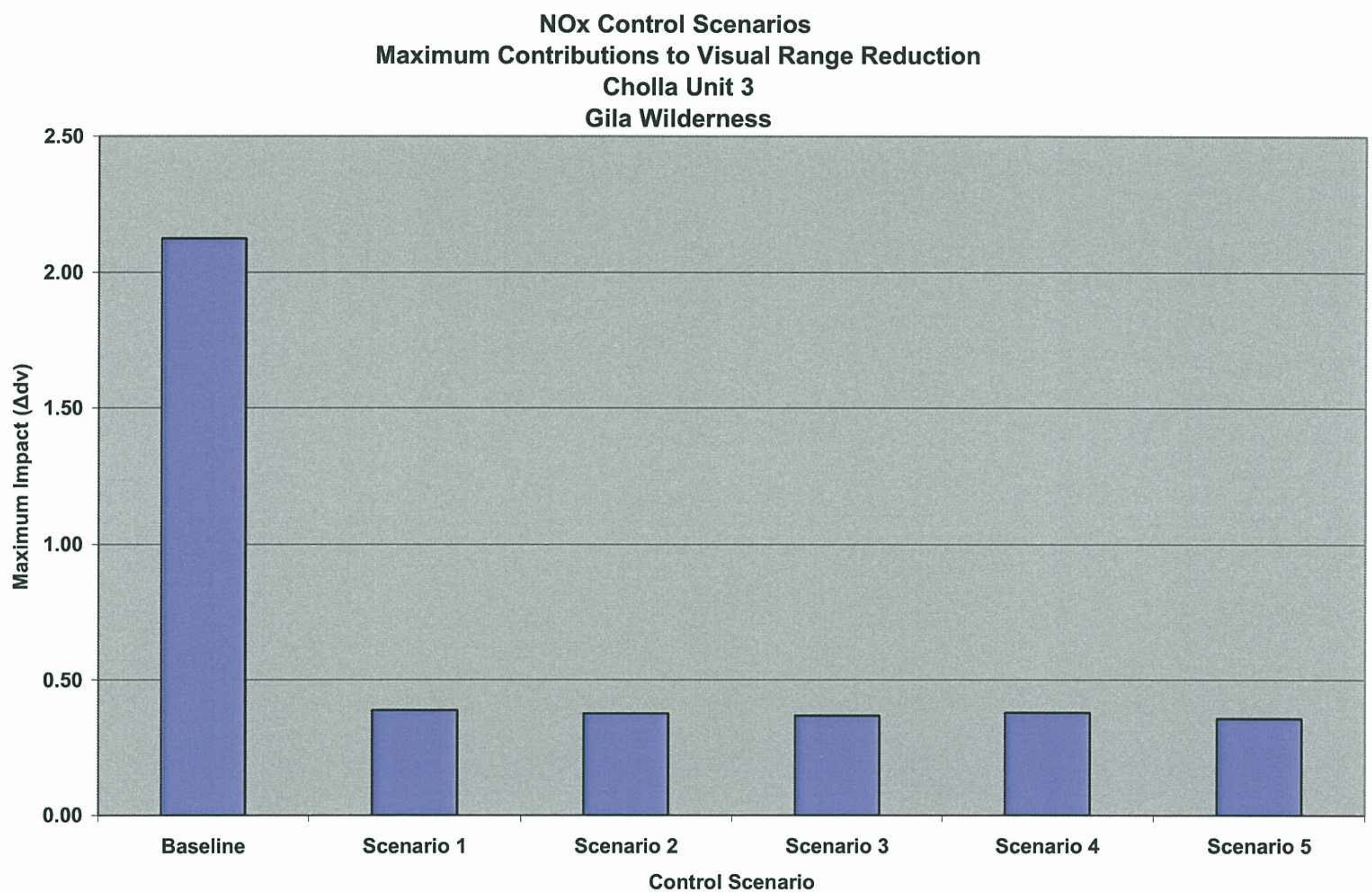

FIGURE C-2
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Mount Baldy Wilderness
Cholla 3

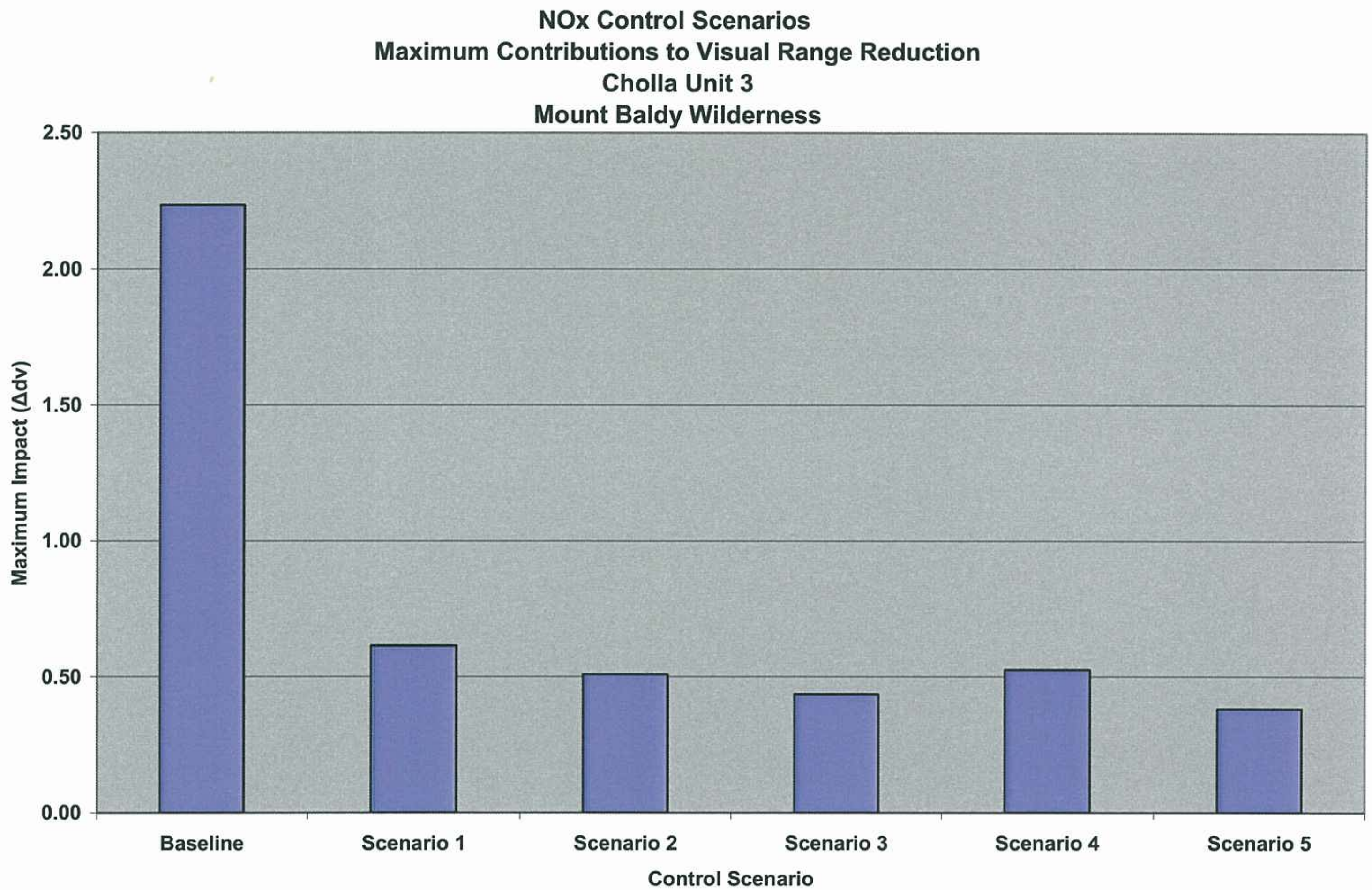

FIGURE C-3
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Sierra Ancha Wilderness
Cholla 3

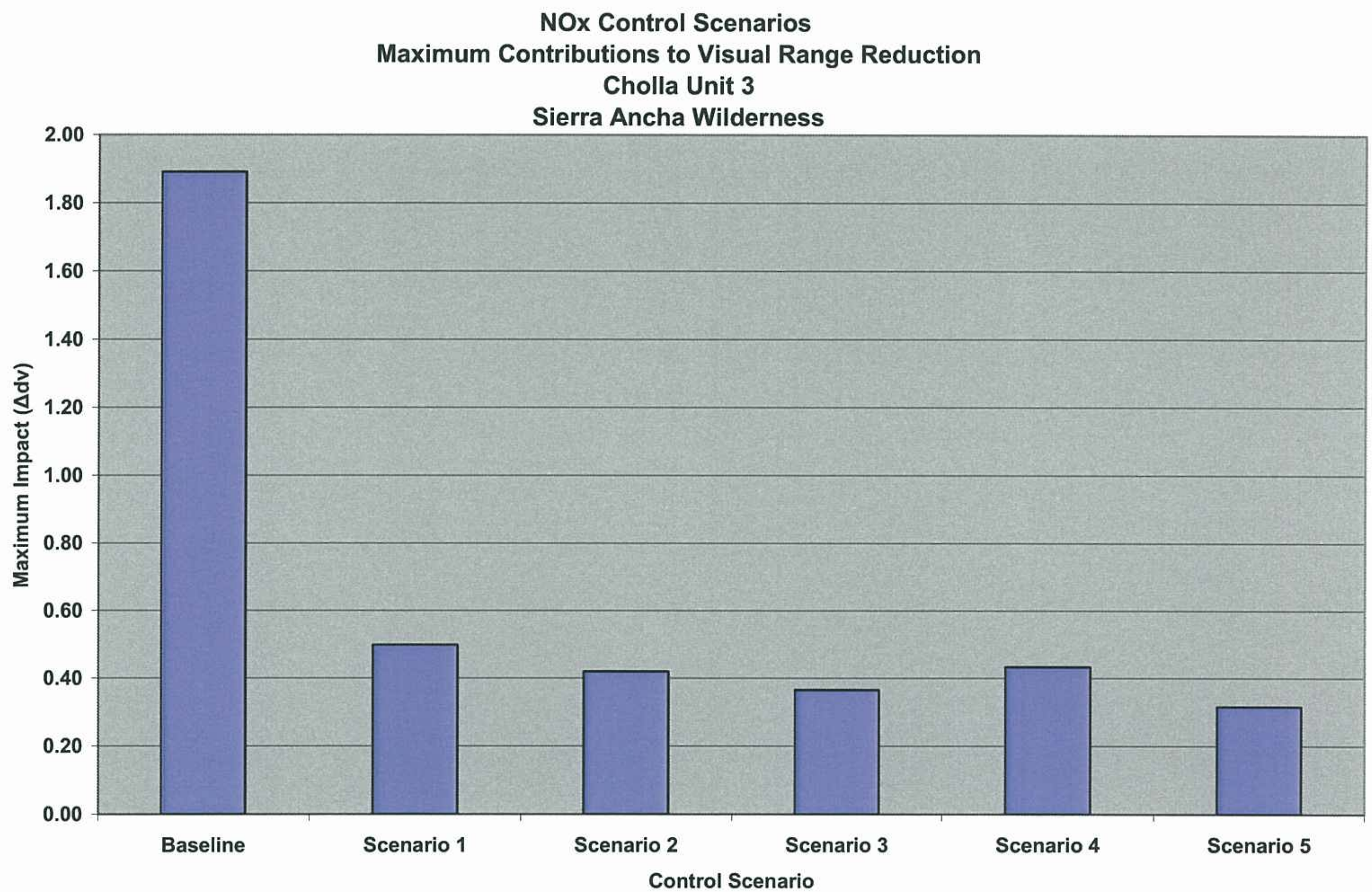

FIGURE C-4
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Mazatzal Wilderness
Cholla 3

