BART Analysis for Tracy Unit 3

Prepared For:

NV Energy
6100 Neil Road
Reno, NV 89520-0024

Revised Report
October 2008

Prepared By:

CH2MHILL

2285 Corporate Circle
Henderson, NV 89074

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 NV Energy (NVE) Tracy Unit 3 (hereafter referred to as Tracy 3). A BART analysis has been conducted for 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}). The Tracy Station consists of three BART eligible units with a total nominal generating capacity of 251 megawatt (MW), of which Tracy 3 is a nominal 113-MW unit. The Title V permit allows burning Pipeline Quality Natural Gas (PNG) or blended residual (No. 2 and No. 6 and non-PCB mineral oil) fuel oil (Tracy 3 is not currently physically configured to allow burning No. 2 fuel oil). BART must be implemented within 5 years after the State Implementation Plan (SIP) is approved by the United States Environmental Protection Agency (EPA), and a compliance date of 2015 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 for when the unit is burning 1) 100 percent PNG, 2) 100 percent No. 6 fuel oil, and 3) 100 percent No. 2 fuel oil. The following technology alternatives were investigated for the PNG and both fuel oil alternatives and are listed below by pollutant:

NO_x emission controls:

- Low NO_x Burners (LNB)
- Low NOx Burners (LNG) with Flue Gas Recirculation (FGR)
- Low NO_x Burners (LNB) with selective non-catalytic reduction system (SNCR)
- Rotating opposed fire air (ROFA) with Rotamix
- LNB with selective catalytic reduction (SCR) system

SO_2 emission controls:

- Use of low sulfur fuel
- Spray Dryer Absorber (SDA)

PM_{10} emission controls:

- Use of low sulfur fuel oil (No. 2 fuel oil) and LNB
- Dry Electrostatic Precipitator (ESP)
- Wet Electrostatic Precipitator
- Fabric filter

BART Engineering Analysis

The specific steps 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 the following:

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 steps are incorporated into the BART analysis as follows:

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

- Costs associated with control technologies are summarized in the economic analysis presented in Appendix A. For clarity, Appendix A also includes sample economic analysis spreadsheet calculations and explanation of assumptions used.

Step 4 – Evaluate Energy and Non-Air Quality Impacts

- 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 2015 BART implementation date.

Establishing Emission Reduction 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, NV Energy operating and engineering data, and internal CH2M HILL historical information.

The level of accuracy of the cost estimate can be broadly classified as American Association of Cost Engineers (AACE) Class V or "Order of Magnitude," which can be categorized as +50 percent/-30 percent. There are several reasons for selecting this range of cost estimates to be included in the BART analysis. They are primarily a result of the difficulty in receiving detailed and accurate information from equipment vendors based on limited available data provided to the vendors. Because of the active power industry marketplace, obtaining engineering and construction information is restricted due to vendor workload. Material and construction labor costs also change rapidly in today's active economy. However, this level of cost estimate precision is adequate for comparison of control technology alternatives. The accuracy of expected emissions may also be questionable, and is also attributable to the inability to gain timely and accurate vendor information. This is exemplified by the difficulty in obtaining background information, and the vendor time required to develop accurate emission projections for study purposes in comparison 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 establishing emission limitations in permits, consideration of variability in cost and expected emissions information must be considered.

Fuel Characteristics

From the Title V Operating Permit, the primary fuel burned at Tracy 3 will be PNG. The secondary fuel source is blended fuel oil (blended fuel oil is defined as the blending of No. 6 residual oil and No. 2 distillate fuel oil), and a third fuel option is co-fired PNG and blended fuel oil. Only the 100 percent PNG and 100 percent fuel oil options will be examined, and no co-firing or blended fuel alternatives will be reviewed. The capability to exclusively burn No. 2 fuel oil does not currently exist, and capital expenditures would be required to allow this fuel option. This BART analysis has considered the higher nitrogen content and the different combustion characteristics of fuel oil as compared to PNG used at Tracy 3, and has evaluated the effect of these qualities on NO_x formation and achievable emission rates.

The Nevada Public Utilities Commission has mandated that Tracy Unit 3 maintain the capability to use both PNG and fuel oil. However, as a first step in the BART implementation plan, NV Energy has committed to use only low-sulfur No. 2 fuel oil. Thus, the listing of No. 6 fuel oil in the BART engineering analysis is for historical and comparison purposes only.

Recommendations

NO_x Emission Control

New LNB has been selected as the NO_x reduction technology with a NV Energy BART Limit (NVEBL) of 0.27 lb/MMBtu averaged on an annual basis. There is significant uncertainty involved in obtaining vendor emission guarantees and associated equipment/construction costs at this stage of analysis when retrofitting older boiler units. Site specific engineering is required on a "unit by unit" basis to determine the most effective control technology.

SO_2 Emission Control

The utilization of PNG and/or low-sulfur No. 2 fuel oil is BART for Tracy 3 with an NVEBL of 0.05 lb/MMBtu averaged on a 24-hour basis. No additional SO_2 emission control is required. No. 6 fuel oil will no longer be burned at the facility.

PM_{10} Emission Control

The utilization of PNG and/or low-sulfur No. 2 fuel oil is BART for Tracy 3 with an NVEBL of 0.03 lb/MMBtu averaged on a 3-hour basis. No additional PM_{10} emission control is required. No. 6 fuel oil will no longer be burned at the facility.

Control Recommendation

The BART selections include the utilization of LNB with PNG and/or low-sulfur No. 2 fuel oil, and are supported by cost and visibility analyses.

BART Modeling Analysis

CH2M HILL is using the Gaussian puff dispersion model (CALPUFF) modeling system to assess the visibility impacts of emissions from Tracy 3 at Class I areas. The Class I areas potentially affected are located more than 50 kilometers, but less than 300 kilometers, from the Tracy Plant.

The Class I areas include the following wilderness areas (WA) and National Parks (NP):

- Ansel Adams Wilderness (Minarets Wilderness)
- Caribou WA
- Desolation WA
- Emigrant WA
- Hoover WA
- John Muir WA
- Kaiser WA
- Kings Canyon NP
- Lava Beds NM
- Lassen Volcanic NP
- Mokelumne WA
- South Warner WA
- Thousand Lakes WA
- Yolla Bolly Middle Eel WA

- Yosemite NP

Visibility impacts were determined for the 1) WRAP baseline, 2) the current Title V emission permit limits, and 3) at an emission rate higher than the proposed NVEBL.

Contents

Appendices

Acronyms and Abbreviations

ACFM	actual cubic feet per minute
BACT	Best Available Control Technology
BAQP	Bureau of Air Quality Planning
BART	Best Available Retrofit Technology
Btu/gal	British thermal unit per gallon
Btu/kW-hr	British thermal unit per kilowatt-hour
Btu/scf	British thermal unit per standard cubic foot
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
CFR	Code of Federal Regulations
COHPAC	Compact Hybrid Particulate Collector
dV	deciview
ΔdV	delta deciview, change in deciview
ESP	electrostatic precipitator
EPA	United States Environmental Protection Agency
°F	degree Fahrenheit
Fuel NO_x	oxidation of fuel bound nitrogen
FGC	flue gas conditioning
FGD	flue gas desulfurization
f (RH)	relative humidity factors
hp	horsepower
H_2S	hydrogen sulfide
ID	internal diameter
kW	kilowatt
kW-Hr	kilowatt-hour
kW-Hr/Yr	kilowatt-hour per year
LAER	lowest achievable emission rate
lb	pound
lb/MMBtu	pound per million British thermal unit
LNB	low-NO_x burner

LOI	loss on ignition
MMBtu	Million British thermal unit
MM5	Mesoscale Meteorological Model, Version 5
MSL	mean sea level
MW	megawatt
N_2	nitrogen
NDEP	Nevada Department of Environmental Protection
NO	nitric oxide
NO_x	oxides of nitrogen
NP	National Park
NVE	NV Energy
NWS	National Weather Service
OFA	over-fire air
O&M	operation and maintenance
PM_{10}	particulate matter less than 10 microns in aerodynamic diameter
PNG	Pipeline Quality Natural Gas
RACT	reasonably available control technology
ROFA	rotating opposed fire air
NVEBL	NV Energy BART Limit
SCR	selective catalytic reduction system
SDA	Spray Dryer Absorber
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction system
SO_2	sulfur dioxide
SO_3	sulfur trioxide
sq. ft.	square feet
Thermal NO_x	high temperature fixation of atmospheric nitrogen in combustion air
Tracy 3	Tracy Unit 3
USGS	U.S. Geological Survey
WA	Wilderness Area

1.0 Introduction

Best Available Retrofit Technology (BART) guidelines were established as a result of United States Environmental Protection Agency (EPA) regulations intended to reduce the occurrence of regional haze in national parks and other Class I protected air quality areas in the United States[1]. These guidelines provide guidance for states when determining which facilities must install additional controls, and the type of controls that must be used. Facilities eligible for BART installation were built between 1962 and 1977, and have the potential to emit more than 250 tons/year of visibility-impairing pollutants.

The State of Nevada has identified those eligible in-state facilities that are required to reduce emissions under BART, and will set BART emissions limits for those facilities. This information will be included in the State of Nevada State Implementation Plan (SIP), which the State has estimated will be formally submitted to the EPA by December 1, 2008. The EPA BART guidelines also state that the BART emission limits must be fully implemented within five years of EPA's approval of the SIP.

