Public Service Company of New Mexico

San Juan Generating Station

Best Available Retrofit Technology Analysis

Black & Veatch Project: 146646
Black & Veatch File No.: 41.1402

Issue Date and Revision
June 6, 2007, Final

BLACK & VEATCH
Building a world of difference.

NMED EX. 7b

Contents

Contents (Continued)

Contents (Continued)

Contents (Continued)

Tables

Contents (Continued)

Tables (Continued)

Contents (Continued)

Tables (Continued)

Figures

Acronyms

A/C	Air-to-Cloth
AQC	Air Quality Control
ASN	Ammonium Sulfate Nitrate
B&W	Babcock & Wilcox
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CaS	Calcium Sulfide
CCS	Clean Combustion System
COHPAC	Compact Hybrid Particulate Collector
CUECost	Coal Utility Environmental Cost
DBA	Dibasic Acid
DCS	Distributed Control System
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FAA	Federal Aviation Administration
FLAG	Federal Land Managers Workgroup
FLGR	Fuel Lean Gas Reburn
H_2SO_4	Sulfuric Acid Mist
Hg	Mercury
HHV	Higher Heating Value
IWAQM	Interagency Workgroup on Air Quality Modeling
LCC	Lambert Conformal Conic
LNB	Low NO_x Burners
MBtu	Million British Thermal Unit
HNO_3	Nitric Acid
NH_3	Ammonia
NH_4	Ammonium
NMED	New Mexico Environment Department
NN	Neural Network
NO_3	Nitrates
NO_x	Nitrogen Oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NWS	National Weather Service

OFA	Overfire Air
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
PRB	Powder River Basin
RMC	Regional Modeling Center
SCR	Selective Catalytic Reduction
SJGS	San Juan Generating Station
SNCR	Selective Non-Catalytic Reduction
SOA	Secondary Organic Aerosol
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SO_4	Sulfate
TAC	Total Annualized Cost
TCI	Total Capital Investment
WRAP	Western Regional Air Partnership

Executive Summary

The New Mexico Environment Department (NMED) identified the Public Service of New Mexico's (PNM's) San Juan Generating Station (SJGS) as a Best Available Retrofit Technology (BART)-eligible source, which required a BART engineering and modeling analysis for reducing visibility impacts in accordance with the US Environmental Protection Agency's (EPA's) *Guidelines for BART Determinations* under the Regional Haze Rules (40 CFR Part 51, Appendix Y). A BART review was required to identify the best control technology for the reduction of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter (PM) emissions. However, because the state of New Mexico will participate in the Western Regional Air Partnership (WRAP) SO_2 emissions trading program, SO_2 emissions reduction will not be analyzed for BART. SJGS consists of four units: Units 1, 2, 3, and 4.

PNM entered into a consent decree with the Grand Canyon Trust, Sierra Club, and NMED on March 10, 2005, to settle alleged violations of the Clean Air Act. Installation of state-of-the-art new low-NO_x burners (LNB) with overfire air (OFA) ports and a neural network (NN) system to reduce NO_x emissions, and a full-sized pulse jet fabric filter (PJFF) to reduce PM emissions is currently under way at SJGS to meet the requirements of the consent decree. All four units will have these controls installed by the spring of 2009.

However, since the NMED determined that the four units at SJGS was BART-eligible based on the currently installed technology (pre-consent decree) and not the technologies being installed for consent decree compliance, it was important to perform the BART analysis on the consent decree technologies, as well as other technologies that could be added to the units.

In the BART rule, presumptive levels of emissions are prescribed as emissions targets for BART-eligible units. For SJGS, the presumptive NO_x limit is 0.23 lb/MBtu (subbituminous coal for a dry-bottom, wall-fired boiler). The NO_x presumptive limit was established based on the type of coal burned and the boiler design. It should be noted that the presumptive limit of 0.23 lb/MBtu is achievable for Powder River Basin (PRB) coal fired, dry-bottom, wall-fired boilers, using state-of-the-art combustion control technologies, but SJGS does not burn PRB coal. For a similarly configured boiler firing bituminous coal, the presumptive limit for NO_x is 0.39 lb/MBtu. There is not a presumptive limit for PM.

The five basic steps of a BART analysis are:

- Identify all available retrofit control technologies.
- Eliminate technically infeasible options.
- Evaluate control effectiveness of remaining control technologies.
- Evaluate impacts and document the results.
- Evaluate visibility impacts.

The BART analysis was performed in two stages. First, a BART analysis was performed for the consent decree technologies currently being implemented at SJGS. This analysis is presented in Section 4.0. Table ES-1 lists control and cost-effectiveness data for the consent decree technologies. The evaluation of the consent decree control technologies indicates that the new LNB, OFA, and NN installed for NO_x emissions represent a state-of-the-art combustion control technology, and the PJFFs installed for PM emissions are the most stringent control technology for PM emissions control. The consent decree control technologies should be considered BART for SJGS.

Table ES-1
Control and Cost-Effectiveness Results of Consent Decree Upgrades

Consent Decree Upgrades Scenario	Emission Performance Level (lb/MBtu)	Expected Emission Rate (lb/h)	Expected Emission Rate (ton/yr)	Expected Emission Reduction (ton/yr)	Total Capital Investment (TCI) (1,000$)	Total Annualized Cost (TAC) (1,000$)	Cost Effectiveness ($/ton)
NOx Reduction - LNB/OFA/NN							
SJGS 1	0.30	1,112.1	4,140	1,794	14,580	1,422	793
SJGS 2	0.30	1,106.4	4,119	2,060	14,126	1,378	669
SJGS 3	0.30	1,727.4	6,431	2,572	12,715	1,240	482
SJGS 4	0.30	1,694.7	6,309	2,524	12,870	1,256	498
PM Reduction - PJFF							
SJGS 1	0.015	55.6	207	483	67,072	10,427	21,586
SJGS 2	0.015	55.3	206	481	69,840	10,764	22,399
SJGS 3	0.015	86.4	322	750	72,696	12,454	16,599
SJGS 4	0.015	84.7	315	736	73,328	12,527	17,018

Notes:

1. All costs are in 2007$.
2. Expected emission rates (ton/yr) calculations were based on 85 percent unit capacity factor (refer to Appendix A Design Basis).
3. Expected emission reduction (ton/yr) calculations were based on the pre-consent decree upgrades control effectiveness as shown in Table 4-1.
4. TCI and TAC are referenced from Appendix C Cost Analysis Summary.
5. Cost-effectiveness ($/ton) is defined as ratio of TAC over expected emission reduction (ton/yr).
6. Expected emission reduction is based on annual emission reduction from pre-consent decree operation emission levels.

In the second stage of the BART analysis, additional control technology alternatives to the consent decree technologies were identified by evaluating the feasibility of the technologies identified as available in Section 3.0. Since the PJFFs being installed for the consent decree are the most stringent technology available, no additional PM control technologies alternatives were evaluated. For NO_x emissions, the selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR)/SCR hybrid technologies were identified as feasible additional NO_x control technology alternatives. The BART analysis of these technologies is presented in Sections 5.0 to 7.0. The results of the control and cost-effectiveness evaluation are summarized in Table ES-2.

The last step of the BART analysis involved performing visibility modeling for the two stage of the BART analysis. The visibility modeling was performed in accordance with the modeling protocol submitted to the NMED. Meteorological data for the years 2001 through 2003 was obtained from the WRAP Regional Modeling Center (RMC) for use in modeling. The WRAP RMC conducted the initial modeling that identified the four SJGS units as causing or contributing to visibility impairment in sixteen Federal Class I areas. For each control technology modeled, the visibility data was analyzed for the 98th percentile modeled visibility and reported as a visibility impairment value in deciview (dv) at the 16 Federal Class I areas.

Based on the total annual cost for the consent decree technologies, the additional NO_x control technology alternatives, and the modeled visibility impacts, the visibility improvement cost-effectiveness was calculated. For all three visibility scenarios (i.e., pre-consent decree [modeling by RMC], consent decree technologies, and additional NO_x control technology alternatives), the average modeled visibility impacts were used to calculate the visibility improvement cost effectiveness ($/dv). A summary of the visibility improvement cost effectiveness is shown in Table ES-3.

In conclusion, for PM emissions control, the PJFFs being added to meet the consent decree requirements represent BACT for similar units. No other technologies have been identified that exceed the emissions reductions achieved by the PJFF. Therefore, the PJFF is considered BART for this project for each SJGS unit.

The BART analysis for NO_x emissions control concludes that the LNB, OFA, and NN should be considered BART for the SJGS units. Another factor to consider is that the presumptive limit for dry-bottom, wall-fired boilers burning subbituminous coal is based on the installation of LNB and OFA as indicated in the BART guidelines. The subbituminous coal fired at SJGS is similar to bituminous coal than PRB subbituminous coal with respect to NO_x control. This similarity to bituminous coal is due to the lower volatility, lower moisture, and lower oxygen content of the coal burned at SJGS. These characteristics result in higher NO_x emissions from the SJGS units than from the same type of boiler with the same combustion controls and burning PRB coal. The LNB, OFA, and NN being installed in the SJGS units are classified as state-of-the-art technologies and are equivalent to the BART technology used to establish the 0.23lb/MBtu presumptive limit.

The SCR and SNCR/SCR Hybrid systems would require significant capital expenditure and modifications that will impact many areas of the plant, including boiler draft systems, air heater performance, SO_3 emissions, and ash handling. The capital cost for SCR ranged from $157 million on Unit 1 to $216 million on Unit 3. This represents a cost of 436 $/kW on Unit 1 to 396 $/kW on Unit 3. For SNCR/SCR Hybrid, the capital cost ranged from $104 million on Unit 1 to $169 million on Unit 3. This represents a cost of 290 $/kW on Unit 1 to 310 $/kW on Unit 3. In addition, the average visibility improvement from these systems is only 0.627 dv for SCR and 0.226 for the hybrid. The visibility improvement cost effectiveness is 155 million $/dv for SCR and 369 million $/dv for SNCR/SCR Hybrid. These minimal visibility improvements do not merit the large capital expenditure required to install SCR or SNCR/SCR Hybrid.

Therefore, LNB, OFA, and NN combustion controls should be considered BART for SJGS.

Table ES-2
Impact Analysis and Cost-Effectiveness Results for Additional NO_x Control Technology Alternatives

All Feasible Technologies	Emission Performance Level (lb/MBtu)	Expected Emission Rate (lb/h)	Expected Emission Rate (ton/yr)	Expected Emission Reduction (ton/yr)	Total Capital Investment (TCI) (1,000$)	Total Annualized Cost (TAC) (1,000$)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Energy Impacts (1,000$)	Non-Air Impacts (1,000$)
SJGS Unit 1										
Selective Catalytic Reduction (SCR)	0.07	259.5	966	3,174	156,805	20,525	6,466	2,844	1,496	--
SNCR/SCR Hybrid	0.18	667.3	2,484	1,656	104,436	16,207	9,786	--	706	1,762
SJGS Unit 2										
Selective Catalytic Reduction (SCR)	0.07	258.2	961	3,158	169,251	21,891	6,932	3,457	1,492	--
SNCR/SCR Hybrid	0.18	663.8	2,471	1,648	108,628	16,670	10,117	--	346	1,762
SJGS Unit 3										
Selective Catalytic Reduction (SCR)	0.07	403.1	1,501	4,931	215,568	28,359	5,752	1,167	2,194	--
SNCR/SCR Hybrid	0.18	1,036.4	3,859	2,572	168,507	25,606	9,954	--	507	2,658
SJGS Unit 4										
Selective Catalytic Reduction (SCR)	0.07	395.4	1,472	4,837	199,558	26,592	5,497	753	2,215	--
SNCR/SCR Hybrid	0.18	1,016.8	3,786	2,524	161,572	24,849	9,846	--	507	2,658

Notes:

1. All costs are in 2007$.
2. Expected emission rates (ton/yr) calculations were based on 85 percent unit capacity factor (referer to Appendix A Design Basis).
3. Expected emission reduction (ton/yr) calculations were based on the consent decree upgrades control effectiveness as shown in Table 4-1.
4. TCI and TAC are referenced from Appendix C Cost Analysis Summary.
5. Cost-effectiveness ($/ton) is defined as ratio of TAC over Expected Emission Reduction (ton/yr).
6. Expected emission reduction is based on annual emission reduction from consent decree upgrade emission levels (Table 4-1).
7. Incremental cost effectiveness are based on increments in expected emission reduction (ton/yr)

Table ES-3
Visibility Improvement Cost-Effectiveness Summary

Visibilitiy Scenario	Total Annualized Cost (TAC) (1,000$)	Scenario Average Deciview Change (dv)	Average Improvement ($/dv)
Consent Decree Scenario			
Pre-consent decree to consent decree	51,468	0.614	83,824,104
Additional Control Technology Alternative			
Consent decree to SCR	97,367	0.627	155,290,271
Consent decree to Hybrid	83,332	0.226	368,725,664
Pre-consent decree to SCR	148,835	1.241	119,931,507
Pre-consent decree to Hybrid	134,800	0.840	160,476,190

Notes:

1. All costs are in 2007$.
2. Pre-consent decree visibility impact from WRAP RMC model, April 2007.
3. Total annualized costs and cost effectiveness ($/ton) are referenced from Table 4-3 and 7-1.
4. Deciview change assumes all four units on the same control technology.

1.0 Introduction and Objectives

The objective of this study was to perform a BART analysis for the PNM SJGS Units 1, 2, 3, and 4. These units were identified as BART-eligible sources by the NMED because they cause visibility impairment in 16 Federal Class I areas that are within a 300 km radius, as identified in accordance with the Regional Haze and BART Rule guidelines that were published by the US EPA on July 6, 2005 (70 FR 39104). The NMED determined SJGS's BART eligibility based on the visibility modeling performed by the WRAP RMC.

Three major pollutants, NO_x, SO_2, and PM, were identified as having an impact on visibility at Federal Class I areas. However, for this BART analysis, SO_2 emissions reductions will not be taken into account for BART consideration, because New Mexico will participate in the WRAP SO_2 emissions trading program. This report documents the BART engineering analysis process and the results obtained, as well as the recommended best control alternative for NO_x and PM.

1.1 Introduction to the SJGS Consent Decree

On March 10, 2005, PNM entered into a consent decree with the Grand Canyon Trust, the Sierra Club, and the NMED. The consent decree became effective May 10, 2005. The decree is a settlement of alleged Clean Air Act violations at SJGS. PNM is required by the consent decree to reduce emissions levels of PM at each unit to 0.015 lb/MBtu (measured using EPA reference Method 5), with a corresponding opacity limit of 20 percent over a 6 minute average period. For NO_x, each unit at SJGS shall not exceed 0.30 lb/MBtu on a 30 day rolling average period. PNM is also required to reduce SO_2 and mercury emissions.

The consent decree compliance deadlines for the reduced emissions levels vary for all four units at SJGS. The earliest required startup date for PM and NO_x controls is October 31, 2007 for SJGS Unit 4. The last required startup date for PM and NO_x controls is March 31, 2009 for SJGS Unit 2. The startup schedule for SJGS Units 3 is April 30, 2008, and Unit 1 is October 31, 2008.

To meet the requirements of the consent decree for NO_x and PM, PNM is installing state-of-the-art LNB with OFA ports, and an NN system on each boiler to reduce NO_x emissions. For PM emissions control, a full-sized PJFF will be installed upstream of the limestone flue gas desulfurization (FGD) on each unit. The existing hot-side ESP will be de-energized. The PJFF is also a component, along with activated carbon injection (ACI), for reducing mercury (Hg) emissions.

The installation of the controls associated with the consent decree is currently under way. However, since the NMED determined that the four units at SJGS units are BART-eligible based on the currently installed technology (pre-consent decree) and not the technologies being installed for consent decree compliance, it was important to perform the BART analysis on the consent decree technologies, as well as any additional technologies that could be added to the units.

1.2 Source Description and Background

SJGS is a minemouth facility burning coal from the San Juan Mine. Although the coal is classified as subbituminous, it is not a PRB subbituminous coal. The fuel combusted at SJGS has a higher heating value (HHV), lower moisture content, higher sulfur content, and lower volatility than PRB coal. A detailed comparison of the difference in fuel characteristics is presented in Section 2.3.

SJGS Units 1 and 2 have a unit capacity of 350 and 360 MW, respectively. The units are equipped with Foster Wheeler subcritical, wall-fired boilers that operate in a forced draft mode. For emissions reduction, the units are equipped with Western Precipitator hot-side ESPs for PM control and Babcock & Wilcox (B&W) wet limestone FGD systems for SO_2 control. SJGS Unit 1 has LNBs.

SJGS Units 3 and 4 each have a unit capacity of 544 MW and are equipped with B&W subcritical, opposed wall-fired boilers that operate in a forced draft mode. For emissions reduction, the units are equipped with Research-Cottrell hot-side ESPs, LNBs, and B&W wet limestone FGD systems. A summary of the pre-consent decree operational characteristics is presented in Table 1-1.

Table 1-1
SJGS Characteristics
Pre-Consent Decree Operation

Item	SJGS 1	SJGS 2	SJGS 3	SJGS 4
Fuel Type	Subbituminous	Subbituminous	Subbituminous	Subbituminous
HHV of Fuel, Btu/lb	9,692	9,692	9,692	9,692
Unit Rating, MW (gross)	360	350	544	544
Boiler Heat Input, MBtu/h	3,707	3,688	5,758	5,649
Type of Boiler/Manufacturer	Wall-fired/ Foster Wheeler	Wall-fired/ Foster Wheeler	Opposed wall-fired/B&W	Opposed wall-fired/B&W
Steam Cycle	Subcritical	Subcritical	Subcritical	Subcritical
Draft of Boiler	Forced	Forced	Forced	Forced
Existing Emissions Controls				
PM	Hot-side ESP	Hot-side ESP	Hot-side ESP	Hot-side ESP
SO_2	Wet FGD	Wet FGD	Wet FGD	Wet FGD
NO_x	Low-NO_x burners	N/A	Low-NO_x burners	Low-NO_x burners

1.3 BART Analysis Methodology

The BART analysis is the engineering and modeling analysis method used to identify the best method or technology to achieve emissions reduction for pollutants from BART-eligible sources that cause visibility impacts in Federal Class I areas. The BART analysis is defined in the regional haze regulations and guidelines in 40 CFR Part 51. The following factors are considered when identifying the best method of emissions reduction:

- Technical feasibility.
- Cost of compliance.
- Energy and non-air quality environmental impacts of compliance.
- Existing pollution control equipment in use or installed at the source.
- Remaining useful life of the source.
- Degree of anticipated improvement in visibility.

The BART analysis consists of the following five steps to arrive at a selection of the best methods of emissions reduction for NO_x and PM at the BART-eligible source:

(1) Identify all available retrofit control technologies.

(2) Eliminate technically infeasible options.

(3) Evaluate control effectiveness of remaining control technologies.
(4) Evaluate impacts and document the results.
(5) Evaluate visibility impacts.

It should be noted that the SJGS BART analysis required a unique approach because of the consent decree. The station was established as a BART-eligible source prior to the installation of technologies associated with the consent decree. Therefore, the pre-consent decree operating conditions, as described in Section 1.2, represent the initial baseline for this BART analysis. As a result, this analysis examines the consent decree technologies as an initial BART compliance scenario (presented in Section 4.0 of this report). Additional control technology alternatives were then evaluated as potential BART compliance scenarios presented in Sections 5.0 to 7.0.

1.3.1 Identify All Available Retrofit Control Technologies (Step 1)

The first step of the BART analysis methodology is to identify all available retrofit control technologies. An emissions control technology is considered an available retrofit option if it has practical potential for application to the BART-eligible source. The technology considered could be a change in plant operation method, addition/modification of emissions control system, or a combination for control of a pollutant. Technologies that have been successfully applied to similar sources or with similar gas stream characteristics are considered as available. However, technologies that have not been applied to commercial-scale operations are considered not available. Since the SJGS units are equipped with existing control technologies, control options including improvements or optimization of the existing control technologies were evaluated. Section 3.0 provides details of Step 1 of the BART analysis.

1.3.2 Eliminate Technically Infeasible Options (Step 2)

Step 2 of the BART analysis involves the evaluation of all the identified available retrofit control technologies to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source or if there is technical agreement between the provider and user that the technology can be applied to the source. Two terms, available and applicable, are used to define the technical feasibility of a control technology. A technology is deemed an available technology if it is being offered commercially by vendors or is in commercial demonstration or licensing. The commercially available technology is applicable if it has been previously installed and operated at a similar type of source, or a source with similar gas stream characteristics. Technologies that are in development and testing stages are classified as not available. Section 4.0 provides details of Step 2 of the BART analysis.

1.3.3 Evaluate Control Effectiveness of Remaining Control Technologies (Step 3)

Once all the technically feasible control technology alternatives are identified in Step 2, the control effectiveness of each control technology is evaluated in Step 3. The control effectiveness is determined using a metric of average steady-state pollutant emissions. For this study, the metric used is the quantity of pollutant mass emissions per unit heat input (lb/MBtu). The control effectiveness of a technology was determined by considering the regulatory decisions and/or evaluations addressing the effectiveness of the technology. Other reference sources included performance data provided by manufacturers (usually in the form of performance guarantees), engineering estimates, and demonstrated effectiveness of the technology at another source. The most stringent level of control proven for each technology was used for its control effectiveness, but less stringent levels of control were also considered as additional options. The results for Step 3 of the BART analysis are described in Section 5.0.

1.3.4 Evaluate Impacts and Document the Results (Step 4)

Once the control effectiveness is established in Step 3 for all the feasible control technologies identified in Step 2, additional evaluations of each technology are performed as part of the BART determination. These evaluations, labeled as "Impact Analyses," are included in Section 6.0. The impact analyses performed include the following:

- Costs of compliance.
- Energy impacts.
- Air quality environmental impacts.
- Non-air quality environmental impacts.
- Remaining useful life.

The first impact analysis evaluated the costs of compliance. This analysis is performed to indicate the cost to purchase, retrofit, and install the control technology. The capital and operating/annual costs are estimated based on established design parameters. The design parameters are established in the Design Concept Definitions in ***Appendix B***. The estimated cost of control is represented as an annualized cost ($/year). The annualized cost in conjunction with the estimated quantity of pollutant removed (tons/year) allows the cost-effectiveness ($/tons) of the control technology to be determined. The cost-effectiveness compares the potential technologies on an economic basis. Two types of cost-effectiveness are considered in a BART analysis: average and incremental. The average cost-effectiveness is defined as the total annualized cost of control divided by the annual quantity of pollutant removed for each control technology. The incremental cost-effectiveness is a comparison of the cost and performance level of a control technology to the next most stringent option. Incremental cost-effectiveness is expressed as dollars ($)/incremental ton removed and is a useful measurement for comparing technologies that have similar removal efficiencies.

The energy impact of each evaluated control technology is the energy penalty or benefit resulting from the operation of the control technology at the source. Direct energy impacts, such as the auxiliary power consumption of the control technology and the power consumption to overcome the additional system pressure loss, were evaluated. The costs of these energy impacts included additional fuel costs and/or the cost of replacement power that would have to be purchased to implement the control technology.

Air quality environmental impacts were evaluated. Some technologies will result in an increase or decrease in other air pollutants such as NO_X, SO_2, sulfur trioxide (SO_3), or PM. The total emissions of all pollutants will affect the control scenario used for the visibility model.

Non-air quality environmental impacts were evaluated to determine the cost to mitigate environmental impacts caused by the operation of a control technology. Examples of non-air quality environmental impacts include water consumption, polluted water discharge, and solids/waste generation.

Finally, the remaining useful life was considered only when there would be an effect on the annualized costs of the retrofit controls for capital recovery. This occurs when the source has a shorter remaining useful life than the expected service life of the control technology. This would require an expedited pace for capital recovery, thus affecting the cost-effectiveness of the control technology, particularly for technologies that require a large capital expenditure.

1.3.5 Evaluate Visibility Impacts (Step 5)

Potential visibility improvements from the addition of each control technology were determined from the modeling results using CALPUFF. The parameters modeled were NO_X, SO_2, and PM emissions. A modeling protocol has been developed by the WRAP RMC and was used as a template for the modeling protocol for the SJGS modeling analysis (located in ***Appendix E***). Items that were considered in the modeling protocol include the following:

- Meteorological and terrain data.
- Stack height, exhaust temperature, exit velocity, and stack elevation.
- Pre- and post-control emissions rates of pollutants.
- Receptor data from appropriate Class I areas.

After model runs were completed, a determination of the visibility improvement was made. The visibility improvements for the initial BART compliance scenario involving the consent decree technologies and the additional BART compliance scenario with additional control technology alternatives were determined by comparing the 98th percentile modeled visibility values. The visibility improvement is quantified in units of deciview, which are defined as a visibility index that linearly scales perceived visual (visibility) changes (Interagency Monitoring of Protected Visual Environments Newsletter, April 1993). A detailed description of the BART modeling for these scenarios has been included in Section 7.0 of this report.

Using the modeled visibility improvement and the annualized cost ($/year), a visibility improvement cost-effectiveness measure can be defined as the cost for a deciview of improvement ($/deciview). This cost-effectiveness metric was used to compare the cost impact of each technology and the resulting visibility improvement.

1.3.6 Select the Best Alternative

By evaluating all of the results from the five steps described above, a decision on the best alternative control technology can be made based on the cost-effectiveness, impacts, and the resultant visibility improvement. Another factor to consider when selecting the best alternative is the effectiveness of the combination of two or more technologies for the control of multiple pollutants. While separately the technologies may not be the best selection for the control of a single pollutant, when combined, they may be very effective in controlling multiple pollutants. An example of such a synergistic approach is the use of LNB and OFA systems in combustion control for NO_x reduction. In addition, the potential of a selected technology to control future regulated pollutants, such as the use of a PJFF for Hg control, is considered when selecting the best alternative.

2.0 Basis of Analysis

2.1 Design Basis

A detailed design basis was established for the SJGS. The information in the design basis was used for equipment sizing, performance calculations, cost estimates (capital, operating and maintenance [O&M]), resource consumption estimates, auxiliary power requirements, and byproduct disposal. The design basis was established with consideration of the unit configuration after the consent decree technologies have been installed. This approach was selected so that the information in the design basis could be used for the evaluation of the additional control technology alternatives for BART consideration. The design basis is shown in ***Appendix A***. The design basis was also developed using the properties of a representative coal typically combusted at SJGS. Combustion calculations were performed using the design basis coal to determine the flue gas flow characteristics for use in equipment sizing and cost estimation.

2.2 Economic Data

2.2.1 Capital Cost Estimates

Capital cost estimates were developed for retrofit control technologies identified as technically feasible for the SJGS units. The capital cost estimates were based on the Coal Utility Environmental Cost (CUECost) estimates, cost data supplied by equipment vendors (budget estimates), and estimates from previous in-house design/build projects. The capital cost estimates include direct and indirect costs and are stated in 2007 dollars. The capital cost accuracy is ± 30 percent.

Direct costs consist of purchased equipment, installation, and miscellaneous costs. The purchased equipment costs are the costs for purchasing the equipment, including taxes and freight. An itemized list of key components of the direct capital cost is included in ***Appendix C*** for each feasible control technology. The installation costs include construction costs for installing the new controls. The installation costs take into account the retrofit difficulty of the existing site configuration and condition and the installation requirements of the evaluated technology. Finally, the costs of miscellaneous items such as purchase of additional water rights, site preparation, buildings, and other site structures needed to implement the control technology are included. The direct cost estimates were based on the following assumptions:

- Costs for regulatory permitting were not included.
- Regular supply of construction craft labor and equipment is available.
- Normal lead-times for equipment deliveries are expected.

Indirect costs are those costs that are not related to the equipment purchased but are associated with any engineering project, such as the retrofit of an air quality control (AQC) technology. Indirect costs addressed in this evaluation include the following:

- Contingency.
- Engineering.
- Owner's Cost.
- Construction Management.
- Startup and Spare Parts.
- Performance Tests.
- Loss of Generation for Construction Outage.

2.2.1.1 Contingency. Contingency accounts for unpredictable events and costs that could not be anticipated during the normal cost development of a project. Costs assumed to be included in the contingency cost category are items such as possible redesign and equipment modifications, errors in estimation, unforeseen weather-related delays, strikes and labor shortages, escalation increases in equipment costs, increases in labor costs, delays encountered in startup, etc.

2.2.1.2 Engineering. Engineering costs include any services provided by an architect/engineer or other consultant for support, design, and procurement of the AQC project.

2.2.1.3 Owner's Cost. Table 2-1 lists possible Owner's costs for this category. The Owner's costs are identified as indirect costs. Some of the categories are not applicable to all of the evaluated technologies, but are representative of the typical expenditures that an Owner would experience as part of an AQC retrofit project.

2.2.1.4 Construction Management. Construction management services include field management staff such as support personnel, field contract administration, field inspection and quality assurance, project control, technical direction, and management of startup. It also includes cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, other required labor-related insurance, performance bond, and liability insurance for equipment and tools.

2.2.1.5 Startup and Spare Parts. Startup services include the management of the startup planning and procedure and the training of personnel for the commissioning of the newly installed AQC technology. Also included are the general low-cost spare parts required for each AQC technology system. High-cost critical spare part components are kept only if recommended by the manufacturer; they are determined and accounted for on a case-by-case basis.

Table 2-1
Typical Owner's Cost Categories

Project Development:	**Plant Startup/Construction Support:**
Legal assistance	Owner's site mobilization
Environmental permitting/offsets	O&M staff training
Public relations/community development	Initial test fluids and lubricants
Road modifications/upgrades	Initial inventory of chemicals/reagents
	Consumables
Financing:	Construction all-risk insurance
Debt service reserve fund	Auxiliary power purchase
Analyst and engineer	
Owner's Project Management:	**Taxes/Advisory Fees/Legal:**
Provide project management	Taxes
Perform engineering due diligence	Market and environmental consultants
Prepare bid documents and select contractors and suppliers	Owner's legal expenses:
	• Power purchase agreement
	• Interconnect agreements
	• Contract--procurement and construction
	• Property transfer

2.2.1.6 Performance Tests. Performance test services are typically required after every AQC technology addition to validate the performance of the emissions reduction system. The results of the performance tests are used to ensure compliance with performance guarantees and emissions limits.

2.2.1.7 Loss of Generation for Construction Outage. For retrofit projects that require a construction outage longer than the 7 week major outage or 3 week minor outage that have been planned for each unit, an estimate is made for the loss of generation. For each retrofit scenario analyzed in this BART study, an estimate of the required outage for construction was made. The replacement electric energy cost listed in Table 2-2 was used to calculate the cost of loss generation, based on the net generation and capacity factor as shown in the design basis in ***Appendix A***.

Table 2-2
Economic Evaluation Factors

Reagent Cost	
Ammonia (anhydrous)	\$700/ton
Dry Granular Urea	\$420/ton
Dibasic Acid (DBA)	\$0.67/lb (dry)
Selective Catalytic Reduction (SCR) Catalyst Cost	\$6,500/m^3
Makeup Water Cost	\$15.57/1,000 gal
Service/Treated Water Cost	\$15.67/1,000 gal
Byproduct Disposal Cost	\$0.99/ton
Auxiliary and Replacement Electric Power Cost	\$60.95/MWh
Lost Fly Ash Sales	\$6.00/ton
Maintenance Cost	3% of cap cost/yr
Plant and Control Technology Economic Life	20 years
Gross Receipt Tax Rate	6.1875%
Present Worth Discount	7.41% (20 years) 7.56% (25+ years)
Capital and O&M Escalation Factor	3.00%
Capital Recovery Factor (to annualize capital cost)	9.74% (20 years)
Interest During Construction	7.41% (20 years)
Contingency Cost	20% of installed cost
Fully Loaded Operating Labor Cost (union)	\$60.03/man-hour

2.2.2 Annual Operating and Maintenance Cost Estimate

Annual O&M costs typically consist of the following cost categories:

- Reagent costs.
- Electric power costs.
- Makeup water costs.
- Wastewater treatment and byproduct disposal costs.
- Operating labor costs.
- Maintenance materials and labor costs.

The costs of reagent, electric power, makeup water, wastewater, and byproduct disposal are variable annual costs and are dependent on the specific control technology. O&M materials and labor are fixed annual costs. Table 2-2 lists the major economic factors used to obtain the annual O&M costs.

2.2.2.1 Reagent Costs. Reagent costs include the costs for the material, delivery of the reagent to the facility, and reagent preparation. Reagent costs are a function of the quantity of the reagent used and the price of the reagent. The quantity of reagent used will vary with the quantity of pollutant removed. Reagent costs were defined for the following reagents:

- Anhydrous ammonia.
- Dry granular urea.

2.2.2.2 Electric Power Costs. Additional auxiliary power will be required to run some of the new control technology systems. The power requirements of each system vary, depending on the type of technology and the complexity of the system. Electric power costs include an increase in fan power caused by the flue gas pressure losses through the new equipment. The additional fan power was estimated with a basis of 90 percent fan efficiency and 80 percent motor efficiency.

2.2.2.3 Makeup and Service Water Costs. Makeup water or service water is required for some of the processes in the new control technology systems. Examples of water consumption include water to support ammonia solution preparation from urea for SCR and SNCR processes. Additional costs might be incurred for water treatment to obtain the required water quality. For the cost estimations, two types of water quality were considered: makeup and service water. Depending on the process, the appropriate water type was included in this cost category.

2.2.2.4 Wastewater and Byproduct Disposal Costs. Some control technologies generate wastewater and/or byproduct that will require treatment or disposal. For wastewater treatment and byproduct disposal costs, the following key assumptions were utilized:

- Fly ash will not be sold after the implementation of the consent decree technologies. Fly ash collected in de-energized hot-side ESPs and PJFFs will be landfilled in the coal mine.
- Other emissions reduction technology reaction byproducts that are collected will be landfilled in the coal mine.
- Ammonia-based NO_x reduction systems would not impact the fly ash characteristics so that additional handling and storage requirements that increase the fly ash disposal cost would be required.

2.2.2.5 Operating Labor Costs. Operating labor costs are developed by estimating the number and type of employees that will be required to run the new AQC equipment. This estimate was based on common industry practices. The labor cost was based on a fully loaded labor rate and 40 hours per work week.

Typically, a complex emissions control technology will require a combination of the following personnel:

- Supervisor.
- Control Room Operator.
- Roving Operator.
- Relief Operator.
- Laboratory Technicians.
- Equipment Operators.

In the evaluation of direct annual costs for each control technology considered in *Appendix C*, the operating labor required for each technology is identified.

2.2.2.6 Maintenance Materials and Labor Costs. The annual maintenance materials and labor costs are typically estimated as a percentage of the total equipment costs of the system. Based on typical electrical utility industry experience, maintenance materials were estimated to be between 1 and 5 percent of the total direct capital costs. Some initial recommended spare parts were included in the capital costs. An annual maintenance value of 3 percent of the total direct capital costs was used as the basis for the yearly maintenance materials and labor cost. For technologies that replace a similar existing technology at the current plant site, a determination of the additional maintenance requirements was performed. If the required maintenance materials and labor were similar to the existing technology, no additional maintenance costs were credited for the new control technology.

2.3 Target Emissions

The final Regional Haze and BART Rule guidelines issued in July 2005 outline the presumptive limits that apply to BART-eligible coal plants for NO_x and SO_2. The BART NO_x presumptive limits vary according to the type of coal burned and the boiler design. For all units at SJGS, the NO_x presumptive limit for a dry-bottom wall-fired, subbituminous coal burning unit is 0.23 lb/MBtu. For a similarly configured boiler firing bituminous coal, the presumptive limit for NO_x is 0.39 lb/MBtu.

The presumptive limit of 0.23 lb/MBtu was determined to be achievable for the majority of dry-bottom, wall-fired boilers firing subbituminous coals and using current combustion control technologies. It should be noted that the presumptive limit is more representative for a boiler firing PRB type bituminous coal. A discussion of the differences between the New Mexico subbituminous coal burned at SJGS and PRB coal is included in Subsection 4.1.4.

As previously noted, New Mexico is participating in the WRAP SO_2 emissions trading program and, therefore, the presumptive limits for SO_2 were not used for this study. For PM emissions control, the BART analysis methodology is similar to that for NO_x. However, the BART guidelines do not specify a presumptive limit for PM.

In addition to this presumptive limit, the BART analysis procedure requires control technologies that are considered as BACT to be included as a control alternative. A summary of the BART presumptive limits and BACT determinations for the pollutants in this BART analysis is presented in Table 2-3.

Table 2-3
Target Emissions

	NO_x	PM[(1)]
BART Presumptive Limits[(2)] (for subbituminous fuel)	0.23 lb/MBtu	N/A
BART Presumptive Limits[(2)] (for bituminous fuel)	0.39 lb/MBtu	N/A
BACT Determination[(3)]	0.07 lb/MBtu	0.012 lb/MBtu

Notes:

[(1)]PM target emissions are for filterable PM only.
[(2)]NO_x BART presumptive limits are for dry bottom, wall-fired coal fired units.
[(3)]BACT limits are referenced from the EPA BACT/LAER Clearinghouse.

2.4 Project Assumptions

In performing the BART analysis, several general assumptions were made to facilitate the conceptual design activities of the technically feasible control technologies that are being evaluated. The following are key project assumptions:

- No significant change will occur in plant availability after the installation of new AQC equipment.
- The site will have sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down areas, and staging.
- Byproducts produced from the emissions reduction processes will be landfilled in the coal mine.

2.5 Modeling Baseline Conditions

Emissions rates of pollutants are required as input data for visibility modeling. Stack outlet conditions for all the technically feasible control technologies were calculated and are presented in ***Appendix D***. The outlet conditions were calculated based on the design basis data, technology control effectiveness, and design parameters. The following stack outlet data are included:

- Flue gas flow rate.
- Flue gas stack exit velocity.
- Flue gas temperature.
- Flue gas pressure.
- NO_x emissions rate.
- SO_2 emissions rate.
- Filterable PM emissions rate.
- SO_3 emissions rate.

3.0 Identification of All Available Retrofit Emissions Control Technologies

In Step 1 of the BART analysis, all available retrofit control technologies that have a practical potential for application at SJGS were identified. These technologies are considered as available technologies. The technology considered could be a change in plant operation method, addition/modification of emissions control system, or a combination for control of a pollutant. Control technologies for the two major pollutants, NO_x and PM, and a description of the technology are presented in this section. Information on the working principle, retrofit considerations, advantages, and disadvantages of the technology are provided in the descriptions contained in Sections 3.1 through 3.2.

3.1 NO_x Control Technologies

There are two approaches to achieving a reduction in NO_x emissions: combustion control and post-combustion control. Combustion control methods seek to suppress NO_x formation during the combustion process by controlling the flame temperature and fuel/oxygen ratio. Combustion control methods include LNBs, OFA, and NN combustion optimization systems. The post-combustion controls consist of SNCR and SCR systems. SNCR and SCR are flue gas treatment technologies that reduce NO_x after its formation. The SNCR and SCR NO_x reduction technologies use either urea or ammonia as a reagent. SCR technology also uses multiple layers of reduction catalyst. Other NO_x reduction techniques were also identified, including emerging technologies.

NO_x control technologies that were identified as available for retrofit at SJGS are listed below. A short description of each technology is included in the following sub-sections:

- LNB, OFA with NN.
- SNCR.
- SCR.
- SNCR/SCR Hybrid.
- LNB, OFA, NN and SNCR.
- LNB, OFA, NN and SCR.
- LNB, OFA, NN and Hybrid.
- Gas Reburn.
- Mobotec ROFA and ROTAMIX.
- NO_xStar.

- ECOTUBE.
- PowerSpan.
- Phenix Clean Combustion.
- e-SCRUB.

3.1.1 Low NO_x Burners, Overfire Air with Neural Network

3.1.1.1 Low NO_x Burners. NO_x, primarily in the form of NO and NO_2, is formed during combustion by two primary mechanisms: thermal NO_x and fuel NO_x. Thermal NO_x results from the dissociation and oxidation of nitrogen in the combustion air. The rate and degree of thermal NO_x formation is dependent on oxygen availability during the combustion process and is exponentially dependent on combustion temperature. Fuel NO_x, on the other hand, results from the oxidation of nitrogen organically bound in the fuel. This is the dominant NO_x producing mechanism in the combustion of pulverized coal, and typically accounts for 75 to 80 percent of total NO_x.

All LNBs offered commercially for application to coal fired boilers control the formation and emissions of NO_x through some form of staged combustion. The basic NO_x reduction principles for LNBs are to control and balance the fuel and airflow to each burner and to control the amount and position of secondary air in the burner zone so that fuel devolatization and high temperature zones are not oxygen rich. In this process, the mixing of the fuel and the air by the burner is controlled in such a way that ignition and initial combustion of the coal take place under oxygen deficient conditions, while the mixing of a portion of the combustion air is delayed along the length of the flame.