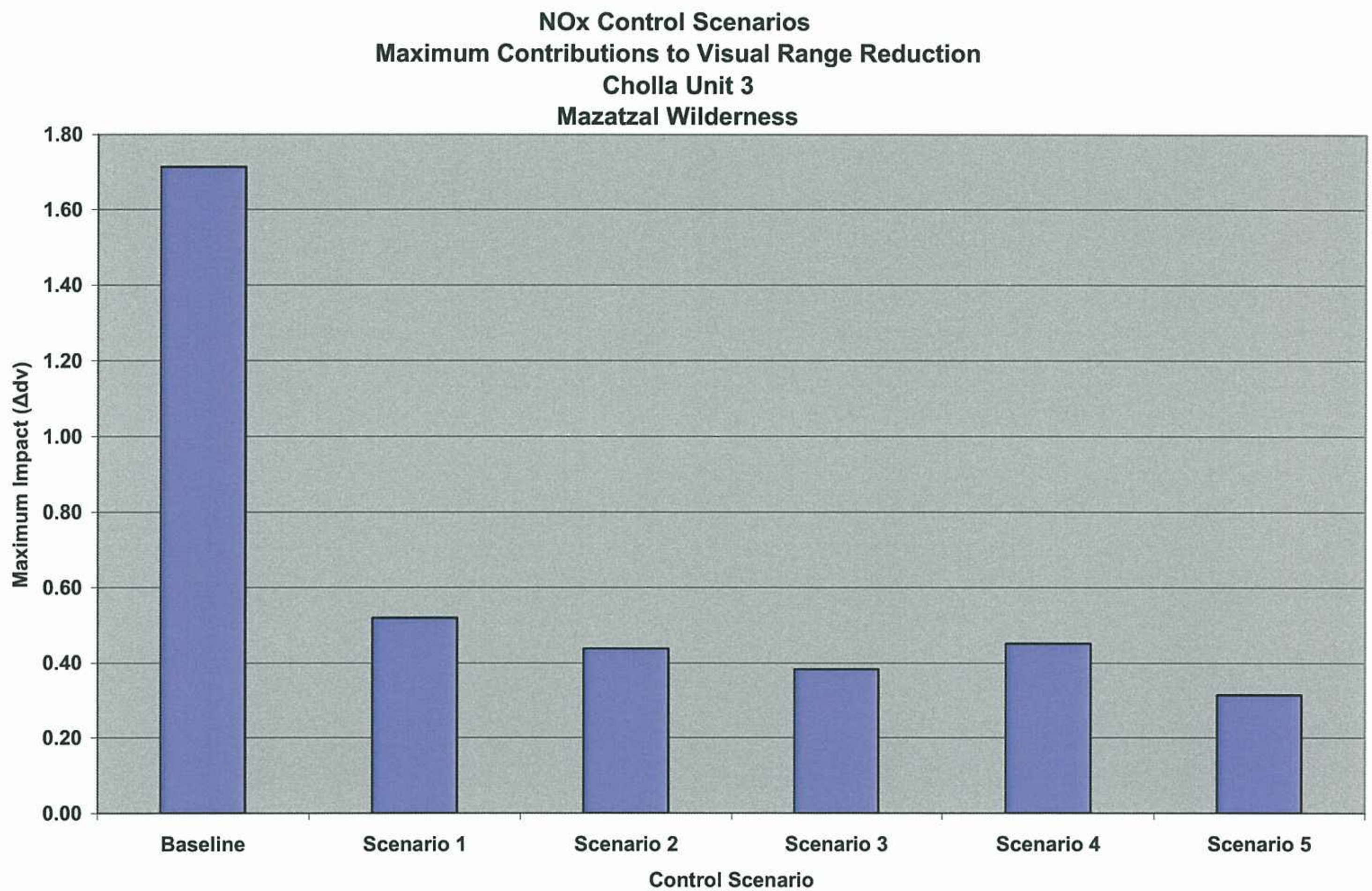

FIGURE C-5
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Pine Mountain Wilderness
Cholla 3

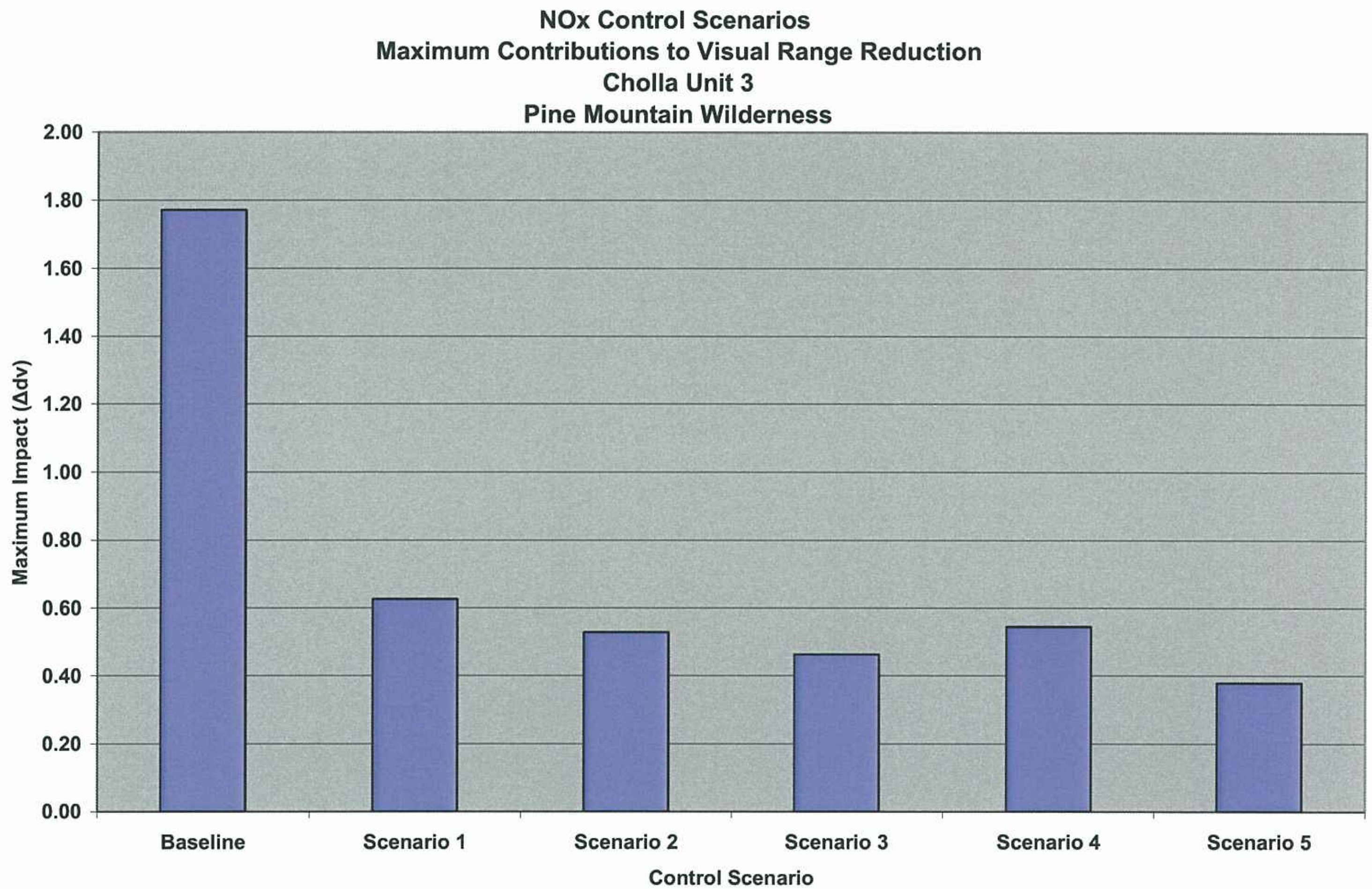

FIGURE C-6
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Superstition Wilderness
Cholla 3

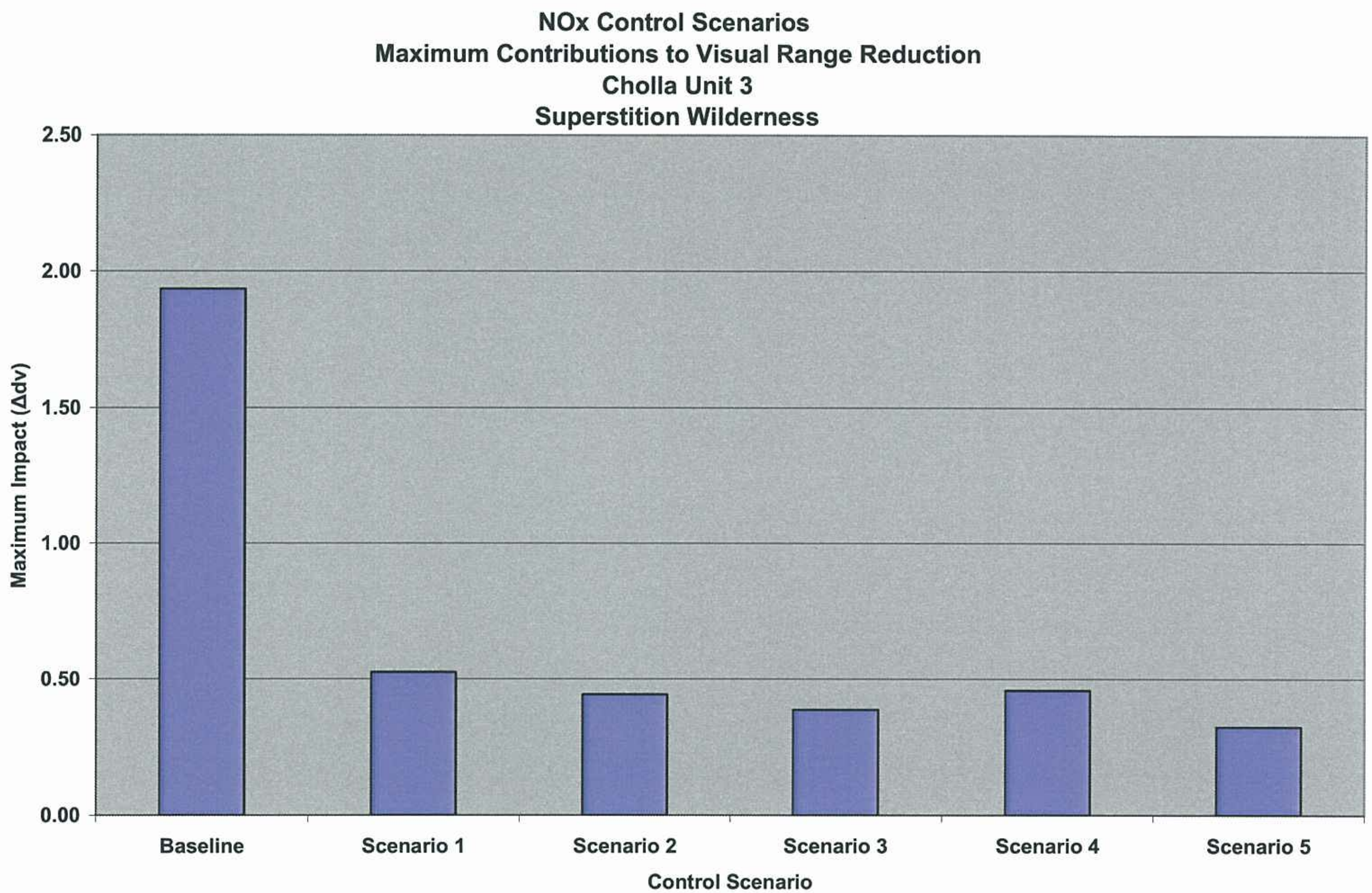

FIGURE C-7
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Galiuro Wilderness
Cholla 3

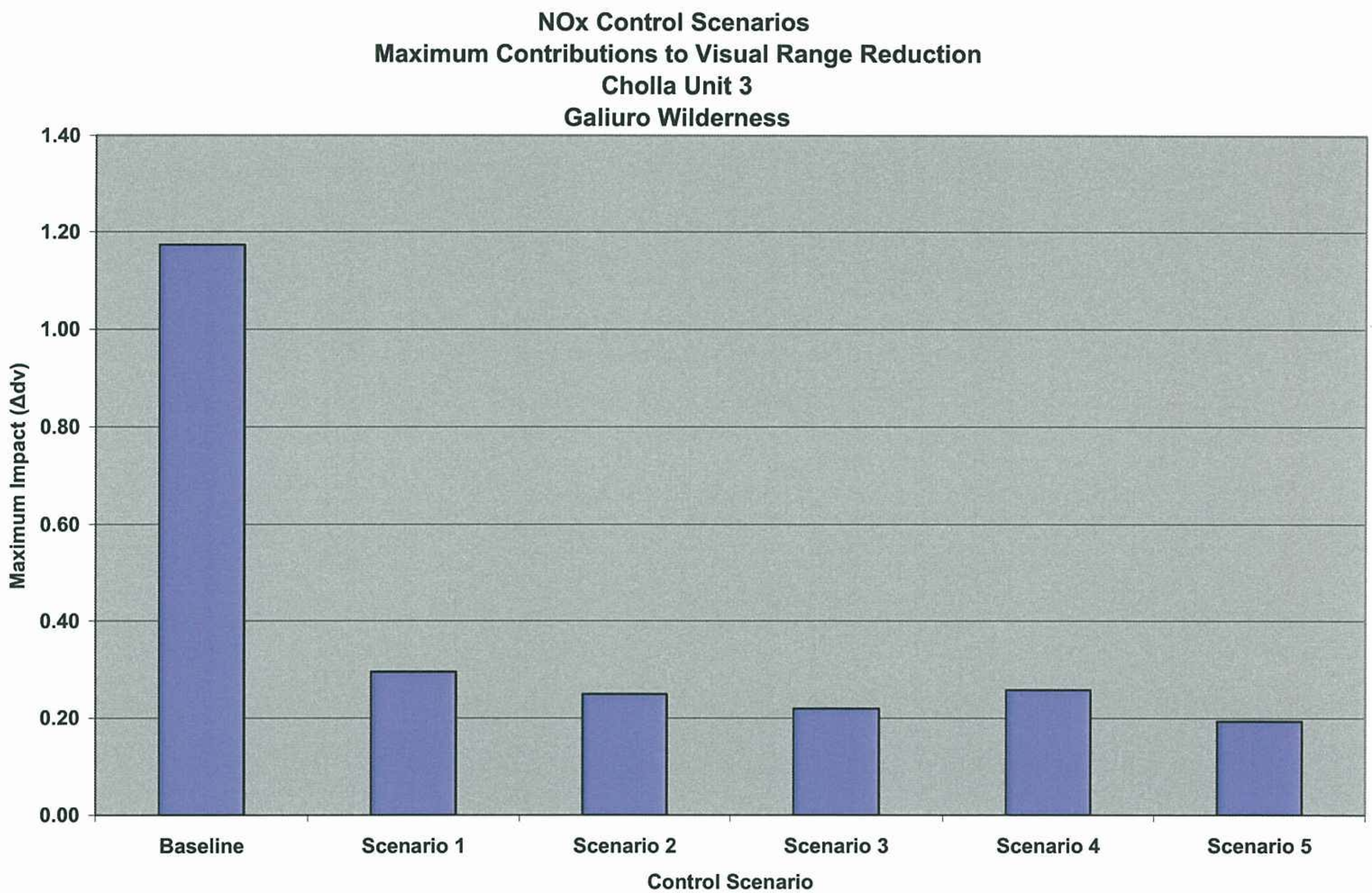

FIGURE C-8
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Mesa Verde Wilderness
Cholla 3