There are five basic elements related to BART, when addressing the issue of emissions for the identified facilities:

- Any existing pollution control technology in use at the source
- The cost of the controls
- The remaining useful life of the source
- The energy and non-air environmental impacts of compliance
- The degree of improvement in visibility that may reasonably be anticipated from the use of such technology

This report documents the BART analysis that was performed on Tracy 3 by CH2M HILL for NV Energy. The analysis was performed for nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter less than 10 microns in aerodynamic diameter (PM_{10}), because they are the primary criteria pollutants that affect visibility for unit operation while burning both natural gas and fuel oil.

Section 2.0 of this report provides a description of the present unit operation, including a discussion of fuel sources and analysis. The BART Engineering Analysis is provided in Section 3.0, by pollutant type. Section 4.0 provides the BART modeling methodology and Section 5.0 discusses the BART analysis and recommendations. References are provided in Section 6.0. Appendices A and B provide supporting information on the Economic Analysis, and BART modeling protocol.

[1] 40 CFR Part 51: Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. 70 Federal Register, 39103-39172, July 6, 2005.

2.0 Present Unit Operation

Tracy 3 is a nominal 113-megawatt (MW) unit located in Storey County, Nevada. The unit is equipped with a front wall-fired boiler manufactured by Babcock and Wilcox. In accordance with the Title V Operating Permit, the unit can currently be fired using 1) pipeline quality natural gas (PNG), 2) blended fuel oil (blended fuel oil is defined as the blending of No. 6 residual oil and No. 2 distillate fuel oil), or 3) co-fired PNG and blended fuel oil.

Tracy 3 began operation in 1974. This analysis is based on a 23-year life for BART control technologies. Assuming a BART implementation date of 2015, this will result in an approximate remaining useful life for Tracy 3 of 23 years from the installation date of any BART-related equipment. This report does not attempt to quantify any additional life extension costs needed to allow the unit at Tracy 3 to operate until 2038.

Determining current operating NO_x levels before any potential emissions control equipment installation is difficult, especially because higher NO_x emissions can be expected at higher unit operating loads. Therefore, PNG current NO_x level is approximated by averaging the highest 75 percent load 24-hour NO_x emission levels for the year 2006 EPA Acid Rain Database. As a simplifying assumption, No. 2 fuel oil NO_x emissions are assumed to be equal to PNG. The No. 6 fuel oil NO_x emissions were estimated by averaging the 24-hour NO_x values for the year 2001 EPA Acid Rain Database. Tracy Unit 3 burned No. 6 fuel oil for a few months during the Western energy crisis in 2001. The SO_2 emissions were also estimated from the EPA Acid Rain Database. PM_{10} values were determined either by test results or AP-42 calculations.

The BART regulations state that the baseline emissions utilized for visibility modeling be established by identifying the highest 24-hour average actual emission rate from the period modeled for the pre-control scenario. Modeling would then consider the expected emissions rate after the installation of BART controls to establish the level of visibility improvement.

For the pre-control scenario, modeling was conducted at the WRAP 24-hour maximum values and at the Title V permit limits for the unit. The post-control scenario was modeled at the proposed NVEBL (discussed in Sections 3, 4, and 5), with the exception of the NO_x emission rate which is higher than the NVEBL.

Table 2-1 lists unit information and emission rates for this analysis.

TABLE 2-1
Unit Operation and Study Assumptions
Tracy Unit 3

General Plant Data	
Site Elevation (feet above MSL)	4,262
Stack Height (feet)	300
Stack Exit ID (feet) /Exit Area (sq. ft.)	9.0 /63.62
Stack Exit Temperature (°F)	312
Stack Exit Velocity (ft/sec)	77.8
Annual Unit Capacity Factor (%)	58
Net Unit Output (Nominal MW)	113
Net Unit Heat Rate (Btu/kW-Hr)(100% load)	10,177
Boiler Heat Input (MMBtu/Hr)(100% load)	1,150
Type of Boiler	Front Wall fired
Boiler Fuel	PNG, Blended Fuel Oil
NO_x Emissions Data (24-hour Average Maximum)	
Current NO_x Controls	None: Good combustion practices
Title V NO_x Permit Limit (lb/MMBtu)	0.45
WRAP NO_x Emission Rate (lb/MMBtu)	0.315
NOx Emission Rate (lb/MMBtu) (PNG)[d]	0.292
NO_x Emission Rate (lb/MMBtu) (No.6 Fuel Oil) [a]	0.323
NOx Emission Rate (lb/MMBtu) (No.2 Fuel Oil) [d]	0.292
SO_2 Emissions Data (24-hour Average Maximum)	
Current SO_2 Controls	None
Title V SO_2 Permit Limit (lb/MMBtu) (3-hr average)	0.76
WRAP SO_2 Emission Rate (lb/MMBtu)	0.540
SO_2 Emission Rate (lb/MMBtu) (PNG) [e]	0.0006
SO_2 Emission Rate (lb/MMBtu) (No.6 Fuel Oil) [a]	0.445
SO_2 Emission Rate (lb/MMBtu) (No.2 Fuel Oil) [b]	0.051
PM_{10} Emissions Data (24-hour Average Maximum)	
Current PM_{10} Controls	None
Title V PM_{10} Permit Limit (lb/MMBtu) (1-hr average)	0.20
WRAP PM_{10} Emission Rate (lb/MMBtu)	0.053
PM_{10} Emission Rate (lb/MMBtu) (PNG)[e]	0.008
PM_{10} Emission Rate (lb/MMBtu) (No.6 Fuel Oil) [c]	0.065
PM_{10} Emission Rate (lb/MMBtu) (No.2 Fuel Oil) [b]	0.014

[a] - Highest 24-hr averages from 2001 CEM data.
[b] - Calculated from EPA AP-42 Table 1.3-1 assuming No. 2 fuel oil sulfur content of 0.05 percent and heating value of 140,000 Btu/gal
[c] - Calculated from EPA AP-42 Table 1.3-1 assuming No. 6 fuel oil sulfur content of 0.75 percent and heating value of 156,000 Btu/gal
[d] – Highest 24-hr averages from 2006 CEM data.
[e] – Calculated from EPA AP-42 Table 1-4.2

EPA did not establish a NO_x presumptive limit for oil- and gas-fired units, but indicates that the states should consider the installation of combustion control technology on these units. Similarly, EPA also did not establish a presumptive BART limit for SO_2 from gas and oil-fired units. The EPA guidelines suggest that a cost effective SO_2 control option for oil-fired units is to consider switching to a low-sulfur fuel oil (No.2 fuel oil—0.05 percent sulfur diesel). EPA also stated that it was unable to find a flue gas desulfurization (FGD) application in the U.S. electric industry on an oil-fired unit.

According to 40 CFR Parts 72 and 75, in order for a gaseous fuel to qualify as "natural gas," the fuel must be either greater than or equal to 70 percent methane by volume, or must have a gross calorific value between 950 and 1,100 British thermal units (Btu)/standard cubic foot (scf). For PNG, the hydrogen sulfide (H_2S) content must be less than or equal to 0.3 grain/100 scf, and H_2S must constitute at least 50 percent (by weight) of the total sulfur in the fuel.

No fuel specification was provided for No. 2 fuel oil, therefore a heating value of 140,000 Btu/gal and a sulfur limit of 0.05 percent were assumed. Heating value for No. 6 fuel oil was assumed at 155,000 Btu/gal.

Specification values for No. 6 fuel oil are listed below:

- 6.1 to 6.45 MMBtu/barrel heating value
- 0.39 lb of sulfur/MMBtu
- Less than 0.1 percent ash by weight
- Less than 50 parts per million (ppm) vanadium
- Less than 50 ppm sodium
- Less than 9.7 percent carbon residue by weight

The BART analysis for Tracy 3 includes a review of PNG, No. 2 fuel oil, and No. 6 fuel oil operation. The WRAP baseline modeling included 2001 operation when No. 6 fuel oil was burned. Therefore, this fuel option is shown in the analysis.

The Nevada Public Utilities Commission has mandated that Tracy Unit 3 maintain the capability to use both PNG and fuel oil. However, as a first step in the BART implementation plan, NV Energy has committed to use only low-sulfur No. 2 fuel oil. Thus, the listing of No. 6 fuel oil in the BART engineering analysis is for historical and comparison purposes only.

3.0 BART Engineering Analysis

This section presents the required BART engineering analysis.

3.1 Applicability

In compliance with regional haze requirements, the State of Nevada must prepare and submit visibility SIPs to the EPA for Class I areas. The State has estimated that the formal submittal of the SIPs to EPA will occur by December 1, 2008. The first phase of the regional haze program is the implementation of BART emission controls on all BART eligible units, within 5 years after EPA approval of the SIP.

3.2 BART Process

The specific steps in a BART engineering analysis are identified in 40 CFR 51 Appendix Y, Section IV. The evaluation must include the following:

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 that may reasonably be anticipated from the use of BART.

These steps are incorporated into the BART analysis as follows:

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

- Costs associated with control technologies are summarized in the economic analysis presented in Appendix A. For clarity, Appendix A also includes sample economic analysis spreadsheet calculations and explanation of assumptions used.

Step 4 – Evaluate Energy and Non-Air Quality Impacts

- 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 BART use.

In order to minimize costs in the BART analysis, 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. In some cases, enhancing the performance of the existing control equipment was considered. Other scenarios with new control equipment were also developed.

Separate analyses have been conducted for NO_x, SO_2, and PM_{10} emissions. Because Tracy 3 currently has the option to burn PNG, No. 2 fuel oil, or a blended No. 6 fuel oil, a separate analysis will be completed for each case. The option to switch to low sulfur fuel oil (No. 2) will be examined, as required by the BART regulations.

For Tracy 3, baseline NO_x, SO_2, PM_{10} emissions were examined to determine whether completion of the five-step BART process is required for each of the three fuel alternatives (100 percent PNG, 100 percent No. 6 fuel oil, and 100 percent No. 2 fuel oil).

