Stanton Station Unit 1

Best Available Retrofit Technology Analysis

Revised January, 2008

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Executive Summary

This report describes the background and methods for the selection of the Best Available Retrofit Technology (BART) as proposed by Great River Energy (GRE) for the Stanton Station located in Stanton, ND. Stanton Station's BART eligible Unit 1 is a front-wall fired boiler that started operation in 1966. The boiler is currently permitted to burn both Lignite and Powder River Basin (PRB) coal. Stanton Station has one turbine with a capacity of up to 188 megawatts. Preliminary visibility modeling conducted by the North Dakota Department of Health (NDDH) found that the Stanton Station emissions 'cause or contribute to visibility impairment' in a federally protected Class 1 area, therefore making the facility subject to BART.

Guidelines included in 40 CFR §51 Appendix Y were used to determine BART for Unit 1. The existing pollution control equipment includes an ESP for particulate matter and low NOx burners (LNB) for NOx control. The CALMET/CALPUFF/CALBART dispersion modeling sequence was used to assess the post-BART visibility impacts associated with the proposed BART emission limits.

Stanton Station is currently permitted to burn either Lignite or Powder River Basin (PRB) coal. The BART analysis was originally premised on Lignite as a worse case fuel. At the request of NDDH, GRE includes PRB as an operational control that is evaluated in conjunction with traditional controls. Great River Energy intends to burn a single fuel on an annual basis. Therefore, the BART controls and corresponding emission rates are determined to be fuel specific without consideration for blending. Based on the results of visibility modeling, economic impacts analyses and consideration for other non-air quality energy and environmental factors, GRE establishes the following as BART:

- For Particulate matter (PM), the BART emission limit is 0.1 lb/MMBtu based upon the existing ESP. Additional PM controls, including condensable PM (CPM) controls, would provide insignificant visibility improvement and require significant capital expenditures. Therefore, the current PM performance standard of 0.1 lb/MMBtu is considered BART for either Lignite or PRB.

- Overfire air (OFA) and Low NOx Burners (LNB) is considered BART to control NOx with a proposed 30-day rolling emission rate of 0.35 lb/MMBtu under normal operational conditions on either fuel.

- SO_2 emissions will be reduced using a non-specific dry scrubbing technology. The scrubber is being designed to achieve 90% removal with a proposed BART limit of 0.24 lb/MMBtu on a 30-day rolling basis for Lignite fuel. Stanton Station is also permitted to burn Powder River Basin (PRB) coal, which is currently a lower sulfur fuel. As discussed in Section 5, Dry Sorbent Injection (DSI) with the existing ESP is considered BART for PRB with a corresponding 30-day rolling emission rate of 0.36 lb/MMBtu.

BART Emission Limits

Pollutant	Existing Permit Limit	BART Limit
PM_{10}	0.10 lb/MMBtu	0.10 lb/MMBtu
NOx	0.46 lb/MMBtu	0.35 lb/MMBtu
SO_2 Lignite	3.0 lb/MMBtu	0.24 lb/MMBtu
SO_2 PRB	3.0 lb/MMBtu	0.36 lb/MMBtu

The proposed BART controls will result in visibility improvements of 60% to 70% for both the 90th and 98th percentile comparisons. According to Pre-BART modeling, Unit 1 is estimated to contribute 1.675 Δ-dV to background at Theodore Roosevelt National Park's (TRNP) South unit in the year 2002, which is the worst case meteorological conditions of the baseline years, with 29 days above 0.5 Δ-dV. Modeling with the proposed BART controls for TRNP South shows an improvement of 1.0 Δ-dV, or a contribution of only 0.666 Δ-dV above background, with 13 days above 0.5 Δ-dV. These reductions represent a significant improvement to assist the state in meeting its reasonable progress goals.

Additional Considerations and Associated Potential Reductions

Great River Energy is evaluating other generation options at Stanton Station including the installation of a new clean coal technology (i.e., integrated gasification combined cycle (IGCC) system capable of carbon capture and sequestration (CCS). If installed, IGCC would allow for either early Unit 1 retirement or significantly reduced utilization while IGCC is brought on-line. The current BART economic evaluations assume at least 20 years of capital depreciation levelized across projected pollution reductions. Clearly, Unit 1 early retirement would completely affect the BART cost effectiveness determinations contained in this evaluation.

Based on our conversations with the NDDH staff on October 31, 2007, the installation of a 'clean coal technology' will require additional air permitting in which proposed BART controls could be re-evaluated in light of lesser Unit 1 utilization. Obviously, Unit 1 retirement in support of a 'clean coal technology' would need to provide comparable, if not greater, visibility improvements. Great River Energy will need to commit to either the IGCC technology or spray dry baghouse technology well in advance of applicable BART requirements in 2013.

If Great River Energy does not pursue a clean coal alternative generation project, the spray dry baghouse will be installed to cover the range of fuels permitted at Stanton at $79 million in 2005 dollars. Even though BART is considered DSI with existing ESP for PRB, Great River Energy would offer additional reductions with construction of the spray dry baghouse and comply with 0.15 lb/MMBtu SO_2 emission limit on a 30-day rolling basis for PRB. This emission rate is inclusive of both the expected dry scrubbing effectiveness with baghouse and the PRB sulfur ranges discussed in Appendix E. Further, with respect to PM emissions based on installation of a baghouse, Great River Energy would offer additional reductions, and comply with a 0.07 lb/MMBtu or 0.05 lb/MMBtu emission rate, for Lignite and PRB, respectively. These additional particulate reductions incorporate the relative ash differences between the fuels and additional particulate control provided by the baghouse.

Stanton Station Unit 1- Additional Reductions to Support Visibility Improvements

Pollutant	Permit Limit	Alternative Lower Limit
PM_{10} Lignite	0.10 lb/MMBtu	0.07 lb/MMBtu
PM_{10} PRB		0.05 lb/MMBtu
NOx	0.46 lb/MMBtu	0.35 lb/MMBtu
SO_2 Lignite	3.0 lb/MMBtu	0.24 lb/MMBtu
SO_2 PRB	3.0 lb/MMBtu	0.15 lb/MMBtu

For reasonable glide path modeling, NDDH can choose to use the higher values between projected PRB and Lignite emission rates rather than the BART emission rates. For PM, this would mean a 0.07 lb/MMBtu emission rate based on lignite. The additional PM reduction does not provide a significant modeled improvement as discussed in Section 7. For SO_2, the modeling value is 0.29 lb/MMBtu, which is based upon the 30-rolling limit of 0.24 lb/MMBtu, as a worse case, 24-hr maximum value. For NOx, there is no proposed difference between BART controls for the permitted fuels at a 30 day rolling emission rate of 0.35 lb/MMBtu. Consequently, the modeled value is 665.3 lb/hr as a 24-hr maximum. The most favorable combined effect of all proposed additional reductions results in an average incremental improvement of only ~ 0.1 dV.

1.0 Introduction

On July 15, 2005, the U.S. Environmental Protection Agency (EPA) published the final rules for regional haze and best available retrofit technology (BART). The BART rules[1], originally promulgated in September 1999, were in effect as of September 6, 2005.

The rules require that each state develop a Regional-Haze State Implementation Plan (RH SIP) to improve visibility impairment in federally-protected national parks and wilderness areas (Class I areas). The SIP must require BART on all BART-eligible sources and mandate a plan to achieve natural background visibility by 2064. Figure 1-1 illustrates the 6 BART eligible units and 4 Class 1 areas in North Dakota. Each state must submit an RH SIP by December 17, 2007 that includes milestones for establishing reasonable progress towards the visibility improvement goals, and plans for the first five-year period. Upon submission of the SIP, states must make the requirements for BART sources enforceable through rules, administrative orders or Title V permit amendments.

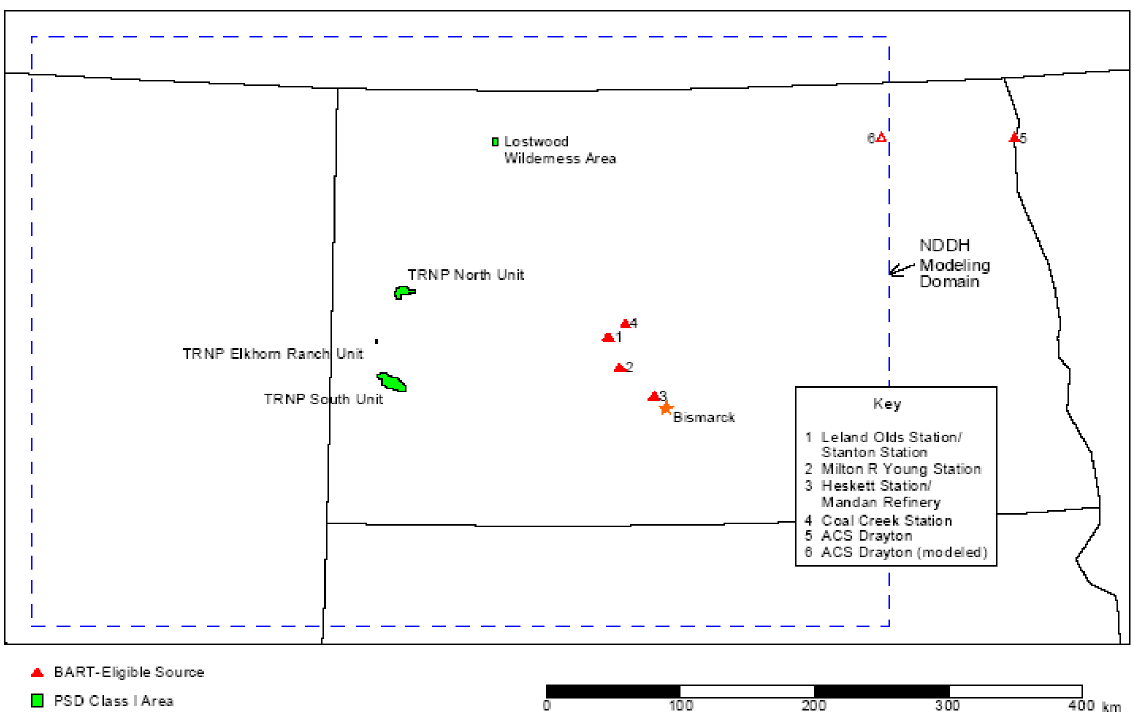


Figure 1-1 North Dakota's BART Geography: The North Dakota SIP will address the 4 PSD Class I Areas and 6 BART Eligible Units illustrated above. (Source *Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota, Final version)*

[1] 40 CFR §51 and Clean Air Act §169A and 169B

By definition, reasonable progress means that the 20 best-visibility days must get no worse, and the 20 worst-visibility days must become as good as the 20 worst days under natural conditions. Assuming a uniform rate of progress, the default glide path, as illustrated in Figure 1-2, would require 1 to 2 percent improvement per year in visibility on the 20 worst days. The state must submit progress reports every five years to establish their advancement toward the Class 1 area natural visibility backgrounds. If a state feels it may be unable to adopt the default glide path, a slower rate of improvement may be proposed on the basis of cost or time required for compliance and non-air quality impacts.

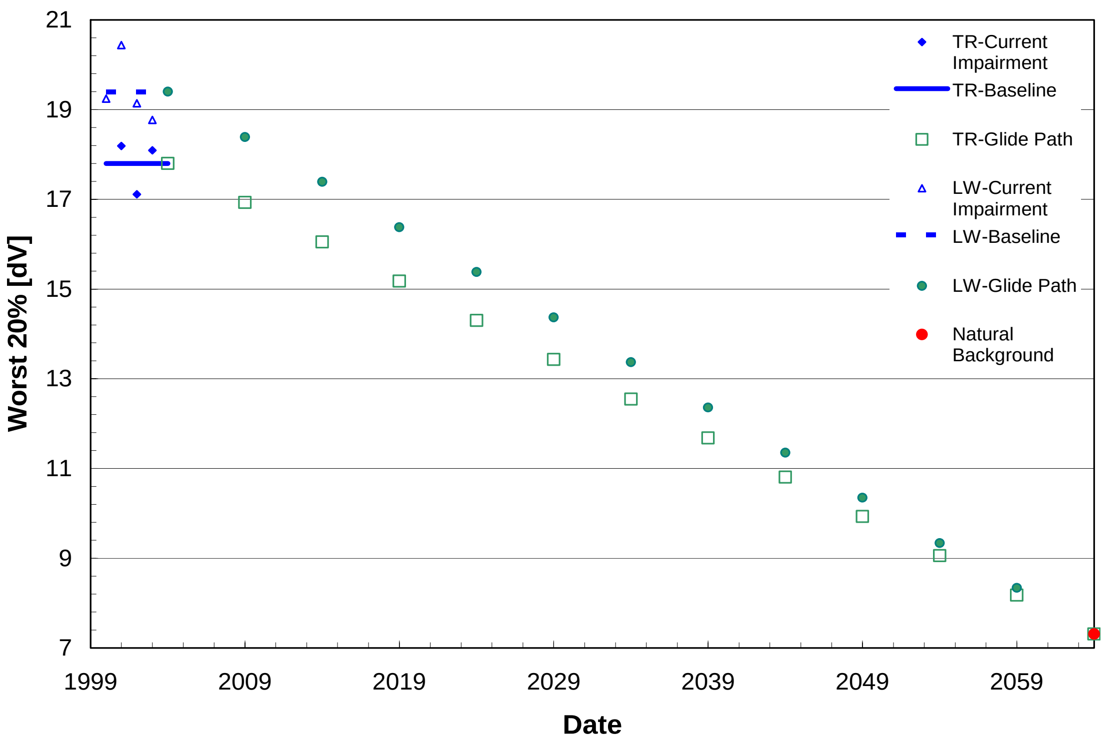


Figure 1-2 Theodore Roosevelt NP and Lostwood WA, ND. Current impairment includes both natural and anthropogenic contributions. (Data from VIEWS database trend analyzer, http://vista.cira.colostate.edu/views/web/AnnualSummaryDev/Trends.aspx DOA 06 Dec 2005)

1.1 BART Eligibility

BART eligibility is established on the basis on 3 criteria. In order to be BART eligible, sources must meet the following three conditions:

1. Contain emission units in one or more of the 26 listed source categories under the PSD rules (e.g., fossil-fuel-fired steam electric plants larger than 250 MMBtu/hr, fossil-fuel boilers larger than 250 MMBtu/hr, petroleum refineries, coal cleaning plants, sulfur recovery plants, etc.)
2. Were in existence on August 7, 1977, but were not in operation before August 7, 1962

3. Have total potential emissions from the emission units meeting the two criteria above greater than 250 tons per year for at least one visibility-impairing pollutant

Under the BART rules, large sources that have previously installed pollution-control equipment required under another standard (e.g., MACT, NSPS and BACT) will be required to conduct visibility analyses. Installation of additional controls may be required to further reduce emissions of visibility impairing pollutants such as PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, and possibly VOCs and ammonia. Sources built before the implementation of the Clean Air Act (CAA), which had previously been grandfathered, may also have to conduct such analyses and possibly install controls, even though they have been exempted to date from any other CAA requirements.

Once BART eligibility is determined, a source must then determine if it is 'subject to BART.' A source is subject to BART if emissions 'cause or contribute' to visibility impairment at any Class I area. Visibility modeling conducted with CALPUFF or another EPA-approved visibility model is necessary to make a definitive visibility impairment determination (>0.5 deciviews). Sources that do not cause or contribute to visibility impairment are exempt from BART requirements, even if they are BART-eligible.

1.2 BART Determinations

Each source that is subject to BART must determine BART on a case-by-case basis. Even if a source was previously part of a group BART determination, individual BART determinations must be made for each source. The BART analysis takes into account six criteria and is analyzed using five steps. The six criteria that comprise the engineering analysis include: the availability of the control technology, existing controls at a facility, the cost of compliance, the remaining useful life of a source, the energy and non-air quality environmental impacts of the technology, and the visibility impacts.[2] The five steps of a BART analysis are:

Step 1 - Identify all Control Technologies
The first step in the analysis is to identify all available retrofit control technologies for each applicable emission unit.

Step 2 - Eliminate Technically Infeasible Options
In the second step, the technical feasibility of each control option identified in step one is evaluated with respect to source-specific factors. Technically infeasible technologies are eliminated from further consideration.

Step 3 - Evaluate Control Effectiveness
In step three, the remaining controls are ranked based on the control efficiency at the expected emission rate (post BART) as compared to the

[2] 40 CFR 51 Appendix Y

emission rate before addition of controls (pre-BART) for the pollutant of concern.

Step 4 - *Evaluate Impacts and Document Results*
In the forth step, an engineering analysis documents the impacts of each remaining control technology option. The economic analysis compares dollar per ton of pollutant removed for each technology. In addition it includes incremental dollar per ton cost analysis to illustrate the economic effectiveness of one technology in relation to the others. Finally, Step Four includes an assessment of energy impacts and other non-air quality environmental impacts.

Economic impacts were analyzed using the procedures found in the EPA Air Pollution Control Cost Manual-Sixth Edition (EPA 452/B-02-001). Vendor cost estimates for this project were used when applicable. Equipment cost estimates from the EPA Control Cost Manual or EPA's Air Compliance Advisor (ACA) Air Pollution Control Technology Evaluation Model version 7.5 were used if no vendor data were available. The source of the control equipment cost data are noted in each of the control cost analysis worksheets as found in Appendix A.

Step 5 - *Evaluate Visibility Impacts*
The fifth step requires a modeling analysis conducted with EPA-approved models such as CALPUFF. The modeling protocol[3], including receptor grid, meteorological data, and other factors used for this part of the analysis were provided by the North Dakota Department of Health. The model outputs, including 98th and 90th percentile visibility impairment days are used to establish the degree of improvement that can be reasonably attributed to each technology.

The established BART for Unit 1 was selected based on the results of information obtained in Steps 4 and 5.

[3] *Protocol for BART-Related Visibility Modeling Analyses in North Dakota*, Final Version, November, 2005.

2.0 Stanton Station BART Determination

As defined by federal guidance and Section 33-25-25-01 of North Dakota's Air Pollution Control Rules, a source "causes or contributes to visibility impairment" if the 98th percentile of any year's modeling results meets or exceeds the threshold of five-tenths of a deciview (dV) at a Class I area receptor. The pre-BART modeled emission rates for eligible sources represent the highest 24-hour average emissions from the years 2000 through 2002. Pre-BART evaluations conducted by the North Dakota Department of Health using the CALPUFF[3] visibility model identified 6 'subject to BART' sources, including Stanton Station, that cause or contribute to visibility impairment in North Dakota.

Using a streamline method for BART determination, BART eligible sources at Stanton Station can be divided into groups based on function, utilization and actual emissions.

2.1 BART Eligible Units

Great River Energy's (GRE) Stanton Station is located on the bank of the Missouri River near Stanton, ND. Stanton Station has one main turbine generator that is run by Unit 1 and Unit 10. The 'BART Eligible' Unit 1 coal-fired boiler has a dry bottom, front wall fired configuration with ratings of 1,800 MMBtu/hr; or an output of 188 megawatts on PRB. Stanton Station is currently permitted to fire both Lignite and PRB coal. For Unit 1, PM is currently controlled with an electrostatic precipitator (ESP). NOx is controlled with low NOx burners (LNB). There are no post combustion SO_2 controls. The use of two coals with different sulfur contents offers a degree of complexity in terms of SO_2 emissions for Unit 1. To respond to NDDH's request, PRB has been included as an operational control in conjunction with post combustion control technologies. GRE does not intend to blend fuels. Therefore, BART controls and associated limits can be determined based upon each fuel, cost effectiveness and most importantly, expected deciview improvements.

At least three sets of emission parameters must be considered to successfully determine BART. As noted in Table 2-1, the current Title V permitted emission limits represent the maximum allowable emission rates. The baseline actual emissions are derived from historical emissions inventories (2000-2004) and represent the 2 highest years for each pollutant. They are used in comparison with design basis emission rates for potential retrofit technologies as noted in Appendix A. The 'BART Screen' emission rate represents the maximum 24-hour average emission rate, for 2000-2002, and it is used as a baseline for visibility modeling analysis. Table 2-1 describes these three data parameters for Unit 1. It is important to note that Stanton is not categorically subject to presumptive BART limits because Unit 1 has a capacity of less than 200 megawatts and the total facility capacity is less than 750 megawatts. Therefore, the presumptive limits are viewed as guidance levels only.

Table 2-1 Unit 1 Emission Bases

Pollutant	Permit Limit	Baseline Actual	BART Screen	Proposed BART Limit
PM_{10}	0.10 lb/MMBtu	33 lb/hr[4] 0.02 lb/MMBtu	36 lb/hr 0.02 lb/MMBtu	0.10 lb/MMBtu
NOx	0.46 lb/MMBtu	554 lb/hr 0.44 lb/MMBtu	669 lb/hr 0.37 lb/MMBtu[5]	0.35 lb/MMBtu
SO_2 - Lignite	3.0 lb/MMBtu	2,267 lb/hr 1.82 lb/MMBtu	3,420 lb/hr 1.90 lb/MMBtu	0.24 lb/MMBtu
SO_2 PRB	3.0 lb/MMBtu	2,267 lb/hr 1.82 lb/MMBtu	3,420 lb/hr 1.90 lb/MMBtu	0.36 lb/MMBtu

The 'Baseline Actual' and 'BART Screen' emissions included in Table 2-1 reflect an average utilization of 68% for Unit 1. The swinging of Unit 1 significantly affects NOx emission rates. Under normal station operating conditions, Unit 10 is run at full utilization while Unit 1 varies (swings) to meet Midwest ISO (MISO) power demands. Unit 1 has a wider range than Unit 10 to swing to meet load. Because of this variable load, the lb/MMBtu emission rate may increase over a rolling period, but the overall lb/hr emission rate remains less than what is derived from converting the lb/MMBtu emission rate with the full boiler duty of 1,800 MMBtu/hr. The lb/hr emission rate is arguably a more appropriate metric since it is ultimately used for regional haze modeling. However, since the presumptive levels are expressed in lb/MMBtu units, the proposed BART emission rate is proposed in the same units as 0.35 lb/MMBtu.

The BART analysis, as described in Section 1.2 of this document, will be presented on a pollutant-by-pollutant basis for Unit 1 with the exception of the assessment of visibility impacts for SO_2 and NOx (Step 5). The visibility analysis for SO_2 and NOx was performed using a multi-pollutant approach, and can be found in Section 7.0 of this document. Stanton Station is currently permitted for PRB and Lignite coal.

2.2 Other BART Eligible Units

Other than Unit 1, the remaining BART eligible emission units at Stanton are exempt from BART analysis because they do not cause or contribute to visibility impairment, and are included under one of the following three categories.

i. *Additional Capacity*

Stanton Unit 10 is a second coal fired boiler with a nominal rating of 642 MMBtu/hr that was operational in 1982. As such, it is not subject to BART. Unit 10 emissions are currently controlled with a spray dry scrubber in

[4] Emission rate differs from BART screen value due to rounding.
[5] The maximum lb/hr emissions rate was required for pre-BART visibility modeling. The 0.37 lb/MMBtu emission rate was back calculated based on the maximum capacity of 1800 MMBtu/hr.

addition to a baghouse. Emissions from Unit 10 are vented through a common stack with Unit 1.

Given the higher PRB Btu content, Stanton Station has additional steam capacity on this fuel. In addition to evaluating IGCC, Great River Energy is evaluating maximizing generation on Unit 1, which would make Unit 10 available for additional capacity. Obviously, any new generation will require a separate permitting action from the BART analysis.

ii. Low Utilization Units

Based on the hours of operation, some emission units can be classified as low emitters. Table 2-2 lists the emergency and auxiliary units at Stanton and their 2005 actual or estimated emissions. Both restricted and limited operation of these units makes additional controls economically infeasible. There would be no measurable visibility improvement associated with installing controls on these low utilization units. No further BART analysis is required.

Table 2-2 Stanton Station Low Utilization Units

Unit Description	Fuel	Maximum Heat Input	Hours of Operation	NOx (tpy)	SO_2 (tpy)	PM (tpy)	PM_{10} (tpy)	Source
Auxiliary Boiler (EUI 3)	No. 2 Fuel Oil	38 MMBtu/hr	93	0.14	0.36	0.01	0.02	2000-2004 averaged actual emissions.
Emergency Diesel Generator (EUI 4)	No. 2 Fuel Oil	10.35 MMBtu/hr	500	8.00	1.30	0.20	0.20	Potential to emit based on 500 hours of operation.[6]
Emergency Fire Pump Engine (EUI 5)	No. 2 Fuel Oil	370 hp	350	1.93	0.13	0.14	0.14	Estimated emission based on 350 hours of operation.[6]

iii. Material Handling and Fugitive Sources

All material handling units (EUI M1 through EUI M5 as listed in the Title V Permit), including coal and lime handling operations and fly ash silos, are controlled through the use of fabric filter baghouses. Baghouses are currently recognized as best available control technology (BACT) for PM emitting sources. No further BART analysis is required for emission units employing BACT or equivalent controls.

[6] Annual emissions are conservatively estimated based on potential to emit at 500 hours per year according to EPA definition for emergency-only generators. The fire pump is restricted to 500 hours per year in the Title V permit. Actual emissions are conservatively estimated at 350 hours per year.

In step three of the BART guidance, the Federal Register[7] states, "Fugitive emissions, to the extent quantifiable, must be counted." The emissions from the coal storage sources listed in Table 2-3 consist of PM only. Because sulfates and nitrates are the primary contributors to visibility impairment, PM sources will not significantly contribute to visibility impairment in Class I areas. The tanks, and other units with no specific permit limits listed below (EUI T1 through EUI T8), are classified as insignificant activities. There would be no measurable visibility improvement associated with installing controls on these sources. For this reason, no further BART analysis is required.

Table 2-3 Stanton Station Fugitive Sources

Fugitive Source/Insignificant Activity Name
FS 1 Active coal storage pile
FS 2 Inactive coal storage pile
T1 and 2 Fuel Oil Storage Tanks (2)
T3 Main Generator Transformer
T4 Spare Main Generator Transformer
T5 Spare Startup Transformer
T6 Sulfuric Acid Storage Tank
T7 Caustic Storage Tank
T8 Turbine Oil Vapor Extractor

[7] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Rules and Regulations.

3.0 Particulate Matter (PM) BART Analysis

Historical particulate emission tests show that under normal operation, Stanton Station Unit 1 emits PM below the permitted limit. The existing ESP controls filterable particulate at 98% or more.

EPA has interpreted 'total particulate' to include condensable particulate matter (CPM) and NDDH has requested that CPM be addressed as part of the BART analysis. As such, Section 6 provides an estimation of CPM. It concludes that CPM emissions from Unit 1 do not significantly impact visibility impairment and will be reduced by the proposed SO_2 BART controls. Further, pre-BART modeling demonstrates that Unit 1 PM contribution to visibility impairment is negligible in comparison to the impairment attributed to sulfates and nitrates.

As illustrated in Section 7.0, Unit 1 post-BART modeling shows a 1.0 Δ-dV improvement in visibility for the proposed SO_2 and NOx controls as compared to a maximum 0.02 Δ-dV improvement for particulate controls[8]. This incremental improvement is an order of magnitude less than the perceptibility threshold set by EPA. It is statistically insignificant given the uncertainty associated with the modeling. Therefore, additional PM controls are not warranted.

3.1 Identify PM Control Options

Table 3-1 lists the available retrofit PM options for Stanton Unit 1.

Table 3-1 Available PM Control Technologies

PM Control Options
ESP – Current Control
WESP
Mechanical Collector (Multiclone)
Fabric Filter/Baghouse

3.2 Eliminate Infeasible PM Control Options

3.2.1 Electrostatic Precipitator (ESP)

An electrostatic precipitator applies electric forces to separate suspended particles from the flue gas stream. In an ESP, an intense electrostatic field is maintained between high-voltage discharge electrodes, which are typically wires or rigid frames, and grounded collecting electrodes, which are typically plates. A corona discharge from the discharge electrodes ionizes the gas passing through the precipitator, and gas ions subsequently ionize the particles. The electric field drives the negatively charged particles to the collecting electrodes. Periodically, the collecting electrodes are rapped mechanically to dislodge collected particulate

[8] 98th percentile comparison of modeling results.

matter, which falls into hoppers for removal. Collector dust is removed from the precipitator for disposal or recycling.

ESP control efficiency under normal load conditions is typically in the range of 98% to 99%+. Reduced efficiencies will occur when the inlet particle concentration is low. Outlet particle concentrations can be reduced to as low as 0.005 gr/dscf. The actual outlet concentration will depend on the size range and nature of the particles. An ESP is currently used to control particulate emissions from the Unit 1. According to BART, ESP replacement or modification is technically feasible.

3.2.2 Wet Electrostatic Precipitator (WESP)

A wet electrostatic precipitator operates in the same manner as a dry ESP; it applies electric forces to separate suspended particles from the flue gas stream. In a WESP, an intense electrostatic field is maintained between high-voltage discharge electrodes, which are typically wires or rigid frames, and grounded collecting electrodes, which are typically plates. A corona discharge from the discharge electrodes ionizes the gas passing through the precipitator, and gas ions subsequently ionize the particles. The electric field drives the negatively charged particles to the collecting electrodes. Particle removal in a WESP is accomplished with water sprays instead of mechanical cleaning methods. As a result of using water sprays, WESPs generate wastewater that must be treated to remove suspended particles and dissolved solids.

Since WESPs use electrical forces for particle collection, the electrical properties of the particles can adversely impact WESP operation. Particles with high resistivity may not readily accept an electric charge and will be difficult to collect. Particles with high conductivity or magnetic properties will strongly adhere to the collection plates and be difficult to remove; WESP water sprays may reduce this problem. However, WESP water spray systems will require more maintenance than dry ESP's in order to keep the water spray system working properly.

WESP control efficiency under normal loading conditions is typically in the range of 98% to 99%+. Reduced efficiencies will occur when the inlet particle concentration is low. Outlet particle concentrations can be reduced to as low as 0.005 gr/dscf. The actual outlet concentration will depend on the size range and nature of the particles. WESP technology has been demonstrated on similar coal-fired boilers. Therefore, replacement of the existing ESP with a WESP is technically feasible as BART for Unit 1.

3.2.3 Mechanical Collector

Cyclone separators are designed to remove particles by inducing a vortex as the gas stream enters the chamber, which causes the exhaust gas stream to flow in a spiral pattern. Centrifugal forces cause the larger particles to concentrate on the outside of the vortex and consequently slide down the outer wall and fall to the bottom of the cyclone, where they are removed. The cleaned gas flows out of the top the cyclone.

There are two principal types of cyclones: tangential entry and axial entry. In tangential entry cyclones, the exhaust gas enters an opening located on the tangent at the top of the unit. In axial flow cyclones, the exhaust gases enter at the middle of one end of a cylinder and flows through vanes that cause the gas to spin. A peripheral stream removes collected particles while the cleaned gas exits at the center of the opposite end of the cylinder.

Overall cyclone control efficiencies range from 50% to 99% with higher efficiencies being achieved with large particles and low efficiencies for smaller particles (< PM_{10}). Mechanical separators are often used upstream of other PM control devices to reduce the loading on the primary control device. This improves overall control efficiency and may reduce the overall cost of the control system when the exhaust is heavily laden with particulate matter.

According to a 2005 report by EPRI[9] on the current controls used for coal-fired power plants, mechanical collectors have only been permitted for use on one similar unit that is not yet operational. Due to the fact that a multiclone has not been successfully demonstrated on a comparable unit, it is a technically infeasible retrofit for Unit 1, and will not be considered further in this analysis.

3.2.4 Fabric Filter/Baghouse

A fabric filter or baghouse consists of a number of fabric bags placed in parallel inside of an enclosure. Particulate matter is collected on the surface of the bags as the gas stream passes through them. The dust cake, which forms on the filter from the collected particulate, can contribute significantly to increasing the collection efficiency.

Two major fabric filter types are the reverse-air fabric filter and the pulse-jet fabric filter. In a reverse-air fabric filter, the flue gas flows upward through the insides of vertical bags that open downward. The particulate matter thus collects on the insides of the bags, and the gas flow keeps the bags inflated. To clean the bags, a compartment of the fabric filter is taken off-line, and the gas flow in this compartment is reversed. This causes the bags to collapse and the collected dust falls from the bags into hoppers. Shaking or other methods are sometimes employed to dislodge the dust from the bags. The cleaning cycle in a reverse-air fabric filter typically lasts about three minutes per compartment. Because reverse-air cleaning is gentle, reverse-air fabric filters typically require a low air-to-cloth ratio of 2 ft/min. In a pulse-jet fabric filter, dirty air flows from the outside of the bags inward, and the bags are mounted on cages to keep them from collapsing. Dust that collects on the outsides of the bags is removed by a reverse pulse of high-pressure air. This cleaning does not require isolation of the bags from the flue gas flow, and thus may be done on-line.

[9] *Status and Performance of Best Available Control Technologies*, EPRI, Palo Alto, CA: 2005. 1008114

The main operating concern for a baghouse is that its operating temperature is limited by the bag material. Most filter materials are limited to 200ºF – 300º F. Some materials like glass fiber or Nomex may be operated at 400ºF, but are more expensive.

Baghouse control efficiency under normal loading conditions is typically in the range of 98% to 99%+. Reduced efficiencies will occur when the inlet particle concentration is low. Outlet particle concentrations can be as low as 0.005 gr/dscf. However, like ESPs, outlet concentrations will depend on the size range and nature of the particles being filtered. Baghouses are currently considered BACT and are commonly used to control particulate emissions from coal-fired boilers. Therefore, they are technically feasible as BART for Unit 1.

3.3 Evaluate the Effectiveness of Feasible PM Options

Based on the current degree of control being achieved on Unit 1, a new ESP, WESP and baghouse technologies are estimated to reasonably provide a 20% reduction in actual emissions from existing annual average emissions[10]. Table 3-2 describes the expected emissions from each of the three remaining control options.

Table 3-2 Control Effectiveness of Technically Feasible PM Control Options

Control Technology	Expected Control Efficiency[10]	Controlled Emissions lb/MMBtu
Dry ESP	20%	0.015
Polishing WESP	20%	0.015
Baghouse	20%	0.015

3.4 Evaluate the Impacts of Feasible PM Options

As illustrated above in Table 3-2, the three technically feasible options are estimated provide identical degrees of increased control. Therefore, in order to differentiate, the economic and environmental impacts for each are presented below.

3.4.1 Economic Impacts

Each technology is estimated to provide controlled emissions of about 73 tons per year, which is a theoretical 20% (17 ton) improvement from the pre-BART historical baseline. The high cost of PM control retrofits in combination with the small reduction in emissions results in a high dollar per ton cost. Table 3-3 details

[10] Control efficiency reflects improvement beyond the performance of the existing ESP. Historic particulate performance test results suggest that sampling variability is expected depending on the test method. This indicates that an additional 20% control represents a high performance estimate for potential retrofit controls.

the expected costs associated with each technology based on the EPA cost model and site specific information. Due to site space constraints, the retrofit of PM controls at Stanton Station would require significant additional expenses that were not included in the control cost evaluation below. Therefore, the cost estimates are best case.

Table 3-3 PM Control Cost Summary

Control Technology	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)
Polishing WESP	$6.90	$2.03	$119,268
Baghouse	$33.65	$4.98	$292,702
Dry ESP	$38.57	$5.80	$340,570

Because the technologies provide identical levels of control, an incremental analysis of the costs is not beneficial. All three options require significant capital investments and large increases in expected operation and maintenance costs. The pollution control costs confirm that additional particulate control for Unit 1would involve an unjustified investment for only an estimated 20% reduction in already low particulate emissions. Economically, additional controls are not justified for achieving regional haze visibility improvements.

3.4.2 Energy and Environmental Impacts

Generally, there are no other energy or non-air quality environmental impacts that would discourage the use of a new ESP, WESP or baghouse as BART. For the WESP, however, there are additional waste water environmental impacts that would need to be addressed. All three options would require energy usage comparable to the existing ESP. The flyash systems needed to handle the solid waste generated by particulate controls are already in place at Stanton, but some modification and additional costs could be expected. In short, there are generally no significant energy or environmental impacts that would preclude installation of the feasible PM controls.

3.5 PM Visibility Impacts

Most importantly, the visibility impact analysis demonstrates that additional PM controls provide negligible improvements in the Class 1 areas. Figure 3-1 illustrates the visibility improvement of particulate controls. Reducing PM emissions from the existing permit limit of 0.1 lb/MMBtu to 0.015 lb/MMBtu results in a maximum visibility improvement of only 0.02 Δ-dV or an average visibility improvement of 0.01 Δ-dV. This improvement is completely insignificant in comparison to the improvement attributed to SO_2 and NOx control as illustrated in Section 7.0. It is an order of magnitude less than EPA's perceptibility threshold and is statistically unreliable given the myriad of modeling assumptions and uncertainties. Therefore, from a visibility impact perspective, additional PM controls, including lowering the permitted limited, are not justified for visibility improvements.

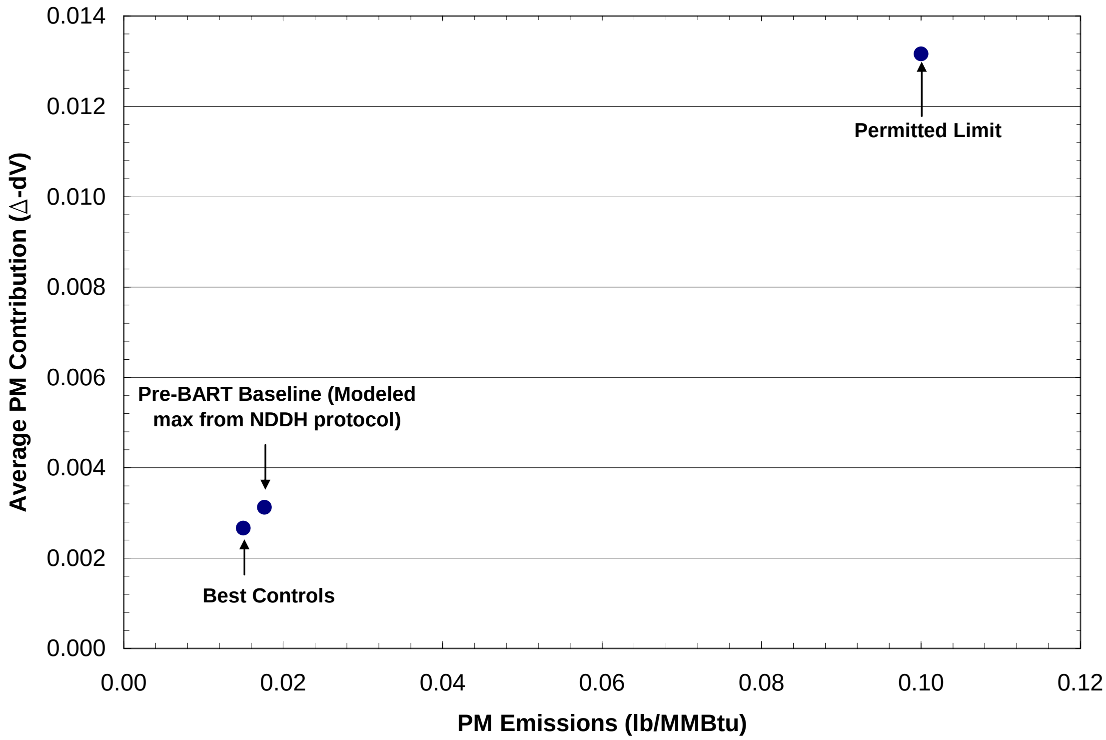


Figure 3-1 Three modeled scenarios illustrate the negligible visibility impacts attributed to particulate matter. All scenarios except for "Pre-BART" were modeled with NOx and SO_2 at their respective proposed BART emission rates. Results represent the average PM visibility impairment contributions from Lostwood Wilderness Area, Theodore Roosevelt National Park (TRNP) South Unit, and TRNP North Unit on the 98th percentile from 2002.

3.6 Proposed BART for PM

Based on the above analysis and the visibility impacts found in Figure 3-1 and Section 7.0, BART is 0.1 lb/MMBtu for particulate emissions based upon the existing ESP. A modification to the existing ESP or the retrofit to another technically feasible control is not cost effective on a dollar per ton basis. Also, most importantly, any additional particulate reductions will provide negligible improvement in visibility. GRE will follow the existing PM CAM plan to comply with the 0.1 lb/MMBtu limit as BART.

PRB BART controls for SO_2 involve the use of dry sorbent injection with the existing ESP, which will lead to additional particulate loading. It is further supportive of maintaining the existing PM permit limit of 0.1 lb/MMBtu. The Unit 1 ESP will continue to operate with automated controls at greater than 98% effectiveness.

Although historical EPA Method 17 particulate emission tests show that Unit 1 can perform below 0.1 lb/MMBtu, a lower BART emission limits is not warranted for the purpose of providing regional haze visibility improvements.

BART PM Emission Limit

Pollutant	Permit Limit	BART Limit
PM_{10}	0.10 lb/MMBtu	0.10 lb/MMBtu

4.0 Nitrogen Oxides (NOx) BART Analysis

Historical NOx emissions for Unit 1 on Lignite are controlled with low NOx burners (LNB) to approximately 0.44 lb/MMBtu. Unit 1 NOx emissions are affected by regional electricity needs as set by MISO and by plant operational protocols. In other words, Stanton's Unit 10 operates at full capacity and Unit 1 is used to meet the remaining power requirements. Unit fluctuations to meet electricity demands from MISO result in variable NOx emissions from Unit 1, with an average utilization of 68%.

There are three mechanisms by which NOx production occurs: thermal, fuel and prompt NOx. Fuel bound NOx is a primary concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. The secondary mechanism of NOx production is through thermal NOx formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air. The thermal oxidation reaction is as follows:

$$N_2 + O_2 \rightarrow 2NO \qquad (1)$$

Downstream of the flame, significant amounts of NO_2 can be formed when NO is mixed with air. The reaction is as follows:

$$2NO + O_2 \rightarrow 2NO_2 \qquad (2)$$

Thermal oxidation is a function of the residence time, free oxygen, and peak reaction temperature. Prompt NOx is a form of thermal NOx which is generated at the flame boundary. It is the result of reactions between nitrogen and carbon radicals generated during combustion. Only minor amounts of NOx are emitted as prompt NOx.

4.1 NOx Control Options

Table 4-1 lists the available retrofit NOx options for Stanton's Unit 1.

Table 4-1 Available NOx Control Technologies

NOx Control Options
Pre-Combustion Controls
• Fuel Switching
Combustion Controls
• External Flue Gas Recirculation
• Overfire Air
• Low NOx Burners
Post Combustion Controls
• Selective Catalytic Reduction (SCR) - High Dust - Low Dust
• Selective Non- Catalytic Reduction (SNCR) - NOxOUT®
• Low Temperature Oxidation - Tri-NOx® - LoTOx
• Non Selective Catalytic Reduction
• Novel Multi-pollutant Controls - Rotating Opposed Fire Air (ROFA ®) - Electro-Catalytic Oxidation - Pahlman Process

4.2 Eliminate Infeasible NOx Control Options

4.2.1 Pre-Combustion Controls

Fuel Switching

Fuel switching represents a viable pre-combustion method of reducing NOx emissions through the use of coals with higher BTU content. Historically, Unit 1 has burned Lignite coal, but is currently permitted to burn both Lignite and PRB coals. The PRB fuel switch has reduced NOx emissions from the Lignite base case on an annual basis.

4.2.2 Combustion Controls

Various combustion controls exist for Unit 1 NOx reduction. However, as discussed in this section, there are essentially only a few feasible controls that include overfire air (OFA), low NOx burners (LNB) adjustment and SNCR. Combustion tuning is an inherent part of any LNB/OFA installation.

External Flue Gas Recirculation (FGR)

Flue gas recirculation is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizer or air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through adsorption of the combustion heat by the relatively inert flue gas, and to reduce the oxygen concentration in the combustion zone. FGR reduces thermal NOx generation in high-temperature emission sources.

Additional ductwork and a blower would be required to recirculate flue gas. These elements must fit in the limited space around the burner's coal mill. The space constraints and the lowered flame temperature created by FGR make it incompatible with the existing combustion controls on Unit 1. The addition of FGR could further result in reduced boiler capacity. Flue gas recirculation is therefore a technically infeasible control option and will not be considered further.

Overfire Air (OFA)

Overfire air diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. OFA is the typical NOx control technology used in coal-fired boilers and is primarily geared to reduce thermal NOx. Staging of the combustion air creates an initial fuel-rich combustion zone for a cooler fuel-rich combustion zone. This reduces the production of thermal NOx by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NOx is most likely to be formed. Based on engineering analyses[11] performed on Unit 1, OFA is compatible with the existing LNB and is a technically feasible option for further NOx reduction. However, Alstom's design targets have some uncertainty because Unit 1 has a relatively short firebox, which may make OFA less effective than on other larger units. Further, with OFA, there is a potential for increased carbon monoxide (CO) emissions from Unit 1, especially on Lignite, as noted on Page 2-1 of the Alstom Report, which will limit the NOx reduction effectiveness.

Low NOx Burners (LNB)

LNB technology utilizes advanced burner design to reduce NOx formation through the restriction of oxygen, flame temperature, and/or residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NOx formation is limited by either one of two methods. Under staged air rich (high fuel) condition, low oxygen levels limit flame temperatures resulting in less NOx formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel lean (low fuel) conditions, excess air will reduce flame

[11] *NOx Reduction Technologies Firing Powder River Basin Coal.* Alstom Power Inc. March 8, 2006. (Appendix D)

temperature to reduce NOx formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NOx formation. Low NOx burners typically achieve NOx emission reductions of 25% - 50%.

LNB are currently used to control NOx emissions from Unit 1. Alone or in combination with additional controls, additional LNB is a technically feasible option to further reduce emissions. Based on the currently achieved emission rates and used in conjunction with OFA, reduction in the range of 15%-30% would be expected depending on operational conditions.

4.2.3 Post Combustion Controls

For post combustion controls, NOx can be reduced to molecular nitrogen (N_2) in add-on systems located downstream of the furnace area of the combustion process. The two main techniques in commercial service include the selective non-catalytic reduction (SNCR) process and the selective catalytic reduction (SCR) process. There are a number of different process systems in each of these categories of control techniques.

In addition to these treatment systems, there are a large number of other processes being developed and tested on the market. These approaches involve innovative techniques of chemically reducing, absorbing, or adsorbing NOx downstream of the combustion chamber. One example of these alternatives is nonselective catalytic reduction (NSCR).

Selective Catalytic Reduction (SCR)

Selective catalytic reduction is a post combustion NOx control technology in which ammonia (NH_3) is injected into the flue gas stream in the presence of a catalyst. SCR control efficiency is typically 70% - 90%. NOx is removed through the following chemical reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_20 \qquad (1)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_20 \qquad (2)$$

The catalyst bed lowers the activation energy required for NOx decomposition. The catalyst contains an active phase such as vanadium pentoxide on a carrier such as titanium dioxide. These are used for their ability to lower the activation energy required for NOx decomposition. SCR requires an optimum temperature range of 650-800°F. There are two types of SCR.

High-dust SCR occurs upstream of particulate control. Typical applications require soot blowers for catalyst cleaning. Firing Lignite coal results in an exhaust stream heavily laden with particulate matter, which can contain catalyst poisons such as sodium. The catalyst plugging observed at the Lignite-fired boiler at Coyote Station [12] was caused by materials that could not be cleaned by a soot blower system. Because of Coyote's experience and the potential for comparable catalyst surface plugging at Stanton, a high-dust SCR is determined to be technically infeasible on Unit 1 on Lignite. Since Stanton Station is permitted for both Lignite and PRB, SCR cannot be installed as a PRB control option because of the lignite limitations as discussed. Therefore, High Dust SCR on either fuel will not be considered further.

Low-dust SCR occurs downstream of particulate control. For Unit 1, it requires reheat to bring the flue gas temperature back to the effective range after it is cooled for particulate removal. With reheat, it is a technically feasible option for NOx reduction. Based on an engineering assessment[11] and current NOx emissions, a low-dust SCR could provide additional reduction in the range of 80%-90%.

Selective Non-Catalytic Reduction (SNCR)

In the SNCR process, urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to molecular nitrogen, N_2, and water. SNCR control efficiency is typically 25% - 50%. Without a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:

$$NO + NH_3 + \tfrac{1}{4}O_2 \rightarrow N_2 + 3/2H_2O \qquad (1)$$

$$NH_3 + \tfrac{1}{4}O_2 \rightarrow NO + 3/2H_2O \qquad (2)$$

At temperature ranges of 1470 to 1830°F reaction (1) dominates. At temperatures above 2000°F, reaction (2) will dominate.

NOxOUT®

NOxOUT® is a commercially available, urea based, SNCR process for the reduction of NOx from stationary sources. The process requires injection of stabilized urea liquid into the combustion flue gas in a location where the temperature range is 1,600 - 2,000 °F.

Based on an SNCR engineering assessment[11] that included the temperature, residence time and the current level of NOx control, an emissions reduction of approximately 15-30% would be expected. However, there are many operational effects to consider. Ideally, SNCR operates at steady state reagent addition rates. Due to the swinging of Unit 1 to meet MISO demands, reagent addition, and corresponding NOx emissions, would vary considerably. Variable reagent addition leads to the formation of

[12] *SCR catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals.* Steven A. Benson; Jason D. Laumb; Charlene R. Crocker; John H. Pavlish. 7/1/2004 (Appendix F)

ammonium sulfate, which can cause plugging and corrosion. Some estimates suggest that the air heaters must be cleaned quarterly for approximately 2-3 days. If unplanned outages were included, it would only increase the average cost effectiveness. Finally, the engineering assessment did not incorporate Unit 1 load changes due to demand requirements, which would further exacerbate air heater fouling. Therefore, percent reductions are simply estimates. It is important to note that the economic analysis does not include unplanned outages to clean the ammonium sulfate from the air heaters because SNCR was already considered well outside the average cost effective ranges in the BART rule (See Appendix B).

Low Temperature Oxidation (LTO)

The LTO system utilizes an oxidizing agent, such as ozone, to oxidize various pollutants including NOx. In the LTO system, NOx in the flue gas is oxidized to form nitrogen pentoxide (equations 1, 2, and 3). The nitrogen pentoxide forms nitric acid vapor as it contacts the water vapor in the flue gas (4). Then the nitric acid vapor is absorbed as dilute nitric acid and is neutralized by the sodium hydroxide or lime in the scrubbing solution, which forms sodium nitrate (5) or calcium nitrate. The nitrates are removed from the scrubbing system and discharged to an appropriate water treatment system.

$$NO + O_3 \rightarrow NO_2 + O_2 \qquad (1)$$

$$NO_2 + O_3 \rightarrow NO_3 + O_2 \qquad (2)$$

$$NO_3 + NO2 \rightarrow N_2O_5 \qquad (3)$$

$$N_2O_5 + H_2O \rightarrow 2HNO_3 \qquad (4)$$

$$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O \qquad (5)$$

LTO systems, including the commercially available Tri-NOx® and LoTOx describer below, generally represent a technically feasible control option for Unit 1, with an expected control efficiency of 80%-90%.