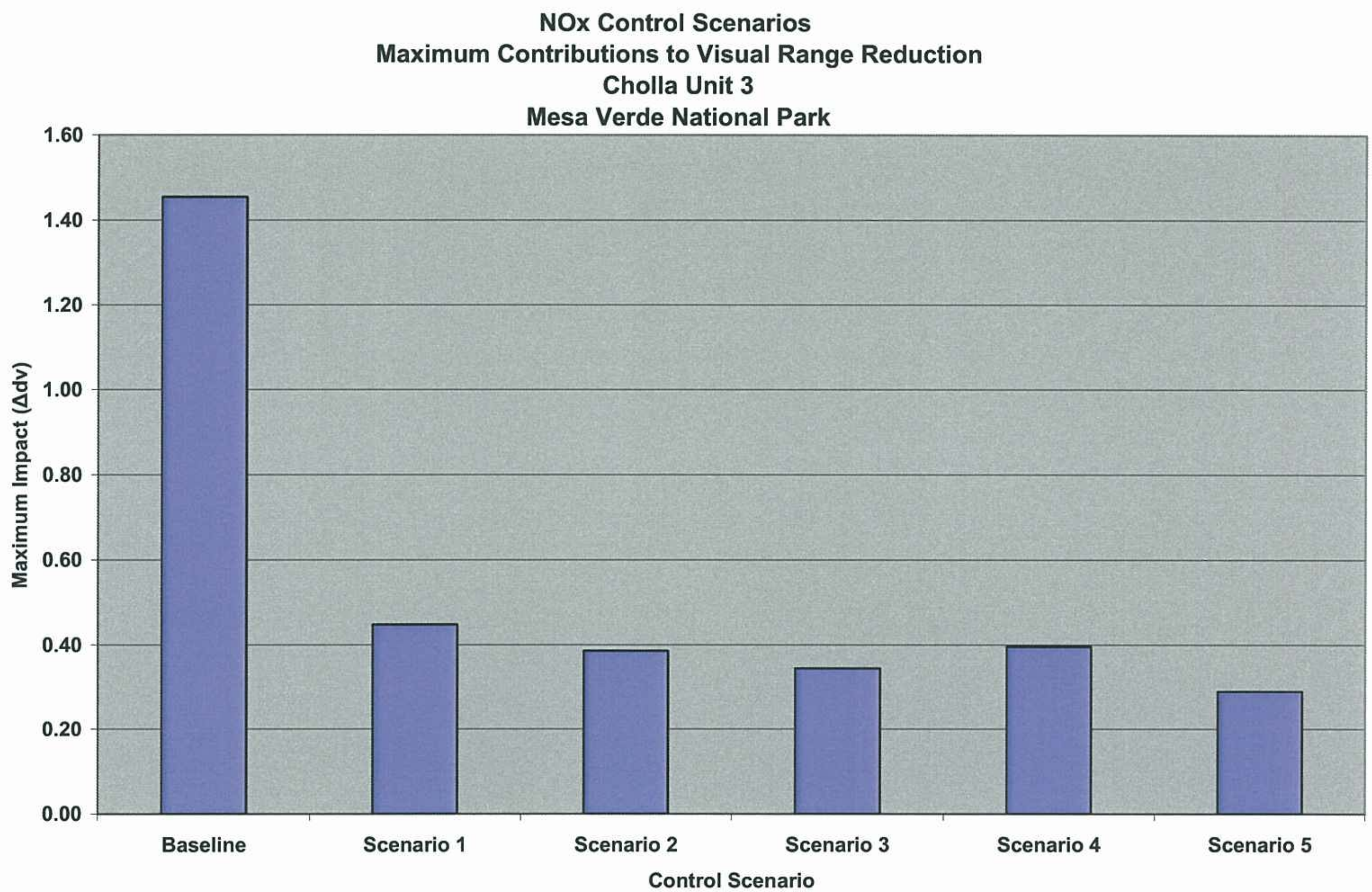

FIGURE C-9
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Saguaro NP
Cholla 3

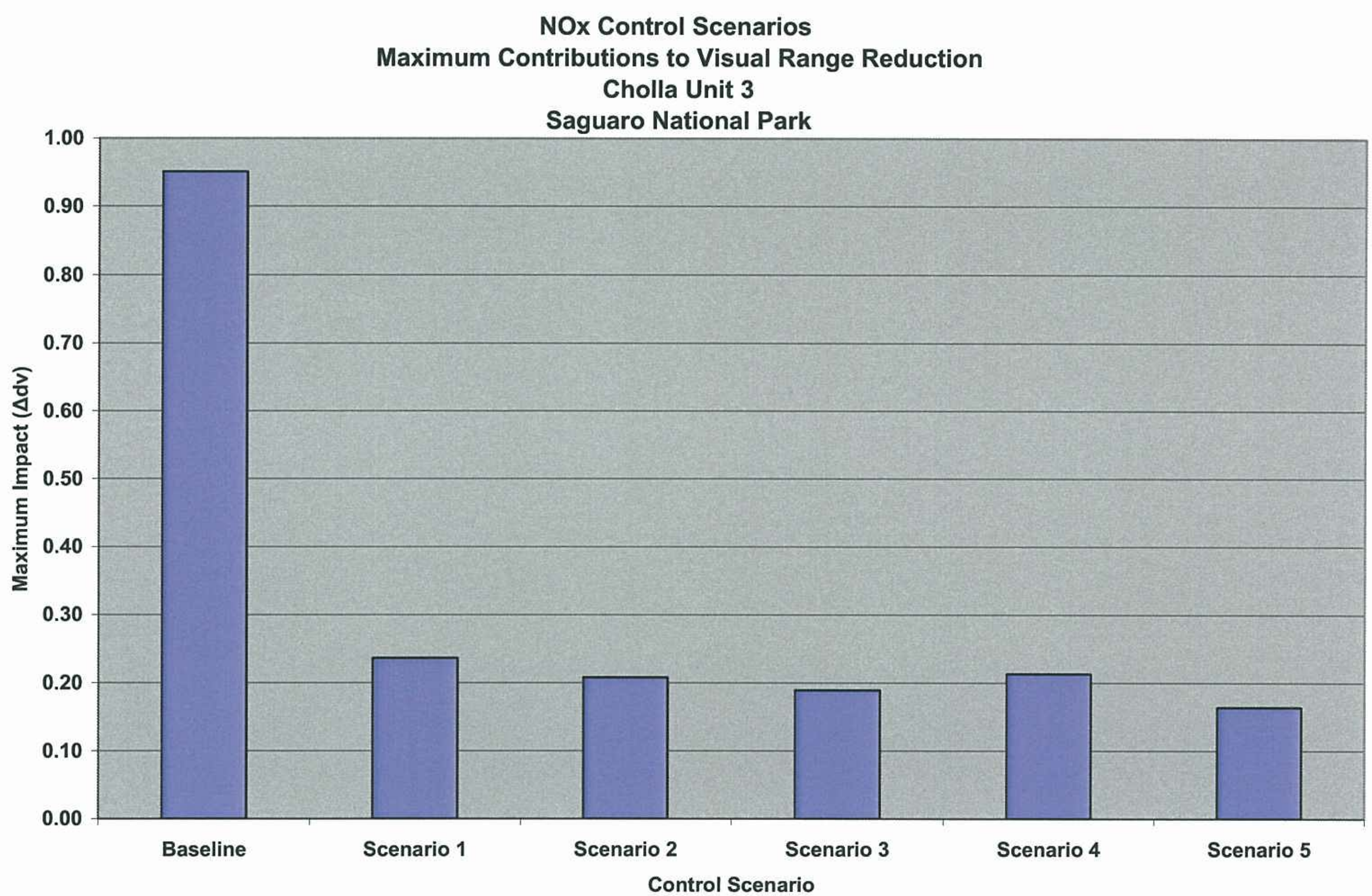

TABLE C-1
NO_x Control Scenario Results for Gila Wilderness
Cholla 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		19	0.000	0.000	0.000	0.000
1	LNB with Existing OFA	0	0.562	0.635	0.033	1.131
2	ROFA	0	0.572	2.243	0.118	3.922
3	ROFA with Rotamix	0	0.578	3.308	0.174	5.723
4	LNB with OFA & SNCR	0	0.571	2.157	0.114	3.777
5	LNB with OFA & SCR	0	0.591	9.569	0.504	16.191

TABLE C-2
NO_x Control Scenario Results for Mount Baldy Wilderness
Cholla 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		21	0.000	0.000	0.000	0.000
1	LNB with Existing OFA	1	0.629	0.635	0.032	1.010
2	ROFA	1	0.647	2.243	0.112	3.467
3	ROFA with Rotamix	0	0.663	3.308	0.158	4.989
4	LNB with OFA & SNCR	1	0.646	2.157	0.108	3.339
5	LNB with OFA & SCR	0	0.674	9.569	0.456	14.197

TABLE C-3
NO_x Control Scenario Results for Sierra Ancha Wilderness
Cholla 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		29	0.000	0.000	0.000	0.000
1	LNB with Existing OFA	0	0.651	0.635	0.022	0.976
2	ROFA	0	0.684	2.243	0.077	3.280
3	ROFA with Rotamix	0	0.706	3.308	0.114	4.686
4	LNB with OFA & SNCR	0	0.678	2.157	0.074	3.181
5	LNB with OFA & SCR	0	0.733	9.569	0.330	13.055

TABLE C-4
NO_x Control Scenario Results for Mazatzal Wilderness
Cholla 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		24	0.000	0.000	0.000	0.000
1	LNB with Existing OFA	1	0.716	0.635	0.028	0.887
2	ROFA	0	0.741	2.243	0.093	3.027
3	ROFA with Rotamix	0	0.754	3.308	0.138	4.387
4	LNB with OFA & SNCR	0	0.739	2.157	0.090	2.918
5	LNB with OFA & SCR	0	0.773	9.569	0.399	12.379

TABLE C-5
NO_x Control Scenario Results for Pine Mountain Wilderness
Cholla 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		16	0.000	0.000	0.000	0.000
1	LNB with Existing OFA	1	0.540	0.635	0.042	1.177
2	ROFA	1	0.555	2.243	0.150	4.042
3	ROFA with Rotamix	0	0.568	3.308	0.207	5.824
4	LNB with OFA & SNCR	1	0.551	2.157	0.144	3.914
5	LNB with OFA & SCR	0	0.578	9.569	0.598	16.555

TABLE C-6
NO_x Control Scenario Results for Superstition Wilderness
Cholla 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		23	0.000	0.000	0.000	0.000
1	LNB with Existing OFA	1	0.705	0.635	0.029	0.901
2	ROFA	0	0.716	2.243	0.098	3.133
3	ROFA with Rotamix	0	0.732	3.308	0.144	4.519
4	LNB with OFA & SNCR	0	0.715	2.157	0.094	3.016
5	LNB with OFA & SCR	0	0.754	9.569	0.416	12.691

TABLE C-7
NO_x Control Scenario Results for Galiuro Wilderness
Cholla 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		9	0.000	0.000	0.000	0.000
1	LNB with Existing OFA	0	0.333	0.635	0.071	1.908
2	ROFA	0	0.343	2.243	0.249	6.540
3	ROFA with Rotamix	0	0.344	3.308	0.368	9.616
4	LNB with OFA & SNCR	0	0.342	2.157	0.240	6.306
5	LNB with OFA & SCR	0	0.351	9.569	1.063	27.262

TABLE C-8
NO_x Control Scenario Results for Mesa Verde Wilderness
Cholla 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		21	0.000	0.000	0.000	0.000
1	LNB with Existing OFA	0	0.510	0.635	0.030	1.246
2	ROFA	0	0.538	2.243	0.107	4.170
3	ROFA with Rotamix	0	0.559	3.308	0.158	5.918
4	LNB with OFA & SNCR	0	0.532	2.157	0.103	4.054
5	LNB with OFA & SCR	0	0.577	9.569	0.456	16.584

TABLE C-9
NO_x Control Scenario Results for Saguaro NP
Cholla 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		7	0.000	0.000	0.000	0.000
1	LNB with Existing OFA	0	0.284	0.635	0.091	2.237
2	ROFA	0	0.295	2.243	0.320	7.604
3	ROFA with Rotamix	0	0.295	3.308	0.473	11.213
4	LNB with OFA & SNCR	0	0.295	2.157	0.308	7.311
5	LNB with OFA & SCR	0	0.300	9.569	1.367	31.897

TABLE C-10
Gila Wilderness NO_x Control Scenario Incremental Analysis Data
Cholla 3

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	19	0.562	0.635	0.033	1.131
Scenario 2 vs. Scenario 1	0	0.010	1.608	NA	160.779
Scenario 3 vs. Scenario 2	0	0.006	1.065	NA	177.462
Scenario 5 vs. Scenario 3	0	0.013	6.261	NA	481.624

TABLE C-11
Mount Baldy Wilderness NO_x Control Scenario Incremental Analysis Data
Cholla 3

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	20	0.629	0.635	0.032	1.010
Scenario 3 vs. Scenario 1	1	0.016	1.065	1.065	66.548
Scenario 5 vs. Scenario 3	0	0.011	6.261	NA	569.191

TABLE C-12
Sierra Ancha Wilderness Incremental Analysis Data
Cholla 3

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	29	0.651	0.635	0.022	0.976
Scenario 3 vs. Scenario 1	0	0.022	1.065	NA	48.399
Scenario 5 vs. Scenario 3	0	0.027	6.261	NA	231.892

TABLE C-13
Mazatzal Wilderness NO_x Control Scenario Incremental Analysis Data
Cholla 3

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	23	0.716	0.635	0.028	0.887
Scenario 2 vs. Scenario 1	1	0.025	1.608	1.608	64.312
Scenario 3 vs. Scenario 2	0	0.013	1.065	NA	81.905
Scenario 5 vs. Scenario 3	0	0.019	6.261	NA	329.531