The objective of this process is to drive the fuel-bound nitrogen out of the coal as quickly as possible, under conditions where no oxygen is present, and force it to form molecular nitrogen rather than be oxidized to NO_x. Any nitrogen escaping the initial fuel-rich region has a greater opportunity to be converted to NO_x as the combustion process is completed. The net result of staged combustion is usually longer and/or wider flames due to this delayed mixing process. Staged combustion may increase the potential for higher levels of unburned carbon in ash and higher carbon monoxide (CO) emissions. This is particularly true of wall-fired boiler systems where, compared to tangential firing, the combustion process must be confined to well-defined flame zones and is less able to make maximum use of the available burner zone volume.

For LNBs to reach their maximum benefit, the proper balance of fuel and airflow to the burners (and from burner to burner) is critical. NO_x reduction is achieved from the ability to control the location of the flame, the length of the flame, and, to a certain extent, the time of combustion.

By balancing the fuel and airflow to the burners, an important step is achieved in controlling the flame characteristics and improving the overall combustion process. Balanced fuel flow ensures that each burner is operated with a similar air-to-fuel ratio. This allows the burners to operate as a NO_x control system rather than as individual burners.

3.1.1.2 Overfire Air System. OFA works by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect and further reducing NO_x emissions. Any residual unburned material, such as CO and unburned carbon that inevitably escapes the main burner zone, is subsequently oxidized as the OFA is added.

As with primary NO_x control, the performance that can be expected from a given OFA system depends on a number of factors. As the amount of OFA is increased, the stoichiometry in the burner zone decreases, and a point is reached where CO emissions reach high levels and become uncontrollable. The point at which this occurs varies, particularly if the fuel has characteristics that make it difficult to burn. For example, low volatility, low oxygen, or high moisture content make fuels more difficult to burn. It will also depend on the balance of flows between individual burners and the fuel fineness. As the OFA amount approaches 10 to 15 percent, the probability for individual burners to be operating under fuel-rich conditions increases so that pockets of very high CO emissions and unburned carbon will be formed. Similarly, fuel-rich operation at burners close to the waterwalls can lead to local slag formation and increased tube wastage rates, particularly if slagging is an ongoing problem. A fairly high level of unburned material leaving the burner zone can be accommodated by proper overfire port design, where requirements call for rapid and complete mixing of the OFA with the boiler flue gases.

Aggressively staging combustion to reduce NO_x emissions creates a reducing environment in the boiler and can damage the boiler waterwall tubes. The reducing environment attacks the iron oxides in the tube metal and can lead to pinholes in the boiler tubes. This phenomenon is referred to as tube wastage. Poor staging in the boiler could lead to tube wastage, an increase in the amount of maintenance, and, in the worst-case scenario, may require a forced outage to repair the tubes.

3.1.1.3 Neural Network Systems. Advances in computer hardware and software technology have enabled power generation companies to implement cost-effective optimization solutions that decrease emissions and maximize plant efficiency. This solution, commonly referred to as the boiler optimization or NN system, may provide improvements in the heat rate of the boiler and reduce combustion-related emissions. NN computing differs from traditional computing in that engineering, statistical, and first-law principles have been replaced by complex, time-varying, nonlinear relationships. NN systems use real-time operational data extracted from a plant DCS, "learn" solutions from plant operational experience, and achieve reductions in the emissions produced, while possibly improving the heat rate of the plant.

NN systems also supplement other NO_x reduction strategies. Some of these include LNB, OFA, and post-combustion controls such as SCR and SNCR. These systems are also used to help boiler manufacturers tune boilers with poor combustion characteristics or after an LNB retrofit or other boiler enhancements, such as OFA addition.

A system for monitoring the air and coal flows provides real-time data for tuning the burners and maximizing performance of combustion system.

Airflow systems measure primary airflow, bulk secondary air, total secondary airflow, and OFA flow distribution. One specific system uses a pitot derivative of the multi-point, self-averaging pitot principle to measure the total and static pressure components of airflow. Pulverized fuel flow is determined by measuring the mass flow distribution and transport velocity of the fuel in the pipelines from the mill to the individual burners. The precise technology used for the measurements varies depending on the specific vendor.

3.1.2 Selective Non-Catalytic Reduction

SNCR systems reduce NO_x emissions by injecting a reagent at multiple levels in the steam generator, as illustrated on Figure 3-1. SNCR systems rely solely on reagent injection (rather than a catalyst) and an appropriate reagent injection temperature, good reagent/gas mixing, and adequate reaction time to achieve NO_x reductions. SNCR systems can use either ammonia or urea as the reagent. Ammonia or urea is injected into areas of the steam generator where the flue gas temperature ranges from 1,500 to 2,200° F. The furnace of a pulverized coal fired boiler operates at temperatures between 2,500 to 3,000° F.

SNCR systems are capable of reducing NO_x emissions by as much as 50 to 60 percent in optimum conditions (adequate reaction time, temperature, and reagent/flue gas mixing; high baseline NO_x conditions; multiple levels of injectors). Ammonia slip is the ammonia that does not react with NO_x and instead "slips" past the boiler as ammonia. High levels of ammonia slip cause several negative operational impacts. First, ammonia will react with SO_3 in the flue gas to form ammonium bisulfate and condense on the air heater surface, degrading its performance and decreasing plant efficiency. Another concern with high ammonia slip arises when SNCR is installed upstream of a fabric filter. The ammonia will condense on the fly ash and land on the fabric filter bags. This will cause bag blinding and require early replacement of fabric filter bags. For this reason, it is recommended that the ammonia slip be maintained below 5 ppmvd.

However, to achieve these high levels of removal efficiency, high levels of ammonia slip (10 to 50 ppmvd) must be allowed. Typically, to maintain a 5 ppmvd ammonia slip limit, NO_X emissions reduction levels of 20 to 40 percent can be achieved. Potential performance is very site-specific and varies with fuel type, steam generator size, allowable ammonia slip, furnace CO concentrations, and steam generator heat transfer characteristics.

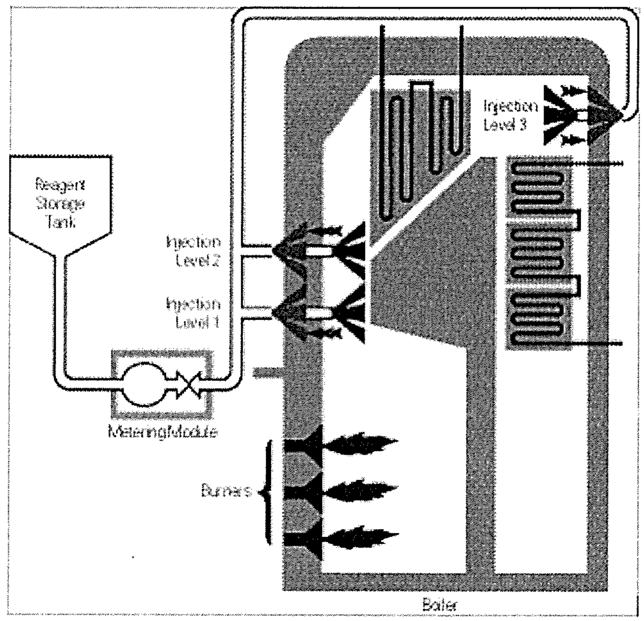


Figure 3-1
Schematic of SNCR System with Multiple Injection Levels

SNCR systems reduce NO_X emissions using the same reduction mechanism as SCR systems. Most of the undesirable chemical reactions occur when reagent is injected at temperatures above or below the optimum range. At best, these undesired reactions consume reagent with no reduction in NO_X emissions; at worst, the oxidation of ammonia can actually generate NO_X. Accordingly, NO_X reductions and overall reaction stoichiometry are very sensitive to the temperature of the flue gas at the reagent injection point. This complicates the application of SNCR for boilers larger than 100 MW because of the large boiler size/volume associated with such boilers.

Reagent injection lances are usually located between the boiler soot blowers in the pendent superheat section. Optimum injector location is mainly a function of temperature and residence time. To accommodate SNCR reaction temperature and boiler turndown requirements, several levels of injection lances are normally installed. Typically, four to five levels of multiple lance nozzles are installed if sufficient boiler height and residence time is available. A flue gas residence time of at least 0.3 second in the optimum temperature range is desired to ensure adequate SNCR performance. Residence times in excess of 1 second yield high NO_x reduction levels even under less than ideal mixing conditions. Computational fluid dynamics and chemical kinetic modeling can be performed to establish the optimum ammonia injection locations and flow patterns. For an existing boiler, minor waterwall reconfigurations are necessary to accommodate installation of SNCR injector lances. A re-examination of the boiler steam piping would probably be required to achieve optimum performance.

3.1.3 Selective Catalytic Reduction

SCR systems are the most widely used post-combustion NO_x control technology for achieving significant NO_x emissions reduction. In SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent when passed over an appropriate amount of catalyst. The NO_x and ammonia reagent react to form nitrogen and water vapor. The reaction mechanisms are very efficient, with a reagent stoichiometry of approximately 1.05 (on a NO_x reduction basis) and a low ammonia slip (unreacted ammonia emissions). A simplified schematic diagram of a typical SCR reactor is illustrated on Figure 3-2. However, most modern SCR systems use sonic horns in place of steam or air soot blowers. Some SCR systems are built without a bypass. However, a unit that uses fuel oil for startup should have a bypass to avoid getting unburned fuel on the catalyst during startup.

SCR in coal fired operation can be placed in one of three locations. The most common is a high dust SCR. With a high dust SCR, the catalyst is located downstream of the economizer and upstream of a boiler. The second option is a low-dust SCR where the catalyst is located downstream of a hot-side ESP. This reduces the cost of an SCR as compared to the high dust SCR since the catalyst volume can be smaller. It should be noted that an SCR located after a de-energized hot-side ESP should be designed and sized as a high dust SCR. The third option is a tail end SCR where the reactor is located downstream of an FGD system. This requires a smaller reactor than the other options but also requires a regenerative heat exchanger to heat the catalyst above the minimum ammonia injection temperature. In selecting a location for the SCR, specific plant issues need to be assessed to determine the most economical solution.

The SCR reactor is the housing for the catalyst. The reactor is basically a widened section of ductwork modified by the addition of gas flow distribution devices, catalyst, catalyst support structures, access doors, and sonic horns/soot blowers. An ammonia injection grid is located upstream of the SCR reactor. The SCR reactor is elevated above and upstream of the air heater.

The SCR reaction occurs within the temperature range of 550 to 850 °F, where the extremes are highly dependent on the fuel quality. Along with the NO_x reaction, the catalyst oxidizes a portion of the SO_2 in the flue gas to SO_3. The oxidation of SO_2 to SO_3 could also require moderate air heater modifications, since the acid dew point temperature of the flue gas is directly related to SO_3 concentration. As the SO_3 concentration increases, the acid dew point of the flue gas increases, potentially increasing corrosion in downstream equipment or possibly requiring an increase in the air heater gas outlet temperature.

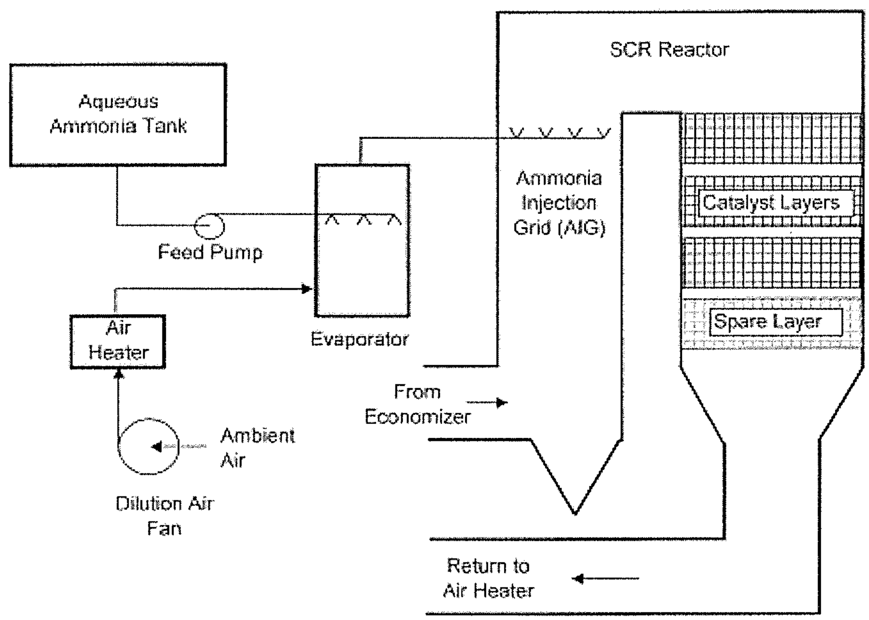


Figure 3-2
Schematic Diagram of a Typical SCR Reactor

The ammonia reagent for SCR systems can be supplied by anhydrous ammonia, aqueous ammonia, or by conversion of urea to ammonia. Since the ammonia is vaporized prior to contact with the catalyst, the selection of ammonia type does not influence the catalyst performance. However, the selection of ammonia type does affect other subsystem components, including reagent storage, vaporization, injection control, and balance-of-plant requirements. The vast majority of installations worldwide use anhydrous ammonia.

SCR systems have a variety of interfacing system requirements to support operations. These requirements include fan draft power, auxiliary power, soot blowing steam, gas temperature, controls, ductwork, reactor footprint, and air heater. The SCR system will affect the boiler draft system. Depending on arrangement and performance requirements, draft losses can range from 4 to 10 in. wg, which would require additional fan power. If necessary, ductwork and/or boiler box reinforcement may also be required. In conjunction with the fan modification, an expansion of the auxiliary power system might be necessary. Auxiliary power modifications may also be necessary for ammonia supply system requirements.

The major impact of the SCR system can be seen at the air heater, where there are two areas of concern. One concern is the formation and deposition of ammonium bisulfate on the air heater surface. This will cause an increase in the pressure drop of the air heater, degrading its performance and decreasing plant efficiency. The other potential concern for the air heater is the tendency for high SO_3 concentrations in the flue gas to form sulfuric acid vapor. If the acid dew point temperature has been increased to more than the air heater exit temperature, a significant amount of acid gases will condense in the air heater and lead to pluggage and corrosion. Several measures can be taken to avoid or correct this situation. Most important is the right composition of the catalyst to minimize the SO_2 to SO_3 conversion rate. Ammonia slip must also be minimized. Air heater basket modifications are often necessary to minimize these harmful effects.

3.1.4 SNCR/SCR Hybrid

The SNCR/SCR hybrid systems use components and operating characteristics of both SNCR and SCR systems. Hybrid systems were developed to combine the low capital cost and high ammonia slip associated with SNCR systems with the high reduction potential and low ammonia slip inherent in the catalyst of SCR systems.

The SNCR component of the hybrid system is identical to the SNCR system described previously, except that the hybrid system may have more levels of multiple injection lances. This will increase the capital cost of the SNCR component of the hybrid system. During operation, the SNCR system would be allowed to inject higher amounts of reagent into the flue gas compared to conventional SNCR. This increased reagent flow has a two-fold effect: NO_x reduction within the boiler is increased, while ammonia slip also increases. The ammonia that slips from the SNCR is then used as the reagent for the catalyst.

There are two design philosophies for using this excess ammonia slip. The most conservative hybrid systems use the catalyst simply as an ammonia slip "scrubber" with some additional NO_x reduction. As with in-duct systems, the flue gas velocity through the catalyst is an important factor in design. Operating in this mode allows maximum NO_x reduction within the boiler by the SNCR, while minimizing the catalyst volume requirement. While some NO_x reduction is realized at the catalyst, the relatively small catalyst requirement of this design allows a true in-duct arrangement, with no significant ductwork changes, arrangement interference, or structural modifications. The second philosophy uses adequate catalyst volume to obtain significant levels of additional NO_x reduction. However, this philosophy is usually not economically advantageous when compared to SCR. As a result, hybrid systems are usually designed using the first philosophy. The additional reduction is a function of the quantity of ammonia slip, catalyst volume, and distribution of ammonia to NO_x within the flue gas. Using ammonia slip produced by the SNCR system is not an efficient method to introduce reagent, because of the low reagent utilization discussed as a part of the SNCR. Therefore, even though the reaction at the catalyst requires 1 ppm of ammonia to remove 1 ppm of NO_x, the SNCR must inject at least 3 ppm of ammonia to generate 1 ppm of ammonia at the catalyst.

Catalyst volume is strongly influenced by the NO_x reduction required and the ammonia distribution. If multiple levels of catalyst operating at low flue gas velocity are required, some modifications will be required to the existing ductwork. If widening the existing ductwork cannot provide adequate catalyst volume, then a separate reactor is required, thus eliminating much of the capital cost advantage of a hybrid system.

The major impact of the hybrid system can be seen at the air heater, where there are two areas of concern. One concern is the formation and deposition of ammonium bisulfate on the air heater surface. This will cause an increase in the pressure drop of the air heater, degrading its performance and decreasing plant efficiency. The other potential concern for the air heater is high concentrations of SO_3 in the flue gas. If the acid dew point temperature has been increased to more than the exhaust temperature, a significant amount of acid gases will condense in the air heater and lead to pluggage and corrosion. Several measures can be taken to avoid or correct this situation. Modifications to the air heater baskets can help to minimize these adverse effects.

3.1.5 Gas Reburn

The natural gas reburning process employs three separate combustion zones to reduce NO_x emissions, as illustrated on Figure 3-3. The first zone consists of the normal combustion zone in the lower furnace, which is formed by the existing wall burners. In this zone, 75 to 80 percent of the total fuel heat input is introduced. The first zone burners are operated with about 10 percent excess air (a 1:10 stoichiometric ratio). A second combustion zone (the reburn zone) is created above the lower furnace by operating a row of conventional natural gas burners at a stoichiometric ratio of less than 1.0. This technology also has the potential for increased furnace corrosion (especially with higher sulfur fuels) because of the reducing atmosphere in the lower furnace.

The sub-stoichiometric reburn zone causes NO_x produced in the lower furnace to be reduced to molecular nitrogen and oxygen. This happens because the oxygen stripped from the NO_x molecules is combined with the more active CO molecules to form CO_2 as combustion is completed in the upper furnace. Fuel burnout is completed in the third zone (the burnout zone) by the introduction of OFA. Sufficient OFA is introduced to complete combustion of the unburned materials in the upper furnace, with an overall excess air rate for the boiler of 15 to 20 percent. Reburn technology has demonstrated NO_x reductions of 40 to 65 percent.

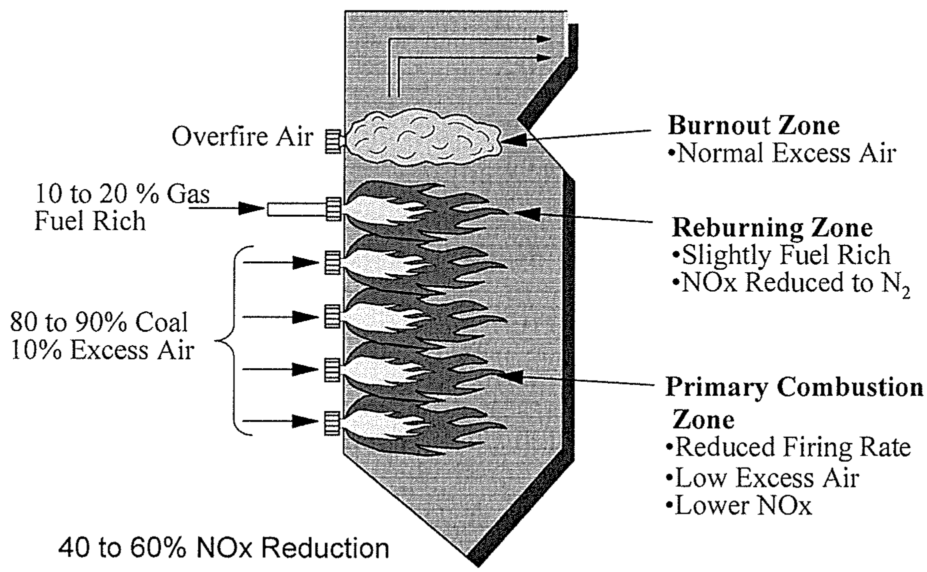


Figure 3-3
Schematic of Gas Reburn System

Sufficient residence time (adequate furnace height) in the reburn and OFA zones is a key factor in determining whether the reburning technology can be applied. Successful retrofit of this technology requires space within the boiler to allow adequate residence time for both the additional burning zone (0.4 to 0.6 second) and the associated OFA burnout zone (0.6 to 0.9 second). When this space is available, reburning can be highly effective, but a low residence time will limit system performance. Also, the high cost of natural gas makes the annual operating costs of this technology prohibitive.

A variation to gas reburn is fuel lean gas reburn (FLGR), which can reduce NO_x emissions from coal fired boilers by 30 to 45 percent. FLGR requires a lower natural gas input than in a conventional gas reburn system and does not require an OFA system to achieve CO burnout. The FLGR technology requires low natural gas flow rates to maintain an overall lean fuel condition (of approximately half the amount required for a conventional reburn system). Mixing between the injected gas and furnace gas is the key to effective NO_x removal. CO burnout is achieved by the excess oxygen that is available in the overall fuel lean furnace gas.

A newer development of the FLGR system consists of incorporating a urea-based SNCR system into the gas reburn system. This technology involves injecting natural gas and urea; the system is called amine-enhanced fuel lean gas reburn (AE-FLGR). This technology is capable of a higher NO_x removal efficiency than the basic gas reburn and FLGR systems. An amine-enhanced system is capable of reducing NO_x emissions by 50 to 70 percent.

3.1.6 Mobotec ROFA and ROTAMIX

Mobotec provides a NO_x reduction system that combines LNBs, OFA, and SNCR technologies into an integrated system. The system uses a modified OFA system with mixing characteristics achieved by adding a rotation to the OFA. This system is called ROFA, or Rotating Opposed Firing Air. A booster fan is used to direct combustion air away from the primary combustion zone and to the upper portion of the furnace. Air nozzles are strategically placed so that the gas flow inside the furnace rotates, causing turbulent mixing. The ROFA system has the potential to provide improved combustion, which results in lower unburned carbon, lower CO and NO_x production, and improved boiler efficiency.

In addition, ROTAMIX can be added to the system, which consists of injecting urea or ammonia into the ROFA air nozzles. The extra mixing produced by combining the OFA nozzles with the reagent injection can achieve additional NO_x reduction because of a homogeneous temperature profile in the boiler. The ROTAMIX system adapts to changes in load and temperature in the furnace and preferentially introduces ammonia where the temperature is most favorable for NO_x reduction. This approach reduces chemical consumption considerably and lowers ammonia slip by increasing the reaction efficiency through mixing. Chemical consumption for a ROTAMIX system can be up to 50 percent less than other SNCR technologies. ROTAMIX installations have yielded up to 60 percent NO_x reduction in addition to the ROFA NO_x reduction.

Although the Mobotec system may offer significant advantages over conventional scrubbing, impacts such as the increased volumes of particulate that would need to be collected, expected additional costs for sorbent, and the limited large-scale installed experience with the system should be considered. A simplified process flow diagram of the ROFA and ROTAMIX system is illustrated on Figure 3-4.

3.1.7 NO_xStar

NO_xStar is the trademarked name for a NO_x control technology that involves the injection of ammonia and a hydrocarbon (typically natural gas) into the flue gas path of a coal fired boiler at around 1,600 to 1,800° F for the reduction of NO_x. The ammonia reduces NO_x through an SNCR reaction, with the hydrocarbon minimizing the ammonia slip. This enables higher reagent injection rates for NO_x reductions than are achievable with a typical SNCR technology. The technology supplier states that the technology has the ability to achieve NO_x emissions of less than 0.20 lb/MBtu without the use of a catalyst and large SCR reactor. Although initially targeting high NO_x reductions, full-scale demonstrations to date have been limited to nominally 50 percent NO_x reduction performance.

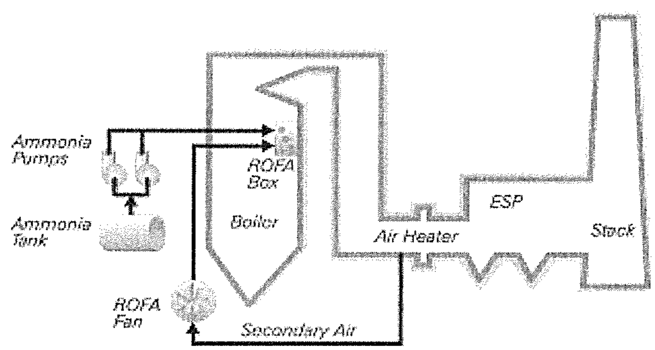


Figure 3-4
Mobotec ROFA and ROTAMIX Simplified Process Flow Diagram (Mobotec USA)

3.1.8 ECOTUBE

The ECOTUBE system utilizes retractable lance tubes that penetrate the boiler above the primary burner zone and inject high-velocity air as well as reagents. The lance tubes work to create turbulent airflow and to increase the residence time for the air/fuel mixture. In principle, the OFA and SNCR processes are combined in this technology.

ECOTUBE is capable of reducing NO_x, CO, and volatile organic compounds, while improving thermal efficiency, by optimizing the combustion process in boilers. An illustration of the ECOTUBE installation in a typical boiler is shown on Figure 3-5.

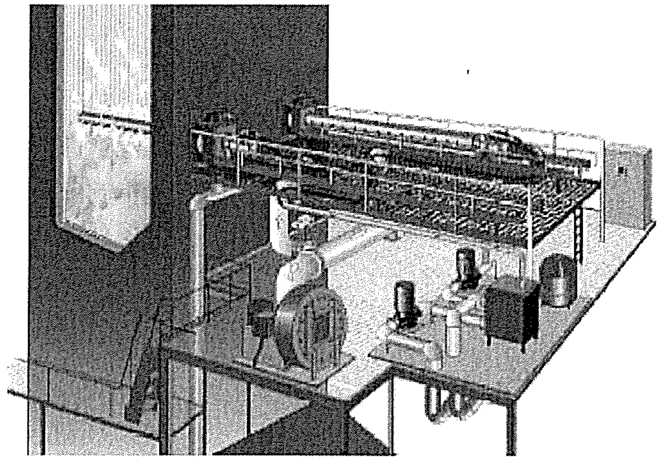


Figure 3-5
ECOTUBE Installation in a Boiler

The water-cooled ECOTUBEs are automatically retracted from the boiler on a regular basis and cleaned to remove layers of soot and other deposits. Additional benefits have been identified by the supplier, including furnace combustion improvements that increase efficiency, reduce fuel usage, and reduce corrosion and erosion in the boiler and back-end equipment.

3.1.9 PowerSpan

There are several emerging multi-pollutant technologies that use high electron beams or other proprietary processes. The PowerSpan ECO system has only limited experience and is beginning small-scale commercial operation. The ECO system is located downstream of an existing particulate control device; the process consists of three stages. A process flow diagram of the ECO system is illustrated on Figure 3-6. In the first stage, the flue gas passes through a dielectric barrier discharge reactor, where it is exposed to a nonthermal plasma discharge, which generates high energy electrons. The electrons initiate a chemical reaction to form oxygen and hydroxyl radicals, which then oxidize NO_X, SO_2, and Hg. This process results in the formation of nitric acid (HNO_3), sulfuric acid, and mercuric oxides. Stage 2 is the collection of these acids and oxides in a downstream ammonia scrubber. The final stage is the collection of acid aerosols, fine PM, and oxidized Hg in the downstream wet ESP. Scrubber effluents contain dissolved ammonium sulfate nitrate (ASN) salts along with solids and Hg. The ASN solution is sent to a recovery process where the Hg is removed via a sulfur-impregnated activated carbon structure. Once the activated carbon bed becomes saturated with Hg, it is disposed of as a hazardous waste. The cleaned stream of ASN is converted to a saleable fertilizer.

The ECO system has been tested on a 1 to 2 MW slipstream unit at FirstEnergy's Burger Plant and has achieved 82, 99, and 85 percent reduction for NO_x, SO_2, and Hg, respectively.

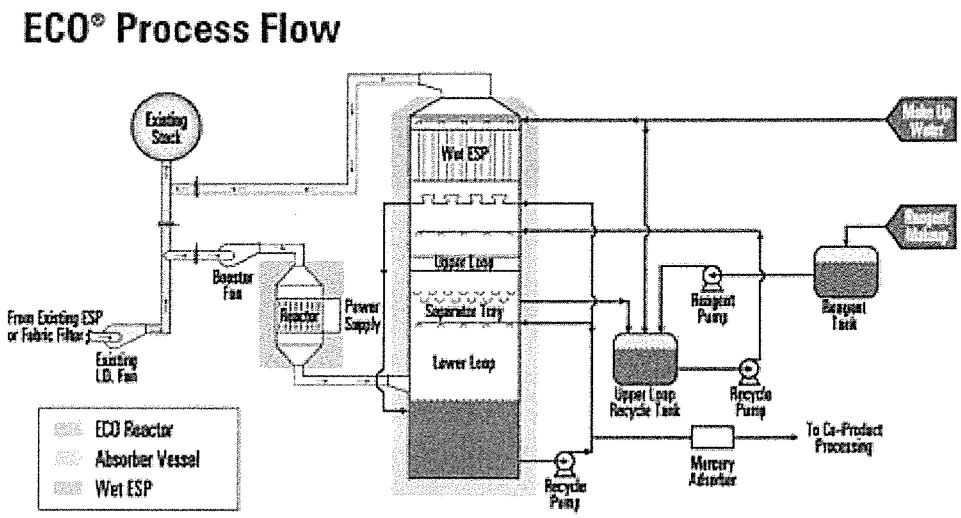


Figure 3-6
ECO Process Flow Diagram (Source: PowerSpan)

3.1.10 Phenix Clean Coal Combustion System

The Phenix Clean Combustion System (CCS) is an advanced hybrid coal gasification/combustion process that prevents the formation of NO_x and SO_2 emissions when burning coal. The only reagent required for pollution control is limestone.

The CCS consists of an entrained-flow coal gasifier, followed by stages of combustion air. The CCS burner is designed to provide the necessary time, temperature, and stoichiometry required for all the chemicals in coal to complete their combustion reactions (to reach equilibrium conditions).

The coal, with limestone added as a source of calcium for sulfur capture, is pulverized and introduced to the burner along with a limited amount of hot combustion air. The initial high temperature combustion gasifies and/or releases all the constituents of coal into the gas; i.e., carbon, sulfur, nitrogen, and ash compounds. At these high temperatures, and with limited available oxygen, the carbon aggressively commands oxygen to form CO from all sources, including such compounds as water. Nitrogen compounds that may form, such as NO_x, hydrogen cyanide, and ammonium (NH_4), are forced to the molecular form (N_2) by the aggressive action of carbon for oxygen. In the presence of calcium, the sulfur reacts to form calcium sulfide (CaS, a solid non-gaseous particle).

The high combustion temperatures melt the coal ash and calcium sulfide solids to form an inert slag that drains from the bottom of the boiler. The hot flue gas, with high concentrations of CO and H_2 and low concentrations of NO_x and sulfur, exits into the boiler furnace. As the gases cool and generate steam, additional OFA is added in stages to the furnace to complete the combustion of CO to CO_2 and H_2 to water. This prevents the formation of any new (thermal) NO_x and completes the combustion with excess air. The clean hot gases then enter the boiler superheat section as they did before the retrofit. A schematic of the process is shown on Figure 3-7.

Retrofits require an annual outage period with a 2 to 3 week extension, for a total of 8 weeks. The CCS retrofit modification requires replacing the existing pulverized coal burners with new down-fired CCS burners and adding OFA to the boiler furnace and powdered limestone to the coal fuel. Most of the new, off-the-shelf equipment fits within the existing boiler space.

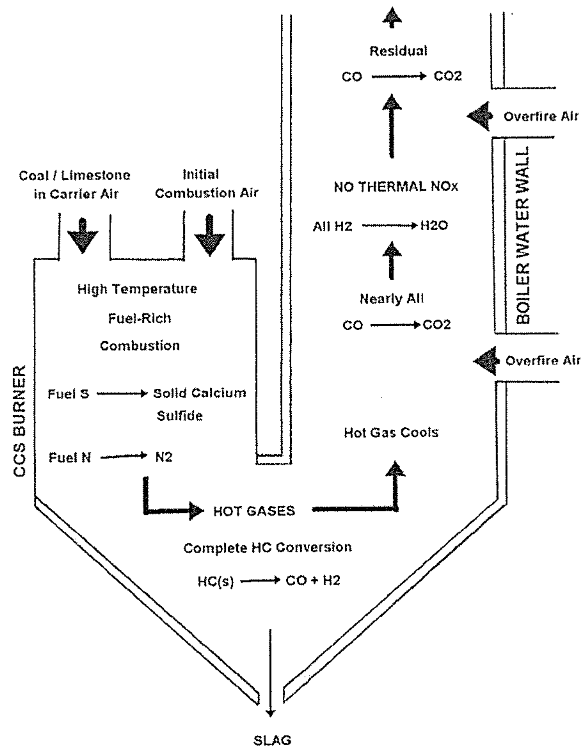


Figure 3-7
Phenix Clean Coal Process Flow Diagram. (Source: Phenix)

A CCS repowered boiler will show improved efficiency from more complete coal combustion (loss on ignition of < 1.0 percent), very low NO_x (< 0.15 lb/MBtu), and control of SO_2 emissions (< 0.5 lb/MBtu) with lower sulfur coals.

3.1.11 e-SCRUB

The e-SCRUB process is similar to the PowerSpan technology in that it uses an energy source to oxidize pollutants in the flue gas. However, there are some variations in the oxidation energy source and byproduct recovery systems. A process flow diagram is shown on Figure 3-8. The process consists of the following:

- e-Beam Chamber--This process uses a high-energy electron beam in a chamber, the e-Beam chamber, to oxidize SO_2 to SO_3 and NO_x to a combination of N_2, HNO_3, and NO_2. Ammonia is injected upstream of the chamber and reacts with the oxidized compounds to form ammonium sulfate and ammonium nitrate.

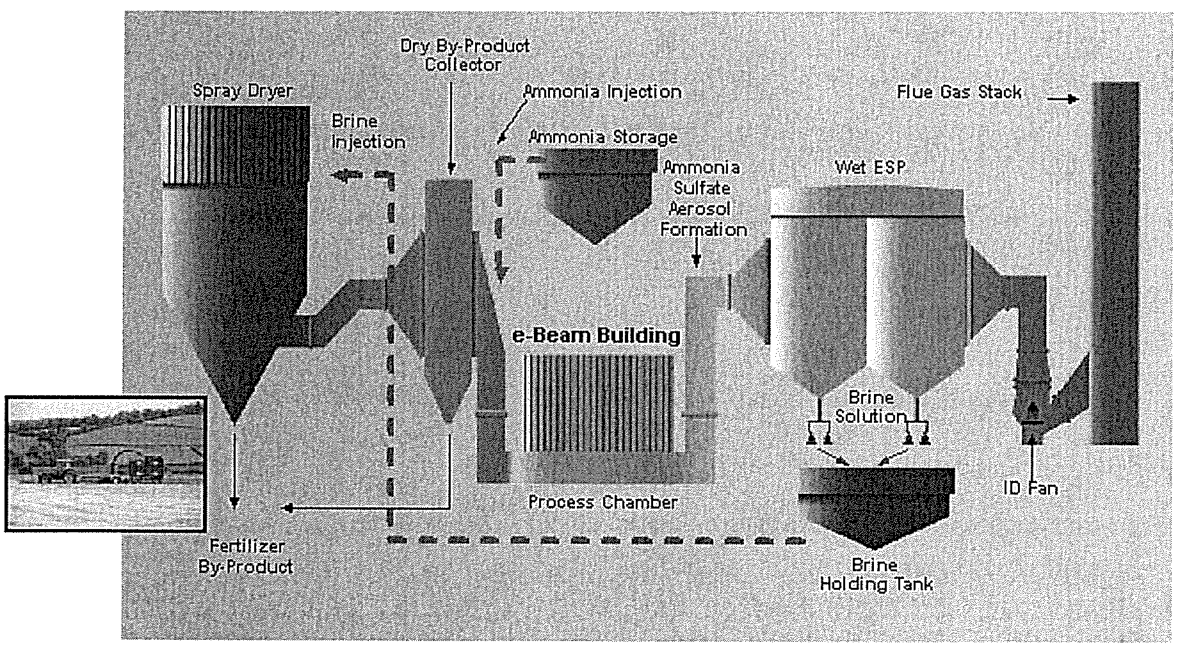


Figure 3-8
e-SCRUB Process Flow Diagram (Source: http://www.escrub.com/escrubprocess.htm)

- Wet ESP--The ammonium sulfate and ammonium nitrate are precipitated and collected as brine. The brine is then sent to an upstream spray dryer absorber and dry ESP.
- Spray Dryer Absorber--The brine from a downstream wet ESP is fed into a spray dryer absorber, which forms a dry ammonium sulfate

$((NH_4)_2SO_4)$/ammonium nitrate (NH_4NO_3) product that can be used as a fertilizer. The temperature of the flue gas is reduced in the spray dryer to an ideal reaction temperature prior to entering the e-Beam chamber.

- Dry ESP--The dry ESP functions as a secondary byproduct collector and is located directly downstream of the spray dryer absorber.

According to pilot data, the vendor estimates that SO_2 and NO_x removals of 98 and 90 percent, respectively, are achievable. To make this system cost-effective, it is important to locate a company to supply the ammonia reagent and remove the fertilizer byproduct. The e-SCRUB technology has been applied commercially on a 200 MW facility in China.

3.2 Particulate Matter Control Technologies

PM control technologies that were identified as available for retrofit at SJGS are listed below. Only post-combustion control is available for PM control. A short summary of each technology is included in the following sub-sections:

- Flue Gas Conditioning with Hot-Side ESP.
- Pulse Jet Fabric Filter.
- Compact Hybrid Particulate Collector.
- Max-9 Electrostatic Fabric Filter.

3.2.1 Flue Gas Conditioning with Hot-Side ESP

For most subbituminous coal fired power boilers, the low sulfur content in the coal causes the fly ash produced to have high resistivity. The reason for the higher fly ash resistivity is the lower concentration of high conductivity ionic sulfur oxide molecules in the flue gas. The high fly ash resistivity is not optimal for fly ash capture in an ESP and also limits the boiler fuel flexibility, since the ESP design is based on a defined range of fly ash characteristics. To improve the capture of the particulate in the ESP, the flue gas leaving the air heater into the ESP can be conditioned by the addition of ionic compounds such as SO_3, ammonia, or both. These compounds combine with the moisture in the flue gas and are deposited on the surface of the fly ash particles. This will increase the conductivity of the fly ash and, therefore, make it suitable for capture.

The effectiveness of a flue gas conditioning system can be determined by evaluating the ESP performance as flue gas conditioning agents are introduced in the flue gas stream ahead of the ESP. This is the most effective method of determining the optimal injection rate of the flue gas conditioning agent.

The equipment needed for injection of the flue gas conditioning agent is usually skid-based. If SO_3 is chosen as the flue gas conditioning agent, it is usually produced onsite through oxidation of SO_2 in a catalytic converter. Dry or molten sulfur feedstock may be used; the feedstock is burned to produce SO_2. Alternatively, ammonia can be used as an agent; ammonia is usually vaporized and injected into the flue gas stream using a standard pump skid.

3.2.2 Pulse Jet Fabric Filter

Fabric filters have been used for more than 20 years on existing and new coal fired boilers. Flue gas passes through media filters to remove the particulate. The success of fabric filters is predominantly due to their ability to economically meet the low particulate emissions limits for a wide range of particulate and fuel characteristics. Proper application of the fabric filter technology can result in clear stack discharges (generally less than 5 percent opacity) for a full range of operations. In addition, the fabric filter is relatively insensitive to ash loadings and various ash types, offering superb coal flexibility.

Fabric filters are the current technology of choice when low outlet particulate emissions or Hg reduction is required for coal fired applications. Fabric filters collect particle sizes ranging from submicron to 100 microns in diameter at high removal efficiencies. Provisions can be made for the future addition of activated carbon injection to enhance gas-phase elemental Hg removal from coal fired plants. A few types of fly ash filter cakes will also absorb some elemental Hg.

The cloth filter medium is typically sewn into cylindrical tubes called bags. Each fabric filter may have thousands of these filter bags. The filter unit is typically divided into compartments that allow online maintenance or bag replacement. The quantity of compartments is determined by maximum economic compartment size, total gas volume rate, air-to-cloth (A/C) ratio, and cleaning system design. Each compartment includes at least one hopper for temporary storage of the collected fly ash. A cutaway view of a PJFF compartment is illustrated on Figure 3-9.

Fabric bags vary in composition, length, and cross section (diameter or shape). Bag selection characteristics vary with cleaning technology, emissions limits, flue gas and ash characteristics, desired bag life, capital cost, A/C ratio, and pressure differential. Fabric bags are typically guaranteed for 3 years but frequently last 5 years or more.

In PJFFs, the flue gas typically enters the compartment hopper and passes from the outside of the bag to the inside, depositing particulate on the outside of the bag. To prevent the collapse of the bag, a metal cage is installed on the inside of the bag. The flue gas passes up through the center of the bag into the outlet plenum. The bags and cages are suspended from a tubesheet.