Tri-NOx®

This technology uses an oxidizing agent such as ozone or sodium chlorite to oxidize NO to NO_2 in a primary scrubbing stage. Then NO_2 is removed through caustic scrubbing in a secondary stage. The reactions are as follows:

$$O_3 + NO \rightarrow O_2 + NO_2 \qquad (1)$$

$$2NaOH + 2NO_2 + ½\ O_2 \rightarrow 2NaNO_3 + H_2O \quad (2)$$

Tri-NOx® is a commercially available multi-staged wet scrubbing process in industrial use. Several process columns, each assigned a separate processing stage, are involved. In the first stage, the incoming material is quenched to reduce its temperature. The second, oxidizing stage, converts NO to NO_2. Subsequent stages reduce NO_2 to nitrogen gas, while the oxygen becomes part of a soluble salt. A major advantage of the Tri-NOx® process is that concurrent scrubbing of SO_2 can be achieved. Tri-NOx is typically applied at small to medium sized sources with high NOx concentration in the exhaust gas (1,000 ppm NOx). Under these conditions control efficiencies of 99% can be achieved.

LoTOx

BOC[13] Gases' Lo-TOx is an example of a commercially available version of an LTO system. LoTOx technology uses ozone to oxidize NO to NO_2 and NO_2 to N_2O_5 in a wet scrubber (absorber). This can be done in the same scrubber used for particulate or sulfur dioxide removal, The N_2O_5 is converted to HNO_3 in a scrubber, and is removed with lime or caustic. Ozone for LoTOx is generated on site with an electrically powered ozone generator. The ozone generation rate is controlled to match the amount needed for NOx control. Ozone is generated from pure oxygen. In order for LoTOx to be economically feasible, a source of low cost oxygen must be available from a pipeline or on site generation. The normal NOx control efficiency range for Lo-TOx is 80% to 95%.

Non-Selective Catalytic Reduction (NSCR)

A non-selective catalytic reduction (NSCR) system is a post combustion add-on exhaust gas treatment system. NSCR is often referred to as a three-way conversion catalyst because it simultaneously reduces NOx, unburned hydrocarbons (UBH), and CO. Typically, NSCR can achieve NOx emission reductions of 90 percent. In order to operate properly, the combustion process must be near stoichiometric conditions. Under these conditions, in the presence of a catalyst, NOx is reduced by CO, resulting in nitrogen (N_2) and carbon dioxide (CO_2). The most important reactions for NOx removal are:

$$2CO + 2NO \rightarrow 2CO_2 + N_2 \quad (1)$$

$$[UBH] + NO \rightarrow N2 + CO_2 + H_2O \quad (2)$$

NSCR catalyst has been applied primarily in natural gas combustion applications. This is due in large part to the catalyst being very sensitive to poisoning, as could be expected with coal exhaust streams. Based on a cursory industry review, there were no

[13] BOC Gases is a part of The BOC Group plc. (www.boc.com)

commercial installations of NSCR on a coal fired boiler. Therefore, NSCR is viewed as technically infeasible as BART for Unit 1.

Novel Multi-Pollutant Controls

Rotating Opposed Fire Air – ROFA®

ROFA technology utilizes the injection of air through nozzles at asymmetrical positions on opposite sides of a boiler to introduce a swirling quality to the combustion gas. The swirling generates turbulence and rotation throughout the furnace. The rotation prevents laminar flow, resulting in greater utilization of the entire volume of the boiler. Efficiency is improved as a resulted of the lowered temperature provided by the swirling combustion gases. Using of ROFA technology results in a reduction of excess air without an increase in CO emissions. Further, the decrease in oxygen as a result of the excess air reduction leads to a decrease in NOx. As mentioned above, Unit 1 has a short fire box, which could limit the effectiveness of the ROFA technology.

Electro-Catalytic Oxidation (ECO)

ECO technology utilizes a reactor in which SO_2 and NOx and mercury are oxidized to nitrogen dioxide (NO_2), sulfuric acid and mercuric oxide, respectively, using non-thermal plasma. The NO_2 and remaining SO_2 are then removed and concentrated in a scrubber with ammonia injection. This technology is intended for use on low-dust streams and must be located downstream of existing particulate controls.

Pahlman Process

The Pahlman process involves the treatment of flue gas with a sorbent containing magnesium oxide. Using the solubility properties of magnesium at different ionization states, SO_2 and NOx are captured and dissolved in a spray dry system. The sorbent is then captured at a downstream baghouse and can be regenerated.

ECO and the Pahlman process technologies are still in the testing and development phase. They are not currently considered commercially available. Therefore, they are not technically feasible as BART for Unit 1. ROFA is a commercially available OFA alternative, but a site specific applicability study has not been performed for Unit 1 at this time to determine the feasibility of installation. Progress on these technologies will be monitored as the BART implementation timeline progresses.

4.3 Evaluate the Effectiveness of Feasible NOx Options

The results of the engineering analysis performed by Alstom Power presented options for the addition of SNCR and OFA in addition to the existing LNB control. Because these technologies are not mutually exclusive, they are also evaluated in combination. The Alstom Report is presented in Appendix D. Alstom projects NOx target emission rates for OFA that are comparable to presumptive limits.

It is important to note that there are several uncertainties associated with Alstom's estimates. First, the Alstom analysis was expedited in an attempt to meet March 1 deadline under NDDH's accelerate BART schedule. The summary results are simply 'targets' as stated in the report. Second, Alstom proposes emission ranges based on specific operational scenarios that are 'representative' of normal operations. These target emission rates represent specific static operational scenarios that may not be reflective of future operation or inclusive of variable load Specifically, GRE may give preference to Unit 1 in the future with the addition of a new scrubber, which would cause heat input to increase over any shorter term averaging period. Third, for the existing low NOx burners that were installed in 1998 Alstom had provided a contractually guaranteed emission rate that was difficult to meet under all boiler operating conditions and burner tuning at that time.

The attached Alstom report estimates that certain 'target' emissions can be met. This is not as certain as a contractual guarantee. Alstom was eventually able to meet their 1998 LNB commitment through significant additional work, but it is an indication of the complexity of predicting NOx emission reductions from Unit 1. Unit 1 has a relatively short fire box, which adds uncertainty to targeted estimates because overfire requires additional space above the burners for ample mixing. Finally, as previously mentioned, carbon monoxide is expected to increase as a result of installing OFA, which may also limit OFA effectiveness for NOx control. For these reasons, a risk factor is appropriate for adjusting the lb/MMBtu equivalents from the Alstom report. Table 4-2 describes the recalculation methodology to adjust the Alstom report to a 30-day rolling BART emission rates.

Table 4-2 Alstom Emissions

Control	Design Emissions for PRB from Alstom Report[14] (BART Annual)	Alstom Design % Reduction from 0.40 lb/MMBtu	Recalculated Lignite Emission Rates at Historic Baseline of 0.44 lb/MMBtu (BART 30-Day)	
			lb/MMBtu	lb/hr based on 1,800 MMBtu/hr
LNB/OFA	0.32 lb/MMBtu	20%	0.35 lb/MMBtu	633.6 lb/hr
SNCR	0.29 lb/MMBtu	27%	0.32 lb/MMBtu	574.2 lb/hr
LNB/OFA +SNCR	0.22 lb/MMBtu	45%	0.24 lb/MMBtu	435.6 lb/hr

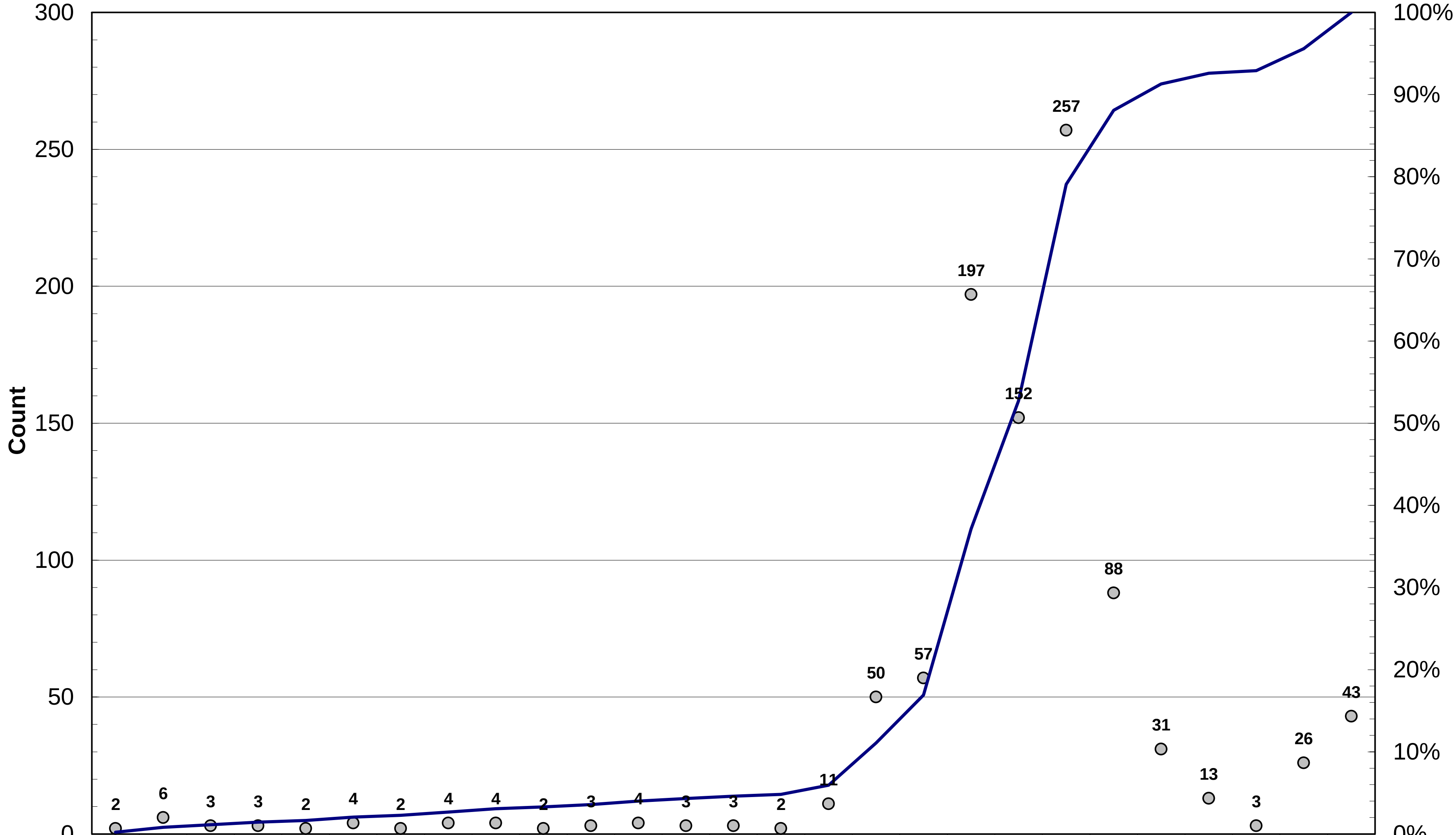
[14] Design emission rates used as annual estimates for projecting ton per year reductions.

Based on the current utilization and design degree of control being achieved on Unit 1, Table 4-3 describes the expected annual emissions from each of the remaining feasible control options.

Table 4-3 Control Effectiveness of Technically Feasible NOx Control Options

Control Technology	Expected Control Efficiency	Controlled Emissions lb/MMBtu	Controlled Emissions ton/year
SCR with Reheat	90%	0.044	210.2
LTO	90%	0.044	210.2
SNCR + PRB + Alstom LNB + OFA	55%	0.196	946.1
SNCR + PRB	47%	0.230	1111.3
Alstom LNB + OFA + SNCR	45%	0.239	1156.3
SNCR	33%	0.290	1401.2
Alstom LNB + OFA + PRB	34%	0.286	1381.9
Alstom LNB + OFA	26%	0.320	1546.2
Fuel Switch to PRB	4%	0.360	1739.5

Figure 4-1 is a statistical analysis of past Unit 1 NOx emissions on a lb/MMBtu basis. It illustrates that an emission rate of 0.44 lb/MMBtu is required to be representative of 90% of historical operating scenarios.



	0.22	0.23	0.24	0.25	0.26	0.27	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35
Count	2	6	3	3	2	4	2	4	4	2	3	4	3	3
Cumulative %	0.2%	0.8%	1.1%	1.4%	1.6%	2.1%	2.3%	2.7%	3.1%	3.3%	3.6%	4.0%	4.3%	4.6%

	0.36	0.37	0.38	0.39	0.40	0.41	0.42	0.43	0.44	0.45	0.46	0.47	0.48
Count	2	11	50	57	197	152	257	88	31	13	3	26	43
Cumulative %	4.8%	5.9%	11.1%	16.9%	37.1%	52.7%	79.1%	88.1%	91.3%	92.6%	92.9%	95.6%	100.0

Emission Values and Cumulative Percentage

Figure 4-1 Historical Distribution of 30 -Day Rolling NOx lb/MMBtu Statistical analysis of historical EDRs for Unit 1 emissions from 2000 through 2002.

4.4 Evaluate the Impacts of Feasible NOx Options

As illustrated above in Table 4-3, the technically feasible control options provide varying levels of emission reduction. Therefore, it is necessary to consider the economic and energy/environmental impacts to better differentiate as presented below.

4.4.1 Economic Impacts

Table 4-4 details the expected costs associated with each technology based on pre-BART historical baseline emissions, the EPA cost model and site specific information. Factors affecting the control cost estimates include extensive renovations necessitated by space constraints, extended downtime for installation, and reagent costs. The detailed cost analysis for each technology is provided in Appendix A.

Table 4-4 NOx Control Cost Summary

Control Technology [15]	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)	Incremental Control Cost ($/ton)
SCR with Reheat	$56.55	$12.49	$6,478	$10,036
LTO	$43.88	$44.78	$23,217	Inferior
SNCR + PRB + Alstom LNB + OFA	$10.67	$5.31	$4,452	$6,910 (D2)
SNCR + PRB	$8.41	$5.01	$4,877	Inferior
Alstom LNB + OFA + SNCR	$10.66	$3.00	$3,053	$6,927
SNCR	$8.39	$2.70	$3,661	Inferior
Alstom LNB + OFA + PRB	$2.27	$2.30	$3,037	$836 (D2)
Alstom LNB + OFA	$2.27	$0.30	$504	NA-Base
Fuel Switch to PRB	$0.00	$2.00	$5,006	NA-Base PRB (D2)[16]

The incremental control cost listed in Table 4-4 represents the incremental value of each technology as compared to the technology with the next highest level of control. Control technologies listed as "inferior" do not represent cost effective options in comparison to the dominant control technologies on an incremental dollar per ton basis. In this analysis, dominant controls are located on the least cost envelope, as illustrated graphically in Figure 4-2[17].

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[15] Cost estimates for LNB and OFA controls rely on March 2006 Alstom evaluation. SNCR Cost revised in November 2007 to reflect estimate by WGI.

[16] (D2) = Secondary dominant control. The addition of PRB fuel scenarios creates parallel least cost envelopes as illustrated in Figure 4-2. Secondary dominant controls represent the alternative incremental scenario, incorporating additional fuel switching controls.

[17] The annual emission reduction shown for LNB/OFA represents 'normal' annual operation and excludes instances of Unit 10 downtime. Future emission rates may vary from historical as discussed.

To reflect PRB fuel and associated NOx controls, a 'Dominant 2 (D2)' scenario has been added to differentiate between incremental costs associated with Lignite reductions.

Based on the BART final rule and other similar regulatory programs like CAIR and BACT, cost-effective NOx controls are in the range of $300 to $1,300 per ton removed as illustrated in Appendix B. EPA presumptive NOx limits were set based on average cost effectiveness of less than $1300/ton. Accordingly, fuel switching, SNCR alone or in combination with LNB/OFA, SCR with reheat, and LTO can arguably be eliminated from BART consideration on the basis of cost effectiveness. All of these technologies represent capital investments that are not justified on a cost per ton or incremental cost basis. In addition to cost effective arguments, the incremental deciview reductions associated with the various controls further support OFA/LNB for either Lignite or PRB as BART. Please refer to Section 7 for more discussion on projected deciview improvements.

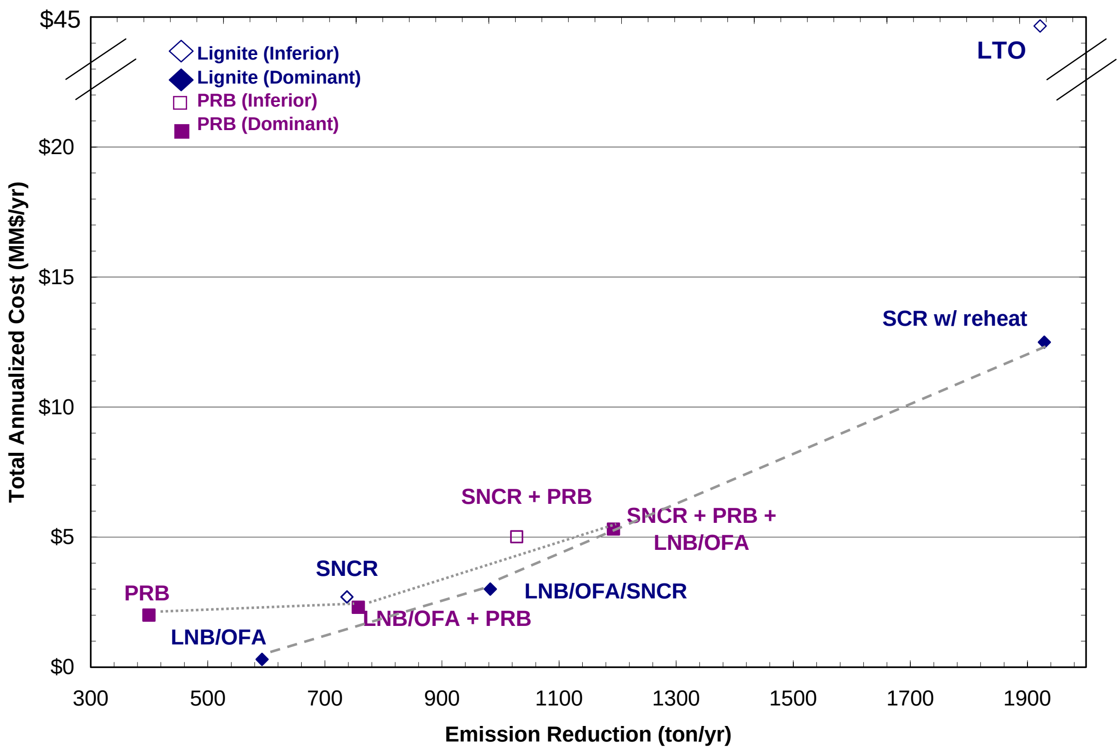

Figure 4-2 Incremental NOx Analysis The remaining feasible technologies are illustrated on the basis of annualized emission reduction in tons per year and total annualized cost in millions of dollars per year. Dominant and inferior controls are represented by darkened or empty diamonds, respectively; secondary dominant controls (PRB scenarios) are shown with darkened or empty squares.

4.4.2 Energy and Environmental Impacts

The energy and non-air quality environmental impacts for OFA/LNB options, SNCR, SCR, and LTO are described in Table 4-5.

Table 4-5 NOx Control Technology Impacts Assessment

Control Option	Energy Impacts	Other Impacts
LTO	- The blower, circulation pump ozone generation and wastewater discharge require additional electrical usage.	- Waste water generated by LTO technologies requires bio-treatment. - Stanton site is limited for additional wastewater controls.
SCR with Reheat	- The reheat required to make SCR technically feasible will result in high energy use and associated costs.	- Reheat would require additional natural gas use, which is not currently available and would require installation of a natural gas line. - Ammonia slip concerns, which contributes to regional haze. - Additional safety and regulatory concerns associated with ammonia storage on site.
SNCR (or SNCR with OFA/LNB)	- Minimal additional energy impacts.	- Ammonia slip concerns, which contributes to regional haze. - Additional safety and regulatory concerns associated with ammonia storage on site. - Variably operating conditions caused by unit swinging will necessitate extensive O&M requirements.[18] - Loss of fly ash re-use. - Potential for an increase in CO emissions as described in Section 2.1 and 2.2 of Appendix D. Any CO increase may require permitting actions and approval from NDDH.
OFA/LNB	- Minimal energy impacts.	- Potential for an increase in CO emissions as described in Section 2.1 of Appendix D. Any CO emissions increase may require permitting actions and approval from NDDH. - Potential for tube wastage.

[18] Unit 1 load swings will cause reagent control problems with SNCR or LNB/OFA/SNCR option leading to ammonium sulfate formation and potential corrosion and plugging issues. Since the SNCR technology is not justified economically, these impacts were not more thoroughly assessed, but would be significant. Some estimates predict quarterly outages of 2-3 days to clean fouled air heater. If incorporated into the economic analysis, it would further increase costs beyond EPA's average cost effective levels.

4.5 Proposed BART for NOx

It is important to precede the control determination with an understanding that Stanton Station Unit 1 is a non-presumptive unit at <200MW. As such, economies of scale for pollution control costs are not realized and emission reductions provide relatively less regional visibility improvements. All factors must be weighed in making the BART control determination.

Based on the above analysis, and the visibility impacts found in Section 7.0, GRE establishes OFA with additional LNB adjustments as BART for NOx reduction at Stanton's Unit 1. From a top down analysis, SCR can be ruled out on $/ton basis as not cost effective. The SNCR/OFA/LNB option can be ruled out on several points including economic arguments ($/ton and incremental $/ton cost effectiveness higher than BART presumptive ranges), several qualitative 'Energy and Environmental Impacts' and most significantly, relatively insignificant incremental visibility improvement over LNB/OFA. The OFA/LNB option represents the most cost effective retrofit technology for further controlling NOx emissions from Stanton Station Unit 1.[19]

The proposed BART emissions limit for Unit 1 is 0.35 lb/MMBtu on a 30-day rolling average. This limit will allow the station to maintain compliance while accommodating Unit 1 swinging as a result of MISO requirements as well as to use currently permitted fuels. GRE will use its existing continuous emissions monitoring systems (CEMS) to demonstrate compliance with the proposed BART limit.

BART NOx Emission Limit

Pollutant	Permit Limit	BART Limit
NOx	0.46 lb/MMBtu	0.35 lb/MMBtu

[19] It is worth noting that EPA established presumptive NOx emission rates for >750MW units based upon combustion controls including OFA and LNB. Other than cyclone units, EPA did not require post combustion controls for BART compliance for these presumptive units. Many preliminary BART analyses, as well as state efforts including the Colorado BART SIP, are finding that OFA/LNB are BART and that post combustion controls are not warranted given cost effectiveness considerations in conjunction with incremental deciview analyses.

5.0 Sulfur Dioxide (SO_2) BART Analysis

5.1 SO_2 Control Options

Stanton Station is permitted for either Lignite or PRB coal. Accordingly, the analysis must consider SO_2 control options with respect to different sulfur contents associated with permitted fuels. There is a detailed discussion in Appendix E regarding the expected sulfur range for PRB and Lignite. Since the current coal contract for PRB expires in late 2009, there are a range of sulfur contents that must be incorporated into the BART limit. Table 5-1 lists the available SO_2 control options for Stanton Unit 1.

Table 5-1 Available SO_2 Control Technologies

SO_2 Control Options
Pre-Combustion Controls
Flue Gas Desulfurization
Dry Sorbent Injection
Spray Dry Absorber
Wet Lime/Limestone Absorber
Novel Control: TurboSorp®

5.2 Eliminate Infeasible SO_2 Control Options

The pollutant SO_2 is formed when sulfur present in fuels is oxidized by either process conditions or by combustion. Pre-combustion controls utilize methods for improving the physical or chemical properties of the fuel before it is combusted. Existing methods for post-combustion SO_2 control can be categorized as either dry or wet flue gas desulfurization (FGD).

5.2.1 Pre-Combustion Controls

Several options exist for the beneficiation of coal. Coal impurities can be reduced through pretreatment options such as coal washing and coal drying. No information could be located in support of the effectiveness of washing Lignite coal. Coal drying is being explored at GRE's Coal Creek Station as a potentially viable option for Lignite fired boilers. In this process, raw coal is crushed and screened to remove rocks and other impurities, such as pyretic sulfur. The crushed coal is then thermally processed to remove excess moisture. It is currently under development as a commercial scale, demonstration at the GRE's Coal Creek Station. Contingent upon the success of this demonstration, it may be evaluated at a later time for Stanton to provide more operational flexibility for SO_2 control. Since it has not been demonstrated commercially at full scale, coal drying will not be further evaluated in this report.

It is worth adding that different boilers have different sulfur removal rates based on the characteristics of the mined coal. The amount of sulfur removed in the boiler at any one time may change. And yet, sulfur removed in the boiler is sulfur being removed from the flue gas stream and not being emitted to the environment.

Reducing the amount of sulfur present in the fuel is another pre-combustion control for SO_2 reductions. It can be achieved by switching to a lower sulfur containing coal. Unit 1 is currently permitted to burn both Lignite and PRB coals. Although Unit 1 could theoretically coal blend as an element of post-BART operational flexibility for added SO_2 control, Stanton Station intends to burn either Lignite or PRB on a long term basis.[20]

5.2.2 Flue Gas Desulfurization (FGD)

The FGD systems commonly used to control SO_2 emissions can be classified as either wet or dry systems. Both systems rely on creating turbulence in the gas stream to increase contact with the absorbing medium. Wet systems are commonly capable of achieving higher removal efficiencies than dry systems because it is easier to mix a gas with a liquid than a solid. FGD requires the use of an alkali slurry powder. Lime (or limestone) is the most widely used compound for acid gas absorption. Sodium based reagents are also available, and while they provide better SO_2 solubility, they are significantly more expensive. Reagent addition at greater than stoichiometric rates is required for dry systems and can improve removal efficiencies in wet systems.

Wet FGD systems may discard all of the waste by-product streams or regenerate and reuse them. Wet systems generally require more extensive networks of pumps and piping than dry systems to recirculate, collect and treat the scrubbing liquid. As implied by the name, dry scrubbers require less water than wet systems but also require higher temperatures to ensure that all moisture has been evaporated before leaving the scrubber. There are many available FGD systems including wet scrubbing, spray dryer absorption, and dry sorbent injection.

Wet Lime/Limestone Scrubbing

Wet lime/limestone scrubbing involves scrubbing the exhaust gas stream with a slurry comprised of lime (CaO) or limestone ($CaCO_3$) in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. The SO_2 in the gas stream reacts with the lime or limestone slurry to form calcium sulfite ($CaSO_3 \bullet 2H_2O$) and calcium sulfate (CaSO4). As applied to Unit 1, wet scrubbing is capable of achieving approximately 95% control. In addition to 100% wet scrubbing scenario, a 10% flue gas bypass of the scrubber will be evaluated below. Both scenarios of wet scrubbing are technically feasible as BART for Unit 1 on either fuel.

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[20] For testing or fuel switching, it is possible that a secondary fuel may be brought on site for a short period. In discussions with NDDH, it was proposed that for a limited time, the alternative fuel and associated limit would apply on a daily basis for the purpose of calculating towards a 30-day rolling BART limit. As an example, if Stanton switches back to Lignite or wishes to test dried Lignite, the Lignite limit would apply to each 24 hour period in which Lignite was the primary fuel.

Spray Dry Absorption and Baghouse

Spray dry absorption is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO_2 is absorbed by the droplets. The absorption of the SO_2 leads to the formation of calcium sulfite ($CaSO_3 \bullet 2H_2O$) and calcium sulfate ($CaSO_4$) within the droplets. The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder, which is carried out with the gas and collected with a fabric filter baghouse. Spray dryer absorption control efficiency is typically in the 70% to 90% range. A spray dry scrubber is technically feasible as BART for Unit 1 on either fuel.

Dry Sorbent Injection (DSI)

Dry sorbent injection involves the injection of a lime or limestone powder into the exhaust gas stream. The stream is then passed through a baghouse or ESP to remove the sorbent and entrained SO_2. The process was developed as a lower cost FGD option because the mixing occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time and gas stream temperature, sorbent injection control efficiency is typically between 50% and 70%. In combination with the existing ESP, DSI is only expected to achieve about 35% removal or less. For Unit 1 on Lignite, the existing ESP could not handle the additional particulate loading without a corresponding increase in particulate emissions. Therefore, it is ‘technically’ feasible, but is not viable as a retrofit due to an increase in PM emissions for Lignite. If the DSI is accompanied with a new baghouse, removal is expected to be 55% for Lignite. On the other hand, given PRB’s lower sulfur content, DSI provides additional cost effective reductions that make it both feasible and viable. ESP performance testing would need to occur in advance of the BART regulatory deadline to confirm ESP control effectiveness as well as to confirm that any increase in PM is within regulatory limits. DSI is therefore technically feasible as BART for Unit 1 on either fuel.

Novel Multi-Pollutant Control: TurboSorp®

TurboSorp® is a dry FGD technology in which the flue gas is pushed through an open chamber reactor. The flue gas enters the reactor through a nozzle with venturi geometry for optimum distribution of gas flow. The fluidized bed of particles circulates above the venturi inlet inside the vessel and water is injected to maintain outlet temperatures in the range of 45ºF to 55ºF above saturation temperature. Recycled particles from the baghouse along with hydrated lime are injected at this location to control outlet SO_2. The stream is then passed through a fabric filter or ESP to remove large particulate before discharge through the stack.

A booster fan would be required at the outlet to control the gas flow rate. The system would also require installation of a hydrator or pug mill to facilitate the lime hydration process. Test plants are currently operating in Europe and the United

States. Though not considered technically feasible due to its lack of commercial availability at this time, TurboSorp® may be considered in future control technology assessments as GRE evaluates BART implementation.

Additional novel controls including ECO and the Pahlman process for NOx and SO_2 are included in Section 4.2.3 for NOx Controls.

5.3 Evaluate the Effectiveness of Feasible SO_2 Options

Table 5-2 describes the expected emissions from each of the remaining feasible control options. Estimated emission rates are based on the control technology's expected reduction, which is then applied to annual emission rates from 2000-2004. (For more information, please refer to the cost analysis spreadsheets in Appendix A.) It is important to note that actual control efficiency will differ from these calculated values based upon the installed control technology's actual performance and the specific fuel characteristics at that time.

Further, these values differ from the emission rates that are used for modeling visibility impact, which are representative of the emission rates that are consistently achievable over any 30-day period. Caution should be used when attempting to derive short term emission rates from calculated annual emission reductions based on general control design values. Finally, this analysis is based only on the sulfur content of the PRB currently used. When Stanton Station's PRB contract expires in 2009, there will no longer be a low sulfur guarantee on the PRB. As presented in Appendix E, there are a range of realistic PRB sulfur contents.

Table 5-2 Control Effectiveness of Technically Feasible SO_2 Control Options

Control Technology	Expected Control Efficiency	Controlled Emissions[21] (lb/MMBtu)	Controlled Emissions (ton/year)
Absorber (Wet Scrubber)	95%	0.091	438.4
Spray Dry Baghouse + PRB	92%[21]	0.150	724.8
Spray Dry Baghouse	90%	0.181	876.9
DSI Baghouse + PRB	86%	0.248	1,195.9
Absorber 10% Bypass	86%	0.263	1,271.4
DSI Existing ESP + PRB	80%	0.358	1,727.4
Fuel Switch to PRB	70%	0.550	2,657.5
DSI Baghouse	55%	0.817	3,945.9
DSI Existing ESP	35%	1.180	5,699.6

5.4 Evaluate the Impacts of Feasible SO_2 Options

The economic and environmental/non-air quality impacts of the remaining controls are illustrated below.

5.4.1 Economic Impacts

Table 5-3 details the expected costs associated with each technology based on pre-BART historical baseline emissions, the EPA cost model and site specific information. The detailed cost analysis for each technology is provided in Appendix A. Based on the BART final rule, EPA set the SO_2 presumptive level for units >750MW based upon an average cost effectiveness of $919 per ton as illustrated in Appendix B.

[21] Controlled emission reductions are projected from pre-BART baseline and historical Lignite operating conditions. Future Lignite could potentially include higher sulfur coal than the baseline. Therefore 24-hour max and 30-day rolling emission will be higher.

Table 5-3 SO_2 Control Cost Summary

Control Technology	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)	Incremental Control Cost ($/ton)
Absorber (Wet Scrubber)	$88.16	$13.18	$1,617	$4,484
Spray Dry Baghouse + PRB	$79.51	$13.31	$1,692	$8,083 (D2)
Spray Dry Baghouse	$77.84	$11.22	$1,454	$4,385
DSI Baghouse + PRB	$57.20	$10.43	$1,411	Inferior
Absorber 10% Bypass	$65.64	$9.49	$1,296	$1,420
DSI Existing ESP + PRB	$11.52	$5.20	$758	$3,444 (D2)
Fuel Switch to PRB	$0.00	$2.00	$337	NA- Base PRB (D2) [22]
DSI Baghouse	$57.20	$8.43	$1,814	Inferior
DSI Existing ESP	$11.52	$3.20	$1,105	NA-Base

The incremental control costs listed in Table 5-3 represent the incremental value of each technology as compared to the technology with the next highest level of control. Control technologies listed as "inferior" do not represent cost effective options in comparison to the dominant control technologies on an incremental dollar per ton basis. In this analysis, dominant controls are located on the least cost envelope, as illustrated graphically in Figure 5-1.

Figure 5-1 shows two dominant curves depending on fuel. To cover the expected range of PRB sulfur contents discussed in Appendix E, the 92% calculated PRB SO_2 Scenario is used to establish the PRB dominant curve. We did not include a PRB Absorber Scenario for both qualitative and quantitative reasons. Qualitatively, Stanton Station Unit 10 already has a spray dry baghouse, which generally supports selection of this control technology for Unit 1 on lignite due to operator knowledge of the control systems as well as potential ability to share existing systems, such as ash and lime handling. Wet scrubbing has several qualitative limitations listed in Table 5-4 Other Impacts. Quantitatively, wet scrubbing with lignite did not represent a significant visibility improvement over dry scrubbing that when combined with cost per ton and incremental cost per ton analyses generally supports dry scrubbing as BART on lignite.

[22] (D2) = Secondary dominant control. The addition of PRB fuel scenarios creates parallel least cost envelopes as illustrated in Figure 5-1. Secondary dominant controls represent the alternative incremental scenario, incorporating additional fuel switching controls.

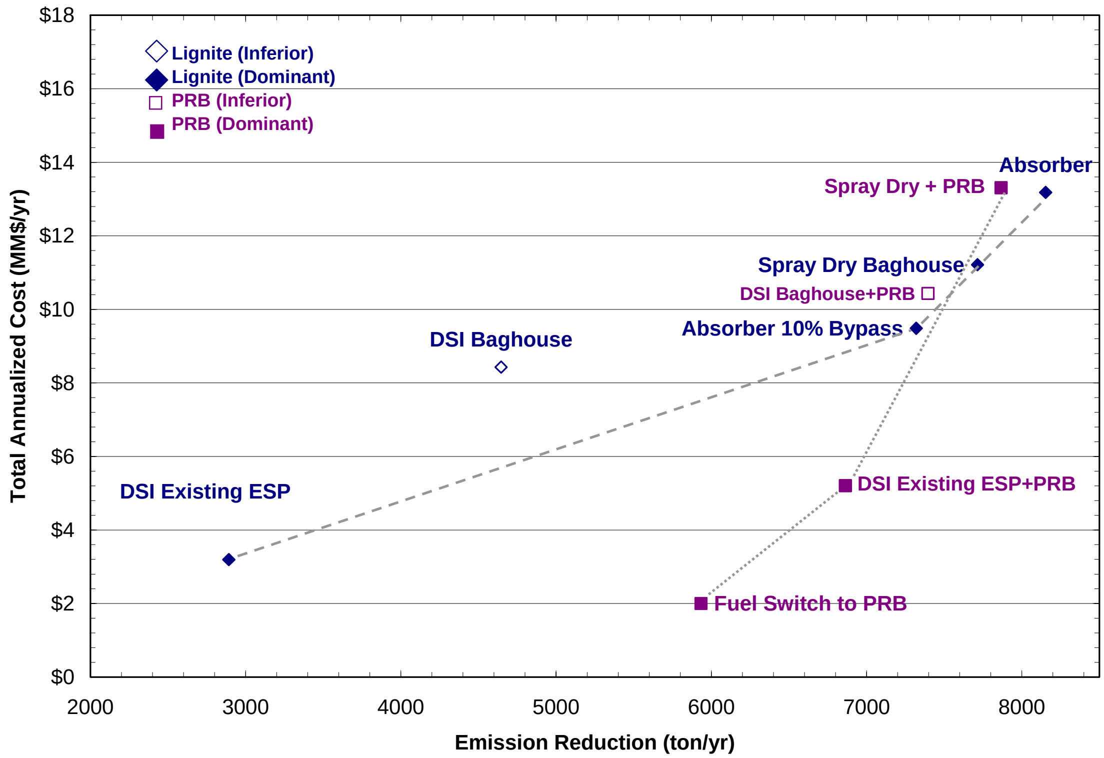

Figure 5-1 Incremental SO_2 Analysis The remaining feasible technologies are illustrated on the basis of annualized emission reduction in tons per year and total annualized cost in millions of dollars per year. Dominant and inferior controls are represented by darkened or empty diamonds respectively. Secondary dominant controls (PRB scenarios) are presented as darkened or empty squares.

The DSI baghouse scenarios can be eliminated because they represent inferior controls on an incremental cost basis. All of these technologies represent significant capital investments that are not strictly justified on a cost per ton or incremental cost basis. Most importantly, for final BART determinations, one must evaluate visibility improvements for the various scenarios as discussed in Section 7.0.

5.4.2 Energy and Environmental Impacts

The energy and non-air quality impacts for absorber wet and dry scrubbing options are presented in Table 5-4. No significant environmental impacts are associated with a fuel switch to PRB.

Table 5-4 SO_2 Control Technology Impacts Analysis

Control Option	Energy Impacts	Other Impacts
Wet Scrubbing (0% and 10% bypass)	- Blower requires increased energy use.	- Ponding for scrubber discharge will be limited because of site space constraints. The space that could potentially be used for wet scrubber ponding was formerly an ash pond[23]. Due to geologic instabilities and proximity to river, the ash had to be removed. - Extensive process downtime for installation, requiring replacement power. - Loss of fly ash re-use. EPA Coal Combustion Products Action Plan prefers dry over wet scrubbers. - Wet stack modifications required. - Due to space constraints, the existing storage warehouse must be relocated. - Additional water consumption and wastewater generation. - Waste water discharge will increase mercury loading in the Missouri River.
DSI with Existing ESP	- An ESP upgrade would require additional energy use.	- For Lignite, sorbent injection would result in increase particulate loading, resulting in higher PM emissions. The existing ESP would need to be upgraded to comply with existing PM limits. - Increased particulate loading rules out the possibility of using carbon injection for future mercury control. - For PRB, performance testing with DSI and/or carbon for mercury would need to occur to ensure compliance with PM limit. It is assumed that an ESP upgrade would not be needed for DSI.
DSI Baghouse	- Blower requires increased energy use.	- Requires process downtime and replacement power during installation. - Due to space constraints, the existing storage warehouse must be relocated.
Spray Dry Baghouse	- Blower requires increased energy use.	- Requires process downtime and replacement power during installation. - Due to space constraints, the existing storage warehouse must be relocated.

[23] See plot plan in Appendix G.

5.5 Proposed BART for SO_2

It is important to precede the control determination with an understanding that Stanton Station Unit 1 is a non-presumptive unit at <200MW. As such, economies of scale for pollution control costs are not realized and emission reductions provide relatively less regional visibility improvements. All factors must be weighed in making the BART control determination.

From a top down analysis, the wet scrubber on either fuel can arguably be eliminated based on dollar per ton and incremental dollar per ton assessments as well as more qualitative Energy and Environmental Impacts as discussed. This determination is further supported by the incremental dV analysis in Section 7.

The next option is dry scrubber and baghouse technology. For lignite, the cost per ton and incremental cost per ton are well above the EPA average cost effective values. Since the spray dry baghouse is modeled to provide perceptible dV reductions on lignite, Great River Energy has agreed to install a spray dry baghouse for lignite. This determination is further supported by the concerns, as discussed, associated with the next level of control as DSI and ESP on lignite.

Because of PRB's relatively lower sulfur content as compared to lignite, both the dollar per ton and incremental dollar per ton cost effectiveness are higher than comparable lignite control scenarios. More importantly, the lower sulfur PRB provides significant dV reductions unscrubbed. Therefore, scrubbed PRB offers relatively less dV improvements than scrubbed lignite fuels. Given careful consideration of the BART requirements, a spray dry baghouse for PRB can arguably be ruled out on both cost per ton and incremental cost per ton effectiveness. This is supported by the incremental dV analyses in Section 7.

The next PRB control option is DSI using the existing ESP. It is the most effective control option based both on cost per ton and incremental cost per ton. Since it is consistent with EPA's average cost effectiveness threshold, it is considered BART for PRB. This determination is further supported by the incremental dV analyses in Section 7.

In order to encompass future operating scenarios, maintain fuel flexibility and ensure SO_2 emission reductions, GRE is therefore proposing a split permit limit reflective of the BART control determinations associated with each fuel. For Lignite, based on installation of a spray dry baghouse, the BART emission is 0.24 lb/MMBtu on a 30-day rolling average period. This value is derived from maximum sulfur concentrations, illustrated in Appendix E, as found in North Dakota Lignite. For PRB, based on installation of DSI with existing ESP, the BART emission limit is 0.36 lb/mmbtu on a 30-day rolling average basis.

BART SO_2 Emission Limits

Pollutant	Permit Limit	BART Limit
SO_2 Lignite	3.0 lb/MMBtu	0.24 lb/MMBtu
SO_2 PRB	3.0 lb/MMBtu	0.36 lb/MMBtu[24]

GRE will use its existing continuous emissions monitoring systems (CEMS) to demonstrate compliance with the proposed lb/MMBtu BART limit.

[24] Please refer to the Executive Summary section entitled Additional Considerations.

6.0 Condensable Particulate Matter (CPM) BART Analysis

Based on EPA's interpretation that 'total particulate' includes condensable particulate matter (CPM) and at NDDH's request, GRE provides an estimate of CPM from Stanton Station's Unit 1. It is important to note that ND utilities are not required to test for CPM. They are only required to test for particulate using Methods 5 or 17, depending on plant permit requirements. Stanton's Title V permit for Unit 1 includes a particulate limit and compliance is demonstrated based on a correlation curve with opacity that was developed using EPA Method 17.

Since GRE does not have stack test data for CPM, a literature review was conducted to estimate CPM emissions based on a correlation to tested filterable values. Unfortunately, there is wide variability in CPM emissions when correlated to filterable emissions, regardless of the methodology selected. Some of the variability it associated with Method 202 and sulfate interference. Since CPM exists in several forms such as ammonia salts and sulfur containing particles, Method 202 cannot compensate for sulfate levels, and consequently overestimates CPM emissions. AP-42 is another methodology that provides a linear relationship between sulfur content and CPM emissions, which is arguably inaccurate, especially at higher sulfur concentrations. Nevertheless, for the purpose of this BART analysis, CPM emissions are approximated and assessed according to BART requirements.

6.1 Identify CPM Control Options

It is generally accepted that CPM is largely formed by ammonia salts and sulfur containing particles. In the absence of ammonia from NO_X controls, no ammonium salts are expected in Unit 1 indicating that the majority of CPM is in the form of sulfuric acid mist (SAM). In general, the inorganic portion of CPM far exceeds the organic portion and is composed primarily of sulfates, which emanate from SO_2. Sulfuric acid mist is formed from sulfur trioxide (SO_3) reacting with water in exhaust streams. SO_3 (and SO_2) is formed when sulfur present in the coal is oxidized by either process conditions or by combustion. Accordingly, the majority of control options for CPM are the SO_2 control technologies described previously in Section 5.0 and listed in Table 6-1 below.

Table 6-1 Available CPM Control Technologies.

CPM Control Options
Wet Electrostatic Precipitator
Dry Sorbent Injection
Spray Dry Absorber
Wet Lime/Limestone Absorber

6.2 Eliminate Infeasible CPM Control Options

Wet Electrostatic Precipitator

In applications where a wet electrostatic precipitator (WESP) is used for particulate removal, it may also be used for SAM removal. A WESP uses a water spray to remove particulate matter from the ESP collection plates. For SAM removal, caustic is added to the water spray system, allowing the spray system to function as an SAM absorber. As indicated in Section 3.0, WESP control is a technically feasible but economically infeasible control option. CPM emissions do not significantly change the economic analysis. As such, WESP is economically infeasible for CPM control. If added to the particulate analysis in Section 3, CPM emissions do not significantly change the economic impacts. No additional PM controls are necessary.

Dry Sorbent Injection (DSI)

Dry sorbent (pulverized lime or limestone) is directly injected into the duct upstream of the fabric filter. SAM reacts with sorbent and the solid particles are collected with a fabric filter. This process was developed as a lower cost option to conventional spray dry absorption (SDA) technology. DSI is technically feasible for controlling CPM. However, as indicated in Section 5.0, DSI represents a lower degree of control than will be achieved by the proposed SO_2 BART controls for Stanton Station.

Spray Dry Absorption

Spray dryer absorption is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the pollutants (SO_2 and SAM) are absorbed by the droplets. The absorption of the SO_2 and SAM leads to the formation of calcium sulfite ($CaSO_3 \bullet 2H_2O$) and calcium sulfate ($CaSO_4$) within the droplets. The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder, which is carried out with the gas and collected with a fabric filter. Dry scrubbing is the proposed SO_2 BART control technology for Stanton Station Unit 1. It is technically feasible for controlling CPM and is expected to provide a corresponding decrease in SAM as the primary component of CPM.

Wet Lime/Limestone Scrubbing

Wet lime/limestone scrubbing involves scrubbing flue gas stream with a slurry comprised of lime (CaO) or limestone ($CaCO_3$) in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. The SO_2 and SAM in the gas stream reacts with the lime or limestone slurry to form calcium sulfite ($CaSO_3 \bullet 2H_2O$) and calcium sulfate ($CaSO_4$). Based on the visibility impacts presented in Section 7.0 and the economic and environmental impacts presented in Section 5.4, wet scrubbing is eliminated as a BART control option.

6.3 Evaluate the Effectiveness of Feasible CPM Options

A number of methods exist with which to estimate CPM emissions. However, consistent and accurate CPM estimates vary widely due in large part to the uncertainties currently associated with CPM emissions measurements as presented below.

EPA's AP-42 emission factor uses a linear relationship between CPM and the sulfur content of coal. Historical coal sulfur contents have ranged from 0.40% to 1.56% for Stanton Station with an average of 1.30%. There are two issues relevant to the uncertainty associated with using AP-42 emission factors: how well they represent the results of Method 202 measurements and the known artifacts in the inorganic portion of Method 202. (Namely, condensable sulfates are formed in the aqueous measurement process that would not otherwise form CPM in the atmosphere. These sulfates are generally termed "pseudo particulates" and their formation results in inflated CPM values when using Method 202[25].)

Five tests from coal-burning boilers in various locations provide some indication of the relationship between Method 202 measurements and AP-42 calculations. These sites all used wall fired boilers and pulverized coal and were equipped with a particulate control (ESP or fabric filter) but had no NO_X or SO_2 controls.

In the AP-42 calculations, CPM varies linearly with sulfur content. However, Method 202 measurements do not yield such a linear relationship. This suggests that the AP-42 correlation with coal sulfur is not appropriate. There is not sufficient data to assess if CPM measurements corrected for pseudo particulates would have a linear relationship with coal sulfur content. At higher sulfur contents, AP-42 calculations appear to overestimate CPM compared to Method 202, which already overestimates CPM. For very low sulfur content coal Method 202 may provide the more conservative estimate.

Since GRE does not have Method 202 test data from its boilers, CPM emissions are estimated by using a ratio of 4:1 for CPM to filterable PM (Method 5) based on the literature data presented in both Figure 6-1 and Table 6-2 below. The bar graph and table below summarizes the sulfur content, Method 202 CPM and AP-42 CPM, as well as the ratio of condensable to filterable PM using these two techniques from these five sites. The tests give a range of condensable to filterable PM ratios of 1.44-6.69 using Method 202, with an average ratio of 3.61.

[25] A comparison of Method 202 with a modified version to correct for pseudo particulates was performed at the Xcel Energy (previously Northern States Power) Black Dog Station, which at the time of the test fired pulverized coal at 0.25% sulfur content with wall-fired burners. The boilers were equipped with electrostatic precipitators for particulate control, but did not have ammonia-based NOX controls or SO2 controls. The comparison was accomplished by measuring CPM with standard Method 5 and Method 202 techniques and then repeating the measurements using a cold filter in the Method 5 train to simulate conditions for formation of CPM in the atmosphere. At Method 5 temperatures, sulfate based CPM can pass through the collection filter. A cold filter will capture these sulfate and sulfuric acid particulates so that any sulfate measured in the impingers of Method 202 may be considered pseudo particulates. This comparison indicates as much as an 83% overestimation of CPM using Method 202.

Table 6-2 Filterable and Condensable PM Comparison[26,27].

Source	Average Coal Sulfur Content	AP-42 CPM (lb/MMBtu)	Method (M) 202 CPM (lb/MMBtu)	Ratio of Condensable (M 202) to Filterable, (M 5) PM	Ratio of Condensable (AP-42) to Filterable, (M 5) PM
Logan Generating Company, L.P. Cogen Facility	1.13	0.083	0.0208	4.56	18.20
PSE & G - Mercer Station Unit 1	0.75	0.045	0.0373	3.00	3.61
PSE & G- Mercer Station Unit 2	0.75	0.045	0.0563	6.69	5.34
Deseret Generation and Trans. Coop.- Bonanza Power Plant	0.47	0.017	0.0096	1.44	2.55
Xcel Energy Black Dog Station	0.25	0.01	0.0437	2.36	0.54
Xcel Energy Black Dog Station – corrected for pseudo particulates (Modified M 202)	*0.25*	*0.01*	*0.0076*	*0.41*	*0.05*
Average Ratio CPM: Filterable				**3.61**	**6.05**

As described above, the existing methodologies for approximating CPM emissions all have their limitations. The Electric Power Research Institute (EPRI) is currently working with the EPA to revise Method 202 in an effort to produce more accurate CPM emission estimates. For the sole purpose of approximating CPM from its Lignite-fired boilers for this BART analysis, GRE has chosen to multiply its filterable particulate matter (PM), as determined using EPA Method 5 test data, by a factor of 4. This ratio is based on literature data comparing the results of CPM measured by EPA Method 202[28] to filterable particulates as measured by EPA Method 5. It is also reflective of recent BACT permit limits[29], which show a range of CPM ratios from roughly 2 to 4 times the corresponding PM limit. Accordingly, the proposed CPM emission factor will conservatively estimate CPM emissions for the purposes of this BART evaluation.

As shown in Figure 6-1, a modified Method 202 can correct for pseudo-particulates. It is shown that Method 202 alone can overestimate CPM by as much as 83%, on a relatively low sulfur coal.

[26] "In Stack Condensible Particulate Matter Measurements and Issues" by Louis A. Corio and John Sherwell in the Journal of Air & Waste Management Association: 50:207-218.
[27] “Measurement of Condensible Particulate Matter: A Review of Alternatives to EPA Method 202, EPRI, Palo Alto, CA: 1998. Report TR-111327.
[28] CPM may be directly measured using EPA Method 202, or it may be estimated using EPA’s AP-42 emissions factor document. Method 202 measures the amount of particulates that condense in water-filled impingers in the “back half” of a Method 5 stack sampling system.
[29] CPM information sources for CFB boiler emission limit determinations. Email from Tom Bachman <tbachman@nd.gov> of NDDH, 15 June 2006.