TABLE C-14
Pine Mountain Wilderness NO_x Control Scenario Incremental Analysis Data
Cholla 3

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	15	0.540	0.635	0.042	1.177
Scenario 3 vs. Scenario 1	1	0.013	1.065	1.065	81.905
Scenario 5 vs. Scenario 3	0	0.010	6.261	NA	626.106

TABLE C-15
Superstition Wilderness NO_x Control Scenario Incremental Analysis Data
Cholla 3

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	22	0.705	0.635	0.029	0.901
Scenario 3 vs. Scenario 1	0	0.016	1.065	NA	66.548
Scenario 5 vs. Scenario 3	0	0.022	6.261	NA	284.596

TABLE C-16
Galiuro Wilderness NO_x Control Scenario Incremental Analysis Data
Cholla 3

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	9	0.333	0.635	0.071	1.908
Scenario 2 vs. Scenario 1	0	0.010	1.608	NA	160.780
Scenario 5 vs. Scenario 2	0	0.007	6.261	NA	894.442

TABLE C-17
Mesa Verde Wilderness NO_x Control Scenario Incremental Analysis Data
Cholla 3

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	21	0.510	0.635	0.030	1.246
Scenario 3 vs. Scenario 1	0	0.021	1.065	NA	50.703
Scenario 5 vs. Scenario 3	0	0.018	6.261	NA	347.838

TABLE C-18
Saguaro NP NO_x Control Scenario Incremental Analysis Data
Cholla 3

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	7	0.284	0.635	0.091	2.237
Scenario 2 vs. Scenario 1	0	0.011	1.608	NA	146.163
Scenario 5 vs. Scenario 2	0	0.005	7.326	NA	1465.165

FIGURE C-10
NO_x Control Scenarios - Least Cost Envelope Gila Wilderness - Days Reduction
Cholla 3

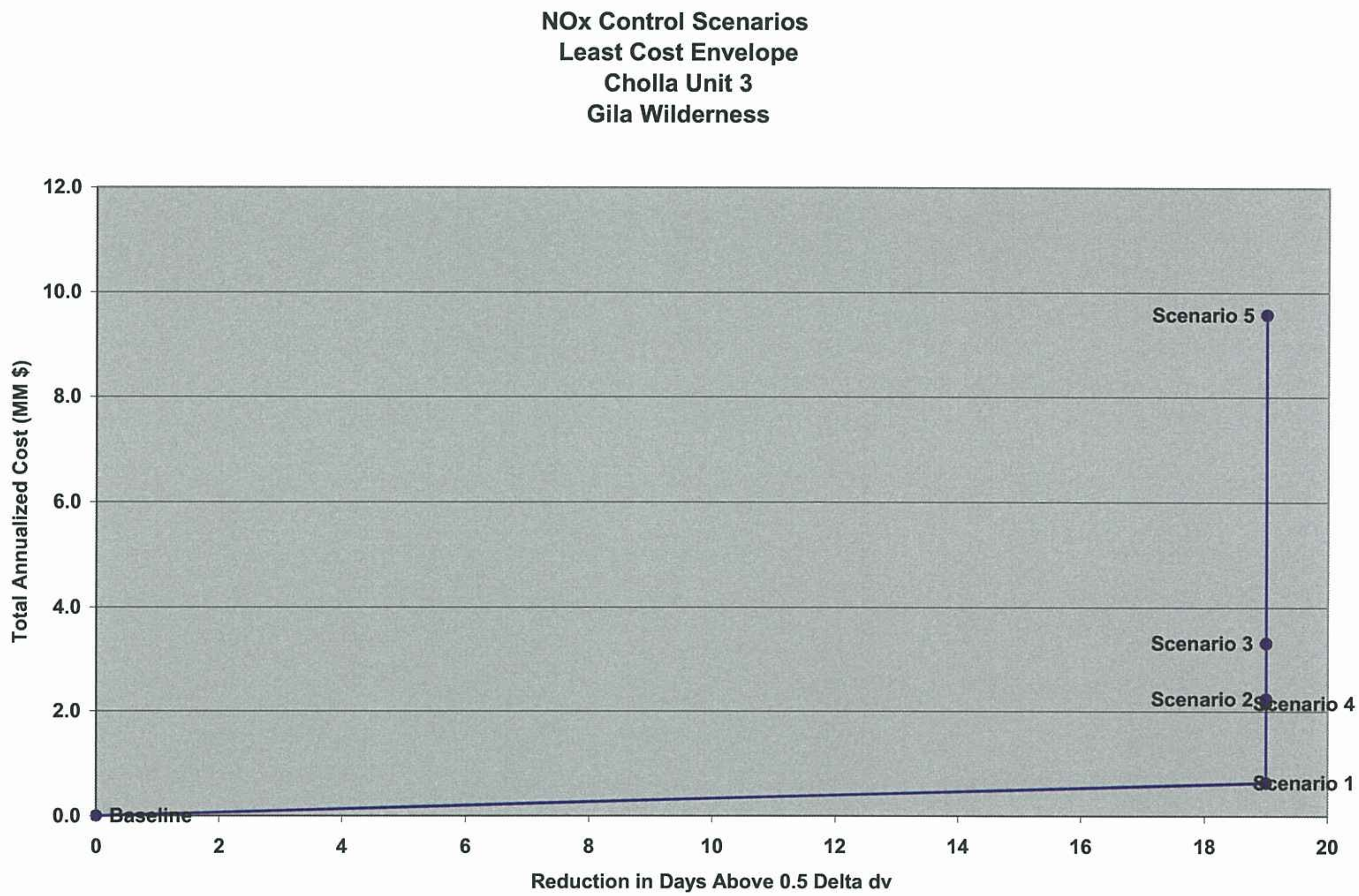

FIGURE C-11
NO_x Control Scenarios - Least Cost Envelope Gila Wilderness - 98th Percentile Reduction
Cholla 3

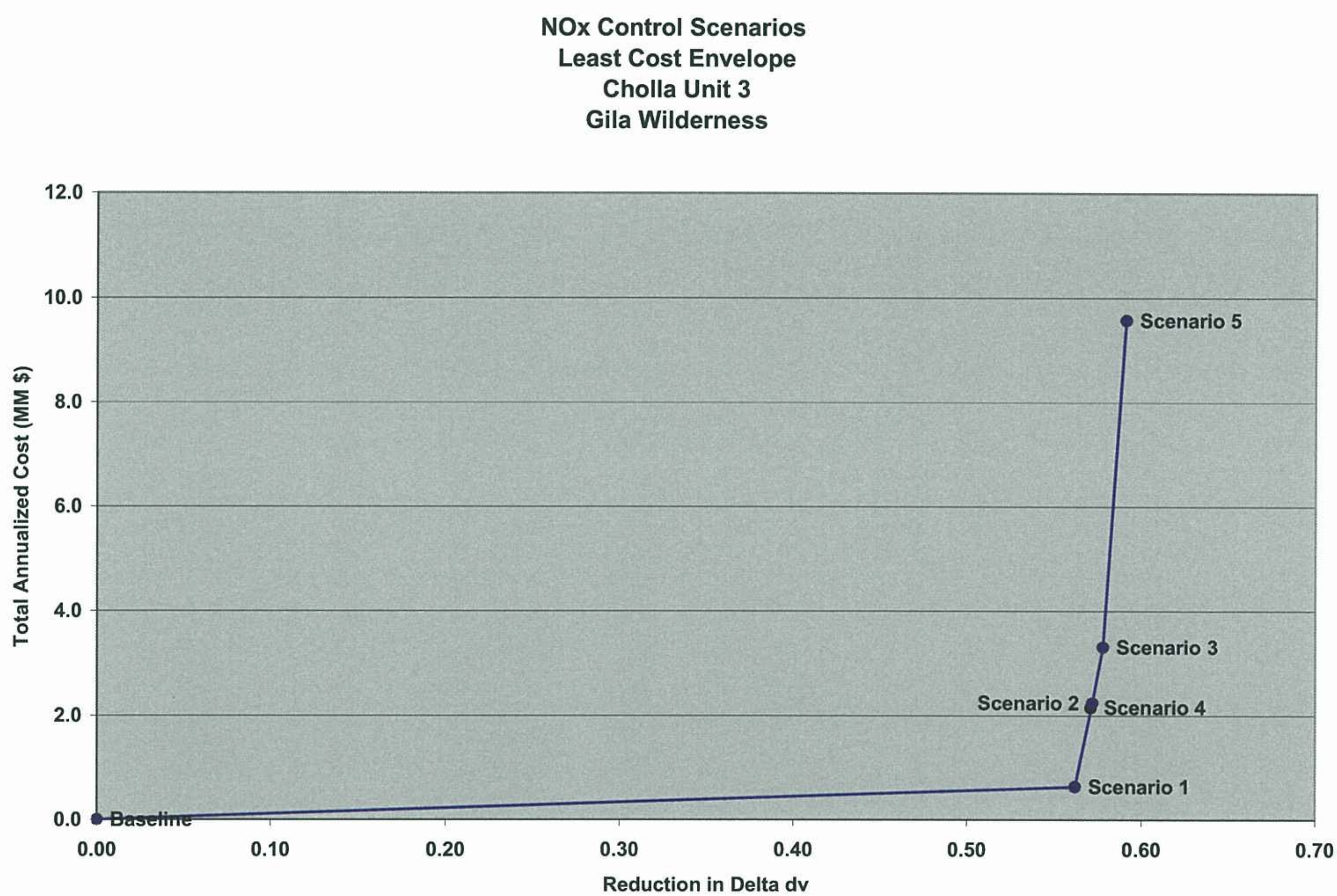

FIGURE C-12
NO_x Control Scenarios - Least Cost Envelope Mount Baldy Wilderness - Days Reduction
Cholla 3

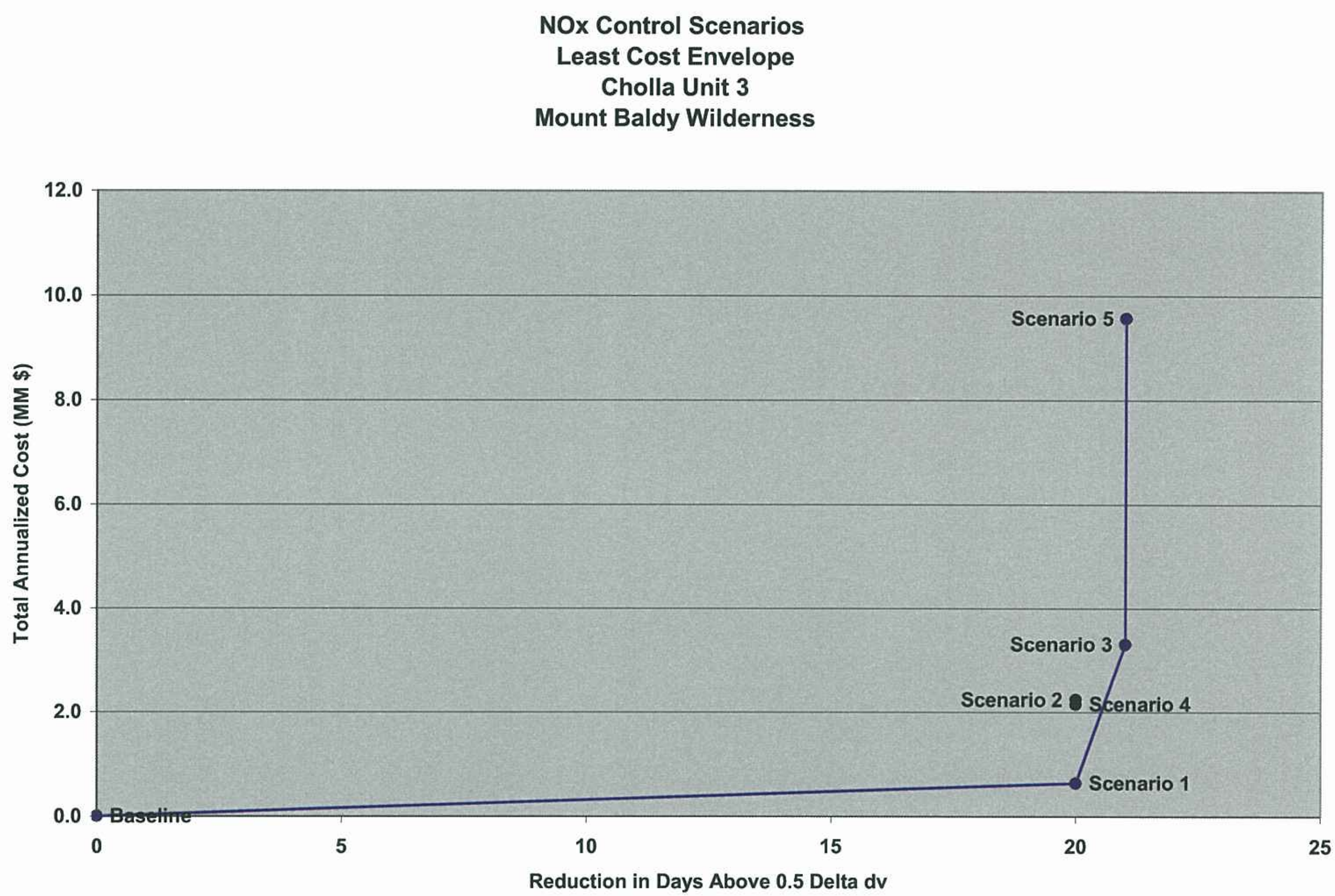

FIGURE C-13
NO_x Control Scenarios - Least Cost Envelope Mount Baldy Wilderness - 98th Percentile Reduction
Cholla 3