Table 3-1 below is a summary of the baseline emissions for Tracy 3.

TABLE 3-1
Current Tracy 3 Baseline Emissions

Baseline Emissions (lb/MMBtu)	PNG	No. 6 Fuel Oil	No. 2 Fuel Oil
NO_x	0.292	0.323	0.292
SO_2	0.0006	0.445	0.051
PM_{10}	0.008	0.065	0.014

A BART NO_x analysis was completed for all fuels. An SO_2 analysis and a PM_{10} analysis for No. 6 fuel oil were completed for comparison purposes (as stated in Section 2 of this report. NV Energy has made a commitment to only use low-sulfur No. 2 fuel oil). The baseline PM_{10} and SO_2 emissions when burning No. 2 fuel oil are considered BART, based on EPA BART guidelines.

All costs included in the BART analysis are in 2007 dollars, and costs have not been escalated to the assumed 2015 BART implementation date.

Establishing Permit Emission Reduction 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, NV Energy 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 percent. There are several reasons for the wide range of cost estimates included in the BART analysis, however are primarily caused by the difficulty in receiving detailed and accurate information from equipment vendors. Because of the extremely active power industry marketplace, obtaining engineering and construction 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 must be considered.

3.2.1 BART NO_x Analysis

NO_x formation in natural gas-fired boilers is a complex process that is dependent on a number of variables, including operating conditions, equipment design, and fuel characteristics. A NO_x BART analysis will be completed for the cases when Tracy 3 burns 100 percent PNG, 100 percent No. 6 fuel oil, and 100 percent No. 2 fuel oil.

3.2.1.1 Formation of NO_x

During combustion NO_x is formed in three different ways; thermal NO_x, fuel NO_x, and prompt NO_x. When combusting PNG, the most dominant source of NO_x is from thermal NO_x, which is due to high temperature fixation of atmospheric nitrogen in the combustion air. Because PNG generally contains small quantities of nitrogen the overall contribution from fuel NO_x is small, while fuel NO_x can be generated from fuel oil combustion. 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.

Good combustion is based on the "three Ts": time, temperature and turbulence. If a performance requirement such as NO_x emission limits is changed, conflicts with other performance issues can result.

When adjusting air flows and distribution to lower NO_x using LNB and over-fire air (OFA), original boiler design restrictions may limit the changes that can be made and still achieve satisfactory combustion performance.

3.2.1.2 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 Tracy 3, including those control technologies identified as BACT by permitting agencies across the United States. A broad range of information sources have been reviewed in an effort to identify potentially applicable and demonstrated in practice emission control technologies. Tracy 3 NO_x emissions are currently controlled through the use of good combustion practices. There is no BART presumptive NO_x level for PNG and oil-fired units.

The following potential NO_x control technology options were considered:

- Low NO_x Burners (LNB)
- Low NOx Burners (LNB) with Flue Gas Recirculation (FGR)
- Low NO_x Burners (LNB with Selective non-catalytic reduction system (SNCR)
- Rotating Opposed Fire Air (ROFA) with Rotamix
- LNB with selective catalytic reduction system (SCR)

3.2.1.3 Step 2: Eliminate Technically Infeasible Options

For Tracy 3, a front wall-fired configuration burning PNG and fuel oil, technical feasibility will primarily be determined by physical constraints, boiler configuration, and on the ability of the technology to achieve NO_x emissions reduction. Current NO_x emissions for Tracy 3 are shown in Table 3-1 while burning PNG, No. 6 fuel oil, and No. 2 fuel oil.

For this BART analysis, information received from Coen ws used as the basis for new LNB and LNB w/FGR. Coen did not propose the installation of OFA due to the cost of boiler water wall changes. The cost estimates for SCR and SNCR were updated from previous CH2M HILL file information and Fuel Tech budgetary proposal respectively. Also, CH2M HILL received a proposal from Mobotec for their ROFA and Rotomix technologies.

Table 3-2 summarizes the control technology options evaluated in this BART analysis, along with projected NO_x emission rates. It should be noted that estimated emissions information from NO_x technologies presented represent design targets. With a significant potential for variability in emissions due to changes in unit operation, a longer averaging period results in a higher probability in meeting the permit emissions value. Emissions based on a 24-hour averaging period are not directly comparable to emissions targets based on a longer averaging time.

TABLE 3-2
NO_x Control Technology Emission Rate Ranking
Tracy Unit 3

Technology	Source of Estimated Emissions	Estimated Emission Rate (lb/MMBtu) (PNG)	Estimated Emission Rate (lb/MMBtu) (No.6 Fuel Oil)	Estimated Emission Rate (lb/MMBtu) (No.2 Fuel Oil)
Current Permit Limits (converted to lb/MMBtu for comparison)	Title V	0.45	0.45	0.45
NV Energy (NVE) BART Limits	NVEBL[d]	0.27 (Annual)	N/A	0.27 (Annual)
LNB	Coen	0.25	0.27	0.25
LNB w/FGR	Coen	0.11	0.23	0.13
LNB w/ SNCR	Coen & Fuel Tech	0.19 [c]	0.20 [c]	0.19 [c]
ROFA w/Rotamix	Mobotec	0.16	0.18 [b]	0.16
LNB w/SCR [a]	CH2M HILL	0.07	0.07	0.07

[a] - SCR estimated NO_x emissions rate is the same for all scenarios. Operating cost would be affected by inlet NO_x levels.
[b] - Calculated from Mobotec proposal information and No. 6 fuel oil baseline NO_x. Estimated percent reduction for PNG from proposal and applied to fuel oil No. 6
[c] - From Coen and Fuel Tech Proposal, a 25 percent reduction of LNB emission rate
[d] – NVEBL – Based on Coen information for LNB and FGR.

3.2.1.4 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 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. Also, emission rates are typically based on a design average value (i.e., 30-day rolling average) versus a maximum 24-hour value. The following subsections describe the control technologies and the control effectiveness evaluated in this BART analysis.

Level of Confidence for Vendor Post-Control 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 natural gas-fired generating units was completed. As a result of this review, it was noted that NO_x emissions can vary around an average emissions level. This variance can be attributed to many reasons, including fuel characteristics, unit load, boiler operation including excess air, burner equipment condition, 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, fuel 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 control technologies and the control effectiveness evaluated in this NO_x BART analysis.

New LNB The mechanism used to lower NO_x with LNB 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. LNB is considered to be a capital cost, combustion technology retrofit that may require water wall tube replacement.

FGR. Flue Gas Recirculation (FGR) generally extracts flue gas from downstream of the economizer or air heater, and is mixed into the combustion air duct. This recirculation can be achieved with a new FGR fan, or by using the existing forced draft (FD) fan to inject the flue gas into the combustion air (induced flue gas recirculation). FGR adds oxygen-lean heat-absorbing mass to the combustion air, thus lowering the combustion temperature and reducing NO_x emissions.

Neural Net Controls. Information regarding neural net controls was 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 NOx reduction technologies. NeuCo predicts that CombustionOpt can reduce NO_x by 15 percent, and SootOpt can provide an additional 5 to 10 percent. Because NeuCo does not offer guarantees on this projected emission reduction, a nominal reduction of 15 percent was assumed for evaluation purposes. The budgetary price for CombustionOpt and SootOpt were $150,000 and $175,000, respectively, with an additional $200,000 for a process link to the unit control system. Because NeuCo does not guarantee NO_x reduction, the estimated emission reduction levels provided cannot be considered as reliable projections. Therefore, neural net should be considered as a supplementary or “polishing” technology, but not on a “stand-alone” basis.

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, 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. The combustion air is also mixed more effectively". A typical ROFA installation will have a booster fan(s) to supply the high-velocity air to the ROFA boxes, and Mobotec would propose one 320 horsepower (hp) fan for Tracy 3.

Mobotec's budgetary proposals included expected NO_x emission rates for PNG and No. 2 and No. 6 fuel oils, and are presented in Table 3-2 above. While a typical installation does not require changes to the existing LNB system, , results of computational fluid dynamics modeling will determine the quantity and location of new ROFA ports. Although not specifically identified, Mobotec generally includes bent tube assemblies for ROFA port installation if required. Mobotec does not provide installation services, because they believe that the owner can more cost effectively contract for these services. However, they do provide one onsite construction supervisor during installation and startup.

Due to previous experience with ROFA, NVE does not consider ROFA as a stand-alone technology option.

ROFA w/Rotamix. As described above, ROFA is marketed as an improved OFA system. Rotamix is Mobotec's technology for adding selective non-catalytic reduction using an ammonia or urea based reagent.

SNCR. Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. 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 degrees Fahrenheit (°F) to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60 percent have been achieved, although 20 to 40 percent is more realistic for most applications.

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 react with sulfur to foul heat exchange surfaces and/or create a visible stack plume. Reagent utilization can have an impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost.

Reductions from higher baseline concentrations (inlet NO_x) are lower in cost per ton, but result in higher operating costs, due to greater reagent consumption. A budgetary proposal was received from Fuel Tech.

SCR. SCR works on the same chemical principle as SNCR but SCR uses a catalyst to promote the chemical reaction. Ammonia 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 any particulate in the flue gas that leaves the boiler. 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. Because of the higher removal rate, a full-scale SCR was used as the basis for analysis at Tracy 2. From previous SCR design experience, a projected NO_x emission rate of 0.07 lb/MMBtu is projected for all emissions control equipment scenarios assuming current equipment can meet retrofit requirements.

3.2.1.5 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. The installation of LNB is not expected to greatly impact the boiler efficiency or FD fan power usage. Therefore, these technologies will not have energy impacts.