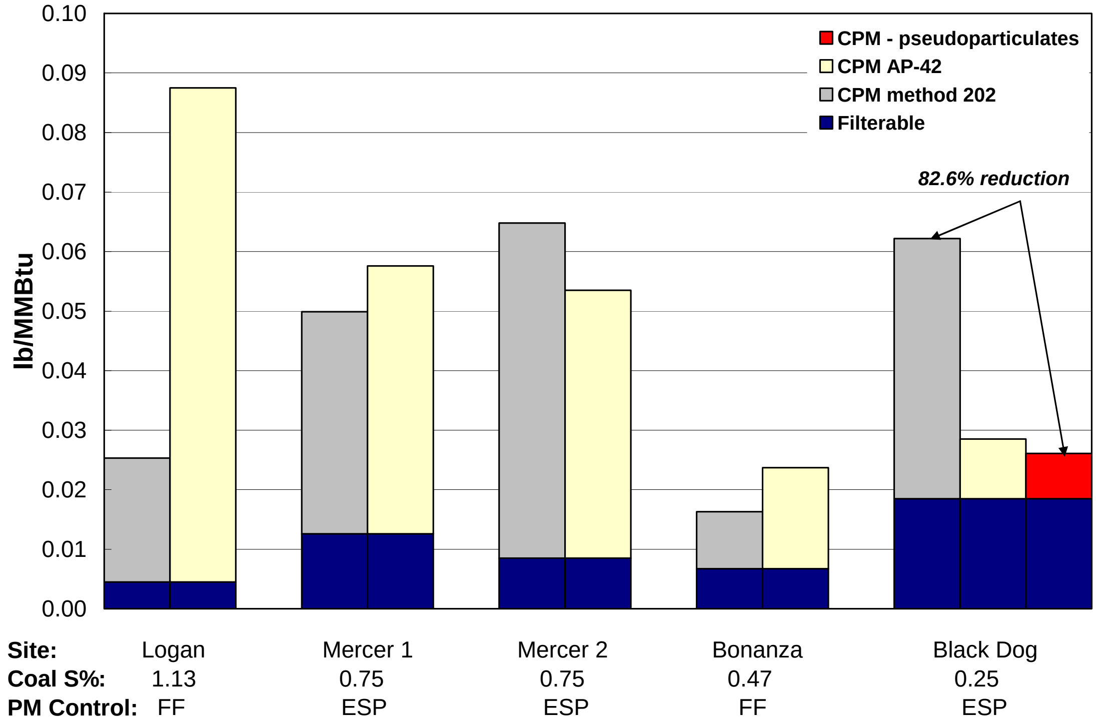

Figure 6-1. Comparison of Method 202 and AP-42. Breakdown of particulate matter is illustrated for 5 power plants[30,31].

Table 6-3 provides CPM estimates using Method 202 and also attempts to correct for pseudo-particulate.

Table 6-3 Annual CPM Emissions Estimate Based on Method 202 Approximation

Unit 1 Method 5 Result (lb/MMBtu)	PM (filterable) Emissions	CPM w/ pseudo-particulates (lb/MMBtu)	CPM w/o pseudo-particulate (lb/MMBtu)	CPM w/ pseudo-particulates (ton/yr)	CPM w/o pseudo-particulate (ton/yr)
0.02	97.3 tpy[32]	0.08	0.014	389.2	67.7

[30] "In Stack Condensible Particulate Matter Measurements and Issues" by Louis A. Corio and John Sherwell in the Journal of Air & Waste Management Association: 50:207-218.
[31] "Measurement of Condensible Particulate Matter: A Review of Alternatives to EPA Method 202, EPRI, Palo Alto, CA: 1998. Report TR-111327.
[32] Annual emissions are based on past actual operations for Stanton Station Unit 1. 7,947 annual operating hours with a utilization rate of 68%. (0.02 lb/MMBtu x 1224 MMBtu/hr x 7947 hr/yr/2000 = 97.27 tpy)

6.4 Evaluate the Impacts of Feasible CPM Options

Baseline SO_2 emissions for Unit 1 are calculated to be 8,592 tons per year. As illustrated in Table 6-3, CPM emissions are estimated at approximately 389.2 tons per year, or only 4.5% of the SO_2 emissions. If corrected for pseudo-particulates, CPM emissions may be as low as 67.7 tons per year, or only 0.8% of the SO_2 emissions. Detailed economic and environmental impacts for the available SO_2 control technologies have been presented in Section 5.4. With either the corrected or uncorrected value, the incorporation of CPM emissions will not significantly change the SO_2 economic evaluation. Further, as discussed in Section 3 and as modeled in Section 7, existing PM controls at the permit limit of 0.1 lb/MMBtu are considered BART. With an uncorrected CPM emission rate (0.08 lb/MMBtu) estimated at 4 times filterable PM (0.02 lb/MMBtu), Unit 1 is still conservatively operating below the filterable emission rate (0.1 lb/MMBtu), which has been modeled and contributes a maximum 0.02 Δ-dV to regional haze (see Section 7.5). Therefore, comparable to the SO_2 determination, CPM emissions do not significantly change the PM determination in Section 3.

6.5 CPM Visibility Impacts

As illustrated in Section 3.5, visibility impairment due to particulate matter is negligible in comparison to the contributions attributed to sulfates and nitrates. For Stanton Station, the modeled comparison of the current Method 5 PM results (0.02 lb/MMBtu) and the existing PM permit limit (0.1 lb/MMBtu) yielded an additional visibility impairment of only 0.02 Δ-dV on the 98^{th} percentile for the fivefold increase in emissions. As stated above, it is assumed that total particulate emissions (uncorrected condensable + filterable) will be 5 times the filterable contribution, or in this case, slightly less than 0.1 lb/MMBtu, given the uncertainties with the methodologies. Consequently, the total visibility impairment attributed to uncorrected CPM is estimated to be less than 0.02 Δ-dV. These results indicate that total particulate emissions (uncorrected condensable + filterable) will have a negligible influence on overall visibility impacts. Therefore, even if CPM emissions are as high 4 times filterable PM, the modeled visibility impairment would not be significant and additional SO_2 and PM controls are not economically justifiable.

6.6 Proposed BART for CPM

GRE has reviewed, summarized and discussed the limitations of various methodologies for estimating CPM emissions. GRE proposes no additional control for CPM as supported by the visibility analysis in Section 6.5. It is recognized that proposed BART SO_2 controls will reduce CPM, or specifically sulfuric acid mist (SAM) as the major component of CPM, by as much as 90% with a dry scrubber technology, or a slightly lower amount with PRB dry sorbent injection. .

7.0 Visibility Impacts Analysis

The degree of visibility improvement is arguably the most critical component of the BART determination process. As indicated in EPA's final BART guidance[33], states are required to consider the degree of visibility improvement resulting from the retrofit technologies in combination with other factors, such as economic, energy and other non-air quality, when determining BART for an individual source. By incorporating visibility improvements, the BART analysis is distinctly different than a traditional Best Available Control Technology (BACT) analysis, which relies more heavily on cost considerations.

The CALPUFF program models how a pollutant contributes to visibility impairment with consideration for the background atmospheric ammonia, ozone and meteorological data. Additionally, the interactions between the visibility impairing pollutants NOx, SO_2 and PM_{10} can play a large part in predicting impairment. It is therefore important to take a multi-pollutant approach when assessing visibility impacts.

7.1 Assessing Visibility Impairment

The CALPUFF program models how a pollutant contributes to visibility impairment with consideration for the background atmospheric ammonia, ozone and meteorological data. Additionally, the interactions between the visibility impairing pollutants NOx, SO_2 and PM_{10} can play a large part in predicting impairment. It is therefore important to take a multi-pollutant approach when assessing visibility impacts.

The visibility impairment contribution for different emission rate scenarios can be determined using the CALMET, CALPUFF, POSTUTIL, and CALBART modeling templates provided by the North Dakota Department of Health (NDDH). The North Dakota BART modeling protocol[34] describes the CALPUFF model inputs including the meteorological data set and background atmospheric ammonia and ozone concentrations along with the functions of the POSTUTIL and CALBART post processing elements. The CALBART output files provide three methods with which to assess the expected post-BART visibility improvement: the 98th percentile, 90th percentile, and the number of days on which a source exceeds an impairment threshold.

As defined by federal guidance and Section 33-15-25-01 of the North Dakota Air Pollution Control Rules, [35] a source "contributes to visibility impairment" if the 98th percentile of any year's modeling results meets or exceeds the threshold of five-tenths of a deciview (dV) at a Federally protected Class I area receptor. The pre-BART evaluation of this criterion conducted by the North Dakota Department of Health identified Stanton Station Unit 1 as subject to BART[36] because it 'causes or contributes' to visibility impairment at the four North Dakota Class I areas.

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[33] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Rules and Regulations p. 39106.
[34] *Protocol for BART-Related Visibility Modeling Analyses in North Dakota*, Final Version, November, 2005.
[35] Chapter 33-15-25 is a new rule on public notice through May 15, 2006.
[36] Subject to BART notification from NDDH is included in Appendix C.

In addition to establishing whether or not a source contributes to impairment on the 98^{th} percentile, the severity of the visibility impairment contribution, or reasonably attributed visibility impairment, can be gauged by assessing the number of days on which a source exceeds 0.5 Δ-dV.

As a worst case, pre-BART modeling of Stanton Station indicated a maximum of 29 days above 0.5 Δ-dV occurred at TRNP South Unit in 2002. There were fewer days above 0.5 Δ-dV for 2000 and 2001. Finally, the determination of reasonable progress along the predicted glide path can be assessed using the 90^{th} percentile prediction.

7.2 Predicting 24-Hour Maximum Emission Rates

Pursuant to verbal guidance from NDDH staff and consistent with use of the highest daily emissions for pre-BART visibility impacts, the post-BART emissions to be used for the visibility impacts analysis should reflect a maximum 24-hour average projected emission rate. The projected 24-hour maximum emission rate was estimated for each control technology considered in this analysis. These predictions were based on a 30-day expected emission rate for each technology, taking into consideration some potential for operational and fuel-based variability for that technology.[37] Table 7-1 and Table 7-2 provide a summary of the modeled 24-hour emission rates and their computational basis for the evaluated NOx and SO_2 control technologies, respectively.[38] For modeling simplification, other stack parameters such as exit temperature and velocity, height, elevation and diameter were not changed and can be found in the protocol[39].

As discussed in Section 4.0, NOx emission rates are highly dependent on Unit 1 load swings due to MISO demands, which can result in a wide range of lb/MMBtu emission rates. For this reason, the 24-hour maximum NOx emissions are presented as lb/hr rates, which is consistent with visibility modeling inputs. Although the 24-hour maximum emission rate for the proposed BART of LNB with OFA shows negligible improvement from pre-BART on either fuel, LNB/OFA will provide more significant reductions with respect to 30-day and annual time periods.

Table 7-1 NOx Predicted 24-hour Maximum Emission Rates

[37] Since the PRB scenario was added after completion of modeling, Barr developed a correlation curve based on existing modeling and used it to extrapolate PRB dV improvements. This information is included in Appendix C.

[38] As noted in the Executive Summary, under Additional Considerations and Associated Potential Reductions, Great River Energy is committing to either installation of a dry scrubbing technology with baghouse or converting Unit 1 to a clean coal technology, such as IGCC. For determining appropriate 24-hr modeling values, it is therefore appropriate to use the lignite SO_2 emission rates in Table 7-2 as worse case. The NOx values are essentially the same between lignite and PRB in Table 7-1. For Particulate, a value of 0.07 lb/mmbtu can be used consistent with worse case fuel assumptions and installation of a baghouse as noted in the Executive Summary.

[39] *Protocol for BART-Related Visibility Modeling Analyses in North Dakota*, Final Version, November, 2005.

Control Strategy	30-day Rolling Emission Rate	24-hour Max. Emission Rate	Basis[40]
Pre-BART Baseline	--	669 lb/hr	Actual emissions data from 2000 – 2002. Represents the highest NOx emission rate per calendar day.
LNB/OFA	633.6 lb/hr	665.3 lb/hr	20% design control efficiency and 5% variability.
SNCR	574.2 lb/hr	631.6 lb/hr	27.5% design control efficiency and 10% variability.
LNB/OFA + SNCR	435.6 lb/hr	479.2 lb/hr	45% design control efficiency and 10% variability.
Low-Dust SCR	79.2 lb/hr	87.1 lb/hr	90% design control efficiency and 10% variability.

With respect to projected maximum SO_2 emission rates, it is important to recall that Stanton Station is currently permitted for both lignite and PRB. Since the current PRB fuel contract expires in 2009, there are a range of possible sulfur contents for either lignite or PRB that must be considered. As discussed in Appendix E, SO_2 maximum emission rates are based on a projected worst case fuel, which is lignite comparable to Milton R. Young. (It is lignite that is located on the same side of Missouri River as Stanton Station and is the closest operating lignite mine.) Past SO_2 emissions from MRY Unit 1 and historical Stanton Station data were used to establish 1.56% as the worst case coal sulfur content. Emission rates were then calculated in Table 7-2 using the expected control efficiencies and AP-42 conversion factor. Please refer to Appendix E for more specific information on projected sulfur values associated with lignite and PRB fuels.

[40] Design rates are based on normal operating conditions and are subject to the conditions described in the Alstom engineering assessment (Appendix D).

Table 7-2 SO_2 Predicted 24-hour Maximum Emission Rates

Control Strategy	30-day Rolling Emission Rate	Control Efficiency	24-hour Maximum Emission Rate	Basis
Pre-BART Baseline	--	--	3,418.0 lb/hr 1.90 lb/MMBtu	Actual emissions data from 2000 – 2002. Represents the highest SO_2 emission rate per calendar day.
Wet Scrubber	216.0 lb/hr 0.12 lb/MMBtu	95%	263.3 lb/hr 0.15 lb/MMBtu	Projected Lignite Values [41]
Spray Dry Baghouse	432.0 lb/hr 0.24 lb/MMBtu	90%	526.5 lb/hr 0.29 lb/MMBtu	Projected Lignite Values [40]
DSI Baghouse	1,944.0 lb/hr 1.08 lb/MMBtu	55%	2,369.3 lb/hr 1.32 lb/MMBtu	Projected Lignite Values [40]
DSI and ESP w/PRB	0.36 lb/MMBtu	80%	778 lb/hr 0.43 lb/MMBtu	Projected PRB Values[42]
Fuel Switch to PRB	0.55 lb/MMBtu	70%	0.66 lb/MMBtu	Projected PRB Values[41]

SO_2 emission rate is based on the control efficiency with 0% variability and the average maximum coal sulfur content for Stanton Unit 1 and Milton R. Young Unit 2 as determined by past coal data or EDR[43] emission calculations.

7.3 Modeled Results

Visibility impairment is modeled using the meteorological data for the years 2000, 2001 and 2002 for the scenarios described below. In addition to the 15 combinations of SO_2 and NOx controls, results for the baseline pre-BART emissions and for the post-BART PM control visibility contribution scenarios, which were presented in Section 3.5, are also included. Results for the 90th, 98th and number of days above 0.5 dV at

[41] Values are derived from maximum sulfur concentrations as found in North Dakota Lignite reserves as could be expected over any 30-day rolling period and are different than the predictions based on past actual operations presented in Section 5.0.
[42] See Appendix E for more information.
[43] Historical (1998 through 2004) Lignite emissions inventories for Stanton Station show a maximum coal sulfur content of 1.55% and EDRs for Milton R. Young Station years 2004 and 2005 show a maximum coal sulfur content of 1.57%. (EDRs available at http://www.epa.gov/airmarkets/emissions/raw/index.html.) See also Appendix E.

each of the Class I areas are included in Table 7-4 through Table 7-6. Additionally, Figure 7-1 illustrates scenarios 1 through 15 on a dollar per dV basis. The figure focuses on year 2002 modeling results because it is the year that showed the most severe pre-BART visibility impairment.

Table 7-3 Visibility Modeling Parameters

Scenario	Description [1]		Emission Rate Input [2]							
			PM_{10}		$PM_{2.5}$ (fine)	PM (coarse)	SO_2		NOx	
	SO_2	NOx	% reduction	lb/hr	lb/hr	lb/hr	% reduction	lb/hr	% reduction	lb/hr
0 pre-BART	Base case	Base Case - LNB	0%	31.8	1.9	29.9	0%	3,418.0	0%	669.0
1	Dry Scrubber	Base Case - LNB	0%	31.8	1.9	29.9	85%	526.5	0%	669.0
2 Proposed BART	Dry Scrubber	LNB/OFA	0%	31.8	1.9	29.9	85%	526.5	1%	665.3
3	Dry Scrubber	SNCR	0%	31.8	1.9	29.9	85%	526.5	6%	631.6
4	Dry Scrubber	LNB/OFA + SNCR	0%	31.8	1.9	29.9	85%	526.5	28%	479.2
5	Dry Scrubber	SCR	0%	31.8	1.9	29.9	85%	526.5	87%	87.1
6	DSI BH	Base Case - LNB	0%	31.8	1.9	29.9	31%	2,369.3	0%	669.0
7	DSI BH	LNB/OFA	0%	31.8	1.9	29.9	31%	2,369.3	1%	665.3
8	DSI BH	SNCR	0%	31.8	1.9	29.9	31%	2,369.3	6%	631.6
9	DSI BH	LNB/OFA + SNCR	0%	31.8	1.9	29.9	31%	2,369.3	28%	479.2
10	DSI BH	SCR	0%	31.8	1.9	29.9	31%	2,369.3	87%	87.1
11	Wet Scrubber	Base Case - LNB	0%	31.8	1.9	29.9	92%	263.3	0%	669.0
12	Wet Scrubber	LNB/OFA	0%	31.8	1.9	29.9	92%	263.3	1%	665.3
13	Wet Scrubber	SNCR	0%	31.8	1.9	29.9	92%	263.3	6%	631.6
14	Wet Scrubber	LNB/OFA + SNCR	0%	31.8	1.9	29.9	92%	263.3	28%	479.2
15	Wet Scrubber	SCR	0%	31.8	1.9	29.9	92%	263.3	87%	87.1
16 [3]	PRB	PRB	0%	31.8	1.9	29.9	70%	1,188.0	17%	648.0
17 [3]	PRB	LNB/OFA + PRB	0%	31.8	1.9	29.9	70%	1,188.0	34%	514.8
18 [3]	DSI/ESP + PRB	LNB/OFA + PRB	0%	31.8	1.9	29.9	80%	774.0	34%	514.8
19 [3]	DSI BH + PRB	LNB/OFA + PRB	0%	31.8	1.9	29.9	86%	446.4	34%	514.8
20 [3]	Dry Scrubber + PRB	LNB/OFA + PRB	0%	31.8	1.9	29.9	92%	270.0	34%	514.8
21	Scenario 2 + Best PM Controls		15%	27.0	1.6	25.4	85%	526.5	1%	665.3
22	Scenario 2 + Permit Limit PM		-466%	180.0	10.8	169.2	85%	526.5	1%	665.3

[1] All scenarios except 16 and 17 have the existing ESP as particulate control.
[2] Percent reduction as compared to pre-BART base case (Scenario 0). SO_2 % reduction represents the modeled emission rates comparison and do not directly indicate the design control efficiencies. Emission rates were determined using the maximum expected coal sulfur content (Appendix E) and the design control efficiencies.
[3] Scenarios 16 through 20 added to reflect PRB fuel use. Updated scenarios were not modeled formally, but visibility impacts were estimated using the correlation provided in Appendix C.

Table 7-4 Model Results for the Year 2000

				Visibility Impairment											
	Description [1]			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
Scenario	SO_2	NOx	Average Improv-ement [2]	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
0 pre-BART	Base case	Base Case - LNB	0%	17	0.228	0.937	17	0.221	0.947	10	0.184	0.868	23	0.344	0.991
1	Dry Scrubber	Base Case - LNB	68%	3	0.066	0.320	4	0.080	0.458	2	0.054	0.224	4	0.118	0.340
2 Proposed BART	Dry Scrubber	LNB/OFA	68%	3	0.066	0.318	4	0.080	0.456	2	0.054	0.224	4	0.117	0.338
3	Dry Scrubber	SNCR	69%	3	0.065	0.305	4	0.077	0.438	2	0.054	0.222	4	0.113	0.323
4	Dry Scrubber	LNB/OFA + SNCR	73%	2	0.055	0.253	4	0.065	0.356	2	0.049	0.215	3	0.096	0.260
5	Dry Scrubber	SCR	85%	1	0.035	0.144	1	0.034	0.144	1	0.028	0.131	1	0.052	0.154
6	DSI BH	Base Case - LNB	24%	12	0.174	0.691	12	0.171	0.770	8	0.139	0.696	13	0.262	0.755
7	DSI BH	LNB/OFA	24%	12	0.174	0.690	12	0.171	0.769	8	0.139	0.694	13	0.261	0.754
8	DSI BH	SNCR	25%	12	0.173	0.679	12	0.165	0.752	8	0.137	0.680	13	0.256	0.744
9	DSI BH	LNB/OFA + SNCR	29%	12	0.162	0.663	11	0.157	0.672	8	0.130	0.614	12	0.240	0.701
10	DSI BH	SCR	43%	9	0.137	0.553	8	0.122	0.557	6	0.106	0.445	11	0.191	0.591
11	Wet Scrubber	Base Case - LNB	75%	2	0.048	0.290	4	0.062	0.369	2	0.040	0.183	3	0.094	0.320
12	Wet Scrubber	LNB/OFA	75%	2	0.048	0.289	4	0.062	0.368	2	0.040	0.182	3	0.094	0.318
13	Wet Scrubber	SNCR	77%	2	0.046	0.277	4	0.059	0.354	2	0.038	0.174	2	0.090	0.303
14	Wet Scrubber	LNB/OFA + SNCR	80%	2	0.039	0.221	3	0.048	0.292	2	0.033	0.135	2	0.074	0.236
15	Wet Scrubber	SCR	91%	0	0.020	0.079	0	0.021	0.097	0	0.017	0.086	0	0.034	0.090
16-20 [3]	Scenarios not directly modeled, see Appendix C for calculation and correlation data.														
21	Scenario 2 + Best PM Controls		68%	3	0.066	0.318	4	0.080	0.455	2	0.054	0.223	1	0.117	0.338
22	Scenario 2 + Permit Limit PM		67%	3	0.071	0.326	4	0.081	0.466	3	0.055	0.236	4	0.122	0.349

[1] All scenarios except 16 and 17 have the existing ESP as particulate control.
[2] Average improvement represents the 90th percentile comparison to the base case (Scenario 0) averaged for the 4 Class 1 areas.
[3] Scenarios 16 through 20 added to reflect PRB fuel use. Updated scenarios were not modeled formally, but visibility impacts were estimated using the correlation provided in Appendix C.

Table 7-5 Model Results for the Year 2001

Scenario	Description [1]		Average Improv-ement [2]	Visibility Impairment											
				TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
	SO_2	NOx		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
0 pre-BART	Base case	Base Case - LNB	0%	17	0.214	0.901	21	0.319	1.205	13	0.144	0.733	30	0.386	1.351
1	Dry Scrubber	Base Case - LNB	69%	4	0.061	0.322	5	0.089	0.385	2	0.036	0.241	8	0.160	0.526
2 Proposed BART	Dry Scrubber	LNB/OFA	69%	4	0.061	0.321	5	0.089	0.383	2	0.036	0.240	8	0.159	0.524
3	Dry Scrubber	SNCR	70%	4	0.059	0.313	5	0.086	0.369	2	0.036	0.234	8	0.153	0.506
4	Dry Scrubber	LNB/OFA + SNCR	73%	1	0.054	0.261	4	0.073	0.318	1	0.034	0.203	7	0.133	0.422
5	Dry Scrubber	SCR	85%	0	0.032	0.141	1	0.049	0.190	0	0.022	0.115	2	0.059	0.210
6	DSI BH	Base Case - LNB	24%	13	0.160	0.715	17	0.245	0.937	10	0.105	0.541	27	0.311	1.062
7	DSI BH	LNB/OFA	24%	13	0.160	0.714	17	0.245	0.936	10	0.105	0.541	27	0.311	1.060
8	DSI BH	SNCR	25%	12	0.158	0.701	17	0.241	0.915	10	0.103	0.535	27	0.306	1.042
9	DSI BH	LNB/OFA + SNCR	30%	12	0.149	0.641	16	0.222	0.854	9	0.101	0.515	24	0.272	0.963
10	DSI BH	SCR	41%	8	0.124	0.544	12	0.201	0.733	6	0.086	0.439	20	0.213	0.821
11	Wet Scrubber	Base Case - LNB	77%	2	0.043	0.270	5	0.061	0.334	1	0.024	0.178	7	0.139	0.449
12	Wet Scrubber	LNB/OFA	77%	2	0.043	0.269	5	0.061	0.333	1	0.023	0.177	7	0.138	0.447
13	Wet Scrubber	SNCR	78%	1	0.041	0.257	5	0.059	0.319	1	0.023	0.169	7	0.132	0.429
14	Wet Scrubber	LNB/OFA + SNCR	81%	1	0.036	0.203	1	0.053	0.255	0	0.021	0.143	6	0.106	0.344
15	Wet Scrubber	SCR	91%	0	0.019	0.091	0	0.029	0.110	0	0.012	0.063	1	0.039	0.129
16-20 [3]	Scenarios not directly modeled, see Appendix C for calculation and correlation data.														
21	Scenario 2 + Best PM Controls		69%	4	0.061	0.321	5	0.088	0.383	2	0.036	0.240	8	0.159	0.524
22	Scenario 2 + Permit Limit PM		68%	4	0.062	0.323	5	0.093	0.389	2	0.036	0.242	8	0.166	0.531

[1] All scenarios except 16 and 17 have the existing ESP as particulate control.
[2] Average improvement represents the 90th percentile comparison to the base case (Scenario 0) averaged for the 4 Class 1 areas.
[3] Scenarios 16 through 20 added to reflect PRB fuel use. Updated scenarios were not modeled formally, but visibility impacts were estimated using the correlation provided in Appendix C.

Table 7-6 Model Results for the Year 2002

Scenario	Description [1]		Average Improv-ement [2]	Visibility Impairment											
				TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
	SO_2	NOx		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
0 pre-BART	Base case	Base Case - LNB	0%	29	0.310	1.675	23	0.312	1.540	14	0.233	1.432	25	0.308	1.150
1	Dry Scrubber	Base Case - LNB	69%	13	0.096	0.668	12	0.097	0.595	8	0.074	0.517	5	0.088	0.410
2 Proposed BART	Dry Scrubber	LNB/OFA	70%	13	0.095	0.666	11	0.096	0.593	8	0.074	0.515	5	0.088	0.408
3	Dry Scrubber	SNCR	71%	13	0.092	0.648	9	0.094	0.569	7	0.071	0.499	5	0.085	0.395
4	Dry Scrubber	LNB/OFA + SNCR	75%	8	0.080	0.565	6	0.083	0.460	6	0.060	0.426	4	0.073	0.334
5	Dry Scrubber	SCR	85%	3	0.047	0.270	1	0.047	0.241	2	0.035	0.232	0	0.048	0.183
6	DSI BH	Base Case - LNB	22%	22	0.243	1.293	21	0.239	1.221	13	0.191	1.111	19	0.236	0.886
7	DSI BH	LNB/OFA	22%	22	0.243	1.291	21	0.239	1.220	13	0.191	1.109	19	0.235	0.885
8	DSI BH	SNCR	22%	22	0.242	1.272	21	0.235	1.208	13	0.191	1.095	19	0.230	0.872
9	DSI BH	LNB/OFA + SNCR	29%	21	0.220	1.196	20	0.219	1.104	13	0.165	1.028	19	0.218	0.813
10	DSI BH	SCR	43%	18	0.186	0.957	18	0.183	0.780	12	0.125	0.782	15	0.168	0.685
11	Wet Scrubber	Base Case - LNB	75%	10	0.089	0.556	9	0.072	0.516	6	0.050	0.429	4	0.078	0.341
12	Wet Scrubber	LNB/OFA	76%	10	0.088	0.553	8	0.071	0.514	6	0.050	0.427	4	0.077	0.339
13	Wet Scrubber	SNCR	77%	9	0.084	0.528	7	0.069	0.490	6	0.047	0.411	4	0.074	0.326
14	Wet Scrubber	LNB/OFA + SNCR	80%	5	0.066	0.422	5	0.059	0.392	2	0.045	0.337	3	0.059	0.264
15	Wet Scrubber	SCR	91%	0	0.029	0.159	1	0.030	0.160	0	0.023	0.140	0	0.028	0.107
16-20 [3]	Scenarios not directly modeled, see Appendix C for calculation and correlation data.														
21	Scenario 2 + Best PM Controls		70%	13	0.095	0.665	11	0.096	0.592	8	0.074	0.515	5	0.088	0.408
22	Scenario 2 + Permit Limit PM		68%	14	0.101	0.686	12	0.097	0.611	8	0.075	0.525	5	0.093	0.411

[1] All scenarios except 16 and 17 have the existing ESP as particulate control.
[2] Average improvement represents the 90^{th} percentile comparison to the base case (Scenario 0) averaged for the 4 Class 1 areas.
[3] Scenarios 16 through 20 added to reflect PRB fuel use. Updated scenarios were not modeled formally, but visibility impacts were estimated using the correlation provided in Appendix C.

Table 7-7 Dollar per Deciview Scenario Descriptions

Scenario	SO_2	NOx	Average Calculated Visibility Improvement (dV)[44]
1	Dry Scrubber	Base Case	N/A, See modeling Tables 7-3 through 7-6
2	Dry Scrubber	LNB/OFA	
3	Dry Scrubber	SNCR	
4	Dry Scrubber	OFA + SNCR	
5	Dry Scrubber	SCR	
6	DSI BH	Base Case	
7	DSI BH	LNB/OFA	
8	DSI BH	SNCR	
9	DSI BH	OFA + SNCR	
10	DSI BH	SCR	
11	Wet Scrubber	Base Case	
12	Wet Scrubber	LNB/OFA	
13	Wet Scrubber	SNCR	
14	Wet Scrubber	OFA + SNCR	
15	Wet Scrubber	SCR	
16	PRB	PRB	0.759
17	PRB	LNB/OFA + PRB	0.836
18	DSI/ESP + PRB	LNB/OFA + PRB	0.946
19	DSI BH + PRB	LNB/OFA + PRB	1.009
20	Dry Scrubber + PRB	LNB/OFA + PRB	1.065

As illustrated by the dollar per deciview analysis in Figure 7-1, there are a range of potential BART control combinations and associated visibility improvements. It is important to note that the range of potential deciview improvements spans from a low of 0.3 dV to a maximum of 1.3 dV. With respect to determining the cost effectiveness of the various scenarios, the annualized cost for each scenario was plotted against the average visibility improvement in Figure 7-1. There are two curves representing control options for Lignite and PRB. The inherently lower sulfur PRB causes the curve to shift significantly to the right, providing more deciview reductions for comparable control costs.

[44] See addendum to Appendix C on modeling correlation based on previously modeled scenarios.

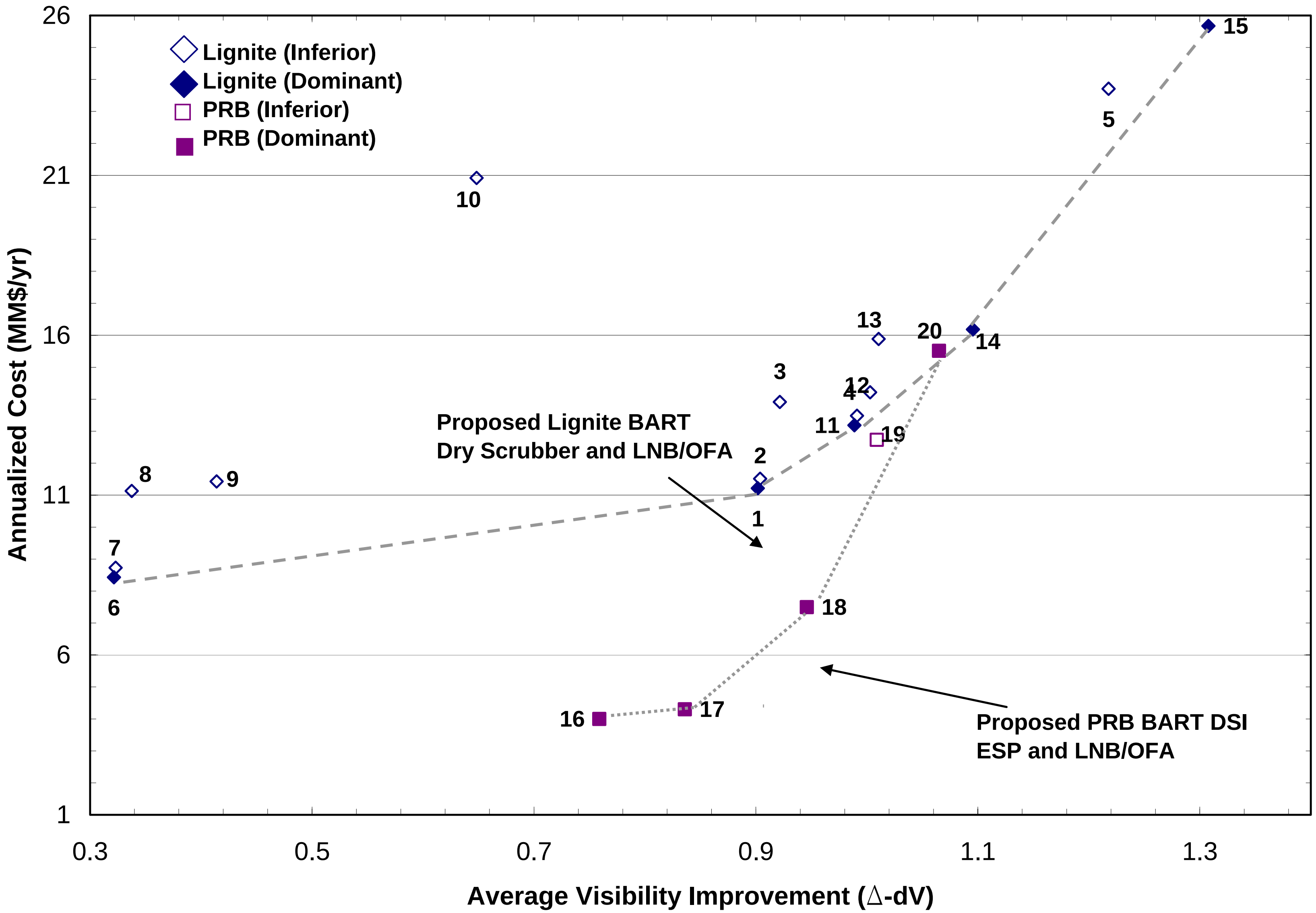

Figure 7-1 Dollar per Deciview Analysis. Scenarios 1 through 15 are plotted for the 98th percentile of 2002 based on the total annualized cost and the average visibility improvement for the 4 Class 1 areas. Dominant controls are presented as filled diamonds and inferior controls are represented as empty diamonds and secondary dominant controls (PRB scenarios) are represented with filled or empty squares. See Table 7-7 for additional scenario description.

The first cluster of Scenarios 6, 7, 8 and 9 represent roughly 0.3 to 0.4 dV improvement from the baseline. Scenario 6 represents the most cost effective Scenario in this cluster and is the start of the least cost envelope curve. The next scenario cluster occurs at an average visibility improvement of 0.9 to 1.0 dV. This second cluster includes Scenario 1, and 2 as part of the least cost envelope curve.

The slope of the least cost envelope increases significantly after Scenario 2. The SNCR addition (Scenarios 4 and 14) causes the curve to rise sharply, which is a graphical representation of the relative significance of additional costs combined with limited dV improvements. After Scenario 2, the graph demonstrates that for an additional 0.1 to 0.2 dV improvement, there will be annualized cost increase from $12.4MM to $15.1MM annualized cost.

Finally, Scenario 2 OFA/LNB did not provide significant modeled deciview improvements from Scenario 1 LNB, which would generally support Scenario 1 as BART from a strictly visibility perspective. Nevertheless, Great River Energy recognizes that the Scenario 2 OFA/LNB will provide 30-day and annual NOx reduction benefits that are supportive of visibility improvements even though the 24-hr modeled effects are not readily apparent.

For the secondary curve based upon PRB control scenarios 16-20, the curve demonstrates that PRB unscrubbed Scenarios 16 and 17 provides approximately the same absolute dV improvement as the Lignite Scenario 2 determined to be BART. The secondary curve climbs to DSI and ESP as the next control. Since it was viewed as cost effective based on dollar per ton and incremental dollar per ton assessments, it is established as BART for PRB. Scenario 20 only provides an additional ~0.1 dV improvement. Therefore, from a visibility perspective in conjunction with cost effectiveness arguments, it is not considered BART on PRB. Since Scenario 2 provides a lesser dV improvement over Scenario 18, Scenario 2 will be used as a conservative basis for further discussion.

7.4 Visibility Impacts of the Proposed BART

Scenario 2 represents a significant reduction in modeled visibility impairment from the baseline in the four North Dakota Class 1 Areas. For example, on average, for the 2002 98^{th} percentile, over a 0.9 Δ-dV improvement is expected from the average baseline of 1.45 dV. Interestingly, the Scenario 2, 0.9 Δ-dV BART average reduction places Stanton Unit 1 only slightly above (at 0.55 dV) EPA's 0.5 dV 'cause or contribute' threshold, which is considered imperceptible to the human eye.

Table 7-8 provides the expected percent visibility improvement for the proposed BART Scenario 2 along with pre-BART and post-BART days above the 0.5 dV contribution threshold. With the 98th percentile correction[45], the eighth highest daily visibility impairment is less than 0.5 Δ-dV at all but one station[46] for the modeled years 2000 and 2001.

Table 7-8 Proposed BART Scenario 2 - Average Improvement Over Baseline

Year	Average Percentile Improvement		Average Days Above 0.5 Δ-dV		
	90th	98th	Pre-BART	Improvement	Post-BART
2000	68%	64%	17	14	3
2001	69%	65%	20	16	4
2002	70%	63%	23	14	9

Additional reductions associated with Scenarios 4, 14, and 15 in Table 7-6, as the worst case year, will not reduce the number of days above the contribution threshold from Scenario 2 without significant additional costs as demonstrate in Figure 7-1. The most significant incremental reductions occur in 2002 in TRNP South Unit. For these reasons, the visibility impacts analysis support Scenario 2 as BART for Stanton Station Unit 1.

[45] As stated in the modeling protocol, the 98th percentile is roughly the eighth-highest daily prediction. By this estimation, any modeled scenario with fewer than 7 days above 0.5 Δ-dV has a 98th percentile below 0.5Δ-dV.
[46] The eighth highest daily impairment for Lostwood NWA in 2001 is only 0.524 Δ-dV

8.0 Summary of Proposed BART

Based on careful consideration of all factors included in this BART analysis, Scenario 2 (Dry Scrubber/Baghouse and OFA/LNB) is considered BART for Stanton Station Unit 1. In order to arrive at this determination, one must first quantitatively assess the average and incremental cost effectiveness of individual pollutant controls as well as qualitatively assess energy and other environmental impacts. As discussed in Sections 3 thru 6, these individual pollutant assessments are then viewed in conjunction with combined control scenarios as part of the visibility assessment in Section 7 to ultimately determine BART.

With respect to particulate controls (PM), as a single pollutant, GRE will maintain the current PM performance standard of 0.1 lb/MMBtu. Section 3.0 PM analysis confirms that additional PM controls are not economically justified on a dollar per ton basis. More importantly, the modeled benefits associated with potential PM reductions are less than 0.02 dV, which is considered an insignificant deciview reduction for North Dakota's Class 1 areas. Therefore, the combined assessment of cost and insignificant deciview improvements support maintaining a PM emission limit of 0.1 lb/MMBtu.

For NOx controls, GRE establishes LNB with OFA as BART as described in Section 4.0. A low dust SCR with reheat can be ruled out on cost per ton and incremental cost effectiveness arguments. SNCR, by itself, and LTO are also arguably above the average cost effective thresholds used by EPA to set presumptive BART limits. EPA clearly did not intend for larger emission units >750MW to install post combustion NOx controls by setting presumptive emission rates consistent with LNB/OFA technologies. Large cyclone units are the only emission units required to install post combustion NOx controls. Figure 7-1 shows that LTO and SNCR without LNB/OFA, are inferior controls since they are not on the dominant curve. The combination of SNCR with OFA can be ruled out on cost per ton and incremental cost per ton along with other operational, energy, environmental impacts as noted in Table 4-4. Further, the operational limitations of SNCR (Scenarios 4 and 14), also support the selection of Scenario 2 as BART. This determination, is most importantly, supported by the visibility analysis, which demonstrates only a 0.1 Δ-dV associated with SNCR (Figure 7-1 – Scenario 2 to Scenario 4). While LNB with OFA shows little modeled improvement with respect to the 24-hour projected maximum emission rate, this control will provide approximately 20-25% reduction on a 30-day and annual basis from the baseline. Potential changes in load variability for Unit 1 as well as visibility modeling support a BART limit of 0.35 lb/MMBtu on a 30-day rolling average rather than a lb/hr limit.

For SO_2 control, GRE proposes to install a dry scrubber technology with 90% design removal efficiency and a 0.24 lb/MMBtu 30-day rolling average BART limit on lignite. Alternatively, a fuel switch to PRB coal in addition to DSI technology utilizing the existing ESP controls is considered BART and would establish a 30-day rolling limit of 0.36 lb/MMBtu.

From a top down analysis, Scenario 15 (Wet FGD & SCR) is considered above the EPA average cost effective thresholds that were used to set presumptive BART limits. More importantly, the incremental deciview improvements from Scenario 2 (Dry scrubber & SCR) are only 0.1 dV, which is viewed as insignificant. There are other qualitative non-air quality, environmental impacts and site limitations, which would preclude wet scrubber from consideration.

In continuing the top down analysis, as discussed in Sections 4 and 5, Scenario 14 (wet FGD & LNB/OFA/SNCR) can arguably be considered above the EPA average cost effective thresholds for SO2 and NOx. Further, the incremental dV improvement from Scenario 2 to Scenario 14 is <0.1dV. Therefore, the combined effective of cost per/ton, incremental cost per ton and incremental deciview improvement strongly supports Scenario 2 as BART.

Scenario 4, which includes SNCR as the only difference with Scenario 2, can be ruled out because the LNB/OFA/SNCR cost per ton reductions are outside of the cost effective range according to BART guidelines. Further, the incremental dollar per ton for SNCR is extremely high and there are other energy and environmental impacts that would preclude it from consideration. In terms of incremental visibility improvement, there would be approximately 0.1 dV improvement from Scenario 2 to Scenario 4.

Arguably, between Scenario 1 and 2, there is not much of a modeled visibility improvement. Because LNB/OFA provides monthly and annual reductions and because the technology is a cost effective retrofit, it is established as BART.

BART Emission Limits

Pollutant	Permit Limit	BART Limit
PM_{10}	0.10 lb/MMBtu	0.10 lb/MMBtu
NOx	0.46 lb/MMBtu	0.35 lb/MMBtu
SO_2 Lignite	3.0 lb/MMBtu	0.24 lb/MMBtu
SO_2 PRB	3.0 lb/MMBtu	0.36 lb/MMBtu

In combination, the Scenario 2 BART controls will provide an average visibility improvement of over 0.9 Δ-dV compared to the pre-BART baseline that will significantly contribute to the state’s effort in meeting its reasonable progress goals under the Regional Haze Rule. From a visibility standpoint, other BART control scenarios do not provide significant incremental improvements and are not justified on cost per ton and incremental cost per ton effectiveness arguments at this time.

Appendices

Appendix A. Economic Evaluations

Appendix B. Cost Threshold Documentation

Appendix C. Visibility Modeling

Appendix D. Alstom NOx Evaluation

Appendix E. Sulfur Content Statistical Analysis

Appendix F. SCR catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals

Appendix G. Stanton Station Site Plan

Appendix A

Economic Evaluations

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-1A: Cost Summary Lignite Basis

Added PRB scenario

Updated per additional cost data, November 2007

PM/PM10 Control Cost Summary

Baseline 0.019 lb/MMBtu

Case	Control Technology	Controlled Emissions lb/MMBtu	Percent Reduction % [2]	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	Polishing Wet ElectroStatic Precipitator (WESP)	0.015	20%	72.5	1	17.0	$6.90	$2.03	$119,268	D	NA-Base	A-4
2	Dry ElectroStatic Precipitator (ESP)	0.015	20%	72.5	--	17.0	$38.57	$5.80	$340,570	I	NA	A-5
3	PM Baghouse	0.015	20%	72.5	--	17.0	$33.65	$4.98	$292,702	I	NA	A-6

SO_2 Control Cost Summary

Baseline 1.815 lb/MMBtu

Case	Control Technology	Controlled Emissions lb/MMBtu	Percent Reduction % [2]	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	Absorber	0.091	95%	438.4	4	8153.1	$88.16	$13.18	$1,617	D	$4,484	A-7
2	Spray Dry Baghouse+PRB	0.150	92%	724.8	D2-3	7866.8	$79.51	$13.31	$1,692	D2	$8,083	A-8
3	Spray Dry Baghouse	0.181	90%	876.9	3	7714.7	$77.84	$11.22	$1,454	D	$4,385	A-9
4	DSI Baghouse+PRB	0.248	86%	1195.9	--	7395.7	$57.20	$10.43	$1,411	I	NA	A-10
5	Absorber 10% Bypass	0.263	86%	1271.4	2	7320.1	$65.64	$9.49	$1,296	D	$1,420	A-11
6	DSI Existing ESP+PRB	0.358	80%	1727.4	D2-2	6864.2	$11.52	$5.20	$758	D2	$3,444	A-14A
7	Fuel Switch to PRB	0.550	70%	2657.5	D2-1	5934.0	$0.00	$2.00	$337	D2	NA- Base PRB	A-12
8	DSI Baghouse	0.817	55%	3945.9	--	4645.7	$57.20	$8.43	$1,814	I	NA	A-13
9	DSI Existing ESP	1.180	35%	5699.6	1	2892.0	$11.52	$3.20	$1,105	D	NA-Base	A-14B

PRB SO_2 Scenario Comparisons

Control Technology	Emission Reduction T/yr Compared to PRB Base	Pollution Control Cost $/ton Compared to PRB Base	Annual Incremental Cost $/ton Compared to PRB Base
Spray Dry Baghouse+PRB (92%)	1932.7	$6,885	$6,100
DSI Baghouse+PRB	1461.6	$7,138	$9,841
DSI Existing ESP+PRB	930.1	$5,594	$3,444
Fuel Switch to PRB	0.0	$0	NA-Base

NO_x Control Cost Summary

Baseline 0.435 lb/MMBtu

Case	Control Technology	Controlled Emissions lb/MMBtu	Percent Reduction % [2]	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	Selective Catalytic Reduction (SCR) w/Reheat	0.044	90%	210.2	3	1928.7	$56.55	$12.49	$6,478	D	$10,036	A-15, A-16
2	Low Temperature Oxidation (LoTOx)	0.044	90%	210.2	--	1928.7	$43.88	$44.78	$23,217	I	NA	A-17
3	SNCR + PRB + Alstom LNB + OFA	0.196	55%	946.1	D2-3	1192.9	$10.67	$5.31	$4,452	D2	$6,910	A-18, A20
4	SNCR + PRB	0.230	47%	1111.3	--	1027.7	$8.41	$5.01	$4,877	I	NA	A-18
5	Alstom LNB + OFA + SNCR	0.239	45%	1156.3	2	982.7	$10.66	$3.00	$3,053	D	$6,927	A-19, A-21
6	Selective Non-Catalytic Reduction (SNCR)	0.290	33%	1401.2	--	737.7	$8.39	$2.70	$3,661	I	NA	A-19
7	Alstom LNB + OFA + PRB	0.286	34%	1381.9	D2-2	757.1	$2.27	$2.30	$3,037	D2	$836	A-20
8	Alstom LNB + OFA	0.320	26%	1546.2	1	592.8	$2.27	$0.30	$504	D	NA-Base	A-21
9	Fuel Switch to PRB	0.360	4%	1739.5	D2-1	399.5	$0.00	$2.00	$5,006	D2	NA-Base PRB	A-12

[1] Control Technology Classification- D=Dominant, D2=Secondary Dominant,I=Inferior. Only dominant costs are used to calculate incremental cost effectiveness. Secondary dominant control evaluation does not include 97% control option.

[2] Percent reduction on a lb/MMBtu basis compared to baseline.

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-1B: GRE Stanton Station Unit 1 FGD Estimates (2012$)

Table 7-1. Capital Cost Estimates for S1 FGD Systems

Capital Cost Component		**LSFO**	**2005 $**	**LSD + FF**	**2005 $**
Area 10: Reagent Feed System	$	$13,400,000	$11,122,000	$3,800,000	$3,154,000
Area 20: SO2 Removal System	$	$23,600,000	$19,588,000	$15,900,000	$13,197,000
Area 30: Flue Gas System	$	$14,200,000	$11,786,000	$18,100,000	$15,023,000
Area 40: Regeneration	$	$0	$0	$0	$0
Area 50: Byproduct Handling	$	$0	$0	$0	$0
Area 60: Solids Handling	$	$2,600,000	$2,158,000	$600,000	$498,000
Area 70: General Support Equipment	$	$1,200,000	$996,000	$1,100,000	$913,000
Area 80: Miscellaneous Equipment*	$	$13,800,000	$11,454,000	$2,000,000	$1,660,000
Fabric Filter	$	N/A		$23,200,000	$19,256,000
TOTAL	**$**	**$68,800,000**	**$57,104,000**	**$64,700,000**	**$53,701,000**
	$/kW	$370	$307	$340	$282
General Facilities	$	$6,900,000	$5,727,000	$6,500,000	$5,395,000
Engineering and Home Office Fees	$	$6,900,000	$5,727,000	$6,500,000	$5,395,000
Process Contingency	$	$1,700,000	$1,411,000	$1,600,000	$1,328,000
Project Contingency	$	$12,700,000	$10,541,000	$11,900,000	$9,877,000
Total Plant Cost (TPC)	**$**	**$97,000,000**	**$80,510,000**	**$91,000,000**	**$75,530,000**
	$/kW	$520	$432	$480	$398
Total Cash Expended (TCE)	**$**	**$94,200,000**	**$78,186,000**	**$89,300,000**	**$74,119,000**
	$/kW	$500	$415	$470	$390
Allowance for Funds (AFDC)	$	$5,100,000	$4,233,000	$4,800,000	$3,984,000
Total Plant Investment (TPI)	**$**	**$99,300,000**	**$82,419,000**	**$93,200,000**	**$77,356,000**
	$/kW	$530	$440	$500	$415
Preproduction Costs	$	$2,400,000	$1,992,000	$2,200,000	$1,826,000
Inventory Capital	$	$47,000	$39,010	$100,000	$83,000
Initial Catalyst and Chemicals	$	$0	$0	$0	$0
Prepaid Royalties	$	$340,000	$282,200	$300,000	$249,000
Total Capital Requirement (TCR)	**$**	**$102,087,000**	**$84,732,210**	**$95,800,000**	**$79,514,000**
	$/kW	$540	$448	$510	$423

*Miscellaneous equipment includes costs for power hook-ups, CEMS replacement, and warehouse demolition and relocation. The LSFO cases also include costs for installation of a new wet stack and waste water treatment plant.