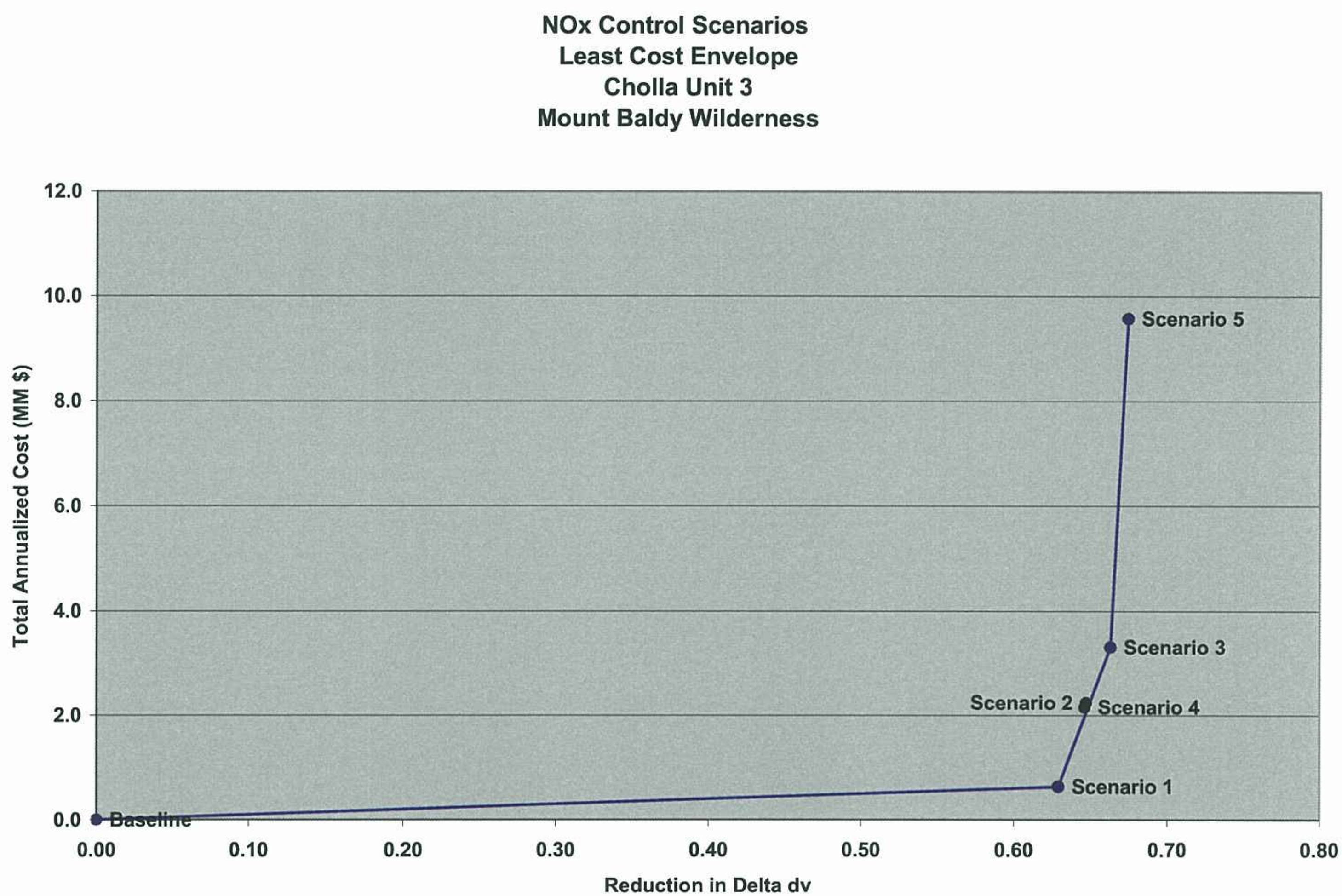

FIGURE C-14
NO_x Control Scenarios - Least Cost Envelope Sierra Ancha Wilderness - Days Reduction
Cholla 3

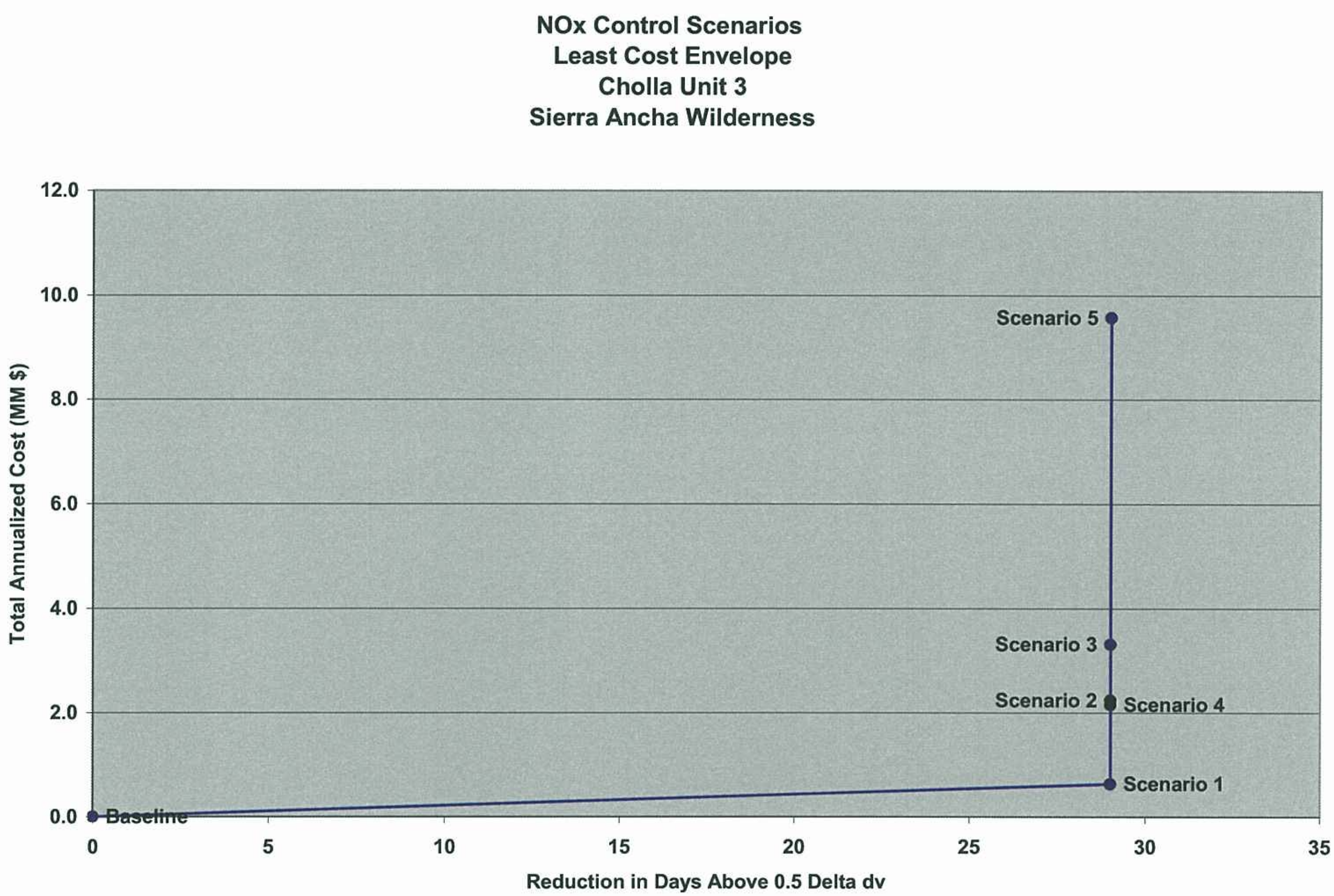

FIGURE C-15
NO_x Control Scenarios - Least Cost Envelope Sierra Ancha Wilderness - 98th Percentile Reduction
Cholla 3

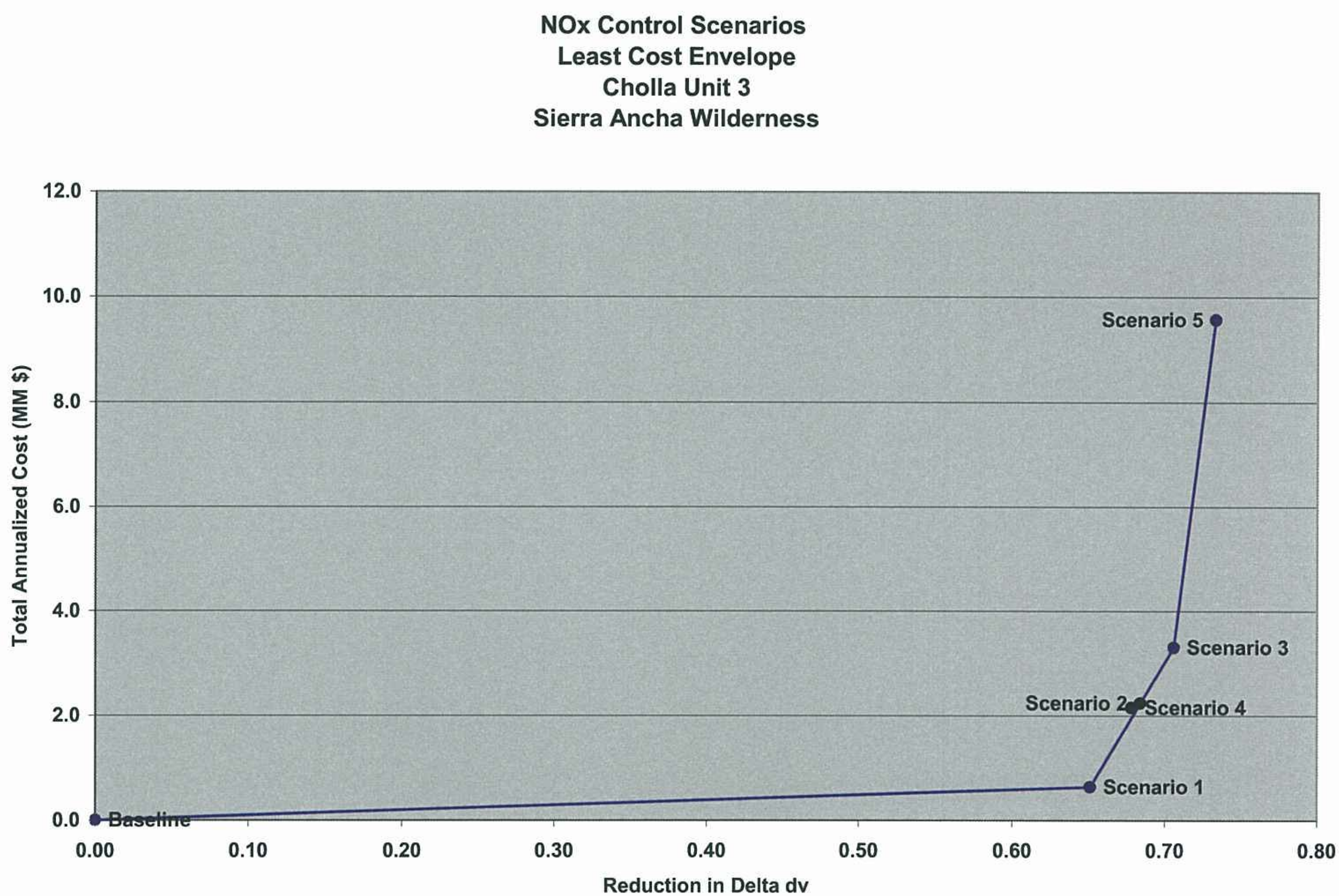

FIGURE C-16
NO_x Control Scenarios - Least Cost Envelope Mazatzal Wilderness - Days Reduction
Cholla 3

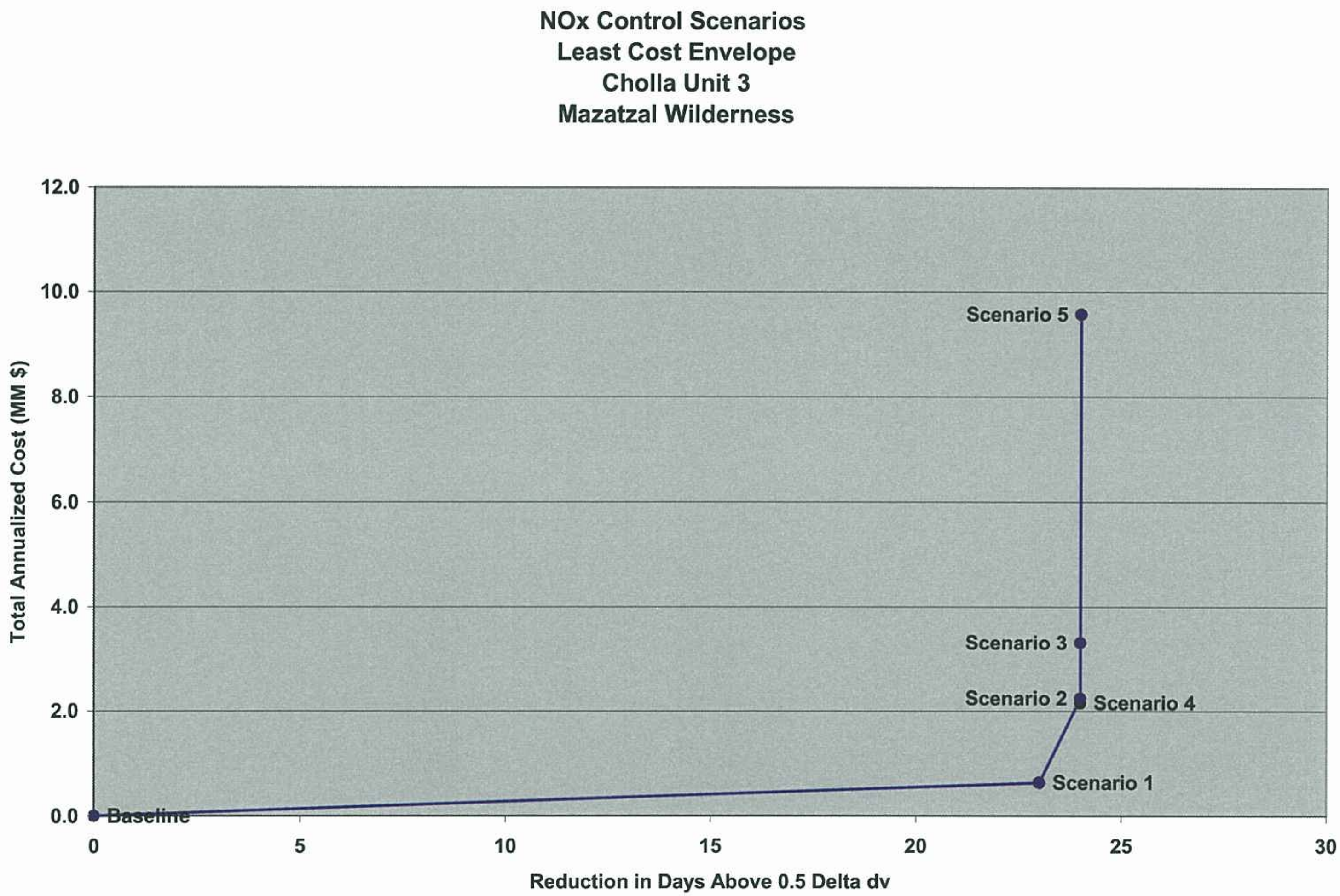

FIGURE C-17
NO_x Control Scenarios - Least Cost Envelope Mazatzal Wilderness - 98th Percentile Reduction
Cholla 3