The Mobotec ROFA system requires installation and operation of one 320 hp ROFA fan (239 kilowatts [kW] total). An estimated auxiliary power requirement for an SNCR system for a nominal 83-MW unit is estimated at 83 kW. 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.

The energy impacts summarized above are included in the economic analysis presented in Appendix A.

Environmental Impacts. SNCR, Rotamix, and SCR installation could potentially create a visible stack plume, which may negate other visibility improvements. Other environmental impacts involve the storage of ammonia, especially if anhydrous ammonia is used, and the transportation of the ammonia to the power plant site.

These environmental impacts have not been quantified in the economic analysis presented in Appendix A.

Economic Impacts. Costs and emissions estimates for LNB, LNB w/FGR, SNCR, and SCR were obtained from equipment vendors. Costs for the ROFA and Rotamix systems were obtained from Mobotec.

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 in Figure 3-1.

The capital costs shown in Table 3-3 are applicable for all of the fuels under consideration. For example, if LNB are installed for PNG, the burner costs include the capability to burn both PNG and No. 2 and 6 fuel oils (with only minor equipment changes, atomization changes, and burner control revisions). Similarly, the cost information for any of the NO_x reduction technologies listed in Table 3-3 will apply for the fuel alternatives under consideration.

The complete Economic Analysis is contained in Appendix A.

3.2.1.6 Step 5: Evaluate Visibility Impacts

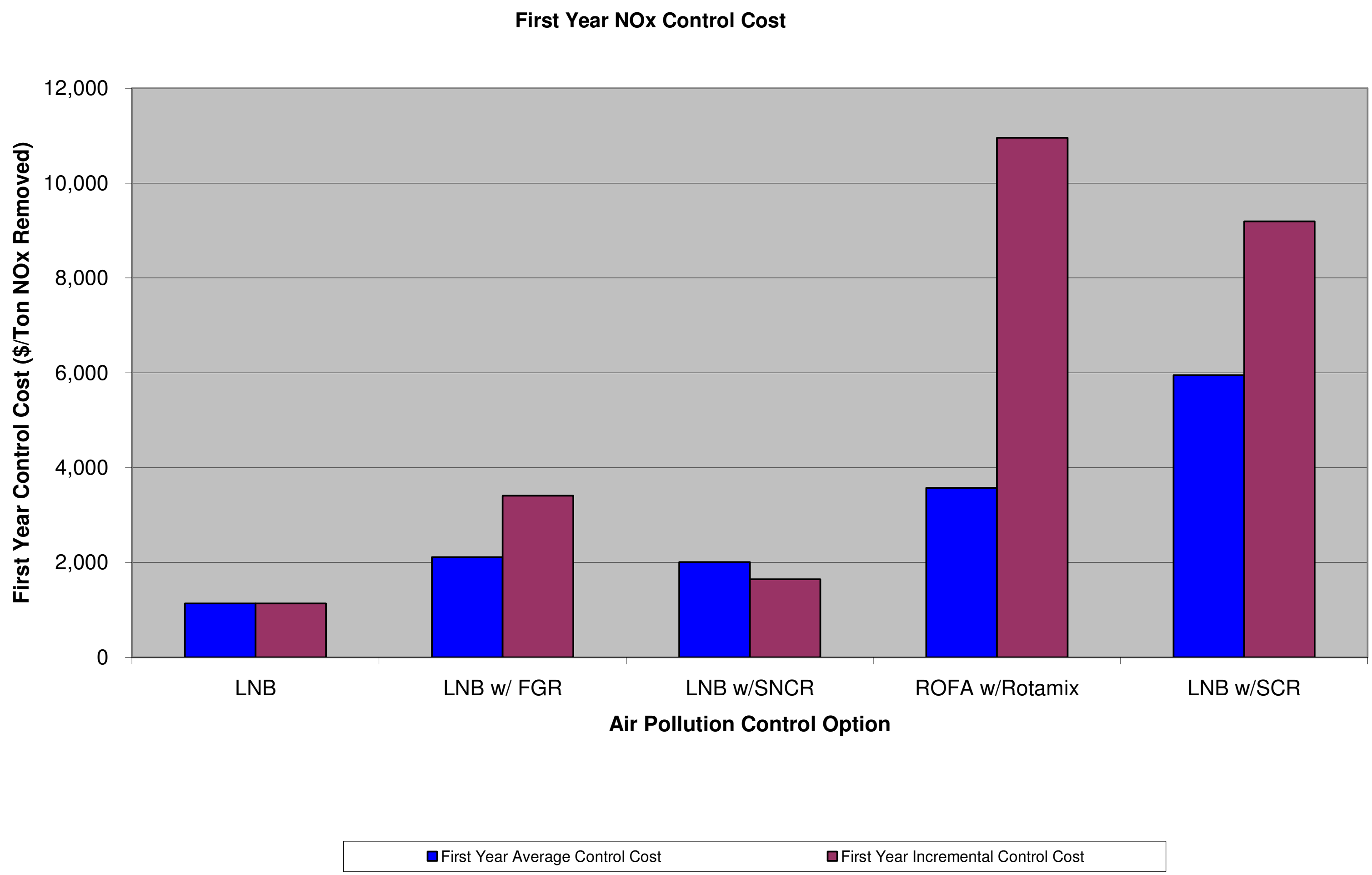
Please see Section 4.0, BART Modeling Analysis.

TABLE 3-3
NO_x Control Cost Comparison using Fuel Oil #6
Tracy Unit 3

Factor	LNB	LNB w/ FGR	LNB w/SNCR	ROFA w/Rotamix	LNB w/SCR
Total Installed Capital Costs	$704,000	$1,184,000	$2,532,500[b]	$5,250,940[a]	$28,690,000
Total Installed Capital Costs with Additional Owner Costs	$1,232,000	$2,072,000	$4,431,875	$9,189,145	$35,862,500
Total First Year Fixed & Variable O&M Costs	$45,200	$354,865	$236,432	$548,326	$593,848
Total First Year Annualized Cost	$175,861	$574,613	$706,459	$1,522,890	$4,397,281
Power Consumption (MW)	-	1.13	0.11	1.24	0.57
Annual Power Usage (Million kW-Hr/Yr)	-	5.7	0.6	6.3	2.9
NO_x Design Control Efficiency	16.4%	28.8%	37.3%	45.2%	78.3%
Tons NO_x Removed per Year	155	272	352	427	739
First Year Ave Control Cost ($/Ton NO_x Removed)	1,136	2,115	2,007	3,570	5,949
Incremental Control Cost ($/Ton NO_x Removed)	1,136	3,412	1,641	10,959	9,195

[a] Based on 75/25 installation cost split between ROFA and Rotamix
[b] Fuel Tech equipment estimate plus 50 percent installation cost

FIGURE 3-1
First Year Control Cost for NO_X Air Pollution Control Options
Tracy Unit 3



3.2.2 BART SO_2 Analysis

SO_2 forms in the boiler during the combustion process, and is primarily dependent on natural gas and fuel oil sulfur content. The BART analysis for SO_2 emissions on Tracy 3 is described below. The analysis completed in Section 3.2 is for the case when burning No. 6 fuel oil.

However, the EPA BART guidelines require that oil-fired units consider limiting the sulfur content of the fuel oil burned. Because current requirements for low sulfur diesel fuel limits sulfur content to 0.05 percent, fuel switching will be analyzed as an SO_2 option for this study. A flue gas desulphurization system (a spray dryer absorber) with similar SO_2 reduction capability as the fuel switch option will be considered. It should be noted that the Nevada Public Utilities Commission has mandated that the Tracy units have both PNG and fuel oil capability.

3.2.2.1 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 Tracy 3; this included control technologies identified as BACT by permitting agencies across the United States.

The following potential SO_2 control technology options were considered:

- Use of low sulfur distillate oil (No. 2 fuel oil)
- Spray Dryer Absorber (SDA)

3.2.2.2 Step 2: Eliminate Technically Infeasible Options

Technical feasibility will primarily be determined by fuel storage delivery constraints, boiler configuration, and on the ability of low sulfur fuel oil to achieve SO_2 emissions reduction. Table 3-4 summarizes the control technology options evaluated in this BART analysis.

TABLE 3-4
Control Technology Options Evaluated
Tracy Unit 3

Technology	Estimated SO_2 Removal Efficiency (%)	Estimated Emission Rate (lb/MMBtu)
Current Title V Permit Limitation (converted to lb/MMBtu for comparison)	N/A	0.76
NVE BART Limit (Low Sulfur No. 2 Fuel Oil)	93%	0.05 (24-hr average)
Spray Dryer Absorber	90%	0.10
PNG	99%	0.0006

3.2.2.3 Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

When evaluating the control effectiveness of SO_2 reduction technologies, each option can be compared to the proposed NVE BART Limit. With a fuel switch to low sulfur diesel, the expected SO_2 emissions are estimated at this level. While an SDA is estimated to achieve approximately a 90 percent reduction in SO_2, with an anticipated emission rate of 0.10 lb/MMBtu. Because Tracy 3 is not currently capable of burning 100% No. 2 fuel oil, capital improvements would be required.

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

Use of low sulfur distillate oil (No. 2 fuel oil)
This alternative entails the use of a low sulfur (0.05 % sulfur) diesel in lieu of No. 6 fuel oil.

Spray Dryer Absorber (SDA)
A spray dryer absorber 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. For Tracy 3, this dry particulate matter would be captured downstream in a baghouse which would be required in conjunction with the SDA. A lime spray dryer system typically produces a dry waste product suitable for landfill disposal. Emissions from an SDA are estimated to meet an emissions level of 0.10 lb/MMBtu.

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. There is no energy impact associated with switching to low sulfur diesel fuel, however additional system pressure drop will result from an installation of an SDA.