Table 7-2: Operating Parameters for FGD Systems at S1

FGD System		LSFO	LSFO	LSD + FF	LSD + FF
		2012 $	2005 $	2012 $	2005 $
Operating Parameters					
Fuel	Type	PRB		PRB	
Percent Sulfur	%	0.36%		0.36%	
SO2 Removal	%	95%		95%	
NOx Removal	%	N/A		N/A	
Hg Removal	%	N/A		N/A	
SO2 Removed	tons/year	6,100		6,100	
SO2 emitted	lbs/MMBtu	0.04		0.04	
Reagent Type		Limestone		Lime	
Reagent Cost	$/ton	$47.80	$39.67	$119.40	$99
Byproduct Credit	$/ton	$0.00	$0.00	$0.00	$0
Solids Disposal Cost	$/ton	$4.80	$3.98	$4.80	$4
Consumption & Production Rates					
FGD Power Consumption	kW	2,800		1,500	
Fabric Filter Power Consumption	kW	N/A		50	
Reagent Required*	tons/yr	10,600		7,200	**
FGD Solid Waste Disposal	tons/yr	17,400		60,400	
Solid Waste Disposal Volume	yd^3/20 yrs	0			
FGD Byproduct	tons/yr	129,000		0	
Water	1000 gal/yr	0		115,000	
Methane		2,800		0	

*Assumes limestone composition of 94% $CaCO_3$ and Lime composition of 90% available CaO/10% inerts.

** The lime feed rate is based on a Ca/S inlet ratio of 1.15 moles CaO/mole of SO_2 inlet in each case. This feed rate was derived from a database available in EPRI report No. 1004706. The actual feed rate required would be provided by the process vendor based on their guarantee, use of recycle, lime quality, coal analyses, approach temperature, inlet gas temperature, etc.

Table 7-3: Fixed and Variable Operating Cost Summary for FGD Systems

FGD System		LSFO	LSFO	LSD + FF	LSD + FF
		2012 $	2005 $	2012 $	2005 $
Fixed O&M Costs			$0		$0
Number of Operators	#	8		7	
Operating Labor Cost	$/yr	$954,000	$791,820	$835,000	$693,050
Maintenance Labor and Materials Cost	$/yr	$3,620,000	$3,004,600	$2,180,000	$1,809,400
Administrative and Support Labor	$/yr	$720,000	$597,600	$512,000	$424,960
Fabric Filter First Year Fixed Cost	$/yr	$0	$0	$870,000	$722,100
TOTAL First Year Fixed O&M Cost	**$/yr**	**$5,294,000**	**$4,394,020**	**$4,047,000 ***	**$3,359,010**
Variable Operating Costs					
Reagent Costs	$/yr	$508,000	$421,640	$857,000	$711,310
Sludge Disposal Cost for FGD System	$/yr	$83,000	$68,890	$288,000	$239,040
Credit for Byproduct	$/yr	$0	$0	$0	$0
SO2 Credits (see Table 3-9 for basis)	$/yr	($1,600,000)	($1,328,000)	($1,600,000)	($1,328,000)
Steam Costs	$/yr	$0	$0	$0	$0
Water Cost - Fresh	$/yr	$0	$0	$3,000	$2,490
Water Cost - Blowdown	$/yr	$0	$0	$0	$0
Additional Power Costs	$/yr	$981,000	$814,230	$527,000	$437,410
Methane Cost	$/yr	$0	$0	$0	$0
Fabric Filter First Year Variable Cost	$/yr	$0	$0	$117,000	$97,110
TOTAL First Year Variable Cost	**$/yr**	**($28,000)**	**($23,240)**	**$15,000 ****	**$12,450**

*LSD+FF assumes that the ESPs will be taken out of service. The Total First Year Fixed O&M Costs includes a $350,000 credit for ESP O&M costs.

**LSD+FF assumes that the ESPs will be taken out of service. The Total First year variable cost includes a $177,000 credit for ESP power consumption.

Table 7-4: First-Year and Levelized Costs for FGD Systems

FGD System		LSFO	LSFO	LSD + FF	LSD + FF
Turbine Arrangement		**2012 $**	**2005 $**	**2012 $**	**2005 $**
***First-Year Costs*:**					
Fixed O&M:	$	$5,294,000	$4,394,020	$4,047,000	$3,359,010
	Mills/KWh	3.6		2.8	
	$/ton SO2 removed	$870	$722	$700	$581
Variable O&M:	$	($28,000)	($23,240)	$15,000	$12,450
	Mills/KWh	-0.02		0.01	
	$/ton SO2 removed	($10)	($8)	$2.00	$2
Fixed Charges:	$	$12,600,000	$10,458,000	$11,800,000	$9,794,000
	Mills/KWh	8.7		8.1	
	$/ton SO2 removed	$2,060	$1,710	$1,900	$1,577
Total:	**$**	**$17,866,000**	**$14,828,780**	**$15,862,000**	**$13,165,460**
	Mills/KWh	12.3		10.9	
	$/ton SO2 removed	$2,920	$2,424	$2,600	$2,158
Levelized Current Dollars:					
Fixed O&M:	Mills/KWh	4.8		3.6	
	$/ton SO2 removed	$1,100		$900	
Variable O&M:	Mills/KWh	-0.1		-0.03	
	$/ton SO2 removed	($20)		($10)	
Fixed Charges:	Mills/KWh	6.5		6.1	
	$/ton SO2 removed	$1,500		$1,400	
Total:	Mills/KWh	11.1		9.7	
	$/ton SO2 removed	$2,600		$2,300	

GRE Stanton Station Unit 1 NOx Estimates (2012$)

Table 7-9. Operating Parameters for S1 NOx Control Methods

***Operating* Parameters**		**SNCR**	**2005 $**	**Mobotec**	**2005 $**
NOx Removal	%	30%		50%	
Baseline NOx Emissions	lbs/MMBtu	0.35		0.35	
NOx Removed	tons/yr	840		1400	
NOx Emitted	lbs/MMBtu	0.25		0.18	
Reagent Type		Urea		19% Aqueous Ammonia	
Reagent Cost	$/ton	$235	$195	$175	$145
Reagent Usage	tons/yr	3,400		3,800	
Water	gpm	30		0	
Additional Power	kW	35		1240	

Table 7-10. Capital and Operating Cost Estimates for S1 NOx Control Methods

Capital Cost Component		**SNCR**	**2005 $**	**Mobotec**	**2005 $**
Total Capital Requirement (TCR)	$	$8,570,000	$7,113,100	$9,280,000	$7,702,400
	$/kW	$45.60	$38	$49.40	$41
			$0		$0
Total First Year Fixed O&M	$/yr	$129,000	$107,070	$312,000	$258,960
Variable O&M Costs			$0		$0
Reagent Cost	$/yr	$791,000	$656,530	$659,000	$546,970
Water Cost	$/yr	$290,000	$240,700	$0	$0
Additional Power Cost	$/yr	$12,000	$9,960	$440,000	$365,200
NOx Credits	$/yr	$0	$0	$0	$0
Total First Year Variable O&M	**$/yr**	**$1,093,000**	**$907,190**	**$1,100,000**	**$913,000**

First Year & Levelized Costs		**SNCR**	**2005 $**	**Mobotec**	**2005 $**
First-Year Cost:					
Fixed O&M:	$	$129,000	$107,070	$312,000	$258,960
	Mills/KWh	0.09		0.22	
	$/ton NOx removed	$150	$125	$220	$183
Variable O&M:	$	$1,090,000	$904,700	$1,100,000	$913,000
	Mills/KWh	0.75		0.76	
	$/ton NOx removed	$1,300	$1,079	$800	$664
Fixed Charges:	$	$1,050,000	$871,500	$1,140,000	$946,200
	Mills/KWh			0.79	
	$/ton NOx removed	$1,250	$1,038	$810	$672
Total First-Year Cost:	$	$2,280,000	$1,892,400	$2,550,000	$2,116,500
	Mills/KWh	1.6		1.8	
	$/ton NOx removed	$2,710	$2,249	$1,820	$1,511
Levelized Cost:			$0		$0
Fixed O&M:	Mills/KWh	0.12		0.28	
	$/ton NOx removed	$200	$166	$290	$241
Variable O&M:	Mills/KWh	0.98		0.95	
	$/ton NOx removed	$1,690	$1,403	$990	$822
Fixed Charges::	Mills/KWh	0.54		0.59	
	$/ton NOx removed	$940	$780	$610	$506
Total Levelized Cost:	Mills/KWh	1.6		1.8	
	$/ton NOx removed	$2,830	$2,349	$1,890	$1,569

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-2: Emission Inventory Data / Baseline Emission Rate for BART Control Cost Analysis

Coal Use/Properties								
	2004 EI	2004 EI	2003 EI	2002 EI	2001 EI	2000 EI	Average	Period
Coal Type	PRB [2]	Lignite	Lignite	Lignite	Lignite	Lignite	Lignite	
Use	113,459	634,265	679,593	808,083	744,341	666,577	776,212	2001-2002
%Ash	7.24	14.7	9.1	8.13	8.7	9.14	8.4	2001-2002
%S	0.31	0.65	0.64	0.66	0.72	0.64	0.69	2001-2002
Heating Value	9257	6514	6558	6551	6694	6764	6,623	2001-2002
Na in Ash	6.03	2.63	3.09	3.91	3.37	2.56	3.64	2001-2002
Op Hrs		8659	7077	8553	8479	7415	7,947	2001-2002
Heat Input		1.036E+07	8.913E+06	1.075E+07	9.965E+06	9.02E+06	1.04E+07	2001-2002
MMBtu/hr		1,197	1,259	1,257	1,175	1,216	1,196	2001-2002
% of Capacity		66.5%	70.0%	69.8%	65.3%	67.6%	67.6%	2001-2002
SO2 lb/MMbtu	[3]	1.519	1.814	1.590	1.816	1.699	1.70	2001-2002
PM lb/MMBtu	[3]	0.012	0.012	0.013	0.019	0.019	0.016	2001-2002
NOx lb/MMBtu	[3]	0.400	0.440	0.430	0.410	0.410	0.42	2001-2002

Highest 2 years on pollutant basis

Emission Inventory Unit 1 Emissions - Tons per Year					
Year	2004	2003	2002	2001	2000
PM10	62	53	70	94	85
PM	63	53	70	95	86
NOx	2,073	1,961	2,312	2,044	1,849
SO2	7,871	8,084	8,548	9,046	7,660

Uncontrolled PM Emission Rate Using AP-42 - For SW Disposal Rates				
	Total	Filterable	Condensable	
T/yr	32,844	32,659	185	
lb/Hr	8266	8219	47	
Filterable PM Emission Factor			84.2	lb/ton coal
Condensable PM Emission Factor - Lignite			0.039	lb/MMBtu

	BART Baseline Emissions [1] 2 Year Averages			
	T/yr	lb/hr	lb/MMBtu	Period
PM10	90	33.3	0.019	2000, 2001
PM	91	33.7	0.019	2000, 2001
NOx	2,139	783.2	0.44	2002, 2003
SO2	8,592	3266.5	1.81	2001, 2003

[1] SO2 and NOx lb/MMBtu is the average of the two highest years (excluding 2004 because both types of coal were used) plus one standard deviation of the years 2000-2003

[2] PRB calculations:

SO2 PRB lb/MMBtu = lb/MMBtu on Lignite * PRB % S / Lignite % S

SO2 PRB lb/hr calculated using lb/MMBtu SO2 * design duty

lb/hr = average emission rate adjusted to 100% utilization

[3] lb/MMBtu in 2004 includes PRB and Lignite

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-3: Summary of Utility, Chemical and Supply Costs

Operating Unit: Unit 1 **Study Year** 2005
Emission Unit Number NA
Stack/Vent Number NA

Item	Unit Cost	Units	Reference Cost	Year	Data Source	Notes
Operating Labor	37.00	$/hr	37.00	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Maintenance Labor	37.00	$/hr	37.00	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Electricity	0.051	$/kwh	0.049	2004	DOE Average Retail Price of Industrial Electricity, 2004	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Natural Gas	6.85	$/kscf		2005	Average natural gas spot price July 04 - June 05, Henry La Hub.,	WTRG Economics, WWW.wtrg.com/daily/small/ngspot.gig
Water	0.31	$/kgal	0.31	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Cooling Water	0.27	$kgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Adsrobers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.31	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.64	$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.15	$/kgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal	4.37	$/ton	4.00	2002	Vision 21 Report by Stone & Webster	cost adjusted for 3% inflation
Hazardous Waste Disposal	273.18	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.55	$/ton-mi	0.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
PRB Coal	2,000,000	$/yr	4,000,000	2005	GRE	Incremental cost to fire PRB Coal $5M/yr Cost - $1M/yr reduced operating cost, total of $4M/yr divided by 2, for a per pollutant basis.
Chemicals & Supplies						
Lime	90.00	$/ton		2005	GRE per Diane Stockdill 12/6/05 email	
Caustic	305.21	$/ton		2005	GRE per Diane Stockdill 12/6/05 email	
Urea	405	$/ton		2005	Hawkins Chemical	50% solution of urea in water, includes delivery
Soda Ash		$/ton				
Oxygen	15.00	kscf	15.00	2005	Get cost from Air Prod Website	
EPA Urea	179.1	$/ton				
Ammonia	0.2	$/lb			$400/ton for 30% aqueous solution.	
Nahcolite	233.52	$/ton	195.57	1999	Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999	
Catayst & Replacement Parts						
SCR Catalyst	500	$/ft^3				
CO Catalyst	650	$/ft^3				
Catalyst #3						
Catalyst #4						
Catalyst #5						
Filter Bags	160.00	$/bag	160	2005	GRE cost per Steve Smokey	
Tower Packing	100	$/ft^3				
Replacement Parts						
Replacement Parts						
Replacement Parts						
Other						
Sales Tax	0	%				
Interest Rate	5.5%	%			GRE per Diane Stockdill	
Please note, for units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal						
Operating Information						
Annual Op. Hrs	7,947	Hours				Stanton Emission Inventories
Utilization Rate	**68%**			Per 12/30 Telcon, G Archer GRE, use existing utilization rate for consistency in calculations		
Equipment Life	20	yrs				Engineering Estimate
Desgin Capacity	1,800	MMBtu/hr				
Standardized Flow Rate	**498,970**	scfm @ 32º F				
Temperature	**330**	Deg F				
Moisture Content	**13.3%**					
Actual Flow Rate	**801,500**	acfm		Lignite Vision 21, Steve Smokey verified		
Standardized Flow Rate	**535,480**	scfm @ 68º F				
Dry Std Flow Rate	**464,261**	dscfm @ 68º F				
F factor lignite	**15,475**	dscf/MMBtu			EPA Method 19	**F-Factor+O2 correction factor for 6.1% O2**
Design Basis	**Baseline Emis.**	**Baseline Emis.**	**Max Emis. (Model)**			
Pollutant	**T/yr**	**lb/MMBtu**	**lb/hr**			
PM10	89.5	0.019	31.8			Baseline-2001, 2002 Stanton Emission Inventories. Max-ND Protocol
Total Particulates	90.5	0.019	31.8			Baseline-2001, 2002 Stanton Emission Inventories. Max-ND Protocol
Nitrogen Oxides (NOx)	2,139	0.435	669.0			Baseline-2001, 2002 Stanton Emission Inventories. Max-ND Protocol
Sulfur Dioxide (SO_2)	8,592	1.815	3,418.0			Baseline-2001, 2002 Stanton Emission Inventories. Max-ND Protocol

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-4: PM Control - Wet ESP Lignite Coal

Operating Unit: **Unit 1**

						Chemical Engineering Chemical Plant Cost Index	
Emission Unit Number	NA		Stack/Vent Number	NA			
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F		
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)								
Purchased Equipment (A)						2005	3,969,555	2,042,478
Purchased Equipment Total (B)	15%	of control device cost (A)						**2,348,849**
Installation - Standard Costs	69%	of purchased equip cost (B)						1,620,706
Installation - Site Specific Costs								1,646,400
Installation Total								3,267,106
Total Direct Capital Cost, DC								3,969,555
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)						1,338,844
Total Capital Investment (TCI) = DC + IC								**6,900,919**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						974,279
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,055,930
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**2,030,210**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	27.0	0.015	72.5	17.0	119,268
Total Particulates	90.5	27.0	0.015	72.5	18.0	112,650
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1. Total Direct Capital Cost Cost Estimated using GRE cost estimate from Coal Creek, 19% as compared to dry ESP cost.
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3
3. ESP Maintenance costs Eq 3.45 EPA Cont Cost Manual Section 6 Chapter 3
4. ESP Maintenance Materials Eq 3.45 EPA Cont Cost Manual Section 6 Chapter 3
5. Used an ESP SCA grid factor of 553 ft^2/1000 acfm per GRE, D. Stockdill.
6. High control cost is due to the small additional decrease in emissions as compared to existing controls.
7. Assumed WESP size is 20% of IAPCS model calculated size for electricity and spray water use.
8. Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-4: PM Control - Wet ESP Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**2,042,478**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	204,248
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	102,124
Purchased Equipment Total (B)	15%		**2,348,849**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	93,954
Handling & erection	50%	of purchased equip cost (B)	1,174,425
Electrical	8%	of purchased equip cost (B)	187,908
Piping	3%	of purchased equip cost (B)	70,465
Insulation	2%	of purchased equip cost (B)	46,977
Painting	2%	of purchased equip cost (B)	46,977
Installation Subtotal Standard Expenses	69%		**1,620,706**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Replacement Power - One 14 day outage [8]	1,646,400
Total Site Specific Costs			1,646,400
Installation Total			**3,267,106**
Total Direct Capital Cost, DC			**3,969,555**
Indirect Capital Costs			
Engineering, supervision	20%	of purchased equip cost (B)	469,770
Construction & field expenses	20%	of purchased equip cost (B)	469,770
Contractor fees	10%	of purchased equip cost (B)	234,885
Start-up	1%	of purchased equip cost (B)	23,488
Performance test	1%	of purchased equip cost (B)	23,488
Model Studies	2%	of purchased equip cost (B)	46,977
Contingencies	3%	of purchased equip cost (B)	70,465
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)	**1,338,844**
Total Capital Investment (TCI) = DC + IC			**5,308,399**
		Retrofit TCI (TCI*1.3)	**6,900,919**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**6,900,919**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Supervisor	48%	% of Operator Costs.	17,642
Maintenance			
Maintenance Labor	443,229	ft2 grid area, 0.8 $/ft2 of grid area	365,664
Maintenance Materials	1	1% of purchased equipment cost	23,488
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,524 kW-hr, 7947 hr/yr, 68% utilization	416,996
NA	NA		-
Water	0.31	$/kgal, 160 gpm, 7947 hr/yr, 68% utilization	16,112
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 4 ton/hr, 7947 hr/yr, 68% utilization	97,621
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**974,279**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	266,130
Administration (2% total capital costs)	2%	of total capital costs (TCI)	106,168
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	53,084
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	53,084
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	577,464
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,055,930**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,030,210**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-4: PM Control - Wet ESP Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/h	OAQPS list replacement times from 5 - 20 min per bag
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower Baghouse & ESP	801,500		4.48			649.9	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.46
	Liq flow	Liquid SPGR	Δ P ft H2O	Efficiency	Hp	kW	
WESP Pump	801 gpm	1.000	40	0.5		12.1	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
WESP H2O WW Disch	160 gpm	1.000	40	0.5		2.4	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
SCA Factor	553	ft^2/1000 acfm					
ESP Grid	443,229	ft^2	1.94E-03	kW/ft^2		859.9	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.48
Total						1524.3	

Reagent Use & Other Operating Costs					
WESP Pump	160,300 acfm	5 gpm/kacfm	801 gpm		EPA Cost Cont Manual 6th ed Section 6 Chapter 3.4.1.9
WESP Water Makeup Rate/WW Disch		20% of circulating water rate =	160 gpm		

Operating Cost Calculations — **Annual hours of operation: 7,947** — **Utilization Rate: 68%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	48%	of Operator Costs.			NA	17,642	% of Operator Costs.
	Maintenance							
	Maint Labor	443,229	ft2 grid area	0.825	$/ft^2 of grid area		365,664	ft2 grid area, 0.8 $/ft2 of grid area
	Maint Mtls	1	% of purchased equipment cost			NA	23,488	1% of purchased equipment cost
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	1524.3	kW-hr	8,237,045	416,996	$/kwh, 1,524 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	160.3	gpm	51,975	16,112	$/kgal, 160 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatement	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	4.1	ton/hr	22,334	97,621	$/ton, 4 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	Mi	0	0	$/ton-mi, 0 Mi, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-5: PM Control - Dry ESP Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						1997 [2]	17,365,400	
Purchased Equipment (A)						2005	20,892,396	10,878,623
Purchased Equipment Total (B)	15%	of control device cost (A)						**12,510,417**
Installation - Standard Costs	67%	of purchased equip cost (B)						8,381,979
Installation - Site Specific Costs								1,646,400
Installation Total								10,028,379
Total Direct Capital Cost, DC								22,538,796
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)						7,130,938
Total Capital Investment (TCI) = DC + IC								**38,570,653**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						1,055,823
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						4,741,455
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**5,797,278**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	27.0	0.015	72.5	17.0	340,570
Total Particulates	90.5	27.0	0.015	72.5	18.0	321,673
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1 Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3

3 ESP Maintenance costs Eq 3.45 EPA Cont Cost Manual Section 6 Chapter 3
4 ESP Maintenance Materials Eq 3.45 EPA Cont Cost Manual Section 6 Chapter 3
5 Used an ESP SCA grid factor of 553 ft^2/1000 acfm per GRE, D. Stockdill.
6 High control cost is due to the small additional decrease in emissions as compared to existing controls.
7 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-5: PM Control - Dry ESP Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**10,878,623**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,087,862
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	543,931
Purchased Equipment Total (B)	15%		**12,510,417**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	500,417
Handling & erection	50%	of purchased equip cost (B)	6,255,208
Electrical	8%	of purchased equip cost (B)	1,000,833
Piping	1%	of purchased equip cost (B)	125,104
Insulation	2%	of purchased equip cost (B)	250,208
Painting	2%	of purchased equip cost (B)	250,208
Installation Subtotal Standard Expenses	67%		**8,381,979**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			1,646,400
Installation Total			**10,028,379**
Total Direct Capital Cost, DC			**22,538,796**
Indirect Capital Costs			
Engineering, supervision	20%	of purchased equip cost (B)	2,502,083
Construction & field expenses	20%	of purchased equip cost (B)	2,502,083
Contractor fees	10%	of purchased equip cost (B)	1,251,042
Start-up	1%	of purchased equip cost (B)	125,104
Performance test	1%	of purchased equip cost (B)	125,104
Model Studies	2%	of purchased equip cost (B)	250,208
Contingencies	3%	of purchased equip cost (B)	375,313
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)	**7,130,938**
Total Capital Investment (TCI) = DC + IC			**29,669,733**
		Retrofit TCI (TCI*1.3)	**38,570,653**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**38,570,653**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Supervisor	48%	% of Operator Costs.	17,642
Maintenance			
Maintenance Labor	443,229	ft2 grid area, 0.8 $/ft2 of grid area	365,664
Maintenance Materials	1	1% of purchased equipment cost	125,104
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,510 kW-hr, 7947 hr/yr, 68% utilization	413,036
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 4 ton/hr, 7947 hr/yr, 68% utilization	97,621
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**1,055,823**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	327,099
Administration (2% total capital costs)	2%	of total capital costs (TCI)	593,395
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	296,697
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	296,697
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	3,227,566
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**4,741,455**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,797,278**

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-5: PM Control - Dry ESP Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:			
Equipment Life	5	years	
CRF	0.0000		
Rep part cost per unit	500	$/ft^3	
Amount Required	0	ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/h	OAQPS list replacement times from 5 - 20 min per bag
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower Baghouse & ESP	801,500		4.48			649.9	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.46
	Liq flow	Liquid SPGR	Δ P ft H2O	Efficiency	Hp	kW	
WESP Pump	0 gpm	1.000	40	0.5		0.0	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
WESP H2O WW Disch	0 gpm	1.000	40	0.5		0.0	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
SCA Factor	553	ft^2/1000 acfm					
ESP Grid	443,229	ft^2	1.94E-03	kW/ft^2		859.9	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.48
Total						1509.8	

Reagent Use & Other Operating Costs				
WESP Pump	acfm	5 gpm/kacfm	0 gpm	EPA Cost Cont Manual 6th ed Section 6 Chapter 3.4.1.9
WESP Water Makeup Rate/WW Disch		20% of circulating water rate =	0 gpm	

Operating Cost Calculations — **Annual hours of operation:** **7,947** — **Utilization Rate:** **68%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	48%	of Operator Costs.			NA	17,642	% of Operator Costs.
	Maintenance							
	Maint Labor	443,229	ft2 grid area	0.825	$/ft^2 of grid area		365,664	ft2 grid area, 0.8 $/ft2 of grid area
	Maint Mtls	1	% of purchased equipment cost			NA	125,104	1% of purchased equipment cost
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	1509.8	kW-hr	8,158,820	413,036	$/kwh, 1,510 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatement	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	4.1	ton/hr	22,334	97,621	$/ton, 4 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	Mi	0	0	$/ton-mi, 0 Mi, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-6: PM Control -Baghouse Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs							Year		
Direct Capital Costs (1)							2012 [2]	23,200,000	
Purchased Equipment (A)							2005	19,256,000	9,623,188
Purchased Equipment Total (B)	15%	of control device cost (A)							**11,066,667**
Installation - Standard Costs	74%	of purchased equip cost (B)							8,189,333
Installation - Site Specific Costs									1,646,400
Installation Total									9,835,733
Total Direct Capital Cost, DC									20,902,400
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)							4,980,000
Total Capital Investment (TCI) = DC + IC									**33,647,120**
Operating Costs									
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.							1,036,754
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost							3,945,692
Total Annual Cost (Annualized Capital Cost + Operating Cost)									**4,982,446**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	27.0	0.015	72.5	17.0	292,702
Total Particulates	90.5	27.0	0.015	72.5	18.0	276,460
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1 Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton
2 WGI total direct installed cost estimate adjusted for inflation 10/2/2007
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 High control cost is due to the small additional decrease in emissions as compared to existing controls.
6 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-6: PM Control -Baghouse Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**9,623,188**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	962,319
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	481,159
Purchased Equipment Total (B)	15%		**11,066,667**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	442,667
Handling & erection	50%	of purchased equip cost (B)	5,533,333
Electrical	8%	of purchased equip cost (B)	885,333
Piping	1%	of purchased equip cost (B)	110,667
Insulation	7%	of purchased equip cost (B)	774,667
Painting	4%	of purchased equip cost (B)	442,667
Installation Subtotal Standard Expenses	74%		**8,189,333**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Replacement Power - One 14 day outage [6]	1,646,400
Total Site Specific Costs			1,646,400
Installation Total			**9,835,733**
Total Direct Capital Cost, DC			**20,902,400**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,106,667
Construction & field expenses	20%	of purchased equip cost (B)	2,213,333
Contractor fees	10%	of purchased equip cost (B)	1,106,667
Start-up	1%	of purchased equip cost (B)	110,667
Performance test	1%	of purchased equip cost (B)	110,667
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	332,000
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	**4,980,000**
Total Capital Investment (TCI) = DC + IC			**25,882,400**
		Retrofit TCI (TCI*1.3)	**33,647,120**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**33,647,120**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr	73,510
Supervisor	15%	15% of Operator Costs	11,026
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization	396,876
NA	NA		-
NA	NA		-
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 4 ton/hr, 7947 hr/yr, 68% utilization	97,621
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**1,036,754**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	94,828
Administration (2% total capital costs)	2%	of total capital costs (TCI)	517,648
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	258,824
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	258,824
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	2,815,568
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**3,945,692**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,982,446**

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-6: PM Control -Baghouse Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = $29.65/hr	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag
Annualized Cost	**224,403**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10			1450.7	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other							
Other							
Other							
Other							
Other							
Total						1450.7	

Baghouse Filter Cost						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2				
Cages	0	ft long	0 in dia	0.00	area/cage ft^2	$/cage
Bags	0	$/ft2 of fabric				$/bag
Total						
Lime Use	0.00	lb/hr SO2	0.96	lb Lime/lb SO2	0.00	lb/hr Lime

Operating Cost Calculations — **Annual hours of operation: 7,947** — **Utilization Rate: 68%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37.00	$/Hr	2.0	hr/8 hr shift	1,987	73,510	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	11,026	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	1450.7	kW-hr	7,839,605	396,876	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	2	scfm/kacfm	519,753	159,808	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatment	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	4.1	ton/hr	22,334	97,621	$/ton, 4 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160	$/bag	0	bags	NA	224,403	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-7: SO2 Control - Wet Scrubber Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	2002	395.6
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465.0
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.18
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						2012 [1]	68,800,000	
Purchased Equipment (A)						2005	57,104,000	26,840,893
Purchased Equipment Total (B)	15%	of control device cost (A)						**30,867,027**
Installation - Standard Costs	85%	of purchased equip cost (B)						26,236,973
Installation - Site Specific Costs								7,646,400
Installation Total								33,883,373
Total Direct Capital Cost, DC								64,750,400
Total Indirect Capital Costs, IC	76%	of purchased equip cost (B)						23,406,000
Total Capital Investment (TCI) = DC + IC								**88,156,400**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,243,462
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						10,937,858
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**13,181,320**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	163.3	0.09	438.4	8,153.1	1,617

Notes & Assumptions

1 WGI total direct installed cost estimate adjusted for inflation 10/2/2007
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1
3 Liquid/Gas ratio = 38 L/G = Gal/1,000 acf
4 Water Makeup Rate/Wastewater Discharge = 2.0% of circulating water rate
5 Evaporation rate calculated from steam table in Basic Principles and Calculations in Chemical Engineering Third Edition.
6 NDDH expected efficiency 4/21/06
7 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-7: SO2 Control - Wet Scrubber Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**26,840,893**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	2,684,089
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	1,342,045
Purchased Equipment Total (B)	15%		**30,867,027**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	3,704,043
Handling & erection	40%	of purchased equip cost (B)	12,346,811
Electrical	1%	of purchased equip cost (B)	308,670
Piping	30%	of purchased equip cost (B)	9,260,108
Insulation	1%	of purchased equip cost (B)	308,670
Painting	1%	of purchased equip cost (B)	308,670
Installation Subtotal Standard Expenses	85%		**26,236,973**
Site Preparation, as required		Sludge Pond	5,000,000
Buildings, as required		Warehouse Relocation, stack modification	1,000,000
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			7,646,400
Installation Total			**33,883,373**
Total Direct Capital Cost, DC			**64,750,400**
Indirect Capital Costs			
Engineering, supervision	19%	of purchased equip cost (B)	5,727,000
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees	19%	of purchased equip cost (B)	5,727,000
Start-up	0%	of purchased equip cost (B)	0
Performance test	0%	of purchased equip cost (B)	0
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	39%	of purchased equip cost (B)	11,952,000
Total Indirect Capital Costs, IC	76%	of purchased equip cost (B)	**23,406,000**
Total Capital Investment (TCI) = DC + IC			**88,156,400**
		Retrofit TCI (TCI*correction factor)	**88,156,400**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**88,156,400**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Supervisor	15%	15% of Operator Costs	2,757
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Maintenance Materials	100%	of maintenance labor costs	18,377
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 2,800 kW-hr, 7947 hr/yr, 68% utilization	766,004
NA	NA		-
Water	0.31	$/kgal, 2,943 gpm, 7947 hr/yr, 68% utilization	295,826
NA	NA		-
NA	NA		-
WW Treat Neutralization	1.64	$/kgal, 609 gpm, 7947 hr/yr, 68% utilization	323,730
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization	800,014
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**2,243,462**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	34,733
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,763,128
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	881,564
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	881,564
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	7,376,868
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**10,937,858**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**13,181,320**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-7: SO2 Control - Wet Scrubber Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Scrubber	801,500		8.55	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	Liquid SPGR	Δ P ft H2O	Efficiency	Hp	kW	
Circ Pump	30456.99612	1	60	0.7 -		0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	2943 gpm	1	60	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
FGD Power Consumption						2800	WGI Cost tables 10/2/2007
Total						2800.0	

Reagent Use & Other Operating Costs					
Caustic Use	3418	lb/hr SO2	2.5 lb NaOH/lb SO2	8545	lb/hr Caustic
Lime Use	3418	lb/hr SO2	0.9625 lb Lime/lb SO2	3289.825	lb/hr lime, lime addition at 1.1 times the stoichiometric ratio
Liquid/Gas ratio	38	* L/G = Gal/1,000 acf			
Circulating Water Rate	30,457	gpm			
Water Makeup Rate/WW Disch =		0.02	of circulating water rate + evap. loss =	2943.14	
Evaopration Loss =		0.793030594			

Design Basis	**Baseline Emis. T/yr**	**Baseline Emi lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				95%	0.09
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations — **Annual hours of operation: 7,947** — **Utilization Rate: 68%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.0	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	2,757	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	18,377	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	2800.0	kW-hr	15,131,088	766,004	$/kwh, 2,800 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	2,943.1	gpm	954,277	295,826	$/kgal, 2,943 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	609.1	gpm	197,506	323,730	$/kgal, 609 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, ($5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost)/2
1	Lime	90.0	$/ton	3289.8	lb/hr	8,889	800,014	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-8: SO2 Control - Spray Dryer and Baghouse Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	2002	395.6
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465.0
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.18
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						2012 [1]	64,700,000	
Purchased Equipment (A)						2005	53,701,000	26,837,081
Purchased Equipment Total (B)	15%	of control device cost (A)						**30,862,644**
Installation - Standard Costs	74%	of purchased equip cost (B)						22,838,356
Installation - Site Specific Costs								2,146,400
Installation Total								24,984,756
Total Direct Capital Cost, DC								55,847,400
Total Indirect Capital Costs, IC	71%	of purchased equip cost (B)						21,995,000
Total Capital Investment (TCI) = DC + IC								**79,514,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						#REF!
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						9,235,943
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**13,307,617**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	270.0	0.15	724.8	7,866.8	1,692

Notes & Assumptions

1 WGI total direct installed cost estimate adjusted for inflation 10/2/2007
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 Bag replacement costs for baghouse need to be updated. Bag costs from EPA example calculations were used. Bags for Stanton would be larger and more expensive.
6 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
7 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-8: SO2 Control - Spray Dryer and Baghouse Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**26,837,081**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	2,683,708
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	1,341,854
Purchased Equipment Total (B)	15%		**30,862,644**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	1,234,506
Handling & erection	50%	of purchased equip cost (B)	15,431,322
Electrical	8%	of purchased equip cost (B)	2,469,011
Piping	1%	of purchased equip cost (B)	308,626
Insulation	7%	of purchased equip cost (B)	2,160,385
Painting	4%	of purchased equip cost (B)	1,234,506
Installation Subtotal Standard Expenses	74%		**22,838,356**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Warehouse Relocation	500,000
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			2,146,400
Installation Total			**24,984,756**
Total Direct Capital Cost, DC			**55,847,400**
Indirect Capital Costs			
Engineering, supervision	17%	of purchased equip cost (B)	5,395,000
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees/General	17%	of purchased equip cost (B)	5,395,000
Start-up	0%	of purchased equip cost (B)	0
Performance test	0%	of purchased equip cost (B)	0
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	36%	of purchased equip cost (B)	11,205,000
Total Indirect Capital Costs, IC	71%	of purchased equip cost (B)	**21,995,000**
Total Capital Investment (TCI) = DC + IC			**77,842,400**
		Retrofit TCI (TCI*correction factor)	**79,514,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**79,514,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 8.0 hr/8 hr shift, 7947 hr/yr	294,039
Supervisor	15%	15% of Operator Costs	44,106
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,550 kW-hr, 7947 hr/yr, 68% utilization	424,038
NA	NA		-
Water	0.31	$/kgal, 219 gpm, 7947 hr/yr, 68% utilization	21,992
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization	38,432
NA	NA		-
NA	NA		-
PRB Coal	2,000,000	$/yr, ($5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost)/2	2,000,000
Lime	90.00	$/ton, 3,254 lb/hr, 7947 hr/yr, 68% utilization	791,346
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**4,071,674**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	246,993
Administration (1% total capital costs)	1%	of total capital costs (TCI)	778,424
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	778,424
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	778,424
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	6,653,678
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**9,235,943**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**13,307,617**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-8: SO2 Control - Spray Dryer and Baghouse Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**224,403**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10			0.0	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
FDG Power Consumtion						1,500.0	WGI Cost tables 10/2/2007
Fabric Filter Power Consumption						50.0	WGI Cost tables 10/2/2007
Other							
Other							
Other							
Total						1550.0	

Baghouse Filter Cost						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2				
Cages	0 ft long	0 in dia	0.00	area/cage ft^2	0.000	$/cage
Bags	0	$/ft2 of fabric			0.00	$/bag
		H2O Use (1)	218.8	gpm	0.000	Total
Lime Use	3232.45	lb/hr SO2	1.01	lb Lime/lb SO2	3254.18	lb/hr lime, lime addition at 1.15 times the stoichiometric ratio

Design Basis	**Baseline Emi T/yr**	**Baseline Emi lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				92%	0.15
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations — **Annual hours of operation:** **7,947** — **Utilization Rate:** **68%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.0	$/Hr	8.0	hr/8 hr shift	7,947	294,039	$/Hr, 8.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	44,106	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	1550.0	kW-hr	8,376,138	424,038	$/kwh, 1,550 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	218.8	gpm	70,942	21,992	$/kgal, 219 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	2	scfm/kacfm	519,753	159,808	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	1.6	ton/hr	8,793	38,432	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	1	2,000,000	$/yr, ($5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost)/2
1	Lime	90.0	$/ton	3254.2	lb/hr	8,793	791,346	$/ton, 3,254 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160	$/bag	0	bags	NA	224,403	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-9: SO2 Control - Spray Dryer and Baghouse Lignite Coal

Operating Unit: **Unit 1**

						Chemical Engineering Chemical Plant Cost Index	
Emission Unit Number	NA		Stack/Vent Number	NA			
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F		
Expected Utiliztion Rate	68%		Temperature	330	Deg F	2002	395.6
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465.0
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.18
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						2012 [1]	64,700,000	
Purchased Equipment (A)						2005	53,701,000	26,837,081
Purchased Equipment Total (B)	15%	of control device cost (A)						**30,862,644**
Installation - Standard Costs	74%	of purchased equip cost (B)						22,838,356
Installation - Site Specific Costs								2,146,400
Installation Total								24,984,756
Total Direct Capital Cost, DC								55,847,400
Total Indirect Capital Costs, IC	71%	of purchased equip cost (B)						21,995,000
Total Capital Investment (TCI) = DC + IC								**77,842,400**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,119,304
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						9,096,065
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**11,215,368**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	326.7	0.18	876.9	7,714.7	1,454

Notes & Assumptions

1 WGI total direct installed cost estimate adjusted for inflation 10/2/2007
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 Bag replacement costs for baghouse need to be updated. Bag costs from EPA example calculations were used. Bags for Stanton would be larger and more expensive.
6 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
7 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-9: SO2 Control - Spray Dryer and Baghouse Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**26,837,081**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	2,683,708
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	1,341,854
Purchased Equipment Total (B)	15%		**30,862,644**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	1,234,506
Handling & erection	50%	of purchased equip cost (B)	15,431,322
Electrical	8%	of purchased equip cost (B)	2,469,011
Piping	1%	of purchased equip cost (B)	308,626
Insulation	7%	of purchased equip cost (B)	2,160,385
Painting	4%	of purchased equip cost (B)	1,234,506
Installation Subtotal Standard Expenses	74%		**22,838,356**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Warehouse Relocation	500,000
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			2,146,400
Installation Total			**24,984,756**
Total Direct Capital Cost, DC			**55,847,400**
Indirect Capital Costs			
Engineering, supervision	17%	of purchased equip cost (B)	5,395,000
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees/General	17%	of purchased equip cost (B)	5,395,000
Start-up	0%	of purchased equip cost (B)	0
Performance test	0%	of purchased equip cost (B)	0
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	36%	of purchased equip cost (B)	11,205,000
Total Indirect Capital Costs, IC	71%	of purchased equip cost (B)	**21,995,000**
Total Capital Investment (TCI) = DC + IC			**77,842,400**
		Retrofit TCI (TCI*correction factor)	**77,842,400**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**77,842,400**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 8.0 hr/8 hr shift, 7947 hr/yr	294,039
Supervisor	15%	15% of Operator Costs	44,106
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,550 kW-hr, 7947 hr/yr, 68% utilization	424,038
NA	NA		-
Water	0.31	$/kgal, 219 gpm, 7947 hr/yr, 68% utilization	21,992
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization	40,638
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 3,441 lb/hr, 7947 hr/yr, 68% utilization	836,770
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**2,119,304**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	246,993
Administration (1% total capital costs)	1%	of total capital costs (TCI)	778,424
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	778,424
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	778,424
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	6,513,800
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**9,096,065**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**11,215,368**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-9: SO2 Control - Spray Dryer and Baghouse Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**224,403**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10			0.0	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
FDG Power Consumtion						1,500.0	WGI Cost tables 10/2/2007
Fabric Filter Power Consumption						50.0	WGI Cost tables 10/2/2007
Other							
Other							
Other							
Total						1550.0	

Baghouse Filter Cost						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2				
Cages	0 ft long	0 in dia	0.00	area/cage ft^2	0.000	$/cage
Bags	0	$/ft2 of fabric			0.00	$/bag
		H2O Use (1)	218.8	gpm	0.000	Total
Lime Use	3418.00	lb/hr SO2	1.01	lb Lime/lb SO2	3440.97	lb/hr lime, lime addition at 1.15 times the stoichiometric ratio

Design Basis	**Baseline Emi T/yr**	**Baseline Emi lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				90%	0.18
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations — **Annual hours of operation:** **7,947** — **Utilization Rate:** **68%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37.0	$/Hr	8.0	hr/8 hr shift	7,947	294,039	$/Hr, 8.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	44,106	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	1550.0	kW-hr	8,376,138	424,038	$/kwh, 1,550 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	218.8	gpm	70,942	21,992	$/kgal, 219 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	2	scfm/kacfm	519,753	159,808	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	1.7	ton/hr	9,297	40,638	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost
1	Lime	90.0	$/ton	3441.0	lb/hr	9,297	836,770	$/ton, 3,441 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160	$/bag	0	bags	NA	224,403	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-10: SO2 Control - Dry Sorbent Injection and Baghouse Lignite Coal

Operating Unit: **Unit 1**

						Chemical Engineering Chemical Plant Cost Index	
Emission Unit Number	NA		Stack/Vent Number	NA			
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F		
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						1997	26,255,500	
Purchased Equipment (A)						2005 [6]	38,531,255	19,256,000
Purchased Equipment Total (B)	15%	of control device cost (A)						**22,144,400**
Installation - Standard Costs	74%	of purchased equip cost (B)						16,386,856
Installation - Site Specific Costs								2,146,400
Installation Total								18,533,256
Total Direct Capital Cost, DC								40,677,655
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)						3,321,660
Total Capital Investment (TCI) = DC + IC								**57,199,110**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						3,792,681
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						6,641,183
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**10,433,865**

Emission Control Cost Calculation

Pollutant	Baseline Emis. T/yr	Predicted Limit lb/hr	Cont. Emis. lb/MMBtu	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	445.5	0.25	1195.9	7,395.7	1,411

Notes & Assumptions

1 Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
6 WGI total direct installed cost estimate for baghouse adjusted for inflation 10/2/2007
7 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-10: SO2 Control - Dry Sorbent Injection and Baghouse Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**19,256,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,925,600
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	962,800
Purchased Equipment Total (B)	15%		**22,144,400**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	885,776
Handling & erection	50%	of purchased equip cost (B)	11,072,200
Electrical	8%	of purchased equip cost (B)	1,771,552
Piping	1%	of purchased equip cost (B)	221,444
Insulation	7%	of purchased equip cost (B)	1,550,108
Painting	4%	of purchased equip cost (B)	885,776
Installation Subtotal Standard Expenses	74%		**16,386,856**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Warehouse Relocation	500,000
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			2,146,400
Installation Total			**18,533,256**
Total Direct Capital Cost, DC			**40,677,655**
Indirect Capital Costs			
Engineering, supervision [6]	5%	of purchased equip cost (B)	1,107,220
Construction & field expenses [6]	0%	of purchased equip cost (B)	0
Contractor fees [6]	5%	of purchased equip cost (B)	1,107,220
Start-up	1%	of purchased equip cost (B)	221,444
Performance test	1%	of purchased equip cost (B)	221,444
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	664,332
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)	**3,321,660**
Total Capital Investment (TCI) = DC + IC			**43,999,315**
		Retrofit TCI (TCI*1.3)	**57,199,110**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**57,199,110**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr	73,510
Supervisor	15%	15% of Operator Costs	11,026
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization	396,876
NA	NA		-
Water	0.31	$/kgal, 146 gpm, 7947 hr/yr, 68% utilization	14,681
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization	38,853
NA	NA		-
NA	NA		-
PRB Coal	2,000,000	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost	2,000,000
Lime	90.00	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization	800,014
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**3,792,681**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	94,828
Administration (2% total capital costs)	2%	of total capital costs (TCI)	879,986
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	439,993
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	439,993
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	4,786,383
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**6,641,183**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**10,433,865**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-10: SO2 Control - Dry Sorbent Injection and Baghouse Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**224,403**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10			1450.7	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other							
Other							
Other							
Other							
Other							
Total						1450.7	

Baghouse Filter Cost						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2				
Cages	0	ft long	5 in dia	0.00	area/cage ft^2	0.000 $/cage
Bags	0	$/ft2 of fabric				0.00 $/bag
		H2O Use (6)		146.06	gpm	0.000 Total
Lime Use	3418.00	lb/hr SO2		0.96	lb Lime/lb SO2	3289.83 lb/hr lime, lime addition at 1.1 times the stoichiometric ratio

Design Basis	**Baseline Emis. T/yr**	**Baseline Emis. lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				86%	0.25
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations — **Annual hours of operation:** **7,947** — **Utilization Rate:** **68%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	$/Hr	2.0	hr/8 hr shift	1,987	73,510	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	11,026	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	1450.7	kW-hr	7,839,605	396,876	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	146.1	gpm	47,360	14,681	$/kgal, 146 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	2	scfm/kacfm	519,753	159,808	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatement	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	1.6	ton/hr	8,889	38,853	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	1	2,000,000	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost
1	Lime	90.0	$/ton	3289.8	lb/hr	8,889	800,014	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160	$/bag	0	bags	NA	224,403	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-11: SO2 Control - Wet Scrubber Lignite Coal 10% Bypass

Operating Unit: **Unit 1**

						Chemical Engineering	
Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Plant Cost Index**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	2002	395.6
Expected Utiliztion Rate	68%		Temperature	330	Deg F	2005	465
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		Inflation Adj	1.18
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm		
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						2012 [1]	48,306,383	
Purchased Equipment (A)						2005	40,094,298	18,845,733
Purchased Equipment Total (B)	15%	of control device cost (A)						**21,672,593**
Installation - Standard Costs	85%	of purchased equip cost (B)						18,421,704
Installation - Site Specific Costs								7,146,400
Installation Total								25,568,104
Total Direct Capital Cost, DC								47,240,698
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)						3,250,889
Total Capital Investment (TCI) = DC + IC								**65,639,063**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						1,938,045
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						7,547,030
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**9,485,075**

Uncontrolled SO2 Emission Rate	8,592	lb/hr
Scrubber Control Efficiency	95.0%	[6]
Scrubber Bypass	10.0%	

Emission Control Cost Calculation

Pollutant	Baseline Emis. T/yr	Predicted Limit lb/hr	Cont. Emis. lb/MMBtu	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	473.6	0.26	1271.4	7,320.1	1,296

Notes & Assumptions

1 WGI total direct installed cost estimate for baghouse adjusted for inflation 10/2/2007
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1
3 Liquid/Gas ratio = 38 L/G = Gal/1,000 acf
4 Water Makeup Rate/Wastewater Discharge = 2.0% of circulating water rate
5 Evaporation rate calculated from steam table in Basic Principles and Calculations in Chemical Engineering Third Edition.
6 NDDH expected efficiency 4/21/06
7 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-11: SO2 Control - Wet Scrubber Lignite Coal 10% Bypass

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**18,845,733**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,884,573
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	942,287
Purchased Equipment Total (B)	15%		**21,672,593**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	2,600,711
Handling & erection	40%	of purchased equip cost (B)	8,669,037
Electrical	1%	of purchased equip cost (B)	216,726
Piping	30%	of purchased equip cost (B)	6,501,778
Insulation	1%	of purchased equip cost (B)	216,726
Painting	1%	of purchased equip cost (B)	216,726
Installation Subtotal Standard Expenses	85%		**18,421,704**
Site Preparation, as required		Sludge Pond	5,000,000
Buildings, as required		Warehouse Relocation	500,000
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			7,146,400
Installation Total			**25,568,104**
Total Direct Capital Cost, DC			**47,240,698**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	1,083,630
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees	5%	of purchased equip cost (B)	1,083,630
Start-up	1%	of purchased equip cost (B)	216,726
Performance test	1%	of purchased equip cost (B)	216,726
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	650,178
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)	**3,250,889**
Total Capital Investment (TCI) = DC + IC			**50,491,587**
		Retrofit TCI (TCI*1.3)	**65,639,063**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**65,639,063**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Supervisor	15%	15% of Operator Costs	2,757
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Maintenance Materials	100%	of maintenance labor costs	18,377
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,684 kW-hr, 7947 hr/yr, 68% utilization	460,586
NA	NA		-
Water	0.31	$/kgal, 2,943 gpm, 7947 hr/yr, 68% utilization	295,826
NA	NA		-
NA	NA		-
WW Treat Neutralization	1.64	$/kgal, 609 gpm, 7947 hr/yr, 68% utilization	323,730
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization	800,014
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**1,938,045**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	34,733
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,009,832
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	504,916
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	504,916
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	5,492,633
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**7,547,030**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,485,075**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-11: SO2 Control - Wet Scrubber Lignite Coal 10% Bypass

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160.00	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		Δ P in H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	801,500		8.55	0.7	-	1,145.4	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**Δ P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	30,457 gpm	1	60	0.7	-	490.8	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	2943 gpm	1	60	0.7	-	47.4	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
Other							
Total						1683.6	

Reagent Use & Other Operating Costs						
Caustic Use	3418.00	lb/hr SO2	2.50	lb NaOH/lb SO2	8545.00	lb/hr Caustic
Lime Use	3418.00	lb/hr SO2	0.96	lb Lime/lb SO2	3289.83	lb/hr lime, lime addition at 1.1 times the stoichiometric ratio
Liquid/Gas ratio	38.0	* L/G = Gal/1,000 acf				
Circulating Water Rate	30,457	gpm				
Water Makeup Rate/WW Disch =	2.0%	of circulating water rate + evap. loss =			2943	gpm
Evaopration Loss =	79.30%					

Design Basis	**Baseline Emi T/yr**	**Baseline Emi lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				86%	0.26
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations — **Annual hours of operation: 7,947** — **Utilization Rate: 68%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
Supervisor	15%	of Op.			NA	2,757	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	18,377	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	1683.6	kW-hr	9,098,091	460,586	$/kwh, 1,684 kW-hr, 7947 hr/yr, 68% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
Water	0.31	$/kgal	2,943.1	gpm	954,277	295,826	$/kgal, 2,943 gpm, 7947 hr/yr, 68% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
WW Treat Neutralization	1.64	$/kgal	609.1	gpm	197,506	323,730	$/kgal, 609 gpm, 7947 hr/yr, 68% utilization
WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost
1 Lime	90.0	$/ton	3289.8	lb/hr	8,889	800,014	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1 Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-12: SO_2/NOx Control - Fuel Switch to PRB Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						1997	0	
Purchased Equipment (A)						2005 [7]	0	0
Purchased Equipment Total (B)	15%	of control device cost (A)						**0**
Installation - Standard Costs	74%	of purchased equip cost (B)						0
Installation - Site Specific Costs								NA
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**0**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,000,000
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						0
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**2,000,000**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	648.0	0.36	1739.5	399.5	5,006
Sulfur Dioxide (SO_2)	8,591.6	990.0	0.55	2657.5	5,934.0	337

Notes & Assumptions

1 Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
6 JXK Revised 1/11 controlled emission rate to account for reduced control effectiveness due to short residence time in available ductwork
7 Stone and Webster 2002 total direct installed cost estimate adjusted for inflation
8 Operation cost is presented on a per pollutant basis, total annual operating cost for a PRB fuel switch is $4,000,000. This cost is divided in half to represent the total cost attributed to each of the pollutant that will show emission reductions as the result of the fuel switch (SO2, NOx).