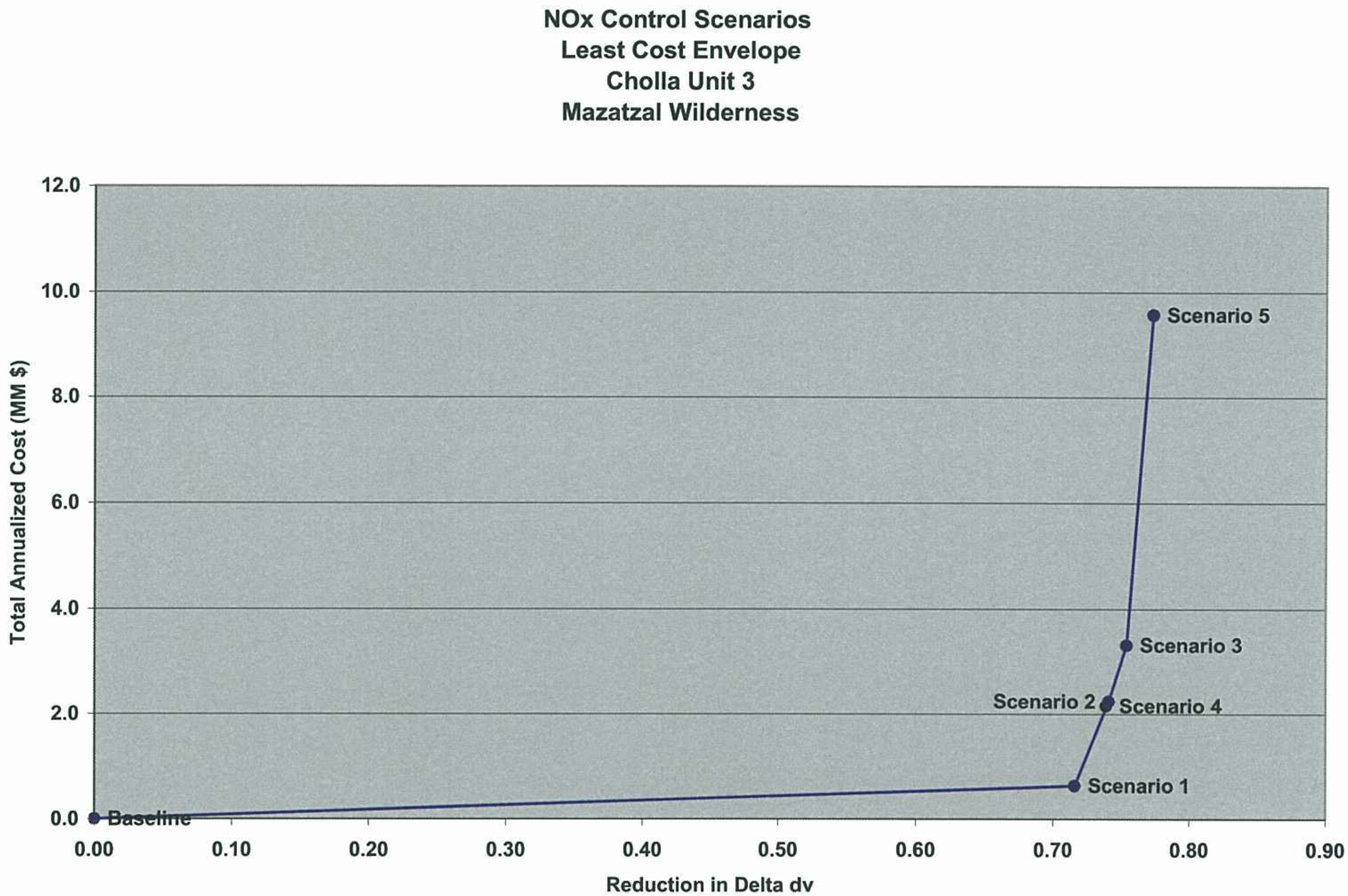

FIGURE C-18
NO_x Control Scenarios - Least Cost Envelope Pine Mountain Wilderness - Days Reduction
Cholla 3

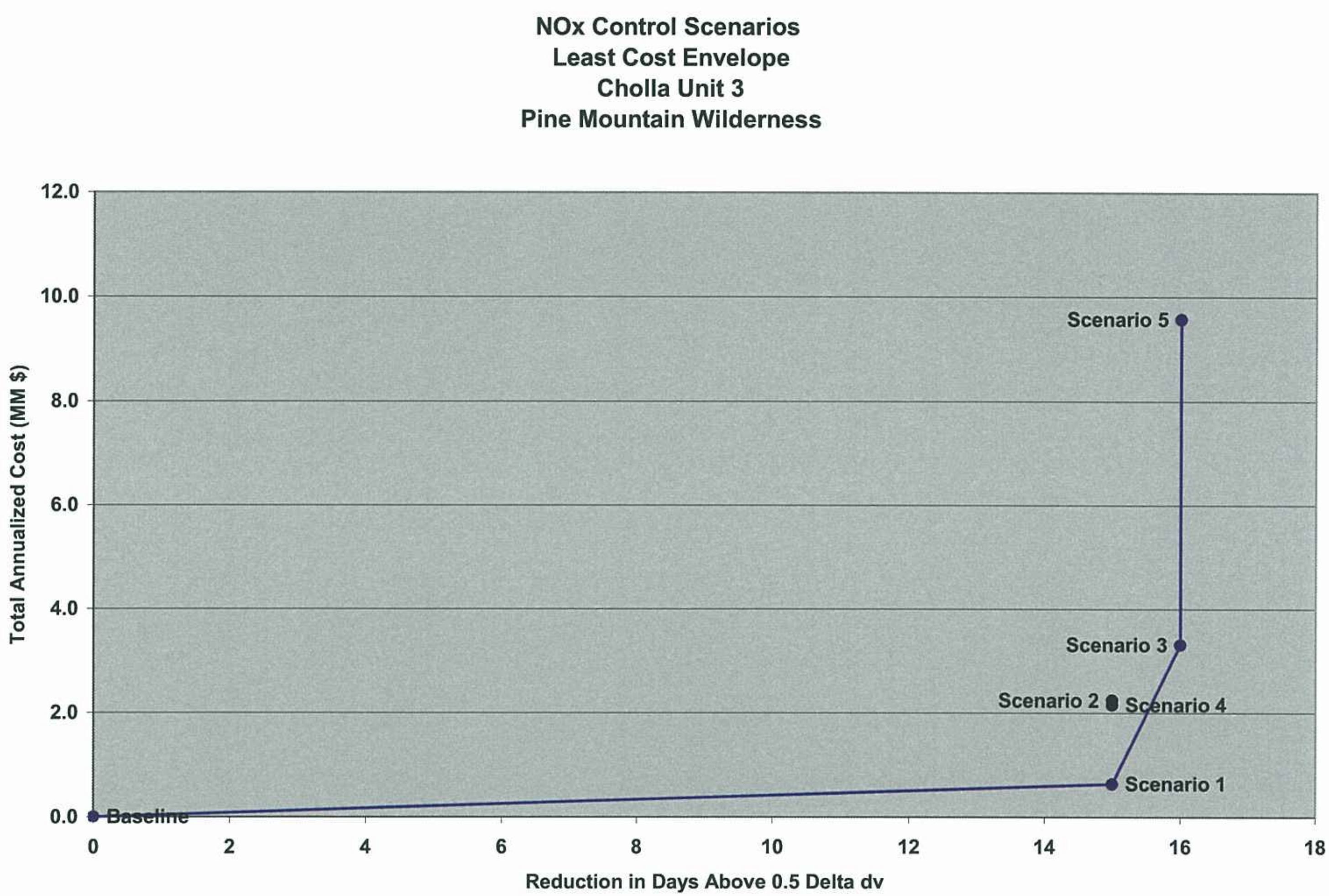

FIGURE C-19
NO_x Control Scenarios - Least Cost Envelope Pine Mountain Wilderness - 98th Percentile Reduction
Cholla 3

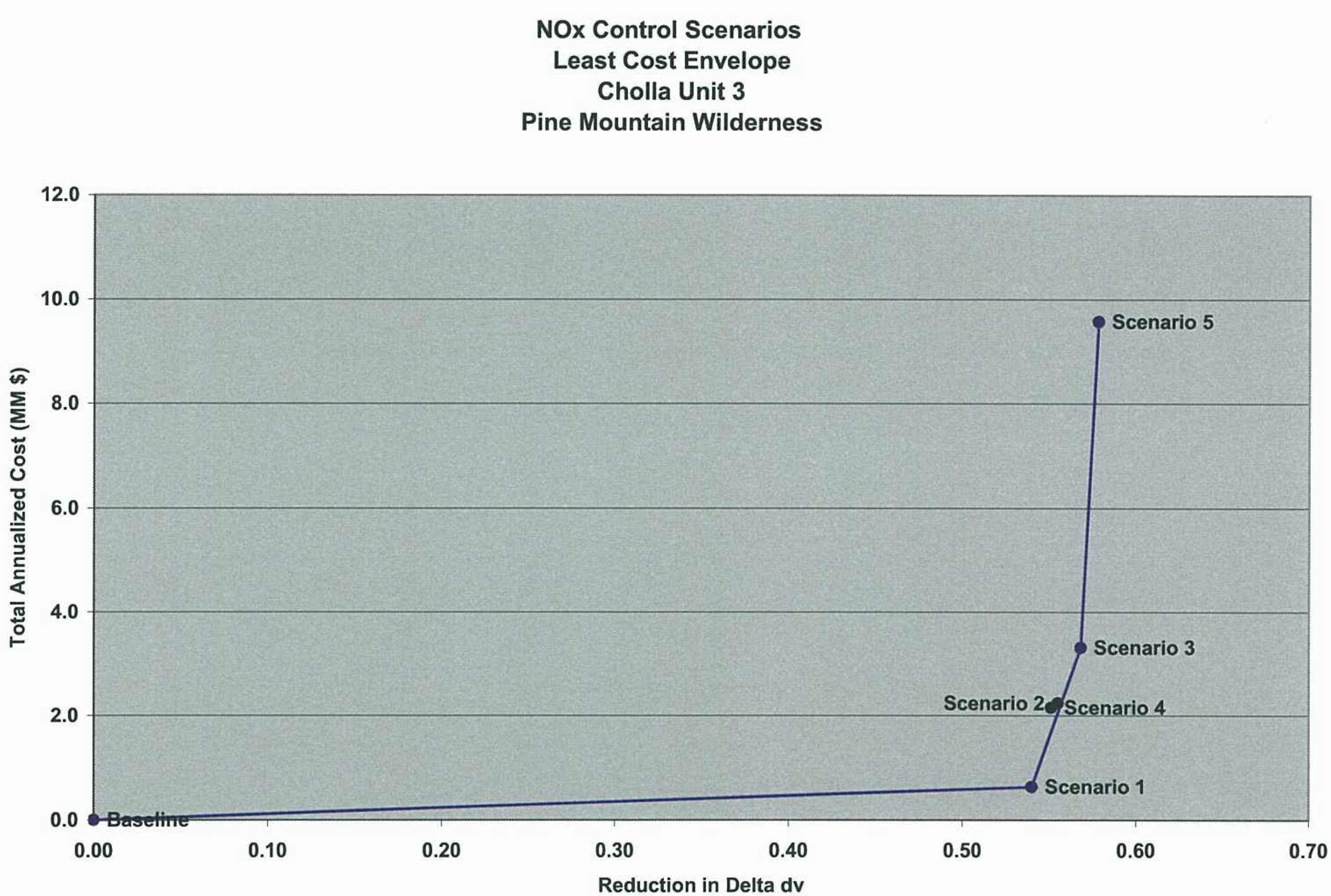

FIGURE C-20
NO_x Control Scenarios - Least Cost Envelope Superstition Wilderness - Days Reduction
Cholla 3