No energy impact costs are included in the economic analysis presented in Appendix A.

Environmental Impacts. There is no environmental impact associated with switching to low sulfur diesel fuel or installation of an SDA.

No environmental impact costs have been quantified in the economic analysis presented in Appendix A.

Economic Impacts. A summary of the costs and amount of SO_2 removed for fuel switching is provided in Table 3-5.

TABLE 3-5
SO_2 Control Cost
Tracy Unit 3

Factor	Spray Dryer Absorber	Switch to Low Sulfur Fuel
Total Installed Capital Costs	\$22,000,000	\$500,000[a]
Total First Year Fixed & Variable Operations & Maintenance Costs	\$544,154	-
Total First Year Annualized Cost	\$2,877,386	-
Power Consumption (MW)	0.40	-
Annual Power Usage (kW-Hr/Yr)	2.0	-
SO_2 Design Control Efficiency	84.8%	93%
Tons SO_2 Removed per Year	1,633	-
First Year Average Control Cost (\$/Ton of SO_2 Removed)	1,762	-
Incremental Control Cost (\$/Ton of SO_2 Removed)	1,762	-

[a] Per unit cost based on Zachry study for fuel switch to No. 2 fuel oil for Tracy Station. Does not include fuel cost differential.

The complete Economic Analysis is contained in Appendix A.

3.2.2.5 Step 5: Evaluate Visibility Impacts

Please see Section 4.0, BART Modeling Analysis.

3.2.3 BART PM_{10} Analysis

Tracy 3 currently is not equipped with a PM_{10} control device. The BART analysis for PM_{10} emissions at Tracy 2 is described below. From the analysis completed in Section 3.2, a PM_{10} BART analysis will only be completed for the case when Tracy 3 burns 100 percent No. 6 fuel oil. The current baseline PM_{10} emissions, while burning PNG or No. 2 fuel oil, already meets the BACT emissions level.

3.2.3.1 Step 1: Identify All Available Retrofit Control Technologies

The following retrofit control technologies have been identified for additional PM_{10} control:

- Use of low sulfur fuel oil (No. 2 fuel oil) and LNB
- Dry Electrostatic Precipitator
- Wet Electrostatic Precipitator
- Fabric filter

3.2.3.2 Step 2: Eliminate Technically Infeasible Options

Low Sulfur Distillate Oil andLNB. PM_{10} emissions would be reduced with the switching of fuel oil grades from No. 6 to No. 2 and the utilization of LNB. PM_{10} emissions while burning No. 2 fuel oil are estimated to meet the NVE BART Limit of 0.03 lb/MMBtu.

Dry Electrostatic Precipitator. A dry ESP operates by first placing a charge on the particulates though a series of electrodes, and then capturing the charged particulates on collection plates. While an ESP can be designed for high-particulate removal, operation is susceptible to particle resistivity, which denotes a collected particle's ability to ultimately discharge to the collection plate. Low-resistivity particles can be easily charged but may quickly lose their charge at the collection plate and tend to be re-entrained into the flue gas stream. Higher resistivity particles may form a "back corona," which is caused by a layer of non-conductive particles being formed on the collection plate. Back corona may prevent other charged gas stream particles from migrating to the collection plate. Particle resistivity is also influenced by flue gas temperature. ESP sizing is in large part determined by particulate size, with larger ESP size required when smaller particulates are expected. In addition, the particulates from an oil-fired unit tend to be small and sticky, and if an SDA is utilized for SO_2 reduction, there will be a greatly increased inlet particulate loading to the ESP.

Because of the uncertainty in chemical and physical characteristics of the oil-fired particulate, and the increased loading from a SDA, a dry ESP is not a good technological match for Tracy 3.

Wet Electrostatic Precipitator. While wet ESP operation is similar to the dry ESP through the charging and collection of flue gas particulates, the wet technology has advantages. The wet ESP is not sensitive to particulate resistivity and can accommodate changes in particulate loading more easily than a dry ESP. Collection plates can be fabricated from metal or fabric, and the collected particulate is washed off the plates with water.

Wet ESPs have successfully been demonstrated on similar oil particulate or chemical mist applications. However, flue gas leaving the wet ESP will be saturated and may result in a visual steam plume exiting the stack. The wet ESP will utilize water to collect and remove the particulates, and will produce a wastewater byproduct.

While the wet ESP PM_{10} emission level is estimated to be similar to a fabric filter without SDA operation, increased particulate loading from an SDA may not allow a wet ESP to meet required collection efficiency. Therefore, a wet ESP is not a technically acceptable alternative when matched with an SDA.

Fabric Filter. Fabric filter technology achieves particulate reduction through the filtration of the flue gas through filter bags. The collected particles are periodically removed from the bag through a pulse-jet or reverse-flow mechanism. A pulse jet filtration system would likely be selected for installation on Tracy 3 because this fabric filter technology results in lower capital cost and a smaller required footprint.

Because of the somewhat sticky particles produced during oil firing, appropriate fabric and/or coating bags with a suitable pre-coat material are imperative. If fabric bags become "blinded" due to allowing hard-to-removal particulates to become embedded in the fabric structure, total bag replacement may be necessary. Blinded bags will continue to provide excellent filtration efficiencies; however, the pressure drop across the fabric may exceed system draft capability.

While a fabric filter is not an acceptable alternative for PM_{10} emissions control for an oil-fired unit without utilization of coating material, it is anticipated to function satisfactorily with a pre-coat and the increased particulate loading from the SDA operation.

3.2.3.3 Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

The PM_{10} control technology emission rates are summarized in Table 3-6.

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

Control Technology	Expected PM_{10} Emission Rate (Lb/MMBtu)
Current Title V Permit Limit (converted to lb/MMBtu for comparison)	0.20 (1-hr average)
NVE BART Limit (Switch to No. 2 Fuel Oil w/LNG)	0.03 (3-hr average)
Fabric Filter	0.015

3.2.3.4 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. No additional energy impact is expected from PM_{10} reduction as a result of new LNB or burning of low sulfur fuel oil. A fabric filter and ductwork will add an estimated 6 to 8 inches of H_2O pressure drop to the system, and additional electrical load requirements for No. 6 fuel oil combustion.

No energy impact costs are included in the economic analysis presented in Appendix A.

Environmental Impacts. There are no negative environmental impacts from the utilization of new LNB switching to low sulfur diesel fuel, or utilizing a fabric filter.

No environmental impact costs have been quantified in the economic analysis presented in Appendix A.

Economic Impacts. A summary of the costs and PM_{10} removed for the alternatives are recorded in Table 3-7. The complete Economic Analysis is contained in Appendix A.

TABLE 3-7
PM_{10} Control Cost Comparison
Tracy Unit 3

Factor	Fabric Filter	Switch to Low Sulfur Fuel
Total Installed Capital Costs	$22,000,000	$500,000
Total First Year Fixed & Variable O&M Costs	$344,816	-
Total First Year Annualized Cost	$2,678,048	-
Power Consumption (MW)	0.40	-
Annual Power Usage (Million kW-Hr/Yr)	2.0	-
PM_{10} Design Control Efficiency	76.9%	-
Tons PM_{10} Removed per Year	145	-
First Year Ave Control Cost ($/Ton PM_{10} Removed)	18,407	-
Incremental Control Cost ($/Ton PM_{10} Removed)	18,407	-

The complete Economic Analysis is contained in Appendix A.

3.2.3.5 Step 5: Evaluate Visibility Impacts

Please see Section 4.0, BART Modeling Analysis.

3.3 Summary

The most cost-effective emissions control scenario includes the utilization of LNB with PNG and/or low-sulfur No. 2 fuel oil. The Nevada Public Utilities Commission has mandated that Tracy Unit 3 maintain the capability to use both PNG and fuel oil. However, as a first step in the BART implementation plan, NV Energy has committed to use only low-sulfur No. 2 fuel oil.

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 NV Energy Tracy Power Plant Unit 3.

To a large extent, the modeling followed 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 the modeling protocol that is included as Appendix B to this report.

4.2 Model Selection

CH2M HILL used the Gaussian puff dispersion model (CALPUFF) modeling system to assess the visibility impacts at Class I areas. Work groups 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 (EPA, 1998). The CALPUFF model is routinely recommended for these types of regulatory analyses.

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 FLMs 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 Nevada BART modeling in WRAP (2006). In addition, the CALMET and CALPUFF Lambert Conformal Conic (LCC) map projection is based on a central meridian of 117° 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-km buffer around all Class I areas within 300 km of the Tracy Power Plant. Grid resolution for this domain was 4 km. Figure 4-1 shows the extent of the modeling domain.

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 all the way to 6,000 meters mean sea level (MSL) 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 m AGL CALMET default maximum would occur in the domain used for this analysis.