Cleaning is performed by initiating a downward pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag. This releases the dust cake from the bag surface, and the dust falls into the hopper. Cleaning may occur with the compartment online or offline. Care must be taken during design to ensure that the upward velocity between the bags is minimized so that PM is not re-entrained during the cleaning process. The PJFF cleans bags in sequential, and usually staggered, rows. During online cleaning, part of the dust cake from the row being cleaned may be captured by the adjacent rows. Online cleaning has been successfully implemented on PJFF on many large units and is a standard feature of the technology.

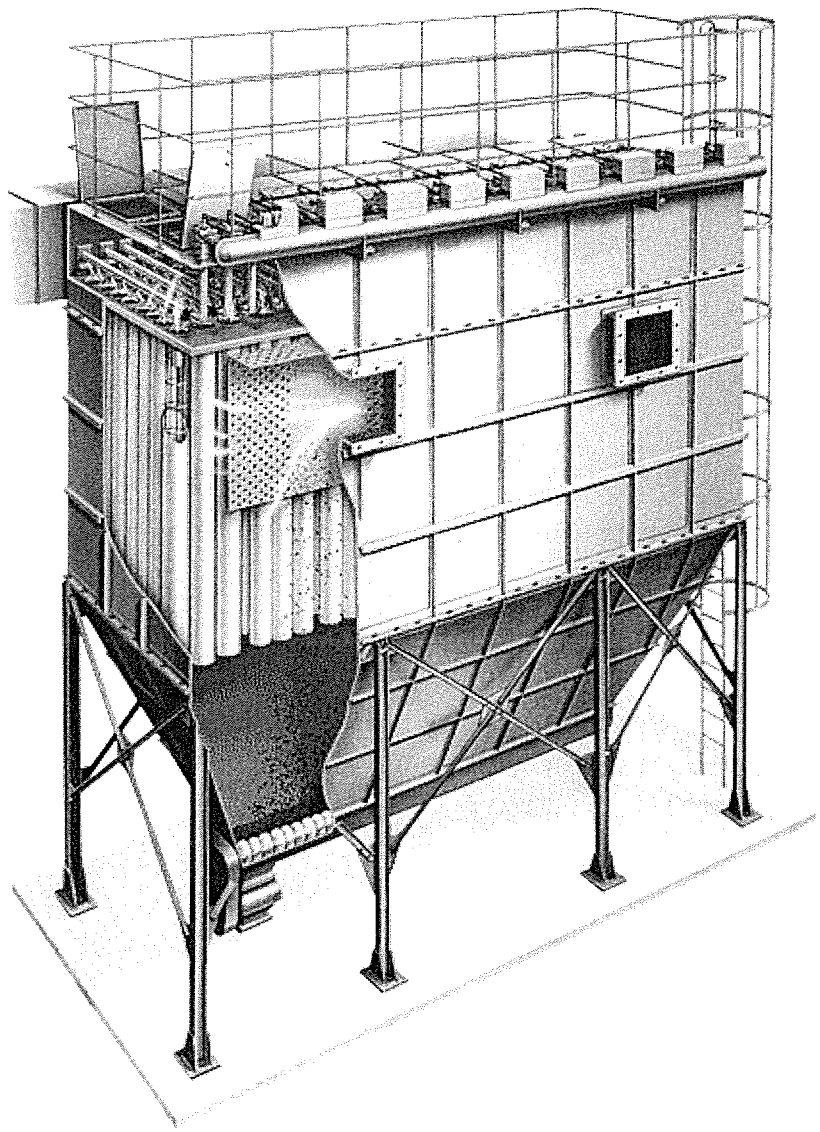


Figure 3-9
Pulse Jet Fabric Filter Compartment (Source: Babcock & Wilcox)

The PJFF bags are typically made of felted materials that do not rely as heavily on the dust cake's filtering capability as woven fiberglass bags. This allows the PJFF bags to be cleaned more vigorously. The felted materials also allow the PJFF to operate at a much higher cloth velocity, which significantly reduces the size of the unit and the space required for installation.

3.2.3 Compact Hybrid Particulate Collector

A variant of the PJFF is the compact hybrid particulate collector (COHPAC). This is a high A/C ratio fabric filter installed downstream of existing particulate collection devices where the majority of PM has been removed. The COHPAC acts as a polishing filter to further remove PM to meet the required emissions rate. This technology was developed and trademarked by the Electric Power Research Institute (EPRI). The COHPAC filter typically operates at A/C ratios ranging from 6 to 8 ft/min (6:1 to 8:1), compared to a conventional fabric filter that typically operates at A/C ratios of about 4 ft/min (4:1).

Since the majority of the particulate is collected in the upstream ESP, the performance requirements of a high A/C ratio fabric filter is reduced, which allows installation of this technology in a smaller footprint area, with less steel and filtration media; both capital and operating costs are lower than those of conventional fabric filters.

3.2.4 Max-9 Electrostatic Fabric Filter

The Max-9 electrostatic filter is essentially a high-efficiency PJFF utilizing a discharge electrode as in an ESP. However, there are no collector plates. When the dust particles are charged, they are attracted to the grounded metal cage inside the filter element, just as they would be attracted to the collecting plates in an ordinary precipitator. A front and side elevation view of the Max-9 particulate filter is illustrated on Figure 3-10. Since the particles are charged positively, they repel each other on the surface of the filter, making the collected dust cake very porous. The porous dust cake layer on the surface of the bags results in a pressure drop of about 25 percent compared to that of a normal fabric filter. Consequently, the Max-9 can operate at an A/C ratio higher than a conventional fabric filter and can treat a significant gas volume with a smaller footprint.

Process gas enters the Max-9 from a hopper inlet duct. The gas then flows upward through the filters and out through the top of the filters. The area above the tubesheet is a clean gas plenum. Compressed air pulses are used to clean the filters. A brief, intense blast of air is fired through the purge air manifold; holes in the blowpipes located above the filters direct the cleaning air pulse down through the filters. The cleaning sequence is controlled by timers that trigger solenoids. The high voltage system operates at very low current densities and at a steady state. There is no danger of fire caused by sparking, and the transformer/rectifier requires no voltage control.

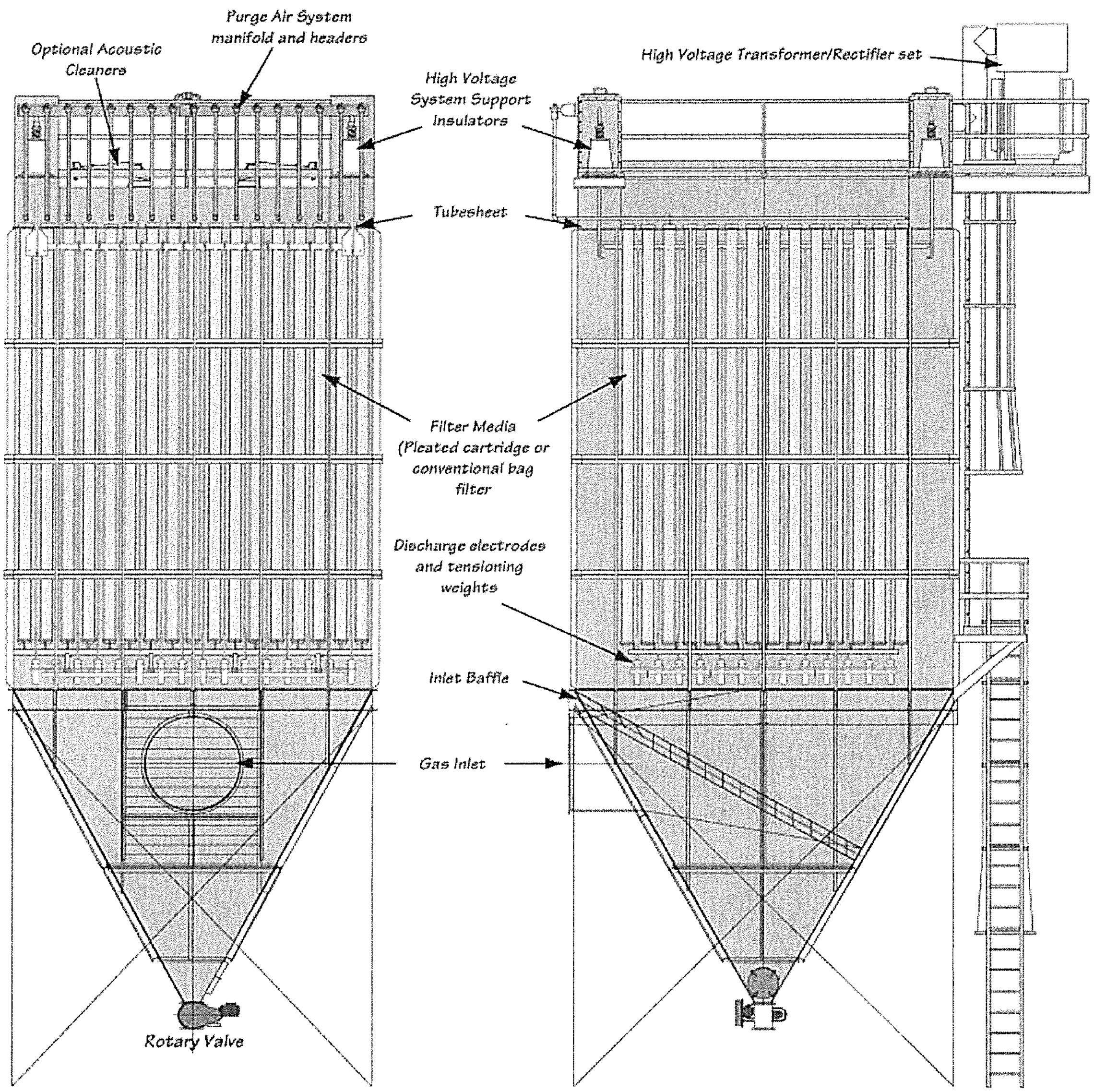


Figure 3-10
Max-9 Electrostatic Filter (Source: GE Environmental)

The Max-9 can be supplied as shop assembled modules that can be erected onsite, although the units are usually custom-engineered for each plant site and application to make the best use of available space.

3.3 Draft System Impacts

The addition of an SCR or hybrid SCR/SNCR would result in additional pressure requirements beyond the capabilities of the current fans on the SJGS units. To provide for this additional pressure drop, three alternatives are available. These alternatives are discussed in the following subsections.

3.3.1 New Booster Fans

The existing booster fans are currently being retrofitted with larger rotors to allow compliance with the upcoming consent decree upgrades. Further modifications to the booster fans are not possible within the existing housing.

New booster fans would be a possible option. Typically, the new fans would be installed near the current ones and the ductwork rerouted to save outage time. This alternative would not change the furnace operating pressure; however, depending on the final design, equipment downstream of the convection pass may operate under a negative pressure.

3.3.2 New Forced Draft Fans

It is unlikely that each unit's current forced draft fan could accommodate a new rotor capable of a 20 to 30 percent increase in total pressure; it is expected that an entirely new forced draft fan would be required. To reduce outage time, the new fans are typically installed close to the current ones and the ductwork rerouted. The limited space available at the SJGS could result in long combustion air duct runs, which would complicate this alternative.

In addition to the new forced draft fan, the boiler and ductwork may need to be stiffened to handle the increased boiler pressure. The increased pressure would increase the leakage of hot flue gas and ash out of the boiler and ductwork, resulting in increased maintenance requirements. This leakage would cause increased housekeeping requirements around the boiler area and an unpleasant working environment for plant personnel.

3.3.3 Balanced Draft Conversion

Conversion to balanced draft operation would move the balance point (zero relative pressure) inside the furnace. SJGS currently operates with the balance point just before the booster fans. The following modifications would be necessary for the balanced draft conversion:

- New induced draft fans and motors.

- Potentially, new motors for the existing forced draft fans to improve fan efficiency.
- Boiler wall stiffening to operate under a negative pressure.
- Ductwork stiffening to operate under a negative pressure.
- Control system modifications.
- Increased power requirements.

These modifications would require an approximate 12 week unit outage to perform.

A balanced draft unit would have significantly less ash and soot leakage around the boiler working area and would experience higher unit availability.

Previous studies have shown that the benefits of this alternative offset the costs in the majority of cases. Based on the previous analyses, costs for the SCR or hybrid installations included in later sections will include the cost of a balanced draft conversion.

4.0 BART Implications of the Consent Decree Technology Selection

As previously discussed in Section 1.1, PNM was required, under a consent decree action, to implement environmental system upgrades at SJGS. The environmental upgrade process is currently in progress with the installation of state-of-the-art LNBs with OFA ports and an NN system for NO_x control. For SO_2 emissions reduction, the wet limestone scrubber is being modified to eliminate flue gas bypass, and DBA is being added to the scrubber process to improve SO_2 removal. The new PJFF's that are being added for PM emissions control will also serve as a component for reducing Hg emissions through activated carbon addition into flue gas. Other balance-of-plant system upgrades are also being performed to support these additional AQC systems.

In this section of the report, the emission reductions from these environmental upgrades and the costs for compliance are quantified for evaluation as emissions control scenarios for BART. Only the NO_x and PM control technologies are included in the BART emissions control scenario, since the state of New Mexico will participate in the WRAP SO_2 trading program.

4.1 NO_x Consent Decree Control Technologies

4.1.1 Description of NO_x Consent Decree Upgrades

B&W will retrofit all four units with state-of-the-art integrated low-NO_x combustion systems. The systems for all units will include LNB (Model DRB-4Z), new dual-zone NO_x ports, and an NN system. To accommodate the new combustion system, work will be performed on the boiler wind box plenum, secondary air feeder ducts, waterwall panel, access platforms. Efforts will also be made to improve fuel/air balancing.

In addition, underfire air ports will be installed on Units 1 and 2 on the bottom two rows of the wall opposite to the burners. These ports will serve to break up the reducing atmosphere on the boiler wall to protect the tubes from degradation.

4.1.2 NO_x Consent Decree Upgrades Control Effectiveness

B&W provided an emissions performance guarantee for the installation of consent decree controls for NO_x reduction. NO_x emissions are guaranteed to a level of 0.293 lb/MBtu on a 30 day rolling average basis for each unit. There will be a year long test on each unit to determined if a lower NO_x emission limit can be achieved. The control effectiveness used for the consent decree NO_x upgrades, which is defined as the controlled emissions level in terms of the amount of pollutant generated per unit of heat input (lb/MBtu) is the guaranteed level of 0.293 lb/MBtu.

The pre-consent decree operation emissions levels (lb/MBtu) were based on annual averages from 2001 to 2003. This information was obtained from the 40 CFR Part 75 Electronic Data Reports for all four units. The hourly emissions rates were determined according to the emissions level and the design basis heat input. Compared to the pre-consent decree operation emissions levels at SJGS, which are shown in Table 4-1, the consent decree upgrade control effectiveness from the environmental upgrade work will result in a yearly emissions reduction ranging from 1,794 ton/yr at Unit 1 to 2,572 ton/yr at Unit 3. These results are detailed in Table 4-2.

4.1.3 NO_x Consent Decree Upgrades Cost-Effectiveness

Cost estimates for the consent decree work were provided by PNM and are summarized in ***Appendix C***. A snapshot of the total capital investment (TCI) and total annualized cost (TAC) for each unit is provided in Table 4-2. From the total cost for the upgrades and the expected emissions reduction from the new LNB, OFA ports, and an NN system, the cost-effectiveness, defined as the cost of control per amount of pollutant removed in $/ton, was estimated for each unit. These values are also shown in Table 4-2.

In summary, the cost-effectiveness of the NO_x consent decree upgrades ranges from 482 $/ton for Unit 3 to 793 $/ton for Unit 1.

4.1.4 Summary of NO_x Consent Decree Upgrades

The NO_x emissions control being installed at SJGS as a result of the consent decree are state-of-the-art combustion controls with a manufacturer's performance guarantee of 0.293 lb/MBtu. Although the guaranteed emission level is higher than the BART presumptive limit of 0.23lb/MBtu, the presumptive limit was developed for a dry bottom wall, fired boiler with LNBs and OFA burning a PRB subbituminous coal. The LNBs, OFA, and NN being installed on each of the SJGS units are equivalent to the BART technology used to develop the 0.23 lb/MBtu presumptive NO_x limit.

SJGS fires a local New Mexico coal. The coal burned at SJGS has been referred to as both a subbituminous coal and a bituminous coal, since it possesses qualities that place it in a "gray area" between the bituminous and the subbituminous categories of coal. Based on these characteristics, the ASTM D388 classification would place the SJGS coal in either of the bituminous Group C or subbituminous Group A coal category. The difference between these two groups is not relevant, but the fact that the SJGS coal cannot be categorized as subbituminous Group C is very important in that subbituminous Group C includes PRB coals, which are known to produce very low NO_x

Table 4-1
Consent Decree Technologies Control Effectiveness (Annual Average Emissions Rates)

Unit	SJGS 1			SJGS 2			SJGS 3			SJGS 4		
Design Basis Heat Input Data, MBtu/h	3,707			3,688			5,758			5,649		
NO_x Emissions Cases	lb/MBtu	lb/h	ton/yr	lb/MBtu	lb/h	ton/yr	lb/MBtu	lb/h	ton/yr	lb/MBtu	lb/h	ton/yr
Pre-Consent Decree Operation	0.43	1,592.0	5,394	0.45	1,649.3	6,179	0.42	2,405.5	9,004	0.42	2,399.6	8,833
Consent Decree Upgrades (LNB/OFA/NN)	0.30	1,112.1	4,140	0.30	1,106.4	4,119	0.30	1,727.4	6,431	0.30	1,694.7	6,309
PM Emissions Cases	lb/MBtu	lb/h	ton/yr	lb/MBtu	lb/h	ton/yr	lb/MBtu	lb/h	ton/yr	lb/MBtu	lb/h	ton/yr
Pre-Consent Decree Operation	0.050	185.4	690	0.050	184.4	687	0.050	287.9	1,072	0.050	282.5	1,052
Consent Decree Upgrades (PJFF)	0.015	55.6	207	0.015	55.3	206	0.015	86.4	322	0.015	84.7	315

Notes:
1. Emissions levels (lb/MBtu) shown are on an annual average basis.
2. Emissions (lb/h) calculations were based on the emissions level (lb/MBtu) and design basis heat input.
3. Pre-consent decree operation emissions were annual averages from the years 2001 to 2003.
4. Emissions levels listed were based on performance guarantees provided by the equipment vendor.
5. Yearly emissions (ton/yr) calculations were based on an annual unit capacity of 85 percent.

Table 4-2
Control and Cost-Effectiveness Results of Consent Decree Upgrades

Consent Decree Upgrades Scenario	Emission Performance Level (lb/MBtu)	Expected Emission Rate (lb/h)	Expected Emission Rate (ton/yr)	Expected Emission Reduction (ton/yr)	Total Capital Investment (TCI) (1,000$)	Total Annualized Cost (TAC) (1,000$)	Cost Effectiveness ($/ton)
NOx Reduction - LNB/OFA/NN							
SJGS 1	0.30	1,112.1	4,140	1,794	14,580	1,422	793
SJGS 2	0.30	1,106.4	4,119	2,060	14,126	1,378	669
SJGS 3	0.30	1,727.4	6,431	2,572	12,715	1,240	482
SJGS 4	0.30	1,694.7	6,309	2,524	12,870	1,256	498
PM Reduction - PJFF							
SJGS 1	0.015	55.6	207	483	67,072	10,427	21,586
SJGS 2	0.015	55.3	206	481	69,840	10,764	22,399
SJGS 3	0.015	86.4	322	750	72,696	12,454	16,599
SJGS 4	0.015	84.7	315	736	73,328	12,527	17,018

Notes:

1. All costs are in 2007$.
2. Expected emission rates (ton/yr) calculations were based on 85 percent unit capacity factor (refer to Appendix A Design Basis).
3. Expected emission reduction (ton/yr) calculations were based on the pre-consent decree upgrades control effectiveness as shown in Table 4-1.
4. TCI and TAC are referenced from Appendix C Cost Analysis Summary.
5. Cost-effectiveness ($/ton) is defined as ratio of TAC over expected emission reduction (ton/yr).
6. Expected emission reduction is based on annual emission reduction from pre-consent decree operation emission levels.

emissions when fired in utility boilers. Table 4-3 compares the fuel fired at SJGS to typical bituminous and PRB fuels. This fundamental understanding of the variation in NO_X formation from different types of US coals explains why the expected NO_X rates of boilers burning the coal fired at SJGS cannot be as low as boilers firing PRB subbituminous coals.

The coal burned at SJGS is less volatile and has a lower oxygen and moisture content than PRB coals. The greater volatility and higher oxygen and moisture content found in PRB fuels are key to the lower NO_X emissions seen in boilers combusting PRB coal. The high volatility in PRB coals reduces combustion time. The higher fuel oxygen content reduces the amount of additional air (i.e., nitrogen) required for combustion; the higher fuel moisture content reduces the flame temperature and, therefore, reduces the formation of thermal NO_X. The nitrogen content in the fuel affects NO_X generation because of the oxidation of fuel-bound nitrogen. As it relates to the amount of NO_X generated from combustion, the coal burned at SJGS is more similar to the low-sulfur bituminous coal than it is to PRB subbituminous coal.

A comparison of the New Mexico subbituminous coal burned at SJGS to a typical subbituminous PRB (Bucksin, WY mine) and a typical low-sulfur bituminous coal (Twentymile, CO mine) is shown in Table 4-3.

Table 4-3
Coal Properties Comparison

	Typical Subbituminous PRB	SJGS New Mexico Subbituminous	Typical Low-Sulfur Bituminous
Ultimate coal analysis, as received			
Carbon, %	49.00	54.52	64.05
Hydrogen, %	3.24	4.24	4.53
Sulfur, %	0.35	0.77	0.50
Nitrogen, %	0.63	1.08	1.63
Oxygen, %	11.68	9.38	10.09
Ash, %	5.15	21.29	9.80
Moisture, %	29.95	8.72	9.40
Total, %	100.00	100.00	100.00
Higher Heating Value, Btu/lb (as received)	8,400	9,692	11,400
Volatile matter, % (as received)	30.25	34.3	35.8
Volatile matter, % (dry)	43.18	37.6	39.5

Notes:
1. Typical subbituminous PRB analysis was based on Buckskin Mine (Wyoming).
2. Low-sulfur bituminous analysis was based on Twentymile Mine (Colorado).
3. SJGS New Mexico subbituminous analysis was based on BART analysis design basis.
4. SJGS New Mexico subbituminous volatile matter is referenced from SJGS consent decree Environmental Project Design Criteria, Sargent & Lundy, June 15, 2006.

Another factor affecting the potential for NO_x reduction at SJGS is the boiler design. Because of the HHV of the coal, the SJGS boilers are smaller in size (effective boiler volume) than similar output capacity boilers combusting PRB coal. This has a negative effect on potential NO_x emissions reduction because a smaller volume boiler will operate hotter, thus increasing thermal NO_x formation. Additionally, SJGS Units 1 and 2 have limited flame length because of the high heat input burners on the front wall of the boiler. This reduces the effectiveness of the overfire air from the OFA ports.

4.2 Particulate Matter Consent Decree Control Technologies

4.2.1 Description of PM Consent Decree Upgrades

For PM emissions reduction, a PJFF system will be installed on each of the four units at SJGS in response to the consent decree. The PJFFs will be installed downstream of the existing hot-side ESPs and air heaters. After the commissioning of the PJFF, the hot-side ESP will be de-energized.

As previously noted, Hg emissions are not being considered in the BART analysis. However, it is important to note that the PJFF will also serve as a component of the Hg control system. Activated carbon will be injected into the flue gas downstream of the air heater for adsorption of Hg in the flue gas. The PJFF is used to capture the Hg-laden activated carbon and other PM.

The PJFF installation will also necessitate modifications to the existing booster fans to handle the additional pressure requirements. Larger rotors will be installed into the existing booster fan housings. The units will continue to have positive pressure furnaces, but cannot be classified as truly forced draft or truly balanced draft. The boiler itself will continue to operate at a positive pressure, but there will be points in the flue gas path where the flue gas will have a negative pressure.

4.2.2 PM Consent Decree Upgrades Control Effectiveness

For each unit, B&W will provide a performance guarantee that the total filterable particulate matter (PM_{10}) will be controlled to 0.015 lb/MBtu at the stack. The PJFF is installed primarily to reduce opacity spikes during upset unit operating conditions and also as a component for Hg control as described above.

In comparison to the pre-consent decree operation emission levels at SJGS, which are shown in Table 4-1, the consent decree upgrade control effectiveness from the environmental upgrade work will result in a yearly emissions reduction ranging from 481 ton/yr at Unit 2 to 750 ton/yr at Unit 3. This result is detailed in Table 4-2.

4.2.3 PM Consent Decree Upgrades Cost-Effectiveness

A cost estimate for the new PJFF was provided by PNM and is summarized in ***Appendix C***. From the total cost for the upgrades and the expected emissions reduction from the new PJFF equipment, the cost-effectiveness in $/ton was estimated and is shown in Table 4-2. Because of the small amount of total emissions reduction, the cost-effectiveness of the new PJFF is very high, ranging from 16,599 $/ton at Unit 3 to 22,399 $/ton for Unit 2.

4.2.4 Summary of PM Consent Decree Upgrades

With the addition of PJFFs for PM emissions control, SJGS will have the most stringent control technology available for limiting the emissions of PM_{10}. The performance guarantee from the equipment vendor is typical of most new PJFF systems. It meets the New Source Performance Standards (NSPS) emissions level for PM_{10} and represents a BACT level of pollution control. Therefore, the new PJFF equipment at SJGS should be considered as BART for PM emissions reduction.

4.3 Summary of Consent Decree Control Technologies

The evaluation of the consent decree control technologies currently being implemented at SJGS for the BART analysis indicates that the new LNB, OFA, and NN installed for NO_x emissions represent the state-of-the-art combustion control technology, and the PJFF installed for PM emissions is the most stringent control technology for PM emissions control.

5.0 Technical Feasibility of Additional Control Technology Alternatives

As stated in Subsection 1.2.2, technically feasible retrofit emissions control technologies are identified by eliminating technically infeasible options. This section describes how the technical feasibility of a control technology is defined by the EPA in the BART guidelines. The technologies identified in Step 1 (Section 3.0) are considered available technologies at the time of issue of this report.

Section 4.0 describes the BART analysis that was performed for the consent decree control technologies. The analysis in Section 4.0 shows that the consent decree control technologies should be considered as BART. However, to provide additional support for that determination, the BART analysis process was applied for additional control technology alternatives to the consent decree technologies.

In the process of eliminating technically infeasible alternatives, it is necessary to demonstrate that a technology is not applicable or not available for application at the source. This demonstration is made by showing that the technology is commercially unavailable and/or there are insurmountable technical difficulties with applying the technology to the applicable unit. Other factors that are considered when determining the technical feasibility of a technology include the following:

- Size of the unit.
- Location of the proposed technology.
- Operating problems after retrofit of technology.
- Space constraints.
- Reliability.
- Adverse effects on the rest of the facility.
- Adverse community impacts.

Additionally, a technology is technically infeasible if its level of emissions control does not achieve the required permit emissions limit applied to the source by the regulating agency. Finally, if there are multiple control technologies that have an equivalent level of control, the BART procedure allows for the consideration of the less costly control technology, therefore eliminating the need to evaluate higher cost technologies.

For all the technologies identified as available in Section 3.0, a determination was made regarding the technical feasibility of the technology at the SJGS site on the basis of the criteria highlighted above.

5.1 Technically Infeasible Additional NO_x Control Technology Alternatives

5.1.1 Selective Non-Catalytic Reduction

SNCR was determined to be technically infeasible because the controlled NO_x emissions do not meet the required presumptive emissions limits. A budgetary performance evaluation from an SNCR vendor indicated that the controlled NO_x emissions level would be 0.24 lb/MBtu for all four units at SJGS. A lower controlled NO_x emissions level of 0.23 lb/MBtu, which would meet the presumptive limit, could be achieved if the ammonia slip limit is raised from 5 ppm to 10 ppm. However, the higher ammonia slip will significantly increase the risk for blinding fabric filter bags and shortening bag life. The risk is also high for air heater pluggage from ammonium bisulfate. Air heater pluggage degrades air heater performance and directly impacts plant efficiency. Therefore, the 10 ppm ammonia slip cannot be tolerated, thus rendering the SNCR infeasible as an additional control technology alternative.

5.1.2 Natural Gas Reburn

Natural gas reburn in the SJGS boilers is not technically feasible because of the lack of space in the boiler for sufficient residence time for the natural gas reburn zone. The ongoing environmental upgrades at each boiler include the addition of new OFA ports, which will limit the physical space on the boiler wall for a natural gas reburn system, especially on Units 1 and 2 where height is limited. In addition, a new natural gas supply line would be required, since the existing natural gas line was abandoned. The exposure to the volatility of natural gas prices is also a negative factor when considering natural gas reburn as a NO_x control technology.

5.1.3 Mobotec ROFA and ROTAMIX

Mobotec's ROTAMIX technology is not considered technically feasible, because there are no current installations at pulverized coal fired boilers of the equivalent size to that of SJGS. The ROFA technology is a variant of the OFA system that is already being added as a result of the consent decree. Although the Mobotec system may offer advantages over conventional scrubbing, the increased volumes of particulate that would need to be collected, the expected additional costs for sorbent, and the limited large-scale experience with the system are significant factors that make it infeasible for this application.

5.1.4 NO_xStar

The major consideration for the NO_xStar technology is that it currently has only one major installation in the United States and may require the installation of a single layer of in-duct catalyst (NO_xStar Plus) to achieve the advertised levels of NO_x reduction. Availability of natural gas is a factor that must be considered when assessing the technical feasibility of this technology. There is no natural gas supply at SJGS. In addition, through recent discussions, the supplier has identified limited ability and willingness to market the commercial technology.

5.1.5 ECOTUBE

This technology has been demonstrated in installations on industrial/small-sized boilers firing solid waste, wood, or biomass. It is not technically feasible to apply this technology to boilers of the size as those at SJGS.

5.1.6 PowerSpan

The PowerSpan process has only been proven on a small scale and has not been applied at large-size commercial systems such as SJGS. Therefore, this process is not applicable for retrofit at SJGS. In addition, the ECO system has not been pilot tested at a facility burning a low sulfur (< 1.5 percent) subbituminous coal or in a large, commercial-scale system. Therefore, it is considered not technically feasible for retrofit at SJGS. It should be noted that the first full-scale commercial unit using this process will be installed in FirstEnergy's Burger plant. After it is installed, a better evaluation of the technical feasibility can be made.

5.1.7 Phenix Clean Combustion

This technology is still in the demonstration and testing stage. There are no commercial retrofits at facilities similar to SJGS. Therefore, this technology is not considered to be applicable for retrofit at SJGS.

5.1.8 e-SCRUB

Although the e-SCRUB process system appears to offer significant advantages, it is still an experimental system with little proven operational data and only one known medium utility-scale installation. Therefore, the e-SCRUB process is not considered applicable for retrofit at SJGS.

5.2 Technically Infeasible Additional PM Control Technology Alternatives

5.2.1 Flue Gas Conditioning with Hot-Side ESP

Flue gas conditioning improves the operability of the ESP but does not increase the level of emissions control to a higher level than the required emissions limit for SJGS after the retrofit of the PJFF. Therefore, it was not evaluated as applicable for SJGS.

5.2.2 Compact Hybrid Particulate Collector

The COHPAC system currently available in the industry does not provide a performance guarantee better than the expected performance of the new PJFFs that are currently being installed at SJGS for the consent decree. Because of this consideration, the COHPAC was not evaluated as a technically feasible control technology.

5.2.3 Max-9 Electrostatic Fabric Filter

The GE Max-9 Hybrid has been recently installed commercially in a smaller-sized utility boiler. However, there are no current commercial installations in similar-sized units as SJGS. Therefore, the GE Max-9 was not considered as technically feasible when evaluated as part of the BART procedures.

5.3 Technical Feasibility Summary

After the completion of the screening process (Step 2 of the BART determination), the following technologies were identified as feasible upgrades to the ongoing consent decree environmental upgrades at SJGS for NO_x reduction:

- SCR.
- SNCR/SCR hybrid.

There were no additional PM control technologies identified that would have better emissions reduction than the PJFFs that are being retrofitted at SJGS for PM and Hg reduction.

A summary result of the evaluation process is detailed in Tables 5-1 and 5-2. Also included in the tables are the reasons for technical infeasibility of the eliminated control technologies.

Table 5-1
Technically Feasible Additional NO_x Control Technology Alternatives

Pollutant	Philosophy	Technology	Technically Feasible and Applicable?	Reasons for Technical Infeasibility
NO_x	Control technologies:	SNCR	No	Emissions control does not achieve required presumptive limit.
		SCR	Yes	--
		SNCR/SCR Hybrid	Yes	--
		Gas Reburn	No	Boiler not suitable for natural gas reburn process due to lack of residence time.
		Mobotec ROFA and ROTAMIX	No	ROTAMIX technology not demonstrated at SJGS scale boiler systems. ROFA will be considered as an OFA variant.
		ECOTUBE	No	Not applied to SJGS scale boiler systems.
		PowerSpan	No	In early commercial application stage. Not applied to SJGS scale boiler systems.
		Phenix Clean Combustion	No	Still in demonstration and testing stage. Not applied to SJGS scale boiler systems.
		e-SCRUB	No	Still in demonstration and testing stage. Not applied to SJGS scale boiler systems.

Table 5-2
Technically Feasible Additional PM Control Technology Alternatives

Pollutant	Philosophy	Technology	Technically Feasible and Applicable?	Reasons for Technical Infeasibility
PM	Control Technologies:	Flue Gas Conditioning with Hot-Side ESP	No	Level of emissions control does not exceed expected level of control with new PJFF retrofit.
		Compact Hybrid Particulate Collector	No	Level of emissions control does not exceed expected level of control with new PJFF retrofit.
		Max-9 Electrostatic Fabric Filter	No	Not applied to SJGS scale boiler systems.

6.0 Evaluation of Technically Feasible Additional Control Technology Alternatives

This section discusses the control effectiveness evaluation of technically feasible additional control technology alternatives for controlling NO_x emissions beyond that achieved by technologies that will be installed for the consent decree.

6.1 Control Effectiveness

The evaluation process in Step 3 determines the control effectiveness of the additional NO_x control technologies. Control effectiveness is expressed in a common metric based on the amount of pollutant generated per unit of heat input (lb/MBtu). The evaluation of the control effectiveness was translated into an hourly rate (lb/h) for each pollutant, according to the design basis heat input data for each SJGS unit. The evaluation of control effectiveness was based on information indicated in Subsection 1.2.3.

Table 6-1 indicates the control effectiveness of each additional NO_x control technology. This control effectiveness was calculated from the consent decree values discussed in Section 4.0.

The control effectiveness for each technology is also summarized in the Design Concept Definition tables in ***Appendix B***.

Table 6-1
NO_x Control Effectiveness for Additional Control Technology Alternatives (Annual Average Emissions Rates)

Unit	SJGS 1			SJGS 2			SJGS 3			SJGS 4		
Design Basis Heat Input Data, MBtu/h	3,707			3,688			5,758			5,649		
NO_x Emissions Cases	lb/MBtu	lb/h	ton/yr	lb/MBtu	lb/h	ton/yr	lb/MBtu	lb/h	ton/yr	lb/MBtu	lb/h	ton/yr
Consent Decree Upgrades (LNB/OFA/NN)	0.30	1,112.1	4,140	0.30	1,106.4	4,119	0.30	1,727.4	6,431	0.30	1,694.7	6,309
SCR	0.07	259.5	966	0.07	258.2	961	0.07	403.1	1,501	0.07	395.4	1,472
SNCR/SCR Hybrid	0.18	667.3	2,484	0.18	663.8	2,471	0.18	1,036.4	3,859	0.18	1,016.8	3,786

Notes:
1. Emissions levels (lb/MBtu) shown are on an annual average basis.
2. Emissions (lb/h) calculations were based on the emissions level (lb/MBtu) and design basis heat input.
3. Emissions levels listed were based on performance guarantees provided by the equipment vendor.
4. Yearly emissions (ton/yr) calculations were based on an annual unit capacity of 85 percent.

7.0 Impact Analysis and Cost-Effectiveness of Additional Control Technology Alternatives

This section discusses the impact analysis and cost-effectiveness for SCR and SNCR/SCR hybrid technologies.

7.1 Types of Impact Analyses

For all the additional NO_X control technologies that are being considered, an impact analysis was performed as part of the BART determination process. The purpose of this exercise was to quantify the cost of applying the technology at the source, so that a comparison of the cost-effectiveness of each technology could be made. The definition of cost-effectiveness is provided in Subsection 1.2.4 of this report. In summary, the four types of impact analyses performed consisted of the following:

- Costs of compliance.
- Energy impacts.
- Non-air quality environmental impacts.
- Remaining useful life.

7.2 Methods of Impact Analysis

The first step in performing the impact analysis was to define the design parameters for each additional NO_X control technology that was identified as technically feasible. The design parameters contain all pertinent information on the control technology system for specific application to the source. Examples of these design parameters include type of reagent used and consumption rate, type of byproduct produced and production rate, flue gas pressure drop across the control technology, etc. The information used to define the design parameter included the following:

- Information from equipment vendors.
- Background information documents used to support NSPS development.
- Control technique guidelines document.
- EPA cost manuals.
- Trade publications.
- Engineering and performance test data.

Design parameters for each control technology that was identified as technically feasible for application at the SJGS site are summarized in the Design Concept Definition tables (***Appendix B***).

7.2.1 Cost of Compliance

Black & Veatch developed the cost of compliance based on the requirements for implementing each technically feasible control technology. The TCI for each control technology when applied specifically to the SJGS site and the annual O&M costs were calculated. The basis for this cost calculation was as follows:

- CUECost workbook, Version 1.0.
- EPA Air Pollution Control Cost Manual - Sixth Edition.
- Budgetary quotes from equipment vendors.
- References to quotes or cost estimation for previous design/build projects or in-house engineering estimates.

7.2.2 Energy Impacts

Energy impacts were estimated for each control technology that consumes auxiliary energy during its operation. Only direct energy impacts for each control technology, such as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance, were accounted for. Indirect energy impacts, such as the energy to produce raw materials used for the control technology system, were not considered. The auxiliary power consumption of the control technology was estimated on the basis of the typical power consumption of similar equipment of an equivalent size. The additional draft system power consumption was calculated on the basis of the volumetric flow rate of the flue gas through the control technology system and the flue gas pressure drop defined in the design parameter of the control technology.

7.2.3 Non-Air Quality Environmental Impacts

The major non-air quality impacts evaluated were the water consumption and disposal requirements for the byproduct and waste generated by each control technology. All quantities of water consumption and byproduct or waste generated by each control technology were calculated on a yearly basis.

7.2.4 Remaining Useful Life

Finally, the impact of the remaining useful life of the control technology on its cost-effectiveness was considered. For this BART analysis, the remaining useful life of the controls was defined as 20 years. Therefore, there was no additional life impact cost for the additional control technologies.

7.3 Cost-Effectiveness

The cost-effectiveness of each control technology was calculated from the cost of compliance and the amount of pollutant reduced. The cost-effectiveness is defined as the cost of control per amount of pollutant removed. The cost of control takes into account the impact analyses performed. The reduced emissions were estimated on a yearly basis according to the reduction from the consent decree emissions level shown in Table 6-1. Both the consent decree emissions level and the additional control technology alternative emissions level are documented in Table 6-1 and in the Design Concept Definition tables (***Appendix B***).

Two types of cost-effectiveness were calculated during the BART determination: average and incremental cost-effectiveness. The general definition of the average and incremental cost-effectiveness can be found in Subsection 1.3.4. The cost-effectiveness values were based on 2007 dollars.

7.4 Impact Analysis and Cost-Effectiveness Results

An impact analysis was performed for all the identified technically feasible control technologies. A summary of the calculated impact analysis is presented in ***Appendix C***.

For all the additional NO_x control technologies evaluated, a summary table was developed for the impact analysis performed and the resultant cost-effectiveness. Table 7-1 presents the final evaluations for all four units. The expected after-control emissions levels are also included in the table. The data in the summary table were used to produce a graphical plot of the TAC versus the expected emissions reduction (ton/yr). The plots are shown on Figures 7-1 to 7-4.

From the graphical plot, a "least-cost envelope" for each group of control technologies was identified. Control technologies that lie on this least-cost envelope are "dominant controls" that should be the focus for the BART determination. Dominant controls are the technologies that have the lowest cost for implementation per quantity of pollutant removed. Therefore, these technologies are considered more cost effective for emissions reduction, barring any additional factors or considerations.

For all the dominant controls, the incremental cost-effectiveness between a technology and the next most stringent control technology was also calculated. This incremental cost-effectiveness indicates the additional cost to increase the removal of pollutant when comparing technologies that have different emissions removal capabilities.