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-12: SO2/NOx Control - Fuel Switch to PRB Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**0**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	0
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	0
Purchased Equipment Total (B)	15%		**0**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	0
Handling & erection	50%	of purchased equip cost (B)	0
Electrical	8%	of purchased equip cost (B)	0
Piping	1%	of purchased equip cost (B)	0
Insulation	7%	of purchased equip cost (B)	0
Painting	4%	of purchased equip cost (B)	0
Installation Subtotal Standard Expenses	74%		**0**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**0**
Total Direct Capital Cost, DC			**0**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	0
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees	5%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	0
Performance test	1%	of purchased equip cost (B)	0
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	0
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)	**0**
Total Capital Investment (TCI) = DC + IC			**0**
		Retrofit TCI (TCI*1.3)	**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**0**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	NA		-
Maintenance Materials	NA	of maintenance labor costs	-
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
PRB Coal	#########	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost	2,000,000
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**2,000,000**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	0
Administration (2% total capital costs)	2%	of total capital costs (TCI)	0
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	0
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	0
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	-
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**0**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,000,000**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-12: SO2/NOx Control - Fuel Switch to PRB Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft³
Amount Required	0	ft³
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10				
Baghouse Shaker	0.0	Gross fabric area ft²				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other							
Other							
Other							
Other							
Other							
Total						0.0	

Baghouse Filter Cost					See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft²			
Cages	0 ft long	5 in dia	0.00	area/cage ft²	0.000 $/cage
Bags	0	$/ft2 of fabric			0.00 $/bag
		H2O Use	0.00	gpm	0.000 Total
Lime Use	3418.00	lb/hr SO2	0.96	lb Lime/lb SO2	0.00 lb/hr lime, lime addition at 1.1 times the stoichiometric ratio

Design Basis	**Baseline Emi T/yr**	**Baseline Emi lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				70%	0.55
Nitrogen Oxides (NOx)	2138.98	0.435	669.00	Reduce to reflect short residence time in available ductwork	
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations **Annual hours of operation:** **7,947**
Utilization Rate: **68%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	0	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	0	scfm/kacfm	0	0	$/kscf, 0 scfm/kacfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	1	2,000,000	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft³	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160	$/bag	0	bags	NA	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-13: SO2 Control - Dry Sorbent Injection and Baghouse Lignite Coal

Operating Unit: **Unit 1**

						Chemical Engineering Chemical Plant Cost Index	
Emission Unit Number	NA		Stack/Vent Number	NA			
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F		
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						1997	26,255,500	
Purchased Equipment (A)						2005 [6]	38,531,255	19,256,000
Purchased Equipment Total (B)	15%	of control device cost (A)						**22,144,400**
Installation - Standard Costs	74%	of purchased equip cost (B)						16,386,856
Installation - Site Specific Costs								2,146,400
Installation Total								18,533,256
Total Direct Capital Cost, DC								40,677,655
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)						3,321,660
Total Capital Investment (TCI) = DC + IC								**57,199,110**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						1,787,350
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						6,641,183
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**8,428,533**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	1,469.9	0.82	3945.9	4,645.7	1,814

Notes & Assumptions

1 Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
6 WGI total direct installed cost estimate for baghouse adjusted for inflation 10/2/2007
7 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-13: SO2 Control - Dry Sorbent Injection and Baghouse Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**19,256,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,925,600
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	962,800
Purchased Equipment Total (B)	15%		**22,144,400**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	885,776
Handling & erection	50%	of purchased equip cost (B)	11,072,200
Electrical	8%	of purchased equip cost (B)	1,771,552
Piping	1%	of purchased equip cost (B)	221,444
Insulation	7%	of purchased equip cost (B)	1,550,108
Painting	4%	of purchased equip cost (B)	885,776
Installation Subtotal Standard Expenses	74%		**16,386,856**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Warehouse Relocation	500,000
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			2,146,400
Installation Total			**18,533,256**
Total Direct Capital Cost, DC			**40,677,655**
Indirect Capital Costs			
Engineering, supervision [6]	5%	of purchased equip cost (B)	1,107,220
Construction & field expenses [6]	0%	of purchased equip cost (B)	0
Contractor fees [6]	5%	of purchased equip cost (B)	1,107,220
Start-up	1%	of purchased equip cost (B)	221,444
Performance test	1%	of purchased equip cost (B)	221,444
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	664,332
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)	**3,321,660**
Total Capital Investment (TCI) = DC + IC			**43,999,315**
		Retrofit TCI (TCI*1.3)	**57,199,110**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**57,199,110**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr	73,510
Supervisor	15%	15% of Operator Costs	11,026
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization	396,876
NA	NA		-
Water	0.31	$/kgal, 93 gpm, 7947 hr/yr, 68% utilization	9,350
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization	38,853
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization	800,014
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**1,787,350**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	94,828
Administration (2% total capital costs)	2%	of total capital costs (TCI)	879,986
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	439,993
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	439,993
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	4,786,383
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**6,641,183**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,428,533**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-13: SO2 Control - Dry Sorbent Injection and Baghouse Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**224,403**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10			1450.7	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other							
Other							
Other							
Other							
Other							
Total						1450.7	

Baghouse Filter Cost						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2				
Cages	0 ft long	5 in dia	0.00	area/cage ft^2	0.000	$/cage
Bags	0	$/ft2 of fabric			0.00	$/bag
		H2O Use (6)	93.02	gpm	0.000	Total
Lime Use	3418.00	lb/hr SO2	0.96	lb Lime/lb SO2	3289.83	lb/hr lime, lime addition at 1.1 times the stoichiometric ratio

Design Basis	**Baseline Emis. T/yr**	**Baseline Emis. lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				55%	0.82
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations — **Annual hours of operation: 7,947** — **Utilization Rate: 68%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37.00	$/Hr	2.0	hr/8 hr shift	1,987	73,510	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr
Supervisor	15%	of Op.			NA	11,026	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	1450.7	kW-hr	7,839,605	396,876	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
Water	0.31	$/kgal	93.0	gpm	30,161	9,350	$/kgal, 93 gpm, 7947 hr/yr, 68% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
Comp Air	0.31	$/kscf	2	scfm/kacfm	519,753	159,808	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
SW Disposal	4.37	$/ton	1.6	ton/hr	8,889	38,853	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost
1 Lime	90.0	$/ton	3289.8	lb/hr	8,889	800,014	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1 Filter Bags	160	$/bag	0	bags	NA	224,403	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-14A: SO2 Control - Dry Sorbent Injection and Existing ESP, Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering Chemical Plant Cost Index**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F		
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						1997	6,783,500	
Purchased Equipment (A)						2005 [7]	8,161,261	4,078,591
Purchased Equipment Total (B)	15%	of control device cost (A)						**4,690,380**
Installation - Standard Costs	74%	of purchased equip cost (B)						3,470,881
Installation - Site Specific Costs								NA
Installation Total								3,470,881
Total Direct Capital Cost, DC								8,161,261
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)						703,557
Total Capital Investment (TCI) = DC + IC								**11,524,264**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						3,789,472
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,413,763
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**5,203,235**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	643.5	0.36	1727.4	6,864.2	758

Notes & Assumptions

1 Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
6 JXK Revised 1/11 controlled emission rate to account for reduced control effectiveness due to short residence time in available ductwork
7 Stone and Webster 2002 total direct installed cost estimate adjusted for inflation

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-14A: SO2 Control - Dry Sorbent Injection and Existing ESP, Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**4,078,591**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	407,859
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	203,930
Purchased Equipment Total (B)	15%		**4,690,380**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	187,615
Handling & erection	50%	of purchased equip cost (B)	2,345,190
Electrical	8%	of purchased equip cost (B)	375,230
Piping	1%	of purchased equip cost (B)	46,904
Insulation	7%	of purchased equip cost (B)	328,327
Painting	4%	of purchased equip cost (B)	187,615
Installation Subtotal Standard Expenses	74%		**3,470,881**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**3,470,881**
Total Direct Capital Cost, DC			**8,161,261**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	234,519
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees	5%	of purchased equip cost (B)	234,519
Start-up	1%	of purchased equip cost (B)	46,904
Performance test	1%	of purchased equip cost (B)	46,904
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	140,711
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)	**703,557**
Total Capital Investment (TCI) = DC + IC			**8,864,818**
		Retrofit TCI (TCI*1.3)	**11,524,264**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,524,264**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr	73,510
Supervisor	15%	15% of Operator Costs	11,026
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization	396,876
NA	NA		-
Water	0.31	$/kgal, 136 gpm, 7947 hr/yr, 68% utilization	13,651
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization	38,752
NA	NA		-
NA	NA		-
PRB Coal	2,000,000.00	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost	2,000,000
Lime	90.00	$/ton, 3,281 lb/hr, 7947 hr/yr, 68% utilization	797,936
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**3,789,472**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	94,828
Administration (2% total capital costs)	2%	of total capital costs (TCI)	177,296
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	88,648
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	88,648
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	964,343
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,413,763**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,203,235**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-14A: SO2 Control - Dry Sorbent Injection and Existing ESP, Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**224,403**		

Electrical Use							
	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10			1450.7	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other							
Other							
Other							
Other							
Other							
Total						1450.7	

Baghouse Filter Cost						
						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2				
Cages	0 ft long	5 in dia	0.00	area/cage ft^2	0.000	$/cage
Bags	0	$/ft2 of fabric			0.00	$/bag
		H2O Use	135.81	gpm	0.000	Total
Lime Use	3418.00	lb/hr SO2	0.96	lb Lime/lb SO2	3281.28	lb/hr lime, lime addition at 1.1 times the stoichiometric ratio

Design Basis	**Baseline Emi**	**Baseline Emi**	**Max Emis. (Model)**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
	T/yr	**lb/MMBtu**	**lb/hr**	80%	0.36
Nitrogen Oxides (NOx)	2138.98	0.435	669.00	Reduce to reflect short residence time in available ductwork	
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations — **Annual hours of operation:** **7,947**; **Utilization Rate:** **68%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	$/Hr	2.0	hr/8 hr shift	1,987	73,510	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	11,026	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	1450.7	kW-hr	7,839,605	396,876	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	135.8	gpm	44,036	13,651	$/kgal, 136 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	2	scfm/kacfm	519,753	159,808	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	1.6	ton/hr	8,866	38,752	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	1	2,000,000	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost
1	Lime	90.0	$/ton	3281.3	lb/hr	8,866	797,936	$/ton, 3,281 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160	$/bag	0	bags	NA	224,403	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-14B: SO2 Control - Dry Sorbent Injection and Existing ESP, Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1997 386.5
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005 465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj 1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F	
			Dry Std Flow Rate	464,261	dscfm @ 68º F	

CONTROL EQUIPMENT COSTS

Capital Costs			Year			
Direct Capital Costs (1)			1997	6,783,500		
Purchased Equipment (A)			2005 [7]	8,161,261	4,078,591	
Purchased Equipment Total (B)	15%	of control device cost (A)			**4,690,380**	
Installation - Standard Costs	74%	of purchased equip cost (B)			3,470,881	
Installation - Site Specific Costs					NA	
Installation Total					3,470,881	
Total Direct Capital Cost, DC					8,161,261	
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)			703,557	
Total Capital Investment (TCI) = DC + IC					**11,524,264**	
Operating Costs						
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.			1,781,771	
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost			1,413,763	
Total Annual Cost (Annualized Capital Cost + Operating Cost)					**3,195,534**	

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	2,123.3	1.18	5699.6	2,892.0	1,105

Notes & Assumptions

1 Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
6 JXK Revised 1/11 controlled emission rate to account for reduced control effectiveness due to short residence time in available ductwork
7 Stone and Webster 2002 total direct installed cost estimate adjusted for inflation

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-14B: SO2 Control - Dry Sorbent Injection and Existing ESP, Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**4,078,591**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	407,859
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	203,930
Purchased Equipment Total (B)	15%		**4,690,380**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	187,615
Handling & erection	50%	of purchased equip cost (B)	2,345,190
Electrical	8%	of purchased equip cost (B)	375,230
Piping	1%	of purchased equip cost (B)	46,904
Insulation	7%	of purchased equip cost (B)	328,327
Painting	4%	of purchased equip cost (B)	187,615
Installation Subtotal Standard Expenses	74%		**3,470,881**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**3,470,881**
Total Direct Capital Cost, DC			**8,161,261**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	234,519
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees	5%	of purchased equip cost (B)	234,519
Start-up	1%	of purchased equip cost (B)	46,904
Performance test	1%	of purchased equip cost (B)	46,904
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	140,711
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)	**703,557**
Total Capital Investment (TCI) = DC + IC			**8,864,818**
		Retrofit TCI (TCI*1.3)	**11,524,264**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,524,264**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr	73,510
Supervisor	15%	15% of Operator Costs	11,026
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization	396,876
NA	NA		-
Water	0.31	$/kgal, 59 gpm, 7947 hr/yr, 68% utilization	5,950
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization	38,752
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 3,281 lb/hr, 7947 hr/yr, 68% utilization	797,936
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**1,781,771**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	94,828
Administration (2% total capital costs)	2%	of total capital costs (TCI)	177,296
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	88,648
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	88,648
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	964,343
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,413,763**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,195,534**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-14B: SO2 Control - Dry Sorbent Injection and Existing ESP, Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**224,403**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10			1450.7	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other							
Other							
Other							
Other							
Other							
Total						1450.7	

Baghouse Filter Cost						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2				
Cages	0	ft long	5 in dia	0.00	area/cage ft^2	0.000 $/cage
Bags	0	$/ft2 of fabric				0.00 $/bag
		H2O Use	59.20	gpm		0.000 Total
Lime Use	3418.00	lb/hr SO2	0.96	lb Lime/lb SO2		3281.28 lb/hr lime, lime addition at 1.1 times the stoichiometric ratio

Design Basis	**Baseline Emi**	**Baseline Emi**	**Max Emis. (Model)**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
	T/yr	**lb/MMBtu**	**lb/hr**	35%	1.18
Nitrogen Oxides (NOx)	2138.98	0.435	669.00	Reduce to reflect short residence time in available ductwork	
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations — **Annual hours of operation:** **7,947**; **Utilization Rate:** **68%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	$/Hr	2.0	hr/8 hr shift	1,987	73,510	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	11,026	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	1450.7	kW-hr	7,839,605	396,876	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	59.2	gpm	19,194	5,950	$/kgal, 59 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	2	scfm/kacfm	519,753	159,808	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	1.6	ton/hr	8,866	38,752	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1	Lime	90.0	$/ton	3281.3	lb/hr	8,866	797,936	$/ton, 3,281 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160	$/bag	0	bags	NA	224,403	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Catalytic Reduction (SCR) with Reheat, Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Year	
Direct Capital Costs	EPRI Correlation		1998	
Purchased Equipment (A)			2005	38,000,000
Purchased Equipment Total (B)	0%	of control device cost (A)	SCR Only	**38,000,000**
Installation - Standard Costs	15%	of purchased equip cost (B)	SCR Only	5,988,085
Installation - Site Specific Costs				0
Installation Total				0
Total Direct Capital Cost, DC				0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)		0
Total Capital Investment (TCI) = DC + IC			SCR + Reheat	**56,554,445**
Operating Costs				
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	SCR + Reheat	7,676,364
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	SCR + Reheat	4,818,174
Total Annual Cost (Annualized Capital Cost + Operating Cost)			SCR + Reheat	**12,494,538**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	78.3	0.04	210.2	1,928.7	6,478
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2. Scaled to reflect Alstom March 2006 cost estimate for SCR without reheat.
2 For Calculation purposes, duty reflects increased flow rate, not actual duty.
3 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
4 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.36 -2.43
5 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.32 - 2.35
6 SCR Catalyst Volume per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.18 - 2.24
7 SCR Reactor Size per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.25 - 2.31
8 SCR Catalyst Replacement per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.50 - 2.53
9 SCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.48
10 SCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.46
11 Control Efficiency = 90% reduction which is typically the upper range of normal SCR control efficiency
12 Adusted cost for high flow from excess are by ratio of Stanton F Factor to Method 19 Lignite F Factor 15,476 dscf/MMBtu Stanton vs 9,860 dscf/MMBtu for Lignite
13 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW
14 Per March 2006 Alstom report, catalyst replacement every 8000 hours. This requires an additional 2 week outage per 3 year outage cycle, annualized to 4.7 days.

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Catalytic Reduction (SCR) with Reheat, Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			**38,000,000**
Instrumentation	10%	of control device cost (A)	NA
ND Sales Taxes	0.0%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**38,000,000**
Indirect Installation			
General Facilities	0%	of purchased equip cost (A)	0
Engineering & Home Office	0%	of purchased equip cost (A)	0
Process Contingency	0%	of purchased equip cost (A)	0
Site Specific-Other	5%	Replacement Power, two weeks	1,920,567
Total Indirect Installation Costs (B)	5%	of purchased equip cost (A)	**1,920,567**
Project Contingeny (C)	15%	of (A + B)	**5,988,085**
Total Plant Cost D		A + B + C	**45,908,652**
Allowance for Funds During Construction (E)		Additional 10 week outage for installation	**8,232,000**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**1,082,813**
Inventory Capital		Reagent Vol * $/gal	**55,904**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**55,279,369**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**NA**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	829,191
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 2,793 kW-hr, 7947 hr/yr, 68% utilization	764,056
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Cat. Replacement [14]	35.00	Catalyst Replacement	548,800
NA	NA		-
Ammonia	0.20	$/lb, 1,647 lb/hr, 7947 hr/yr, 68% utilization	1,780,439
NA	NA		-
SCR Catalyst	500.00	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization	659,187
NA	NA		-
Total Annual Direct Operating Costs			**4,581,674**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	4,625,741
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**4,625,741**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,207,414**

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Catalytic Reduction (SCR) with Reheat, Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst				
Equipment Life	24,000	hours		
FCW	0.3157			
Rep part cost per unit	500	$/ft^3	# of Layers	14
Replacement Factor	14	Layers replaced per year =		1
Amount Required	4,177	ft^3		
Catalyst Cost	2,088,321			
Y catalyst life factor	3	Years		
Annualized Cost	**659,187**			

SCR Capital Cost per EPRI Method			**23,757,633**					
Duty	2,825	MMBtu/hr	Catalyst Area	1,363	ft^2		413	*f* (h SCR)
Q flue gas	1,308,420	acfm	Rx Area	1,567			1	*f* (h NH_3)
NOx Cont Eff	90%	(as faction)	Rx Height	39.6	ft		-728	*f* (h New) new= -728, Retrofit = 0
NOx in	0.44	lb/MMBtu	n layer	14	layers	Y		Bypass? Y or N
Ammonia Slip	2	ppm	h layer	15.3	ft		127	*f* (h Bypass)
Fuel Sulfur	0.67	wt % (as %)	n total	15	layers		14,033,519	*f* (vol catalyst)
Temperature	330	Deg F	h SCR	98	ft			*f* (h SCR)
Catalyst Volume	**58,473**	ft^3	New/Retrofit	N	N or R			

Electrical Use				
Duty	2,825	MMBtu/hr		kW
NOx Cont Eff	90%	(as faction)	Power	2,792.9
NOx in	0.44	lb/MMBtu		
n catalyst layers	15	layers		
Press drop catalyst	1	in H_2O per layer		
Press drop duct	3	in H_2O		
Total				2792.9

Reagent Use & Other Operating Costs						
Ammonia Use		56.0	lb/ft^3 Density			
478	lb/hr Neat	220.1	gal/hr			
29%	solution	Volume 14 day inventory		73,943 gal	$55,904	Inventory Cost
1647	lb/hr					

Design Basis	Baseline Emi	Baseline Emi	Max Emis. (Model)	Control Eff (%)	Cont. Emis (lb/MMBtu)
	T/yr	lb/MMBtu	lb/hr	90%	0.04
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		
Actual	15,475	dscf/MMBtu			
Method 19 Factor	9,860	dscf/MMBtu			
Adjusted Duty	2,825	MMBtu/hr			

Operating Cost Calculations — **Annual hours of operation: 7,947** — **Utilization Rate: 68%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37.00	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7947 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				829,191	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	2792.9	kW-hr	15,092,622	764,056	$/kwh, 2,793 kW-hr, 7947 hr/yr, 68% utilization
Natural Gas	6.85	$/kscf	0.0	scfh	0	0	$/kscf, 0 scfh, 7947 hr/yr, 68% utilization
Water	0.31	$/kgal	0.0	gph	0	0	$/kgal, 0 gph, 7947 hr/yr, 68% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
Comp Air	0.31	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 7947 hr/yr, 68% utilization
WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
Cat. Replacement [14]	35	$/MW-hr	140.0	mw	112	548,800	Catalyst Replacement
1 Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
7 Ammonia	0.2	$/lb	1647	lb/hr	8,902,197	1,780,439	$/lb, 1,647 lb/hr, 7947 hr/yr, 68% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	659,187	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1 Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization
		** Std Air use is 2 scfm/kacfm			*annual use rate is in same units of measurement as the unit cost factor		

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-16: Cost of Flue Gas Re-Heating (Thermal Oxidizer)

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**		
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**		
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1998/1999	390	
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465	
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.19	
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F			
			Dry Std Flow Rate	464,261	dscfm @ 68º F			

CONTROL EQUIPMENT COSTS

Capital Costs									
Direct Capital Costs									
Purchased Equipment (A)									688,672
Purchased Equipment Total (B)	15%	of control device cost (A)							**791,972**
Installation - Standard Costs	30%	of purchased equip cost (B)							237,592
Installation - Site Specific Costs									NA
Installation Total									237,592
Total Direct Capital Cost, DC									1,029,564
Total Indirect Capital Costs, IC	31%	of purchased equip cost (B)							245,511
Total Capital Investment (TCI) = DC + IC									**1,275,076**
Operating Costs									
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.							3,094,690
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost							192,434
Total Annual Cost (Annualized Capital Cost + Operating Cost)									**3,287,124**

Notes & Assumptions

1 Equipment cost estimate EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2.5.1
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-16: Cost of Flue Gas Re-Heating (Thermal Oxidizer)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**688,672**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	68,867
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	34,434
Purchased Equipment Total (B)	15%		**791,972**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	63,358
Handling & erection	14%	of purchased equip cost (B)	110,876
Electrical	4%	of purchased equip cost (B)	31,679
Piping	2%	of purchased equip cost (B)	15,839
Insulation	1%	of purchased equip cost (B)	7,920
Painting	1%	of purchased equip cost (B)	7,920
Installation Subtotal Standard Expenses	30%		**237,592**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**237,592**
Total Direct Capital Cost, DC			**1,029,564**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	79,197
Construction & field expenses	5%	of purchased equip cost (B)	39,599
Contractor fees	10%	of purchased equip cost (B)	79,197
Start-up	2%	of purchased equip cost (B)	15,839
Performance test	1%	of purchased equip cost (B)	7,920
Model Studies		of purchased equip cost (B)	0
Contingencies	3%	of purchased equip cost (B)	23,759
Total Indirect Capital Costs, IC	31%	of purchased equip cost (B)	**245,511**
Total Capital Investment (TCI) = DC + IC			**1,275,076**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**1,275,076**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Supervisor	15%	15% of Operator Costs	2,757
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Maintenance Materials	100%	of maintenance labor costs	18,377
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 2,970 kW-hr, 7947 hr/yr, 68% utilization	812,390
Natural Gas	6.85	$/kscf, 1,002 scfm, 7947 hr/yr, 68% utilization	2,224,411
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**3,094,690**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	34,733
Administration (2% total capital costs)	2%	of total capital costs (TCI)	25,502
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	12,751
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	12,751
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	106,697
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**192,434**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,287,124**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-16: Cost of Flue Gas Re-Heating (Thermal Oxidizer)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:	**Catalyst**	
Equipment Life	2	years
CRF	0.5416	
Rep part cost per unit	650	$/ft^3
Amount Required	39	ft^3
Catalyst Cost	26,618	Cost adjusted for freight & sales tax
Installation Labor	3,993	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Thermal	801,500		19	0.6		2,969.6	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Blower, Catalytic	801,500		23	0.6		3,594.7	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Oxidizer Type	**thermal**	(catalytic or thermal)				2969.6	

Reagent Use & Other Operating Costs Oxidizers - NA

Operating Cost Calculations — **Annual hours of operation:** **7,947** — **Utilization Rate:** **68%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	2,757	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	18,377	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	2969.6	kW-hr	16,047,368	812,390	$/kwh, 2,970 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	1,002	scfm	324,732	2,224,411	$/kscf, 1,002 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
2	CO Catalyst	650	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-16: Cost of Flue Gas Re-Heating (Thermal Oxidizer)

Flue Gas Re-Heat Equipment Cost Estimate Basis Thermal Oxidizer with 70% Heat Recovery

Auxiliary Fuel Use Equation 3.19

T_{wi}	300	Deg F - Temperature of waste gas into heat recovery
T_{fi}	450	Deg F - Temperature of Flue gas into of heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	70%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	405	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	345	Deg F - Temperature of flue gas into of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.2684	Btu/lb - Deg F Heat Capacity of waste gas (air)
ρ_{wg}	0.0739	lb/scf - Density of waste gas (air) at 77 Deg F
ρ_{af}	0.0408	lb/scf - Density of auxiliary fuel (methane) at 77 Deg F
Q_{wg}	535,480	scfm - Flow of waste gas
Q_{af}	1,002	scfm - Flow of auxiliary fuel

Year 2005   Inflation Rate 3.0%

Cost Calculations   536,482 scfm Flue Gas   Cost in 1989 $'s $577,596

Current Cost Using CHE Plant Cost Index $688,672

Heat Rec %	A	B	
0	10,294	0.2355	Exponents per equation 3.24
0.3	13,149	0.2609	Exponents per equation 3.25
0.5	17,056	0.2502	Exponents per equation 3.26
0.7	21,342	0.2500	Exponents per equation 3.27

Indurator Flue Gas Heat Capacity - Basis Typical Composition

100 scfm   359 scf/lbmole

		Gas Composition		lb/hr f	wt %	Cp Gas	Cp Flue
28	mw CO	0	v %	0			
44	mw CO2	15	v %	184	22.0%	0.24	0.0528
18	mw H2O	10	v %	50	6.0%	0.46	0.0276
28	mw N2	60	v %	468	56.0%	0.27	0.1512
32	mw O2	15	v %	134	16.0%	0.23	0.0368
	Cp Flue Gas	100	v %	836	100.0%		0.2684

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators (EPA 453/B-96-001)

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-17: NOx Control - LoTOx - (Low Temperature Oxidation), Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F
Expected Utiliztion Rate	68%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F
			Dry Std Flow Rate	464,261	dscfm @ 68º F

	Control Eff	NOx in lb/MMBtu
NOx loading & efficiency for sizing	90.0%	0.44

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			4,989,702
Purchased Equipment Total (B)	15%	of control device cost (A)	**5,738,157**
Installation - Standard Costs	85%	of purchased equip cost (B)	4,877,433
Installation - Site Specific Costs			2,146,400
Installation Total			7,023,833
Total Direct Capital Cost, DC			12,761,990
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	2,008,355
Total Capital Investment (TCI) = DC + IC			**43,877,532**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	39,318,066
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	5,461,477
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**44,779,543**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	78.3	0.04	210.2	1,928.7	23,217
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1. Sept 2005 Cost Estimate Procedure from **BOC Gases**
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1 (absorbers)
3. Liquid/Gas ratio = 10 L/G = Gal/1,000 acf
4. Water Makeup Rate/Wastewater Discharge = 20% of circulating water rate
5. WWTP cost basis sending waste water to municipal system; consider developing cost for installation and operation of biotreatment system.
6. Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-17: NOx Control - LoTOx - (Low Temperature Oxidation), Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**4,989,702**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	498,970
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	249,485
Purchased Equipment Total (B)	15%		**5,738,157**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	688,579
Handling & erection	40%	of purchased equip cost (B)	2,295,263
Electrical	1%	of purchased equip cost (B)	57,382
Piping	30%	of purchased equip cost (B)	1,721,447
Insulation	1%	of purchased equip cost (B)	57,382
Painting	1%	of purchased equip cost (B)	57,382
Installation Subtotal Standard Expenses	85%		**4,877,433**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Stack Replacement	500,000
Site Specific - Other		Replacement Power - One 14 day outage [8]	1,646,400
Total Site Specific Costs			2,146,400
Installation Total			**7,023,833**
Total Direct Capital Cost, DC			**12,761,990**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	573,816
Construction & field expenses	10%	of purchased equip cost (B)	573,816
Contractor fees	10%	of purchased equip cost (B)	573,816
Start-up	1%	of purchased equip cost (B)	57,382
Performance test	1%	of purchased equip cost (B)	57,382
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	172,145
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	**2,008,355**
Ozone Generator, Installed Cost			**29,107,187**
Total Capital Investment (TCI) = DC + IC			**43,877,532**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**43,877,532**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Supervisor	15%	15% of Operator Costs	2,757
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Maintenance Materials	100%	of maintenance labor costs	18,377
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 17,088 kW-hr, 7947 hr/yr, 68% utilization	4,674,748
NA	NA		-
Water	0.31	$/kgal, 1,603 gpm, 7947 hr/yr, 68% utilization	161,123
Cooling Water	0.27	$kgal, 8,663 gpm, 7947 hr/yr, 68% utilization	754,623
NA	NA		-
NA	NA		-
WW Treat Biotreatement	4.15	$/kgal, 1,603 gpm, 7947 hr/yr, 68% utilization	2,158,202
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Oxygen	15.00	kscf, 389 kscf/hr, 7947 hr/yr, 68% utilization	31,511,481
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**39,318,066**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	34,733
Administration (2% total capital costs)	2%	of total capital costs (TCI)	877,551
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	438,775
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	438,775
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	3,671,642
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**5,461,477**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**44,779,543**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-17: NOx Control - LoTOx - (Low Temperature Oxidation), Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/$ft^3$
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		**Δ P in H2O**	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	801,500		10	0.7	-	1,339.6	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**Δ P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	8,015 gpm	1	60	0.7	-	129.2	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	1603 gpm	1	60	0.7	-	25.8	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5	kW/lb O_3				15,593	
Other							
Total						17087.8	

Reagent Use & Other Operating Costs							
Ozone Needed	1.8	lb O3/lb NOx	3,465.1	lb/hr O3			
Oxygen Needed	10%	wt O2 to O3 conversion		34,651	lb/hr O2	388,746	scfh O2
LTO Cooling Water	150	gal/lb O3	8,663	gpm			
Liquid/Gas ratio	10.0	* L/G = Gal/1,000 acf					
Circulating Water Rate	8,015	gpm					
Water Makeup Rate/WW Disch =	20.0%	of circulating water rate =		1603 gpm			
Scrubber Cost	10	$/scfm Gas	$4,989,702		Incremental cost per BOC. Need to increase vessel size over standard absorber.		
Ozone Generator	$350	lb O3/day	$29,107,187	Installed	Installed cost factor per BOC.		

Operating Cost Calculations			**Annual hours of operation:**			**7,947**	
			Utilization Rate:			**68%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
Supervisor	15%	of Op.			NA	2,757	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	18,377	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	17087.8	kW-hr	92,341,607	4,674,748	$/kwh, 17,088 kW-hr, 7947 hr/yr, 68% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
Water	0.31	$/kgal	1,603.0	gpm	519,753	161,123	$/kgal, 1,603 gpm, 7947 hr/yr, 68% utilization
Cooling Water	0.27	$kgal	8,662.9	gpm	2,808,823	754,623	$kgal, 8,663 gpm, 7947 hr/yr, 68% utilization
Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
WW Treat Biotreatemen	4.15	$/kgal	1,603.0	gpm	519,753	2,158,202	$/kgal, 1,603 gpm, 7947 hr/yr, 68% utilization
SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost
1 Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5 Oxygen	15	kscf	388.7	kscf/hr	2,100,765	31,511,481	kscf, 389 kscf/hr, 7947 hr/yr, 68% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1 Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization
					*annual use rate is in same units of measurement as the unit cost factor		

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-18: NOx Control - Selective Non-Catalytic Reduction (SNCR), PRB Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs							Year	
Direct Capital Costs	EPRI Correlation, 1998 $'s							
Purchased Equipment (A)							2005	**7,113,100**
Purchased Equipment Total (B)	0%	of control device cost (A)						**7,113,100**
Installation - Standard Costs	15%	of purchased equip cost (B)						1,066,965
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**8,406,968**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						4,308,007
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						703,489
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**5,011,496**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	414.0	0.23	1111.3	1,027.7	4,877
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1 Estimated Equipment Cost per WGI report November, 2007. Installation cost included.
2 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.19
3 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.22
4 Water use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.25
5 Additional Fuel Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.29
6 SNCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.23
7 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
8 Lignite Coal Assumptions 6,054 Btu/lb (wet) Ash 6.2% 42% moisture $10.20/ton delivered

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-18: NOx Control - Selective Non-Catalytic Reduction (SNCR), PRB Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			**7,113,100**
Instrumentation	10%	of control device cost (A)	NA
ND Sales Taxes	0.0%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**7,113,100**
Indirect Installation [1]			
General Facilities	0%	of purchased equip cost (A)	0
Engineerin & Home Office	0%	of purchased equip cost (A)	0
Process Contingency	0%	of purchased equip cost (A)	0
Total Indirect Installation Costs (B)	0%	of purchased equip cost (A)	**0**
Project Contingeny (C)	15%	of (A + B)	**1,066,965**
Total Plant Cost D		A + B + C	**8,180,065**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**163,601**
Inventory Capital		Reagent Vol * $/gal	**63,302**
Intial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**8,406,968**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**8,406,968**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	15.00	% of Total Capital Investment	1,261,045
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 98 kW-hr, 7947 hr/yr, 68% utilization	26,771
NA	NA		-
Water	0.31	$/kgal, 446 gph, 7947 hr/yr, 68% utilization	747
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization	1,346
NA	NA		-
NA	NA		-
PRB Coal	2,000,000	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2	2,000,000
NA	NA		-
Urea	405.00	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization	1,018,098
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**4,308,007**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	703,489
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**703,489**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,011,496**

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-18: NOx Control - Selective Non-Catalytic Reduction (SNCR), PRB Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	500	\$/ft^3
Amount Required	12	ft^3
Packing Cost	6,300	Cost adjusted for freight & sales tax
Installation Labor	945	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	160	\$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = \$29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.44	lb/MMBtu	kW
NSR	1.61		
Power			97.9
Total			97.9

Reagent Use & Other Operating Costs			Urea Use			
37.30	Coal Moisture Content %		465	lb/hr Neat		
1.16	Coal Sulfur Content		50%	solution	71.0	lb/ft^3 Density 50% Solution
6,580	Btu/lb Coal		930	lb/hr	98.0	gal/hr
9.95	wt % Ash (wet)	Volume 14 day inventory	32,938	gal	\$63,302	Inventory Cost
Water Use 446	gal/hr	Inject at 10% solution		Fuel Use	7.54	MMBtu/hr
				Ash Generation	113.96	lb/hr

Design Basis	**Baseline Emi T/yr**	**Baseline Emi lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				47%	**0.23**
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		
Actual	15,475	dscf/MMBtu			
Method 19 Factor	9,860	dscf/MMBtu			
Adjusted Duty	2,825	MMBtu/hr			

Operating Cost Calculations — **Annual hours of operation: 7,947** — **Utilization Rate: 68%**

	Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	\$/Hr	0.0	hr/8 hr shift	0	0	\$/Hr, 0.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maintenance Total	15	% of Total Capital Investment				1,261,045	% of Total Capital Investment
	Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	\$/kwh	97.9	kW-hr	528,811	26,771	\$/kwh, 98 kW-hr, 7947 hr/yr, 68% utilization
	Coal	0.00		0.0	MMBtu/hr	0	0	, 0 MMBtu/hr, 7947 hr/yr, 68% utilization
	Water	0.31	\$/kgal	445.9	gph	2,410	747	\$/kgal, 446 gph, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	\$kgal	0.0	gpm	0	0	\$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	\$/kscf	0.0	scfm/kacfm**	0	0	\$/kscf, 0 scfm/kacfm**, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	\$/ton	0.057	ton/hr	308	1,346	\$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	\$/ton-mi	0.0	ton/hr	0	0	\$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	\$/yr	0.0	ton/hr	1	2,000,000	\$/yr, \$5.1MM/yr extra for PRB - \$1MM/yr Lower O&M Cost/2
1	Lime	90.00	\$/ton	0.0	lb/hr	0	0	\$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
3	Urea	405	\$/ton	0.4652	ton/hr	2,514	1,018,098	\$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	\$/ft3	0	ft^3	0	0	\$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160.00	\$/bag	0	bags	0	0	\$/bag, 0 bags, 7947 hr/yr, 68% utilization

** Std Air use is 2 scfm/kacfm   *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-19: NOx Control - Selective Non-Catalytic Reduction (SNCR), Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

			Year	
Capital Costs				
Direct Capital Costs	EPRI Correlation, 1998 $'s			
Purchased Equipment (A)			2005	**7,113,100**
Purchased Equipment Total (B)	0%	of control device cost (A)		**7,113,100**
Installation - Standard Costs	15%	of purchased equip cost (B)		1,066,965
Installation - Site Specific Costs				0
Installation Total				0
Total Direct Capital Cost, DC				0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)		0
Total Capital Investment (TCI) = DC + IC				**8,388,450**
Operating Costs				
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.		1,998,959
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost		701,940
Total Annual Cost (Annualized Capital Cost + Operating Cost)				**2,700,899**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	522.0	0.29	1401.2	737.7	3,661
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions
1 Estimated Equipment Cost per WGI report November, 2007. Installation cost included.
2 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.19
3 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.22
4 Water use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.25
5 Additional Fuel Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.29
6 SNCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.23
7 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
8 Lignite Coal Assumptions 6,054 Btu/lb (wet) Ash 6.2% 42% moisture $10.20/ton delivered

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-19: NOx Control - Selective Non-Catalytic Reduction (SNCR), Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			**7,113,100**
Instrumentation	10%	of control device cost (A)	NA
ND Sales Taxes	0.0%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**7,113,100**
Indirect Installation [1]			
General Facilities	0%	of purchased equip cost (A)	0
Engineerin & Home Office	0%	of purchased equip cost (A)	0
Process Contingency	0%	of purchased equip cost (A)	0
Total Indirect Installation Costs (B)	0%	of purchased equip cost (A)	**0**
Project Contingeny (C)	15%	of (A + B)	**1,066,965**
Total Plant Cost D		A + B + C	**8,180,065**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**163,601**
Inventory Capital		Reagent Vol * $/gal	**44,784**
Intial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**8,388,450**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**8,388,450**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	15.00	% of Total Capital Investment	1,258,268
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 69 kW-hr, 7947 hr/yr, 68% utilization	18,939
NA	NA		-
Water	0.31	$/kgal, 315 gph, 7947 hr/yr, 68% utilization	529
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization	952
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	405.00	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization	720,271
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**1,998,959**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	701,940
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**701,940**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,700,899**

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-19: NOx Control - Selective Non-Catalytic Reduction (SNCR), Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost	
Equipment Life	5	years	
CRF	0.2342		
Rep part cost per unit	500	$/ft^3	
Amount Required	12	ft^3	
Packing Cost	6,300	Cost adjusted for freight & sales tax	
Installation Labor	945	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	160	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.44	lb/MMBtu	kW
NSR	1.14		
Power			69.2
Total			69.2

Reagent Use & Other Operating Costs			Urea Use				
	37.30	Coal Moisture Content %		329	lb/hr Neat		
	1.16	Coal Sulfur Content		50%	solution	71.0	lb/ft^3 Density 50% Solution
	6,580	Btu/lb Coal		658	lb/hr	69.4	gal/hr
	9.95	wt % Ash (wet)	Volume 14 day inventory	23,302	gal	$44,784	Inventory Cost
Water Use	315	gal/hr	Inject at 10% solution		Fuel Use	5.33	MMBtu/hr
					Ash Generation	80.62	lb/hr

Design Basis	**Baseline Emi** **T/yr**	**Baseline Emi** **lb/MMBtu**	**Max Emis. (Model)** **lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				33%	**0.29**
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		
Actual	15,475	dscf/MMBtu			
Method 19 Factor	9,860	dscf/MMBtu			
Adjusted Duty	2,825	MMBtu/hr			

Operating Cost Calculations — **Annual hours of operation:** **7,947** — **Utilization Rate:** **68%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37.00	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maintenance Total	15	% of Total Capital Investment				1,258,268	% of Total Capital Investment
	Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	69.2	kW-hr	374,117	18,939	$/kwh, 69 kW-hr, 7947 hr/yr, 68% utilization
	Coal	0.00		0.0	MMBtu/hr	0	0	, 0 MMBtu/hr, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	315.5	gph	1,705	529	$/kgal, 315 gph, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	0.040	ton/hr	218	952	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
3	Urea	405	$/ton	0.3291	ton/hr	1,778	720,271	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

** Std Air use is 2 scfm/kacfm — *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-20: NOx Control - Alstom LNB (Low NOx Burners) + Over Fire Air (OFA), PRB Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F
Expected Utiliztion Rate	68%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F
			Dry Std Flow Rate	464,261	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**1,460,000**
Purchased Equipment Total (B)	15%	of control device cost (A)	**1,679,000**
Installation - Standard Costs	0%	of purchased equip cost (B)	0
Installation - Site Specific Costs			NA
Installation Total			0
Total Direct Capital Cost, DC			1,679,000
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	587,650
Total Capital Investment (TCI) = DC + IC			**2,266,650**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	2,011,578
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	287,284
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,298,862**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	514.8	**0.29 [5]**	1381.9	757.1	3,037
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1 March 2006 Cost Estimate from Alstom Power Inc, Option 2 . Installation cost included.
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)
3 Control efficiency basis 0.2 lb NOx/MMBtu average per May 2005 Cost Estimate from Alstom Power Inc, Option 2
4 Assumed 0.1 hr/shift operatior and maintenance labor for LNB
5 Additional control for lower Nox inherent with PRB coal.

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-20: NOx Control - Alstom LNB (Low NOx Burners) + Over Fire Air (OFA), PRB Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**1,460,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	146,000
Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	73,000
Purchased Equipment Total (B)	15%		**1,679,000**
Installation [1]			
Foundations & supports	0%	of purchased equip cost (B)	0
Handling & erection	0%	of purchased equip cost (B)	0
Electrical	0%	of purchased equip cost (B)	0
Piping	0%	of purchased equip cost (B)	0
Insulation	0%	of purchased equip cost (B)	0
Painting	0%	of purchased equip cost (B)	0
Installation Subtotal Standard Expenses	0%		**0**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**0**
Total Direct Capital Cost, DC			**1,679,000**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	167,900
Construction & field expenses	10%	of purchased equip cost (B)	167,900
Contractor fees	10%	of purchased equip cost (B)	167,900
Start-up	1%	of purchased equip cost (B)	16,790
Performance test	1%	of purchased equip cost (B)	16,790
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	50,370
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	**587,650**
Ozone Generator, Installed Cost			**0**
Total Capital Investment (TCI) = DC + IC			**2,266,650**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**2,266,650**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr	3,675
Supervisor	15%	15% of Operator Costs	551
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr	3,675
Maintenance Materials	100%	of maintenance labor costs	3,675
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
PRB Coal	2,000,000	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2	2,000,000
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**2,011,578**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	6,947
Administration (2% total capital costs)	2%	of total capital costs (TCI)	45,333
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	22,667
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	22,667
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	189,672
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**287,284**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,298,862**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-20: NOx Control - Alstom LNB (Low NOx Burners) + Over Fire Air (OFA), PRB Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		Δ P in H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	801,500		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**Δ P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5	kW/lb O_3				0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs					
Ozone Needed	1.8	lb O3/lb NOx	-	lb/hr O3	
Oxygen Needed	10%	wt O2 to O3 conversion	0	lb/hr O2	0 scfh O2
LTO Cooling Water	150	gal/lb O3	0	gpm	
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf			
Circulating Water Rate	0	gpm			
Water Makeup Rate/WW Disch =	20%	of circulating water rate =	0	gpm	
Scrubber Cost	10	$/scfm Gas	$0		Incremental cost per BOC. Need to increase vessel size over standard absorber.
Ozone Generator	$350	lb O3/day	$0	Installed	Installed cost factor per BOC.

Operating Cost Calculations — **Annual hours of operation:** **7,947** — **Utilization Rate:** **68%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	$/Hr	0.1	hr/8 hr shift	99	3,675	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	551	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	99	3,675	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	3,675	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	1	2,000,000	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-21: NOx Control - Alstom LNB (Low NOx Burners) + Over Fire Air (OFA), Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F
Expected Utiliztion Rate	68%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F
			Dry Std Flow Rate	464,261	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**1,460,000**
Purchased Equipment Total (B)	15%	of control device cost (A)	**1,679,000**
Installation - Standard Costs	0%	of purchased equip cost (B)	0
Installation - Site Specific Costs			NA
Installation Total			0
Total Direct Capital Cost, DC			1,679,000
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	587,650
Total Capital Investment (TCI) = DC + IC			**2,266,650**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	11,578
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	287,284
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**298,862**

Emission Control Cost Calculation

Pollutant	Baseline Emis. T/yr	Predicted Limit lb/hr	Cont. Emis. lb/MMBtu	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	576.0	**0.32**	1546.2	592.8	504
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1 March 2006 Cost Estimate from Alstom Power Inc, Option 2 . Installation cost included.
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)
3 Control efficiency basis 0.2 lb NOx/MMBtu average per May 2005 Cost Estimate from Alstom Power Inc, Option 2
4 Assumed 0.1 hr/shift operatior and maintenance labor for LNB

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-21: NOx Control - Alstom LNB (Low NOx Burners) + Over Fire Air (OFA), Lignite Coal

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) (1)		**1,460,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC		
Instrumentation	10% of control device cost (A)	146,000
Sales Taxes	0.0% of control device cost (A)	0
Freight	5% of control device cost (A)	73,000
Purchased Equipment Total (B)	15%	**1,679,000**
Installation [1]		
Foundations & supports	0% of purchased equip cost (B)	0
Handling & erection	0% of purchased equip cost (B)	0
Electrical	0% of purchased equip cost (B)	0
Piping	0% of purchased equip cost (B)	0
Insulation	0% of purchased equip cost (B)	0
Painting	0% of purchased equip cost (B)	0
Installation Subtotal Standard Expenses	0%	**0**
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Site Specific - Other	Site Specific	NA
Total Site Specific Costs		NA
Installation Total		**0**
Total Direct Capital Cost, DC		**1,679,000**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	167,900
Construction & field expenses	10% of purchased equip cost (B)	167,900
Contractor fees	10% of purchased equip cost (B)	167,900
Start-up	1% of purchased equip cost (B)	16,790
Performance test	1% of purchased equip cost (B)	16,790
Model Studies	NA of purchased equip cost (B)	NA
Contingencies	3% of purchased equip cost (B)	50,370
Total Indirect Capital Costs, IC	35% of purchased equip cost (B)	**587,650**
Ozone Generator, Installed Cost		**0**
Total Capital Investment (TCI) = DC + IC		**2,266,650**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**2,266,650**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	37.00 $/Hr, 0.1 hr/8 hr shift, 7947 hr/yr	3,675
Supervisor	15% 15% of Operator Costs	551
Maintenance		
Maintenance Labor	37.00 $/Hr, 0.1 hr/8 hr shift, 7947 hr/yr	3,675
Maintenance Materials	100% of maintenance labor costs	3,675
Utilities, Supplies, Replacements & Waste Management		
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
Total Annual Direct Operating Costs		**11,578**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	6,947
Administration (2% total capital costs)	2% of total capital costs (TCI)	45,333
Property tax (1% total capital costs)	1% of total capital costs (TCI)	22,667
Insurance (1% total capital costs)	1% of total capital costs (TCI)	22,667
Capital Recovery	8% for a 20- year equipment life and a 5.5% interest rate	189,672
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**287,284**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**298,862**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-21: NOx Control - Alstom LNB (Low NOx Burners) + Over Fire Air (OFA), Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		Δ P in H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	801,500		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**Δ P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5	kW/lb O_3				0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs						
Ozone Needed	1.8	lb O3/lb NOx	-	lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion		0 lb/hr O2		0 scfh O2
LTO Cooling Water	150	gal/lb O3	0 gpm			
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf				
Circulating Water Rate	0	gpm				
Water Makeup Rate/WW Disch =	20%	of circulating water rate =	0 gpm			
Scrubber Cost	10	$/scfm Gas	$0		Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350	lb O3/day	$0 Installed		Installed cost factor per BOC.	

Operating Cost Calculations — **Annual hours of operation: 7,947** — **Utilization Rate: 68%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37.00	$/Hr	0.1	hr/8 hr shift	99	3,675	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr
Supervisor	15%	of Op.			NA	551	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	99	3,675	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	3,675	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 7947 hr/yr, 68% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1 Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1 Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Appendix B

Cost Threshold Documentation

Summary of Relevant Economic Feasibility ($/ton) Control Costs

		Avg. Expected Values ($/ton)		Limiting/Marginal values ($/ton)		
Reference	Regulatory Body/Rule	SO_2	NOx	SO_2	NOx	Comments
FR Notice 6JULY05 Final Rule	BART	100 - 1000	100 - 1000			70 FR 39135
	BART		281 - 1296			70 FR 39135 Table 3
	BART	919				70 FR 39133
	BART					Guidelines disparagingly reference "thousands of dollars per ton" in commenting on the need to exceed MACT and its general unreasonableness.
70 FR 25210 CAIR	CAIR		1300			Estimated Marginal cost 2009
FR Notice 5MAY04 Proposed Rule	BART(proposed rule)	200-1000				BART proposed lists this as values for 90-95% SO2 control, which is still assumed, or .1 to .15 lb/MMBtu. Dropped from final to give states flexibility to require more. Says for scrubbers, bypasses aren't BART, only 100% scrubbing is BART.
	BART(proposed rule)					0.2 lb/MMBtu for NOx is assumed reasonable. Recognizes that some sources may need SCR to get this level. For those, state discretion of the cost vs. visibility value is necessary.
Midwest RPO Report Referencing CAIR	CAIR(using IPM)			1000	1500	
	CAIR (2009 in 1999$)		900		2400	
	CAIR (2015 in 1999$)		1800		3000	
	CAIR (depending on Nat'l emissions)			1200 - 3000	1400- 2100	This was modeled with TRUM (Technology Retrofitting Updating Model) to develop the marginal values.
Kammer EPA Decision	Kammer Decision			> 1000	> 1000	
LADCO Midwest RPO Boiler Analysis	LADCO/Midwest RPO	1240 - 3822	607 - 4493			
MANE-VU BART Control Assessment	MANE-VU			200 - 500	200 - 1500	
Bowers vs. SWAPCA	Bowers vs. SWAPCA	300	300	1000	1000	954-1134 was ruled too much, in favor of 256-310 for SO2. This did consider incremental value. Sections XVII to XIX
WRAP Trading Program Methodology	WRAP			3000		
	EPA - Referenced by Wrap					References EPA-600S\7-90-018. Low is <$500/ton, Moderate is $500-3000/ton, High is over $3000/ton

The dollars per ton estimates cited above were obtained from BART guidance, documentation of similar regulatory programs such as CAIR, and relevant court decisions. These materials indicate that most EPA sanctioned documents, including the final BART ruling, concretely support an average expected reasonable cost range of $1,300 to $1,800 per ton of NOx removed and a range of $1,000 to $1,300 per ton of SO_2 removed. The BART presumptive limits were set based on cost effective controls that were on average less than these ranges. As an example, the presumptive SO_2 limit was established based on an average cost effectiveness of less than $1,000/ton. As the cost analysis extends into RPO, WRAP and other regional planning documentation, the cost ranges become more variable and difficult to predict. For ease of comparison, the federally established ranges for NOx and SO_2 were used as a BART cost threshold basis.