FIGURE 4-1
Tracy Power Plant, CALMET/CALPUFF Domain

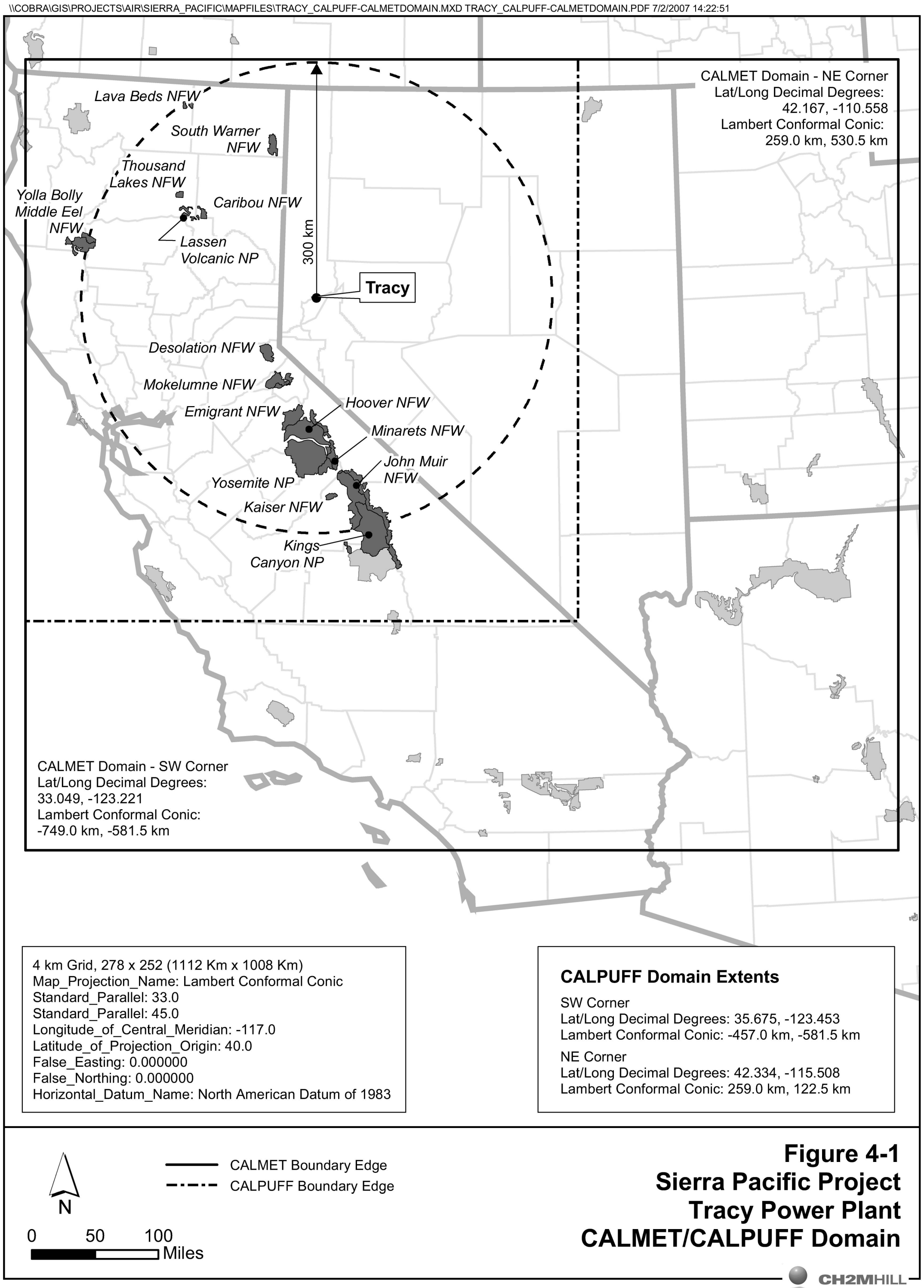


Table 4-1 lists the key user-specified options.

TABLE 4-1
User-Specified CALMET Options
Tracy Unit 3

Description	CALMET Input Parameter	Value
	CALMET Input Group 2	
Map projection	PMAP	Lambert Conformal Conic (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	100
Radius of influence of terrain features (km)	TERRAD	10
Relative weight at surface of Step 1 field and obs	R1	100
Relative weight aloft of Step 1 field and obs	R2	200
	CALMET Input Group 6	
Maximum over-land mixing height (m)	ZIMAX	4500

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 km.

For 2001, CH2M HILL used 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 used 36-km MM5 data obtained from Alpine Geophysics, originally developed for the WRAP. Data 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 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 2001-2003 were obtained from the National Climatic Data Center (NCDC). 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 (CTG) 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 (DEM) 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 NCDC. 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 (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.

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. We used 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.

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.

4.4.1.1 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 (ppb). Background ammonia was set to 1 ppb as recommended in WRAP (2006).

4.4.1.2 Stack Parameters

The baseline stack parameters for the baseline and post-control scenarios were the same as those used the WRAP Regional Modeling Center (RMC) analyses. None of the emission controls included in this BART analysis would greatly affect the exhaust exit flows or temperatures.

4.4.1.3 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 selected the emissions rates used in the WRAP RMC modeling as the Pre-control (baseline) emission rates. The WRAP PM10 and SO2 were speciated to determine emission rates for coarse particulate, fine particulate, elemental carbon, organic aerosols, and sulfates.

Emissions were 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)

4.4.1.4 Post-control Emission Rates

Post-control emission rates represent the NVE BART Limit emission levels presented in Table 5-1, with the exception of the NO_x emission rate which is in excess of the NVEBL.

4.4.1.5 Modeling Process

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

- Model WRAP-RMC parameters to verify results
- Model Title V Permit Limits
- Model Scenario 1 (NVE BART Limit) emissions, with the exception of the NO_x emission rate which is in excess of the NVEBL.
- Determine the degree of visibility improvement

4.4.2 Receptor Grids and Coordinate Conversion

The TRC COORDS program was 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) 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 km of the Tracy Power Plant, discrete receptors for the CALPUFF modeling were 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) were included in the modeling analysis. The following Class I areas were modeled for the Tracy facility:

- Ansel Adams Wilderness (Minarets Wilderness) (anad)
- Caribou Wilderness (cari)
- Desolation Wilderness (deso)
- Emigrant Wilderness (emig)
- Hoover Wilderness (hoov)
- John Muir Wilderness (jomu)
- Kaiser Wilderness (kais)
- Kings Canyon NP (kica)
- Lava Beds NM (labe)
- Lassen Volcanic NP (lavo)
- Mokelumne Wilderness (moke)
- South Warner Wilderness (sowa)
- Thousand Lakes Wilderness (thla)
- Yolla Boly Middle Eel Wilderness (yobo)
- Yosemite NP (yose)

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. 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 delta-deciview (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
Tracy Unit 3

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. 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 upon request.

4.6.1 WRAP Verification Runs Results

Tables 4-3 and 4-4 present the results of WRAP-RMC model verification runs. The results show good correlation in estimated maximum Δdv. Much of the difference between these values is probably attributed to the different alignment of the LCC grids (reference discussion in Section 4.3.1).

TABLE 4-3
Results from WRAP-RMC CALPUFF Modeling for Tracy 1-3 (WRAP 2007)
Tracy 3

Class I Area	Min Distance (km)	Max Delta Δdv	98th Percentile Δdv	Days > 0.5 Δdv	98th Percentile Δdv for Each Year			98th Δdv 3-year Avg
					2001	2002	2003	
deso	81	2.33	0.83	47	0.83	1.20	0.64	0.89
moke	101	2.27	0.60	32	0.47	0.88	0.51	0.62
emig	138	1.39	0.35	10	0.22	0.49	0.27	0.33
hoov	142	1.46	0.33	11	0.23	0.52	0.25	0.33
yose	153	1.42	0.38	11	0.25	0.50	0.28	0.34
cari	170	2.00	0.92	48	0.94	1.03	0.69	0.89
lavo	175	1.99	0.80	44	0.75	0.94	0.71	0.80
anad	182	1.46	0.26	8	0.26	0.43	0.23	0.31
sowa	189	3.68	0.87	62	0.83	0.85	0.99	0.89
thla	209	1.27	0.54	22	0.43	0.46	0.54	0.48
jomu	221	1.13	0.27	6	0.23	0.32	0.23	0.26
kais	249	0.77	0.18	5	0.16	0.21	0.16	0.18
kica	265	1.22	0.20	2	0.20	0.26	0.18	0.21
labe	286	1.26	0.54	25	0.74	0.34	0.54	0.54

TABLE 4-4
Verification CALPUFF Modeling Results
Tracy Unit 3

Class I Area	Min Distance (km)	Max Delta Δdv	98th Percentile Δdv	Days > 0.5 Δdv	98th Percentile Δdv for Each Year 2001	2002	2003	98th Δdv 3-year Avg
deso	81	3.58	0.99	38	0.65	1.08	1.04	0.92
moke	101	2.46	0.84	23	0.80	0.87	0.86	0.84
emig	139	1.75	0.51	9	0.56	0.46	0.49	0.51
hoov	143	1.76	0.53	10	0.53	0.59	0.43	0.52
yose	153	1.62	0.52	11	0.54	0.51	0.43	0.49
cari	171	2.31	1.12	23	1.09	0.80	1.12	1.00
lavo	176	2.34	1.12	24	1.15	0.82	1.12	1.03
anad	182	1.29	0.37	6	0.35	0.45	0.32	0.38
sowa	190	2.67	0.91	22	0.96	0.91	0.86	0.91
thla	210	1.44	0.68	12	0.63	0.67	0.82	0.71
jomu	221	1.01	0.41	7	0.37	0.46	0.39	0.41
kais	249	0.82	0.30	1	0.30	0.32	0.28	0.30
kica	265	0.88	0.40	5	0.40	0.37	0.38	0.38
labe	286	1.09	0.49	9	0.52	0.35	0.46	0.45
yobo	287	1.26	0.35	4	0.23	0.45	0.32	0.33

4.6.2 BART Modeling Analysis

The results and comparisons of the CALPUFF modeling for the baseline emission rates and those for the NVE BART Limit emission rates are provided in Section 5. As previously mentioned, the NO_x emission rate modeled is in excess of the NVEBL.