Table 7-1

Impact Analysis and Cost-Effectiveness Results of Additional NO_x Control Technologies

All Feasible Technologies	Emission Performance Level (lb/MBtu)	Expected Emission Rate (lb/h)	Expected Emission Rate (ton/yr)	Expected Emission Reduction (ton/yr)	Total Capital Investment (TCI) (1,000$)	Total Annualized Cost (TAC) (1,000$)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Energy Impacts (1,000$)	Non-Air Impacts (1,000$)
SJGS Unit 1										
Selective Catalytic Reduction (SCR)	0.07	259.5	966	3,174	156,805	20,525	6,466	2,844	1,496	--
SNCR/SCR Hybrid	0.18	667.3	2,484	1,656	104,436	16,207	9,786	--	706	1,762
SJGS Unit 2										
Selective Catalytic Reduction (SCR)	0.07	258.2	961	3,158	169,251	21,891	6,932	3,457	1,492	--
SNCR/SCR Hybrid	0.18	663.8	2,471	1,648	108,628	16,670	10,117	--	346	1,762
SJGS Unit 3										
Selective Catalytic Reduction (SCR)	0.07	403.1	1,501	4,931	215,568	28,359	5,752	1,167	2,194	--
SNCR/SCR Hybrid	0.18	1,036.4	3,859	2,572	168,507	25,606	9,954	--	507	2,658
SJGS Unit 4										
Selective Catalytic Reduction (SCR)	0.07	395.4	1,472	4,837	199,558	26,592	5,497	753	2,215	--
SNCR/SCR Hybrid	0.18	1,016.8	3,786	2,524	161,572	24,849	9,846	--	507	2,658

Notes:

1. All costs are in 2007$.
2. Expected emission rates (ton/yr) calculations were based on 85 percent unit capacity factor (referer to Appendix A Design Basis).
3. Expected emission reduction (ton/yr) calculations were based on the consent decree upgrades control effectiveness as shown in Table 4-1.
4. TCI and TAC are referenced from Appendix C Cost Analysis Summary.
5. Cost-effectiveness ($/ton) is defined as ratio of TAC over Expected Emission Reduction (ton/yr).
6. Expected emission reduction is based on annual emission reduction from consent decree upgrade emission levels (Table 4-1).
7. Incremental cost effectiveness are based on increments in expected emission reduction (ton/yr)

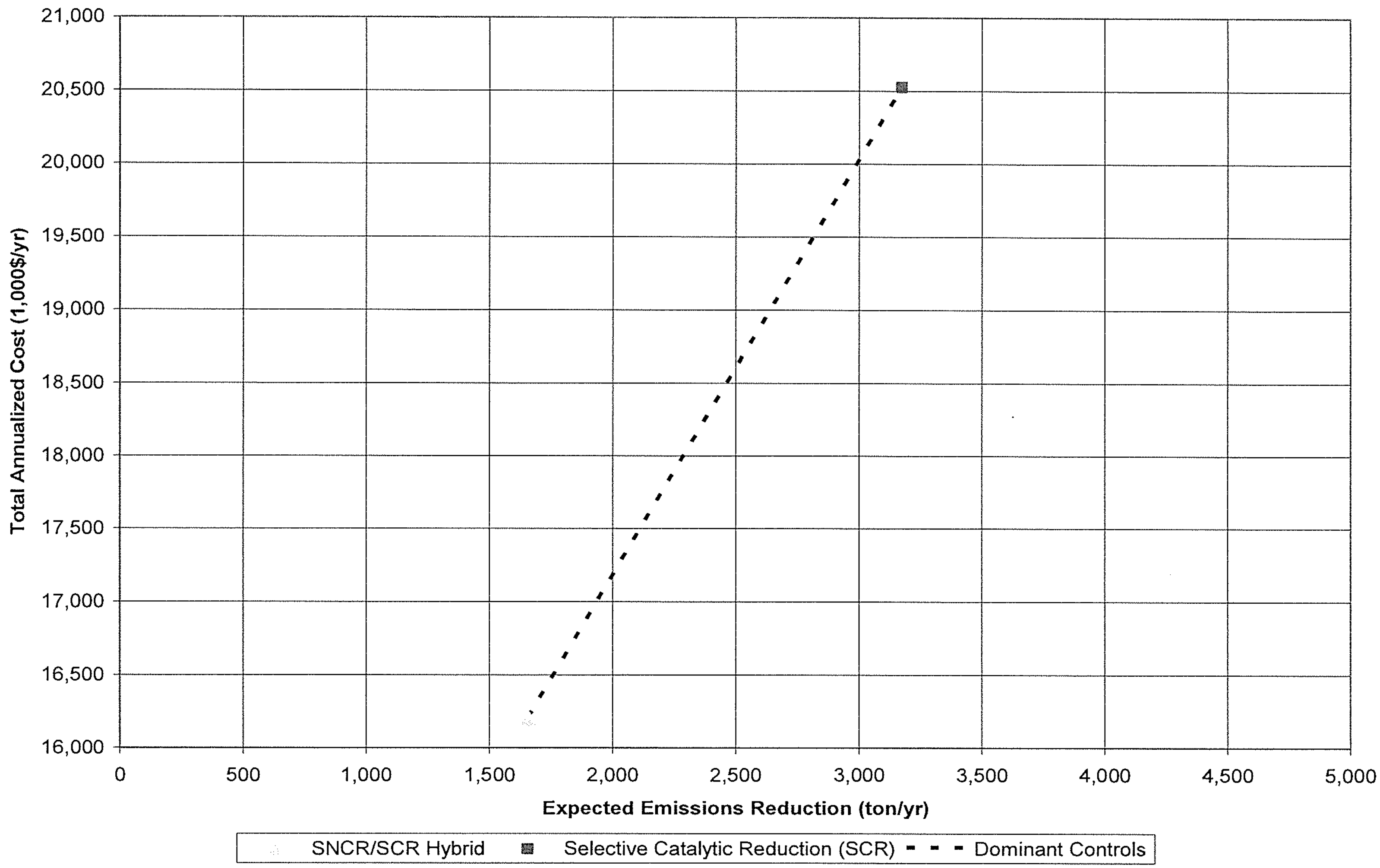


Figure 7-1
SJGS Unit 1 Additional NO_x Control Technology Cost-Effectiveness

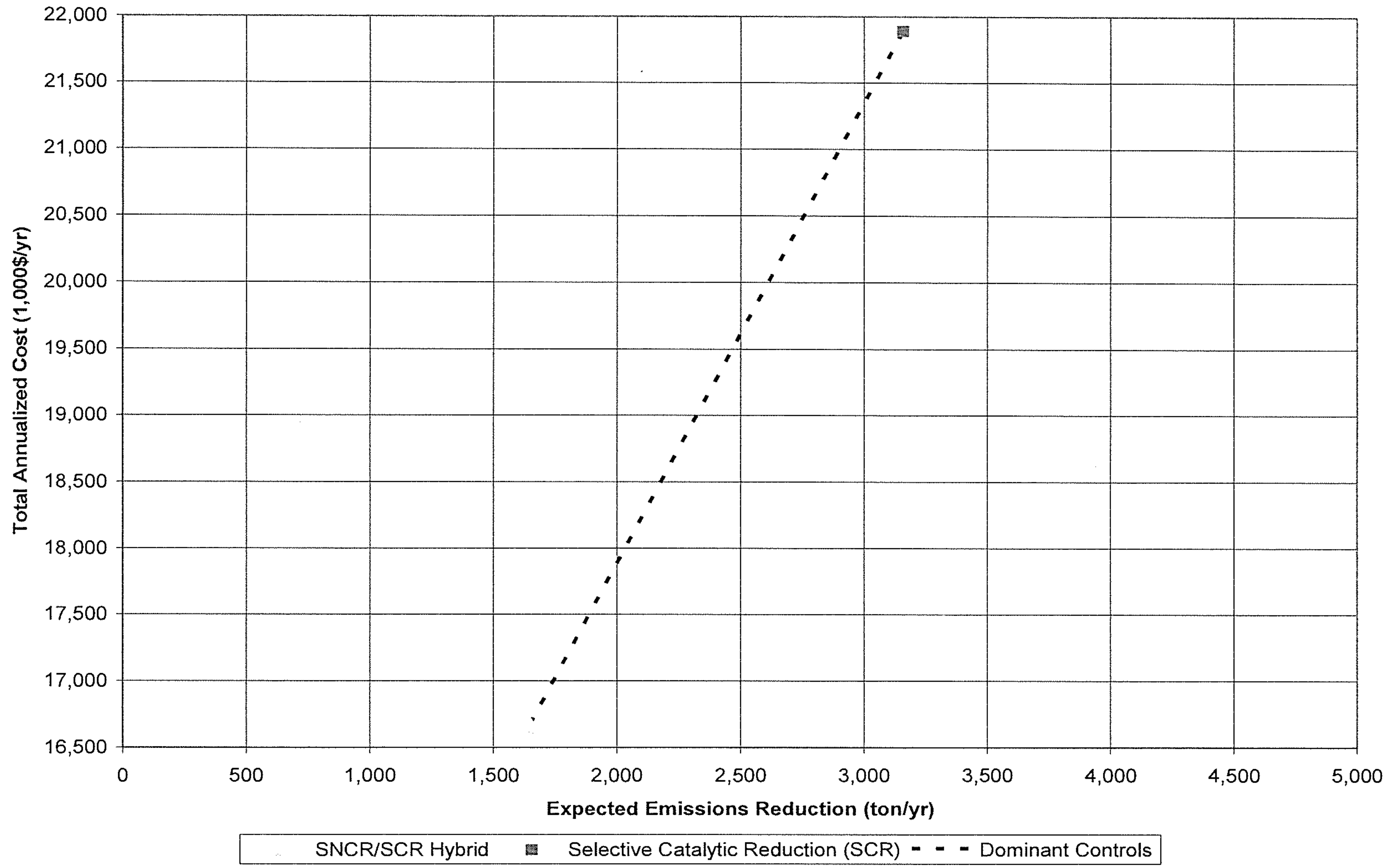


Figure 7-2
SJGS Unit 2 Additional NO_x Control Technology Cost-Effectiveness

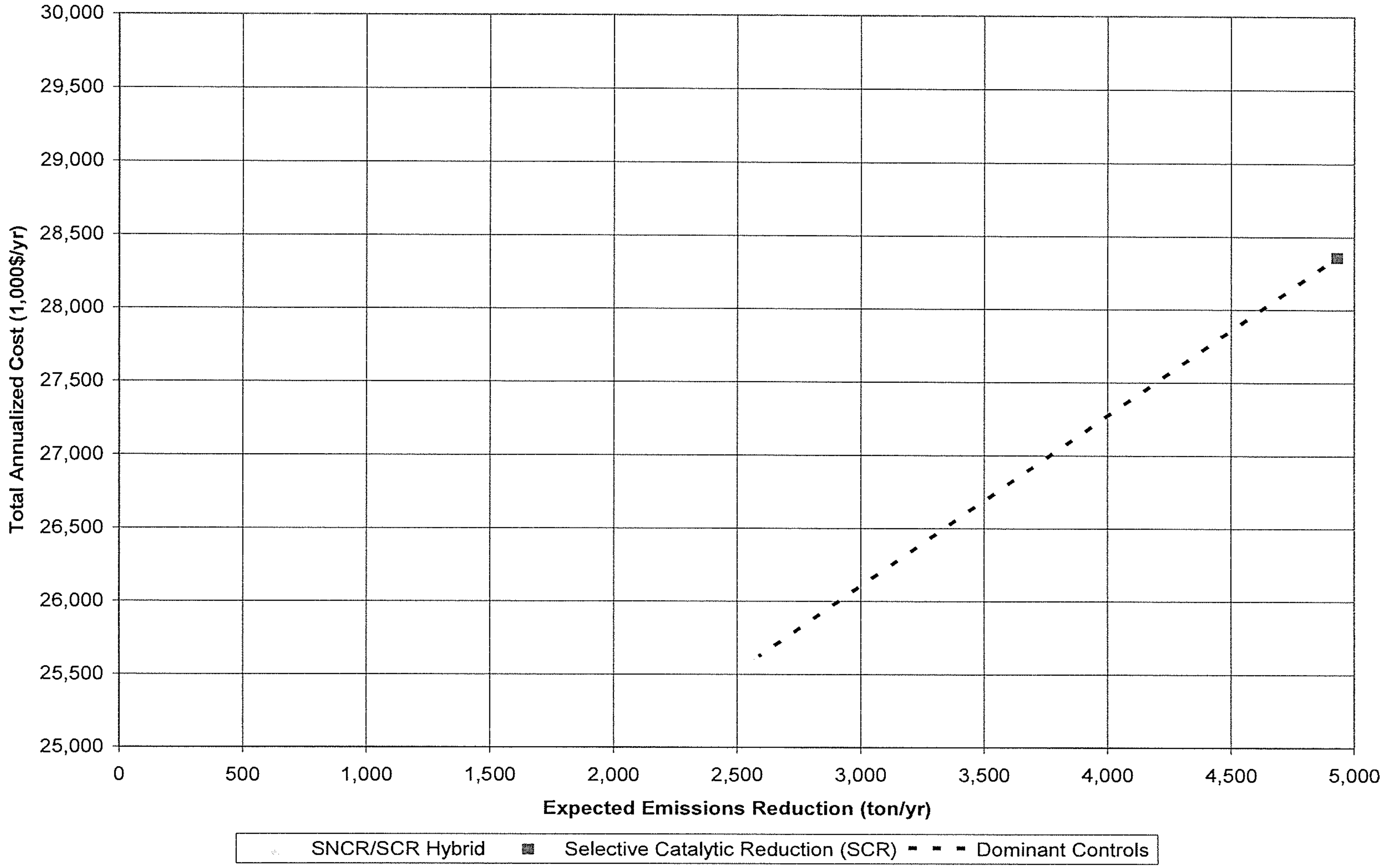


Figure 7-3
SJGS Unit 3 Additional NO_x Control Technology Cost-Effectiveness

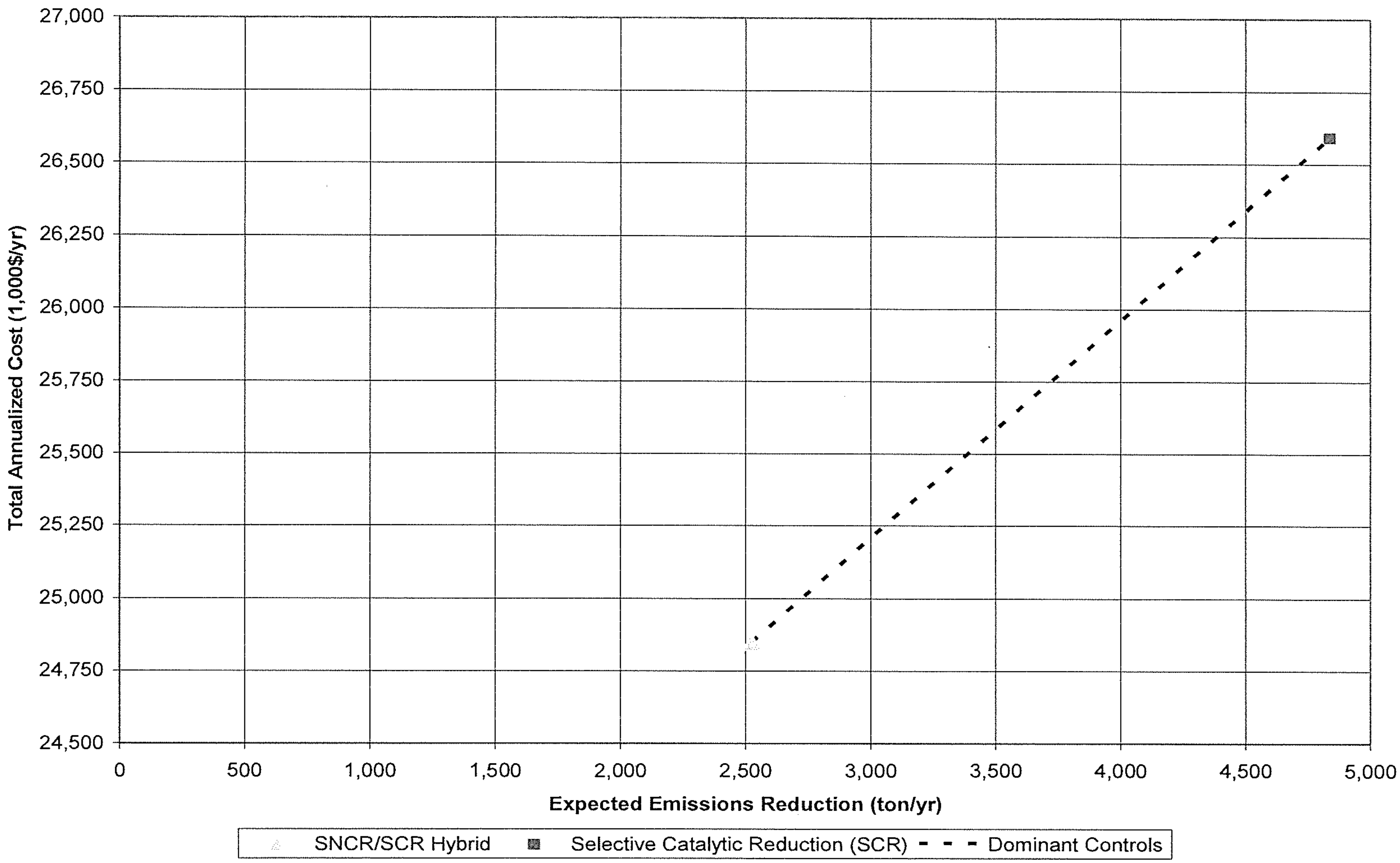


Figure 7-4
SJGS Unit 3 Additional NO_x Control Technology Cost-Effectiveness

7.4.1 Dominant Control Technologies

After completing the evaluation of the impacts and cost-effectiveness, it was determined that all additional NO_x control technologies evaluated lie on the least-cost envelope and are dominant control technologies for the additional reduction of NO_x emissions than that currently expected after the completion of the consent decree upgrades.

These dominant control technologies were modeled to determine the visibility change or improvement. The modeled visibility change or improvement was used for determining the NO_x BART control technology.

7.4.2 Cost-Effectiveness Comparison

The higher cost-effectiveness observed for all four units was the hybrid technology, ranging from 8,776 to 9,102 \$/ton. The cost-effectiveness for the SCR technology ranged from 4,426 to 5,198 \$/ton.

The high cost-effectiveness for the hybrid technology (refer to Table 7-1) can be attributed to the high TAC, which was just slightly lower than that of the SCR technology. Another factor that affects the cost-effectiveness value for the hybrid technology is the lower expected emissions reduction (ton/yr) when compared to that for SCR.

Unit 2 costs are higher than Unit 1, and Unit 3 costs are higher than Unit 4. This difference is due to the additional cost required for the installation of these technologies on Units 2 and 3. Accessibility to Units 2 and 3 is limited by the plant layout and the presence of other balance-of-plant equipment, such as the coal conveyor. The reduced accessibility means that the SCR system or hybrid system will need to be built in smaller pieces, thus increasing construction costs as compared to their sister units.

8.0 Visibility Impacts

Visibility impact is the fifth step to consider in the engineering analysis required under the EPA BART guidelines. This step addresses the degree of improvement in visibility that may reasonably be anticipated to result from the use of the ''best control technology'' for sources subject to BART. Visibility impact analysis is achieved through a two phase process. First, the model was run using the pre-BART conditions to establish a baseline. For this analysis, the baseline consisted of the technologies and unit operations associated with the consent degree. Second model runs were conducted for the control technologies identified for each unit during the BART engineering analysis. The model results were then tabulated for the pre-BART and post-BART control scenarios over the time period of the meteorology modeled. The difference in the averages between the first and second phases is the expected degree of improvement in visibility. The following sections discuss the modeling methodology in greater detail.

8.1 Introduction

The objective of this modeling analysis is to evaluate visibility impacts for the control technologies selected using the first four steps of the BART analysis (as discussed in the previous sections) for PNM's SJGS Units 1, 2, 3, and 4. Based on air dispersion modeling analyses conducted by the WRAP RMC and published as a draft report November 8, 2006, these units were identified as BART-applicable sources by the NMED in January of 2007 under the Regional Haze and BART rule guidelines.

The air dispersion modeling analyses presented in this report were conducted in accordance with the *CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States* dated August 15, 2006, (hereinafter referred to as the WRAP Protocol) and the protocol submitted to NMED on April 13, 2007. The protocol can be found in ***Appendix E***, Sections 1 and 2.

It should be noted that correspondence between NMED and the WRAP on April 2, 2007, indicated an error(s) in the original BART modeling conducted by WRAP in 2006. The error(s) was corrected, and WRAP has since rerun the previous BART modeling; however, at the time of this report, the extent of the error(s), their corresponding correction(s), and the results are not known. Therefore, it is not known how these errors have affected the previously described WRAP modeling or the modeling conducted for this report.

8.2 Source Description

The SJGS facility is located in Farmington, New Mexico, within San Juan County. It has four pulverized coal units that are BART-eligible: Units 1, 2, 3, and 4. Units 1 and 2 are single, wall-fired Foster Wheeler boilers rated at 360 and 350 MW gross, respectively. Each unit is equipped with primary and secondary preheaters, an ESP, and a wet FGD system. Units 3 and 4 are opposed, wall-fired B&W boilers, each rated at 544 MW gross. Each of these units is equipped with primary and secondary preheaters, an ESP, and a wet FGD system. Units 1, 3, and 4 are also equipped with LNBs. The plant currently burns local coal from the San Juan Mine. A detailed description of the units is included in Section 2.0.

8.3 Location of Sources Versus Relevant Class I Areas

Modeling conducted by the WRAP RMC has determined that the 16 Class I areas within 300 km of SJGS listed in Table 8-1 must be addressed in Step 5 of the BART analysis. The location of these 16 Class I areas are shown in Table 8-1 and are illustrated on Figure 8-1.

Table 8-1
Class I Areas

1. Mesa Verde National Park	9. West Elk Wilderness
2. Weminuche Wilderness	10. Arches National Park
3. San Pedro Parks Wilderness	11. Capitol Reef National Park
4. La Garita Wilderness	12. Pecos Wilderness
5. Canyonlands National Park	13. Wheeler Peak Wilderness
6. Black Canyon of the Gunnison National Park	14. Great Sand Dunes National Park
7. Bandelier National Monument	15. Maroon Bells-Snowmass Wilderness
8. Petrified Forest National Park	16. Grand Canyon National Park

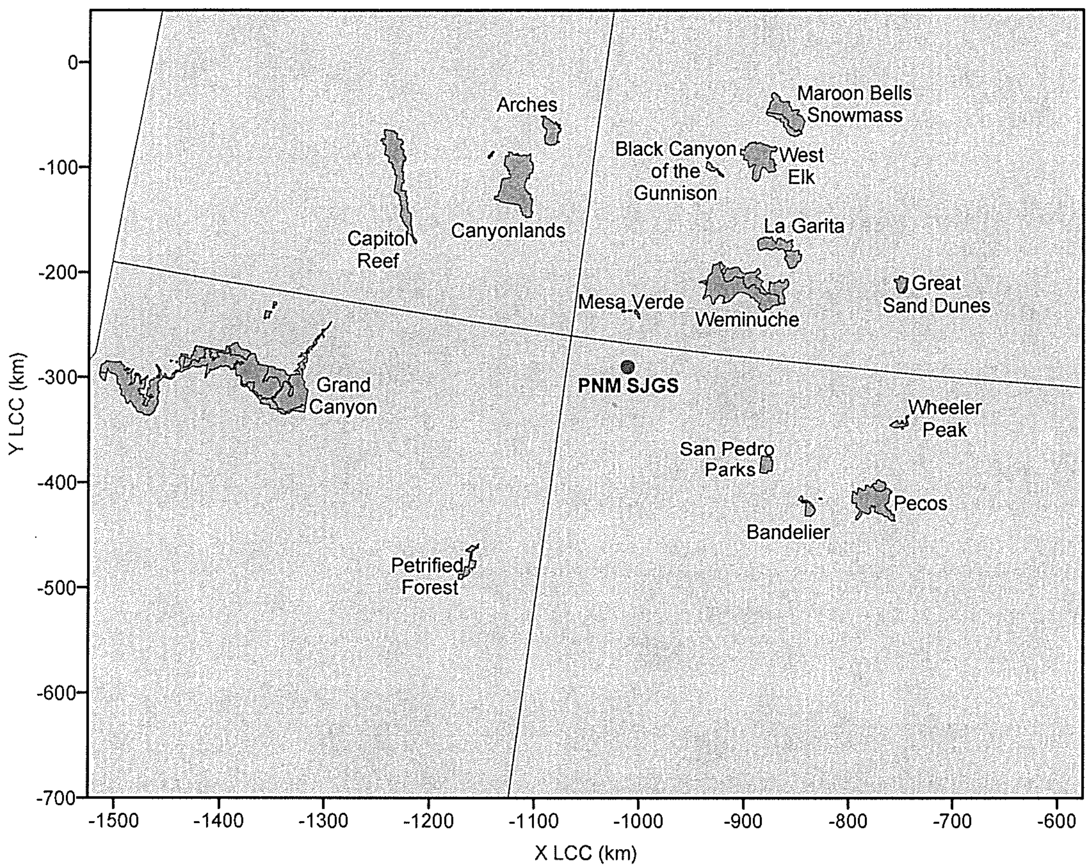


Figure 8-1
Location of SJGS and the Class I Areas

8.4 Model Processing

The CALPUFF modeling system is the recommended model for conducting BART visibility impact analyses. The CALPUFF modeling system includes three main components: CALMET, CALPUFF, CALPOST. The system also includes a large set of preprocessing programs designed to interface with the model to process standard, routinely available meteorological and geophysical data sets. In the simplest terms, CALMET is a meteorological model that develops hourly wind and temperature fields on a three- dimensional gridded modeling domain. Associated fields, such as mixing height, surface characteristics, and dispersion properties, are also included in the file produced by CALMET. CALPUFF is a transport and dispersion model that advects "puffs" or material emitted from modeled sources, simulating the dispersion and chemical transformation process along the way. In doing so, it typically uses the fields generated by CALMET, or as an option, it might use simpler, not gridded meteorological data much like existing plume models. Temporal and spatial variations in the meteorological fields selected are explicitly incorporated into the resulting distribution of puffs throughout a simulation period. The primary output files from CALPUFF contain either hourly concentrations or hourly deposition fluxes evaluated at selected receptor locations. CALPOST is used to process these files and produce tabulations that summarize the results of the simulation. When performing visibility-related modeling, CALPOST uses concentrations from CALPUFF to compute extinction coefficients and related measures of visibility, reporting these for a 24 hour averaging period at selected locations.

The geophysical and meteorological data necessary to conduct the Class I visibility modeling was provided by the WRAP RMC on its Web site (http://pah.cert.ucr.edu/aqm/308/bart.shtml). All applicable files were downloaded for use in the aforementioned analyses.

The versions of the CALPUFF modeling system suggested in the WRAP protocol and used by the WRAP RMC for the initial modeling were used for the PNM modeling analyses and are summarized in Table 8-2. It should be noted that the WRAP RMC provided limited information on its BART modeling. Based on what was provided, it did not appear that the WRAP RMC speciated the PM/PM_{10} emissions; therefore, the use of POSTUTIL and CALSUM would not be required.

Table 8-2
Model Versions

Program	WRAP Protocol		PNM Analyses	
	Version	Level	Version	Level
CALMET	6.211	060414	6.211	060414
CALPUFF	6.112	060412	6.112	060412
POSTUTIL	N/A	N/A	1.52	060412
CALSUM	N/A	N/A	1.33	051122
CALPOST	6.131	060410	6.131	060410

8.4.1 Modeling Domain

The modeling domain was the same domain established in the provided GEO.DAT file. The origin coordinates of the domain was Latitude 40.0 N, Longitude 97.0 W; these coordinates were assigned as the 0, 0 reference point of the domain. The southwest corner of the modeling domain was Latitude 30.9 N, Longitude 111.3 W, which translates to -1,368.0 km (X) and -900.0 (Y) in Lambert Conformal Conic (LCC) coordinates. The domain measured 864 km in the east-west (X) and north-south (Y) direction. At a refined grid spacing of 4 km, the number of X grid cells and the number of the Y grid cells was 216. The modeling domain is shown on Figure 8-2.

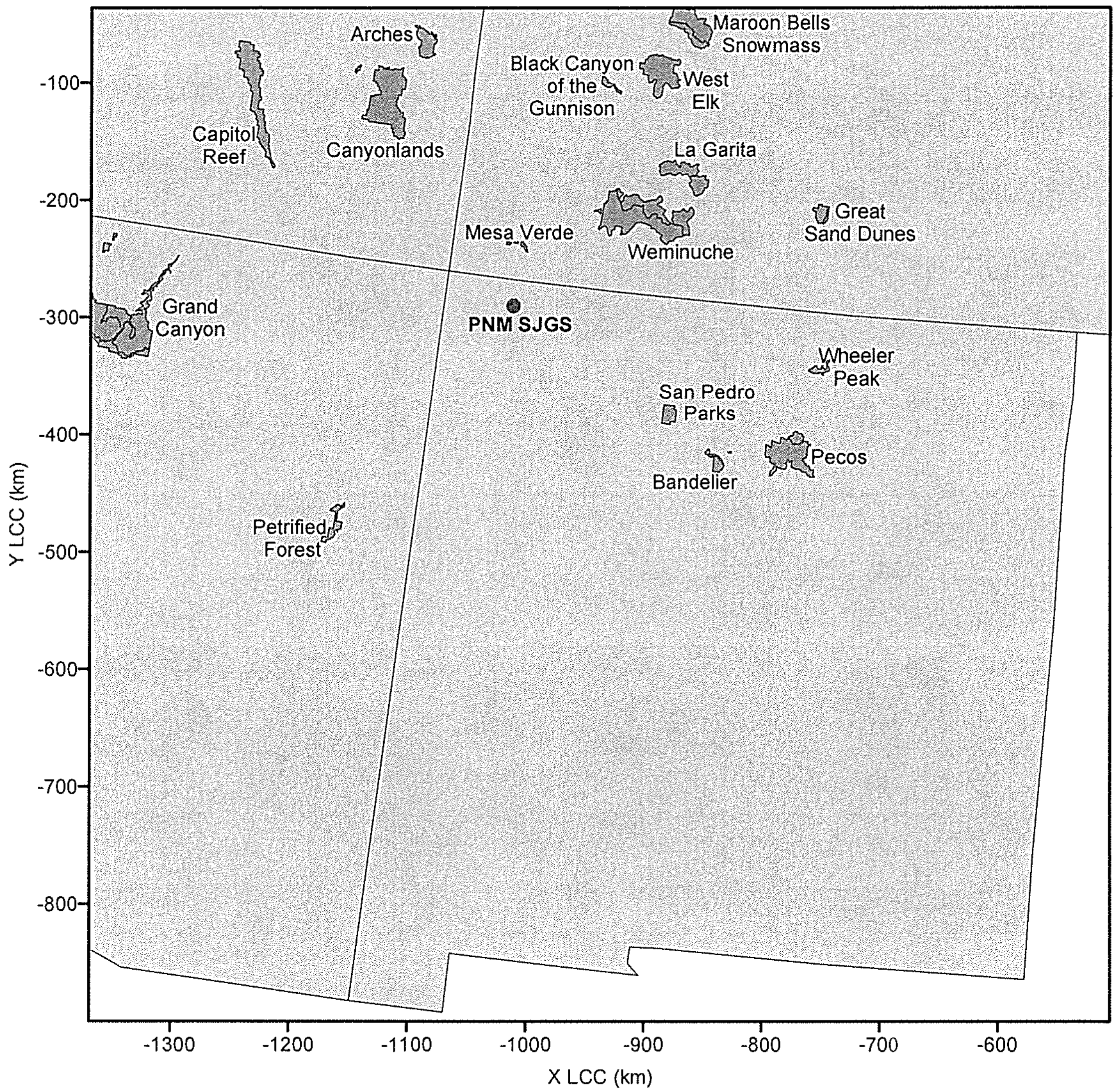


Figure 8-2
Geophysical and Meteorological Modeling Domain

8.5 Geophysical and Meteorological Data

As previously noted, all the geophysical and meteorological data necessary to conduct the Class I visibility modeling were provided by the WRAP RMC and were downloaded from its Web site for use in the aforementioned analyses.

8.5.1 Mesoscale Model Data

Pennsylvania State University in conjunction with the National Center for Atmospheric Research Assessment Laboratory have developed mesoscale eteorological data sets of prognostic wind fields, or "guess" fields, for the United States. The hourly meteorological variables used to create these data sets are extensive and are used to initialize the modeling domain with meteorological data. The daily MM5 meteorological data files provided by the WRAP RMC for the years 2001, 2002, and 2003 were utilized as input into CALMET.

The MM5 data sets used to simulate atmospheric variables within the modeling domain in CALMET, although advanced, lack the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables were processed into the appropriate format and introduced into the CALMET model through the utilization of additional meteorological data files. These ancillary data files are described in more detail in the following subsections.

8.5.2 Surface Data Station and Processing

The surface station data for the CALPUFF analysis consisted of data from National Weather Service (NWS) stations or Federal Aviation Administration (FAA) flight service stations within the CALMET domain. Figure 8-3 provides an illustration of the location of the surface stations used. The surface station parameters included wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that was based on current weather conditions.

The surface data were preprocessed by the WRAP RMC to create CALMET-ready SURF.DAT files. The CALMET-ready surface station data files were downloaded from the WRAP RMC Web site for use in the modeling analyses. A listing of the surface stations is provided in ***Appendix E***, Section 2.

8.5.3 Upper Air Data Station and Processing

The WRAP RMC used the upper air data contained in the MM5 files for the necessary upper air data and did not supplement it with additional upper air data. Because of this, the modeling conducted for this report followed these procedures and did not include any additional upper air data other than that contained in the MM5 files.

8.5.4 Precipitation Data Stations and Processing

Precipitation data was processed from a network of hourly precipitation data files collected from NWS precipitation recording stations within the CALMET domain. Figure 8-4 provides an illustration of the location of the precipitation stations used.

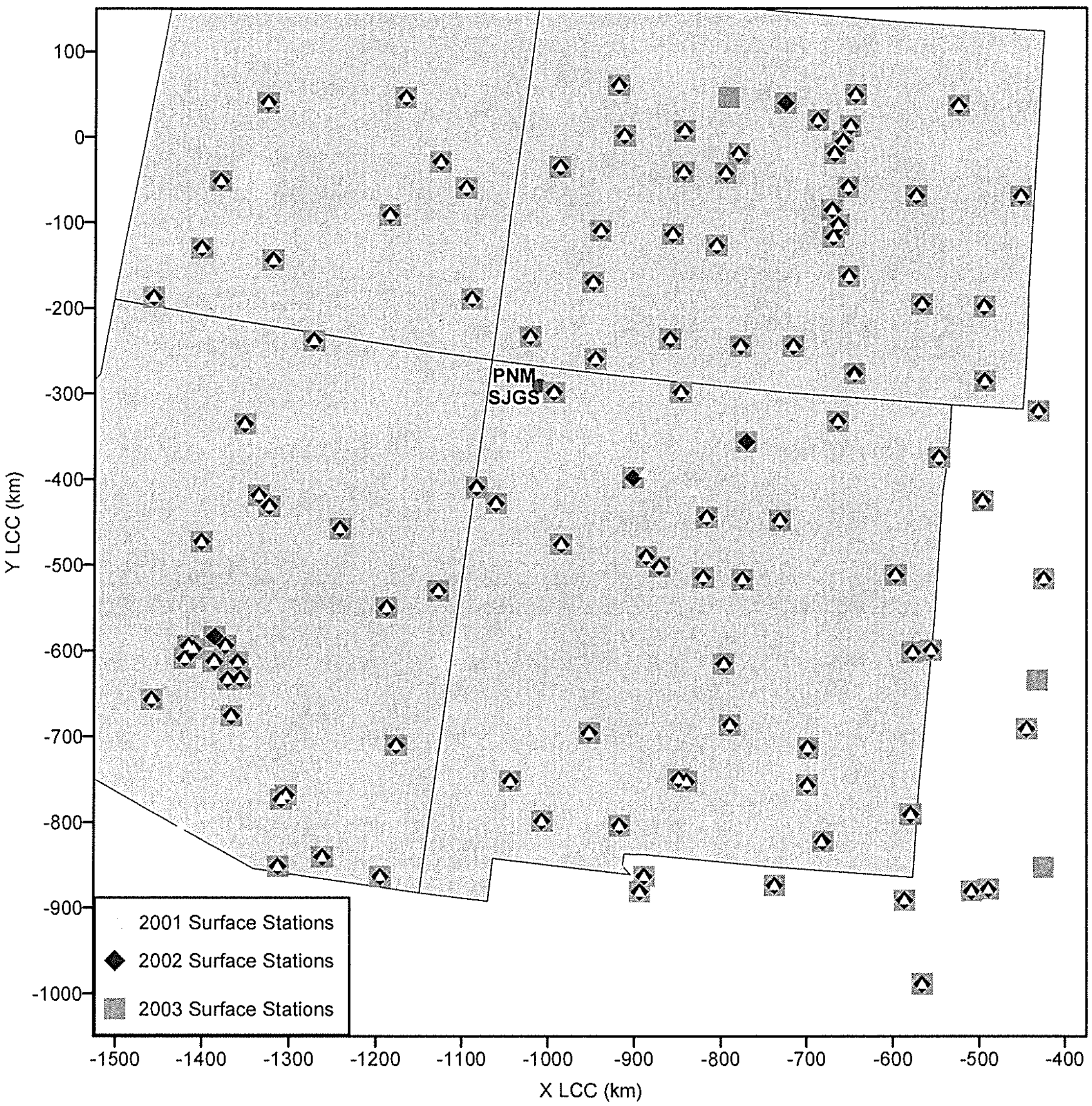


Figure 8-3
Surface Stations

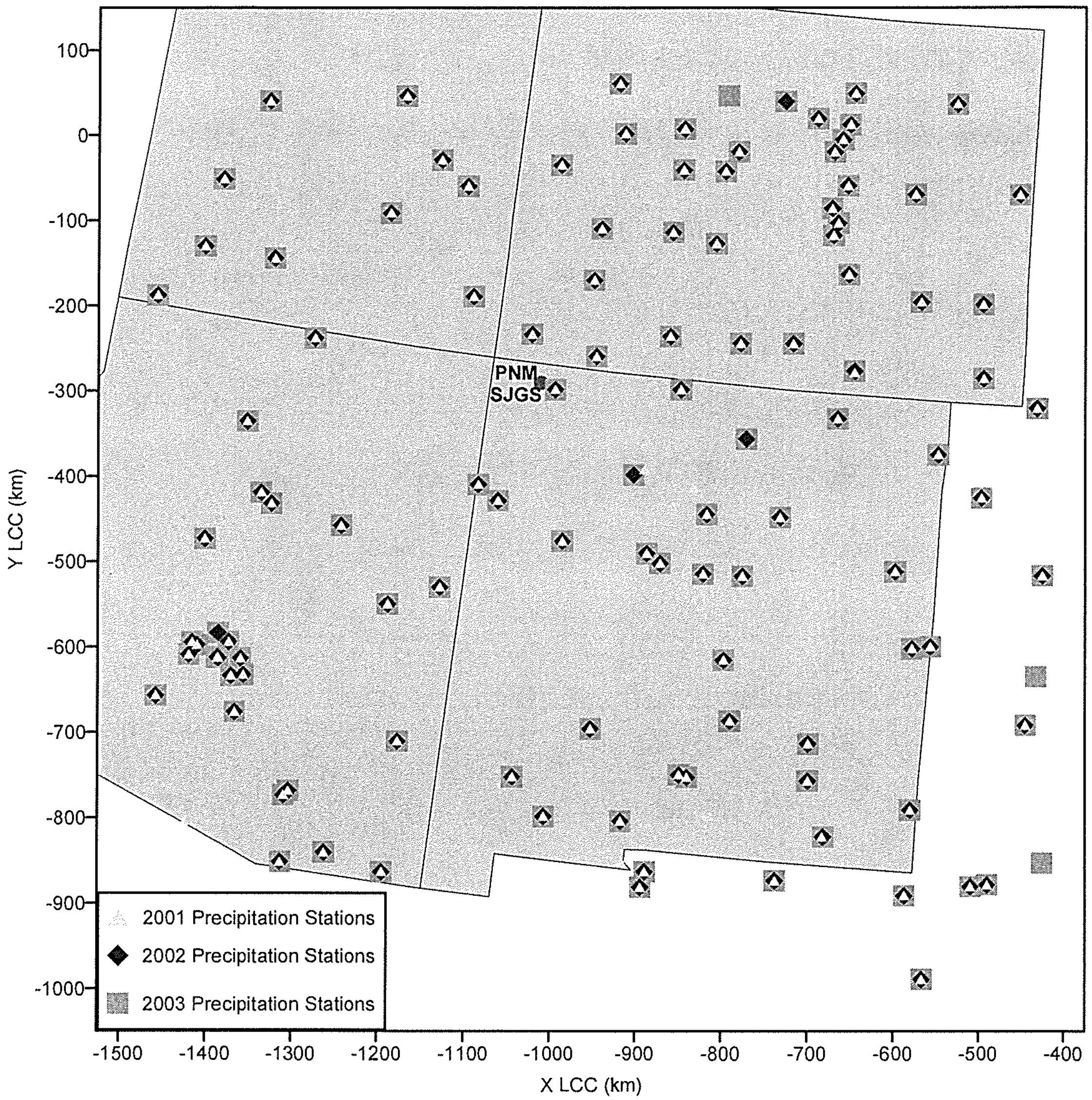


Figure 8-4
Precipitation Stations

The precipitation data were preprocessed by WRAP to create CALMET-ready PRECIP.DAT files. The CALMET-ready precipitation data files were downloaded from the WRAP RMC Web site for use in the modeling analyses. A list of the precipitation stations is provided in ***Appendix E***, Section 2.