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July 3, 2007

Mr Terry O'Clair
North Dakota Department of Health
Division of Air Quality
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

RE: Great River Energy – Coal Creek and Stanton Stations Supplemental Information for Cost Effectiveness under BART

Dear Mr O'Clair:

As follow-up to our June 4, 2007, meeting with you and Mr. David Glatt, this document serves to outline information relevant to determining an appropriate cost effectiveness threshold for evaluations under Best Available Retrofit Technology (BART). Great River Energy (GRE) submits this information as an addendum to the BART analyses and proposal documents that have been submitted to the North Dakota Department of Health (NDDH) for GRE's Coal Creek and Stanton stations. This information and proposal is for your consideration, and we look forward to continuing our dialogue with you on this matter.

Cost effectiveness is one of several important factors evaluated to determine BART in accordance with U S. Environmental Protection Agency (EPA) rules and guidance. The EPA is specific in its assignment of presumptive BART emission rates and cost effectiveness expectations.[1] Alternative cost effectiveness values referenced through Section 309 of the Clean Air Act are of interest, but are not as specifically tailored to the goals of the BART rules.

The NDDH has suggested a value deemed cost effective for purposes of economic impacts under BART. This value stems from a reference in the 2004 proposed rule for BART determinations.[2] Specifically, the proposed BART Rule references a draft technical support document[3] (TSD) for

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[1] Technical Support Document for the Best Available Retrofit Technology (BART) Notice of Final Rulemaking – Setting BART SO_2 Limits for Electric Generating Units: Control Technology and Cost Effectiveness, April 2005. Note that scatter plot evaluations for NOx and SO_2 illustrate that presumptive levels are established from large electricity generating units (EGUs) to ensure the highest visibility reduction.

[2] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Proposed Rule; F R. Vol. 69, No 87, May 5, 2004, p. 25198

[3] Western Regional Air Partnership Regional Haze BART (Trading Program Option) TSD 6A, Draft: July 16, 1999

the Western Regional Air Partnership's (WRAP) Annex[4] to a report submitted to the EPA by the Grand Canyon Visibility Transport Commission (GCVTC) in 1996.[5]

The cost effectiveness ranges stated in this WRAP TSD reference an EPA assessment of NOx and SO_2 controls for coal-fired boilers that was published in 1990.[6,7] While the information presented is of interest to BART, a straight inflation adjustment from an analysis performed in the late 1980s and published in 1990 does not provide an accurate reflection of current pollution control technologies and associated capital and operating cost effectiveness

The 1990 EPA document presents a range of control costs that vary by coal sulfur content, boiler type, and generating capacity. It further states that cost estimates rely heavily on site-specific parameters and that both cost and pollutant removal efficiency should be balanced when selecting a control technology for a given boiler. At the time of the report, many technologies considered for BART, including selective non-catalytic reduction (SNCR) for NOx, were not commercially available and are therefore not reflected in the analysis. With the wide variety of specific control costs presented in the document, the range of \$500 to \$3,000 presented as moderate in the WRAP TSD is a subjective number that broadly incorporated all NOx and SO_2 costs for every type and size of utility.

The document states that \$3,000 was used as an approximation to exclude controls that meet BACT level emissions. While BACT controls have been accepted as BART in many cases, the opposite is not necessarily true. Therefore, while BACT average and incremental cost effectiveness thresholds may be reviewed while determining BART cost effectiveness, the EPA's BART Rule and TSDs as well as associated visibility improvements should ultimately be the determinative guidance.

The WRAP TSD was produced under the assumption that BART may not be required for EGUs, which is the premise of the WRAP trading program. Further, in the executive summary to the WRAP annex, it is explained that the goal of WRAP is to employ reductions that are "better than BART" to achieve greater reductions than dictated by reasonable progress goals

For these reasons, WRAP cost estimates include more than just "BART-eligible sources." As a final WRAP comment, note that the WRAP Annex explicitly sets program penalties at \$5,000/ton of excess emissions.[8] This penalty is established at "three to four times greater than the expected market trading price," which is, by definition, an expected cost effectiveness of approximately \$1,200/ton to \$1,600/ton.

---

[4] Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and A Backstop Market Trading Program, September 29, 2000

[5] Report from Grand Canyon Visibility Transport Commission to the United States Environmental Protection Agency, June 1996

[6] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Proposed Rule; F.R. Vol. 69, No. 87, May 5, 2004, p. 25198.

[7] Assessment of Control Technologies for Reducing Emissions of SO_2 and NOx from Existing Coal-Fired Utility Boilers, EPA-600/7-90-018, September 1990

[8] Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and A Backstop Market Trading Program, September 29, 2000, p. 47

Given the outdated nature of the EPA control assessment that is at the root of WRAP's $500 to $3,000/ton range, it is critically important to rely on more recent cost documentation as provided by the EPA in the BART Rule and associated technical support documents and as provided in GRE's BART analyses reports to the NDDH.

With respect to cost effectiveness as defined in the BART Final Rule,[9] the expected control costs range from $900/ton to $2,400/ton for SO_2 removal and from $300/ton to $1,300/ton for NOx, with most NOx estimates at less than $1,000/ton. Again, these estimates rely heavily on boiler type, capacity, and the fuel burned. The following two excerpted figures illustrate not only the EPA's intent to evaluate BART cost effectiveness on the type and size of boiler, but also confirms that average cost effectiveness is established at a much lower level than that suggested by the NDDH. As an example, highlighted in the two excerpted figures are the rows that would apply to Stanton Station.

FIGURE 1

Unit capacity (MW)	Tons (K) of SO_2 emitted in 2001	Percent of BART eligible coal-fired unit's 2001 emissions	Calculated average cost effectiveness for MW grouping ($/ton SO_2 removed)	Percent of estimated removable BART SO_2 emissions from coal-fired units*
<50 MW	26	0.4	1982	0.3
50–100 MW	93	1.4	2399	1.6
100–150 MW	171	2.5	1796	2.2
150–200 MW	235	3.5	1324	3.4
200–250 MW	253	3.8	1282	3.1
250–300 MW	281	3.2	1128	4.0
>300 MW	5712	85.2		84.8
All Units	6707	100	984	100
BART Units (>200MW)	6246	92.2	919	91.9

TABLE 3.—AVERAGE COST-EFFECTIVENESS OF NOx CONTROLS FOR BART-ELIGIBLE COAL-FIRED UNITS

Unit type	Coal type	Number units nation-wide	National average ($/ton)
Dry-bottom wall-fired	Bituminous	114	1220
	Sub-bituminous	66	576
	Lignite	3	1298
Tangential-fired	Bituminous	105	567
	Sub-bituminous	72	281
	Lignite	9	614
Cell Burners	Bituminous	32	1287
	Sub-bituminous	3	1021
Dry-turbo-fired	Bituminous	7	775
	Sub-bituminous	7	509
Wet-bottom	Bituminous	6	378
Cyclones (with SCR)	All	56	900

In the determination of NOx control cost effectiveness the NDDH should also be cognizant of determinations made by other states in EPA Region 8. As an example, in Colorado's final BART guidance[10] it has been stated that no post-combustion NOx controls will be required, precluding the need to consider SNCR and selective catalytic reduction (SCR) as potential control options.

[9] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule; F.R. Vol. 70, No. 128, July 6, 2005, p. 39133-39135

[10] Colorado BART, March 16, 2006

In the proposed BART Rule[11] the EPA also states that post-combustion NOx controls should not be necessary, other than on cyclone units.

The BART Final Rule further supports that visibility impacts are a key component of the BART determination. If one control technology provides a significant improvement in visibility over another, the State may and should consider this information in its BART determination Under this assumption, one cost effectiveness threshold would not be appropriate for all units because there would be varying degrees of visibility improvements.

In terms of visibility improvement, a 0.5 deciview (dV) level has already been determined by the EPA to be a "contribution threshold" for states in determining BART-eligible sources that cause or contribute to visibility impairment and thus become "subject to BART." It can be asserted that any change in impairment from an individual facility with BART-eligible sources less than 0.5 dV can and should be deemed insignificant by a state. In the 2005 document from the NDDH addressing regional haze status[12] the NDDH determined that a newly permitted coal-fired ethanol production facility and a new 175-MW power plant that will be located closer to Class I areas than GRE's facilities would not adversely affect visibility in the North Dakota Class I areas. The fact that these two projects have already been deemed insignificant supports a *de minimis* contribution threshold.

We understand that regional-scale dispersion modeling for BART is pending. Until this analysis is completed it is unknown whether North Dakota will meet its reasonable further progress goals Accordingly, before requiring emission controls beyond BART, the regional-scale dispersion modeling analysis should be completed with source attribution assessments including those from North Dakota, other contributing states and Canadian sources with their projected reductions. If it can be shown that sources outside the United States are preventing North Dakota Class I areas from meeting their glide path goals, consideration should be given to revising the natural background goal to account for sources that cannot be controlled under the EPA regional haze rules.

Cost effectiveness thresholds have been determined for many other regulatory programs similar to BART. However, BART has the distinct goal of improving/reducing regional haze and is unique in its consideration of visibility impacts. Regardless of the references used to determine cost effectiveness thresholds, it is obvious that pollutant specific thresholds are supported by the EPA. GRE maintains that based on the EPA BART Rule with ranges of $900/ton to $2,400/ton for SO_2 removal and $300/ton to $1,300/ton for NOx removal, and associated references presented in this document, a value of $1,500/ton or less is appropriate for determining cost effectiveness for both NOx and SO_2 control technologies under BART.

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[11] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Proposed Rule; F.R. Vol 69, No. 87, May 5, 2004, p 25202

[12] Report on Progress Made Toward the National Visibility Goal, November 2005.

Should you have any questions regarding this submittal, please contact me or Greg Archer at 763-241-2278.

Sincerely,

GREAT RIVER ENERGY

Mary Jo Roth
Manager, Environmental Services

c: David Glatt – NDDH
Greg Archer – GRE
Deb Nelson – GRE
Steve Smokey – GRE, Stanton
Diane Stockdill – GRE, Coal Creek
Joel Trinkle – Barr Engineering Co.

Appendix C

Visibility Modeling

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
1200 Missouri Avenue, Bismarck, ND 58504-5264
P.O. Box 5520, Bismarck, ND 58506-5520
701.328.5200 (fax)
www.ndhealth.gov

November 30, 2005

Mr. Steve Smokey
Environmental Coordinator
Great River Energy
4001 Highway 200A
Stanton, ND 58571

Dear Mr. Smokey:

As specified in the June 15, 2005 final amendments to the EPA July, 1999 regional haze rule, the Department has completed visibility modeling to determine which North Dakota BART-eligible (Best Available Retrofit Technology) sources are subject to BART. The Department's visibility analysis for this BART screening followed the protocol outlined in "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota" (North Dakota Department of Health, November, 2005).

As you are aware, the Great River Energy Stanton Generating Station Unit 1 is a BART-eligible source. Completed visibility modeling for Stanton Station Unit 1 indicates that the maximum 98^{th} percentile delta-deciview prediction for the facility exceeds the BART screening threshold of 0.5 deciviews. Therefore, Stanton Unit 1 is subject to BART.

Two summaries of modeling results are enclosed. Attachment A provides a summary of 98^{th} percentile predictions for the worst-case meteorological year for all BART-eligible facilities. Attachment B provides more detailed results specific to the Stanton Station Unit 1. Included in Attachment B are results for all delta-deciview metrics recommended in the North Dakota protocol, for each year of meteorological data. Also provided are worst-case day and receptor, and the percent contribution for each species.

If you have any questions regarding these results, please contact Steve Weber or Rob White of my staff at (701)328-5188. We look forward to working with you to develop an appropriate BART control strategy for Stanton Station Unit 1.

Sincerely,

Steve Weber for

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/SW:csc
Enc:
xc/enc: Deb Nelson - Great River Energy

Attachment A

Summary of BART Screening Results
98th Percentile Prediction for Worst-case Met. Year (2000-2002)
(24-hr Delta-Deciview)

	TRNP South	TRNP North	TRNP Elk. Ranch	Lostwood NWA
Leland Olds Station	6.22	5.32	4.49	5.42
Milton R Young Station	6.69	5.58	6.10	4.88
Coal Creek Station	4.48	3.56	3.04	4.04
Stanton Station Unit 1	1.68	1.54	1.43	1.35
Heskett Station Unit 2	0.82	0.54	0.61	0.58
Mandan Refinery	0.05	0.04	0.04	0.04

29-Nov-05

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Base Case) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	3.134	5.367	2.234	2000	74	48	102	2.80	82.39	17.54	0.05	0.01
98th %tile Delta-DV	0.937	3.170	2.234	2000	71	45	45	2.80	73.49	26.34	0.14	0.02
90th %tile Delta-DV	0.228	2.356	2.127	2000	110	49	103	2.30	52.31	46.77	0.79	0.13

Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	3.031	5.264	2.234	2000	36	82	71	2.80	70.43	29.39	0.15	0.03
98th %tile Delta-DV	0.947	3.181	2.234	2000	44	83	112	2.80	62.34	37.42	0.20	0.04
90th %tile Delta-DV	0.221	2.327	2.106	2000	261	83	112	2.20	91.67	7.86	0.41	0.07

Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	3.787	6.020	2.234	2000	74	90	72	2.80	83.38	16.56	0.05	0.01
98th %tile Delta-DV	0.868	3.101	2.234	2000	44	90	72	2.80	66.10	33.73	0.14	0.03
90th %tile Delta-DV	0.184	2.312	2.127	2000	100	90	72	2.30	80.07	19.68	0.21	0.04

Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	4.385	6.660	2.275	2000	47	97	79	2.90	86.50	13.42	0.06	0.01
98th %tile Delta-DV	0.991	3.267	2.275	2000	72	97	79	2.90	80.71	19.22	0.06	0.01
90th %tile Delta-DV	0.344	2.576	2.232	2000	212	99	81	2.70	98.41	1.47	0.09	0.03

Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 1) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.059	3.293	2.234	2000	74	48	102	2.80	41.84	57.94	0.17	0.05
98th %tile Delta-DV	0.320	2.574	2.255	2000	11	51	105	2.90	30.84	68.92	0.17	0.06
90th %tile Delta-DV	0.066	2.215	2.149	2000	199	45	45	2.40	67.89	30.40	1.47	0.24

Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.352	3.585	2.234	2000	36	82	71	2.80	26.53	73.03	0.36	0.08
98th %tile Delta-DV	0.458	2.691	2.234	2000	44	83	112	2.80	20.23	79.27	0.42	0.08
90th %tile Delta-DV	0.080	2.207	2.127	2000	101	82	71	2.30	33.14	66.16	0.60	0.10

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.278	3.511	2.234	2000	74	90	72	2.80	43.39	56.40	0.17	0.05
98th %tile Delta-DV	0.224	2.330	2.106	2000	247	90	72	2.20	84.32	14.46	1.06	0.16
90th %tile Delta-DV	0.054	2.182	2.127	2000	98	90	72	2.30	33.90	65.82	0.22	0.06

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.698	3.974	2.275	2000	47	97	79	2.90	39.61	60.15	0.19	0.04
98th %tile Delta-DV	0.340	2.615	2.275	2000	88	91	73	2.90	11.97	87.33	0.56	0.14
90th %tile Delta-DV	0.118	2.350	2.232	2000	185	91	73	2.70	61.29	37.88	0.70	0.13

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 2) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.056	3.289	2.234	2000	74	48	102	2.80	41.98	57.80	0.17	0.05
98th %tile Delta-DV	0.318	2.573	2.255	2000	11	51	105	2.90	30.96	68.80	0.18	0.06
90th %tile Delta-DV	0.066	2.215	2.149	2000	199	45	45	2.40	68.00	30.28	1.47	0.24

Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.347	3.580	2.234	2000	36	82	71	2.80	26.64	72.92	0.36	0.08
98th %tile Delta-DV	0.456	2.689	2.234	2000	44	83	112	2.80	20.32	79.18	0.43	0.08
90th %tile Delta-DV	0.080	2.207	2.127	2000	101	82	71	2.30	33.26	66.04	0.60	0.10

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.274	3.508	2.234	2000	74	90	72	2.80	43.52	56.26	0.17	0.05
98th %tile Delta-DV	0.224	2.330	2.106	2000	247	90	72	2.20	84.39	14.39	1.06	0.16
90th %tile Delta-DV	0.054	2.182	2.127	2000	98	90	72	2.30	34.02	65.69	0.22	0.06

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.693	3.968	2.275	2000	47	97	79	2.90	39.75	60.02	0.19	0.04
98th %tile Delta-DV	0.338	2.613	2.275	2000	88	91	73	2.90	12.02	87.27	0.57	0.14
90th %tile Delta-DV	0.117	2.350	2.232	2000	185	91	73	2.70	61.42	37.75	0.70	0.13

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 3) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.026	3.260	2.234	2000	74	48	102	2.80	43.26	56.51	0.18	0.05
98th %tile Delta-DV	0.305	2.581	2.276	2000	336	6	6	3.00	15.23	83.87	0.80	0.10
90th %tile Delta-DV	0.065	2.214	2.149	2000	199	45	45	2.40	69.06	29.21	1.50	0.24

Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.300	3.534	2.234	2000	36	82	71	2.80	27.66	71.88	0.37	0.09
98th %tile Delta-DV	0.438	2.671	2.234	2000	44	83	112	2.80	21.17	78.30	0.44	0.08
90th %tile Delta-DV	0.077	2.310	2.234	2000	76	82	71	2.80	28.03	71.69	0.22	0.07

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.239	3.473	2.234	2000	74	90	72	2.80	44.82	54.95	0.18	0.05
98th %tile Delta-DV	0.222	2.328	2.106	2000	247	90	72	2.20	85.00	13.77	1.07	0.16
90th %tile Delta-DV	0.054	2.202	2.149	2000	187	90	72	2.40	94.08	5.37	0.45	0.09

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.644	3.920	2.275	2000	47	97	79	2.90	41.03	58.73	0.20	0.04
98th %tile Delta-DV	0.323	2.599	2.275	2000	88	91	73	2.90	12.58	86.68	0.59	0.15
90th %tile Delta-DV	0.113	2.345	2.232	2000	197	99	81	2.70	16.41	82.50	0.84	0.25

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 4) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.891	3.124	2.234	2000	74	48	102	2.80	50.19	49.55	0.21	0.06
98th %tile Delta-DV	0.253	2.529	2.276	2000	335	53	107	3.00	37.01	61.86	1.01	0.13
90th %tile Delta-DV	0.055	2.182	2.127	2000	287	46	46	2.30	57.89	41.62	0.41	0.08

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.086	3.320	2.234	2000	36	82	71	2.80	33.47	65.97	0.45	0.10
98th %tile Delta-DV	0.356	2.483	2.127	2000	98	71	60	2.30	24.61	74.15	1.09	0.15
90th %tile Delta-DV	0.065	2.192	2.127	2000	101	82	71	2.30	40.84	58.30	0.74	0.13

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.081	3.315	2.234	2000	74	90	72	2.80	51.79	47.95	0.20	0.06
98th %tile Delta-DV	0.215	2.321	2.106	2000	247	90	72	2.20	87.91	10.82	1.10	0.17
90th %tile Delta-DV	0.049	2.219	2.170	2000	155	90	72	2.50	58.32	41.36	0.24	0.09

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.422	3.697	2.275	2000	47	97	79	2.90	47.99	51.73	0.23	0.05
98th %tile Delta-DV	0.260	2.557	2.297	2000	14	91	73	3.00	37.05	62.43	0.45	0.07
90th %tile Delta-DV	0.096	2.329	2.232	2000	203	91	73	2.70	81.78	17.60	0.53	0.08

Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 5) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.538	2.771	2.234	2000	74	48	102	2.80	84.63	14.93	0.35	0.09
98th %tile Delta-DV	0.144	2.377	2.234	2000	71	45	45	2.80	76.68	22.22	0.93	0.16
90th %tile Delta-DV	0.035	2.162	2.127	2000	110	49	103	2.30	53.45	40.45	5.25	0.86

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	0.513	2.747	2.234	2000	36	82	71	2.80	72.90	25.89	0.99	0.22
98th %tile Delta-DV	0.144	2.377	2.234	2000	44	83	112	2.80	65.55	32.81	1.37	0.26
90th %tile Delta-DV	0.034	2.161	2.127	2000	101	82	71	2.30	78.20	20.14	1.42	0.24

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.669	2.902	2.234	2000	74	90	72	2.80	85.50	14.08	0.33	0.09
98th %tile Delta-DV	0.131	2.365	2.234	2000	44	90	72	2.80	69.45	29.40	0.96	0.19
90th %tile Delta-DV	0.028	2.156	2.127	2000	100	90	72	2.30	81.42	16.94	1.37	0.27

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.840	3.116	2.275	2000	47	97	79	2.90	83.64	15.87	0.40	0.09
98th %tile Delta-DV	0.154	2.429	2.275	2000	72	97	79	2.90	83.50	16.05	0.38	0.07
90th %tile Delta-DV	0.052	2.197	2.145	2000	131	91	73	2.30	46.47	51.85	1.44	0.24

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 6) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	2.432	4.665	2.234	2000	74	48	102	2.80	76.42	23.49	0.07	0.02
98th %tile Delta-DV	0.691	2.946	2.255	2000	11	51	105	2.90	66.90	32.98	0.08	0.03
90th %tile Delta-DV	0.174	2.302	2.127	2000	287	46	46	2.30	81.90	17.95	0.13	0.03

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.456	4.689	2.234	2000	36	82	71	2.80	62.09	37.68	0.19	0.04
98th %tile Delta-DV	0.770	3.004	2.234	2000	44	83	112	2.80	53.36	46.35	0.25	0.05
90th %tile Delta-DV	0.171	2.426	2.255	2000	16	82	71	2.90	33.45	66.31	0.17	0.06

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 1

TRNP ELKHORN RANCH

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.950	5.183	2.234	2000	74	90	72	2.80	77.56	22.35	0.07	0.02
98th %tile Delta-DV	0.696	2.929	2.234	2000	44	90	72	2.80	57.43	42.36	0.18	0.04
90th %tile Delta-DV	0.139	2.267	2.127	2000	100	90	72	2.30	73.50	26.17	0.27	0.05

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 1

LOSTWOOD NWA

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	3.652	5.928	2.275	2000	47	97	79	2.90	74.87	25.04	0.08	0.02
98th %tile Delta-DV	0.755	3.030	2.275	2000	72	97	79	2.90	74.35	25.56	0.07	0.01
90th %tile Delta-DV	0.262	2.407	2.145	2000	125	94	76	2.30	40.36	59.12	0.34	0.18

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 7) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	2.429	4.662	2.234	2000	74	48	102	2.80	76.52	23.39	0.07	0.02
98th %tile Delta-DV	0.690	2.945	2.255	2000	11	51	105	2.90	67.03	32.86	0.08	0.03
90th %tile Delta-DV	0.174	2.302	2.127	2000	287	46	46	2.30	81.98	17.86	0.13	0.03

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	2.451	4.685	2.234	2000	36	82	71	2.80	62.22	37.55	0.19	0.04
98th %tile Delta-DV	0.769	3.002	2.234	2000	44	83	112	2.80	53.50	46.21	0.25	0.05
90th %tile Delta-DV	0.171	2.425	2.255	2000	16	82	71	2.90	33.57	66.19	0.17	0.06

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	2.947	5.180	2.234	2000	74	90	72	2.80	77.66	22.25	0.07	0.02
98th %tile Delta-DV	0.694	2.928	2.234	2000	44	90	72	2.80	57.57	42.22	0.18	0.04
90th %tile Delta-DV	0.139	2.267	2.127	2000	100	90	72	2.30	73.61	26.06	0.27	0.05

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	3.648	5.923	2.275	2000	47	97	79	2.90	74.97	24.93	0.08	0.02
98th %tile Delta-DV	0.754	3.029	2.275	2000	72	97	79	2.90	74.46	25.45	0.08	0.01
90th %tile Delta-DV	0.261	2.407	2.145	2000	125	94	76	2.30	40.49	58.99	0.34	0.18

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 8) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	2.403	4.636	2.234	2000	74	48	102	2.80	77.45	22.46	0.07	0.02
98th %tile Delta-DV	0.679	2.934	2.255	2000	11	51	105	2.90	68.16	31.72	0.08	0.03
90th %tile Delta-DV	0.173	2.300	2.127	2000	287	46	46	2.30	82.73	17.11	0.13	0.03

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	2.410	4.643	2.234	2000	36	82	71	2.80	63.42	36.35	0.19	0.04
98th %tile Delta-DV	0.752	2.985	2.234	2000	44	83	112	2.80	54.80	44.89	0.25	0.05
90th %tile Delta-DV	0.165	2.419	2.255	2000	16	82	71	2.90	34.74	65.02	0.18	0.07

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	2.917	5.151	2.234	2000	74	90	72	2.80	78.56	21.35	0.07	0.02
98th %tile Delta-DV	0.680	2.914	2.234	2000	44	90	72	2.80	58.85	40.93	0.18	0.04
90th %tile Delta-DV	0.137	2.265	2.127	2000	100	90	72	2.30	74.60	25.06	0.28	0.06

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	3.609	5.884	2.275	2000	47	97	79	2.90	75.95	23.95	0.08	0.02
98th %tile Delta-DV	0.744	3.020	2.275	2000	72	97	79	2.90	75.46	24.44	0.08	0.01
90th %tile Delta-DV	0.256	2.401	2.145	2000	98	91	73	2.30	69.20	30.61	0.16	0.03

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 9) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	2.285	4.518	2.234	2000	74	48	102	2.80	81.94	17.96	0.08	0.02
98th %tile Delta-DV	0.663	2.897	2.234	2000	71	45	45	2.80	72.99	26.78	0.20	0.03
90th %tile Delta-DV	0.162	2.289	2.127	2000	110	49	103	2.30	51.29	47.41	1.12	0.18

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT												
Largest Delta-DV	2.220	4.454	2.234	2000	36	82	71	2.80	69.51	30.23	0.21	0.05
98th %tile Delta-DV	0.672	2.906	2.234	2000	44	83	112	2.80	61.53	38.13	0.29	0.05
90th %tile Delta-DV	0.157	2.327	2.170	2000	153	83	112	2.50	40.21	59.07	0.62	0.10

Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 1

TRNP ELKHORN RANCH												
Largest Delta-DV	2.784	5.018	2.234	2000	74	90	72	2.80	82.89	17.02	0.07	0.02
98th %tile Delta-DV	0.614	2.848	2.234	2000	44	90	72	2.80	65.37	34.38	0.20	0.04
90th %tile Delta-DV	0.129	2.256	2.127	2000	100	90	72	2.30	79.45	20.19	0.30	0.06

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 1

LOSTWOOD NWA												
Largest Delta-DV	3.429	5.704	2.275	2000	47	97	79	2.90	80.69	19.20	0.09	0.02
98th %tile Delta-DV	0.701	2.976	2.275	2000	72	97	79	2.90	80.32	19.58	0.08	0.02
90th %tile Delta-DV	0.240	2.472	2.232	2000	212	99	81	2.70	98.30	1.53	0.14	0.04

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 10) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.979	4.212	2.234	2000	74	48	102	2.80	96.12	3.76	0.09	0.02
98th %tile Delta-DV	0.553	2.659	2.106	2000	238	3	3	2.20	98.62	0.59	0.69	0.10
90th %tile Delta-DV	0.137	2.371	2.234	2000	41	47	101	2.80	80.52	18.01	1.29	0.19

Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.714	3.948	2.234	2000	36	82	71	2.80	92.41	7.25	0.28	0.06
98th %tile Delta-DV	0.557	2.705	2.149	2000	184	58	47	2.40	98.95	0.78	0.23	0.04
90th %tile Delta-DV	0.122	2.228	2.106	2000	238	85	114	2.20	98.95	0.68	0.32	0.05

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	2.438	4.672	2.234	2000	74	90	72	2.80	96.37	3.52	0.08	0.02
98th %tile Delta-DV	0.445	2.678	2.234	2000	44	90	72	2.80	91.11	8.56	0.28	0.06
90th %tile Delta-DV	0.106	2.234	2.127	2000	110	90	72	2.30	75.80	21.05	2.68	0.47

Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	2.957	5.233	2.275	2000	47	97	79	2.90	95.85	4.02	0.10	0.02
98th %tile Delta-DV	0.591	2.866	2.275	2000	72	97	79	2.90	95.80	4.09	0.10	0.02
90th %tile Delta-DV	0.191	2.531	2.340	2000	362	99	81	3.20	95.02	4.91	0.05	0.02

Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 11) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.847	3.080	2.234	2000	74	48	102	2.80	26.46	73.27	0.22	0.06
98th %tile Delta-DV	0.290	2.566	2.276	2000	316	46	46	3.00	20.40	79.25	0.30	0.04
90th %tile Delta-DV	0.048	2.175	2.127	2000	287	46	46	2.30	33.12	66.32	0.47	0.09

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.184	3.417	2.234	2000	36	82	71	2.80	15.29	84.21	0.41	0.09
98th %tile Delta-DV	0.369	2.603	2.234	2000	74	67	56	2.80	26.18	73.60	0.16	0.06
90th %tile Delta-DV	0.062	2.295	2.234	2000	56	82	71	2.80	19.27	79.98	0.66	0.09

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.014	3.248	2.234	2000	74	90	72	2.80	27.70	72.02	0.22	0.06
98th %tile Delta-DV	0.183	2.311	2.127	2000	110	90	72	2.30	4.87	93.32	1.55	0.27
90th %tile Delta-DV	0.040	2.168	2.127	2000	97	90	72	2.30	14.28	85.35	0.29	0.08

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.385	3.660	2.275	2000	47	97	79	2.90	24.70	75.02	0.24	0.05
98th %tile Delta-DV	0.320	2.595	2.275	2000	88	91	73	2.90	6.36	92.89	0.60	0.15
90th %tile Delta-DV	0.094	2.434	2.340	2000	362	99	81	3.20	21.56	78.30	0.10	0.05

Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 12) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.843	3.077	2.234	2000	74	48	102	2.80	26.56	73.16	0.22	0.06
98th %tile Delta-DV	0.289	2.565	2.276	2000	316	46	46	3.00	20.49	79.16	0.30	0.04
90th %tile Delta-DV	0.048	2.175	2.127	2000	287	46	46	2.30	33.24	66.20	0.47	0.09

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.178	3.412	2.234	2000	36	82	71	2.80	15.36	84.13	0.42	0.09
98th %tile Delta-DV	0.368	2.601	2.234	2000	74	67	56	2.80	26.29	73.49	0.16	0.06
90th %tile Delta-DV	0.062	2.295	2.234	2000	56	82	71	2.80	19.35	79.89	0.66	0.09

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.011	3.244	2.234	2000	74	90	72	2.80	27.81	71.91	0.22	0.06
98th %tile Delta-DV	0.182	2.310	2.127	2000	110	90	72	2.30	4.89	93.28	1.56	0.27
90th %tile Delta-DV	0.040	2.168	2.127	2000	97	90	72	2.30	14.35	85.28	0.29	0.08

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.379	3.654	2.275	2000	47	97	79	2.90	24.80	74.91	0.24	0.05
98th %tile Delta-DV	0.318	2.593	2.275	2000	88	91	73	2.90	6.40	92.85	0.60	0.15
90th %tile Delta-DV	0.094	2.433	2.340	2000	362	99	81	3.20	21.65	78.20	0.10	0.05

Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 13) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.813	3.046	2.234	2000	74	48	102	2.80	27.60	72.11	0.23	0.06
98th %tile Delta-DV	0.277	2.553	2.276	2000	316	46	46	3.00	21.39	78.25	0.31	0.05
90th %tile Delta-DV	0.046	2.174	2.127	2000	287	46	46	2.30	34.40	65.02	0.48	0.10

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.131	3.364	2.234	2000	36	82	71	2.80	16.04	83.43	0.43	0.10
98th %tile Delta-DV	0.354	2.588	2.234	2000	74	67	56	2.80	27.32	72.45	0.17	0.06
90th %tile Delta-DV	0.059	2.293	2.234	2000	56	82	71	2.80	20.17	79.05	0.69	0.10

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.975	3.208	2.234	2000	74	90	72	2.80	28.88	70.83	0.23	0.06
98th %tile Delta-DV	0.174	2.301	2.127	2000	110	90	72	2.30	5.13	92.95	1.63	0.29
90th %tile Delta-DV	0.038	2.166	2.127	2000	97	90	72	2.30	15.00	84.61	0.30	0.09

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.329	3.604	2.275	2000	47	97	79	2.90	25.81	73.89	0.25	0.05
98th %tile Delta-DV	0.303	2.579	2.275	2000	88	91	73	2.90	6.71	92.49	0.63	0.16
90th %tile Delta-DV	0.090	2.430	2.340	2000	362	99	81	3.20	22.55	77.29	0.10	0.05

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 14) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.674	2.908	2.234	2000	74	48	102	2.80	33.50	66.14	0.28	0.07
98th %tile Delta-DV	0.221	2.454	2.234	2000	46	48	102	2.80	7.24	91.91	0.71	0.14
90th %tile Delta-DV	0.039	2.167	2.127	2000	100	46	46	2.30	19.58	79.47	0.79	0.16

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	0.913	3.146	2.234	2000	36	82	71	2.80	20.09	79.24	0.54	0.12
98th %tile Delta-DV	0.292	2.526	2.234	2000	74	67	56	2.80	33.19	66.53	0.21	0.08
90th %tile Delta-DV	0.048	2.281	2.234	2000	56	82	71	2.80	24.92	74.11	0.85	0.12

Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.812	3.046	2.234	2000	74	90	72	2.80	34.94	64.71	0.27	0.08
98th %tile Delta-DV	0.135	2.262	2.127	2000	110	90	72	2.30	6.61	90.91	2.10	0.37
90th %tile Delta-DV	0.033	2.266	2.234	2000	56	90	72	2.80	31.31	68.14	0.46	0.10

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.099	3.374	2.275	2000	47	97	79	2.90	31.57	68.06	0.30	0.06
98th %tile Delta-DV	0.236	2.511	2.275	2000	88	91	73	2.90	8.65	90.33	0.81	0.21
90th %tile Delta-DV	0.074	2.241	2.167	2000	286	99	81	2.40	27.46	71.08	1.28	0.18

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 15) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.314	2.547	2.234	2000	74	48	102	2.80	73.36	25.87	0.61	0.16
98th %tile Delta-DV	0.079	2.249	2.170	2000	164	46	46	2.50	95.16	1.87	2.59	0.38
90th %tile Delta-DV	0.020	2.147	2.127	2000	287	46	46	2.30	77.54	21.15	1.08	0.22

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	0.329	2.563	2.234	2000	36	82	71	2.80	57.34	40.75	1.55	0.35
98th %tile Delta-DV	0.097	2.225	2.127	2000	98	71	60	2.30	45.55	49.87	4.04	0.54
90th %tile Delta-DV	0.021	2.149	2.127	2000	287	85	114	2.30	71.28	27.60	0.91	0.21

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.388	2.622	2.234	2000	74	90	72	2.80	74.67	24.59	0.58	0.16
98th %tile Delta-DV	0.086	2.319	2.234	2000	44	90	72	2.80	53.19	45.04	1.48	0.29
90th %tile Delta-DV	0.017	2.144	2.127	2000	138	90	72	2.30	80.36	18.94	0.53	0.17

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.498	2.773	2.275	2000	47	97	79	2.90	71.88	27.28	0.69	0.15
98th %tile Delta-DV	0.090	2.365	2.275	2000	72	97	79	2.90	71.68	27.55	0.65	0.12
90th %tile Delta-DV	0.034	2.179	2.145	2000	125	94	76	2.30	35.26	60.64	2.66	1.44

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 21) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.055	3.289	2.234	2000	74	48	102	2.80	41.99	57.82	0.15	0.04
98th %tile Delta-DV	0.318	2.573	2.255	2000	11	51	105	2.90	30.97	68.83	0.15	0.05
90th %tile Delta-DV	0.066	2.215	2.149	2000	199	45	45	2.40	68.18	30.36	1.25	0.20

Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.346	3.579	2.234	2000	36	82	71	2.80	26.66	72.97	0.31	0.07
98th %tile Delta-DV	0.455	2.582	2.127	2000	98	71	60	2.30	19.14	80.05	0.72	0.10
90th %tile Delta-DV	0.080	2.207	2.127	2000	101	82	71	2.30	33.29	66.11	0.51	0.09

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.274	3.507	2.234	2000	74	90	72	2.80	43.54	56.28	0.14	0.04
98th %tile Delta-DV	0.223	2.329	2.106	2000	247	90	72	2.20	84.54	14.42	0.90	0.14
90th %tile Delta-DV	0.054	2.181	2.127	2000	98	90	72	2.30	34.04	65.72	0.19	0.05

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.693	3.968	2.275	2000	47	97	79	2.90	39.76	60.04	0.16	0.03
98th %tile Delta-DV	0.338	2.613	2.275	2000	88	91	73	2.90	12.04	87.36	0.48	0.12
90th %tile Delta-DV	0.117	2.349	2.232	2000	185	91	73	2.70	61.50	37.80	0.59	0.11

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 22) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.066	3.300	2.234	2000	74	48	102	2.80	41.55	57.21	0.98	0.26
98th %tile Delta-DV	0.326	2.602	2.276	2000	335	53	107	3.00	28.64	66.38	4.41	0.58
90th %tile Delta-DV	0.071	2.220	2.149	2000	203	51	105	2.40	45.14	53.33	1.28	0.25

Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.373	3.606	2.234	2000	36	82	71	2.80	26.10	71.44	2.00	0.46
98th %tile Delta-DV	0.466	2.700	2.234	2000	44	83	112	2.80	19.85	77.35	2.36	0.45
90th %tile Delta-DV	0.081	2.314	2.234	2000	76	82	71	2.80	26.60	71.84	1.19	0.36

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.286	3.520	2.234	2000	74	90	72	2.80	43.09	55.69	0.95	0.27
98th %tile Delta-DV	0.236	2.342	2.106	2000	247	90	72	2.20	79.83	13.61	5.68	0.88
90th %tile Delta-DV	0.055	2.204	2.149	2000	187	90	72	2.40	91.48	5.51	2.50	0.52

Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.710	3.985	2.275	2000	47	97	79	2.90	39.32	59.38	1.07	0.23
98th %tile Delta-DV	0.349	2.624	2.275	2000	88	91	73	2.90	11.64	84.47	3.10	0.79
90th %tile Delta-DV	0.122	2.354	2.232	2000	185	91	73	2.70	59.13	36.34	3.80	0.73

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Base Case) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.736	3.970	2.234	2001	64	52	106	2.80	84.43	15.53	0.04	0.01
98th %tile Delta-DV	0.901	3.177	2.276	2001	329	53	107	3.00	69.58	30.05	0.30	0.07
90th %tile Delta-DV	0.214	2.447	2.234	2001	43	52	106	2.80	82.16	17.79	0.04	0.02

Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	4.052	6.307	2.255	2001	12	83	112	2.90	82.21	17.66	0.11	0.02
98th %tile Delta-DV	1.205	3.438	2.234	2001	42	82	71	2.80	82.36	17.57	0.06	0.02
90th %tile Delta-DV	0.319	2.467	2.149	2001	195	85	114	2.40	97.64	2.29	0.06	0.01

Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	2.026	4.280	2.255	2001	12	90	72	2.90	81.37	18.57	0.05	0.01
98th %tile Delta-DV	0.733	2.839	2.106	2001	261	90	72	2.20	93.65	6.27	0.07	0.02
90th %tile Delta-DV	0.144	2.271	2.127	2001	94	90	72	2.30	82.66	17.29	0.04	0.01

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	4.914	7.254	2.340	2001	326	91	73	3.20	82.39	17.50	0.09	0.02
98th %tile Delta-DV	1.351	3.626	2.275	2001	41	91	73	2.90	73.92	25.97	0.09	0.02
90th %tile Delta-DV	0.386	2.596	2.211	2001	179	93	75	2.60	69.89	29.70	0.37	0.04

Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 1) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.729	2.835	2.106	2001	258	36	36	2.20	18.15	80.61	1.11	0.13
98th %tile Delta-DV	0.322	2.556	2.234	2001	63	53	107	2.80	49.33	50.52	0.12	0.03
90th %tile Delta-DV	0.061	2.336	2.276	2001	310	54	108	3.00	31.86	67.61	0.38	0.15

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.465	3.719	2.255	2001	12	83	112	2.90	40.89	58.71	0.35	0.05
98th %tile Delta-DV	0.385	2.661	2.276	2001	315	82	71	3.00	26.72	72.96	0.26	0.06
90th %tile Delta-DV	0.089	2.195	2.106	2001	248	83	112	2.20	63.77	30.83	4.76	0.64

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.696	2.950	2.255	2001	12	90	72	2.90	40.31	59.48	0.17	0.04
98th %tile Delta-DV	0.241	2.474	2.234	2001	63	90	72	2.80	54.55	45.31	0.12	0.03
90th %tile Delta-DV	0.036	2.185	2.149	2001	195	90	72	2.40	87.37	12.24	0.32	0.07

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.798	4.138	2.340	2001	326	91	73	3.20	40.83	58.83	0.29	0.05
98th %tile Delta-DV	0.526	2.801	2.275	2001	41	91	73	2.90	30.30	69.41	0.23	0.05
90th %tile Delta-DV	0.160	2.370	2.211	2001	179	93	75	2.60	26.32	72.68	0.89	0.11

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 2) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.726	2.832	2.106	2001	258	36	36	2.20	18.23	80.52	1.11	0.13
98th %tile Delta-DV	0.321	2.555	2.234	2001	63	53	107	2.80	49.48	50.38	0.12	0.03
90th %tile Delta-DV	0.061	2.336	2.276	2001	310	54	108	3.00	31.98	67.49	0.38	0.15

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT												
Largest Delta-DV	1.460	3.715	2.255	2001	12	83	112	2.90	41.02	58.58	0.35	0.05
98th %tile Delta-DV	0.383	2.659	2.276	2001	315	82	71	3.00	26.83	72.85	0.26	0.06
90th %tile Delta-DV	0.089	2.195	2.106	2001	248	83	112	2.20	63.88	30.71	4.77	0.64

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

TRNP ELKHORN RANCH												
Largest Delta-DV	0.693	2.948	2.255	2001	12	90	72	2.90	40.45	59.35	0.17	0.04
98th %tile Delta-DV	0.240	2.474	2.234	2001	63	90	72	2.80	54.69	45.16	0.12	0.03
90th %tile Delta-DV	0.036	2.184	2.149	2001	195	90	72	2.40	87.43	12.18	0.32	0.07

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

LOSTWOOD NWA												
Largest Delta-DV	1.793	4.132	2.340	2001	326	91	73	3.20	40.97	58.69	0.29	0.05
98th %tile Delta-DV	0.524	2.799	2.275	2001	41	91	73	2.90	30.42	69.29	0.23	0.05
90th %tile Delta-DV	0.159	2.370	2.211	2001	179	93	75	2.60	26.43	72.57	0.90	0.11

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 3) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.697	2.803	2.106	2001	258	36	36	2.20	19.01	79.70	1.16	0.13
98th %tile Delta-DV	0.313	2.546	2.234	2001	63	53	107	2.80	50.82	49.03	0.12	0.03
90th %tile Delta-DV	0.059	2.334	2.276	2001	310	54	108	3.00	33.10	66.35	0.39	0.16

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.419	3.674	2.255	2001	12	83	112	2.90	42.29	57.30	0.36	0.06
98th %tile Delta-DV	0.369	2.645	2.276	2001	315	82	71	3.00	27.87	71.79	0.27	0.07
90th %tile Delta-DV	0.086	2.320	2.234	2001	85	79	68	2.80	16.67	82.63	0.61	0.08

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.673	2.927	2.255	2001	12	90	72	2.90	41.73	58.06	0.17	0.04
98th %tile Delta-DV	0.234	2.468	2.234	2001	63	90	72	2.80	56.05	43.79	0.12	0.03
90th %tile Delta-DV	0.036	2.184	2.149	2001	195	90	72	2.40	87.98	11.62	0.32	0.07

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.744	4.083	2.340	2001	326	91	73	3.20	42.22	57.42	0.30	0.06
98th %tile Delta-DV	0.506	2.781	2.275	2001	41	91	73	2.90	31.56	68.14	0.24	0.05
90th %tile Delta-DV	0.153	2.364	2.211	2001	179	93	75	2.60	27.45	71.51	0.93	0.11

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 4) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.567	2.673	2.106	2001	258	36	36	2.20	23.53	74.87	1.44	0.16
98th %tile Delta-DV	0.261	2.537	2.276	2001	339	37	37	3.00	16.37	82.99	0.56	0.08
90th %tile Delta-DV	0.054	2.224	2.170	2001	163	51	105	2.50	57.01	42.19	0.67	0.12

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.234	3.488	2.255	2001	12	83	112	2.90	49.12	50.39	0.42	0.06
98th %tile Delta-DV	0.318	2.552	2.234	2001	42	82	71	2.80	50.19	49.52	0.23	0.07
90th %tile Delta-DV	0.073	2.243	2.170	2001	182	86	115	2.50	23.40	74.18	2.14	0.28

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.580	2.834	2.255	2001	12	90	72	2.90	48.65	51.10	0.20	0.04
98th %tile Delta-DV	0.203	2.437	2.234	2001	84	90	72	2.80	39.00	60.49	0.43	0.07
90th %tile Delta-DV	0.034	2.267	2.234	2001	82	90	72	2.80	53.03	46.66	0.25	0.06

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.519	3.859	2.340	2001	326	91	73	3.20	49.03	50.56	0.34	0.06
98th %tile Delta-DV	0.422	2.697	2.275	2001	41	91	73	2.90	37.93	61.71	0.29	0.06
90th %tile Delta-DV	0.133	2.279	2.145	2001	267	99	81	2.30	13.17	85.13	1.42	0.28

Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 5) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.280	2.514	2.234	2001	64	52	106	2.80	86.64	13.03	0.28	0.05
98th %tile Delta-DV	0.141	2.417	2.276	2001	329	53	107	3.00	71.17	26.33	2.02	0.48
90th %tile Delta-DV	0.032	2.266	2.234	2001	43	52	106	2.80	84.78	14.83	0.28	0.11

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	0.742	2.997	2.255	2001	12	83	112	2.90	83.70	15.48	0.71	0.11
98th %tile Delta-DV	0.190	2.423	2.234	2001	42	82	71	2.80	84.74	14.76	0.38	0.11
90th %tile Delta-DV	0.049	2.177	2.127	2001	94	82	71	2.30	83.50	16.20	0.26	0.05

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.340	2.595	2.255	2001	12	90	72	2.90	83.84	15.74	0.35	0.08
98th %tile Delta-DV	0.115	2.242	2.127	2001	92	90	72	2.30	73.90	24.86	1.05	0.19
90th %tile Delta-DV	0.022	2.149	2.127	2001	94	90	72	2.30	85.01	14.71	0.23	0.05

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.917	3.257	2.340	2001	326	91	73	3.20	83.72	15.58	0.59	0.11
98th %tile Delta-DV	0.210	2.355	2.145	2001	259	97	79	2.30	92.58	6.71	0.60	0.11
90th %tile Delta-DV	0.059	2.398	2.340	2001	337	91	73	3.20	60.98	36.57	2.14	0.32

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 6) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.312	3.546	2.234	2001	64	52	106	2.80	78.97	20.96	0.06	0.01
98th %tile Delta-DV	0.715	2.991	2.276	2001	329	53	107	3.00	61.32	38.21	0.39	0.09
90th %tile Delta-DV	0.160	2.394	2.234	2001	43	52	106	2.80	76.14	23.78	0.06	0.02

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	3.201	5.456	2.255	2001	12	83	112	2.90	75.80	24.03	0.14	0.02
98th %tile Delta-DV	0.937	3.170	2.234	2001	63	82	71	2.80	84.92	15.03	0.04	0.01
90th %tile Delta-DV	0.245	2.372	2.127	2001	94	82	71	2.30	74.85	25.09	0.05	0.01

Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.570	3.825	2.255	2001	12	90	72	2.90	75.17	24.75	0.07	0.01
98th %tile Delta-DV	0.541	2.817	2.276	2001	328	90	72	3.00	77.96	21.98	0.04	0.01
90th %tile Delta-DV	0.105	2.232	2.127	2001	302	90	72	2.30	40.62	58.79	0.51	0.08

Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	3.897	6.237	2.340	2001	326	91	73	3.20	76.02	23.84	0.12	0.02
98th %tile Delta-DV	1.062	3.337	2.275	2001	41	91	73	2.90	66.27	33.59	0.11	0.02
90th %tile Delta-DV	0.311	2.457	2.145	2001	93	91	73	2.30	71.18	28.65	0.13	0.05

Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 7) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

									% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.311	3.545	2.234	2001	64	52	106	2.80	79.07	20.87	0.06	0.01
98th %tile Delta-DV	0.714	2.990	2.276	2001	329	53	107	3.00	61.44	38.08	0.39	0.09
90th %tile Delta-DV	0.160	2.394	2.234	2001	43	52	106	2.80	76.24	23.68	0.06	0.02

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	3.197	5.452	2.255	2001	12	83	112	2.90	75.90	23.93	0.14	0.02
98th %tile Delta-DV	0.936	3.169	2.234	2001	63	82	71	2.80	85.00	14.95	0.04	0.01
90th %tile Delta-DV	0.245	2.372	2.127	2001	94	82	71	2.30	74.95	24.99	0.05	0.01

Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.568	3.823	2.255	2001	12	90	72	2.90	75.27	24.64	0.07	0.02
98th %tile Delta-DV	0.541	2.816	2.276	2001	328	90	72	3.00	78.06	21.88	0.04	0.01
90th %tile Delta-DV	0.105	2.232	2.127	2001	302	90	72	2.30	40.75	58.66	0.52	0.08

Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	3.893	6.232	2.340	2001	326	91	73	3.20	76.12	23.74	0.12	0.02
98th %tile Delta-DV	1.060	3.335	2.275	2001	41	91	73	2.90	66.40	33.46	0.11	0.03
90th %tile Delta-DV	0.311	2.456	2.145	2001	93	91	73	2.30	71.29	28.53	0.13	0.05

Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 8) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.298	3.531	2.234	2001	64	52	106	2.80	79.93	20.00	0.06	0.01
98th %tile Delta-DV	0.701	2.976	2.276	2001	329	53	107	3.00	62.64	36.87	0.39	0.09
90th %tile Delta-DV	0.158	2.392	2.234	2001	43	52	106	2.80	77.20	22.72	0.06	0.02