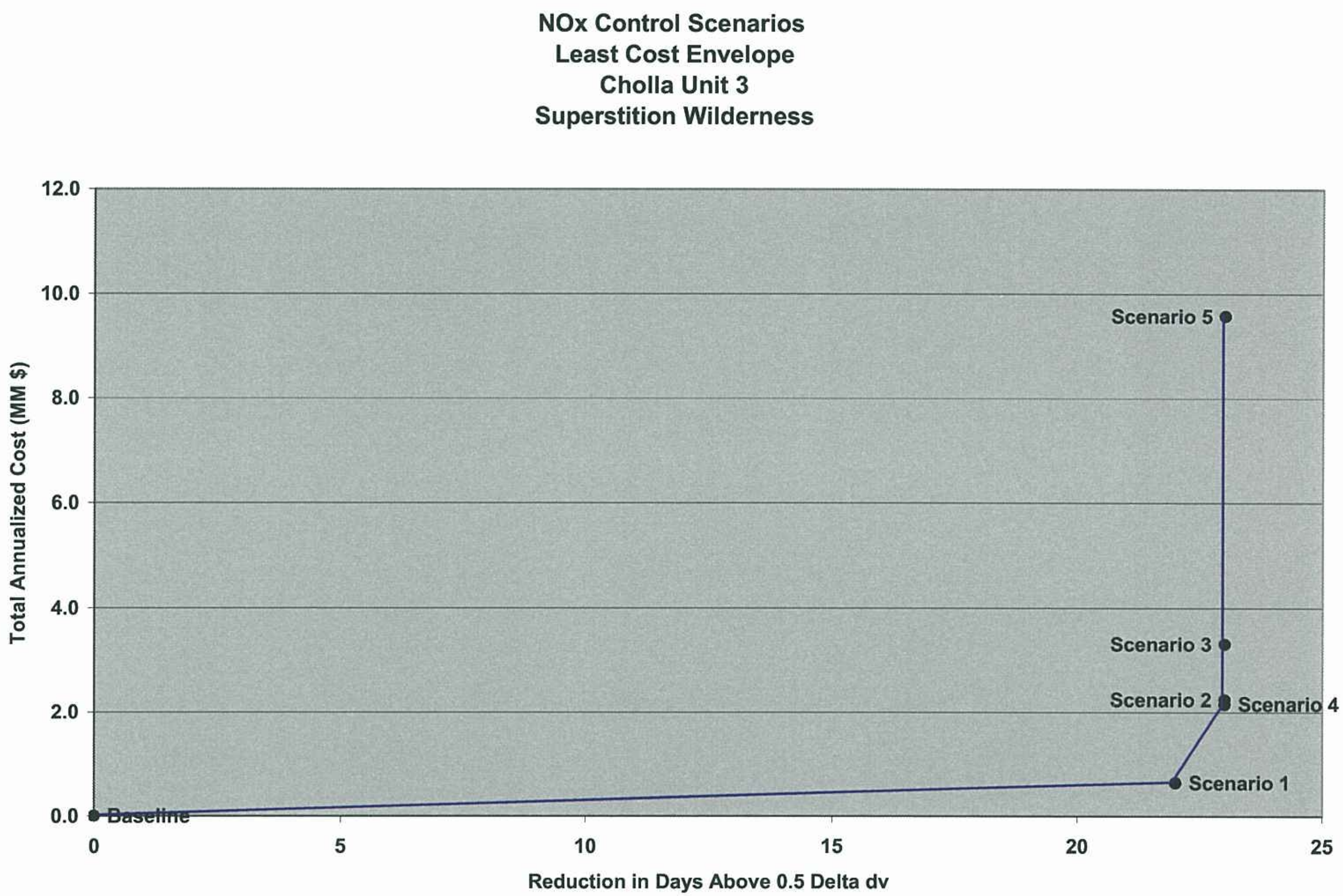

FIGURE C-21
NO_x Control Scenarios - Least Cost Envelope Superstition Wilderness - 98th Percentile Reduction
Cholla 3

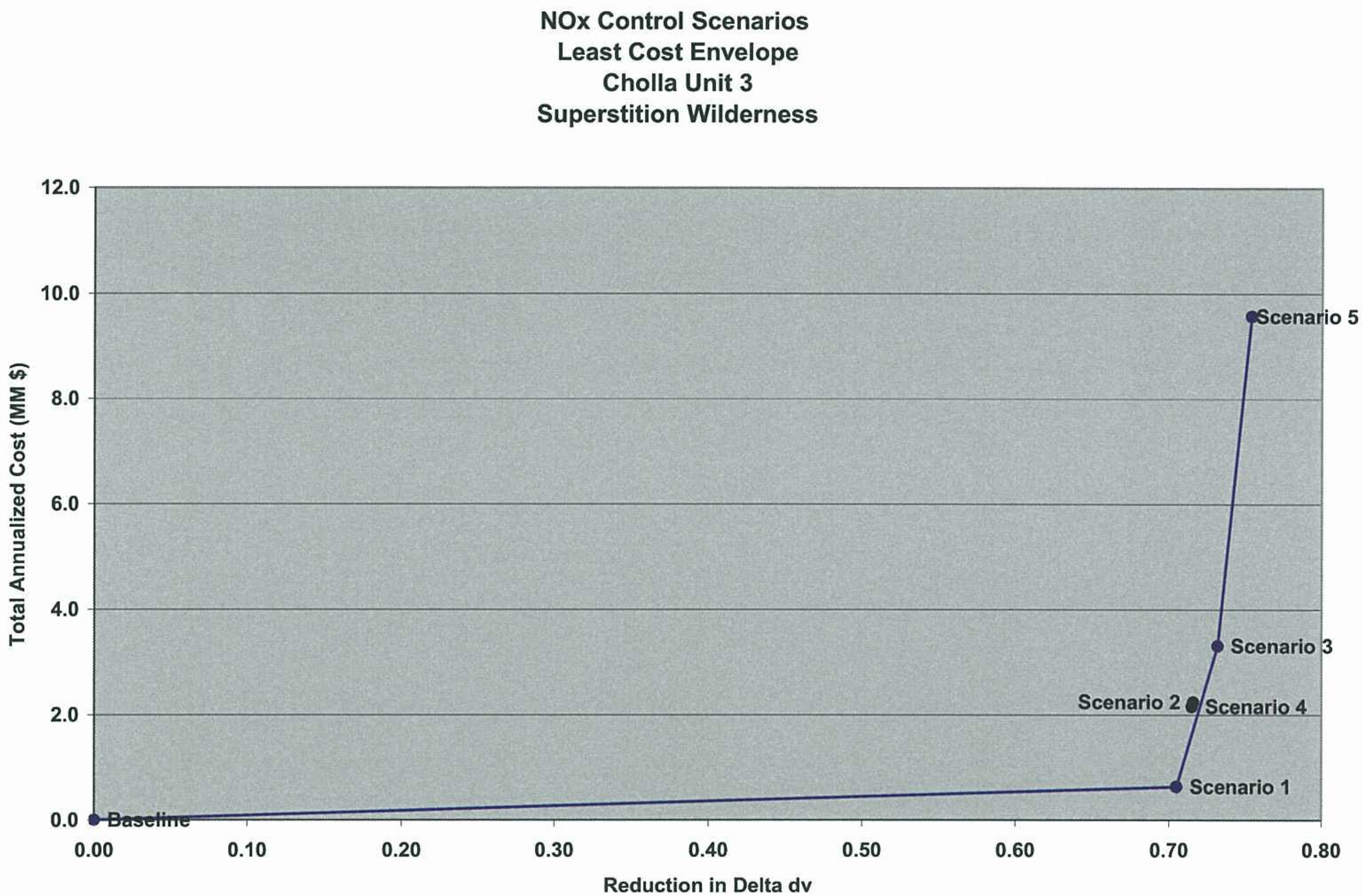

FIGURE C-22
NO_x Control Scenarios - Least Cost Envelope Galiuro Wilderness - Days Reduction
Cholla 3

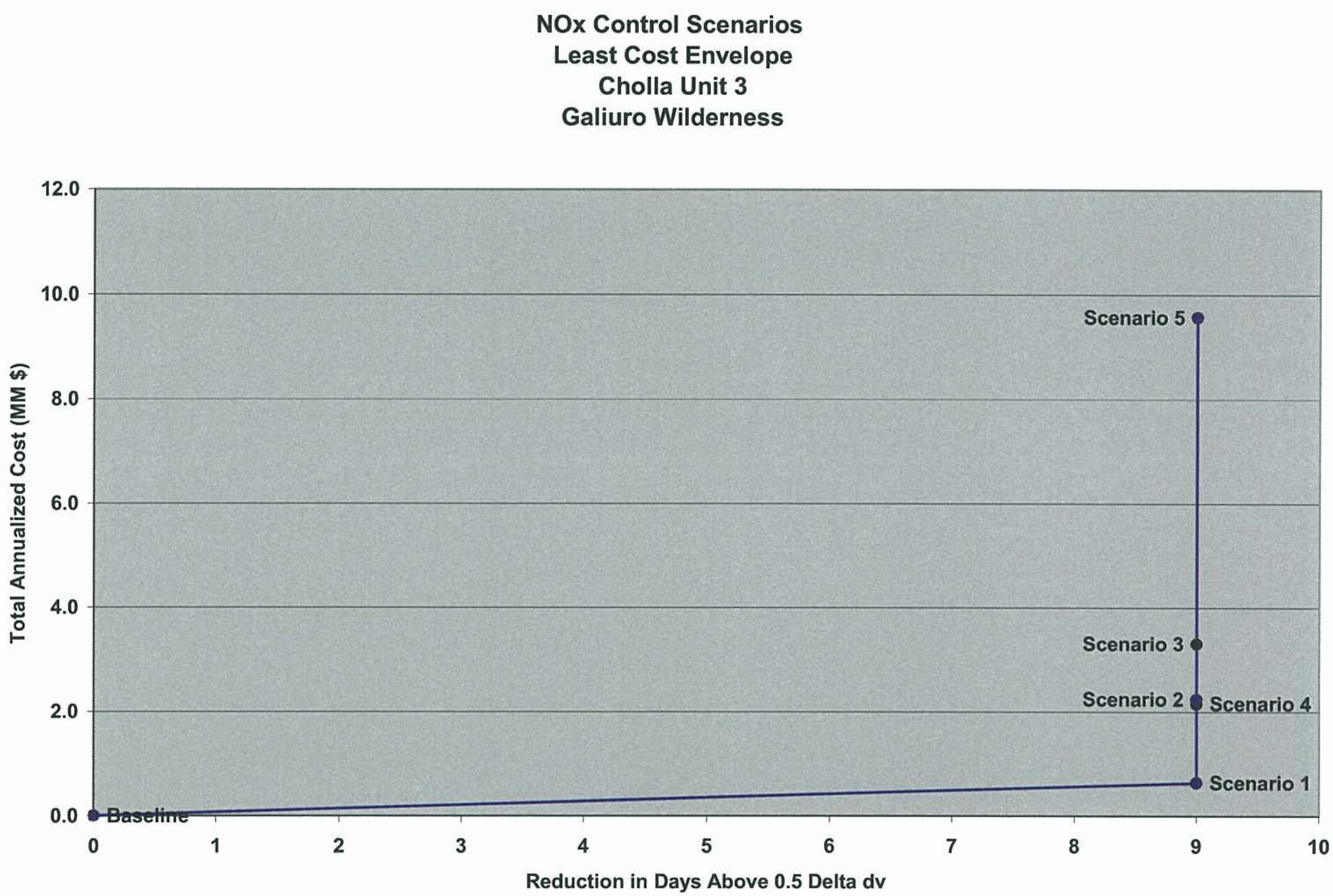

FIGURE C-23
NO_x Control Scenarios - Least Cost Envelope Galiuro Wilderness - 98th Percentile Reduction
Cholla 3