8.5.5 Geophysical Data Processing (Terrain and Land Use)

Terrain and land use data were preprocessed by the WRAP RMC to create a CALMET-ready GEO.DAT file. This GEO.DAT file was downloaded from the WRAP RMC Web site for use in the analyses. Figure 8-5 depicts the terrain elevations in the domain; Figure 8-6 shows the land use of the domain.

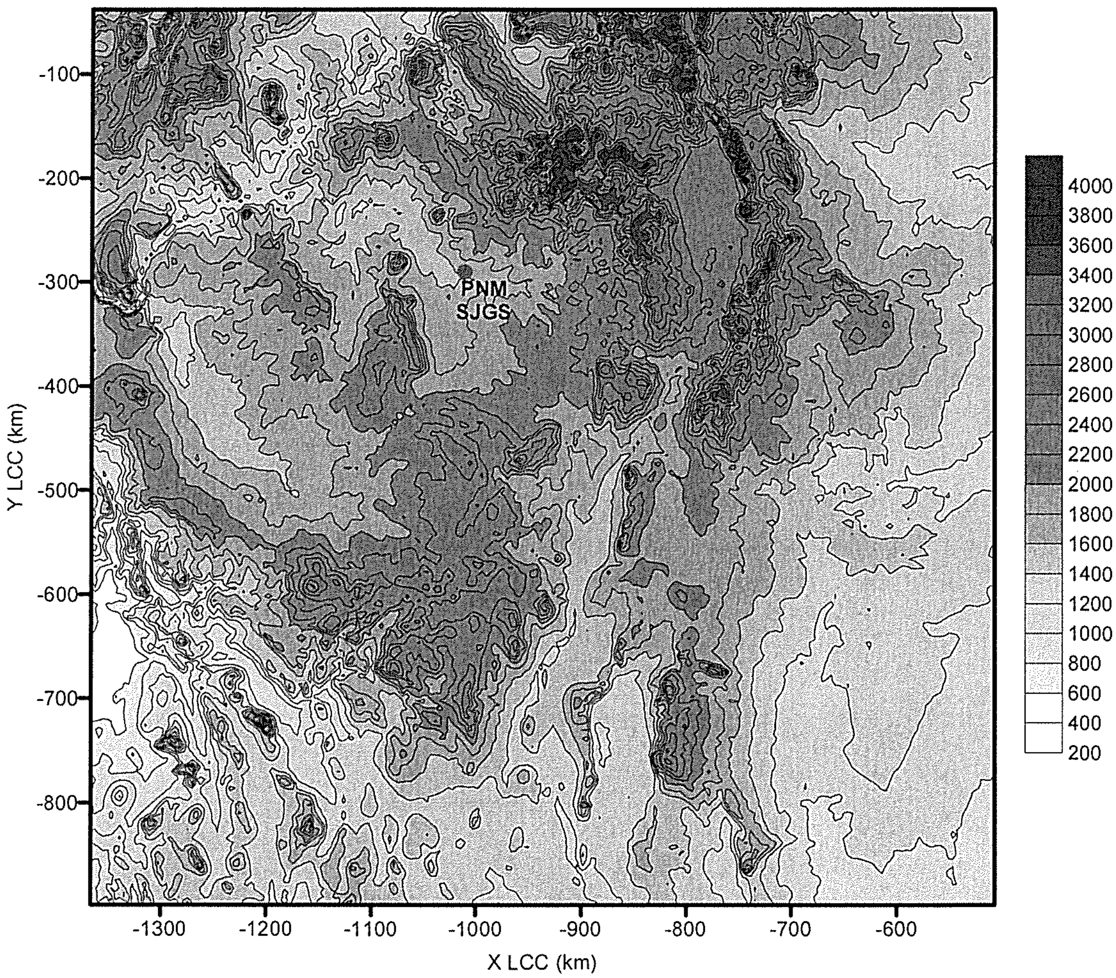


Figure 8-5
Terrain Elevation Plot

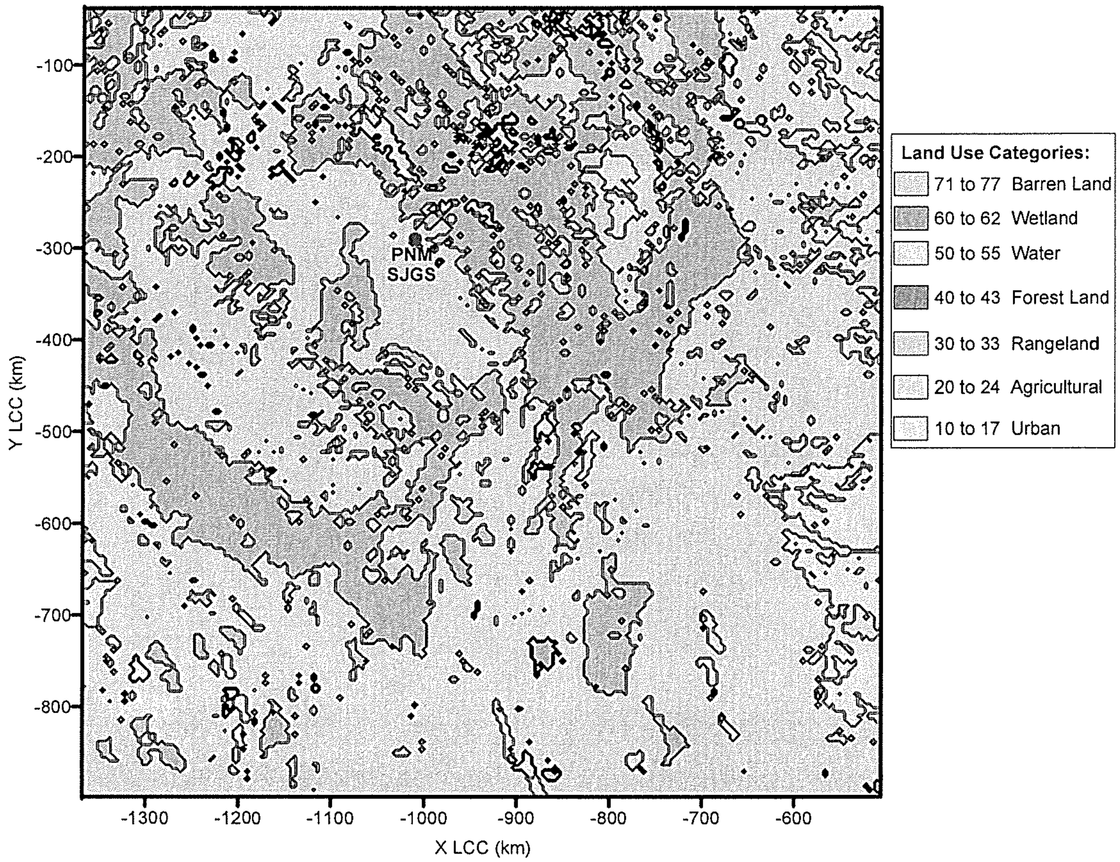


Figure 8-6
Land Use Plot

8.5.6 CALMET

CALMET (Version 6.211, Level 060414) was run using the aforementioned preprocessed CALMET-ready geographical and meteorological files provided by WRAP RMC to create the CALMET.DAT for use in CALPUFF.

8.6 CALPUFF

The CALPUFF modeling system is recommended as the preferred modeling approach for use in BART analyses. CALPUFF and its meteorological model, CALMET, are designed to handle the complexities posed by complex terrain, large source-receptor distances, chemical transformation and deposition, as well as other issues related to Class I visibility impacts. The CALPUFF modeling system has been adopted by the EPA as a guideline model for source-receptor distances greater than 50 km and for use on a case-by-case basis in complex flow situations for shorter distances

(68 FR 18440-18482). CALPUFF is recommended for Class I impact assessments by the Federal Land Managers Workgroup (FLAG 2000) and the Interagency Workgroup on Air Quality Modeling (IWAQM) (EPA 1998). The final BART guidance recommends CALPUFF as "the best modeling application available for predicting a singe source's contribution to visibility impairment" (70 FR 39122).

CALPUFF is a non-steady-state, Lagrangian, puff transport and dispersion model that advects Gaussian puffs of multiple pollutants from modeled sources. CALPUFF's algorithms have been designed to be applicable on spatial scales from a few tens of meters to hundreds of kilometers from a source. It includes algorithms for near-field effects such as building downwash, stack tip downwash, and transitional plume rise, as well as processes important in the far-field, such as chemical transformation, wet deposition, and dry deposition. CALPUFF contains an option to allow puff splitting in the horizontal and vertical directions, which extends the distance range of the model. The primary outputs from CALPUFF are hourly concentrations and hourly deposition fluxes evaluated at user-specified receptor locations.

CALPUFF (Version 6.112, Level 060412) was used to calculate the hourly concentrations at each Class I receptor from SJGS Units 1, 2, 3, and 4. Each CALPUFF run contained 12 monthly CALMET.DAT files to create a single yearly concentration file for use in CALPOST.

8.6.1 CALPUFF Domain and Variables

The WRAP RMC computational domain covered an extensive area, specifically, New Mexico, eastern Arizona, southeastern Utah, and southern Colorado. To reduce the computational requirements of the model, the CALPUFF computational domain was reduced to a subset of the WRAP RMC CALMET domain established to encompass the SJGS and the applicable 16 Class I areas. The CALPUFF computational domain is shown on Figure 8-7.

8.6.2 Receptors

The CALPUFF analyses used an array of discrete receptors with receptor elevations for the Class I areas, which were created and distributed by the National Park Service (NPS). Specifically, the array consisted of receptors spaced to cover the extent of the Class I areas. Receptor elevations were included in the same NPS-provided receptor files. ***Appendix E***, Section 2, provides illustrations of the receptors that were used in the modeling analysis for each Class I area.

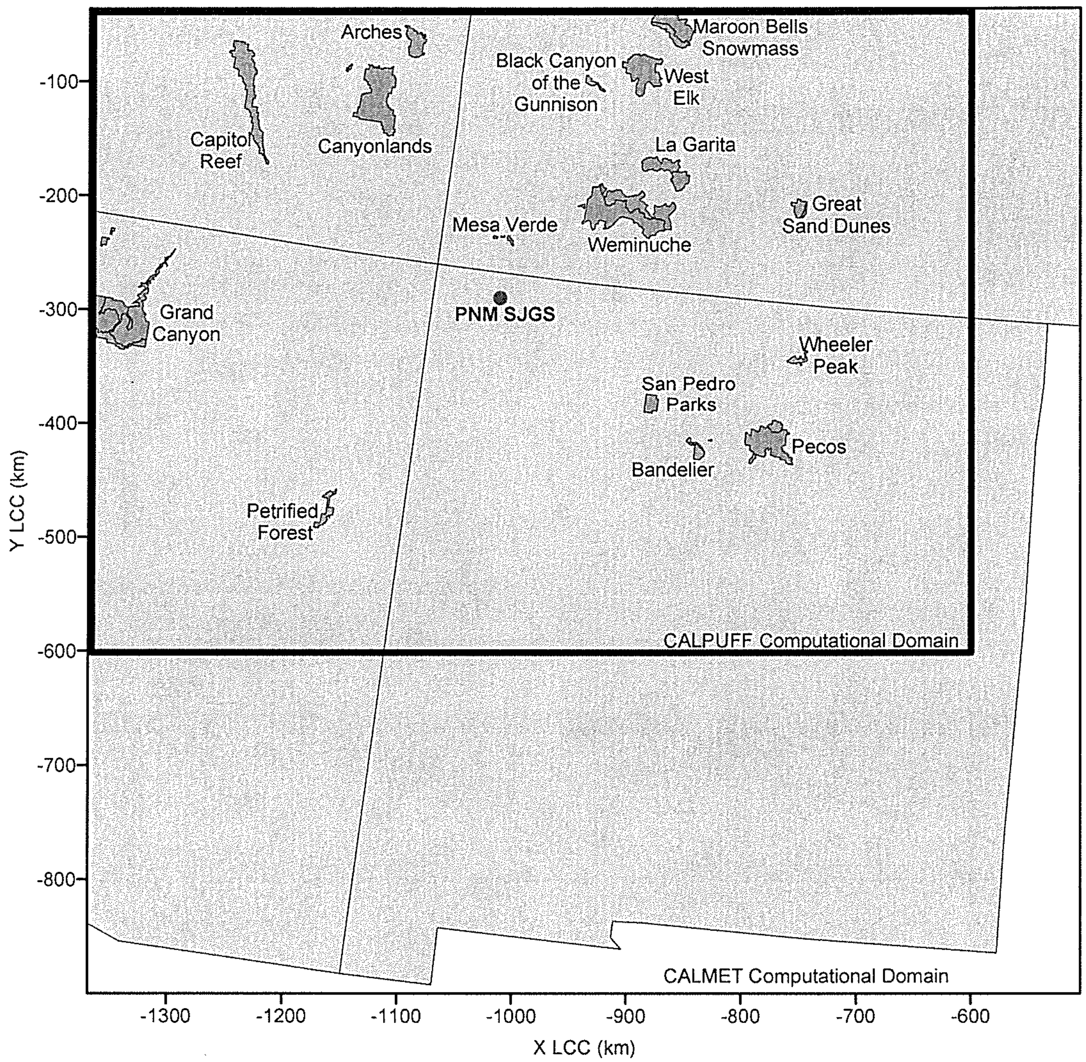


Figure 8-7
CALPUFF Computational Domain

8.6.3 Downwash

Because the modeling conducted for BART is concerned with long-range transport, not localized impacts, data about building heights and widths that are used to calculate building-induced downwash were not included in the modeling analyses. Stack tip downwash, a phenomenon different from building-induced downwash, is additionally a regulatory default option (i.e., to turn stack tip downwash off, the user must also change the variable to skip regulatory checks of the model). Because of this, stack tip downwash was used for the analyses.

8.6.4 Ozone Concentrations

Background ozone concentrations are important for the photochemical conversion of SO_2 and NO_x to SO_4 and NO_3, respectively. CALPUFF allows the use of a single background ozone value, monthly background ozone values, or spatial, hourly ozone data from one or more ozone monitoring stations (the preferred method) to represent the background ozone concentrations within the domain.

The hourly ozone concentrations files that were used by the WRAP RMC in the initial modeling were used for the BART technology evaluation. These hourly ozone data files were obtained directly from the WRAP RMC Web site. In addition to the hourly ozone data, the same monthly average background ozone value of 80 ppb as used in the initial modeling was used in this modeling for times when hourly ozone data were not available.

8.6.5 Ammonia Concentrations

The BART modeling was performed using the same fixed background ammonia level of 1 ppb that was used for the initial modeling performed by WRAP RMC.

8.6.6 Unit-Specific Source Data

As previously presented in Sections 3 through 6 of this report, various emissions control strategies and technologies have been evaluated for SJGS Units 1, 2, 3, and 4. The baseline emissions for PM, NO_x, and SO_2 were based on emissions limits established as part of the consent decree between PNM and NMED. Additionally, emissions of SO_4 were included in the analyses. The emissions were composed of the relative fraction of fine and course particles obtained by using speciation profiles available from the Federal Land Managers through the NPS (http://www2.nature.nps.gov/air/permits/ect/index.cfm). For this analysis, condensable PM_{10} was subdivided into inorganic and organic compounds using the NPS speciation spreadsheets. The inorganic portion was by default assumed to be H_2SO_4 and was modeled as SO_4. The organic portion was modeled as secondary organic aerosols (SOA).

As required by EPA BART guidance, each technically feasible BART control technology must be assessed to determine the potential degree of visibility improvement. These relative improvements from various technologies and/or control levels can then be factored into the technology evaluation process to reach a BART determination.

Because New Mexico participates in an SO_2 trading program, an SO_2 BART analysis was not evaluated in Steps 1 though 4, and was not modeled as a separate feasible control technology option. However, SO_2 emissions were included as a modeled pollutant as part of both the baseline and post-baseline controlled scenarios. Therefore, NO_x and PM_{10} are the only pollutants subject to BART analyses. However, as previously determined in Subsection 4.2.4, the addition of the PJFF technology for PM control is considered BART technology and no further evaluation was undertaken. PM_{10} emissions were assumed the as consent decree (baseline) limits and speciated as described in the baseline modeling section. NO_x was the only pollutant evaluated in this analysis.

As specified in Section 7.0, additional NO_x control was proposed for the BART control scenario. The aforementioned approach consisted of the potential addition of SCR or SNCR/SCR hybrid on all four units for additional NO_x control. For NO_x technologies with a catalyst, an additional 1 percent SO_2 to SO_3 conversion based on design basis economizer outlet SO_2 and zero removal in the PJFF was accounted for and added to the NPS speciation spreadsheet SO_4 values. The baseline and BART control scenarios stack parameters are presented in Table 8-3. The baseline and BART control scenario emissions are presented in Tables 8-4 and 8-5, respectively.

8.7 CALPOST

CALPOST (Version 6.131, Level 060410) was used to process the CALPUFF outputs by producing tabulations summarizing the results of the simulations and identifying, for example, the highest and second-highest hourly average concentrations at each receptor. When performing visibility-related modeling, CALPOST uses concentrations from CALPUFF to compute light extinction and related measures of visibility (haze index in deciviews) and reports these for a 24 hour averaging time.

8.7.1 Light Extinction

Light extinction must be computed to calculate visibility. CALPOST has seven methods for computing light extinction. As recommended by the WRAP RMC protocol, this BART technology analysis used Method 6, which computes extinction from speciated PM with monthly Class I area-specific relative humidity adjustment factors. Relative humidity is an important factor in determining light extinction (and therefore visibility) because sulfate and nitrate aerosols, which absorb moisture from the air, have greater extinction efficiencies with greater relative humidity. This BART analysis used relative humidity correction factors [f(RH)s], obtained from Table A-3 of the EPA's *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule* (EPA, 2003), to determine sulfate and nitrate concentrations outputs from CALPUFF. The f(RH) values for the Class I areas that were assessed are provided in Table 8-6. The default Rayleigh scatter value (bray) of 10 Mm-1 was also used. The light extinction equation is as follows:

$$b_{ext} = 3 * f(RH) * [(NH_4)_2SO_4] + 3* f(RH) * [NH_4NO_3] + 4*[OC] + 1* [PM_f] + 0.6*[PM_c] + 10* [EC] + b_{ray}$$

Table 8-3
CALPUFF Modeling Stack Parameters

Unit	Stack Location[a] LCC East (km)	Stack Location[a] LCC North (km)	Stack Height[b] (m)	Base Elevation[b] (m)	Stack Diameter[b] (m)	Stack Exit Velocity[b] (m/s)	Stack Exit Temperature[b] (K)
Baseline							
SJGS 1	-1010.859	-290.127	121.92	1615.44	6.0960	21.34	322.83
SJGS 2	-1010.859	-290.127	121.92	1615.44	6.0960	21.34	322.83
SJGS 3	-1010.859	-290.127	121.92	1615.44	8.5344	17.07	322.83
SJGS 4	-1010.859	-290.127	121.92	1615.44	8.5344	16.76	322.83
BART Controls							
SJGS 1	-1010.859	-290.127	121.92	1615.44	6.0960	21.34	322.83
SJGS 2	-1010.859	-290.127	121.92	1615.44	6.0960	21.34	322.83
SJGS 3	-1010.859	-290.127	121.92	1615.44	8.5344	17.07	322.83
SJGS 4	-1010.859	-290.127	121.92	1615.44	8.5344	16.76	322.83

[a]Stack Coordinates in Lambert format included in the CALPUFF modeling.
[b]Stack parameters from engineering analysis. Refer to Appendix D.

Table 8-4
Consent Decree Baseline
CALPUFF Modeling Emission Rates

Unit	SO_2 Emission Rate (lb/h)	NO_x[a] Emission Rate (lb/h)	Primary Particle Speciation[b]				
			EC (lb/h)	Fine PM (lb/h)	Course PM (lb/h)	H_2SO_4[c] (lb/h)	SOA (lb/h)
SJGS 1	667.3	1,223.3	1.03	31.11	23.57	40.50	10.10
SJGS 2	663.8	1,217.0	1.03	30.79	23.49	40.30	10.10
SJGS 3	1,900.1	1,036.4	1.59	48.18	36.37	62.90	15.70
SJGS 4	1,016.8	1,864.2	1.58	47.38	35.95	61.7	15.4

[a]The modeled NO_x emission rate is based on an assumed 24 hour rolling averaging basis versus the 30 day rolling average basis for each unit from the consent decree.
[b]Primary particulate speciated into the following categories using the NPS Speciation Spreadsheet: Elemental Carbon (EC), Fine PM, Course PM, and SO_4. Refer to Appendix E, Section 4.
[c]H_2SO_4 assumed to be 100 percent of the SO_4 emissions calculated by the NPS Speciation Spreadsheet.

Table 8-5
NO_x BART Control Technologies
CALPUFF Modeling Emission Rates

Unit	SO_2 Emission Rate (lb/h)	NO_x Emission Rate (lb/h)	Primary Particle Speciation[a,c]				
			EC (lb/h)	Fine PM (lb/h)	Course PM (lb/h)	H_2SO_4[b] (lb/h)	SOA (lb/h)
SCR							
SJGS 1	667.3	222.4	1.03	31.11	23.57	114.2	10.10
SJGS 2	663.8	221.3	1.03	30.79	23.49	113.6	10.10
SJGS 3	1,036.4	345.5	1.59	48.18	36.37	177.3	15.70
SJGS 4	1,016.8	338.9	1.58	47.38	35.95	174.0	15.4
SNCR/SCR Hybrid							
SJGS 1	667.3	667.3	1.03	31.11	23.57	114.2	10.10
SJGS 2	663.8	663.8	1.03	30.79	23.49	113.6	10.10
SJGS 3	1,036.4	1,036.4	1.59	48.18	36.37	177.3	15.70
SJGS 4	1,016.8	1,016.8	1.58	47.38	35.95	174.0	15.4

(a)Primary particulate speciated into the following categories using the NPS Speciation Spreadsheet: Elemental Carbon (EC), Fine PM, Course PM, and SO_4. Refer to Appendix E, Section 4.
(b)H_2SO_4 assumed to be 100 percent of the SO_4 emissions calculated by the NPS Speciation Spreadsheet and for the NO_x control technologies with catalyst accounts for an additional 1.0 percent SO_2 to SO_3 conversion based on design basis economizer outlet SO_2 levels and 0 percent removal in the PJFF.
(c)Ammonia slip from the pollution control process has not been included in the modeling analysis.

Table 8-6
Monthly Relative Humidity Factors[a]

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arches	2.6	2.3	1.8	1.6	1.6	1.3	1.4	1.5	1.6	1.6	2.0	2.3
Bandelier	2.2	2.1	1.8	1.6	1.6	1.4	1.7	2.1	1.9	1.7	2.0	2.3
Black Canyon of the Gunnison	2.4	2.2	1.9	1.9	1.9	1.6	1.7	1.9	2.0	1.8	2.1	2.3
Canyonlands	2.6	2.3	1.7	1.6	1.5	1.2	1.3	1.5	1.6	1.6	2.0	2.3
Capitol Reef	2.7	2.4	2.0	1.7	1.6	1.4	1.4	1.6	1.6	1.7	2.1	2.5
Grand Canyon	2.4	2.3	1.9	1.5	1.4	1.2	1.4	1.7	1.6	1.6	1.9	2.3
Great Sand Dunes	2.4	2.3	2.0	1.9	1.9	1.8	1.9	2.3	2.2	1.9	2.4	2.4
La Garita	2.3	2.2	1.9	1.8	1.8	1.6	1.7	2.1	2.0	1.8	2.2	2.3
Maroon Bells Snowmass	2.2	2.1	2.0	2.0	2.1	1.7	1.9	2.2	2.1	1.8	2.1	2.1
Mesa Verde	2.5	2.3	1.9	1.5	1.5	1.3	1.6	2.0	1.9	1.7	2.1	2.3
Pecos	2.3	2.1	1.8	1.7	1.7	1.5	1.8	2.1	2.0	1.7	2.0	2.2
Petrified Forest	2.4	2.2	1.7	1.4	1.3	1.2	1.5	1.8	1.7	1.6	1.9	2.3
San Pedro Parks	2.3	2.1	1.8	1.6	1.6	1.4	1.7	2.0	1.9	1.7	2.1	2.2
West Elk	2.3	2.2	1.9	1.9	1.9	1.7	1.8	2.1	2.0	1.8	2.1	2.2
Weminuche	2.4	2.2	1.9	1.7	1.7	1.5	1.6	2.0	1.9	1.7	2.1	2.3
Wheeler Peak	2.3	2.2	1.9	1.8	1.8	1.6	1.8	2.2	2.1	1.8	2.2	2.3

[a]Table A-3 of the EPA's *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule*

8.7.2 Natural Background

The EPA's default average annual aerosol concentrations for the eastern and western halves of the United States, included in Table 2-1 of EPA's *Guidance for Estimating Natural Visibility Conditions Under Regional Haze Program*, was used to determine the natural background at each of the Class I areas. The values are provided in Table 8-7.

Table 8-7
Average Annual Natural Background Levels[a]

Component	Average Annual Natural Background ($\mu g/m^3$)
Ammonium Sulfate	0.12
Ammonium Nitrate	0.10
Organic Carbon Mass	0.47
Elemental Carbon	0.02
Soil	0.50
Coarse Mass	3.0

[a]Table 2-1 of the EPA's *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule.*

8.8 Modeling Results

From the air dispersion modeling methodology outlined in the previous sections, the CALPUFF-modeled visibility impacts from Units 1, 2, 3, and 4 for each NO_x control technology option were determined. Visibility impairment is based on the 98th percentile modeled value. Over an annual period, this implies the 8th highest 24 hour value. A DVD of all electronic files is provided in ***Appendix E***, Section 5.

8.8.1 Consent Decree Baseline Scenario

The results of the consent decree baseline modeling are presented in Table 8-8. The consent decree baseline impacts were used to establish a comparison for the BART control technology impacts. As Table 8-8 illustrates, the combined visibility impacts for the SJGS BART sources (assuming control technology and emissions levels from the consent decree) exceed the recommended exemption guideline value of 0.5 dv, subjecting the units to the aforementioned BART engineering and refined modeling analysis.

Table 8-8
Baseline (Consent Decree) Visibility Modeling Results
98th Percentile for Each Year (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	3.828	2.934	2.808	3.190	3.828
Bandelier	1.345	2.326	2.312	1.994	2.326
Black Canyon	1.529	1.585	1.815	1.643	1.815
Canyonlands	4.944	3.362	3.125	3.810	4.944
Capitol Reef	2.922	0.929	1.394	1.748	2.922
Grand Canyon	1.505	1.001	0.730	1.079	1.505
Great Sand Dunes	0.920	0.798	0.710	0.809	0.920
La Garita	1.090	1.145	1.163	1.133	1.163
Maroon Bells	0.703	0.668	0.654	0.675	0.703
Mesa Verde	7.355	7.853	6.759	7.322	7.853
Pecos	1.232	1.570	1.693	1.498	1.693
Petrified Forest	1.045	0.676	0.644	0.788	1.045
San Pedro	2.711	3.356	3.021	3.029	3.356
West Elk	1.116	1.170	1.144	1.143	1.170
Weminuche	1.635	2.147	1.806	1.863	2.147
Wheeler Peak	1.042	1.062	1.164	1.089	1.164
Overall				**2.051**	**7.853**

8.8.2 BART Control Technology Scenario

The results of the modeling for the BART emissions control option are presented in Tables 8-9 through 8-20. Tables 8-9 and 8-10 show the visibility impacts of the entire plant, assuming that the same control technology (SCR or hybrid) is installed on each of the four units. Tables 8-12 through 8-18 illustrate the resultant visibility impacts of each control technology on a unit-by-unit basis.

Table 8-9
SCR Visibility Modeling Results
98th Percentile Impact for Each Year (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	2.279	1.600	1.665	1.848	2.279
Bandelier	1.006	1.403	1.401	1.270	1.403
Black Canyon	0.949	0.848	1.061	0.953	1.061
Canyonlands	2.876	1.922	2.339	2.379	2.876
Capitol Reef	1.734	0.744	1.094	1.191	1.734
Grand Canyon	0.806	0.625	0.625	0.685	0.806
Great Sand Dunes	0.596	0.549	0.489	0.545	0.596
La Garita	0.626	0.678	0.717	0.674	0.717
Maroon Bells	0.440	0.428	0.367	0.412	0.440
Mesa Verde	6.404	6.011	6.565	6.327	6.565
Pecos	0.895	1.019	1.068	0.994	1.068
Petrified Forest	0.738	0.523	0.573	0.611	0.738
San Pedro	1.875	2.139	1.994	2.003	2.139
West Elk	0.654	0.661	0.679	0.665	0.679
Weminuche	1.249	1.733	1.556	1.513	1.733
Wheeler Peak	0.776	0.658	0.708	0.714	0.776
Overall				**1.424**	**6.565**

Table 8-10
Hybrid Visibility Modeling Results
98th Percentile Impact for Each Year (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	3.201	2.382	2.327	2.637	3.201
Bandelier	1.222	1.939	1.911	1.691	1.939
Black Canyon	1.292	1.276	1.411	1.326	1.411
Canyonlands	4.025	2.759	2.875	3.220	4.025
Capitol Reef	2.288	0.783	1.324	1.465	2.288
Grand Canyon	1.153	0.841	0.700	0.898	1.153
Great Sand Dunes	0.776	0.770	0.614	0.720	0.776
La Garita	0.863	1.010	0.997	0.957	1.010
Maroon Bells	0.614	0.615	0.535	0.588	0.615
Mesa Verde	6.974	7.721	7.491	7.395	7.721
Pecos	1.190	1.466	1.409	1.355	1.466
Petrified Forest	0.898	0.627	0.607	0.711	0.898
San Pedro	2.240	3.008	2.573	2.607	3.008
West Elk	0.848	1.010	0.935	0.931	1.010
Weminuche	1.388	2.197	1.843	1.809	2.197
Wheeler Peak	0.899	0.833	0.942	0.891	0.942
Overall				**1.825**	**7.721**

Table 8-11
Unit 1 SCR Visibility Modeling Results
98th Percentile Impact for Each Year (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	0.486	0.378	0.410	0.425	0.486
Bandelier	0.211	0.325	0.273	0.270	0.325
Black Canyon	0.194	0.195	0.203	0.197	0.203
Canyonlands	0.673	0.468	0.511	0.551	0.673
Capitol Reef	0.401	0.155	0.248	0.268	0.401
Grand Canyon	0.176	0.134	0.129	0.146	0.176
Great Sand Dunes	0.117	0.103	0.098	0.106	0.117
La Garita	0.135	0.139	0.144	0.139	0.144
Maroon Bells	0.092	0.084	0.075	0.084	0.092
Mesa Verde	1.442	1.748	1.720	1.637	1.748
Pecos	0.179	0.224	0.220	0.208	0.224
Petrified Forest	0.145	0.110	0.116	0.124	0.145
San Pedro	0.381	0.506	0.438	0.442	0.506
West Elk	0.135	0.139	0.135	0.136	0.139
Weminuche	0.261	0.407	0.325	0.331	0.407
Wheeler Peak	0.157	0.136	0.164	0.152	0.164
Overall				**0.326**	**1.748**

Table 8-12
Unit 2 SCR Visibility Modeling Results
98th Percentile Impact for Each Year (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	0.483	0.376	0.408	0.422	0.483
Bandelier	0.210	0.323	0.271	0.268	0.323
Black Canyon	0.193	0.194	0.202	0.196	0.202
Canyonlands	0.670	0.465	0.508	0.548	0.670
Capitol Reef	0.399	0.154	0.247	0.267	0.399
Grand Canyon	0.175	0.134	0.128	0.146	0.175
Great Sand Dunes	0.117	0.102	0.098	0.106	0.117
La Garita	0.134	0.138	0.143	0.138	0.143
Maroon Bells	0.091	0.083	0.075	0.083	0.091
Mesa Verde	1.435	1.740	1.712	1.629	1.740
Pecos	0.178	0.223	0.219	0.207	0.223
Petrified Forest	0.144	0.109	0.115	0.123	0.144
San Pedro	0.380	0.503	0.436	0.440	0.503
West Elk	0.134	0.138	0.134	0.135	0.138
Weminuche	0.260	0.405	0.323	0.329	0.405
Wheeler Peak	0.156	0.135	0.163	0.151	0.163
Overall				**0.324**	**1.740**

Table 8-13
Unit 3 SCR Visibility Modeling Results
98th Percentile Impact for Each Year (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	0.734	0.440	0.561	0.578	0.734
Bandelier	0.316	0.383	0.470	0.390	0.470
Black Canyon	0.305	0.246	0.331	0.294	0.331
Canyonlands	0.918	0.563	0.674	0.718	0.918
Capitol Reef	0.542	0.219	0.323	0.361	0.542
Grand Canyon	0.241	0.176	0.193	0.203	0.241
Great Sand Dunes	0.185	0.165	0.153	0.168	0.185
La Garita	0.227	0.201	0.235	0.221	0.235
Maroon Bells	0.133	0.125	0.113	0.124	0.133
Mesa Verde	2.312	1.776	2.516	2.201	2.516
Pecos	0.288	0.279	0.362	0.310	0.362
Petrified Forest	0.237	0.155	0.179	0.190	0.237
San Pedro	0.631	0.592	0.640	0.621	0.640
West Elk	0.202	0.190	0.192	0.195	0.202
Weminuche	0.424	0.453	0.563	0.480	0.563
Wheeler Peak	0.246	0.182	0.216	0.215	0.246
Overall				**0.454**	**2.516**

Table 8-14
Unit 4 SCR Visibility Modeling Results
98th Percentile Impact for Each Year (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	0.718	0.517	0.532	0.589	0.718
Bandelier	0.311	0.446	0.459	0.405	0.459
Black Canyon	0.297	0.284	0.328	0.303	0.328
Canyonlands	0.931	0.655	0.678	0.755	0.931
Capitol Reef	0.530	0.237	0.319	0.362	0.530
Grand Canyon	0.238	0.195	0.190	0.208	0.238
Great Sand Dunes	0.183	0.183	0.150	0.172	0.183
La Garita	0.224	0.223	0.219	0.222	0.224
Maroon Bells	0.131	0.153	0.114	0.133	0.153
Mesa Verde	2.304	2.234	2.455	2.331	2.455
Pecos	0.280	0.336	0.353	0.323	0.353
Petrified Forest	0.233	0.162	0.175	0.190	0.233
San Pedro	0.618	0.706	0.631	0.652	0.706
West Elk	0.199	0.219	0.192	0.203	0.219
Weminuche	0.412	0.547	0.549	0.503	0.549
Wheeler Peak	0.240	0.206	0.213	0.220	0.240
Overall				**0.473**	**2.455**

Table 8-15 Unit 1 Hybrid Visibility Modeling Results 98th Percentile Impact for Each Year (dv)					
Class I Area	2001	2002	2003	Average	Maximum
Arches	0.731	0.560	0.601	0.631	0.731
Bandelier	0.277	0.437	0.384	0.366	0.437
Black Canyon	0.274	0.269	0.297	0.280	0.297
Canyonlands	1.002	0.691	0.677	0.790	1.002
Capitol Reef	0.558	0.186	0.286	0.343	0.558
Grand Canyon	0.269	0.170	0.148	0.196	0.269
Great Sand Dunes	0.162	0.153	0.128	0.148	0.162
La Garita	0.189	0.199	0.203	0.197	0.203
Maroon Bells	0.130	0.113	0.105	0.116	0.130
Mesa Verde	2.076	2.385	2.135	2.199	2.385
Pecos	0.250	0.309	0.288	0.282	0.309
Petrified Forest	0.183	0.122	0.129	0.145	0.183
San Pedro	0.494	0.708	0.608	0.603	0.708
West Elk	0.199	0.201	0.195	0.198	0.201
Weminuche	0.307	0.497	0.413	0.406	0.497
Wheeler Peak	0.194	0.164	0.202	0.187	0.202
Overall				**0.443**	**2.385**

Table 8-16
Unit 2 Hybrid Visibility Modeling Results
98th Percentile Impact for Each Year (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	0.728	0.558	0.598	0.628	0.728
Bandelier	0.276	0.435	0.382	0.364	0.435
Black Canyon	0.273	0.268	0.296	0.279	0.296
Canyonlands	0.997	0.687	0.673	0.786	0.997
Capitol Reef	0.555	0.185	0.285	0.342	0.555
Grand Canyon	0.268	0.169	0.148	0.195	0.268
Great Sand Dunes	0.162	0.152	0.127	0.147	0.162
La Garita	0.188	0.198	0.201	0.196	0.201
Maroon Bells	0.130	0.112	0.104	0.115	0.130
Mesa Verde	2.067	2.374	2.125	2.189	2.374
Pecos	0.249	0.308	0.287	0.281	0.308
Petrified Forest	0.182	0.121	0.128	0.144	0.182
San Pedro	0.492	0.705	0.605	0.601	0.705
West Elk	0.198	0.200	0.194	0.197	0.200
Weminuche	0.305	0.495	0.411	0.404	0.495
Wheeler Peak	0.193	0.164	0.201	0.186	0.201
Overall				**0.441**	**2.374**

Table 8-17
Unit 3 Hybrid Visibility Modeling Results
98th Percentile Impact for Each Year (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	1.018	0.774	0.669	0.820	1.018
Bandelier	0.349	0.631	0.612	0.531	0.631
Black Canyon	0.382	0.412	0.474	0.423	0.474
Canyonlands	1.237	0.924	0.856	1.006	1.237
Capitol Reef	0.702	0.248	0.377	0.442	0.702
Grand Canyon	0.322	0.267	0.201	0.263	0.322
Great Sand Dunes	0.229	0.248	0.180	0.219	0.248
La Garita	0.299	0.328	0.306	0.311	0.328
Maroon Bells	0.171	0.202	0.158	0.177	0.202
Mesa Verde	2.430	2.892	2.558	2.627	2.892
Pecos	0.341	0.469	0.433	0.414	0.469
Petrified Forest	0.272	0.204	0.176	0.217	0.272
San Pedro	0.709	0.984	0.772	0.822	0.984
West Elk	0.254	0.335	0.275	0.288	0.335
Weminuche	0.422	0.755	0.551	0.576	0.755
Wheeler Peak	0.263	0.281	0.253	0.266	0.281
Overall				**0.588**	**2.892**

Table 8-18
Unit 4 Hybrid Visibility Modeling Results
98th Percentile Impact for Each Year (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	1.102	0.755	0.740	0.866	1.102
Bandelier	0.411	0.616	0.672	0.566	0.672
Black Canyon	0.426	0.407	0.510	0.448	0.510
Canyonlands	1.369	0.919	1.002	1.097	1.369
Capitol Reef	0.754	0.243	0.412	0.470	0.754
Grand Canyon	0.344	0.262	0.221	0.276	0.344
Great Sand Dunes	0.251	0.240	0.194	0.228	0.251
La Garita	0.329	0.323	0.319	0.324	0.329
Maroon Bells	0.196	0.197	0.170	0.188	0.197
Mesa Verde	3.006	2.845	3.164	3.005	3.164
Pecos	0.383	0.461	0.467	0.437	0.467
Petrified Forest	0.290	0.199	0.192	0.227	0.290
San Pedro	0.777	0.963	0.864	0.868	0.963
West Elk	0.275	0.328	0.283	0.295	0.328
Weminuche	0.496	0.733	0.697	0.642	0.733
Wheeler Peak	0.289	0.275	0.290	0.285	0.290
Overall				**0.639**	**3.164**

8.8.3 WRAP RMC Baseline Scenario

The results of the WRAP RMC baseline modeling from April 21, 2007, are presented in Table 8-19. As previously noted, correspondence between NMED and the WRAP on April 2, 2007, indicated an error(s) in the original BART modeling conducted by WRAP in 2006. The error(s) was corrected, and WRAP has since rerun the previous BART modeling; however, at the time of this report, the extent of the error(s), their corresponding correction(s), and the results are not known. Therefore, it is not known how these errors have affected the previously described WRAP modeling.