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	3.164	5.419	2.255	2001	12	83	112	2.90	76.84	22.99	0.15	0.02
98th %tile Delta-DV	0.915	3.042	2.127	2001	92	71	60	2.30	46.93	52.39	0.61	0.07
90th %tile Delta-DV	0.241	2.475	2.234	2001	55	82	71	2.80	65.53	34.40	0.05	0.02

Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.550	3.804	2.255	2001	12	90	72	2.90	76.24	23.67	0.07	0.02
98th %tile Delta-DV	0.535	2.810	2.276	2001	328	90	72	3.00	78.97	20.98	0.04	0.01
90th %tile Delta-DV	0.103	2.251	2.149	2001	196	90	72	2.40	96.89	3.01	0.09	0.02

Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	3.854	6.194	2.340	2001	326	91	73	3.20	77.04	22.82	0.12	0.02
98th %tile Delta-DV	1.042	3.317	2.275	2001	41	91	73	2.90	67.58	32.28	0.12	0.03
90th %tile Delta-DV	0.306	2.452	2.145	2001	93	91	73	2.30	72.35	27.47	0.13	0.05

Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 9) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.237	3.471	2.234	2001	64	52	106	2.80	84.08	15.85	0.06	0.01
98th %tile Delta-DV	0.641	2.917	2.276	2001	329	53	107	3.00	68.70	30.76	0.43	0.10
90th %tile Delta-DV	0.149	2.383	2.234	2001	43	52	106	2.80	81.80	18.12	0.06	0.02

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	3.012	5.266	2.255	2001	12	83	112	2.90	81.37	18.45	0.15	0.02
98th %tile Delta-DV	0.854	3.088	2.234	2001	42	82	71	2.80	81.95	17.94	0.08	0.02
90th %tile Delta-DV	0.222	2.371	2.149	2001	195	85	114	2.40	97.53	2.36	0.08	0.02

Number of days with Delta-Deciview > 0.50: 16
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.466	3.721	2.255	2001	12	90	72	2.90	80.94	18.97	0.07	0.02
98th %tile Delta-DV	0.515	2.621	2.106	2001	261	90	72	2.20	93.29	6.59	0.10	0.02
90th %tile Delta-DV	0.101	2.228	2.127	2001	94	90	72	2.30	82.24	17.70	0.05	0.01

Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	3.677	6.016	2.340	2001	326	91	73	3.20	81.52	18.33	0.13	0.02
98th %tile Delta-DV	0.963	3.238	2.275	2001	41	91	73	2.90	73.43	26.42	0.13	0.03
90th %tile Delta-DV	0.272	2.612	2.340	2001	311	97	79	3.20	51.12	48.66	0.17	0.05

Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 10) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.085	3.318	2.234	2001	64	52	106	2.80	96.69	3.23	0.07	0.01
98th %tile Delta-DV	0.544	2.819	2.276	2001	328	45	45	3.00	96.24	3.69	0.05	0.02
90th %tile Delta-DV	0.124	2.230	2.106	2001	248	47	101	2.20	99.49	0.22	0.23	0.05

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	2.611	4.865	2.255	2001	12	83	112	2.90	95.87	3.92	0.18	0.03
98th %tile Delta-DV	0.733	2.966	2.234	2001	42	82	71	2.80	96.16	3.72	0.10	0.03
90th %tile Delta-DV	0.201	2.477	2.276	2001	316	82	71	3.00	93.03	6.78	0.15	0.04

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.252	3.506	2.255	2001	12	90	72	2.90	95.88	4.01	0.09	0.02
98th %tile Delta-DV	0.439	2.715	2.276	2001	328	90	72	3.00	96.56	3.37	0.05	0.02
90th %tile Delta-DV	0.086	2.213	2.127	2001	94	90	72	2.30	96.23	3.70	0.06	0.01

Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	3.204	5.543	2.340	2001	326	91	73	3.20	95.92	3.90	0.15	0.03
98th %tile Delta-DV	0.821	3.054	2.232	2001	196	91	73	2.70	99.01	0.83	0.14	0.02
90th %tile Delta-DV	0.213	2.358	2.145	2001	265	99	81	2.30	96.15	3.35	0.43	0.08

Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 11) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.665	2.771	2.106	2001	258	36	36	2.20	9.98	88.66	1.22	0.14
98th %tile Delta-DV	0.270	2.398	2.127	2001	92	51	105	2.30	14.66	84.84	0.43	0.07
90th %tile Delta-DV	0.043	2.170	2.127	2001	131	53	107	2.30	21.78	77.82	0.31	0.09

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

TRNP NORTH UNIT												
Largest Delta-DV	1.183	3.437	2.255	2001	12	83	112	2.90	25.69	73.81	0.44	0.07
98th %tile Delta-DV	0.334	2.610	2.276	2001	315	82	71	3.00	15.42	84.21	0.30	0.07
90th %tile Delta-DV	0.061	2.188	2.127	2001	145	71	60	2.30	13.45	85.17	1.23	0.15

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

TRNP ELKHORN RANCH												
Largest Delta-DV	0.559	2.814	2.255	2001	12	90	72	2.90	25.24	74.50	0.21	0.05
98th %tile Delta-DV	0.178	2.453	2.276	2001	338	90	72	3.00	9.61	89.09	1.15	0.15
90th %tile Delta-DV	0.024	2.299	2.276	2001	345	90	72	3.00	25.13	74.43	0.37	0.07

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

LOSTWOOD NWA												
Largest Delta-DV	1.506	3.846	2.340	2001	327	99	81	3.20	20.50	79.18	0.26	0.06
98th %tile Delta-DV	0.449	2.725	2.275	2001	41	91	73	2.90	17.87	81.79	0.27	0.06
90th %tile Delta-DV	0.139	2.349	2.211	2001	179	93	75	2.60	15.16	83.69	1.03	0.12

Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 12) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.662	2.768	2.106	2001	258	36	36	2.20	10.03	88.60	1.23	0.14
98th %tile Delta-DV	0.269	2.396	2.127	2001	92	51	105	2.30	14.74	84.76	0.43	0.07
90th %tile Delta-DV	0.043	2.170	2.127	2001	131	53	107	2.30	21.88	77.72	0.32	0.09

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.178	3.433	2.255	2001	12	83	112	2.90	25.79	73.70	0.44	0.07
98th %tile Delta-DV	0.333	2.608	2.276	2001	315	82	71	3.00	15.50	84.13	0.30	0.07
90th %tile Delta-DV	0.061	2.188	2.127	2001	302	86	115	2.30	9.43	89.50	0.94	0.13

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.557	2.812	2.255	2001	12	90	72	2.90	25.35	74.39	0.21	0.05
98th %tile Delta-DV	0.177	2.453	2.276	2001	338	90	72	3.00	9.65	89.04	1.15	0.15
90th %tile Delta-DV	0.023	2.299	2.276	2001	345	90	72	3.00	25.23	74.32	0.38	0.07

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.500	3.839	2.340	2001	327	99	81	3.20	20.59	79.09	0.26	0.06
98th %tile Delta-DV	0.447	2.722	2.275	2001	41	91	73	2.90	17.95	81.71	0.28	0.06
90th %tile Delta-DV	0.138	2.349	2.211	2001	179	93	75	2.60	15.23	83.62	1.04	0.12

Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 13) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.633	2.739	2.106	2001	258	36	36	2.20	10.50	88.07	1.28	0.15
98th %tile Delta-DV	0.257	2.384	2.127	2001	92	51	105	2.30	15.43	84.04	0.45	0.08
90th %tile Delta-DV	0.041	2.168	2.127	2001	131	53	107	2.30	22.82	76.76	0.33	0.09

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.136	3.391	2.255	2001	12	83	112	2.90	26.80	72.67	0.46	0.07
98th %tile Delta-DV	0.319	2.594	2.276	2001	315	82	71	3.00	16.20	83.42	0.31	0.08
90th %tile Delta-DV	0.059	2.293	2.234	2001	89	82	71	2.80	28.58	71.22	0.14	0.06

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.536	2.791	2.255	2001	12	90	72	2.90	26.36	73.37	0.22	0.05
98th %tile Delta-DV	0.169	2.403	2.234	2001	63	90	72	2.80	38.95	60.84	0.17	0.04
90th %tile Delta-DV	0.023	2.298	2.276	2001	345	90	72	3.00	26.22	73.32	0.39	0.07

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.443	3.782	2.340	2001	327	99	81	3.20	21.47	78.20	0.27	0.06
98th %tile Delta-DV	0.429	2.704	2.275	2001	41	91	73	2.90	18.75	80.90	0.29	0.06
90th %tile Delta-DV	0.132	2.343	2.211	2001	179	93	75	2.60	15.91	82.88	1.08	0.13

Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 14) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.502	2.608	2.106	2001	258	36	36	2.20	13.34	84.85	1.63	0.19
98th %tile Delta-DV	0.203	2.330	2.127	2001	92	51	105	2.30	19.59	79.74	0.57	0.10
90th %tile Delta-DV	0.036	2.185	2.149	2001	190	46	46	2.40	93.48	3.37	2.80	0.34

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	0.945	3.199	2.255	2001	12	83	112	2.90	32.55	66.81	0.55	0.09
98th %tile Delta-DV	0.255	2.530	2.276	2001	315	82	71	3.00	20.34	79.18	0.39	0.10
90th %tile Delta-DV	0.053	2.159	2.106	2001	248	83	112	2.20	53.58	37.36	7.99	1.07

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.442	2.696	2.255	2001	12	90	72	2.90	32.14	67.53	0.27	0.06
98th %tile Delta-DV	0.143	2.377	2.234	2001	63	90	72	2.80	46.07	53.69	0.20	0.05
90th %tile Delta-DV	0.021	2.148	2.127	2001	99	90	72	2.30	41.82	57.96	0.14	0.07

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.181	3.520	2.340	2001	327	99	81	3.20	26.59	73.00	0.33	0.08
98th %tile Delta-DV	0.344	2.620	2.275	2001	41	91	73	2.90	23.43	76.13	0.36	0.08
90th %tile Delta-DV	0.106	2.316	2.211	2001	179	93	75	2.60	19.95	78.53	1.36	0.16

Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 15) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.160	2.393	2.234	2001	64	52	106	2.80	76.44	22.98	0.49	0.10
98th %tile Delta-DV	0.091	2.367	2.276	2001	329	53	107	3.00	55.25	40.87	3.13	0.75
90th %tile Delta-DV	0.019	2.252	2.234	2001	43	52	106	2.80	73.58	25.74	0.49	0.19

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	0.438	2.693	2.255	2001	12	83	112	2.90	71.96	26.62	1.22	0.19
98th %tile Delta-DV	0.110	2.343	2.234	2001	42	82	71	2.80	73.52	25.62	0.66	0.20
90th %tile Delta-DV	0.029	2.178	2.149	2001	205	58	47	2.40	93.12	2.64	3.78	0.46

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.199	2.454	2.255	2001	12	90	72	2.90	72.18	27.09	0.60	0.13
98th %tile Delta-DV	0.063	2.339	2.276	2001	328	90	72	3.00	75.67	23.83	0.39	0.11
90th %tile Delta-DV	0.012	2.140	2.127	2001	94	90	72	2.30	73.94	25.58	0.41	0.08

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.544	2.883	2.340	2001	326	91	73	3.20	71.97	26.83	1.01	0.19
98th %tile Delta-DV	0.129	2.404	2.275	2001	41	91	73	2.90	62.93	35.89	0.97	0.21
90th %tile Delta-DV	0.039	2.250	2.211	2001	168	93	75	2.60	88.04	10.00	1.71	0.25

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 21) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.724	2.830	2.106	2001	258	36	36	2.20	18.27	80.68	0.95	0.11
98th %tile Delta-DV	0.321	2.555	2.234	2001	63	53	107	2.80	49.49	50.39	0.10	0.02
90th %tile Delta-DV	0.061	2.336	2.276	2001	310	54	108	3.00	32.00	67.55	0.32	0.13

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.459	3.714	2.255	2001	12	83	112	2.90	41.05	58.61	0.30	0.05
98th %tile Delta-DV	0.383	2.659	2.276	2001	315	82	71	3.00	26.85	72.88	0.22	0.05
90th %tile Delta-DV	0.088	2.194	2.106	2001	248	83	112	2.20	64.41	30.97	4.09	0.54

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.693	2.948	2.255	2001	12	90	72	2.90	40.46	59.37	0.14	0.03
98th %tile Delta-DV	0.240	2.474	2.234	2001	63	90	72	2.80	54.71	45.17	0.10	0.03
90th %tile Delta-DV	0.036	2.184	2.149	2001	195	90	72	2.40	87.48	12.19	0.27	0.06

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.792	4.131	2.340	2001	326	91	73	3.20	40.99	58.72	0.24	0.05
98th %tile Delta-DV	0.524	2.799	2.275	2001	41	91	73	2.90	30.44	69.32	0.20	0.04
90th %tile Delta-DV	0.159	2.369	2.211	2001	179	93	75	2.60	26.46	72.68	0.76	0.09

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 22) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.766	2.872	2.106	2001	258	36	36	2.20	17.24	76.12	5.96	0.69
98th %tile Delta-DV	0.323	2.557	2.234	2001	63	53	107	2.80	49.14	50.03	0.67	0.16
90th %tile Delta-DV	0.062	2.338	2.276	2001	310	54	108	3.00	31.20	65.86	2.10	0.84

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.486	3.740	2.255	2001	12	83	112	2.90	40.27	57.50	1.93	0.30
98th %tile Delta-DV	0.389	2.665	2.276	2001	315	82	71	3.00	26.44	71.77	1.44	0.36
90th %tile Delta-DV	0.093	2.326	2.234	2001	85	79	68	2.80	15.46	80.88	3.21	0.44

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.700	2.954	2.255	2001	12	90	72	2.90	40.07	58.79	0.94	0.20
98th %tile Delta-DV	0.242	2.475	2.234	2001	63	90	72	2.80	54.32	44.85	0.66	0.17
90th %tile Delta-DV	0.036	2.185	2.149	2001	195	90	72	2.40	85.87	11.96	1.79	0.38

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.819	4.158	2.340	2001	326	91	73	3.20	40.32	57.77	1.60	0.30
98th %tile Delta-DV	0.531	2.806	2.275	2001	41	91	73	2.90	30.02	68.38	1.31	0.29
90th %tile Delta-DV	0.166	2.377	2.211	2001	179	93	75	2.60	25.24	69.32	4.86	0.58

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Base Case) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	3.841	6.074	2.234	2002	73	49	103	2.80	78.06	21.83	0.09	0.02
98th %tile Delta-DV	1.675	3.781	2.106	2002	233	53	107	2.20	86.14	13.70	0.14	0.02
90th %tile Delta-DV	0.310	2.416	2.106	2002	270	48	102	2.20	55.36	44.28	0.30	0.06

Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	4.809	7.042	2.234	2002	73	89	118	2.80	72.40	27.42	0.16	0.02
98th %tile Delta-DV	1.540	3.774	2.234	2002	50	71	60	2.80	63.26	36.45	0.26	0.04
90th %tile Delta-DV	0.312	2.546	2.234	2002	91	82	71	2.80	77.06	22.87	0.05	0.02

Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	4.345	6.579	2.234	2002	73	90	72	2.80	76.06	23.81	0.11	0.02
98th %tile Delta-DV	1.432	3.666	2.234	2002	39	90	72	2.80	78.88	20.97	0.12	0.03
90th %tile Delta-DV	0.233	2.467	2.234	2002	83	90	72	2.80	51.30	48.24	0.41	0.05

Number of days with Delta-Deciview > 0.50: 14
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	2.442	4.717	2.275	2002	74	97	79	2.90	81.69	18.24	0.05	0.01
98th %tile Delta-DV	1.150	3.489	2.340	2002	363	97	79	3.20	77.19	22.76	0.04	0.01
90th %tile Delta-DV	0.308	2.541	2.232	2002	195	99	81	2.70	71.54	27.70	0.68	0.09

Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 4

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 1) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.555	3.810	2.255	2002	26	48	102	2.90	27.55	72.02	0.37	0.06
98th %tile Delta-DV	0.668	2.774	2.106	2002	250	56	110	2.20	43.65	55.68	0.52	0.15
90th %tile Delta-DV	0.096	2.223	2.127	2002	105	45	45	2.30	14.51	84.26	1.05	0.18

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	2.155	4.388	2.234	2002	73	89	118	2.80	28.64	70.89	0.41	0.05
98th %tile Delta-DV	0.595	2.829	2.234	2002	83	71	60	2.80	17.47	81.65	0.76	0.11
90th %tile Delta-DV	0.097	2.267	2.170	2002	155	82	71	2.50	50.00	49.90	0.07	0.03

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.779	4.012	2.234	2002	73	90	72	2.80	32.75	66.88	0.31	0.05
98th %tile Delta-DV	0.517	2.751	2.234	2002	39	90	72	2.80	35.26	64.31	0.33	0.09
90th %tile Delta-DV	0.074	2.308	2.234	2002	82	90	72	2.80	21.20	78.34	0.39	0.07

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.821	3.096	2.275	2002	74	97	79	2.90	40.69	59.10	0.18	0.04
98th %tile Delta-DV	0.410	2.749	2.340	2002	363	97	79	3.20	34.36	65.50	0.12	0.03
90th %tile Delta-DV	0.088	2.234	2.145	2002	134	97	79	2.30	12.59	86.14	1.06	0.21

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 2) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.550	3.804	2.255	2002	26	48	102	2.90	27.66	71.90	0.38	0.06
98th %tile Delta-DV	0.666	2.772	2.106	2002	250	56	110	2.20	43.78	55.55	0.52	0.15
90th %tile Delta-DV	0.095	2.329	2.234	2002	91	47	101	2.80	34.60	65.34	0.02	0.04

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	2.147	4.380	2.234	2002	73	89	118	2.80	28.76	70.77	0.42	0.05
98th %tile Delta-DV	0.593	2.826	2.234	2002	83	71	60	2.80	17.55	81.57	0.76	0.12
90th %tile Delta-DV	0.096	2.266	2.170	2002	155	82	71	2.50	50.14	49.76	0.07	0.03

Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.772	4.006	2.234	2002	73	90	72	2.80	32.88	66.76	0.32	0.05
98th %tile Delta-DV	0.515	2.749	2.234	2002	39	90	72	2.80	35.38	64.19	0.34	0.09
90th %tile Delta-DV	0.074	2.307	2.234	2002	82	90	72	2.80	21.30	78.24	0.39	0.07

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.818	3.094	2.275	2002	74	97	79	2.90	40.82	58.96	0.18	0.04
98th %tile Delta-DV	0.408	2.748	2.340	2002	363	97	79	3.20	34.48	65.37	0.12	0.03
90th %tile Delta-DV	0.088	2.233	2.145	2002	134	97	79	2.30	12.65	86.07	1.06	0.21

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 3) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.497	3.752	2.255	2002	26	48	102	2.90	28.71	70.84	0.39	0.06
98th %tile Delta-DV	0.648	2.754	2.106	2002	250	56	110	2.20	45.02	54.29	0.54	0.16
90th %tile Delta-DV	0.092	2.326	2.234	2002	91	47	101	2.80	35.80	64.14	0.02	0.04

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	2.076	4.310	2.234	2002	73	89	118	2.80	29.85	69.67	0.43	0.06
98th %tile Delta-DV	0.569	2.802	2.234	2002	83	71	60	2.80	18.32	80.77	0.79	0.12
90th %tile Delta-DV	0.094	2.264	2.170	2002	155	82	71	2.50	51.45	48.45	0.07	0.03

Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.716	3.950	2.234	2002	73	90	72	2.80	34.05	65.58	0.33	0.05
98th %tile Delta-DV	0.499	2.733	2.234	2002	39	90	72	2.80	36.55	63.01	0.35	0.10
90th %tile Delta-DV	0.071	2.304	2.234	2002	82	90	72	2.80	22.22	77.30	0.41	0.07

Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.794	3.069	2.275	2002	74	97	79	2.90	42.12	57.66	0.18	0.04
98th %tile Delta-DV	0.395	2.734	2.340	2002	363	97	79	3.20	35.68	64.17	0.12	0.03
90th %tile Delta-DV	0.085	2.317	2.232	2002	185	97	79	2.70	42.09	57.28	0.50	0.14

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 4) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.256	3.511	2.255	2002	26	49	103	2.90	34.89	64.56	0.47	0.08
98th %tile Delta-DV	0.565	2.671	2.106	2002	250	56	110	2.20	51.83	47.37	0.62	0.18
90th %tile Delta-DV	0.080	2.186	2.106	2002	220	51	105	2.20	62.90	36.83	0.21	0.07

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.751	3.985	2.234	2002	73	89	118	2.80	35.98	63.43	0.52	0.07
98th %tile Delta-DV	0.460	2.693	2.234	2002	83	71	60	2.80	22.78	76.09	0.99	0.15
90th %tile Delta-DV	0.083	2.189	2.106	2002	241	82	71	2.20	88.85	10.73	0.36	0.06

Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.460	3.694	2.234	2002	73	90	72	2.80	40.55	59.00	0.39	0.06
98th %tile Delta-DV	0.426	2.659	2.234	2002	39	90	72	2.80	43.00	56.48	0.41	0.11
90th %tile Delta-DV	0.060	2.208	2.149	2002	189	90	72	2.40	95.24	3.19	1.36	0.22

Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.685	2.960	2.275	2002	74	97	79	2.90	49.11	50.63	0.21	0.05
98th %tile Delta-DV	0.334	2.674	2.340	2002	363	97	79	3.20	42.30	57.52	0.14	0.04
90th %tile Delta-DV	0.073	2.305	2.232	2002	185	97	79	2.70	48.91	50.35	0.58	0.16

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 5) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.675	2.908	2.234	2002	73	49	103	2.80	80.64	18.62	0.63	0.11
98th %tile Delta-DV	0.270	2.504	2.234	2002	74	49	103	2.80	83.18	16.29	0.44	0.09
90th %tile Delta-DV	0.047	2.281	2.234	2002	75	51	105	2.80	89.89	9.95	0.11	0.06

Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	0.876	3.110	2.234	2002	73	89	118	2.80	75.20	23.57	1.09	0.14
98th %tile Delta-DV	0.241	2.474	2.234	2002	50	71	60	2.80	66.67	31.32	1.76	0.25
90th %tile Delta-DV	0.047	2.323	2.276	2002	352	71	60	3.00	71.29	28.00	0.56	0.15

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.779	3.012	2.234	2002	73	90	72	2.80	78.70	20.42	0.76	0.12
98th %tile Delta-DV	0.232	2.465	2.234	2002	39	90	72	2.80	79.76	19.28	0.76	0.21
90th %tile Delta-DV	0.035	2.269	2.234	2002	67	90	72	2.80	54.80	41.79	3.01	0.39

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.405	2.680	2.275	2002	74	97	79	2.90	84.28	15.27	0.37	0.08
98th %tile Delta-DV	0.183	2.479	2.297	2002	29	97	79	3.00	81.45	17.91	0.54	0.09
90th %tile Delta-DV	0.048	2.344	2.297	2002	31	97	79	3.00	88.69	11.16	0.11	0.04

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 6) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	3.047	5.281	2.234	2002	73	49	103	2.80	71.12	28.74	0.12	0.02
98th %tile Delta-DV	1.293	3.526	2.234	2002	74	49	103	2.80	74.28	25.62	0.09	0.02
90th %tile Delta-DV	0.243	2.413	2.170	2002	178	55	109	2.50	88.70	11.11	0.16	0.03

Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	3.926	6.160	2.234	2002	73	89	118	2.80	64.45	35.32	0.21	0.03
98th %tile Delta-DV	1.221	3.370	2.149	2002	199	79	68	2.40	78.42	20.66	0.82	0.10
90th %tile Delta-DV	0.239	2.473	2.234	2002	91	82	71	2.80	69.96	29.95	0.06	0.03

Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	3.489	5.722	2.234	2002	73	90	72	2.80	68.73	31.10	0.15	0.02
98th %tile Delta-DV	1.111	3.344	2.234	2002	39	90	72	2.80	71.65	28.15	0.15	0.04
90th %tile Delta-DV	0.191	2.297	2.106	2002	255	90	72	2.20	92.29	6.91	0.68	0.12

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.884	4.159	2.275	2002	74	97	79	2.90	75.55	24.36	0.07	0.02
98th %tile Delta-DV	0.886	3.226	2.340	2002	363	97	79	3.20	70.13	29.80	0.05	0.01
90th %tile Delta-DV	0.236	2.576	2.340	2002	313	99	81	3.20	51.02	48.84	0.08	0.06

Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 7) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

TRNP SOUTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	3.043	5.277	2.234	2002	73	49	103	2.80	71.23	28.62	0.12	0.02
98th %tile Delta-DV	1.291	3.524	2.234	2002	74	49	103	2.80	74.39	25.51	0.09	0.02
90th %tile Delta-DV	0.243	2.413	2.170	2002	178	55	109	2.50	88.76	11.05	0.16	0.03

Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	3.920	6.153	2.234	2002	73	89	118	2.80	64.58	35.19	0.21	0.03
98th %tile Delta-DV	1.220	3.369	2.149	2002	199	79	68	2.40	78.50	20.58	0.82	0.10
90th %tile Delta-DV	0.239	2.472	2.234	2002	91	82	71	2.80	70.08	29.83	0.06	0.03

Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	3.484	5.717	2.234	2002	73	90	72	2.80	68.85	30.98	0.15	0.02
98th %tile Delta-DV	1.109	3.343	2.234	2002	39	90	72	2.80	71.76	28.04	0.15	0.04
90th %tile Delta-DV	0.191	2.297	2.106	2002	255	90	72	2.20	92.33	6.87	0.68	0.12

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.881	4.157	2.275	2002	74	97	79	2.90	75.66	24.26	0.07	0.02
98th %tile Delta-DV	0.885	3.224	2.340	2002	363	97	79	3.20	70.25	29.69	0.05	0.01
90th %tile Delta-DV	0.235	2.575	2.340	2002	313	99	81	3.20	51.16	48.70	0.08	0.06

Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 8) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	3.004	5.238	2.234	2002	73	49	103	2.80	72.30	27.55	0.12	0.02
98th %tile Delta-DV	1.272	3.505	2.234	2002	64	53	107	2.80	56.33	43.31	0.31	0.05
90th %tile Delta-DV	0.242	2.412	2.170	2002	178	55	109	2.50	89.29	10.52	0.16	0.03

Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	3.861	6.094	2.234	2002	73	89	118	2.80	65.77	33.99	0.21	0.03
98th %tile Delta-DV	1.208	3.357	2.149	2002	199	79	68	2.40	79.31	19.76	0.83	0.10
90th %tile Delta-DV	0.235	2.469	2.234	2002	91	82	71	2.80	71.16	28.75	0.07	0.03

Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	3.436	5.670	2.234	2002	73	90	72	2.80	69.96	29.86	0.15	0.02
98th %tile Delta-DV	1.095	3.328	2.234	2002	39	90	72	2.80	72.77	27.03	0.15	0.04
90th %tile Delta-DV	0.190	2.296	2.106	2002	255	90	72	2.20	92.66	6.54	0.68	0.12

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.859	4.135	2.275	2002	74	97	79	2.90	76.62	23.29	0.07	0.02
98th %tile Delta-DV	0.872	3.212	2.340	2002	363	97	79	3.20	71.34	28.60	0.05	0.01
90th %tile Delta-DV	0.230	2.569	2.340	2002	313	99	81	3.20	52.45	47.41	0.08	0.06

Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 9) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	2.828	5.061	2.234	2002	73	49	103	2.80	77.53	22.31	0.13	0.02
98th %tile Delta-DV	1.196	3.302	2.106	2002	233	53	107	2.20	85.67	14.10	0.20	0.03
90th %tile Delta-DV	0.220	2.326	2.106	2002	270	48	102	2.20	54.39	45.10	0.42	0.09

Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	3.591	5.824	2.234	2002	73	89	118	2.80	71.73	28.01	0.23	0.03
98th %tile Delta-DV	1.104	3.337	2.234	2002	50	71	60	2.80	62.58	37.00	0.37	0.05
90th %tile Delta-DV	0.219	2.452	2.234	2002	91	82	71	2.80	76.51	23.39	0.07	0.03

Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	3.222	5.455	2.234	2002	73	90	72	2.80	75.48	24.34	0.16	0.02
98th %tile Delta-DV	1.028	3.261	2.234	2002	39	90	72	2.80	77.76	22.03	0.16	0.05
90th %tile Delta-DV	0.165	2.398	2.234	2002	83	90	72	2.80	50.50	48.85	0.58	0.07

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.761	4.037	2.275	2002	74	97	79	2.90	81.30	18.60	0.08	0.02
98th %tile Delta-DV	0.813	3.153	2.340	2002	363	97	79	3.20	76.69	23.24	0.06	0.02
90th %tile Delta-DV	0.218	2.450	2.232	2002	195	99	81	2.70	70.61	28.30	0.97	0.12

Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 10) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	2.372	4.605	2.234	2002	73	51	105	2.80	95.08	4.73	0.17	0.03
98th %tile Delta-DV	0.957	3.233	2.276	2002	337	55	109	3.00	92.67	7.19	0.10	0.04
90th %tile Delta-DV	0.186	2.292	2.106	2002	241	49	103	2.20	99.30	0.63	0.06	0.01

Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	2.871	5.104	2.234	2002	73	89	118	2.80	93.19	6.47	0.30	0.04
98th %tile Delta-DV	0.780	3.014	2.234	2002	50	71	60	2.80	90.00	9.39	0.53	0.08
90th %tile Delta-DV	0.183	2.310	2.127	2002	116	82	71	2.30	82.69	16.36	0.79	0.16

Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	2.655	4.889	2.234	2002	73	90	72	2.80	94.34	5.43	0.20	0.03
98th %tile Delta-DV	0.782	2.910	2.127	2002	293	90	72	2.30	90.34	8.81	0.72	0.13
90th %tile Delta-DV	0.125	2.231	2.106	2002	233	90	72	2.20	92.40	6.25	1.20	0.15

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.511	3.786	2.275	2002	74	97	79	2.90	96.02	3.86	0.09	0.02
98th %tile Delta-DV	0.685	2.982	2.297	2002	29	97	79	3.00	95.19	4.65	0.14	0.02
90th %tile Delta-DV	0.168	2.400	2.232	2002	195	99	81	2.70	91.95	6.63	1.26	0.16

Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 11) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.355	3.610	2.255	2002	26	48	102	2.90	15.98	83.52	0.43	0.07
98th %tile Delta-DV	0.556	2.831	2.276	2002	336	54	108	3.00	6.52	92.60	0.77	0.11
90th %tile Delta-DV	0.089	2.216	2.127	2002	105	45	45	2.30	7.82	90.85	1.13	0.19

Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.874	4.107	2.234	2002	73	89	118	2.80	16.71	82.74	0.48	0.06
98th %tile Delta-DV	0.516	2.644	2.127	2002	294	79	68	2.30	6.77	92.08	1.01	0.14
90th %tile Delta-DV	0.072	2.178	2.106	2002	220	82	71	2.20	28.32	71.27	0.31	0.10

Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.509	3.742	2.234	2002	73	90	72	2.80	19.58	79.98	0.38	0.06
98th %tile Delta-DV	0.429	2.663	2.234	2002	39	90	72	2.80	21.34	78.14	0.40	0.11
90th %tile Delta-DV	0.050	2.177	2.127	2002	296	90	72	2.30	10.99	88.36	0.58	0.07

Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.773	3.112	2.340	2002	337	91	73	3.20	5.24	94.25	0.39	0.12
98th %tile Delta-DV	0.341	2.680	2.340	2002	363	97	79	3.20	20.74	79.08	0.14	0.04
90th %tile Delta-DV	0.078	2.223	2.145	2002	122	97	79	2.30	15.11	84.21	0.44	0.24

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 12) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.349	3.604	2.255	2002	26	48	102	2.90	16.05	83.44	0.44	0.07
98th %tile Delta-DV	0.553	2.829	2.276	2002	336	54	108	3.00	6.55	92.56	0.78	0.11
90th %tile Delta-DV	0.088	2.216	2.127	2002	105	45	45	2.30	7.86	90.80	1.14	0.19

Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.866	4.099	2.234	2002	73	89	118	2.80	16.79	82.66	0.49	0.06
98th %tile Delta-DV	0.514	2.641	2.127	2002	294	79	68	2.30	6.81	92.04	1.01	0.14
90th %tile Delta-DV	0.071	2.177	2.106	2002	220	82	71	2.20	28.44	71.15	0.31	0.10

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.502	3.736	2.234	2002	73	90	72	2.80	19.67	79.89	0.38	0.06
98th %tile Delta-DV	0.427	2.661	2.234	2002	39	90	72	2.80	21.43	78.04	0.41	0.11
90th %tile Delta-DV	0.050	2.177	2.127	2002	296	90	72	2.30	11.05	88.30	0.58	0.07

Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.769	3.109	2.340	2002	337	91	73	3.20	5.27	94.22	0.39	0.12
98th %tile Delta-DV	0.339	2.679	2.340	2002	363	97	79	3.20	20.84	78.99	0.14	0.04
90th %tile Delta-DV	0.077	2.223	2.145	2002	122	97	79	2.30	15.18	84.14	0.44	0.24

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 13) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.296	3.550	2.255	2002	26	48	102	2.90	16.76	82.71	0.46	0.07
98th %tile Delta-DV	0.528	2.803	2.276	2002	336	54	108	3.00	6.87	92.20	0.82	0.12
90th %tile Delta-DV	0.084	2.212	2.127	2002	105	45	45	2.30	8.25	90.35	1.20	0.20

Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.793	4.027	2.234	2002	73	89	118	2.80	17.54	81.89	0.51	0.07
98th %tile Delta-DV	0.490	2.618	2.127	2002	294	79	68	2.30	7.14	91.65	1.06	0.14
90th %tile Delta-DV	0.069	2.175	2.106	2002	220	82	71	2.20	29.57	70.01	0.32	0.11

Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.445	3.678	2.234	2002	73	90	72	2.80	20.51	79.03	0.39	0.06
98th %tile Delta-DV	0.411	2.644	2.234	2002	39	90	72	2.80	22.30	77.16	0.42	0.12
90th %tile Delta-DV	0.047	2.175	2.127	2002	296	90	72	2.30	11.58	87.73	0.61	0.08

Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.733	3.073	2.340	2002	337	91	73	3.20	5.53	93.93	0.41	0.12
98th %tile Delta-DV	0.326	2.665	2.340	2002	363	97	79	3.20	21.72	78.10	0.15	0.04
90th %tile Delta-DV	0.074	2.220	2.145	2002	122	97	79	2.30	15.85	83.44	0.46	0.26

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 14) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.050	3.304	2.255	2002	26	48	102	2.90	20.95	78.39	0.57	0.09
98th %tile Delta-DV	0.422	2.528	2.106	2002	250	56	110	2.20	34.90	64.03	0.83	0.24
90th %tile Delta-DV	0.066	2.193	2.127	2002	105	45	45	2.30	10.59	87.61	1.54	0.26

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

TRNP NORTH UNIT												
Largest Delta-DV	1.458	3.692	2.234	2002	73	89	118	2.80	21.94	77.35	0.63	0.08
98th %tile Delta-DV	0.392	2.625	2.234	2002	75	82	71	2.80	27.21	72.27	0.42	0.10
90th %tile Delta-DV	0.059	2.229	2.170	2002	155	82	71	2.50	41.18	58.67	0.11	0.04

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP ELKHORN RANCH												
Largest Delta-DV	1.181	3.415	2.234	2002	73	90	72	2.80	25.43	74.01	0.49	0.08
98th %tile Delta-DV	0.337	2.570	2.234	2002	39	90	72	2.80	27.32	72.02	0.52	0.15
90th %tile Delta-DV	0.045	2.151	2.106	2002	240	90	72	2.20	83.95	15.32	0.63	0.11

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1

LOSTWOOD NWA												
Largest Delta-DV	0.572	2.911	2.340	2002	337	91	73	3.20	7.16	92.15	0.53	0.16
98th %tile Delta-DV	0.264	2.604	2.340	2002	363	97	79	3.20	26.83	72.95	0.18	0.05
90th %tile Delta-DV	0.059	2.205	2.145	2002	122	97	79	2.30	19.82	79.29	0.57	0.32

Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 22) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.766	2.872	2.106	2001	258	36	36	2.20	17.24	76.12	5.96	0.69
98th %tile Delta-DV	0.323	2.557	2.234	2001	63	53	107	2.80	49.14	50.03	0.67	0.16
90th %tile Delta-DV	0.062	2.338	2.276	2001	310	54	108	3.00	31.20	65.86	2.10	0.84

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.486	3.740	2.255	2001	12	83	112	2.90	40.27	57.50	1.93	0.30
98th %tile Delta-DV	0.389	2.665	2.276	2001	315	82	71	3.00	26.44	71.77	1.44	0.36
90th %tile Delta-DV	0.093	2.326	2.234	2001	85	79	68	2.80	15.46	80.88	3.21	0.44

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.700	2.954	2.255	2001	12	90	72	2.90	40.07	58.79	0.94	0.20
98th %tile Delta-DV	0.242	2.475	2.234	2001	63	90	72	2.80	54.32	44.85	0.66	0.17
90th %tile Delta-DV	0.036	2.185	2.149	2001	195	90	72	2.40	85.87	11.96	1.79	0.38

Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.819	4.158	2.340	2001	326	91	73	3.20	40.32	57.77	1.60	0.30
98th %tile Delta-DV	0.531	2.806	2.275	2001	41	91	73	2.90	30.02	68.38	1.31	0.29
90th %tile Delta-DV	0.166	2.377	2.211	2001	179	93	75	2.60	25.24	69.32	4.86	0.58

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 21) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.549	3.803	2.255	2002	26	48	102	2.90	27.68	71.95	0.32	0.05
98th %tile Delta-DV	0.665	2.771	2.106	2002	250	56	110	2.20	43.83	55.60	0.44	0.13
90th %tile Delta-DV	0.095	2.329	2.234	2002	91	47	101	2.80	34.61	65.34	0.02	0.03

Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	2.146	4.379	2.234	2002	73	89	118	2.80	28.78	70.82	0.35	0.05
98th %tile Delta-DV	0.592	2.826	2.234	2002	83	71	60	2.80	17.58	81.68	0.65	0.10
90th %tile Delta-DV	0.096	2.266	2.170	2002	155	82	71	2.50	50.15	49.77	0.06	0.02

Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.772	4.005	2.234	2002	73	90	72	2.80	32.89	66.80	0.27	0.04
98th %tile Delta-DV	0.515	2.748	2.234	2002	39	90	72	2.80	35.40	64.23	0.29	0.08
90th %tile Delta-DV	0.074	2.307	2.234	2002	82	90	72	2.80	21.32	78.29	0.33	0.06

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.818	3.093	2.275	2002	74	97	79	2.90	40.84	58.98	0.15	0.03
98th %tile Delta-DV	0.408	2.748	2.340	2002	363	97	79	3.20	34.49	65.39	0.10	0.03
90th %tile Delta-DV	0.088	2.233	2.145	2002	134	97	79	2.30	12.68	86.24	0.90	0.18

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 15) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.408	2.642	2.234	2002	73	49	103	2.80	67.56	31.21	1.05	0.19
98th %tile Delta-DV	0.159	2.392	2.234	2002	74	49	103	2.80	71.20	27.89	0.75	0.16
90th %tile Delta-DV	0.029	2.156	2.127	2002	95	46	46	2.30	48.73	48.93	2.00	0.34

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	0.556	2.789	2.234	2002	73	89	118	2.80	60.25	37.78	1.74	0.23
98th %tile Delta-DV	0.160	2.309	2.149	2002	199	79	68	2.40	70.06	22.54	6.61	0.78
90th %tile Delta-DV	0.030	2.136	2.106	2002	270	68	57	2.20	36.62	57.15	5.44	0.78

Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.480	2.713	2.234	2002	73	90	72	2.80	64.88	33.68	1.25	0.19
98th %tile Delta-DV	0.140	2.374	2.234	2002	39	90	72	2.80	66.26	32.13	1.26	0.35
90th %tile Delta-DV	0.023	2.129	2.106	2002	233	90	72	2.20	57.27	35.17	6.72	0.84

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	0.236	2.511	2.275	2002	74	97	79	2.90	72.84	26.39	0.63	0.14
98th %tile Delta-DV	0.107	2.447	2.340	2002	363	97	79	3.20	66.89	32.54	0.45	0.12
90th %tile Delta-DV	0.028	2.260	2.232	2002	204	99	81	2.70	92.15	5.12	2.30	0.43

Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0

Great River Energy - Stanton Station
BART Modeling 2002, 98th Percentile
Lignite Basis
Previously Modeled Emission Rate Correlations

Additional modeling runs were not performed to determine the visibility impacts of the PRB fuel scenarios added in the November 2007 report revisions. Instead, previous modeling data (from presentations to NDDH in 2006 and 2007) as well as the modeling results presented in the original report were used to develop a correlation between dV reductions and changes in SO2 and NOx emission rates. The correlations assume that one of the pollutants (either SO2 or NOx) is varried while all other modeled pollutant emission rates remain constant. These correlations are then used to calculate the impacts of control scenarios incorporating the use of fuel switching to PRB coal. (Basis for Scenarios 16-20 in report Section 7)

NOx Constant, Changing SO2

NOx lb/MMBtu	SO2 lb/MMBtu	dV	Notes
0.26	0.60	0.848	y = -0.5513x + 1.1794 R2 = 0.9996
	0.42	0.948	
	0.13	1.111	
	0.08	1.134	
	0.05	1.148	
0.11	0.60	0.974	y = -0.6081x + 1.3385 R2 = 1
	0.42	1.082	
	0.13	1.257	
	0.08	1.292	
	0.05	1.306	
0.37	1.90	0.000	y = -0.5658x + 1.07 R2 = 0.9999
	0.29	0.902	
	0.15	0.989	
	1.32	0.322	
0.23	0.60	0.870	y = -0.5622x + 1.2108 R2 = .9995
	0.42	0.979	
	0.13	1.139	
	0.08	1.166	
	0.05	1.179	

NOx lb/MMBtu	m	b
0.26	-0.5513	1.1794
0.37	-0.5658	1.07
0.11	-0.6081	1.3385
0.23	-0.5622	1.2108
avg	**-0.57185**	**b= -1.0335 *NOx +1.4503**
stdev	**0.0249405**	**R2 = .9996**

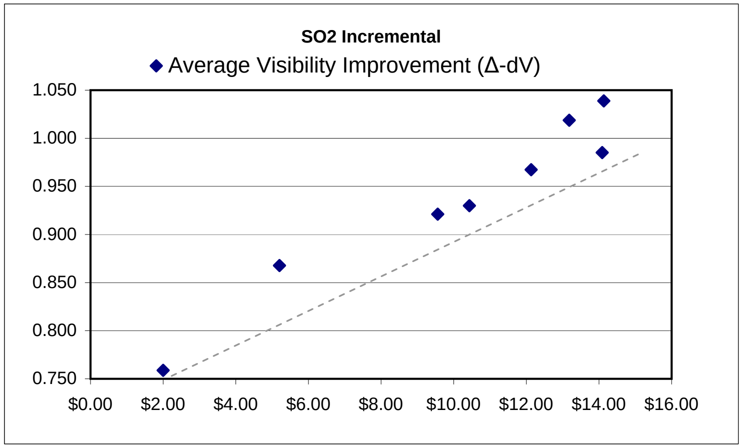
SO2 Constant, Changing NOx

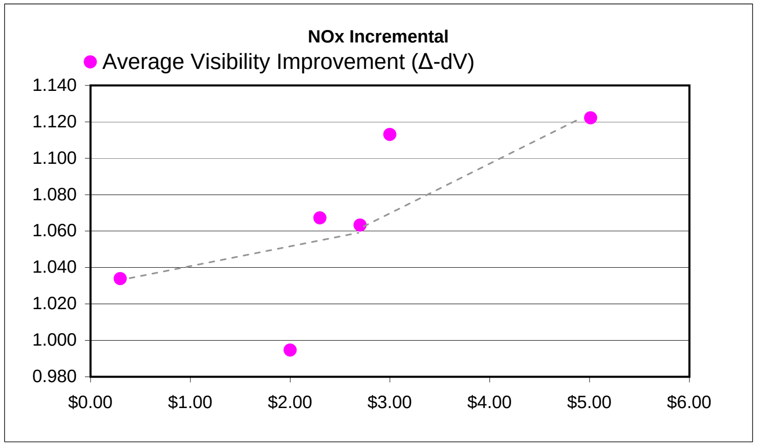
SO2 lb/MMBtu	NOx lb/MMBtu	dV	Notes
0.05	0.36	1.047	y = -1.0221x + 1.4143 R2 = 0.9999
	0.26	1.148	
	0.23	1.179	
	0.11	1.306	
	0.04	1.376	
1.32	0.37	0.322	y = -1.0132x + 0.6939 R2 = 0.9981
	0.37	0.323	
	0.35	0.338	
	0.27	0.414	
	0.05	0.648	
0.29	0.37	0.902	y = -0.9777x + 1.2646 R2 = 1
	0.37	0.904	
	0.35	0.922	
	0.27	1.003	
	0.05	1.218	
0.6	0.36	0.756	y = -0.9116x + 1.0822 R2 = 0.9971
	0.26	0.848	
	0.23	0.870	
	0.11	0.974	
	0.04	1.057	

SO2 lb/MMBtu	m	b
0.05	-1.0221	1.4143
1.32	-1.0132	0.6939
0.29	-0.9777	1.2646
0.6	-0.91116	1.0822
avg	**-0.98104**	**b= -0.5639 *SO2 +1.4324**
stdev	**0.0503804**	**R2 = .999**

Great River Energy - Stanton Station
BART Modeling 2002, 98th Percentile
Lignite Basis - $/dV Summary

Pollutant Info	Control	Emissions (lb/MMBtu)	Annual Operating Cost (MM$)	Average Visibility Improvement (Δ-dV)	Annual MM$/dV	Incremental MM$/dV [1]
SO2 (Assume constant NOx at 0.37)	Spray Dry Baghouse+PRB (97%)	0.055	$14.13	**1.039**	$13.60	$43.32
	Absorber	0.091	$13.18	**1.019**	$12.94	$43.03
	Spray Dry Baghouse+PRB (92%)	0.150	$14.09	**0.985**	$14.30	$53.40
	Spray Dry Baghouse	0.181	$12.13	**0.967**	$12.54	$48.60
	DSI Baghouse+PRB	0.248	$10.43	**0.930**	$11.22	$49.28
	Absorber 10% Bypass	0.263	$9.56	**0.921**	$10.38	$46.58
	DSI with Existing ESP+PRB	0.358	$5.20	**0.868**	$6.00	$29.41
	Fuel Switch to PRB	0.550	$2.00	**0.759**	$2.64	Base
NOx (Assume constant SO2 at 0.15)	SNCR + PRB	0.230	$5.01	**1.122**	$4.47	$691.26
	Alstom LNB + OFA + SNCR	0.239	$3.00	**1.113**	$2.70	Inferior
	SNCR	0.290	$2.70	**1.063**	$2.54	$81.62
	Alstom LNB + OFA + PRB	0.286	$2.30	**1.067**	$2.15	-$102.45
	Alstom LNB + OFA	0.320	$0.30	**1.034**	$0.29	Base
	Fuel Switch to PRB	0.360	$2.00	**0.995**	$2.01	Inferior





[1] For SO2 controls, incremental cost from base case to selected technology; no clearly defined least-cost envelope exists (only 2 dominant controls).
[2] Equation for NOx dV improvement at 0.15 lb/MMBtu SO2 emission rate interpolated from correlations of previously modeled scenarios.

Appendix D

Alstom NOx Evaluation

A Final Report to

GREAT RIVER ENERGY

Stanton Generating Station
Boiler No. 1

FOR:

NOx Reduction Technologies Firing Powder River Basin Coal

SUBMITTED BY:

ALSTOM POWER INC.
BOILER RETROFIT GROUP – U.S. OPERATION
WINDSOR, CONNECTICUT

ENGINEERING STUDY PROJECT
CONTRACT NO. 11070606
ALSTOM PROPOSAL NO. 43033142-00
March 8, 2006

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Executive Summary

The Boiler Retrofits Group of ALSTOM Power Inc. (ALSTOM) is pleased to submit this report to Great River Energy (GRE) Stanton Generating Station. This report details the results of a Phase 1 review of the current PRB and previous Lignite fuels and the available technologies that would reduce NOx emissions to less than 0.29#/mmBtu when firing lignite coal and 0.23 #/mmBtu firing Power Powder River Basin coal, in boiler 1. This study work was authorized by GRE under GRE Contract No. 6072846, dated 01/12/06, and executed under ALSTOM's Engineering Study Contract No. 011070606. Report technical input are from ALSTOM's Firing Systems Engineering – Windsor, CT, and Environmental Controls Systems, Knoxville, TN, and Fuel Tech of Stamford, CT.

A recent Spring Creek, PRB, coal analysis is the base coal for this study, as is lignite coal fired during the original ALSTOM Low NOx burner retrofit contract guarantee tests. The chemical analysis of these fuels can be found in Appendix 5.1. The following table is a summary of the costs and predicted NOx reductions for each technology evaluated specifically for Stanton 1 boiler, firing PRB coal, bottom 2 mills in service at 800k lb/hr feedwater flow: The predicted reductions are based on separate technology capabilities and not the predicted reductions of any combination of technologies:

NOx Reduction Method	COST ESTIMATE ($m)						
	Material	Install	Operating	Total	NOx Reduction	Outage	Cost/NOx Red.
RSFC Burner Mods	0.664	0.8	0	1.46	15% - 25%	3 wks	5.8 to 9.7
SNCR (Fuel Tech)	0.8	1.8	0.1	2.7	15%	4 wks	18.0
SCR (ALSTOM)	15*	23	2**	38	90%	14 wks	42.2

* Indicative pricing does NOT include: new trisector air preheater, SCR gas inlet temperature control device(s), ID Fan alterations, furnace/flue path NFPA Code reinforcements.

** Operating cost includes: 1 yr catalyst replacement + ammonia consumption ~ 340 lb/hr @ full load, $500/ton

1.0 INTRODUCTION

GRE requested a detailed feasibility engineering evaluation of the predicted emissions impacts and the resultant project budgetary estimates of available “in-furnace” and “gas treatment technologies” to further reduce the NOx emissions rate. GRE indicated that the target NOx emissions rate to be considered in this proposed feasibility study is 0.23 lb/mmBtu with 2 mill operation firing PRB and 0.29 lb/mmBtu with 3 mill operation firing lignite. GRE’s emission rate targets are based on a 30 day rolling average. The evaluation considers only ALSTOM designed products or new design technologies that are within ALSTOM’s experience/expertise. The evaluation also considers NOx reduction improvements that may be applied to the RSFC™ burners in combination with “back-end” gas treatment technologies on boiler 1 at Great River Energy’s Stanton Generating Station, located in Stanton, ND.

A. <u>Inquiry Background</u>

In Spring, 2004, GRE began an extended test-burn of the Powder River Basin (PRB) coal from Kennecott Energy Company’s, Spring Creek Mine, located in Montana. ALSTOM Power’s, Technical Services assisted GRE with boiler and burner performance consultation, and with collecting boiler operating data under various loads and furnace conditions on both boiler 1 and 10. Subsequently, GRE converted the Stanton Station to sustained PRB coal firing in November, 2004 marking the start of a five-year coal purchase contract with Kennecott.

Spring Creek Mine coal was test-fired in both boilers 1 & 10 in November, 1996. GRE’s operational results of the PRB test-burn experiences, furnace and mill impacts, and lessons learned during the 1 month test burn were documented and submitted to ALSTOM. The main problem encountered was coal pulverizers running too hot, and causing pulverizer internal fires. The firing of PRB then, presented many coal and ash handling related problems, as well. ALSTOM is also in receipt of overall plant emissions and proximate coal analysis of the PRB fired during the November, 1996 test-burn. In 1997, boiler 1 originally equipped round burners were removed and retrofitted with new Low NOx technology RSFC™ round burners, designed by ABB C-E Services, Inc. (ABB C-E Services Inc., a predecessor to ALSTOM Power).