5.0 BART Analysis and Recommendations

5.1 Recommended BART Controls

As a result of the completed technical and economic evaluations, and consideration of the modeling analysis for Tracy 3, the recommended BART controls include installing LNB for NO_x and utilizing PNG and/or low-sulfur No. 2 fuel oil for SO_2 and PM_{10} emissions reduction. There are no presumptive limits assigned by the United States Environmental Protection Agency (EPA) for wall-fired boilers burning PNG or fuel oil. In the absence of a specific Federal guidance, Nevada has chosen to establish the NVEBL based on the control technology that meets the BART guidelines for each specific unit.

Table 5-1 compares the WRAP baseline control scenario with the Title V Permit Limit and expected emission levels utilizing the NVE BART Limit emission levels. While the NO_x emission rate modeled is in excess of the current NVEBL, modeling results represent worst case visibility impacts. Because of the basis utilized to establish the estimated emissions rate for each of these cases, it is important to consider economic and dispersion modeling results for each scenario in making the overall BART recommendation.

The WRAP baseline represents a snap-shot view of emissions based upon the year 2006, and does not necessarily represent worst case potential emission rates. The Title V permit limit offers a more representative view of maximum potential emission rates, since these are enforceable operating limits. Comparison of dispersion modeling results for the three scenarios are presented below.

TABLE 5-1
Modeled Emission Control Scenarios
Tracy Unit 3

CASE	Estimated NO_x Emissions (lb/MMBtu)	Estimated SO_2 Emissions (lb/MMBtu)	Estimated PM_{10} Emissions (lb/MMBtu)
WRAP Baseline	0.315	0.540	0.053
Title V Emission Limit Baseline	0.45	0.76	0.20
Scenario 1 – NVE BART Limit	0.40[a]	0.05	0.03

[a] – NO_x emission rate higher than NVEBL

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
Tracy Unit 3

Rank	Scenario	Total Annual Cost
1	LNB	$175,861
2	LNB w/FGR	$574,613
3	New LNB with SNCR	$706,459
4	ROFA with Rotamix	$1,522,890
5	New LNB and SCR	$4,397,281

5.2 Dispersion Modeling Results

The results of the dispersion modeling are shown below. In this analysis the WRAP emission rates are used as a historical baseline. Table 5-3 compares visibility impacts of the WRAP baseline, the current Title V permit limits and the NVEBART Limit emission rates. The NVE BART Limit emission rates for Tracy Unit 3 demonstrate an improvement in visibility.

TABLE 5-3
Comparison of Visibility Impacts by Class I Area
Tracy Unit 3

		98th Percentile Δdv			Number of Days Exceeding 0.5 Δdv		
Area	Distance (km)	WRAP Baseline	Title V Permit Limit	NVE BART Limit	WRAP Baseline	Title V Permit Limit	NVE BART Limit
deso	81	0.57	0.78	0.33	13	28	5
moke	101	0.44	0.61	0.28	6	13	1
emig	139	0.27	0.37	0.16	2	5	1
hoov	143	0.25	0.34	0.18	2	5	1
yose	153	0.26	0.36	0.17	2	3	0
cari	171	0.51	0.70	0.36	9	12	5
lavo	176	0.45	0.61	0.28	6	13	1
anad	182	0.19	0.26	0.095	1	2	0
sowa	190	0.46	0.62	0.30	8	12	3
thla	210	0.33	0.45	0.21	6	7	1
jomu	221	0.21	0.28	0.11	0	4	0
kais	249	0.15	0.21	0.07	0	1	0
kica	265	0.20	0.28	0.10	0	1	0
labe	286	0.24	0.34	0.14	1	4	0
yobo	287	0.20	0.27	0.07	2	3	0

FIGURE 5-1
Comparison of 98th Percentile Delta Deciview Visibility Impacts Part 1
Tracy 3

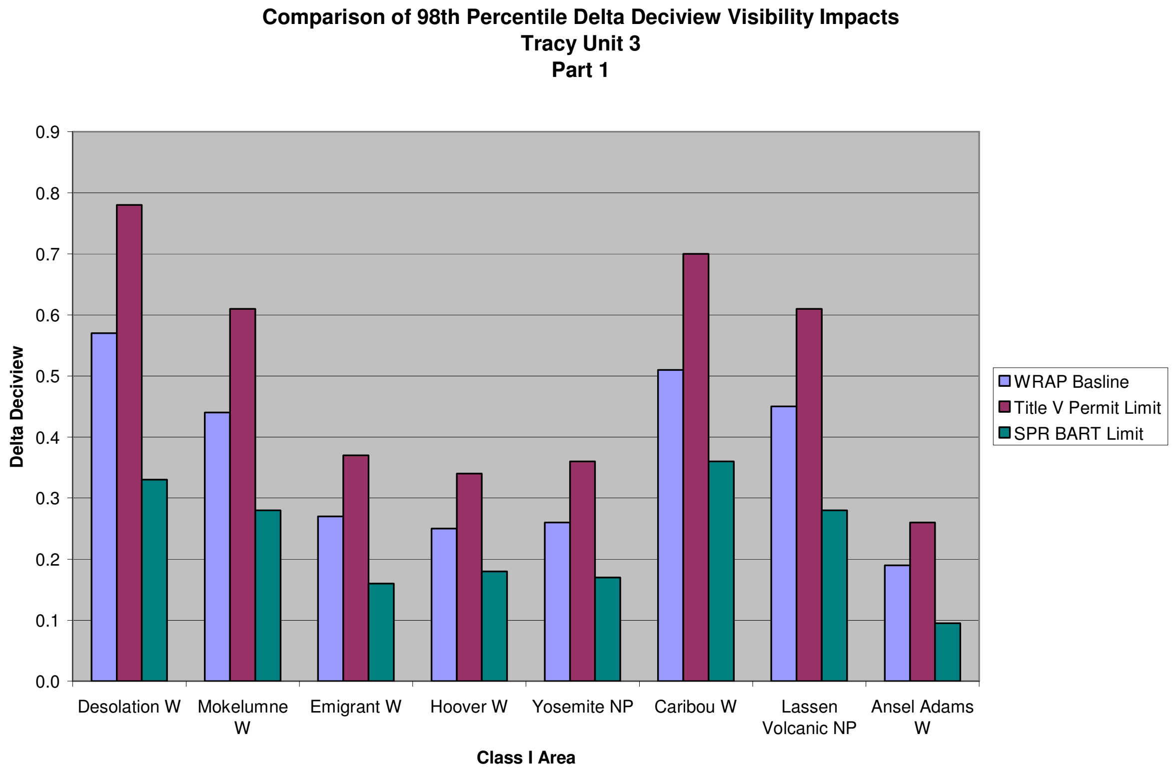


FIGURE 5-2
Comparison of 98th Percentile Delta Deciview Visibility Impacts Part 2
Tracy 3

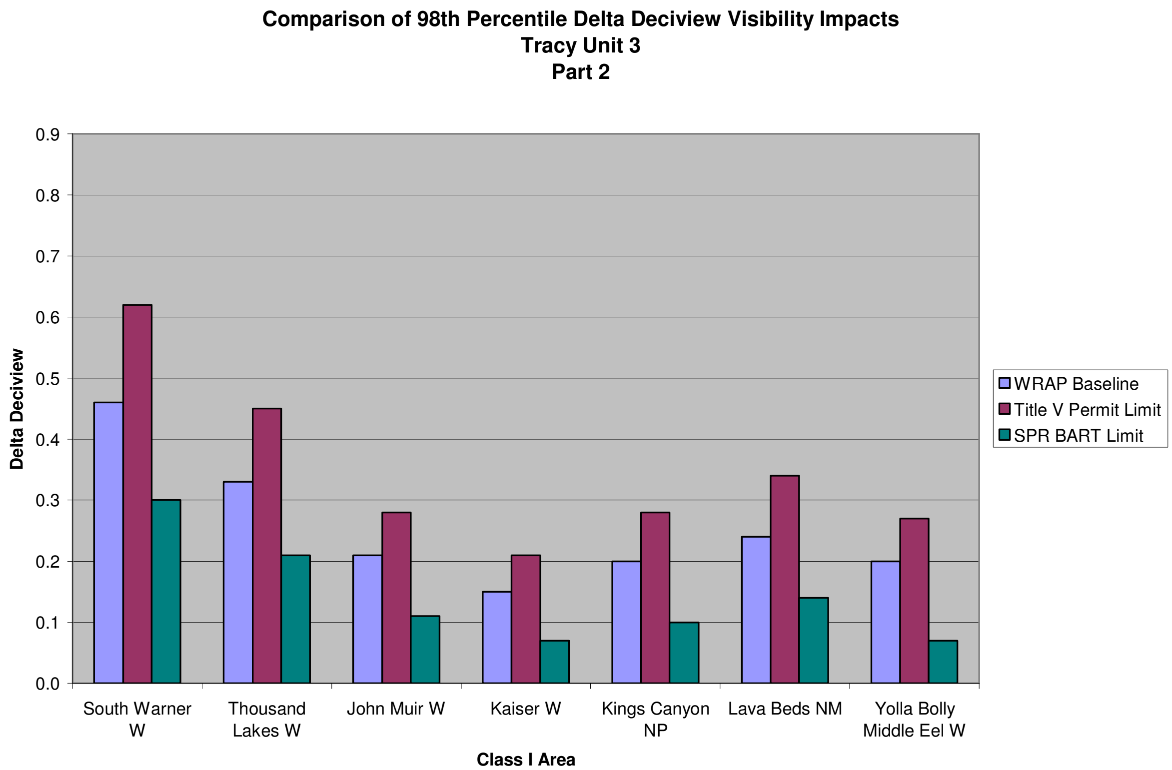


FIGURE 5-3
Comparison of Days of Visibility Impacts Exceeding 0.5 ∆dv Part 1
Tracy 3