8.8.4 Summary

As previously described, the SJGS BART modeling for the BART emissions control options are presented in Tables 8-9 through 8-20. Tables 8-9 and 8-10 show the results, assuming that the same control technology is installed on all four units. Table 8-19 presents the results of the analysis conducted by the WRAP RMC. These tables summarize the scenarios and the maximum visibility (deciview) improvement seen at any of the 16 Class I areas at any time over the 2001 to 2003 period. The expected degree of visibility improvement for each control scenario for each unit analyzed was determined by the difference in the average visibility improvement for each receptor at each of the sixteen Class I areas. However, it is important to note that the control technology associated with the consent decree formulated the SJGS's baseline case for the purposes of this analysis. Therefore, using the WRAP RMC's April 2007 modeling results and the SJGS's consent decree baseline results, the average visibility improvement is 0.6 dv.

Similar calculations for the SCR and hybrid control technology options were also conducted. To simplify this analysis, the total average amount of visibility improvement at all 16 Class I areas, assuming that all units installed the same control technology, was compared to the total average visibility improvement from the consent decree baseline. These visibility improvements for the three cases range from 0.2 dv to 0.6 dv of expected visibility improvement above the consent decree technology baseline case, which is less than or equal to the visibility improvement gained by going from the WRAP RMC's baseline case to the consent decree technology baseline case. For Mesa Verde, the average number of days that exceed the recommended exemption guideline value of 0.5 dv is higher for the SCR and hybrid control technology options than the consent decree technology baseline. Table 8-20 illustrates the average change in visibility improvement. Additionally, differences in data processing, model control options, and methodologies can yield variations between the WRAP modeling and SJGS BART modeling. In the case of the visibility impacts at Mesa Verde Class I area, WRAP's visibility impacts from April 2007, shown in Table 8-19 are less than those presented in this report for the consent decree technology baseline scenario, shown in Table 8-8 or the additional control scenarios for SCR or hybrid control technology options, shown in Table 8-9 and 8-10, respectively.

Table 8-19
WRAP RMC Baseline Modeling Results
98th Percentile Impact for Each Year (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	4.06	3.71	3.59	3.787	4.060
Bandelier	2.47	2.90	3.08	2.817	3.080
Black Canyon	2.38	2.27	2.43	2.360	2.430
Canyonlands	6.21	4.33	4.44	4.993	6.210
Capitol Reef	4.00	2.02	2.35	2.790	4.000
Grand Canyon	2.12	1.50	1.18	1.600	2.120
Great Sand Dunes	1.47	1.59	1.74	1.600	1.740
La Garita	1.63	1.82	1.77	1.740	1.820
Maroon Bells	1.19	1.27	1.15	1.203	1.270
Mesa Verde[a]	5.54	5.34	5.30	5.393	5.540
Pecos	2.17	2.63	2.81	2.537	2.810
Petrified Forest	1.62	1.27	1.03	1.307	1.620
San Pedro	3.80	4.07	4.14	4.003	4.140
West Elk	2.24	2.99	2.41	2.547	2.990
Weminuche	2.14	1.90	2.20	2.080	2.200
Wheeler Peak	1.94	1.73	1.97	1.880	1.970
Overall				**2.665**	**6.210**

[a]Differences in data processing, model control options, and methodologies can yield variations between the WRAP modeling and SJGS BART modeling. In the case of the visibility impacts at Mesa Verde Class I area, WRAP's visibility impacts from April 2007 are less than those presented for the consent decree technology baselinescenario (Table 8-8) or the SCR and Hybrid control technology scenarios (Table 8-9 and 8-10).

Table 8-20
Average Change in Visibility Improvement[(a)]

Visibility Scenario	Baseline Average Impact (dv)	Control Technology Average Impact (dv)	Scenario Average Deciview Change[(b)] (dv)
WRAP RMC to Consent Decree	2.665	2.051	0.614
Consent Decree to SCR	2.051	1.424	0.627
Consent Decree to Hybrid	2.051	1.825	0.226

[(a)]Average impact is the average impact from all 16 Class I Areas at all receptors for the period 2001-2003.
[(b)]Scenario average deciview change is the difference between the average baseline scenario and average control technology scenario.

8.9 Visibility Improvement Cost-Effectiveness

The visibility improvement cost-effectiveness defined in Subsection 1.2.5 was determined according to the TAC for the consent decree upgrades shown in Table 4-2 and for the additional control technology alternatives shown in Table 7-1. The maximum and average modeled visibility impacts at the 16 Federal Class I areas were used for the determination of the visibility improvement cost-effectiveness in \$/deciview (\$/dv). Three major scenarios are shown in the visibility improvement cost effectiveness summary in Table 8-21:

- Pre-consent decree to consent decree.
- Consent decree to additional NO_x control technology alternatives scenario.
- Pre-consent decree to additional NO_x control technology alternatives scenario.

The pre-consent decree visibility impact was based on the visibility modeling performed by the RMC for WRAP for the determination of BART eligibility.

Table 8-21
Visibility Improvement Cost-Effectiveness Summary

Visibilitiy Scenario	Total Annualized Cost (TAC) (1,000$)	Scenario Average Deciview Change (dv)	Average Improvement ($/dv)
Consent Decree Scenario			
Pre-consent decree to consent decree	51,468	0.614	83,824,104
Additional Control Technology Alternative			
Consent decree to SCR	97,367	0.627	155,290,271
Consent decree to Hybrid	83,332	0.226	368,725,664
Pre-consent decree to SCR	148,835	1.241	119,931,507
Pre-consent decree to Hybrid	134,800	0.840	160,476,190

Notes:

1. All costs are in 2007$.
2. Pre-consent decree visibility impact from WRAP RMC model, April 2007.
3. Total annualized costs and cost effectiveness ($/ton) are referenced from Table 4-3 and 7-1.
4. Deciview change assumes all four units on the same control technology.

9.0 Conclusions

The BART analysis was performed in two stages. First, a BART analysis was performed for the consent decree technologies. Then, additional control technology alternatives were examined through the BART process.

After completing all five steps of the BART analysis, feasible technologies for all four units at SJGS were selected and evaluated for visibility improvement at the affected Federal Class I areas. The visibility improvement modeling is summarized in Section 8.0 of this report.

The recommended BART control for SJGS is LNB, OFA, and a NN for NO_x control and PJFF for PM control. The recommended BART control scenario was based on an evaluation of the most cost-effective technology. This evaluation was performed as detailed in Sections 3.0 to 7.0 of this report. For PM emissions control, the addition of the PJFF to meet the consent decree requirements represents BACT for similar units. No other technologies have been identified that exceed the emissions reductions achieved by the PJFF. Therefore, the PJFF is considered BART for this project.

For NO_x emissions control, the LNB, OFA, and NN should be considered BART for the SJGS units. The presumptive limit for subbituminous units is based on the installation of state-of-the-art combustion control (i.e. LNB and OFA) on a PRB-fired unit. The fuel characteristics of the subbituminous coal fired at SJGS are very similar to those of bituminous coal. The low volatility, low moisture, and low oxygen content of the coal burned at SJGS distinguishes it from other fuels, such as PRB fuels, included in the same category of "subbituminous". These characteristics result in higher NO_x emissions than on a PRB-fired unit with the same control technology. The LNB, OFA, and NN technologies being installed at the SJGS units are classified as state-of-the-art technologies and are equivalent to the BART technology used to establish the presumptive NO_x limit.

The visibility improvements modeled for the BART control scenario (as described in Section 8.0) indicate an average visibility improvement of 0.614 dv based on the pre-consent decree visibility modeled by WRAP's RMC for all identified Federal Class I areas.

Based on the visibility improvement modeled and the total annual cost evaluated in the impact analysis stage, the cost-effectiveness for visibility improvement (annual cost per improvement in visibility, \$/dv), was determined for SJGS. The total annual cost for the implementation of LNB, OFA, NN, and PJFF technologies is approximately \$51.5 million/yr, and the visibility improvement cost-effectiveness is 83.8 million \$/dv.

The SCR and SNCR/SCR Hybrid systems would require significant capital expenditure and modifications that will impact many areas of the plant including boiler draft systems, air heater performance, SO_3 emissions, and ash handling. The capital costs for SCR ranged from $157 million on Unit 1 to $216 million on Unit 3. This represents a cost range of 436 $/kW on Unit 1 to 396 $/kW on Unit 3. For SNCR/SCR Hybrid, the capital costs ranged from $104 million on Unit 1 to $169 million on Unit 3. This represents a cost range of 290 $/kW on Unit 1 to 310 $/kW on Unit 3. In addition, the average visibility improvement from these systems is only 0.627 dv for SCR and 0.226 for the hybrid. The visibility improvement cost effectiveness is 155 million $/dv for SCR and 369 million $/dv for SNCR/SCR Hybrid. These minimal visibility improvements do not merit the large capital expenditure required to install SCR or SNCR/SCR Hybrid. In addition to the prohibitive cost associated with SCR and SNCR/SCR Hybrid, there is another important reason that LNB, OFA and NN should be considered BART for the SJGS units. The LNB, OFA and NN systems being installed to meet the consent decree are state-of-the-art combustion controls. The LNB, OFA and NN technologies were used to form the basis for the BART presumptive limits for NO_x. Therefore, LNB, OFA and NN should be considered BART for NO_x control on the SJGS units.

Appendix A
Design Basis

Public Service Company of New Mexico (PNM) - San Juan Generating Station (SJGS)
Best Available Retrofit Technology (BART) Engineering Analysis
Design Basis Rev. 3

	SJGS Unit 1	Reference	SJGS Unit 2	Reference	SJGS Unit 3	Reference	SJGS Unit 4	Reference
Ultimate Coal analysis, wet basis								
Carbon, %	54.52	Ref 1	54.52	Ref 1	54.52	Ref 1	54.52	Ref 1
Hydrogen, %	4.24	Ref 1	4.24	Ref 1	4.24	Ref 1	4.24	Ref 1
Sulfur, %	0.77	Ref 1	0.77	Ref 1	0.77	Ref 1	0.77	Ref 1
Nitrogen, %	1.08	Ref 1	1.08	Ref 1	1.08	Ref 1	1.08	Ref 1
Oxygen, %	9.38	Ref 1	9.38	Ref 1	9.38	Ref 1	9.38	Ref 1
Chlorine, %	NA	Ref 1	NA	Ref 1	NA	Ref 1	NA	Ref 1
Ash, %	21.29	Ref 1	21.29	Ref 1	21.29	Ref 1	21.29	Ref 1
Moisture, %	8.72	Ref 1	8.72	Ref 1	8.72	Ref 1	8.72	Ref 1
Total, %	100.00	Ref 1	100.00	Ref 1	100.00	Ref 1	100.00	Ref 1
Higher Heating Value, Btu/lb	9,692	Ref 1	9,692	Ref 1	9,692	Ref 1	9,692	Ref 1
Unit Characteristics								
Unit Rating, Gross MW	360	Ref 2	350	Ref 2	544	Ref 2	544	Ref 2
Boiler Type	Wall-Fired	Ref 2	Wall-Fired	Ref 2	Opposed Wall-Fired	Ref 2	Opposed Wall-Fired	Ref 2
Boiler Heat Input, MBtu/h (HHV)	3,707	Ref 3	3,688	Ref 3	5,758	Ref 3	5,649	Ref 3
Coal Flow Rate, lb/h	382,480	Calculated	380,520	Calculated	594,098	Calculated	582,852	Calculated
Capacity Factor, %	85	Note 5	85	Note 5	85	Note 5	85	Note 5
Fly Ash Portion of Total Ash, %	80	Ref 4	80	Ref 4	80	Ref 4	80	Ref 4
Air Heater Leakage, %	15	Note 5	15	Note 5	15	Note 5	15	Note 5
Excess Air, %	20	Ref 5	20	Ref 5	20	Ref 5	20	Ref 5
PRE-CONSENT DECREE OPERATION CONDITIONS								
Emission Summary								
Nitrogen Oxides (NO_x), lb/MBtu	0.43	Ref 4	0.45	Ref 4	0.42	Ref 4	0.42	Ref 4
Nitrogen Oxides (NO_x), lb/h	1,592.0	Calculated	1,649.3	Calculated	2,405.5	Calculated	2,399.6	Calculated
Sulfur Dioxide (SO_2), lb/MBtu	0.24	Ref 4	0.23	Ref 4	0.28	Ref 4	0.29	Ref 4
Sulfur Dioxide (SO_2), lb/MBtu	877.8	Calculated	844.0	Calculated	1,591.1	Calculated	1,662.4	Calculated
Particulate Matter (PM), lb/MBtu	0.050	Ref 4	0.050	Ref 4	0.050	Ref 4	0.050	Ref 4
Particulate Matter (PM), lb/h	185.4	Calculated	184.4	Calculated	287.9	Calculated	282.5	Calculated
CONSENT DECREE UPGRADES CONDITIONS								
Economizer Outlet Conditions								
Flue Gas Temperature, °F	707	Ref 6	710	Ref 7	720	Ref 8	720	Ref 9
Flue Gas Pressure, in. wg	12.0	Ref 6	11.0	Ref 7	19.0	Ref 8	19.0	Ref 9
Flue Gas Mass Flow Rate, lb/h	3,674,408	Ref 6	3,655,575	Ref 7	5,707,376	Ref 8	5,599,334	Ref 9
Volumetric Flue Gas Flow Rate, acfm	2,082,166	Ref 6	2,082,819	Ref 7	3,205,572	Ref 8	3,144,890	Ref 9

Flue Gas Composition								
Oxygen (O_2), % by volume	3.2	Ref 6	3.2	Ref 7	3.2	Ref 8	3.2	Ref 9
Carbon Dioxide (CO_2), % by volume	13.7	Ref 6	13.7	Ref 7	13.7	Ref 8	13.7	Ref 9
Moisture (H_2O), % by volume	9.7	Ref 6	9.7	Ref 7	9.7	Ref 8	9.7	Ref 9
Sulfur Dioxide (SO_2), % by volume	0.07	Ref 6	0.07	Ref 7	0.07	Ref 8	0.07	Ref 9
Sulfur Dioxide (SO_2), lb/MBtu	1.59	Calculated	1.59	Calculated	1.59	Calculated	1.59	Calculated
Sulfur Dioxide (SO_2), lb/h	5,884	Ref 6	5,854	Ref 7	9,140	Ref 8	8,967	Ref 9
Sulfur Trioxide (SO_3), lb/h	74	Note 1	73	Note 1	114	Note 1	112	Note 1
Sulfur Trioxide (SO_3), lb/MBtu	0.020	Calculated	0.020	Calculated	0.020	Calculated	0.020	Calculated
Particulate Matter (PM), lb/MBtu	17.6	Calculated	17.6	Calculated	17.6	Calculated	17.57	Calculated
Particulate Matter (PM), lb/h	65,144	Ref 6	64,810	Ref 7	101,187	Ref 8	99,271	Ref 9
Nitrogen Oxides (NOx), lb/MBtu	0.30	Ref 10	0.30	Ref 10	0.30	Ref 10	0.30	Ref 10
Nitrogen Oxides (NOx), lb/h	1,112	Calculated	1,106	Calculated	1,727	Calculated	1,695	Calculated
De-Energized Hot-Side ESP Outlet Conditions								
Flue Gas Temperature, °F	695	Ref 6	698	Ref 7	640	Ref 8	673	Ref 9
Flue Gas Pressure, in. wg	6.5	Ref 6	6.5	Ref 7	8.2	Ref 8	8.2	Ref 9
Flue Gas Mass Flow Rate, lb/h	3,674,408	Ref 6	3,655,575	Ref 7	5,707,376	Ref 8	5,599,334	Ref 9
Volumetric Flue Gas Flow Rate, acfm	2,093,930	Ref 6	2,088,609	Ref 7	3,082,239	Ref 8	3,114,609	Ref 9
Flue Gas Composition								
Oxygen (O_2), % by volume	3.2	Ref 6	3.2	Ref 7	3.2	Ref 8	3.2	Ref 9
Carbon Dioxide (CO_2), % by volume	13.7	Ref 6	13.7	Ref 7	13.7	Ref 8	13.7	Ref 9
Moisture (H_2O), % by volume	9.7	Ref 6	9.7	Ref 7	9.7	Ref 8	9.7	Ref 9
Sulfur Dioxide (SO_2), % by volume	0.07	Ref 6	0.07	Ref 7	0.07	Ref 8	0.07	Ref 9
Sulfur Dioxide (SO_2), lb/MBtu	1.59	Calculated	1.59	Calculated	1.59	Calculated	1.59	Calculated
Sulfur Dioxide (SO_2), lb/h	5,884	Ref 6	5,854	Ref 7	9,140	Ref 8	8,967	Ref 9
Sulfur Trioxide (SO_3), lb/h	74	Note 1	73	Note 1	114	Note 1	112	Note 1
Sulfur Trioxide (SO_3), lb/MBtu	0.020	Calculated	0.020	Calculated	0.020	Calculated	0.020	Calculated
Particulate Matter (PM), lb/MBtu	8.79	Calculated	8.79	Calculated	8.79	Calculated	8.79	Calculated
Particulate Matter (PM), lb/h	32,572	Note 3	32,405	Note 3	50,593	Note 3	49,636	Note 3
Nitrogen Oxides (NOx), lb/MBtu	0.30	Ref 10	0.30	Ref 10	0.30	Ref 10	0.30	Ref 10
Nitrogen Oxides (NOx), lb/h	1,112	Calculated	1,106	Calculated	1,727	Calculated	1,695	Calculated
Air Heater Outlet Conditions								
Flue Gas Temperature, °F	277	Ref 6	277	Ref 7	277	Ref 8	277	Ref 9
Flue Gas Pressure, in. wg	0.0	Ref 6	0.0	Ref 7	0.0	Ref 8	0.0	Ref 9
Flue Gas Mass Flow Rate, lb/h	4,225,569	Ref 6	4,203,912	Ref 7	6,563,482	Ref 8	6,439,234	Ref 9
Volumetric Flue Gas Flow Rate, acfm	1,571,717	Ref 6	1,563,662	Ref 7	2,441,313	Ref 8	2,395,099	Ref 9

Flue Gas Composition								
Oxygen (O_2), % by volume	5.5	Ref 6	5.5	Ref 7	5.5	Ref 8	5.5	Ref 9
Carbon Dioxide (CO_2), % by volume	11.9	Ref 6	11.9	Ref 7	11.9	Ref 8	11.9	Ref 9
Moisture (H_2O), % by volume	8.7	Ref 6	8.7	Ref 7	8.7	Ref 8	8.7	Ref 9
Sulfur Dioxide (SO_2), % by volume	0.06	Ref 6	0.06	Ref 7	0.06	Ref 8	0.06	Ref 9
Sulfur Dioxide (SO_2), lb/MBtu	1.59	Calculated	1.59	Calculated	1.59	Calculated	1.59	Calculated
Sulfur Dioxide (SO_2), lb/h	5,884	Ref 6	5,854	Ref 7	9,140	Ref 8	8,967	Ref 9
Particulate Matter (PM), lb/MBtu	8.79	Calculated	8.79	Calculated	8.79	Calculated	8.79	Calculated
Particulate Matter (PM), lb/h	32,572	Note 3	32,405	Note 3	50,593	Note 3	49,636	Note 3
Nitrogen Oxides (NOx), lb/MBtu	0.30	Ref 10	0.30	Ref 10	0.30	Ref 10	0.30	Ref 10
Nitrogen Oxides (NOx), lb/h	1,112	Calculated	1,106	Calculated	1,727	Calculated	1,695	Calculated
Fabric Filter Outlet Conditions								
Fabric Filter Particulate Matter Removal, percent	99.86%	Calculated	99.86%	Calculated	99.86%	Calculated	99.86%	Calculated
Flue Gas Temperature, °F	277	Ref 6	277	Ref 7	277	Ref 8	277	Ref 9
Flue Gas Pressure, in. wg	-10	Ref 6	-10	Ref 7	-10.0	Ref 8	-10.0	Ref 9
Flue Gas Mass Flow Rate, lb/h	4,225,569	Ref 6	4,203,912	Ref 7	6,563,482	Ref 8	6,439,234	Ref 9
Volumetric Flue Gas Flow Rate, acfm	1,620,055	Ref 6	1,611,752	Ref 7	2,516,395	Ref 8	2,468,760	Ref 9
Flue Gas Composition								
Sulfur Dioxide (SO_2), lb/MBtu	1.59	Calculated	1.59	Calculated	1.59	Calculated	1.59	Calculated
Sulfur Dioxide (SO_2), lb/h	5,884	Ref 6	5,854	Ref 7	9,140	Ref 8	8,967	Ref 9
Particulate Matter (PM), lb/MBtu	0.012	Ref 5	0.012	Ref 5	0.012	Ref 5	0.012	Ref 5
Particulate Matter (PM), lb/h	44	Calculated	44	Calculated	69	Calculated	68	Calculated
FGD Booster Fan Outlet Conditions								
Flue Gas Temperature, °F	290	Ref 6	290	Ref 7	290	Ref 8	290	Ref 9
Flue Gas Pressure, in. wg	10	Ref 6	9	Ref 7	14.2	Ref 8	14.2	Ref 9
Flue Gas Mass Flow Rate, lb/h	4,225,569	Ref 6	4,203,912	Ref 7	6,563,482	Ref 8	6,439,234	Ref 9
Volumetric Flue Gas Flow Rate, acfm	1,553,101	Ref 6	1,549,630	Ref 7	2,383,394	Ref 8	2,338,276	Ref 9
Flue Gas Composition								
Sulfur Dioxide (SO_2), lb/MBtu	1.59	Calculated	1.59	Calculated	1.59	Calculated	1.59	Calculated
Sulfur Dioxide (SO_2), lb/h	5,884	Ref 6	5,854	Ref 7	9,140	Ref 8	8,967	Ref 9
Scrubber Outlet Conditions								
Scrubber SO_2 Removal, percent	90%	Note 4	90%	Note 4	90%	Note 4	90%	Note 4
Flue Gas Temperature, °F	121	Ref 6	121	Ref 7	121	Ref 8	121	Ref 9
Flue Gas Pressure, in. wg	1.0	Ref 6	1.0	Ref 7	1.0	Ref 8	1.0	Ref 9
Flue Gas Mass Flow Rate, lb/h	4,396,972	Ref 6	4,374,435	Ref 7	6,829,718	Ref 8	6,700,430	Ref 9
Volumetric Flue Gas Flow Rate, acfm	1,319,596	Ref 6	1,312,832	Ref 7	2,049,699	Ref 8	2,010,898	Ref 9
Flue Gas Composition								
Sulfur Dioxide (SO_2), lb/MBtu	0.16	Calculated	0.16	Calculated	0.16	Calculated	0.16	Calculated
Sulfur Dioxide (SO_2), lb/h	588	Calculated	585	Calculated	914	Calculated	897	Calculated

Stack Outlet Conditions								
Flue Gas Temperature, °F	121	Ref 6	121	Ref 7	121	Ref 8	121	Ref 9
Flue Gas Pressure, in. wg	0.01	Ref 6	0.01	Ref 7	0.01	Ref 8	0.01	Ref 9
Flue Gas Mass Flow Rate, lb/h	4,396,972	Ref 6	4,374,435	Ref 7	6,829,718	Ref 8	6,700,430	Ref 9
Volumetric Flue Gas Flow Rate, acfm	1,323,494	Ref 6	1,316,710	Ref 7	2,055,753	Ref 8	2,016,837	Ref 9
Stack Height, m	121.92	Ref 11	121.92	Ref 11	121.92	Ref 11	121.92	Ref 11
Stack Diameter, m	6.10	Ref 11	6.10	Ref 11	8.53	Ref 11	8.53	Ref 11
Flue Gas Exit Velocity, ft/s	70	Calculated	70	Calculated	56	Calculated	55	Calculated
Flue Gas Composition								
Sulfur Dioxide (SO_2), lb/MBtu	0.16	Calculated	0.16	Calculated	0.16	Calculated	0.16	Calculated
Sulfur Dioxide (SO_2), lb/h	588	Calculated	585	Calculated	914	Calculated	897	Calculated
H_2SO_4 Emissons, lb/h	21.6	Ref 12	21.5	Ref 12	33.6	Ref 12	33.0	Ref 12
Particulate Matter (PM), lb/MBtu	0.015	Ref 5	0.015	Ref 5	0.015	Ref 5	0.015	Ref 5
Particulate Matter (PM), lb/h	56	Calculated	55	Calculated	86	Calculated	85	Calculated
Nitrogen Oxides (NOx), lb/MBtu	0.30	Ref 10	0.30	Ref 10	0.30	Ref 10	0.30	Ref 10
Nitrogen Oxides (NOx), lb/h	1,112	Calculated	1,106	Calculated	1,727	Calculated	1,695	Calculated

Notes:

1. Sulfur dioxide to sulfur trioxide conversion is assumed to be 1% across the boiler.
2. The particulate matter concentrations listed are filterable particulate matter only.
3. 50% total particulate matter drop-out expected through de-energized hot ESP, N. Norem, 03/02/2007.
4. SO_2 post-consent decree emission limits is a minimum of 90% removal.
5. Assumptions verified in weekly phone conference, 03/08/2007.

References

1. Composite delivery sample analysis representing November 2005 (642,775 tons).
2. Section 3.2 Design Criteria for PNM SJGS Environmental Project.
3. Environmental Upgrades "6% plus" Permitting Heat Input Basis.
4. Study project basis information.
5. B&W LNB and AQCS Performance Guarantee, Page 2 of 14.
6. M10 Combustion Calculation for SJGS Unit 1, K. Whitehead, 03/09/2007.
7. M10 Combustion Calculation for SJGS Unit 2, K. Whitehead, 03/09/2007.
8. M10 Combustion Calculation for SJGS Unit 3, K. Whitehead, 03/09/2007.
9. M10 Combustion Calculation for SJGS Unit 4, K. Whitehead, 03/09/2007.
10. Post-consent decree NO_x emission limit.
11. SJGS boiler stack exit parameters.
12. San Juan Generating Station BART SO_4 Emission Comparison (National Park Service spreadsheet calculation for April 2003 to January 2007), K. Lucas, 04/12/2007.

Revision History

Rev	Date	Purpose
0	2/21/2007	Initial issue to client
1	3/9/2007	Revision to address comments on air heater outlet conditions and hot-ESP particulate drop-out rate
2	4/18/2007	Revision to include H_2SO_4 emissions data
3	5/24/2007	Revision to update references and table layout

Appendix B
Design Concept Definitions

Design Concept Definition

Site Name	San Juan Generating Station	**Units**	1, 2, 3, 4	
Client Name	PNM	**Process Technology**	Selective Non-Catalytic Reduction	

Process Description	Addition of Selective Non-Catalytic Reduction (SNCR) process into boiler pendant superheat section.				
	Pollutant	NO_x (Unit 1)	NO_x (Unit 2)	NO_x (Unit 3)	NO_x (Unit 4)
	Emissions				
	lb/MBtu	0.30	0.30	0.30	0.30
	lb/h	1,112	1,106	1,727	1,695
	Controlled Emissions				
	lb/MBtu	0.24	0.24	0.24	0.24
	lb/h	NA	NA	NA	NA
	Inlet Flow Basis, acfm	2,082,166	2,082,819	3,205,572	3,144,890
	Pressure Drop Added, in. wg	None			
	Coal Source and Type	New Mexico, Subbituminous			
	Capacity Factor	85.0%			
Consumables	Reagent (Urea), lb/h	NA	NA	NA	NA
	Water, gpm	NA	NA	NA	NA
	Energy, kW	NA	NA	NA	NA
	Maintenance	3% of direct material cost.			
Byproduct	Description	No impact on ash sales.			
	Other	Up to 5 ppm ammonia slip.			

Location of Major Process Equipment	Truck-filled reagent storage tank, reagent circulation unit in enclosure with metering and distribution module, wall-injectors and multi-nozzle lances (MNL) in boiler penetrations.
Inlet/Outlet Connections and Interconnecting Ducts	Dilution water to metering module, atomizing air to injectors and MNL, cooling water for MNL.
Reagent Storage	Reagent tank at grade.
Control System Modifications	SNCR controls interfaced into existing control system.
Fan Modifications	None.
Power Supply/Aux Power Modifications	Minimum impact/modifications.
Enclosures Requirements	Injection equipment enclosed in existing boiler building, enclosure for reagent circulation unit.
Demolition or Relocation Requirements	Penetrations into boiler wall for injectors and MNL, access platforms.
Major Constructability Issues	Routing of SNCR reagent supply lines.
Significant Issues or Challenges	Ammonia slip may cause buildup of ammonium bisulfate on the air heater, which may require more frequent cleaning, air heater modifications included.

Other Assumptions:

- No major impact in plant availability.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
- No boiler/duct stiffening included.
- Air heater modifications included in analysis.
- No impact on potential ash sales.
- Reagent is urea solution.

State of Availability	Availability.
State of Applicability	Not applicable.
Technical Feasibility	Not technically feasible. Controlled NO_x level does not presumptive NO_x limits. Undeveloped data fields will be marked as "NA".

Design Concept Definition

Site Name	San Juan Generating Station	**Units**	1, 2, 3, 4		
Client Name	PNM	**Process Technology**	Selective Catalytic Reduction		
Process Description	Install Selective Catalytic Reduction (SCR) ammonia injection and reactor downstream of de-energized hot-side ESP.				
	Pollutant	NO_x (Unit 1)	NO_x (Unit 2)	NO_x (Unit 3)	NO_x (Unit 4)
	Emissions				
	lb/MBtu	0.30	0.30	0.30	0.30
	lb/h	1,112	1,106	1,727	1,695
	Controlled Emissions				
	lb/MBtu	0.07	0.07	0.07	0.07
	lb/h	259.5	258.2	403.1	395.4
	Inlet Flow Basis, acfm	2,093,930	2,088,609	3,082,239	3,114,609
	Pressure Drop Added, in. wg	10			
	Coal Source and Type	New Mexico, Subbituminous			
	Capacity Factor	85.0%			
Consumables	Reagent (Ammonia), lb/h	350	348	543	533
	Energy, kW	3,296	3,287	4,835	4,881
	Catalyst	Add and/or replace one catalyst layer every 2 years.			
	Maintenance	3% of direct material cost.			
Byproduct	Description	No impact on ash sales.			
	Other	2 ppm ammonia slip (max)			

Location of Major Process Equipment	Install SCR reactor as high-dust configuration, downstream of de-energized hot-side ESP and upstream of existing air heaters. Ammonia injection location will be upstream of the reactor. Install ammonia vaporizers at grade.
Inlet/Outlet Connections and Interconnecting Ducts	SCR inlet and outlet ducts connected into duct exiting de-energized hot-side ESP and entering air heater, dilution water and atomizing air for reagent preparation and delivery.
Reagent Storage	Locate ammonia storage at grade in suitable protective structure or away from unit to limit risk from ammonia leakage.
Control System Modifications	SCR controls interfaced into existing control system.
Fan Modifications	Assume additional fan capacity will be required, requiring balanced draft conversion.
Power Supply/Aux Power Modifications	Aux electric system upgrade will be required for additional fan capacity, ammonia preparation and delivery system, and reactor catalyst cleaning system.
Enclosures Requirements	Ammonia injection grid area and sonic horns are to be enclosed.
Demolition or Relocation Requirements	Existing ductwork between de-energized hot-side ESP outlet and air heater inlet.
Major Constructability Issues	Support steel design for SCR reactor and location of piling for steel support. Crane access for constructing SCR reactor for SJGS units 2 and 3.
Significant Issues or Challenges	Ammonia slip in the SCR may cause ammonium bisulfate formation on the air heater and require more frequent cleaning, air heater modifications included.

Other Assumptions:

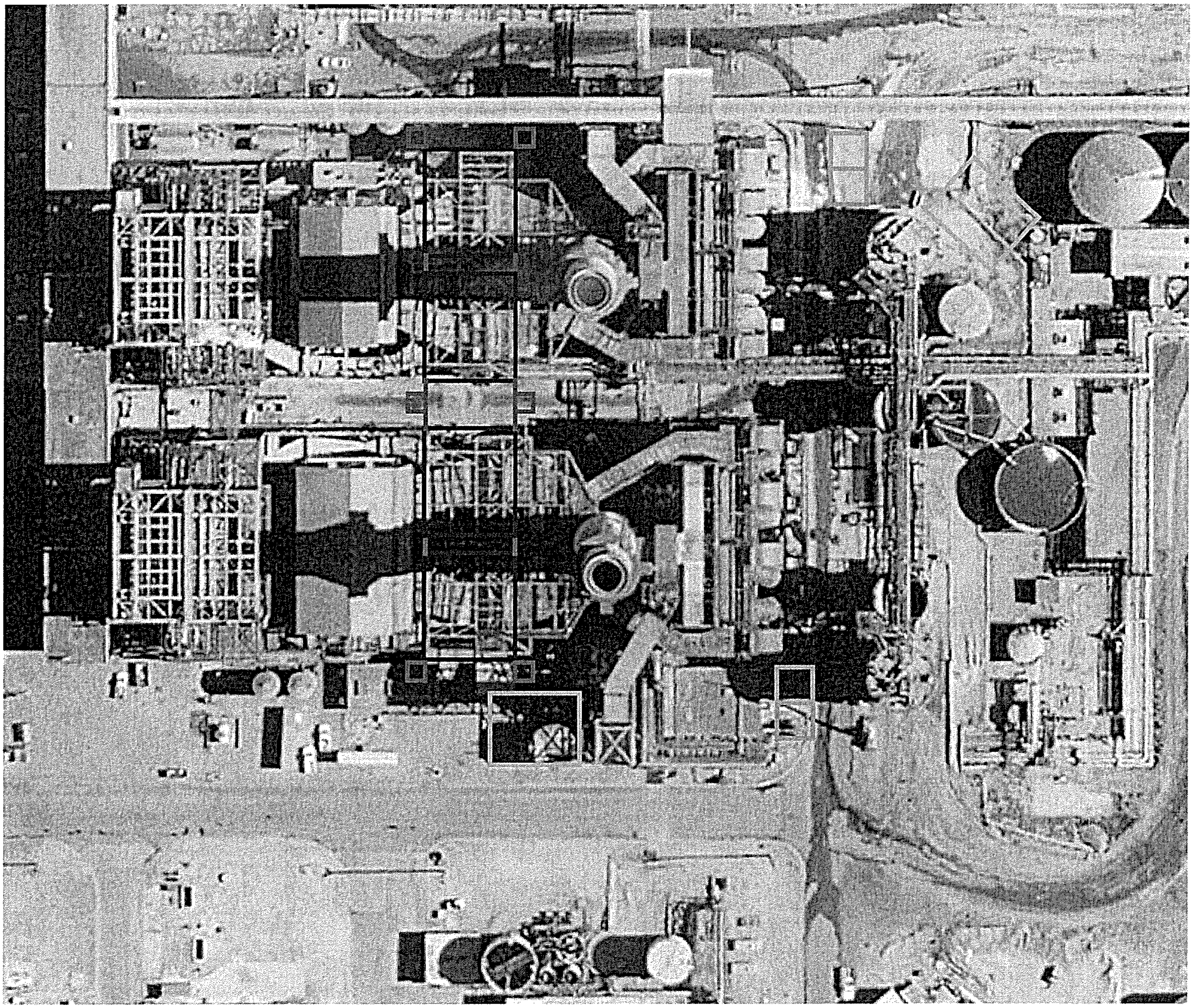
- No major impact in plant availability.
- Temperature range of flue gas at de-energized hot-side ESP outlet is acceptable and no additional heating required at low loads.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging. Crane access to Units 2 and 3 might be limited (see attached plant layout).
- Air heater modifications, flue gas handling systems, and ammonia handling systems included.
- SCR bypass included to allow the SCR to be bypassed during startup on fuel oil.
- SCR reactor includes three initial catalyst layers and one spare layer (3 + 1 arrangement).

State of Availability	Availability.
State of Applicability	Applicable.
Technical Feasibility	Technically feasible.

SJGS Unit 1 and 2 Proposed SCR Layout Plan

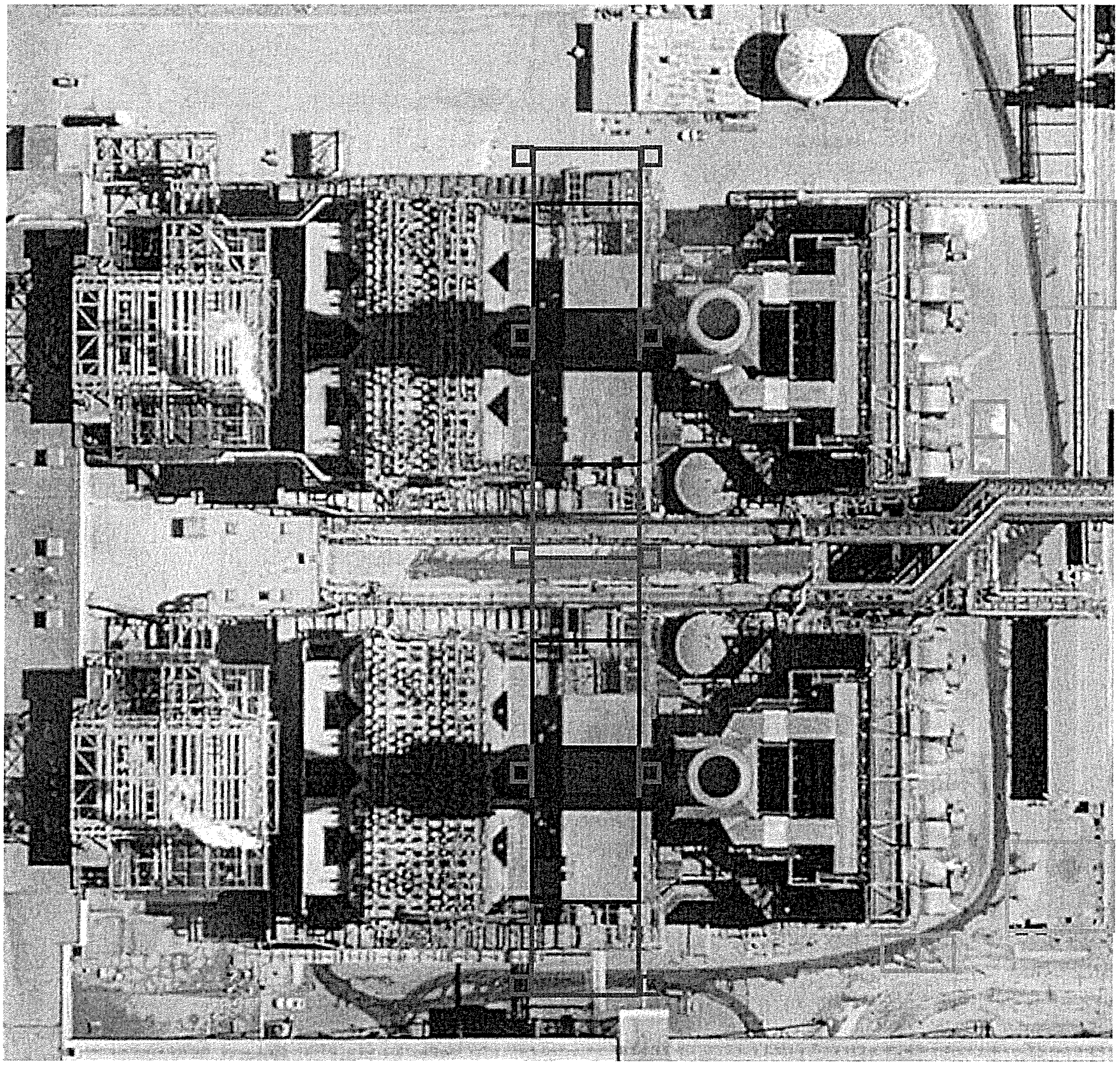
Legend:

Blue	= SCR Reactor
Red	= Structural Steel Supports
Orange	= PJFF Location – Consent Decree Modifications
Green	= Induced Draft Fan Locations



SJGS Unit 3 and 4 Proposed SCR Layout Plan

Legend:
Blue = SCR Reactor
Red = Structural Steel Supports
Orange= PJFF Location – Consent Decree Modifications
Green = Induced Draft Fan Locations



Design Concept Definition

Site Name	San Juan Generating Station	**Units**	1, 2, 3, 4			
Client Name	PNM	**Process Technology**	SNCR/SCR Hybrid			
Process Description	Install SNCR/SCR hybrid system. Single layer catalyst added in ductwork downstream of de-energized hot-side ESP outlet.					
	Pollutant	NO_x (Unit 1)	NO_x (Unit 2)	NO_x (Unit 3)	NO_x (Unit 4)	
	Emissions					
	lb/MBtu	0.30	0.30	0.30	0.30	
	lb/h	1,112	1,106	1,727	1,695	
	Controlled Emissions					
	lb/MBtu	0.18	0.18	0.18	0.18	
	lb/h	667.3	663.8	1,036.4	1,061.8	
	Inlet Flow Basis, acfm	2,082,166	2,082,819	3,205,572	3,144,890	
	Pressure Drop Added, in. wg	6				
	Coal Source and Type	New Mexico, Subbituminous				
	Capacity Factor	85.0%				
Consumables	Reagent (Urea), lb/h	1,089	1,089	1,689	1,689	
	Water, gpm	252	252	380	380	
	Energy, kW	1,477	1,477	2,197	2,197	
	Catalyst	Replace catalyst layer every 2 years.				
	Maintenance	3% of direct material cost.				
Byproduct	Description	No impact on ash sales.				
	Other	5 ppm ammonia slip (max)				

Location of Major Process Equipment	Truck-filled reagent storage tank, reagent circulation unit in enclosure with metering and distribution module, wall-injectors and multi-nozzle lances (MNL) in boiler penetrations. Single layer catalyst is added in ductwork downstream of de-energized hot-side ESP.
Inlet/Outlet Connections and Interconnecting Ducts	Catalyst inlet and outlet ducts connected into duct exiting de-energized hot-side ESP and entering air heater. Increase duct size to include as much catalyst as possible.
Reagent Storage	Reagent tank at grade.
Control System Modifications	SNCR/SCR hybrid controls interfaced into existing control system.
Fan Modifications	Assume additional fan capacity will be required, requiring balanced draft conversion.
Power Supply/Aux Power Modifications	Aux electric system upgrade will be required for additional fan capacity, ammonia preparation and delivery system, and reactor catalyst cleaning system.
Enclosures Requirements	Injection equipment enclosed in existing boiler building, enclosure for reagent circulation unit.
Demolition or Relocation Requirements	Existing ductwork between de-energized hot-side ESP outlet and air heater inlet. Penetrations into boiler wall for injectors and MNL, access platforms.
Major Constructability Issues	Support steel design for SCR reactor and location of piling for steel support. Crane access for constructing SCR reactor for SJGS units 2 and 3. Routing of SNCR reagent supply lines.
Significant Issues or Challenges	Ammonia slip may cause buildup of ammonium bisulfate on the air heater, which may require more frequent cleaning, air heater modifications included.