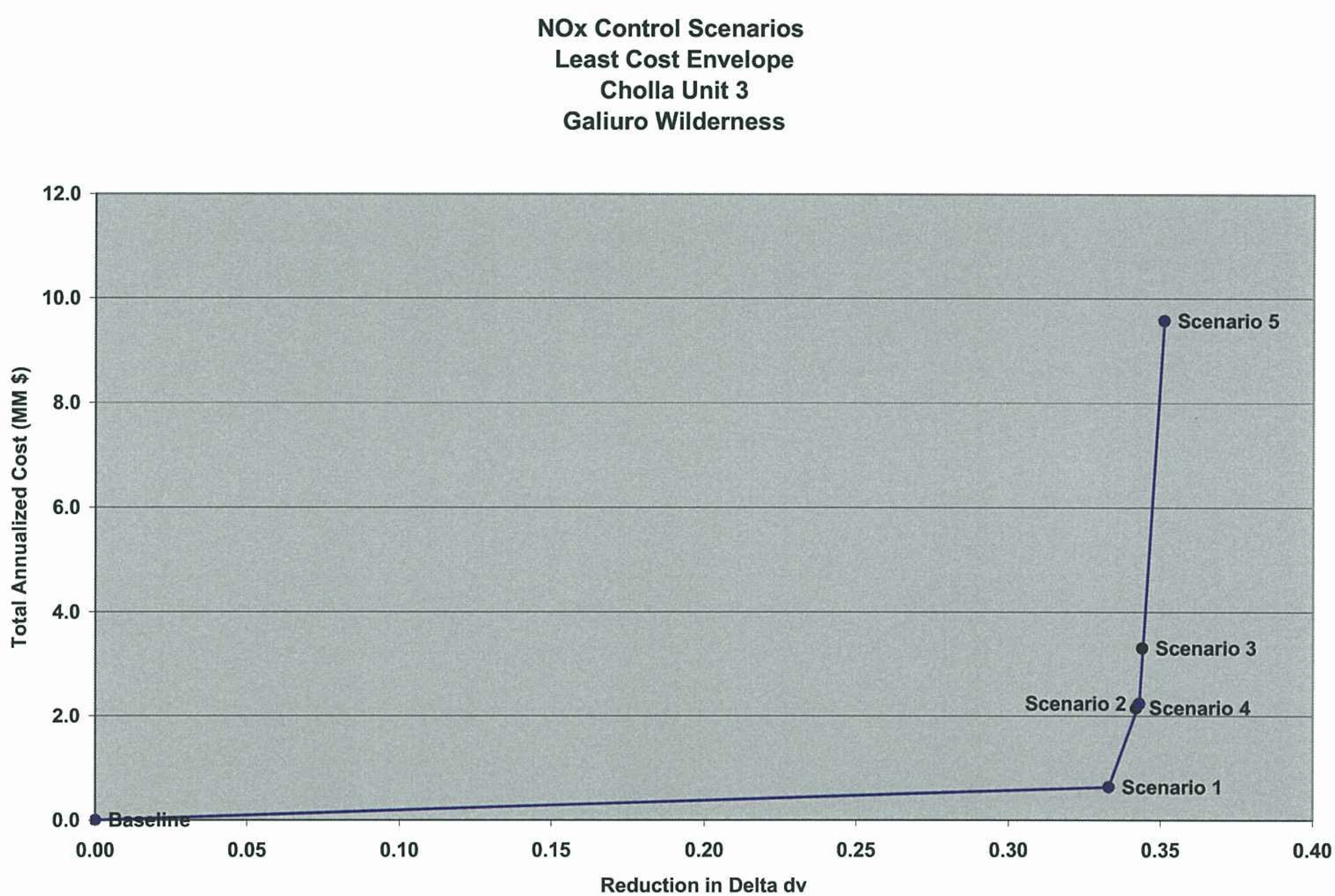

FIGURE C-24
NO_x Control Scenarios - Least Cost Envelope Mesa Verde Wilderness - Days Reduction
Cholla 3

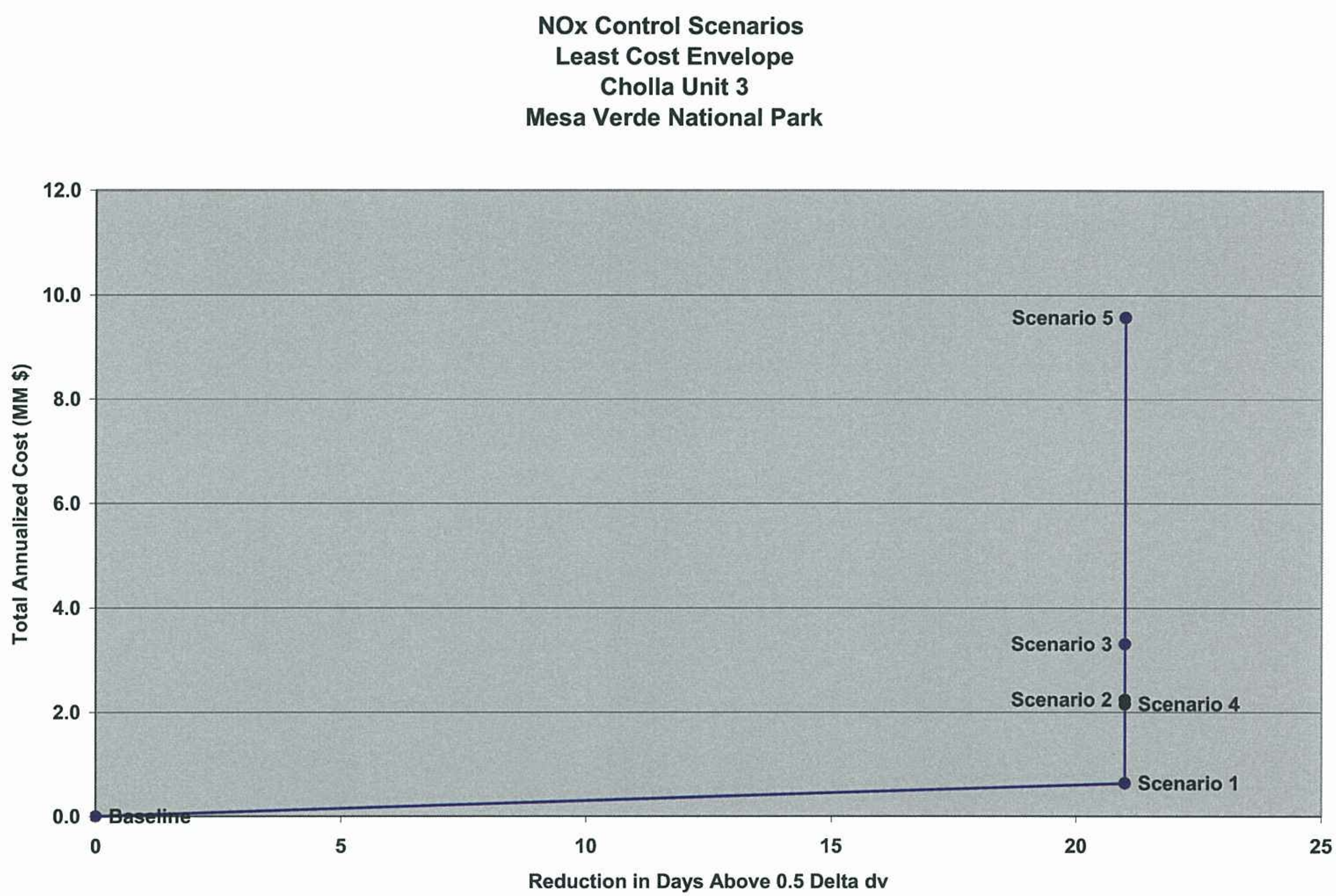

FIGURE C-25
NO_x Control Scenarios - Least Cost Envelope Mesa Verde Wilderness - 98th Percentile Reduction
Cholla 3

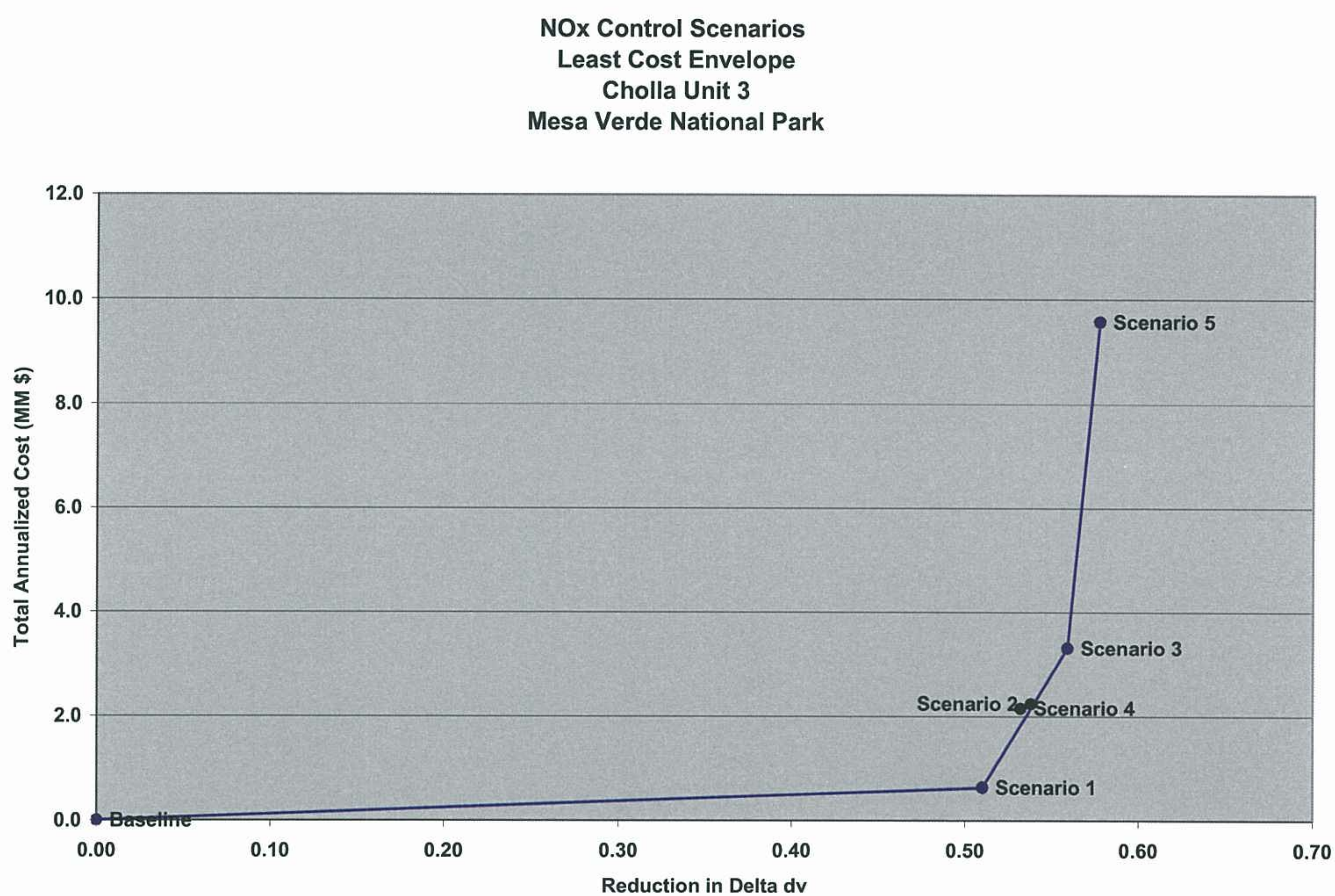

FIGURE C-26
NO_x Control Scenarios - Least Cost Envelope Saguaro NP - Days Reduction
Cholla 3

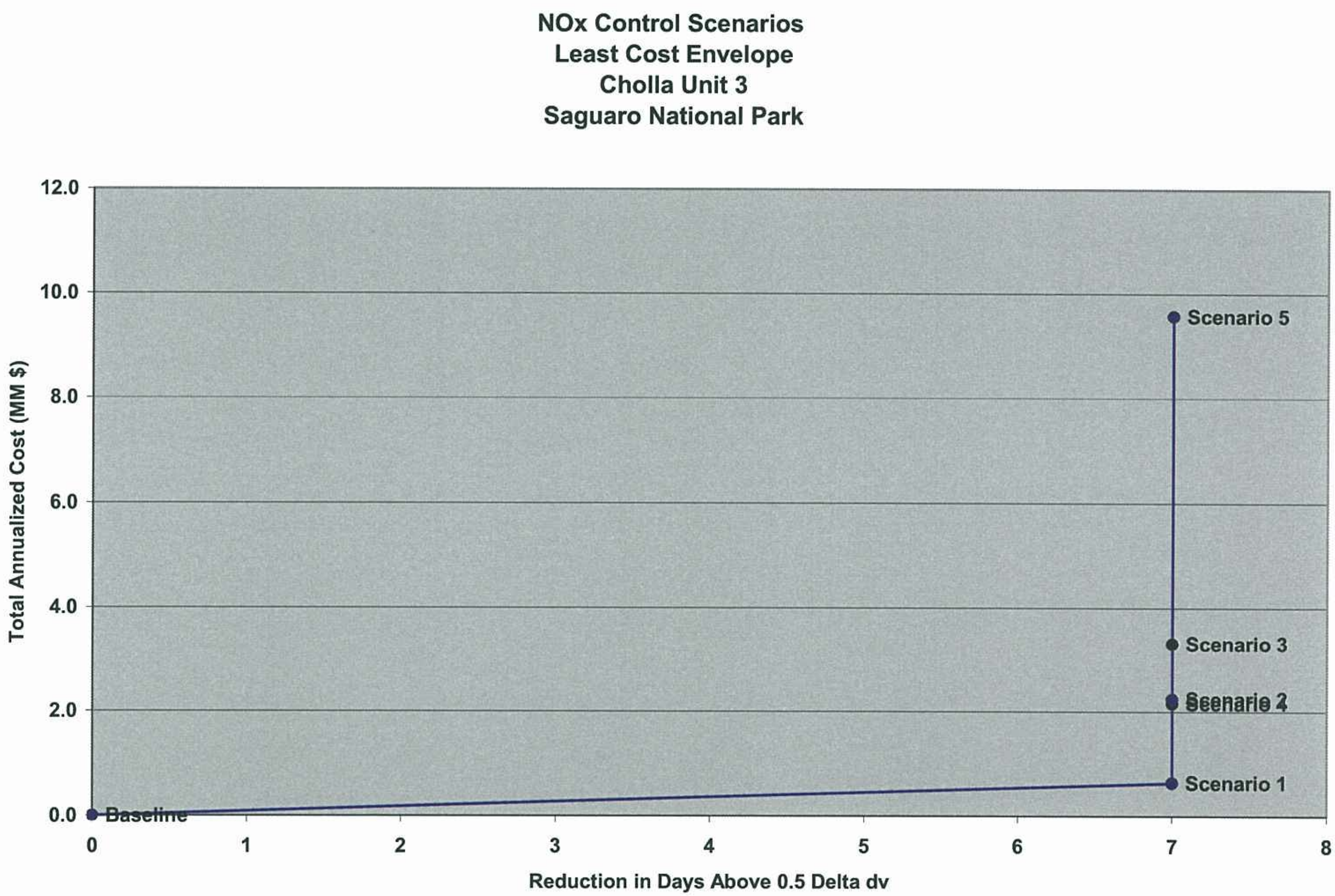

FIGURE C-27
NO_x Control Scenarios - Least Cost Envelope Saguaro NP - 98th Percentile Reduction
Cholla 3