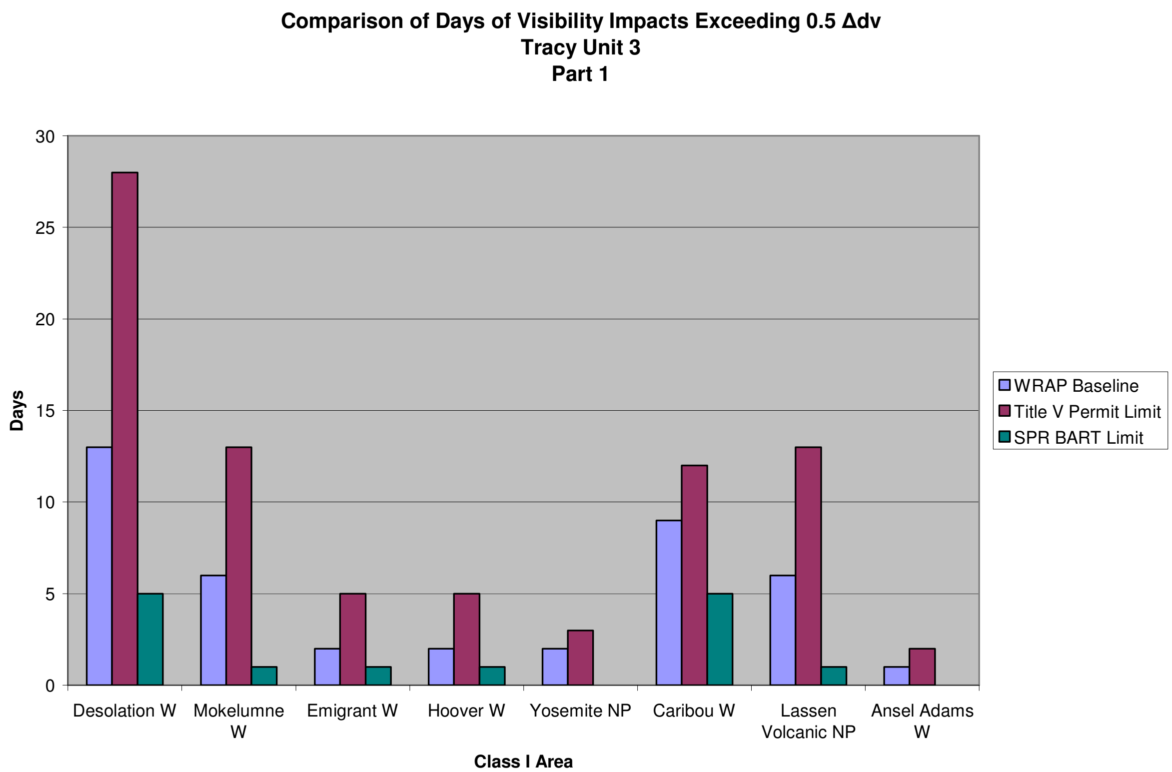
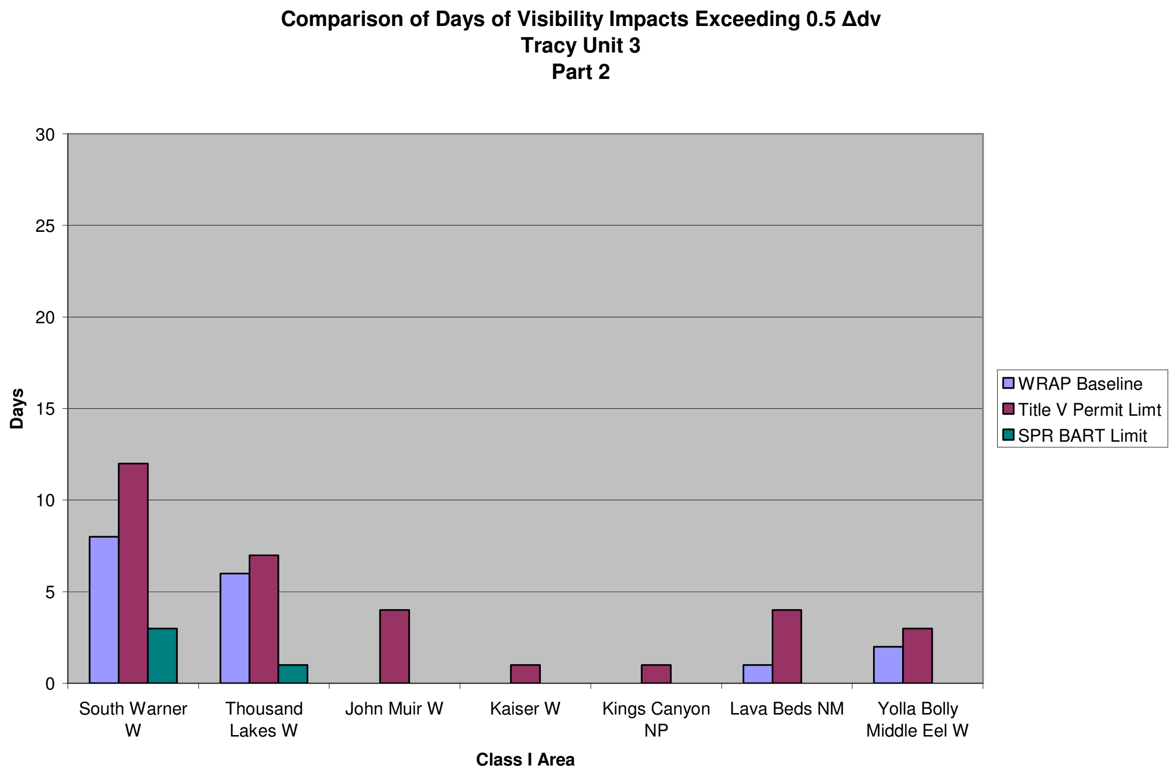


FIGURE 5-4
Comparison of Days of Visibility Impacts Exceeding 0.5 Δdv Part 2
Tracy 3



As shown in Figures 5-1 through 5-4, there is a significant decrease in modeled visibility impact when reducing the modeled emission levels from the WRAP and Title V Permit values, to the NVEBL emission rates.

5.2.1 NO_x Control Scenario Visibility Modeling

While visibility modeling has not been completed for the combination of NO_x, SO_2, and PM_{10} NBEBL values, Tables 5-4 and 5-5 below compare the results for the various NO_x control technologies. Results from two representative Class I areas are provided.

Based on an evaluation of the cost per Δdv reduction from Tables 5-4 and 5-5, new LNB is selected as BART for Tracy 3.

TABLE 5-4

NO_x Control Scenario Results for Desolation Wilderness
Tracy Unit 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		7	0	0	0
1	New LNB	5	0.032	0.176	5.496
2	New LNB and FGR	4	0.056	0.575	10.261
3	New LNB and SNCR	2	0.072	0.706	9.812
4	ROFA w/Rotamix	2	0.087	1.523	17.504
5	New LNB and SCR	2	0.15	4.397	29.315

TABLE 5-5

NO_x Control Scenario Results for Yosemite NP
Tracy Unit 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		2	0	0	0
1	New LNB	1	0.014	0.176	12.562
2	New LNB and FGR	1	0.025	0.575	22.985
3	New LNB and SNCR	1	0.036	0.706	19.624
4	ROFA w/Rotamix	1	0.04	1.523	38.072
5	New LNB and SCR	0	0.064	4.397	68.708

5.3 Recommendations

5.3.1 NO_x Emission Control

New LNB has been selected as the NO_x reduction technology with an NVEBL of 0.27 lb/MMBtu averaged on an annual basis. New LNB is based on utilizing enhanced combustion to meet the proposed NVE BART Limit. There is significant uncertainty involved in obtaining vendor emission guarantees and associated equipment/construction costs at this stage of analysis when retrofitting older boiler units. Site specific engineering is required on a "unit by unit" basis to determine the most effective control technology.

5.3.2 SO_2 Emission Control

The utilization of PNG and/or low-sulfur No. 2 fuel oil is BART for Tracy 3 with an NVEBL of 0.05 lb/MMBtu averaged on a 24-hour basis. No additional SO_2 emission control is required. No. 6 fuel oil will no longer be burned at the facility.

5.3.3 PM_{10} Emission Control

The utilization of PNG and/or low-sulfur No. 2 fuel oil is BART for Tracy 3 with an NVEBL of 0.03 lb/MMBtu averaged on a 3-hour basis. No additional PM_{10} emission control is required. No. 6 fuel oil will no longer be burned at the facility.

5.4 Just-Noticeable Differences in Atmospheric Haze

Conclusions reached in the reference document *Just-Noticeable Differences in Atmospheric Haze* by Dr. Ronald Henry of the University of Southern California state that only dV differences of approximately 1.5 to 2.0 dV, or more are perceivable 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 an impact of background visibility in these Class I areas. If natural obscuration were to reduce the reduction in visibility impacts modeled for the Tracy 3 facility, the effect would be to increase the costs per ΔdV reduction that are presented in this report.

6.0 References

40 CFR Part 51. 2005. *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations; Final Rule* (July 6, pg 39129).

United States Environmental Protection Agency. 1990. *New Source Review Workshop Manual – Prevention of Significant Deterioration and Nonattainment Area Permitting.* October.

EPA. 1998. *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts.* 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.

Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule.

Henry, Ronald C. 2002. "Just-Noticeable Differences in Atmospheric Haze." *Journal of the Air and Waste Management Association* 52:1238-1243. October 2002

Western Regional Air Partnership (WRAP). 2007. *Summary of WRAP RMC BART Modeling for Nevada, Draft#8*. May 14, 2007.

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

Appendices

APPENDIX A

Economic Analysis

APPENDIX B

BART Protocol