Other Assumptions:
- No major impact in plant availability.
- Temperature range of flue gas at de-energized hot-side ESP outlet is acceptable and no additional heating required at low loads.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging. Crane access to Units 2 and 3 might be limited.
- Air heater modifications, flue gas handling systems, and reagent handling systems included.
- Reagent is urea solution.

State of Availability	Availability.
State of Applicability	Applicable.
Technical Feasibility	Technically feasible.

Design Concept Definition

Site Name	San Juan Generating Station	**Units**	1, 2, 3, 4		
Client Name	PNM	**Process Technology**	Gas Reburn		
Process Description	Natural gas reburn in boiler. Includes; standard natural gas reburn, fuel lean gas reburn (FLGR) and amine-enhanced fuel lean gas reburn (AE-FLGR).				
	Pollutant	NO_x (Unit 1)	NO_x (Unit 2)	NO_x (Unit 3)	NO_x (Unit 4)
	Emissions				
	lb/MBtu	0.30	0.30	0.30	0.30
	lb/h	1,112	1,106	1,727	1,695
	Controlled Emissions				
	lb/MBtu	NA	NA	NA	NA
	lb/h	NA	NA	NA	NA
	Inlet Flow Basis, acfm	2,082,166	2,082,819	3,205,572	3,144,890
	Pressure Drop Added, in. wg	NA			
	Coal Source and Type	New Mexico, Subbituminous			
	Capacity Factor	85.0%			
Consumables	Reagent (Natural gas)	NA	lb/h		
	Energy	NA	kW		
	Maintenance	3% of direct material cost.			
Byproduct	Description	Not applicable			
	Other	None.			

Location of Major Process Equipment	Additional natural gas reburn levels to be installed in boiler wall.
Inlet/Outlet Connections and Interconnecting Ducts	Natural gas supply line required.
Reagent Storage	None.
Control System Modifications	Incorporated into existing control system.
Fan Modifications	None.
Power Supply/Aux Power Modifications	Minor aux electric system modifications required for natural gas handling system.
Enclosures Requirements	Enclosed in existing boiler building.
Demolition or Relocation Requirements	Penetrations into boiler wall.
Major Constructability Issues	None.
Significant Issues or Challenges	Potential for increased furnace corrosion issues due to reducing atmosphere at lower furnace.

Other Assumptions

- Gas required is typically 7% of total heat input.

State of Availability	Available.
State of Applicability	Not applicable.
Technical Feasibility	Boiler not suitable for reburn due to current modifications to add OFA, not sufficient residence time for natural gas reburn. Not technically feasible. Undeveloped data fields will be marked as "NA".

Design Concept Definition

Site Name	San Juan Generating Station	**Units**	1, 2, 3, 4
Client Name	PNM	**Process Technology**	Mobotec ROFA and ROTAMIX

Process Description	Mobotec ROFA and ROTAMIX				
	Pollutant	NO_x (Unit 1)	NO_x (Unit 2)	NO_x (Unit 3)	NO_x (Unit 4)
	Emissions				
	lb/MBtu	0.30	0.30	0.30	0.30
	lb/h	1,112	1,106	1,727	1,695
	Controlled Emissions				
	lb/MBtu	NA	NA	NA	NA
	lb/h	NA	NA	NA	NA
	Inlet Flow Basis, acfm	2,082,166	2,082,819	3,205,572	3,144,890
	Pressure Drop Added, in. wg	NA			
	Coal Source and Type	New Mexico, Subbituminous			
	Capacity Factor	85.0%			

Consumables	Reagent	NA	lb/h
	Energy	NA	kW
	Maintenance	3% of direct material cost.	
Byproduct	Description	No impact on ash sales.	
	Other	5ppm ammonia slip (if ROTAMIX).	

Location of Major Process Equipment	Install ROFA ports above existing close coupled overfire air ports. Injection skid and reagent tank at grade with truck unloading station.
Inlet/Outlet Connections and Interconnecting Ducts	Tie-in to existing air duct.
Reagent Storage	50,000 gallon tank at grade.
Control System Modifications	Incorporated into existing control system.
Fan Modifications	None.
Power Supply/Aux Power Modifications	Minimum impact/modifications.
Enclosures Requirements	Enclosed in existing boiler building.
Demolition or Relocation Requirements	Penetrations into boiler wall.
Major Constructability Issues	None.
Significant Issues or Challenges	Ammonia slip may cause buildup of ammonium bisulfate on the air heater, which may require more frequent cleaning. Up to 5 ppm ammonia slip.

Other Assumptions:
- No major impact in plant availability.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
- No air heater modifications. Boiler/duct penetrations included.
- Minimal impact on potential ash sales.

State of Availability	Available.
State of Applicability	Applicable (ROFA only).
Technical Feasibility	ROFA is technically feasible. ROTAMIX is not technically feasible (not demonstrated on similar sized boilers as SJGS). Undeveloped data fields will be marked as "NA."

Design Concept Definition

Site Name	San Juan Generating Station	**Units**	1, 2, 3, 4		
Client Name	PNM	**Process Technology**	NO_xStar		
Process Description	NO_xStar (injection of natural gas and ammonia mixture into boiler) and NO_xStar Plus (with in-duct catalyst)				
	Pollutant	NO_x (Unit 1)	NO_x (Unit 2)	NO_x (Unit 3)	NO_x (Unit 4)
	Emissions				
	lb/MBtu	0.30	0.30	0.30	0.30
	lb/h	1,112	1,106	1,727	1,695
	Controlled Emissions				
	lb/MBtu	NA	NA	NA	NA
	lb/h	NA	NA	NA	NA
	Inlet Flow Basis, acfm	2,082,166	2,082,819	3,205,572	3,144,890
	Pressure Drop Added, in. wg	NA			
	Coal Source and Type	New Mexico, Subbituminous			
	Capacity Factor	85.0%			

Consumables	Reagent (Ammonia)	NA	lb/h
	Reagent (Natural gas)	NA	lb/h
	Energy	NA	kW
	Catalyst	Add and/or replace one catalyst layer every 3 years (if NO_xStar Plus).	
	Maintenance	3% of direct material cost.	
Byproduct	Description	No impact on ash sales.	
	Other	5ppm ammonia slip.	

Location of Major Process Equipment	Injection skid and ammonia tank at grade with truck unloading station. Install in-duct catalyst between economizer outlet and air heater inlet.
Inlet/Outlet Connections and Interconnecting Ducts	Catalyst inlet and outlet ducts connected into duct exiting the de-energized hot-side ESP. Natural gas supply line connection into injection system.
Reagent Storage	50,000 gallon tank at grade.
Control System Modifications	Incorporated into existing control system.
Fan Modifications	Fan modifications required if to account for in-duct catalyst for NO_xStar Plus (if installed).
Power Supply/Aux Power Modifications	Minimum impact/modifications.
Enclosures Requirements	Enclosed in existing boiler building.
Demolition or Relocation Requirements	Penetrations into boiler wall.
Major Constructability Issues	Economizer outlet ductwork modifications required to house in-duct catalyst for NO_xStar Plus (if installed).
Significant Issues or Challenges	Ammonia slip may cause buildup of ammonium bisulfate on the air heater, which may require more frequent cleaning.

Other Assumptions:

- No major impact in plant availability.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
- No air heater modifications or boiler/duct stiffening included.
- No impact on potential ash sales.
- Reagent is ammonia and natural gas. If NO_xStar Plus, only single layer in-duct catalyst installed.

State of Availability	Available.
State of Applicability	Not applicable.
Technical Feasibility	No commercial deployment of technology. Only proven at one site. Not technically feasible. Undeveloped data fields will be marked as "NA."

Design Concept Definition

Site Name	San Juan Generating Station	**Units**	1, 2, 3, 4
Client Name	PNM	**Process Technology**	ECOTUBE

Process Description	Injection of high-velocity air into boiler. Ammonia/urea can be added into air for additional NO_x reduction.				
	Pollutant	NO_x (Unit 1)	NO_x (Unit 2)	NO_x (Unit 3)	NO_x (Unit 4)
	Emissions				
	lb/MBtu	0.30	0.30	0.30	0.30
	lb/h	1,112	1,106	1,727	1,695
	Controlled Emissions				
	lb/MBtu	NA	NA	NA	NA
	lb/h	NA	NA	NA	NA
	Inlet Flow Basis, acfm	2,082,166	2,082,819	3,205,572	3,144,890
	Pressure Drop Added, in. wg	NA			
	Coal Source and Type	New Mexico, Subbituminous			
	Capacity Factor	85.0%			

Consumables	Reagent (Ammonia or Urea)	NA	lb/h
	Energy	NA	kW
	Maintenance	3% of direct material cost.	
Byproduct	Description	No impact on ash sales.	
	Other	5ppm ammonia slip.	

Location of Major Process Equipment	Injection skid and urea tank at grade with truck unloading station. Install water-cooled, retractable lances at to be determined location in boiler.
Inlet/Outlet Connections and Interconnecting Ducts	Tie-in to existing air duct.
Reagent Storage	Tank at grade.
Control System Modifications	Incorporated into existing control system.
Fan Modifications	None.
Power Supply/Aux Power Modifications	Minimum impact/modifications.
Enclosures Requirements	Enclosed in existing boiler building.
Demolition or Relocation Requirements	Penetrations into boiler wall.
Major Constructability Issues	None.
Significant Issues or Challenges	Ammonia slip may cause buildup of ammonium bisulfate on the air heater, which may require more frequent cleaning.

Other Assumptions:

- No major impact in plant availability.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
- No air heater modifications or boiler/duct stiffening included.
- No impact on potential ash sales.
- Reagent is ammonia or urea.

State of Availability	Available.
State of Applicability	Not applicable. Largest coal boiler application of 175 MW.
Technical Feasibility	Not technically feasible due to applicability. Undeveloped data fields will be marked as "NA."

Design Concept Definition

Site Name	San Juan Generating Station	**Units**	1, 2, 3, 4		
Client Name	PNM	**Process Technology**	PowerSpan		
Process Description	Install PowerSpan process equipment train for multi-pollutant control (NO_x, SO_2, Hg). Process is based on oxidation and capture of pollutants in flue gas stream.				
	Pollutant	NO_x (Unit 1)	NO_x (Unit 2)	NO_x (Unit 3)	NO_x (Unit 4)
	Emissions				
	lb/MBtu	0.30	0.30	0.30	0.30
	lb/h	1,112	1,106	1,727	1,695
	Controlled Emissions				
	lb/MBtu	NA	NA	NA	NA
	lb/h	NA	NA	NA	NA
	Inlet Flow Basis, acfm	1,620,055	1,611,752	2,516,395	2,468,760
	Pressure Drop Added, in. wg	NA			
	Coal Source and Type	New Mexico, Subbituminous			
	Capacity Factor	85.0%			
Consumables	Reagent (Ammonia)	NA	lb/h		
	Water	NA	gpm		
	Energy	NA	kW		
	Maintenance	3% of direct material cost.			
Byproduct	Description	Commercial grade fertilizer (ammonium sulfate).			
	Other	None.			

Location of Major Process Equipment	ECO reactor and ammonia scrubber with wet ESP located downstream of PJFF. Ammonia reagent preparation and byproduct processing equipment located in a dedicated building.
Inlet/Outlet Connections and Interconnecting Ducts	Equipment train connected to booster fan discharge downstream of PJFF.
Reagent Storage	Ammonia storage and preparation system required
Control System Modifications	Incorporated into existing control system.
Fan Modifications	Assume additional fan capacity will be required.
Power Supply/Aux Power Modifications	Aux electric system upgrade will be required for additional fan capacity, ECO reactor operations, ammonia preparation and delivery system, scrubber operation and wet ESP operation.
Enclosures Requirements	Enclosures for ammonia reagent preparation and byproduct processing.
Demolition or Relocation Requirements	Remove existing wet FGD, reroute ductwork to new equipment train.
Major Constructability Issues	Site area availability for new equipment train and associated reagent preparation and byproduct processing equipment.
Significant Issues or Challenges	Recovered byproduct cannot be landfilled. Fertilizer material to be used by nearby agriculture industry.

Other Assumptions:
- No major impact in plant availability.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
- Assumed byproduct can be disposed to nearby agriculture industry.
- Reagent is ammonia.

State of Availability	Available.
State of Applicability	Not applicable. Small-scale testing recently completed. First small-scale commercial implementation in progress.
Technical Feasibility	Not technically feasible. Undeveloped data fields will be marked as "NA."

Design Concept Definition

Site Name	San Juan Generating Station	**Units**	1, 2, 3, 4
Client Name	PNM	**Process Technology**	Phenix Clean Combustion System

Process Description

Boiler combustion system conversion to the Phenix Clean Combustion System (CCS). Process is based on gasification of coal upstream of the regular boiler combustion system.

Pollutant	NO_x (Unit 1)	NO_x (Unit 2)	NO_x (Unit 3)	NO_x (Unit 4)
Emissions				
lb/MBtu	0.30	0.30	0.30	0.30
lb/h	1,112	1,106	1,727	1,695
Controlled Emissions				
lb/MBtu	NA	NA	NA	NA
lb/h	NA	NA	NA	NA
Inlet Flow Basis, acfm	2,082,166	2,082,819	3,205,572	3,144,890
Pressure Drop Added, in. wg	NA			
Coal Source and Type	New Mexico, Subbituminous			
Capacity Factor	85.0%			

Consumables	Reagent (Urea)	NA	lb/h
	Water	NA	gpm
	Energy	NA	kW
	Maintenance	3% of direct material cost.	
Byproduct	Description	Combustion byproduct (slag).	
	Other	None	

Location of Major Process Equipment	Coal gasification process equipment integrated into boiler combustion system. Limestone preparation and delivery system located at coal gasification process zone.
Inlet/Outlet Connections and Interconnecting Ducts	Connection to boiler combustion equipment.
Reagent Storage	None.
Control System Modifications	Coal gasification control system integrated into boiler combustion control system.
Fan Modifications	None.
Power Supply/Aux Power Modifications	Aux electric system upgrade will be required for the limestone preparation system and slag removal system.
Enclosures Requirements	Enclosed in existing boiler building.
Demolition or Relocation Requirements	Reconfiguration of existing boiler required to integrate gasification process equipment. Downstream AQC equipment left in place for contingency purpose.
Major Constructability Issues	Access to boiler building and modifications of boiler combustion systems to retrofit coal gasification process equipment.
Significant Issues or Challenges	None.

Other Assumptions:
- No major impact in plant availability.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
- No air heater modifications or included.
- No fly ash produced. Ash sales will be impacted.

State of Availability	Available.
State of Applicability	Not applicable. Still in development stage, no full-scale commercial implementation yet.
Technical Feasibility	Not technically feasible. Undeveloped data fields will be marked as "NA."

Design Concept Definition

Site Name	San Juan Generating Station		**Units**	1, 2, 3, 4	
Client Name	PNM		**Process Technology**	e-SCRUB	
Process Description	Install e-SCRUB process equipment train for multi-pollutant control (NO_x, SO_2, Hg). Process is based on oxidation and capture of pollutants in flue gas stream. Byproduct is processed using spray dryer and particulate collector system.				
	Pollutant	NO_x (Unit 1)	NO_x (Unit 2)	NO_x (Unit 3)	NO_x (Unit 4)
	Emissions				
	lb/MBtu	0.30	0.30	0.30	0.30
	lb/h	1,112	1,106	1,727	1,695
	Controlled Emissions				
	lb/MBtu	NA	NA	NA	NA
	lb/h	NA	NA	NA	NA
	Inlet Flow Basis, acfm	1,620,055	1,611,752	2,516,395	2,468,760
	Pressure Drop Added, in. wg	NA			
	Coal Source and Type	New Mexico, Subbituminous			
	Capacity Factor	85.0%			
Consumables	Reagent (Ammonia)	NA	lb/h		
	Water	NA	gpm		
	Energy	NA	kW		
	Maintenance	3% of direct material cost.			
Byproduct	Description	Commercial grade fertilizer (ammonium sulfate).			
	Other	None.			

Location of Major Process Equipment	Spray dryer absorber and particulate collector system for byproduct drying located upstream of actual e-SCRUB process. e-Beam building and wet ESP located downstream of PJFF. Ammonia reagent preparation and delivery system is upstream of the e-Beam building.
Inlet/Outlet Connections and Interconnecting Ducts	Process equipment is located after booster fans downstream of PJFF.
Reagent Storage	Ammonia storage and preparation system required
Control System Modifications	Incorporated into existing control system.
Fan Modifications	Assume additional fan capacity will be required.
Power Supply/Aux Power Modifications	Aux electric system upgrade will be required for additional fan capacity, e-Beam operations, ammonia preparation and delivery system, scrubber operation and wet ESP operation.
Enclosures Requirements	Enclosures for ammonia reagent preparation.
Demolition or Relocation Requirements	Remove existing wet FGD, reroute ductwork to new equipment train.
Major Constructability Issues	Site area availability for new equipment train and associated reagent preparation and byproduct processing equipment.
Significant Issues or Challenges	Recovered byproduct cannot be landfilled. Fertilizer material to be used by nearby agriculture industry.

Other Assumptions:

- No major impact in plant availability.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
- Assumed byproduct can be disposed to nearby agriculture industry.
- Reagent is ammonia.

State of Availability	Available.
State of Applicability	Not applicable. Still in development stage, no full-scale commercial implementation yet.
Technical Feasibility	Not technically feasible. Undeveloped data fields will be marked as "NA."

Design Concept Definition

Site Name	San Juan Generating Station	**Units**	1, 2, 3, 4		
Client Name	PNM	**Process Technology**	Flue Gas Conditioning with Hot-side ESP		
Process Description	Install flue gas conditioning system upstream of existing hot-side ESP. Process is based on addition of ammonia or SO_3 into flue gas upstream of hot-side ESP to augment fly ash resistivity.				
	Pollutant	PM (Unit 1)	PM (Unit 2)	PM (Unit 3)	PM (Unit 4)
	Emissions				
	lb/MBtu	17.6	17.6	17.6	17.6
	lb/h	65,144	64,810	101,187	99,271
	Controlled Emissions				
	lb/MBtu	NA	NA	NA	NA
	lb/h	NA	NA	NA	NA
	Inlet Flow Basis, acfm	2,082,166	2,082,819	3,205,572	3,144,890
	Pressure Drop Added, in. wg	NA			
	Coal Source and Type	New Mexico, Subbituminous			
	Capacity Factor	85.0%			
Consumables	Reagent (NH_3/SO_3)	NA	lb/h		
	Energy	NA	kW		
	Maintenance	3% of direct material cost.			
Byproduct	Description	No impact on ash sales.			
	Other	None.			

Location of Major Process Equipment	Flue gas conditioning reagent delivery system in ductwork upstream of ESP.
Inlet/Outlet Connections and Interconnecting Ducts	Ductwork connection upstream of ESP.
Reagent Storage	Reagent preparation and storage for flue gas conditioning at grade.
Control System Modifications	New stand-alone control system, tie in to plant DCS control system.
Fan Modifications	None.
Power Supply/Aux Power Modifications	Minor aux electric system modification required for reagent preparation and delivery systems.
Enclosures Requirements	No additional enclosures required.
Demolition or Relocation Requirements	Demolition of ductwork upstream of ESP for retrofit.
Major Constructability Issues	None.
Significant Issues or Challenges	Planned outage required for retrofit project.

Other Assumptions
- No major impact on plant availability.
- Determination of type of reagent and quantity of injection based on further study and trial of flue gas conditioning agents.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.

State of Availability	Available.
State of Applicability	Not applicable.
Technical Feasibility	Not technically feasible because new PJFF retrofit capable of achieving similar controlled emissions level. Undeveloped data fields will be marked as "NA."

Design Concept Definition

Site Name	San Juan Generating Station	**Units**	1, 2, 3, 4		
Client Name	PNM	**Process Technology**	Compact Hybrid Particulate Collector		
Process Description	Add a high air-to-cloth ratio fabric filter (COHPAC) as a polishing filter downstream of existing ESP.				
	Pollutant	PM (Unit 1)	PM (Unit 2)	PM (Unit 3)	PM (Unit 4)
	Emissions				
	lb/MBtu	8.8	8.8	8.8	8.8
	lb/h	32,572	32,405	50,593	49,636
	Controlled Emissions				
	lb/MBtu	NA	NA	NA	NA
	lb/h	NA	NA	NA	NA
	Inlet Flow Basis, acfm	1,518,669	1,517,269	2,267,380	2,224,459
	Pressure Drop Added, in. wg	NA			
	Coal Source and Type	New Mexico, Subbituminous			
	Capacity Factor	85.0%			
Consumables	Reagent	None			
	Energy	NA kW			
	Maintenance	3% of direct material cost (not including fabric filter bag and cage replacement)			
Byproduct	Description	Fly ash.			
	Other	N/A.			

Location of Major Process Equipment	COHPAC located downstream of air heater and upstream of FGD booster fans. New ash handling system also installed.
Inlet/Outlet Connections and Interconnecting Ducts	Ductwork connection downstream of air heater outlet and upstream of FGD booster fans.
Reagent Storage	None.
Control System Modifications	New stand-alone control system, tie in to plant DCS control system.
Fan Modifications	FGD booster fan modifications required to overcome additional pressure drop.
Power Supply/Aux Power Modifications	Aux electric system modification required for bag cleaning system, FGD booster fan modifications, and ash handling system.
Enclosures Requirements	COHPAC designed with penthouse.
Demolition or Relocation Requirements	Replace existing ductwork with connections to COHPAC.
Major Constructability Issues	Site access to construction site.
Significant Issues or Challenges	Planned major outage required for retrofit project.

Other Assumptions

- No major impact in plant availability.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
- Fabric filter bag life is 3 years. Fabric filter cage life is 6 years.
- COHPAC can be used as a component for Hg removal systems.

State of Availability	Available.
State of Applicability	Not applicable.
Technical Feasibility	Not technically feasible because new PJFF retrofit capable of achieving similar controlled emissions level. Undeveloped data fields will be marked as "NA."

Design Concept Definition

Site Name	San Juan Generating Station		**Units**	1, 2, 3, 4	
Client Name	PNM		**Process Technology**	Max-9 Electrostatic Fabric Filter	
Process Description	Retrofit new Max-9 Electrostatic Fabric Filter (ESFF) system into flue gas path, upstream of wet FGD. Existing hot-side ESP will be de-energized and left in place.				
	Pollutant	PM (Unit 1)	PM (Unit 2)	PM (Unit 3)	PM (Unit 4)
	Emissions				
	lb/MBtu	8.8	8.8	8.8	8.8
	lb/h	32,572	32,405	50,593	49,636
	Controlled Emissions				
	lb/MBtu	NA	NA	NA	NA
	lb/h	NA	NA	NA	NA
	Inlet Flow Basis, acfm	1,518,669	1,517,269	2,267,380	2,224,459
	Pressure Drop Added, in. wg	NA			
	Coal Source and Type	New Mexico, Subbituminous			
	Capacity Factor	85.0%			
Consumables	Reagent	None			
	Energy	NA kW			
	Maintenance	3% of direct material cost (not including fabric filter bag and cage replacement).			
Byproduct	Description	Fly ash.			
	Other	None.			

Location of Major Process Equipment	Max-9 located downstream of air heater and upstream of FGD booster fans. New ash handling system also installed.
Inlet/Outlet Connections and Interconnecting Ducts	Ductwork connection downstream of air heater outlet and upstream of FGD booster fans.
Reagent Storage	None.
Control System Modifications	New stand-alone control system, tie in to plant DCS control system.
Fan Modifications	FGD booster fan modifications required to overcome additional pressure drop.
Power Supply/Aux Power Modifications	Aux electric system modification required for bag cleaning system, FGD booster fan modifications, and ash handling system.
Enclosures Requirements	Max-9 designed with penthouse.
Demolition or Relocation Requirements	Replace existing ductwork with connections to Max-9.
Major Constructability Issues	Site access to construction site.
Significant Issues or Challenges	Planned major outage required for retrofit project.

Other Assumptions
- No major impact in plant availability.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
- Fabric filter bag life is 3 years. Fabric filter cage life is 6 years.
- Max-9 can be used as a component for Hg removal systems.

State of Availability	Available.
State of Applicability	Not applicable.
Technical Feasibility	Not technically feasible because there are no commercial applications on SJGS sized flue gas system. Undeveloped data fields will be marked as "NA."

Appendix C
Cost Analysis Summary

Low NO_x Burners (LNB) and Overfire Air (OFA)

Technology: Low NOx Burners & OFA - SJGS Unit 1 **Date:** 4/25/2007

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
LNB-OFA system scope:	$5,639,000	PNM environmental upgrade cost		
Low NOx Burners				
Dual Zone NOx Ports				
Boiler Modifications				
Ductwork				
Access Platforms				
CFD Modeling				
Control System Modificatons				
Balance of plant modificatons	$689,000	PNM environmental upgrade cost		
Subtotal capital cost (CC)	$6,328,000			
Gross Receipt Tax	$665,000	PNM environmental upgrade cost		
Total purchased equipment cost (PEC)	$6,993,000			
Direct installation costs				
Project construction costs	$4,946,000	PNM environmental upgrade cost		
Total direct installation costs (DIC)	$4,946,000			
Total direct costs (DC) = (PEC) + (DIC)	$11,939,000			
Indirect Costs				
Engineering	$149,000	PNM environmental upgrade cost		
Owner's cost	$345,000	PNM environmental upgrade cost		
Construction management	$597,000	(DC) X	5.0%	
Start-up and spare parts	$239,000	(DC) X	2.0%	
Performance test	$50,000	Engineering estimate		
Contingencies	$740,000	PNM environmental upgrade cost		
Total indirect costs (IC)	$2,120,000			
Interest During Construction (IDC)	$521,000	[(DC)+(IC)] X	7.41%	1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (IDC)	**$14,580,000**			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Maintenance labor	$2,000	B&V estimate, 1 man week/yr		
Total fixed annual costs	$2,000			
Variable annual costs				
N/A	$0	No associated annual cost		
Total variable annual costs	$0			
Total direct annual costs (DAC)	$2,000			
Indirect Annual Costs				
Cost for capital recovery	$1,420,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life
Total indirect annual costs (IDAC)	$1,420,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$1,422,000**			

Technology: Low NOx Burners & OFA - SJGS Unit 2 **Date:** 4/25/2007

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
LNB-OFA system scope:	$5,184,000	PNM environmental upgrade cost		
Low NOx Burners				
Dual Zone NOx Ports				
Boiler Modifications				
Ductwork				
Access Platforms				
CFD Modeling				
Control System Modificatons				
Balance of plant modificatons	$742,000	PNM environmental upgrade cost		
Subtotal capital cost (CC)	$5,926,000			
Gross Receipt Tax	$645,000	PNM environmental upgrade cost		
Total purchased equipment cost (PEC)	$6,571,000			
Direct installation costs				
Project construction costs	$5,014,000	PNM environmental upgrade cost		
Total direct installation costs (DIC)	$5,014,000			
Total direct costs (DC) = (PEC) + (DIC)	$11,585,000			
Indirect Costs				
Engineering	$141,000	PNM environmental upgrade cost		
Owner's cost	$334,000	PNM environmental upgrade cost		
Construction management	$579,000	(DC) X	5.0%	
Start-up and spare parts	$232,000	(DC) X	2.0%	
Performance test	$50,000	Engineering estimate		
Contingencies	$700,000	PNM environmental upgrade cost		
Total indirect costs (IC)	$2,036,000			
Interest During Construction (IDC)	$505,000	[(DC)+(IC)] X	7.41%	1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (IDC)	**$14,126,000**			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Maintenance labor	$2,000	B&V estimate, 1 man week/yr		
Total fixed annual costs	$2,000			
Variable annual costs				
N/A	$0	No associated annual cost		
Total variable annual costs	$0			
Total direct annual costs (DAC)	$2,000			
Indirect Annual Costs				
Cost for capital recovery	$1,376,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life
Total indirect annual costs (IDAC)	$1,376,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$1,378,000**			

Technology: Low NOx Burners & OFA - SJGS Unit 3

Date: 4/25/2007

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
LNB-OFA system scope:	$4,431,000	PNM environmental upgrade cost		
Low NOx Burners				
Dual Zone NOx Ports				
Boiler Modifications				
Ductwork				
Access Platforms				
CFD Modeling				
Control System Modificatons				
Balance of plant modificatons	$658,000	PNM environmental upgrade cost		
Subtotal capital cost (CC)	$5,089,000			
Gross Receipt Tax	$597,000	PNM environmental upgrade cost		
Total purchased equipment cost (PEC)	$5,686,000			
Direct installation costs				
Project construction costs	$5,035,000	PNM environmental upgrade cost		
Total direct installation costs (DIC)	$5,035,000			
Total direct costs (DC) = (PEC) + (DIC)	$10,721,000			
Indirect Costs				
Engineering	$177,000	PNM environmental upgrade cost		
Owner's cost	$311,000	PNM environmental upgrade cost		
Construction management	$536,000	(DC) X	5.0%	
Start-up and spare parts	$214,000	(DC) X	2.0%	
Performance test	$50,000	Engineering estimate		
Contingencies	$252,000	PNM environmental upgrade cost		
Total indirect costs (IC)	$1,540,000			
Interest During Construction (IDC)	$454,000	[(DC)+(IC)] X	7.41%	1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (IDC)	**$12,715,000**			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Maintenance labor	$2,000	B&V estimate, 1 man week/yr		
Total fixed annual costs	$2,000			
Variable annual costs				
N/A	$0	No associated annual cost		
Total variable annual costs	$0			
Total direct annual costs (DAC)	$2,000			
Indirect Annual Costs				
Cost for capital recovery	$1,238,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life
Total indirect annual costs (IDAC)	$1,238,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$1,240,000**			

Technology: Low NOx Burners & OFA - SJGS Unit 4 **Date:** 4/25/2007

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
LNB-OFA system scope:	$4,663,000	PNM environmental upgrade cost		
Low NOx Burners				
Dual Zone NOx Ports				
Boiler Modifications				
Ductwork				
Access Platforms				
CFD Modeling				
Control System Modificatons				
Balance of plant modificatons	$753,000	PNM environmental upgrade cost		
Subtotal capital cost (CC)	$5,416,000			
Gross Receipt Tax	$605,000	PNM environmental upgrade cost		
Total purchased equipment cost (PEC)	$6,021,000			
Direct installation costs				
Project construction costs	$4,836,000	PNM environmental upgrade cost		
Total direct installation costs (DIC)	$4,836,000			
Total direct costs (DC) = (PEC) + (DIC)	$10,857,000			
Indirect Costs				
Engineering	$177,000	PNM environmental upgrade cost		
Owner's cost	$314,000	PNM environmental upgrade cost		
Construction management	$543,000	(DC) X	5.0%	
Start-up and spare parts	$217,000	(DC) X	2.0%	
Performance test	$50,000	Engineering estimate		
Contingencies	$252,000	PNM environmental upgrade cost		
Total indirect costs (IC)	$1,553,000			
Interest During Construction (IDC)	$460,000	[(DC)+(IC)] X	7.41%	1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (IDC)	**$12,870,000**			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Maintenance labor	$2,000	B&V estimate, 1 man week/yr		
Total fixed annual costs	$2,000			
Variable annual costs				
N/A	$0	No associated annual cost		
Total variable annual costs	$0			
Total direct annual costs (DAC)	$2,000			
Indirect Annual Costs				
Cost for capital recovery	$1,254,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life
Total indirect annual costs (IDAC)	$1,254,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$1,256,000**			

Pulse Jet Fabric Filter (PJFF)

Technology: Pulse Jet Fabric Filter - SJGS Unit 1   Date: 4/25/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
PJFF system scope	$9,020,000	PNM environmental upgrade cost			
Ductwork	$812,000	PNM environmental upgrade cost			
Ash handling system scope	$1,155,000	PNM environmental upgrade cost			
Booster fan modifications	$3,434,000	PNM environmental upgrade cost			
Balance of plant modifications	$3,938,000	PNM environmental upgrade cost			
Subtotal capital cost (CC)	$18,359,000				
Gross Receipt Tax	$2,855,000	PNM environmental upgrade cost			
Total purchased equipment cost (PEC)	$21,214,000				
Direct installation costs					
PJFF construction cost	$7,543,000	PNM environmental upgrade cost			
Ductwork construction cost	$10,958,000	PNM environmental upgrade cost			
Ash handling construction cost	$475,000	PNM environmental upgrade cost			
Booster fan construction cost	$1,283,000	PNM environmental upgrade cost			
Balance of plant construction cost	$8,099,000	PNM environmental upgrade cost			
Total direct installation costs (DIC)	$28,358,000				
Total direct costs (DC) = (PEC) + (DIC)	$49,572,000				
Indirect Costs					
Engineering	$2,304,000	PNM environmental upgrade cost			
Owner's cost	$1,479,000	PNM environmental upgrade cost			
Construction management	$4,957,000	(DC) X	10.0%		
Start-up and spare parts	$744,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$3,289,000	PNM environmental upgrade cost			
Total indirect costs (IC)	$12,873,000				
Interest During Construction (IDC)	$4,627,000	[(DC)+(IC)] X	7.41%	2 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (IDC)	**$67,072,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$1,487,000	(DC) X	3.0%		
Total fixed annual costs	$1,487,000				
Variable annual costs					
Bag replacement cost	$296,000		2,957 bags and	100 $/bag	B&W bag offerings, 3 yr replacements
Cage replacement cost	$74,000		1,478 cages and	50 $/cage	B&W cage offerings, 6 yr replacements
ID fan power	$1,828,000		4,028 kW and	0.06095 $/kWh	B&W guarantees, 15 in. H_2O d.p.
Auxiliary power	$209,000		460 kW and	0.06095 $/kWh	Engineering estimate
Total variable annual costs	$2,407,000				
Total direct annual costs (DAC)	$3,894,000				
Indirect Annual Costs					
Cost for capital recovery	$6,533,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life	
Total indirect annual costs (IDAC)	$6,533,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$10,427,000**				

Technology: Pulse Jet Fabric Filter - SJGS Unit 2 **Date:** 4/25/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
PJFF system scope	$8,658,000	PNM environmental upgrade cost			
Ductwork	$904,000	PNM environmental upgrade cost			
Ash handling system scope	$1,155,000	PNM environmental upgrade cost			
Booster fan modifications	$3,434,000	PNM environmental upgrade cost			
Balance of plant modifications	$4,072,000	PNM environmental upgrade cost			
Subtotal capital cost (CC)	$18,223,000				
Gross Receipt Tax	$2,977,000	PNM environmental upgrade cost			
Total purchased equipment cost (PEC)	$21,200,000				
Direct installation costs					
PJFF construction cost	$7,412,000	PNM environmental upgrade cost			
Ductwork construction cost	$13,335,000	PNM environmental upgrade cost			
Ash handling construction cost	$472,000	PNM environmental upgrade cost			
Booster fan construction cost	$1,283,000	PNM environmental upgrade cost			
Balance of plant construction cost	$8,139,000	PNM environmental upgrade cost			
Total direct installation costs (DIC)	$30,641,000				
Total direct costs (DC) = (PEC) + (DIC)	$51,841,000				
Indirect Costs					
Engineering	$2,238,000	PNM environmental upgrade cost			
Owner's cost	$1,541,000	PNM environmental upgrade cost			
Construction management	$5,184,000	(DC) X	10.0%		
Start-up and spare parts	$778,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$3,340,000	PNM environmental upgrade cost			
Total indirect costs (IC)	$13,181,000				
Interest During Construction (IDC)	$4,818,000	[(DC)+(IC)] X	7.41%	2 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (IDC)	**$69,840,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$1,555,000	(DC) X	3.0%		
Total fixed annual costs	$1,555,000				
Variable annual costs					
Bag replacement cost	$296,000		2,957 bags and	100 $/bag	B&W bag offerings, 3 yr replacements
Cage replacement cost	$74,000		1,478 cages and	50 $/cage	B&W cage offerings, 6 yr replacements
ID fan power	$1,828,000		4,028 kW and	0.06095 $/kWh	B&W guarantees, 15 in. H_2O d.p.
Auxiliary power	$209,000		460 kW and	0.06095 $/kWh	Engineering estimate
Total variable annual costs	$2,407,000				
Total direct annual costs (DAC)	$3,962,000				
Indirect Annual Costs					
Cost for capital recovery	$6,802,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life	
Total indirect annual costs (IDAC)	$6,802,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$10,764,000**				

Technology: Pulse Jet Fabric Filter - SJGS Unit 3 Date: 4/25/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
PJFF system scope	$10,901,000	PNM environmental upgrade cost			
Ductwork	$1,364,000	PNM environmental upgrade cost			
Ash handling system scope	$977,000	PNM environmental upgrade cost			
Booster fan modifications	$2,871,000	PNM environmental upgrade cost			
Balance of plant modifications	$4,733,000	PNM environmental upgrade cost			
Subtotal capital cost (CC)	$20,846,000				
Gross Receipt Tax	$3,183,000	PNM environmental upgrade cost			
Total purchased equipment cost (PEC)	$24,029,000				
Direct installation costs					
PJFF construction cost	$11,089,000	PNM environmental upgrade cost			
Ductwork construction cost	$9,007,000	PNM environmental upgrade cost			
Ash handling construction cost	$706,000	PNM environmental upgrade cost			
Booster fan construction cost	$1,403,000	PNM environmental upgrade cost			
Balance of plant construction cost	$9,286,000	PNM environmental upgrade cost			
Total direct installation costs (DIC)	$31,491,000				
Total direct costs (DC) = (PEC) + (DIC)	$55,520,000				
Indirect Costs					
Engineering	$2,535,000	PNM environmental upgrade cost			
Owner's cost	$1,655,000	PNM environmental upgrade cost			
Construction management	$5,552,000	(DC) X	10.0%		
Start-up and spare parts	$833,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$1,486,000	PNM environmental upgrade cost			
Total indirect costs (IC)	$12,161,000				
Interest During Construction (IDC)	$5,015,000	[(DC)+(IC)[X	7.41%	2 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (IDC)	**$72,696,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$1,666,000	(DC) X	3.0%		
Total fixed annual costs	$1,666,000				
Variable annual costs					
Bag replacement cost	$462,000		4,620 bags and	100 $/bag	B&W bag offerings, 3 yr replacements
Cage replacement cost	$116,000		2,310 cages and	50 $/cage	B&W cage offerings, 6 yr replacements
ID fan power	$2,856,000		6,294 kW and	0.06095 $/kWh	B&W guarantees, 15 in. H_2O d.p.
Auxiliary power	$273,000		601 kW and	0.06095 $/kWh	Engineering estimate
Total variable annual costs	$3,707,000				
Total direct annual costs (DAC)	$5,373,000				
Indirect Annual Costs					
Cost for capital recovery	$7,081,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life	
Total indirect annual costs (IDAC)	$7,081,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$12,454,000**				

Technology: Pulse Jet Fabric Filter - SJGS Unit 4 **Date:** 4/25/2007

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
PJFF system scope	$12,572,000	PNM environmental upgrade cost				
Ductwork	$1,479,000	PNM environmental upgrade cost				
Ash handling system scope	$932,000	PNM environmental upgrade cost				
Booster fan modifications	$2,870,000	PNM environmental upgrade cost				
Balance of plant modifications	$5,040,000	PNM environmental upgrade cost				
Subtotal capital cost (CC)	$22,893,000					
Gross Receipt Tax	$3,212,000	PNM environmental upgrade cost				
Total purchased equipment cost (PEC)	$26,105,000					
Direct installation costs						
PJFF construction cost	$10,937,000	PNM environmental upgrade cost				
Ductwork construction cost	$7,946,000	PNM environmental upgrade cost				
Ash handling construction cost	$685,000	PNM environmental upgrade cost				
Booster fan construction cost	$1,406,000	PNM environmental upgrade cost				
Balance of plant construction cost	$8,856,000	PNM environmental upgrade cost				
Total direct installation costs (DIC)	$29,830,000					
Total direct costs (DC) = (PEC) + (DIC)	$55,935,000					
Indirect Costs						
Engineering	$2,645,000	PNM environmental upgrade cost				
Owner's cost	$1,670,000	PNM environmental upgrade cost				
Construction management	$5,594,000	(DC) X	10.0%			
Start-up and spare parts	$839,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$1,486,000	PNM environmental upgrade cost				
Total indirect costs (IC)	$12,334,000					
Interest During Construction (IDC)	$5,059,000	[(DC)+(IC)] X	7.41%	2 years (project time length X 1/2)		
Total Capital Investment (TCI) = (DC) + (IC) + (IDC)	**$73,328,000**					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$1,678,000	(DC) X	3.0%			
Total fixed annual costs	$1,678,000					
Variable annual costs						
Bag replacement cost	$462,000		4,620 bags and	100 $/bag		B&W bag offerings, 3 yr replacements
Cage replacement cost	$116,000		2,310 cages and	50 $/cage		B&W cage offerings, 6 yr replacements
ID fan power	$2,856,000		6,294 kW and	0.06095 $/kWh		B&W guarantees, 15 in. H_2O d.p.
Auxiliary power	$273,000		601 kW and	0.06095 $/kWh		Engineering estimate
Total variable annual costs	$3,707,000					
Total direct annual costs (DAC)	$5,385,000					
Indirect Annual Costs						
Cost for capital recovery	$7,142,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life		
Total indirect annual costs (IDAC)	$7,142,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$12,527,000**					

Selective Catalytic Reduction (SCR)

Technology: Selective Catalytic Reduction - SJGS Unit 1 **Date:** 5/31/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Anhydrous Ammonia Injection System	$437,000	B&V cost estimate			
Anhydrous Ammonia Vaporization System	$436,000	B&V cost estimate			
Reactor Box, Breeching and Ductwork	$4,451,000	B&V cost estimate			
Ductwork Expansion Joints	$294,000	B&V cost estimate			
Catalyst	$2,557,000	B&V cost estimate			
Sonic Horns	$188,000	B&V cost estimate			
Elevator	$1,236,000	B&V cost estimate			
Structural Steel	$4,881,000	B&V cost estimate			
SCR Bypass	$10,000,000	B&V cost estimate			
NOx Monitoring System	$440,000	B&V cost estimate			
Electrical System Upgrade	$378,000	B&V cost estimate			
Instrumentation and Control System	$279,000	B&V cost estimate			
Subtotal capital cost (CC)	$25,577,000				
Gross Receipt Tax	$1,583,000	(CC) X	6.2%		
Freight	$1,279,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$28,439,000				
Direct installation costs					
Foundation & supports	$8,532,000	(PEC) X	30.0%		
Handling & erection	$8,532,000	(PEC) X	30.0%		
Electrical	$4,266,000	(PEC) X	15.0%		
Piping	$711,000	(PEC) X	2.5%		
Insulation	$2,844,000	(PEC) X	10.0%		
Painting	$284,000	(PEC) X	1.0%		
Demolition	$2,844,000	(PEC) X	10.0%		
Relocation	$1,422,000	(PEC) X	5.0%		
Total direct installation costs (DIC)	$29,435,000				
Air preheater modifications	$1,071,000	B&V cost estimate			
Balanced draft conversion	$13,366,000	B&V cost estimate			
Site preparation	$2,000,000	Engineering estimate			
Buildings & enclosures	$500,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$74,811,000				
Indirect Costs					
Engineering	$5,237,000	(DC) X	7.0%		
Owner's cost	$3,741,000	(DC) X	5.0%		
Construction management	$7,481,000	(DC) X	10.0%		
Construction indirect	$18,344,000	B&V labor market review			
Start-up and spare parts	$2,244,000	(DC) X	3.0%		
Performance test	$200,000	Engineering estimate			
Contingencies	$14,962,000	(DC) X	20.0%		
Total indirect costs (IC)	$52,209,000				
Interest During Construction (IDC)	$14,118,000	[(DC)+(IC)] X	7.41%	3 years (project time length X 1/2)	
Loss Generation during Outage (GEN)	$15,667,000		5 weeks and	0.06095 $/kWh	12 weeks required for BDC, 7 weeks major outage available
Total Capital Investment (TCI) = (DC) + (IC) + (IDC) + (GEN)	**$156,805,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$125,000		1 FTE and	124,862 $/year	Estimated manpower level
Maintenance labor & materials	$2,244,000	(DC) X	3.0%		
Yearly emissions testing	$25,000	Engineering estimate			
Catalyst activity testing	$5,000	Engineering estimate			
Fly ash sampling and analysis	$20,000	Engineering estimate			
Total fixed annual costs	$2,419,000				
Variable annual costs					
Reagent	$911,000		350 lb/hr and	700 $/ton	B&V Calculated
Auxiliary and ID fan power	$1,496,000		3,296 kW and	0.06095 $/kWh	B&V Calculated
Catalyst replacement	$426,000		66 m^3 and	6,500 $/$m^3$	2 yr catalyst replacement rate
Total variable annual costs	$2,833,000				
Total direct annual costs (DAC)	$5,252,000				
Indirect Annual Costs					
Cost for capital recovery	$15,273,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life	
Total indirect annual costs (IDAC)	$15,273,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$20,525,000**				

Technology: Selective Catalytic Reduction - SJGS Unit 2 Date: 5/31/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Anhydrous Ammonia Injection System	$429,000	B&V cost estimate			
Anhydrous Ammonia Vaporization System	$429,000	B&V cost estimate			
Reactor Box, Breeching and Ductwork	$4,444,000	B&V cost estimate			
Ductwork Expansion Joints	$294,000	B&V cost estimate			
Catalyst	$2,553,000	B&V cost estimate			
Sonic Horns	$188,000	B&V cost estimate			
Elevator	$1,236,000	B&V cost estimate			
Structural Steel	$5,998,000	B&V cost estimate			
SCR Bypass	$10,000,000	B&V cost estimate			
NOx Monitoring System	$440,000	B&V cost estimate			
Electrical System Upgrade	$372,000	B&V cost estimate			
Instrumentation and Control System	$278,000	B&V cost estimate			
Subtotal capital cost (CC)	$26,661,000				
Gross Receipt Tax	$1,650,000	(CC) X	6.2%		
Freight	$1,333,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$29,644,000				
Direct installation costs					
Foundation & supports	$8,893,000	(PEC) X	30.0%		
Handling & erection	$11,858,000	(PEC) X	40.0%		
Electrical	$4,447,000	(PEC) X	15.0%		
Piping	$741,000	(PEC) X	2.5%		
Insulation	$2,964,000	(PEC) X	10.0%		
Painting	$296,000	(PEC) X	1.0%		
Demolition	$2,964,000	(PEC) X	10.0%		
Relocation	$1,482,000	(PEC) X	5.0%		
Total direct installation costs (DIC)	$33,645,000				
Air preheater modifications	$1,071,000	B&V cost estimate			
Balanced draft conversion	$13,366,000	B&V cost estimate			
Site preparation	$2,000,000	Engineering estimate			
Buildings & enclosures	$500,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$80,226,000				
Indirect Costs					
Engineering	$5,616,000	(DC) X	7.0%		
Owner's cost	$4,011,000	(DC) X	5.0%		
Construction management	$8,023,000	(DC) X	10.0%		
Construction indirect	$22,085,000	B&V labor market review			
Start-up and spare parts	$2,407,000	(DC) X	3.0%		
Performance test	$200,000	Engineering estimate			
Contingencies	$16,045,000	(DC) X	20.0%		
Total indirect costs (IC)	$58,387,000				
Interest During Construction (IDC)	$15,407,000	[(DC)+(IC)] X	7.41%	3 years (project time length X 1/2)	
Loss Generation during Outage (GEN)	$15,231,000		5 weeks and	0.06095 $/kWh	12 weeks required for BDC, 7 weeks major outage available
Total Capital Investment (TCI) = (DC) + (IC) + (IDC) + (GEN)	**$169,251,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$125,000		1 FTE and	124,862 $/year	Estimated manpower level
Maintenance labor & materials	$2,407,000	(DC) X	3.0%		
Yearly emissions testing	$25,000	Engineering estimate			
Catalyst activity testing	$5,000	Engineering estimate			
Fly ash sampling and analysis	$20,000	Engineering estimate			
Total fixed annual costs	$2,582,000				
Variable annual costs					
Reagent	$906,000		348 lb/hr and	700 $/ton	B&V Calculated
Auxiliary and ID fan power	$1,492,000		3,287 kW and	0.06095 $/kWh	B&V Calculated
Catalyst replacement	$426,000		65 m^3 and	6,500 $/$m^3$	2 yr catalyst replacement rate
Total variable annual costs	$2,824,000				
Total direct annual costs (DAC)	$5,406,000				
Indirect Annual Costs					
Cost for capital recovery	$16,485,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life	
Total indirect annual costs (IDAC)	$16,485,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	$21,891,000				

Technology: Selective Catalytic Reduction - SJGS Unit 3 Date: 5/31/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Anhydrous Ammonia Injection System	$559,000	B&V cost estimate			
Anhydrous Ammonia Vaporization System	$559,000	B&V cost estimate			
Reactor Box, Breeching and Ductwork	$5,613,000	B&V cost estimate			
Ductwork Expansion Joints	$371,000	B&V cost estimate			
Catalyst	$3,225,000	B&V cost estimate			
Sonic Horns	$188,000	B&V cost estimate			
Elevator	$1,236,000	B&V cost estimate			
SCR Bypass	$10,000,000	B&V cost estimate			
Structural Steel	$7,816,000	B&V cost estimate			
NOx Monitoring System	$440,000	B&V cost estimate			
Electrical System Upgrade	$484,000	B&V cost estimate			
Instrumentation and Control System	$291,000	B&V cost estimate			
Subtotal capital cost (CC)	$30,782,000				
Gross Receipt Tax	$1,905,000	(CC) X	6.2%		
Freight	$1,539,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$34,226,000				
Direct installation costs					
Foundation & supports	$10,268,000	(PEC) X	30.0%		
Handling & erection	$13,690,000	(PEC) X	40.0%		
Electrical	$5,134,000	(PEC) X	15.0%		
Piping	$856,000	(PEC) X	2.5%		
Insulation	$3,423,000	(PEC) X	10.0%		
Painting	$342,000	(PEC) X	1.0%		
Demolition	$3,423,000	(PEC) X	10.0%		
Relocation	$1,711,000	(PEC) X	5.0%		
Total direct installation costs (DIC)	$38,847,000				
Air preheater modifications	$8,685,000	B&V cost estimate			
Balanced draft conversion	$17,122,000	B&V cost estimate			
Site preparation	$2,000,000	Engineering estimate			
Buildings & enclosures	$500,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$101,380,000				
Indirect Costs					
Engineering	$7,097,000	(DC) X	7.0%		
Owner's cost	$5,069,000	(DC) X	5.0%		
Construction management	$10,138,000	(DC) X	10.0%		
Construction indirect	$25,498,000	B&V labor market review			
Start-up and spare parts	$3,041,000	(DC) X	3.0%		
Performance test	$200,000	Engineering estimate			
Contingencies	$20,276,000	(DC) X	20.0%		
Total indirect costs (IC)	$71,319,000				
Interest During Construction (IDC)	$19,195,000	[(DC)+(IC)] X	7.41%	3 years (project time length X 1/2)	
Loss Generation during Outage (GEN)	$23,674,000		5 weeks and	0.06095 $/kWh	12 weeks required for BDC, 7 weeks major outage available
Total Capital Investment (TCI) = (DC) + (IC) + (IDC) + (GEN)	**$215,568,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$125,000		1 FTE and	124,862 $/year	Estimated manpower level
Maintenance labor & materials	$3,041,000	(DC) X	3.0%		
Yearly emissions testing	$25,000	Engineering estimate			
Catalyst activity testing	$5,000	Engineering estimate			
Fly ash sampling and analysis	$20,000	Engineering estimate			
Total fixed annual costs	$3,216,000				
Variable annual costs					
Reagent	$1,415,000		543 lb/hr and	700 $/ton	B&V Calculated
Auxiliary and ID fan power	$2,194,000		4,835 kW and	0.06095 $/kWh	B&V Calculated
Catalyst replacement	$538,000		83 m^3 and	6,500 $\$/m^3$	2 yr catalyst replacement rate
Total variable annual costs	$4,147,000				
Total direct annual costs (DAC)	$7,363,000				
Indirect Annual Costs					
Cost for capital recovery	$20,996,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life	
Total indirect annual costs (IDAC)	$20,996,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$28,359,000**				

Technology: Selective Catalytic Reduction - SJGS Unit 4 Date: 5/31/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Anhydrous Ammonia Injection System	$559,000	B&V cost estimate			
Anhydrous Ammonia Vaporization System	$559,000	B&V cost estimate			
Reactor Box, Breeching and Ductwork	$5,648,000	B&V cost estimate			
Ductwork Expansion Joints	$373,000	B&V cost estimate			
Catalyst	$3,245,000	B&V cost estimate			
Sonic Horns	$188,000	B&V cost estimate			
Elevator	$1,236,000	B&V cost estimate			
Structural Steel	$6,252,000	B&V cost estimate			
SCR Bypass	$10,000,000	B&V cost estimate			
NOx Monitoring System	$440,000	B&V cost estimate			
Electrical System Upgrade	$484,000	B&V cost estimate			
Instrumentation and Control System	$291,000	B&V cost estimate			
Subtotal capital cost (CC)	$29,275,000				
Gross Receipt Tax	$1,811,000	(CC) X	6.2%		
Freight	$1,464,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$32,550,000				
Direct installation costs					
Foundation & supports	$9,765,000	(PEC) X	30.0%		
Handling & erection	$9,765,000	(PEC) X	30.0%		
Electrical	$4,883,000	(PEC) X	15.0%		
Piping	$814,000	(PEC) X	2.5%		
Insulation	$3,255,000	(PEC) X	10.0%		
Painting	$326,000	(PEC) X	1.0%		
Demolition	$3,255,000	(PEC) X	10.0%		
Relocation	$1,628,000	(PEC) X	5.0%		
Total direct installation costs (DIC)	$33,691,000				
Air preheater modifications	$8,685,000	B&V cost estimate			
Balanced draft conversion	$17,122,000	B&V cost estimate			
Site preparation	$2,000,000	Engineering estimate			
Buildings & enclosures	$500,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$94,548,000				
Indirect Costs					
Engineering	$6,618,000	(DC) X	7.0%		
Owner's cost	$4,727,000	(DC) X	5.0%		
Construction management	$9,455,000	(DC) X	10.0%		
Construction indirect	$20,996,000	B&V labor market review			
Start-up and spare parts	$2,836,000	(DC) X	3.0%		
Performance test	$200,000	Engineering estimate			
Contingencies	$18,910,000	(DC) X	20.0%		
Total indirect costs (IC)	$63,742,000				
Interest During Construction (IDC)	$17,594,000	[(DC)+(IC)] X	7.41%	3 years (project time length X 1/2)	
Loss Generation during Outage (GEN)	$23,674,000		5 weeks and	0.06095 $/kWh	12 weeks required for BDC, 7 weeks major outage available
Total Capital Investment (TCI) = (DC) + (IC) + (IDC) + (GEN)	**$199,558,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$125,000		1 FTE and	124,862 $/year	Estimated manpower level
Maintenance labor & materials	$2,836,000	(DC) X	3.0%		
Yearly emissions testing	$25,000	Engineering estimate			
Catalyst activity testing	$5,000	Engineering estimate			
Fly ash sampling and analysis	$20,000	Engineering estimate			
Total fixed annual costs	$3,011,000				
Variable annual costs					
Reagent	$1,388,000		533 lb/hr and	700 $/ton	B&V Calculated
Auxiliary and ID fan power	$2,215,000		4,881 kW and	0.06095 $/kWh	B&V Calculated
Catalyst replacement	$541,000		83 m^3 and	6,500 $/$m^3$	2 yr catalyst replacement rate
Total variable annual costs	$4,144,000				
Total direct annual costs (DAC)	$7,155,000				
Indirect Annual Costs					
Cost for capital recovery	$19,437,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life	
Total indirect annual costs (IDAC)	$19,437,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$26,592,000**				

SNCR/SCR Hybrid
(Hybrid)

Technology: SNCR/SCR Hybrid - SJGS Unit 1 | **Date:** 5/31/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Hybrid system scope:	$15,753,000	B&V cost development from vendor quote			
Reagent delivery system					
Wall injectors and multiple nozzle lances					
Automatic injector and lance retract system					
Flue gas temperature, NOx monitors					
Reagent storage tank					
Single layer catalyst SCR system					
Ductwork modifications					
Electrical system upgrades	$378,000	Similar scope to SCR modifications			
Instrumentation and control system	$279,000	Similar scope to SCR modifications			
Subtotal capital cost (CC)	$16,410,000				
Gross Receipt Tax	$1,015,000	(CC) X	6.2%		
Freight	$821,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$18,246,000				
Direct installation costs					
Foundation & supports	$3,649,000	(PEC) X	20.0%		
Handling & erection	$5,474,000	(PEC) X	30.0%		
Electrical	$2,737,000	(PEC) X	15.0%		
Piping	$456,000	(PEC) X	2.5%		
Insulation	$1,825,000	(PEC) X	10.0%		
Painting	$182,000	(PEC) X	1.0%		
Demolition	$1,825,000	(PEC) X	10.0%		
Relocation	$912,000	(PEC) X	5.0%		
Total direct installation costs (DIC)	$17,060,000				
Air preheater modifications	$1,071,000	B&V cost estimate			
Balanced draft conversion	$13,366,000	B&V cost estimate			
Site preparation	$1,000,000	Engineering estimate			
Buildings	$200,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$50,943,000				
Indirect Costs					
Engineering	$3,566,000	(DC) X	7.0%		
Owner's cost	$2,547,000	(DC) X	5.0%		
Construction management	$5,094,000	(DC) X	10.0%		
Construction indirect	$11,222,000	B&V labor market review			
Start-up and spare parts	$1,528,000	(DC) X	3.0%		
Performance test	$509,000	(DC) X	1.0%		
Contingencies	$10,189,000	(DC) X	20.0%		
Total indirect costs (IC)	$34,655,000				
Interest During Construction (IDC)	$3,171,000	[(DC)+(IC)] X	7.41%	1 years (project time length X 1/2)	
Loss Generation during Outage (GEN)	$15,667,000		5 weeks and	0.06095 $/kWh	12 weeks required for BDC, 7 weeks major outage available
Total Capital Investment (TCI) = (DC) + (IC) + (GEN)	**$104,436,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$125,000		1 FTE and	124,862 $/year	Estimated manpower level
Maintenance labor & materials	$1,528,000	(DC) X	3.0%		
Total fixed annual costs	$1,653,000				
Variable annual costs					
Urea	$1,703,000		1,089 lb/hr and	420 $/ton	Engineering estimate
Water	$1,762,000		252 gpm and	15.67 $/1,000 gal	Engineering estimate
Catalyst replacement	$215,000		33 m3 and	6,500 $/m3	2 yr catalyst replacement rate
Auxiliary power	$32,000		70 kW and	0.06095 $/kWh	Engineering estimate
ID fan power	$670,000		1,477 kW and	0.06095 $/kWh	Engineering estimate
Total variable annual costs	$4,382,000				
Total direct annual costs (DAC)	$6,035,000				
Indirect Annual Costs					
Cost for capital recovery	$10,172,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life	
Total indirect annual costs (IDAC)	$10,172,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$16,207,000**				

Technology: SNCR/SCR Hybrid - SJGS Unit 2 **Date:** 5/31/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Hybrid system scope:	$15,753,000	B&V cost development from vendor quote			
Reagent delivery system					
Wall injectors and multiple nozzle lances					
Automatic injector and lance retract system					
Flue gas temperature, NOx monitors					
Reagent storage tank					
Single layer catalyst SCR system					
Ductwork modifications					
Electrical system upgrades	$372,000	Similar scope to SCR modifications			
Instrumentation and control system	$278,000	Similar scope to SCR modifications			
Subtotal capital cost (CC)	$16,403,000				
Gross Receipt Tax	$1,015,000	(CC) X	6.2%		
Freight	$820,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$18,238,000				
Direct installation costs					
Foundation & supports	$3,648,000	(PEC) X	20.0%		
Handling & erection	$7,295,000	(PEC) X	40.0%		
Electrical	$2,736,000	(PEC) X	15.0%		
Piping	$456,000	(PEC) X	2.5%		
Insulation	$1,824,000	(PEC) X	10.0%		
Painting	$182,000	(PEC) X	1.0%		
Demolition	$1,824,000	(PEC) X	10.0%		
Relocation	$912,000	(PEC) X	5.0%		
Total direct installation costs (DIC)	$18,877,000				
Air preheater modifications	$1,071,000	B&V cost estimate			
Balanced draft conversion	$13,366,000	B&V cost estimate			
Site preparation	$1,000,000	Engineering estimate			
Buildings	$200,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$52,752,000				
Indirect Costs					
Engineering	$3,693,000	(DC) X	7.0%		
Owner's cost	$2,638,000	(DC) X	5.0%		
Construction management	$5,275,000	(DC) X	10.0%		
Construction indirect	$13,041,000	B&V labor market review			
Start-up and spare parts	$1,583,000	(DC) X	3.0%		
Performance test	$528,000	(DC) X	1.0%		
Contingencies	$10,550,000	(DC) X	20.0%		
Total indirect costs (IC)	$37,308,000				
Interest During Construction (IDC)	$3,337,000	[(DC)+(IC)] X	7.41%	1 years (project time length X 1/2)	
Loss Generation during Outage (GEN)	$15,231,000		5 weeks and	0.06095 $/kWh	12 weeks required for BDC, 7 weeks major outage available
Total Capital Investment (TCI) = (DC) + (IC) + (GEN)	**$108,628,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$125,000		1 FTE and	124,862 $/year	Estimated manpower level
Maintenance labor & materials	$1,583,000	(DC) X	3.0%		
Total fixed annual costs	$1,708,000				
Variable annual costs					
Urea	$1,703,000		1,089 lb/hr and	420 $/ton	Engineering estimate
Water	$1,762,000		252 gpm and	15.67 $/1,000 gal	Engineering estimate
Catalyst replacement	$215,000		33 m3 and	6,500 $/m3	2 yr catalyst replacement rate
Auxiliary power	$32,000		70 kW and	0.06095 $/kWh	Engineering estimate
ID fan power	$670,000		1,477 kW and	0.06095 $/kWh	Engineering estimate
Total variable annual costs	$4,382,000				
Total direct annual costs (DAC)	$6,090,000				
Indirect Annual Costs					
Cost for capital recovery	$10,580,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life	
Total indirect annual costs (IDAC)	$10,580,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$16,670,000**				

Technology: SNCR/SCR Hybrid - SJGS Unit 3 — Date: 5/31/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Hybrid system scope:	$23,680,000	B&V cost development from vendor quote			
Reagent delivery system					
Wall injectors and multiple nozzle lances					
Automatic injector and lance retract system					
Flue gas temperature, NOx monitors					
Reagent storage tank					
Single layer catalyst SCR system					
Ductwork modifications					
Electrical system upgrades	$484,000	Similar scope to SCR modifications			
Instrumentation and control system	$291,000	Similar scope to SCR modifications			
Subtotal capital cost (CC)	$24,455,000				
Gross Receipt Tax	$1,513,000	(CC) X	6.2%		
Freight	$1,223,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$27,191,000				
Direct installation costs					
Foundation & supports	$5,438,000	(PEC) X	20.0%		
Handling & erection	$10,876,000	(PEC) X	40.0%		
Electrical	$4,079,000	(PEC) X	15.0%		
Piping	$680,000	(PEC) X	2.5%		
Insulation	$2,719,000	(PEC) X	10.0%		
Painting	$272,000	(PEC) X	1.0%		
Demolition	$2,719,000	(PEC) X	10.0%		
Relocation	$1,360,000	(PEC) X	5.0%		
Total direct installation costs (DIC)	$28,143,000				
Air preheater modifications	$8,685,000	B&V cost estimate			
Balanced draft conversion	$17,122,000	B&V cost estimate			
Site preparation	$1,000,000	Engineering estimate			
Buildings	$200,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$82,341,000				
Indirect Costs					
Engineering	$5,764,000	(DC) X	7.0%		
Owner's cost	$4,117,000	(DC) X	5.0%		
Construction management	$8,234,000	(DC) X	10.0%		
Construction indirect	$19,442,000	B&V labor market review			
Start-up and spare parts	$2,470,000	(DC) X	3.0%		
Performance test	$823,000	(DC) X	1.0%		
Contingencies	$16,468,000	(DC) X	20.0%		
Total indirect costs (IC)	$57,318,000				
Interest During Construction (IDC)	$5,174,000	[(DC)+(IC)] X	7.41%	1 years (project time length X 1/2)	
Loss Generation during Outage (GEN)	$23,674,000		5 weeks and	0.06095 $/kWh	12 weeks required for BDC, 7 weeks major outage available
Total Capital Investment (TCI) = (DC) + (IC) + (GEN)	**$168,507,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$125,000		1 FTE and	124,862 $/year	Estimated manpower level
Maintenance labor & materials	$2,470,000	(DC) X	3.0%		
Total fixed annual costs	$2,595,000				
Variable annual costs					
Urea	$2,641,000		1,689 lb/hr and	420 $/ton	Engineering estimate
Water	$2,658,000		380 gpm and	15.67 $/1,000 gal	Engineering estimate
Catalyst replacement	$270,000		42 m3 and	6,500 $/m3	2 yr catalyst replacement rate
Auxiliary power	$32,000		70 kW and	0.06095 $/kWh	Engineering estimate
ID fan power	$997,000		2,197 kW and	0.06095 $/kWh	Engineering estimate
Total variable annual costs	$6,598,000				
Total direct annual costs (DAC)	$9,193,000				
Indirect Annual Costs					
Cost for capital recovery	$16,413,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life	
Total indirect annual costs (IDAC)	$16,413,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$25,606,000**				

Technology: SNCR/SCR Hybrid - SJGS Unit 4 Date: 5/31/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Hybrid system scope:	$23,680,000	B&V cost development from vendor quote			
Reagent delivery system					
Wall injectors and multiple nozzle lances					
Automatic injector and lance retract system					
Flue gas temperature, NOx monitors					
Reagent storage tank					
Single layer catalyst SCR system					
Ductwork modifications					
Electrical system upgrades	$484,000	Similar scope to SCR modifications			
Instrumentation and control system	$291,000	Similar scope to SCR modifications			
Subtotal capital cost (CC)	$24,455,000				
Gross Receipt Tax	$1,513,000	(CC) X	6.2%		
Freight	$1,223,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$27,191,000				
Direct installation costs					
Foundation & supports	$5,438,000	(PEC) X	20.0%		
Handling & erection	$8,157,000	(PEC) X	30.0%		
Electrical	$4,079,000	(PEC) X	15.0%		
Piping	$680,000	(PEC) X	2.5%		
Insulation	$2,719,000	(PEC) X	10.0%		
Painting	$272,000	(PEC) X	1.0%		
Demolition	$2,719,000	(PEC) X	10.0%		
Relocation	$1,360,000	(PEC) X	5.0%		
Total direct installation costs (DIC)	$25,424,000				
Air preheater modifications	$8,685,000	B&V cost estimate			
Balanced draft conversion	$17,122,000	B&V cost estimate			
Site preparation	$1,000,000	Engineering estimate			
Buildings	$200,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$79,622,000				
Indirect Costs					
Engineering	$5,574,000	(DC) X	7.0%		
Owner's cost	$3,981,000	(DC) X	5.0%		
Construction management	$7,962,000	(DC) X	10.0%		
Construction indirect	$16,723,000	B&V labor market review			
Start-up and spare parts	$2,389,000	(DC) X	3.0%		
Performance test	$796,000	(DC) X	1.0%		
Contingencies	$15,924,000	(DC) X	20.0%		
Total indirect costs (IC)	$53,349,000				
Interest During Construction (IDC)	$4,927,000	[(DC)+(IC)] X	7.41%	1 years (project time length X 1/2)	
Loss Generation during Outage (GEN)	$23,674,000		5 weeks and	0.06095 $/kWh	12 weeks required for BDC, 7 weeks major outage available
Total Capital Investment (TCI) = (DC) + (IC) + (GEN)	**$161,572,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$125,000		1 FTE and	124,862 $/year	Estimated manpower level
Maintenance labor & materials	$2,389,000	(DC) X	3.0%		
Total fixed annual costs	$2,514,000				
Variable annual costs					
Urea	$2,641,000		1,689 lb/hr and	420 $/ton	Engineering estimate
Water	$2,658,000		380 gpm and	15.67 $/1,000 gal	Engineering estimate
Catalyst replacement	$270,000		42 m3 and	6,500 $/m3	2 yr catalyst replacement rate
Auxiliary power	$32,000		70 kW and	0.06095 $/kWh	Engineering estimate
ID fan power	$997,000		2,197 kW and	0.06095 $/kWh	Engineering estimate
Total variable annual costs	$6,598,000				
Total direct annual costs (DAC)	$9,112,000				
Indirect Annual Costs					
Cost for capital recovery	$15,737,000	(TCI) X	9.74%	CRF at 7.41% interest & 20 year life	
Total indirect annual costs (IDAC)	$15,737,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$24,849,000**				

Appendix D
Stack Outlet Conditions for Visibility Modeling

Public Service Company of New Mexico (PNM) - San Juan Generating Station (SJGS) Unit 1
Best Available Retrofit Technology (BART) Engineering Analysis
Stack Outlet Conditions for Visibility Modeling (24-hour Average Emission Rates) Rev. 2

SJGS Unit 1, Heat Input (HHV) = 3,707 MBtu/hr

Stack Outlet Conditions	Flow (acfm)	Stack Velocity (ft/s)	Temperature (°F)	Pressure (in, wg)	NO_x (lb/MBtu)	NO_x (lb/hr)	SO_2 (lb/MBtu)	SO_2 (lb/hr)	PM (lb/MBtu)	PM (lb/hr)	SO_3 (lb/MBtu)	SO_3 (lb/hr)
Pre-Consent Decree Operation					0.43	1,592.0	0.24	877.8	0.050	185.4	0.013	50.0
Visibility Modeling Baseline Case												
Post-Consent Decree Upgrades (LNB/OFA, PJFF)	1,323,494	70	121.42	0.01	0.33	1,223.3	0.18	667.3	0.015	55.6	0.011	40.5
With additional NO_x Control Technologies												
1. Selective Catalytic Reduction (SCR)	1,325,998	70	121.42	0.01	0.07	259.5	0.18	667.3	0.015	55.6	0.031	114.2
2. SNCR/SCR Hybrid	1,324,112	70	121.42	0.01	0.18	667.3	0.18	667.3	0.015	55.6	0.031	114.2

Notes
1. Emission levels (lb/MBtu) shown are on a 24-hour average basis.
2. Emission in (lb/hr) is calculated based on the emission level (lb/MBtu) and design basis heat input.
3. Emission levels on a 24-hour average basis are assumed to be similar to the annual average basis.
4. Pre-consent decree operation emission level (lb/MBtu) are based on annual averages from year 2001 to 2003.
5. Post-consent decree upgrades emissions for visibility modeling purpose are based on information provided by PNM, 4/19/2007.
6. Stack velocity is calculated based upon volumetric flowrate and 6.10 m stack diameter.
7. All flow conditions are based on the coal as shown in the Design Basis document.
8. All SO_3 emissions are reported as Sulfuric Acid Mist (H_2SO_4).
9. SO_3 emissions for the pre- and post-consent decree cases are determined using the National Park Service calculation formula.
10. SO_3 emissions for the additional NO_x control technologies with catalyst accounts for an additional 1.0% SO_2 to SO_3 conversion (based on design basis economizer outlet SO_2 levels) and 0% SO_3 removal in PJFF.

Revision History

Rev	Date	Purpose
0	4/25/2007	Initial issue to client
1	5/2/2007	Revision to incorporate PNM comments
2	5/24/2007	Final revision

Public Service Company of New Mexico (PNM) - San Juan Generating Station (SJGS) Unit 2
Best Available Retrofit Technology (BART) Engineering Analysis
Stack Outlet Conditions for Visibility Modeling (24-hour Average Emission Rates) Rev. 2

SJGS Unit 2, Heat Input (HHV) = 3,688 MBtu/hr

Stack Outlet Conditions	Flow (acfm)	Stack Velocity (ft/s)	Temperature (°F)	Pressure (in, wg)	NO_x (lb/MBtu)	NO_x (lb/hr)	SO_2 (lb/MBtu)	SO_2 (lb/hr)	PM (lb/MBtu)	PM (lb/hr)	SO_3 (lb/MBtu)	SO_3 (lb/hr)
Pre-Consent Decree Operation					0.45	1,649.3	0.23	844.0	0.050	184.4	0.013	49.7
Visibility Modeling Baseline Case												
Post-Consent Decree Upgrades (LNB/OFA, PJFF)	1,316,710	70	121.42	0.01	0.33	1,217.0	0.18	663.8	0.015	55.3	0.011	40.3
With additional NO_x Control Technologies												
1. Selective Catalytic Reduction (SCR)	1,319,201	70	121.42	0.01	0.07	258.2	0.18	663.8	0.015	55.3	0.031	113.6
2. SNCR/SCR Hybrid	1,317,328	70	121.42	0.01	0.18	663.8	0.18	663.8	0.015	55.3	0.031	113.6

Notes

1. Emission levels (lb/MBtu) shown are on a 24-hour average basis.
2. Emission in (lb/hr) is calculated based on the emission level (lb/MBtu) and design basis heat input.
3. Emission levels on a 24-hour average basis are assumed to be similar to the annual average basis.
4. Pre-consent decree operation emission level (lb/MBtu) are based on annual averages from year 2001 to 2003.
5. Post-consent decree upgrades emissions for visibility modeling purpose are based on information provided by PNM, 4/19/2007.
6. Stack velocity is calculated based upon volumetric flowrate and 6.10 m stack diameter.
7. All flow conditions are based on the coal as shown in the Design Basis document.
8. All SO_3 emissions are reported as Sulfuric Acid Mist (H_2SO_4).
9. SO_3 emissions for the pre- and post-consent decree cases are determined using the National Park Service calculation formula.
10. SO_3 emissions for the additional NO_x control technologies with catalyst accounts for an additional 1.0% SO_2 to SO_3 conversion (based on design basis economizer outlet SO_2 levels) and 0% SO_3 removal in PJFF.

Revision History

Rev	Date	Purpose
0	4/25/2007	Initial issue to client
1	5/2/2007	Revision to incorporate PNM comments
2	5/24/2007	Final revision

Public Service Company of New Mexico (PNM) - San Juan Generating Station (SJGS) Unit 3
Best Available Retrofit Technology (BART) Engineering Analysis
Stack Outlet Conditions for Visibility Modeling (24-hour Average Emission Rates) Rev. 2

SJGS Unit 3, Heat Input (HHV) = 5,758 MBtu/hr

Stack Outlet Conditions	Flow (acfm)	Stack Velocity (ft/s)	Temperature (°F)	Pressure (in, wg)	NO_x (lb/MBtu)	NO_x (lb/hr)	SO_2 (lb/MBtu)	SO_2 (lb/hr)	PM (lb/MBtu)	PM (lb/hr)	SO_3 (lb/MBtu)	SO_3 (lb/hr)
Pre-Consent Decree Operation					0.42	2,405.5	0.28	1,591.1	0.050	287.9	0.013	77.7
Visibility Modeling Baseline Case												
Post-Consent Decree Upgrades (LNB/OFA, PJFF)	2,055,753	56	121.42	0.01	0.33	1,900.1	0.18	1,036.4	0.015	86.4	0.011	62.9
With additional NO_x Control Technologies												
1. Selective Catalytic Reduction (SCR)	2,059,643	56	121.42	0.01	0.07	403.1	0.18	1,036.4	0.015	86.4	0.031	177.3
2. SNCR/SCR Hybrid	2,056,712	56	121.42	0.01	0.18	1,036.4	0.18	1,036.4	0.015	86.4	0.031	177.3

Notes

1. Emission levels (lb/MBtu) shown are on a 24-hour average basis.
2. Emission in (lb/hr) is calculated based on the emission level (lb/MBtu) and design basis heat input.
3. Emission levels on a 24-hour average basis are assumed to be similar to the annual average basis.
4. Pre-consent decree operation emission level (lb/MBtu) are based on annual averages from year 2001 to 2003.
5. Post-consent decree upgrades emissions for visibility modeling purpose are based on information provided by PNM, 4/19/2007.
6. Stack velocity is calculated based upon volumetric flowrate and 6.10 m stack diameter.
7. All flow conditions are based on the coal as shown in the Design Basis document.
8. All SO_3 emissions are reported as Sulfuric Acid Mist (H_2SO_4).
9. SO_3 emissions for the pre- and post-consent decree cases are determined using the National Park Service calculation formula.
10. SO_3 emissions for the additional NO_x control technologies with catalyst accounts for an additional 1.0% SO_2 to SO_3 conversion (based on design basis economizer outlet SO_2 levels) and 0% SO_3 removal in PJFF.

Revision History

Rev	Date	Purpose
0	4/25/2007	Initial issue to client
1	5/2/2007	Revision to incorporate PNM comments
2	5/24/2007	Final revision

Public Service Company of New Mexico (PNM) - San Juan Generating Station (SJGS) Unit 4
Best Available Retrofit Technology (BART) Engineering Analysis
Stack Outlet Conditions for Visibility Modeling (24-hour Average Emission Rates) Rev. 2

SJGS Unit 4, Heat Input (HHV) = 5,649 MBtu/hr

Stack Outlet Conditions	Flow (acfm)	Stack Velocity (ft/s)	Temperature (°F)	Pressure (in, wg)	NO_x (lb/MBtu)	NO_x (lb/hr)	SO_2 (lb/MBtu)	SO_2 (lb/hr)	PM (lb/MBtu)	PM (lb/hr)	SO_3 (lb/MBtu)	SO_3 (lb/hr)
Pre-Consent Decree Operation					0.42	2,399.6	0.29	1,662.4	0.050	282.5	0.013	76.2
Visibility Modeling Baseline Case												
Post-Consent Decree Upgrades (LNB/OFA, PJFF)	2,016,837	55	121.42	0.01	0.33	1,864.2	0.18	1,016.8	0.015	84.7	0.011	61.7
With additional NO_x Control Technologies												
1. Selective Catalytic Reduction (SCR)	2,020,653	55	121.42	0.01	0.07	395.4	0.18	1,016.8	0.015	84.7	0.031	174.0
2. SNCR/SCR Hybrid	2,017,796	55	121.42	0.01	0.18	1,016.8	0.18	1,016.8	0.015	84.7	0.031	174.0

Notes

1. Emission levels (lb/MBtu) shown are on a 24-hour average basis.
2. Emission in (lb/hr) is calculated based on the emission level (lb/MBtu) and design basis heat input.
3. Emission levels on a 24-hour average basis are assumed to be similar to the annual average basis.
4. Pre-consent decree operation emission level (lb/MBtu) are based on annual averages from year 2001 to 2003.
5. Post-consent decree upgrades emissions for visibility modeling purpose are based on information provided by PNM, 4/19/2007.
6. Stack velocity is calculated based upon volumetric flowrate and 6.10 m stack diameter.
7. All flow conditions are based on the coal as shown in the Design Basis document.
8. All SO_3 emissions are reported as Sulfuric Acid Mist (H_2SO_4).
9. SO_3 emissions for the pre- and post-consent decree cases are determined using the National Park Service calculation formula.
10. SO_3 emissions for the additional NO_x control technologies with catalyst accounts for an additional 1.0% SO_2 to SO_3 conversion (based on design basis economizer outlet SO_2 levels) and 0% SO_3 removal in PJFF.

Revision History

Rev	Date	Purpose
0	4/25/2007	Initial issue to client
1	5/2/2007	Revision to incorporate PNM comments
2	5/24/2007	Final revision

Appendix E
CALPUFF Modeling Support Documents

APPENDIX E

OF NMED Ex. 7b

IS ON CD ONLY