GRE’s December 7, 2005 request letter specifies that the primary focus of the study will be the available “in-furnace” NOx reduction burner technologies with less emphasis on “back-end” gas treatment technologies. GRE cautions that due to the furnace volume and furnace retention duration, use of over-fire air (OFA) to reduce NOx, may not be a practical solution. ALSTOM agrees that further detailed studies would be required to carefully assess the furnace conditions and dynamics to arrive at confident NOx reduction strategies. GRE requested that this feasibility study include recommendations to address firing of either the current PRB coal or the former Lignite coal from Dakota Coal Company. GRE requests that the ultimate outcome of the study include a set of feasible NOx reduction alternatives identifying the predicted NOx emissions and their correlating recommended equipment budgetary estimates for both “in-furnace” and “back-end” technologies. A site visit by key members of the ALSTOM Study team was conducted on January 17 and 18, 2006 as the initial study activity.

B. Intent and Objective of Study

The intent of this study is to provide Great River Energy a feasibility engineering evaluation of the potential equipment retrofit alternatives that would allow further NOx emissions reductions by implementing "in-furnace" or "back-end" technologies. Budgetary material estimates (+/-25% accuracy) are developed of the recommended modifications resulting from this proposed study. GRE has also requested that the recommendations should consider the flexibility to revert to either North Dakota Lignite or PRB coal types.

C. Unit Description

Boiler 1, designed and supplied by Foster Wheeler, under FW Contract # 2-79-2009, as a lignite, pulverized coal, front wall fired unit. The boiler was designed for balanced draft furnace operation, natural boilerwater circulation, with a split backpass and attemporator spray flow for SH and RH outlet temperature control, radiant superheat division walls, platen superheater and convective reheater surface The original design maximum continuous rating (MCR) is 1,200,000 lb/hr at 1875 psig and 1005°F superheat outlet steam conditions with 463°F economizer feedwater temperature. There are 2 secondary air and 1 primary air regenerative air preheaters for flue gas heat recovery. Furnace dimensions are 27'- 1-1/4" in depth and 48' – 11-3/4" in width, by 80'-9" in height.

Boiler 1 was originally equipped with 3 – MB 23 Foster Wheeler mills which were later replaced with 3 – 943 RP Combustion Engineering Pulverizers, in 1979. These three mills presently connect to 12 **RSFC™** round burners in a four burner – 3 row arrangement. The originally supplied 20 inch diameter coal pipes were changed to 22 inch coal pipes, in 1979. Each of the 943 RP mills is designed to process 115,900 lbs/hr raw coal feed at 1-1/4 x 0 size, 40 HGI, @ 656°F mill inlet temperature to 65% fineness through the 200 mesh screen.

D. Study Deliverables

ALSTOM deliverables under this study contract are:

1. Provide commentary on coal pipe sizing as it relates to the impact of firing of PRB fuel vs lignite and what, if any, compromise may be expected with NOx emissions between a system that is designed specifically for one fuel vs. a system designed to fire either fuel.
2. Provide commentary on predicted changes in unit NOx, CO, and unburned carbon emissions
3. Provide input on additional changes to the firing system design that may be implemented to address detrimental impacts of PRB firing
4. Provide a list of at least two NOx reduction alternatives categorized by both "in furnace" and "back end" technologies, with budgetary estimates for materials .
5. Where necessary to illustrate a potential modification recommended in the report, ALSTOM will provide conceptual sketches of the suggested modification.
6. Budgetary pricing estimates (+/- 25%) will be provided on a final engineering and material supply basis for suggested modifications to the firing system and back end gas treatment system on boiler #1
7. Preparation of a draft report (for GRE comment) prior to final report release.
8. Study kick off meeting and engineering data gathering on site

E. Study Assumptions

While preparing this study , ALSTOM has made numerous assumptions regarding our analysis ,in conjunction with information gathered during and subsequent to the site scoping trip and kick off meeting. Should GRE desire that ALSTOM revise our assumptions or exceptions, ALSTOM would be pleased to discuss these changes with GRE . The items currently identified as assumptions are as follows:

1. ALSTOM's engineering study estimated NOx based on ten(10) different operating conditions , based on feedwater flow, coal type, and number of mills in service. The specific cases were agreed to between GRE and ALSTOM during the site meeting January 17 & 18, 2006.
2. The PRB analysis used for the study was identified as Sample # 05069253-Sa (Dakota Gasification Company Great Plains Synfuels plant) dated 12/16/2005 ,9:46 am . The complete analysis is shown in Appendix 5.1.
3. The Lignite coal analysis used in the study is that fired during the Alstom Low Nox burner retrofit contract (76797) .The complete analysis of this coal is shown in Appendix 5.1.
4. Alstom has evaluated application of overfire air technology to the unit, assuming current best practice approach to the design, installation, and operation of the overfire system.
5. ALSTOM's study scope does not include the detailed assessment of boiler thermal performance or steam flow capacity, tubing metal temperatures in any section of SH or RH, slagging or fouling or the capability of any boiler equipment such as fans, mills, etc., in achieving the operating conditions used for the basis of the NOx emission predictions.
6. ALSTOM's emission modeling assumes firing 100% of each candidate coal at indicated feedwater flow and conditions assuming the burner /overfire air system optimized for the specific fuel. Additional modeling was performed to predict NOx emissions at all ten(10) different operating conditions, assuming the firing system (burner and overfire air system) is modified to accommodate firing either fuel interchangeably. The study has not included any consideration for blended fuels.
7. ALSTOM's assessment of the current Low NOx system is limited to the equipment originally supplied by C-E (C-E, a predecessor to ALSTOM Power).
8. ALSTOM has assumed that all of the boiler firing and pulverizer equipment and the pressure parts are in good working condition. The assessment offered in this proposal is not intended to serve as a condition assessment of pressure parts or other boiler equipment.

2.0 CONCLUSIONS

2.1 Firing Systems Performance and Emissions Predictions

1. The target NOx level of 0.23 lb/mmBtu appears achievable on the PRB with burner modifications and the addition of an overfire air system, with mill #13 (top mill) out of service, at the "normal, current" feedwater flow of 800 k lb/hr. ALSTOM would predict NOx in the range of 0.18-0.23 lb/mmBtu under these conditions, depending upon final operating excess air and the amount of overfire air used.

2. The target NOx level of 0.29 lb/mmBtu appears achievable on the lignite coal with burner modifications and the addition of an overfire air system, with all mills in service, at the "normal, current" feedwater flow of 870 k lb/hr. ALSTOM would predict NOx in the range of 0.27-0.31 lb/mmBtu under these conditions, depending upon final operating excess air and the amount of overfire air used.

3. Generally, NOx will be reduced at feedwater flows below the above conditions, and, conversely, NOx will increase as feedwater flow increases above those conditions cited above. This is due to the relative contribution from Zeldovitch mechanism NOx, commonly referred to as thermal NOx. Thermal NOx is formed by the atmospheric fixation of nitrogen and oxygen at high (> 2600ºF) temperatures. Higher feedwater (steam) flows require greater coal feed rates, which contribute to higher furnace gas temperatures. A detailed breakdown of predicted NOx for the seven(7) PRB coal firing cases and the three (3) Lignite coal firing cases is given in Appendix 5.2 of this report.

4. Based on prior testing at GRE Stanton Unit 1, as well as ALSTOM field experience elsewhere, lowest NOx will be achieved with Mill 13 (top mill) out of service, as compared with having Mill 12 (bottom mill) out of service. The unit operates in a "simulated overfire air mode" with the top mill out of service, which tends to reduce overall NOx emissions. ALSTOM would predict similar result given the assumption of future modifications to the firing system to add overfire air technology.

5. Operation of Unit 1 above the current feedwater (steam) flow levels of 800k lb/hr on PRB coal (i.e. with all mills in service) would reduce the potential for meeting the 0.23 lb/mmBtu NOx target for this fuel. ALSTOM would anticipate NOx in the overall range of 0.36-0.40 lb/mmBtu with the current low NOx burner only arrangement with all mills in service at feedwater flows in the 900-1100 k lb/hr range. With low NOx burner modifications and an overfire air system retrofits implemented, ALSTOM would estimate NOx in the range of 0.25 –0.32 lb/mmBtu, at feedwater flows in the 900-1100 k lb/hr range with all mills in service on the PRB fuel. The study did not consider operation of the unit on lignite at feedwater flows in excess of 870 k lb/hr per agreement with GRE.

6. CO emissions are a strong function of the efficiency of combustion, which is dependent on a multitude of system design and operating parameters. Operating excess air (O_2) levels in the furnace, fuel reactivity, furnace residence time, and fuel/air mixing effectiveness all have a first order effect on CO emission levels. Based on historical CO emission data from prior unit testing with the PRB fuel, using the multipoint grid in the flue gas stream, the current CO levels on PRB can be less than 10 ppm, but appear to be more typically on the order of 100ppm average(corrected to 3% O_2). Measured CO level during the low NOx burner retrofit guarantee tests was 32 ppm (corrected to 3% O_2), but can be higher based on operational variables. From ALSTOM field experience with firing both PRB and lignite coals in utility boilers, the CO would be expected to increase somewhat post retrofit to an overfire air system, as staged

combustion slightly delays the fuel/air mixing (to lower thermal and fuel NOx) necessary to minimize CO. ALSTOM would therefore anticipate CO emissions on the order of 100 to 300 ppm post retrofit to a low NOx system using overfire air on PRB coal. CO emissions on the order of 100 to 300ppm would be likely on the lignite coal. These values are very sensitive to firing system and boiler controls tuning and operation, and may vary substantially based on unit condition and operation variations. CO can increase exponentially as excess O2 is lowered or allowed to vary below nominal threshold levels .

7. Unburned carbon in flyash (UBC) levels are typically less than 1% by weight with the current low NOx burner system. Both the PRB and lignite coals fired are reactive coals, in terms of both ignitability and carbon burnout characteristics. One measure of a coal's relative reactivity is its fixed carbon to volatile matter ratio. The specified PRB coal has a FC/VM ratio of 1.22, and the lignite ratio is 0.99, these ratio values are indicative of very reactive coals with low unburned carbon in flyash levels expected. Some increase in UBC may be expected with the addition of an overfire system, due to the inherent fuel/air staging as well as limited upper furnace residence time in Unit #1. It is expected that UBC levels would remain below 2% post retrofit to an overfire air low NOx system.

8. A review was conducted of current coal pipe size (diameter) vs. coal /mill transport air velocity at measured transport air/fuel ratios on the PRB coal. The standard maximum airflow thru a 943 RP mill is 3300 lb/min. For PRB, the expected transport air/coal (A/F) ratio should be 3.55 at the "typical" feedwater flow of 800k lb/hr, with two (2) mills in service. This is generally consistent with the measured values of A/F ratio in ALSTOM test report dated Dec, 2005. Under these conditions, coal velocities of 93.5 ft/sec can be expected firing PRB, calculated for a 21" I.D. coal pipe. This velocity slightly exceeds the ALSTOM design standard velocity of 70-90 ft/sec. ALSTOM would expect negligible negative impact on firing system performance at the calculated velocity. ALSTOM would also expect negligible impact on erosive wear in the coal pipes and/or coal nozzle at the calculated velocity.

9. A review was conducted of current coal pipe size (diameter) vs. coal /mill transport air velocity at measured transport air/fuel ratios on the lignite coal . The standard maximum airflow thru a 943 RP mill is 3300 lb/min. For lignite, the expected transport air/coal (A/F) ratio should be 3.62 at the "typical" feedwater flow of 870k lb/hr, with three (3) mills in service. Under these conditions, coal velocities of 94.7 ft/sec can be expected firing lignite, calculated for a 21" I.D. coal pipe. This velocity slightly exceeds the ALSTOM design standard velocity of 70-90 ft/sec. ALSTOM would expect negligible negative impact on firing system performance at the calculated velocity. ALSTOM would also expect negligible impact on erosive wear in the coal pipes and/or coal nozzle at the calculated velocity.

10. ALSTOM has reviewed the current coal piping and future low NOx burner/overfire air system in terms of flexibility of operation on either PRB coal or lignite coal, and <u>has determined that either fuel could be fired interchangeably, in terms of coal pipe/ and burner coal nozzle velocity within ALSTOM design limits</u>. This conclusion is valid with two (2) mills in service firing PRB @ feedwater flow of 800k lb/hr, and with three (3) mills in service firing lignite @ feedwater flow of 870 k lb/hr. It should be noted that ALSTOM expects NOx emissions to vary dependent on the fuel fired, as above.

11. For reference, ALSTOM has calculated expected coal (pipe) velocities when firing PRB with all three mills in service at a feedwater flow of 900k, 1000k, and 1100 k lb/hr (consistant with Case's 5, 6 and 7). Although the boiler cannot currently sustain these feedwater flow levels, it is noted that the coal (pipe) and burner coal nozzle tip velocity will be on the order of 93.3,

93.4, 93.5 ft/sec, respectively, which slightly exceeds the ALSTOM design standard velocity of 70-90 ft/sec. ALSTOM would expect negligible negative impact on firing system performance at the calculated velocity. ALSTOM would also expect negligible impact on erosive wear in the coal pipes and/or coal nozzle at the calculated velocity.

12. 12. ALSTOM has reviewed how long term operation with PRB may affect firing system performance. Beyond the emissions impacts cited above, it is suggested that refractory throat modifications be made along with air register modifications. These modifications would be required in conjunction with installation of an overfire air system. The modifications would serve two purposes. First, they would account for the percentage of secondary air flow diverted from the burner air registers to the overfire air ports, required to optimize secondary air velocity thru the burner register with overfire air in operation (consistant with Company design standards) and to achieve best burner performance in terms of emissions, turn down, flame shaping, and flame stability. Secondly, the refractory throat modifications would reflect latest ALSTOM field experience to minimize or avoid slagging or "burner eyebrows".

13. Based on preliminary firing system design of a Low NOx system incorporating burner modifications with overfire air, the current burner air register should be modified for a target heat input consistent with a realistically achievable steam flow target. In general, the current air registers are oversized for the "typical", current day, feedwater flows in the 800-870 k lb/hr range. IF GRE plans to continue operation at these feedwater flows, and add overfire air to further reduce NOx in the future (with either 2 mill operation on PRB or 3 mill operation on lignite), ALSTOM would recommend modifications to downsize the burner air registers.

14. If GRE intends to operate with three mills in service with PRB coal at feedwater flow rates in excess of the current 870 k lb/hr "typical" MCR condition, it is suggested that a comprehensive boiler thermal performance study would also be recommended to access feasibility of same and equipment modifications that may be required to achieve same.

15. ALSTOM has completed a preliminary design for an overfire air system based on target NOx reduction requirements, boiler physical layout, equipment interferences and obstructions as determined in the site scoping trip, and current day "typical " operating feedwater flows. The preliminary design is comprised of four (4) each overfire air ports, located directly above each column of burners on the front wall of the boiler. The centerline of the overfire air ports would be located at approx elevation of 1754'. The main burner windbox would be the source of (secondary) air for the overfire air ports, four (4) each simple ducts (with flexible joint) would be installed at the top of the windbox to divert a portion of the main windbox secondary air to the overfire air assemblies. This location has proven successful in several Company installations of RSFC burners with overfire air. Side wall overfire air was considered, but optimum performance would not be expected with this configuration. Side wall overfire air would also require more extensive (and expensive) ductwork installation, with takeoffs from each side of the main burner windbox. A schematic of the proposed overfire air arrangement is shown in the attached conceptual drawing.

16. The estimated budgetary cost (engineering and materials) for the proposed overfire air system and associated RSFC burner modifications is $644,000.00. More detail of the cost estimate and scope of material supply is shown in section 3.0.

2.2 SNCR Conclusions

The following table summarizes the SNCR conclusions. See Appendix 5.4 at the rear of this report for more detailed material information.

DESIGN CRITERIA	Case 1	Case 2	Case 3
Type of Furnace	FW PC		
Fuel Fired	PRB	PRB	Lignite
Mills in Operation	3	2	3
Maximum Heat Input (mmBtu/hr)	1489	1191	1295
Uncontrolled NOx; (lb/mmBtu)	0.38	0.27	0.40
lb/hr	566	322	518
Percent NOx Reduction	20%	15%	27.5%
Controlled NOx (lb/mmBtu)	0.304	0.23	0.29
lb/hr	453	274	378
NOx Removed lb/hr	113	48	142
Expected NOxOUT® A Flow (gph)	84	38	94
Furnace CO, (ppm)	<200	<200	<200
Expected Ammonia Slip (ppm,as measured)	5	5	10
Flue Gas Temp (°F)	2150 to	2000 to	2050 to
	2250	2100	2150
Injectors – Level 1 Wall Injectors	9	9	9

2.3 SCR Conclusions

The following table summarizes the SCR conclusions. See Appendix 5.5 at the rear of this report for more detailed material information.

NO_x removal	90% minimum 24 hour average
Draft Loss	Not to exceed 4 inches of WG, from the economizer outlet to the air heater inlet.
Ammonia Slip	Not to exceed 2 ppm
Catalyst life	8000 hr. of operation, or 12 months from initial operation, whichever occurs first.
SO_3 Oxidation.	Less than 1.2% as measured during the first month of operation.
Ammonia consumption as NH3	Not to exceed 370 lb./hr

3.0 RECOMMENDATIONS

3.1 Modifications to Radially Stratified Flame Core (RSFC™) Burners

Item	Quantity	Description
1.	Twelve (12)	RSFC™ burner air register modifications ,comprised of a cylindrical sleeve in teriary air zone .and revised inserts in primary and secondary zone swirler assemblies .
2.	One (1) Set	Drawings for revised burner throat refractory profile to meet RSFC™ requirements
3.	One (1) Lot	SAMA control diagrams which illustrate proposed function of burner /SOFA dampers
4.	One (1) Lot	General arrangement drawings illustrating burner modification installation instructions and weights

Equipment Required for Separated Overfire Air (SOFA) Installation

5.	Four (4) each	SOFA registers with two (2) compartments, top and bottom crotch cooling air; complete with manual adjustable yaw and tilt nozzle tips, partition plates, dampers and necessary linkages
6.	Four(4) each	Seal boxes for above SOFA registers(tube sheet to SOFA register seal
6.	Four(4) each	Shop optimized tube panel assemblies (26” wide, 2.5” OD fined tubes on 3.25” centerlines)
7.	Four(4) each	OFA ductwork to connect SOFA registers to takeoff at top of existing burner windboxes (with flexible joint)
8.	Eight (8)	Electric rotary drive mechanisms for the OFA register damper control – [Two (2) per register](modulation with steam flow rate)
9.	As Required	SOFA guides, windbox structural modifications, Insulation and lagging
10.	One (1) Lot	General arrangement drawings illustrating SOFA and SOFA ductwork installation instructions and weights
11.	One(1) Lot	Commissioning staff for a three week period to observe final burner/SOFA installation, make initial burner adjustments prior to post outage boiler startup, support demonstration of design heat input operation, tuning to make final adjustments to firing system to meet predicted levels of performance, and observation and support during final guarantee tests. Includes supply of temporary economizer outlet gas sampling test probes grid (O2/CO/NOx) and instrumentation to support initial burner /SOFA commissioning and tuning

3.2 SNCR Recommendations

The proposed NOxOUT® SNCR system for all three design cases would consist of a 20,000 gallon FRP heated and insulated Reagent Storage Tank that would feed into a Circulation Module (SLP3-C) installed in a heated enclosure located near the tank. This would provide reagent feed to a Redundant Pump Metering Module (SPL3-RP) that will automatically meter the reagent into a dilution water stream based on the demands of the system.

The diluted reagent is then pumped to a distribution module that will then control the flow of diluted reagent and atomizing air to one level of 9 wall injectors installed through the waterwalls in the upper furnace. The flow to the injectors is automatically controlled based on the operation of the unit and is determined during start-up and optimization of the system. See Appendix 5.4 for greater detail of recommended system components

3.3 SCR Recommendations

The following equipment is recommended to achieve 90% NOx reduction

SCR Reactor and Accessories

QUAN.		ITEM	DESCRIPTION
1	Only	**SCR Reactor**	SCR Reactor, carbon steel
4	Only	**Soot Blowers**	Sonic type soot blowers
60	Only	**SCR Catalyst Modules**	High dust type catalyst.
1	Lot	**Access**	Access at each catalyst level
1	Lot	**Catalyst Handling Equipment**	catalyst handling and hoisting equipment,.
1	Lot	**Ductwork**	1/4" carbon steel ductwork.

Mechanical Equipment, Ammonia System

QUANTITY		ITEM	DESCRIPTION
2	Only	**Dilution Fans**	One (1) operating, one (1) spare unit.
1	Lot	**Ammonia Vapor Piping**	from ammonia storage tank to injectors
1	Only	**Ammonia Injection Grid and mixer**	Ammonia injection grid inlet of SCR

ELECTRICAL Equipment

QUANTITY		ITEM	DESCRIPTION
SCR, Ammonia and Ash Systems			
1	Only	**Field Instruments**	Instrumentation and controls
1	Only	**PLC and Control Logic**	PLC controller with I/O
1	Only	**SCR Inlet Gas Analyzer & Monitoring System**	Complete with microprocessor based NOx, and oxygen analyzers

4.0 Discussion/Study Methodology

4.1 Discussion

During the site visit, GRE raised a question concerning the reasons and logistics of constructing a single cell SCR versus construction of three (3) separate SCRs for each of the three air preheaters.

ALSTOM responds to this question with the following: The current temperatures at the economizer outlet are too high for SCR operation at some load conditions and too low at other load conditions. This is made more extreme if one considers the three air heaters separately. The existing economizer needs to be reworked with either a water or gas bypass or some alternate form of SCR gas inlet temperature control and the existing three small air-heaters replaced with one or two modern design trisector air heaters. ALSTOM ECS is basing the design at Stanton on the use of a single SCR reactor.

The ALSTOM ECS conceptual drawings of the SCR includes work termination points (ductwork points) in correlation to the material estimate.

The SCR gas inlet conditions of 0.5 lb/mmBtu is the basis upon which the 0.05 lb/mmBtu controlled outlet NOx is predicted (90% reduction). The output NOx predictions is based on an inlet NOx and an bulk inlet gas temperature between 600°F and 800°F.

After review of the operating data and plant GA drawings, ALSTOM ECS has the following comment to the SCR design:

> The flue gas temperatures leaving the economizer often vary outside the normal range of operation for the SCR. This will require modification to the economizer and air heaters in order to bring the temperature within an acceptable range. The three air heater design is typically unsuitable for use with an SCR system. We would recommend that they be replaced with a trisector design. The SCR reactor is best located above the air heater section of the building. In order to properly route the ductwork from the economizer to the air heater, extensive modification to the building will be necessary. After completion of these modifications, NOx emissions of .05 lb/MBtu should be achievable.

4.2 Methodology

To address the impact of firing 100% Spring Creek, lignite, or a combination of the two, ALSTOM's methodology was to:

- Review the laboratory coal analysis of coals provided by GRE.
- Using test data from PRB testing (supported by ALSTOM field staff) during April and May of 2004, and Sept/Oct 2005, as well as the final low NOx burner guarantee tests (on lignite) as a baseline, ALSTOM's Firing Systems Engineering (FSE) assessed potential impacts that may occur in the firing system with the current low NOx burner arrangement and with future over-fire air installation.

4.3 NOx Predictions at Specified Conditions

ALSTOM completed a detailed series of NOx predictions under several operating conditions. These results can be found in Appendix 5.2

APPENDIX 5.1 PRB and Lignite FUEL ANALYSIS

Table 6

Unit #1	PRB* As received % by wt	Lignite** As received % by wt
Moisture	25.08	35.47
Ash	3.75	8.17
Sulfur	0.35	0.68
Gross Calorific value (Btu/lb)	9350	6896
Sodium oxide total in ash	5.57	n/a
Volatiles	32.1	28.35
Fixed carbon	39.1	28.01
Carbon	55.2	41.43
Hydrogen	6.55	2.63
Nitrogen	0.648	0.65
Oxygen	33.5	10.97

* Ref: Dakota Gasification Company, Sample 05069253-Sa , dated 12/16/2005 , 9: 46:21 AM
** Ref: 1996 Low NOx burner guarantee tests

Table 6 Coal Analysis Comparisons

The Spring Creek coal analysis presents a typical analysis for a Sub. Bit "C" Powder River Basin coal. This coal is highly reactive with a low FC/VM ratio of 1.22 and is conducive to low NOx emissions, low sulfur emissions and low flyash unburned carbon levels. The Spring Creek coal has a heating value approximately 25% higher than the lignite coal. The Lignite coal, which is also very reactive, has a lower FC/VM ratio of 0.99 compared to the PRB. As received coal sulfur levels for the lignite coal is approximately twice the level of the PRB coal (0.68 % by weight vs 0.35 % by weight), but on a corrected lb/mmBtu basis , lignite is approximately 1.0 lb/mmBtu sulfur, vs, approximately 0.4 lb/mmBtu sulfur for PRB.

APPENDIX 5.2

NOX Predictions - GRE Stanton #1 (cases per site meeting 1/17/06) **Page 1 of 2** RCL 2/15/06

Note : Mill #13 top, Mill # 12 bottom) Note - Use FW flow ,not steam flow(per plant eng)

PRB Coal - (FC/VM = 1.22 , 0.65 % N ,sample 05069253-SA,12/16/05)

FW Flow(#/hr) (2 mills -#12 off)	NOx w/o ofa	NOx w ofa	FW Flow(#/hr) (2 mills -#13 off)	NOx w/o ofa	NOx w ofa	FW Flow(#/hr) (all 3 mills)	NOx w/o ofa	NOx w ofa
Case 1-800 k (3% O2)	0.32-0.34	0.24-0.29	Case 3-800 k (3% O2)	0.26-0.28	0.18-0.23	Case 5-1100 k (3% O2)	0.38-0.40	0.27-0.32
Case 2-600k (4.3% O2)	0.3-0.32	0.22-0.27	Case 4-600k (4.3% O2)	0.26-0.28	0.18-0.23	Case 6-1000k (3% O2)	0.37-0.39	0.26-0.31
						Case 7 -900k	0.36-.38	0.25-0.30

Reference field data :

Test #11 (Pete F.)	Test #2 (Alex K)	Tests # 6&7(Pete F)	Test # 8 (Pete F)	Test #16 (Pete F)
1170k FW	998 k FW	1090/1120 k FW	1086 k FW	1225 k FW
0.38#/mbtu	0.34-0.38 #/mbtu NOx	0..28-0.29 #/mbtu NOx	0.38 #/mbtu	0.41-0.43 #/mbtu NOx
3.1% O2	3.4% O2	3% O2	3.09% O2	3.1% O2
	#12 mill out	#13 mill out		

Assumptions - Use 500F sec air temp, 130 F mill outlet temp, 5.0" w to f DP,3.73 transport air/coal ratio, 3% O2 at econ. Outlet(except as noted)

Case # 3 is "normal " unit operation on PRB

Case # 6 is "design" case

APPENDIX 5.2

NOX Predictions - GRE Stanton #1 (cases per site meeting 1/17/06) Page 2 of 2

Note : Mill #13 top, Mill # 12 bottom) Note - Use FW flow ,not steam flow(per plant eng)

Lignite Coal - (FC/VM = 0.99 , 0.65 % N ,sample taken original contract post mod guarantee tests)

FW Flow(#/hr) (2 mills -#12 off)	NOx (#/mbtu) w/o ofa	NOx w/ofa	FW Flow(#/hr) (all 3 mills)	NOx(#/mbtu) w/o ofa	NOx w/ofa
Case 8 -430 k (O2 TBD)	0.36-0.38	0.25-0.30	Case 9-870 k (O2 TBD)	0.39-0.41	0.27-0.32
			Case 10 -670k (O2 TBD)	0.36-0.38	0.25-.30

Reference field data :

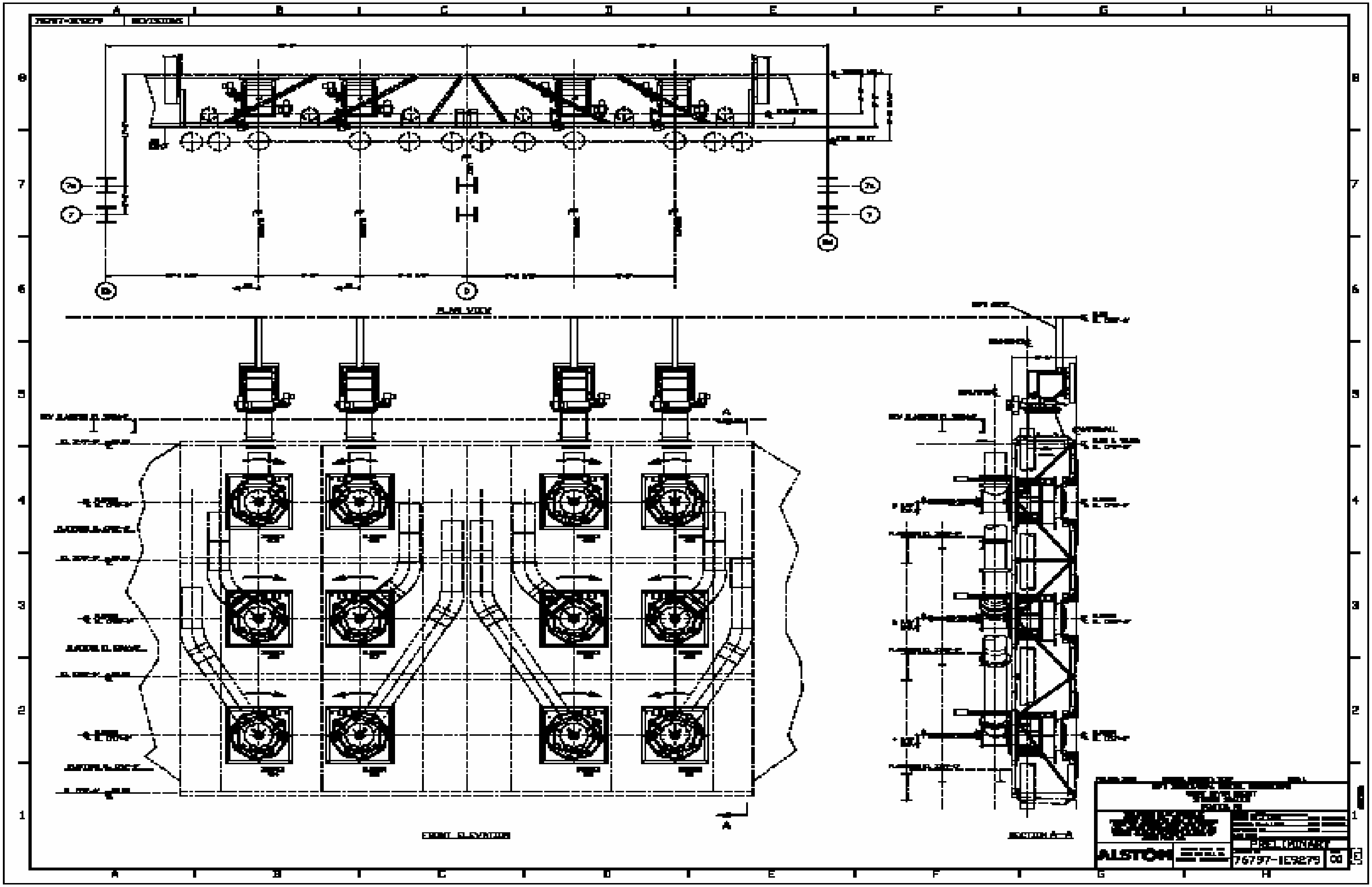
1998/1999 Original contract field data (0.39 #/mbtu NOx , 4 % O2(CR) ,900 k fw flow (typ max mill load with lignite))

Case 8 - NOx range from 0.34-0.43 #/mbtu (Brian Goven to confirm)
Case 9 - NOx range from 0.36-0.37 #/mbtu (Brian Goven to confirm)
Case 10 - NOx range from 0.36-0.39 #/mbtu (Brian Goven to confirm)

Assumptions - Use 500F sec air temp, 140 F mill outlet temp, 5.0" w to f DP,2.59 transport air/coal ratio, O2 at econ. outlet per contract data

Case #9 is "normal" lignite operation

APPENDIX 5.3



APPENDIX 5.4 SNCR Proposal Letter

For this application, the following cases have been evaluated:

Case 1: For 3 mill operation burning PRB, the SNCR System will provide a 20% NOx reduction from a baseline of 0.38lbs/mmBTU with 5 ppm ammonia slip.

Case 2: For 2 mill operation burning PRB, the SNCR System will provide the requested 15% NOx reduction from a baseline of 0.27lbs/mmBTU with 5 ppm ammonia slip.

Case 3: For 3 mill operation burning Lignite, the SNCR System will provide the requested 27.5% NOx reduction from a baseline of 0.40lbs/mmBTU with 10 ppm ammonia slip..

The proposed NOxOUT® SNCR system for all the cases would consist of a 20,000 gallon FRP heated and insulated Reagent Storage Tank that would feed into a Circulation Module (SLP3-C) installed in a heated enclosure located near the tank. This would provide reagent feed to a Redundant Pump Metering Module (SPL3-RP) that will automatically meter the reagent into a dilution water stream based on the demands of the system.

The diluted reagent is then pumped to a distribution module that will then control the flow of diluted reagent and atomizing air to one level of 9 wall injectors installed through the water walls in the upper furnace. The flow to the injectors is automatically controlled based on the operation of the unit and is determined during start-up and optimization of the system.

The NOxOUT® Process incorporates the controlled injection of a 50% urea based reagent in to the furnace at gas temperatures of 1600 to 2200 ^{0}F to reduce NOx to N_2, CO_2 and H_20. The Process has been successfully applied to nearly 350 units worldwide include more than 30 utility boilers up 700MW.

The NOxOUT® A reagent, a 50% urea based solution, would be supplied by tank truck from licensed suppliers.

The budgetary proposal for the NOxOUT® SNCR system is as follows:

PROCESS DESIGN TABLE

	Case 1	Case 2	Case 3
Type of Furnace	FW PC		
Fuel Fired	PRB	PRB	Lignite
Mills in Operation	3	2	3
Maximum Heat Input (mmBtu/hr)	1489	1191	1295
Uncontrolled NOx; (lb/mmBtu)	0.38	0.27	0.40
lb/hr	566	322	518
Percent NOx Reduction	20%	15%	27.5%
Controlled NOx (lb/mmBtu)	0.304	0.23	0.29
lb/hr	453	274	378
NOx Removed lb/hr	113	48	142
Expected NOxOUT® A Flow (gph)	84	38	94
Furnace CO, (ppm)	<200	<200	<200
Expected Ammonia Slip (ppm,as measured)	5	5	10
Flue Gas Temp (°F)	2150 to	2000 to	2050 to
	2250	2100	2150
Injectors – Level 1 Wall Injectors	9	9	9

II. FUEL TECH EQUIPMENT SCOPE

a. 1 20,000 gallon heated and insulated FRP Storage Tank
b. 1 Circulation Module (SLP3-C) installed in a heated building
c. 1 Redundant Pump Metering Module (SLP3-RP)
d. 1 Distribution Module (SLP3-D-4)
e. 1 Distribution Module (SLP3-D-5)
f. 9 Wall Injector Assemblies
g. 1 Controls Package
h.

III. ENGINEERING

a. Internal Project Engineering
b. Process Engineering to Include CFD and CKM Modeling as required
c. CAD Drawings and Manuals
d. 30 Mandays for Installation and Startup

IV. UTILITIES

a. Power: (480 VAC, 3-Φ, 60 Hz) 60kw
b. Dilution Water: 9 gpm
c. Plant Air: @ 60 to 80psig 110 scfm

V. SNCR SYSTEM PRICE:

For the Equipment, Engineering and Start-up of the SNCR system, the following is the budgetary quote for the material listed above:

EIGHT HUNDRED THOUSAND DOLLARS

($800,000.00 US)

This price is quoted F.O.B. Point of Manufacture.

APPENDIX 5.5 ***SCR Assessment***

1.0 DESIGN INFORMATION

1.1. GENERAL

The following description applies to the SCR systems for the Stanton plant.

Selective Catalytic Reduction (SCR) is a method of reducing the amount of nitrogen oxides (NO and NO_2) in the flue gas of fossil-fired industrial and electric utility equipment. The SCR system is comprised of various components, with the central component being the catalytic reactor that contains the catalyst. This catalyst is typically an active phase of vanadium pentoxide on a carrier of titanium dioxide, formed into elements of a parallel flow configuration. Plates or extruded ceramics (honeycomb design) are used as the substrate for the elements onto which the active material is deposited. Elements are then assembled into larger blocks called modules, which are combined into layers in the reactor. The reactor has one layers of catalyst modules, and operating temperature for the catalyst/reactor is normally 650° to 800°F.

The SCR technique uses a reducing agent, ammonia, to convert the NO_x to nitrogen (N_2) and water vapor on the catalyst surface. The ammonia is introduced into the flue gas duct ahead of the SCR reactor and catalyst, and is diluted with air before injection to aid in distribution. On the catalyst surface, the primary chemical reactions that occur are:

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

$$NO + NO_2 + 2\ NH_3 \Rightarrow 2\ N_2 + 3\ H_2O$$

Other reactions between NO_x and ammonia will also take place but to a minor extent. The main components produced are nitrogen and water, which both are harmless compounds. One mole of ammonia reacts with one mole of NO_x. Some ammonia will leave the catalyst unreacted, and is referred to as ammonia slip.

ALSTOM has endeavored to provide a system that matches the plant requirements as closely as possible. ALSTOM would be pleased to discuss the design premises in detail to clarify any assumptions and provide GRE with the most economical and reliable system possible.

BASE BID:

For the Base Bid, ALSTOM offers to provide an SCR Reactor system to reduce the NO_x emissions by 90%. The scope will generally include:

- SCR reactor and catalyst
- static mixers
- sonic sootblowers
- analyzer system
- anhydrous ammonia injection system
- controls and instrumentation for the equipment and processes offered
- cold flow modeling

SCR System for GRE Stanton

ALSTOM is proposing the use of one (1) SCR reactor to treat the flue gas at the Stanton Plant. Flue gas from the boiler after the economizer sections will pass through the SCR and then through the air heaters. The ammonia injection system will employ anhydrous ammonia from an existing storage facility.

Plate type catalyst will be used in the reactor, with a 6.4 mm pitch spacing to meet a 90% NOx reduction.

The reactor is designed with a superficial velocity of about 12 feet per second. Each catalyst layer will be comprised of modules, with the installed module size being approximately 1 meter x 2 meter x 1.5 meter high.

The reactor is designed to accommodate one layer of catalyst. A second layer is provided as a warehouse spare. These layers will be exchanged when necessary to maintain continued performance. The used layer will be washed and stored for reuse at the next scheduled exchange point.

1.2 Operating and Design Conditions

1.2.1 Economizer Outlet Conditions

Alstom is using the customer specified design conditions for the SCR system.

2.0 ADDITIONAL TECHNICAL INFORMATION

EQUIPMENT DESCRIPTIONS

SCR System

The SCR System offered consists of catalyst modules, framework, pedal protection (grating), and sonic sootblowers. The catalyst modules are located in one, high dust, vertical downflow reactor. The reactor is located between the boiler economizer outlet and the air heater inlet. The SCR reactors are of outdoors design, operating under negative pressure conditions.

Catalyst System

The operating life of the catalyst is 8,000 hours of operation between washings.

To minimize the catalyst cost over the plant lifetime, the catalyst activity must be monitored. The objective is to maximize the useful life of the catalyst with minimum investment cost. Accumulation of Vanaduim containing flyash will over time cause the SO2 to SO3 oxidation rate to increase. When this reaches an unacceptable level the catalyst should be removed and washed. Tests have shown that after washing the catalyst performance will return to its original level. A second warehouse spare layer of catalyst has been provided to allow for expeditious exchange of the installed catalyst layer followed by washing on a more relaxed schedule.

To gauge the deactivation of the catalyst, a number of coupons may be installed with the initial catalyst in the reactor. These pieces are periodically removed and tested for their remaining activity in a laboratory. ALSTOM proposes that testing be carried out by removing several plates from an installed module. Annual activity testing on a total of 3 coupons is included for the estimate period.

Catalyst Handling System

The catalyst handling system is designed allow the removal and replacement of the catalyst layer when necessary. Replacement of a catalyst layer is considered to be an outage activity and generally can be accomplished within approximately one (1) work week with the removal system offered.

The catalyst is supplied in modules, approximately 1m x 2m in plan area and 1.5m high. (3'-3" x 6'-6" x 5' high). Each module weighs approximately 3000 lb. The modules consist of a steel box filled with catalyst and with top lifting attachment points. The modules are base supported on beams with sealing strips when installed.

Lifting equipment supplied by ALSTOM includes carts for transport of the modules inside the reactor, special lifting beams for attachment of hoists to the module attachment points, air powered chain hoists for transport of the modules into and out of the reactor.

The handling procedure for addition of new catalyst to the empty layer is as follows: The new catalyst modules are delivered to the plant and stored at grade. A plant forklift is used to bring the catalyst modules to the lifting points under the electric cable lift. The special lifting beam is attached to the module. The cable lift is used to bring the module up from grade to the installation level. The cable lift is mounted on a beam or jib crane that can move under power and set the module on a work platform at the catalyst entrance door to the reactor. After the cable hoist is unhooked, the air powered chain hoist is used to lift the module a few inches off the platform for transport into the reactor. The chain hoist also has an air powered trolley. Inside the reactor, the module is lowered onto the cart for final transport between support beams to its final installed position. Sealing strips are attached to the top of the support beams before the module is lowered onto them. The workers push the cart into position, lower the module onto the strips and pull the cart back to receive the next module. The air-powered hoist can be used to move the cart from track to track. The only manual moving of the module is rolling the cart a maximum of 20 ft. All other operations are powered.

Removal of spent modules is accomplished in reverse of the above procedure.

Replacement Program/Design Margins

Based upon results from catalyst coupon tests at the Stanton plant, a deactivation rate of 10% per operating year is expected. To cover these ranges, a safety margin has been included in the catalyst design. Certain additional margin has been included for uneven distribution of flue gas parameters such as velocity, temperature, NO_x concentrations and stoichiometric ratios. Also based on coupon tests, the SO2 to SO3 oxidation is expected to increase significantly over time due to Vanadium contamination from the fly ash.

Catalyst Sealing System

To avoid flue gas leakage, the modules are placed on seals between the support structure and the modules. On top of the modules there will be baffle plates installed between adjacent modules to avoid dust deposits in that area.

Ammonia Injection / Mixing

The purpose of the ammonia injection system is to expose the entire catalyst section with an even distribution of ammonia upstream of the first catalyst layer. ALSTOM typically designs to a specific gas flow variation coefficient upstream of the injection grid. This is achieved by means of proper duct design, utilizing ALSTOM's experience with gas modeling, duct bends and vaning. The process uses ammonia gas from the existing storage tanks and meters it, as required by boiler load, into a constant flow of hot dilution air. This 20:1 dilution avoids any risk of handling an explosive mixture of ammonia in air. A static mixer is located in the dilution air pipe downstream of the ammonia line to ensure proper mixing of the ammonia in the dilution air. Ammonia concentration is kept below the lower flammability limit. The ammonia/air mixture is injected into the flue gas duct, through a specially designed injection grid, upstream of the catalyst. This grid has been designed to work together with a sophisticated flue gas mixer to assure uniform distribution of the ammonia and NOx. The flue gas mixer allows the design of the grid to be greatly simplified. Only 28 injection points are required for this application. This design does not require tuning the AIG, thus eliminating all the balancing valves and flow meters on the grid. Use of a nonadjustable grid reduces the time needed to commission the system and also reduces the annual maintenance required.

ALSTOM proposes to use the patented Sulzer type SMV flue gas mixer as illustrated above. A static SMV gas mixer is made up of one or more mixing elements. These consist of corrugated plates which form intersecting channels. The mixing effect takes place between two neighboring plates by a relative displacement of part of each flow, as well as due to the increased turbulence at the open channel intersections. Two mixing elements, oriented 90 degrees from each other, are required to produce a homogenous mixture across both the x and y axes of the duct. Two additional stages of mixing take place in the open duct immediately downstream of each mixing element. This is due to the segmented flow streams that exit the SMV element at various angles to the main axis of the duct and intersect with each other in free space.

Sulzer Chemtech is the worlds leading supplier of static mixers, mixer-heat exchangers and plug-flow reactors. More than 25 years of experience in static mixing results in unique technology, proven design, economical solutions and competent support.

Anhydrous ammonia, per the specification, is being employed as the ammonia type. This ammonia gas is extracted from existing connections on the top of the existing ammonia storage tanks. A new pipeline will run along the existing piperack to transport this gas from the ammonia tanks to the boiler building. Flow from the tanks to the dilution air duct is regulated by a control valve, which receives its signal from the overall SCR control logic.

Fans located near the ammonia injection grid supply dilution air. This dilution airflow is fixed and is set to maintain approximately a 20:1 air/ammonia ratio at maximum ammonia flow to the system. This air/ammonia mixture will be directed to the ammonia feed duct at the nozzle grid.

The preliminary design of the ammonia injection grid calls for 28 injection pipes entering the gas duct ahead of the SCR reactor. Each pipe is about 3 inches in diameter. The location of these 28 injection points is coordinated with the design of the mixer. Duct penetrations are staggered to reduce flue gas pressure drop but, at the same time, provide good mixing of ammonia with the flue gas.

Sootblowers

Sonic Sootblowers are being included to aid in the prevention of the accumulation of deposits. They have proven themselves effective in high dust plants with both coal and oil firing. All reactor levels should be cleaned from reactor top to reactor bottom. An initial cleaning frequency of at least once per hour is recommended, with adjustments made as required.

NO_x Control System

General Control Principles

The most common way of controlling the ammonia injection is to use a set point for the outlet NOx concentration, thus keeping the NOx emission at a constant level across the entire load range of the SCR reactor. The objective is to maintain the emission just below the design point in order to reduce ammonia consumption at lower boiler loads, and lowest achievable ammonia slip.

Alternatively, NOx removal efficiency can be fixed and the control system will calculate a required outlet NOx concentration at any operating condition. The operator would select the choice of control method.

Operation

The required outlet NOx emission initiates process control. As described, the outlet will either be fixed directly or calculated based on the inlet concentration and the desired removal efficiency. Measured NOx concentrations at the SCR inlet, provided by Alstom, and outlet, using the existing CEM, are corrected to standard O_2 levels.

The inlet NOx concentration is used in conjunction with the fixed or calculated NOx outlet value and the flue gas flow rate to determine the mass flow of NOx to be removed. This mass flow is used by the control logic in conjunction with the required mole ratio (NH3/NOx) to determine the mass flow of ammonia needed for the reduction. The controller increases or decreases the ammonia flow, depending on the difference between the NOx outlet set point and the actual NOx outlet value measured downstream of the SCR reactor.

Electrical Controls and Instrumentation

ALSTOM will provide all field instrumentation, PLC hardware, and control logic for the SCR system described herein, including engineering design, drafting and documentation for ALSTOM supplied equipment.

ALSTOM will also provide training and assistance to the customer during the installation of the control equipment for the entire SCR system and its associated processes.

SCR/Ammonia Start up And Shut down Procedures

To start up and shut down the SCR system, the following general procedures and sequences shall be followed. Depending upon the overall system design and layout, certain modifications to the procedure may be necessary and, if so, will be provided by ALSTOM.

Start Up Procedure

1. Prepare the unit for purge by positioning boiler gas path dampers according to manufacturers recommendations, starting fans and airheaters.
2. Purge the boiler, SCR reactor, airheater, and duct.
3. Verify ammonia tank level and pressure. Verify that all isolation valves from the ammonia tank to the flow control valve are open. However do not open the ammonia flow control valve to the dilution air duct.
4. Verify that the sootblowing sequence is activated and that correct airflow and pressure is available to the soot blowers..
5. Place auxiliary fuel firing equipment in service as required for boiler warm-up.
6. Wait until the SCR reactor has passed the established acid dew point temperature, and the flue gas temperature leaving the reactor is above 300 °F.
7. Begin firing solid fuel.
8. Heat the SCR reactor with flue gas until the temperature in the SCR reactor is above the minimum catalyst operating temperature.
9. Start the ammonia injection system control loop and slowly open the ammonia control valve.

Shut Down Procedure

1. Shut off the ammonia supply valve and stop the ammonia injection system control loop.
2. Stop fuel feed to the boiler and continue operation of fans until flue gas has been purged from the entire gas path.

Air Heater Washing

It has been our experience that properly operated plants using SCR units designed for less than 3 ppm of ammonia slip require minimal (once or twice per year) washing of the air heater to control bisulfate formation. Operation outside of the design conditions for the system can easily result in excessive slip and high air heater pressure drop. It is important that the system be both properly designed and operated for satisfactory performance.

Flue Gas Flow Modeling

Gas flow design and modeling is one of ALSTOM Power's primary areas of expertise. We maintain two in house laboratories for gas flow modeling and an extensive staff of people experienced in building, testing, and interpreting the results of gas flow models. The proper design and operation of most of our pollution control equipment, low NOx burners, and large fans are dependent on well-controlled gas flow distribution in the equipment and surrounding ductwork.

ALSTOM has been designing SCR equipment for large boilers since 1985. Every plant is unique and requires a custom solution to achieving proper gas distribution. We have included a gas flow model for Stanton in our proposal to assure optimum performance of the SCR.

3.0 CONSTRUCTION/DESIGN FEATURES

Reactor Vessel

The SCR Reactor will be fabricated from carbon steel plate and will be externally stiffened. The Reactor is configured to hold one layer of catalyst. A second layer will be also be supplied and stored by Haldor Topsoe for future installation when needed. Flow turning, straightening, and mixing vanes are provided in the reactor to optimize the removal of NO_x and maintain minimum flue gas pressure loss.

Catalyst Modules

Catalyst modules, completely assembled and ready for installation into each reactor chamber, will be provided. The catalyst material will be titanium dioxide with tungsten and molybdenum oxides and vanadium pentoxide as the active components. Molybdenum oxide provides protection against poisoning by trace elements. Lifting lugs are provided on each catalyst module for ease of installation and maintenance into and out of the reactor chamber. To avoid flue gas leakage, the modules are placed on sealing strips between the support structure and the modules. On the tops of the modules baffle plates are installed between the modules to avoid dust deposits.

Framework for Modules

The framework for the catalyst modules will be fabricated from steel. Hot-rolled steel shapes and plates will be ASTM-A36. High strength bolts will be ASTM-A307 and/or ASTM-A490. Machine bolts will be ASTM-A307. Structural welding will conform to the Structural Welding Code AWS D1.1. All framework materials will be compatible with the catalytic material. Proper internal module sealing between the plate catalyst and module frame will be provided, where applicable. To facilitate placement and removal of the individual modules, spacing will be provided along two (2) adjacent sides of each reactor, with flashing installed once the modules are in place.

Grating

Grating (pedal protection) on each module face will be furnished. The grating is provided for ease of internal maintenance and inspection. Grating material is of stainless steel, providing corrosion and erosion resistance. Both grating and structural detail drawings will be provided to GRE, and will be compatible with the process and operating requirements.

Special Tools

All special tools required for the installation and normal maintenance of the modules will be provided. A cart will be provided within the reactor chamber for individual module positioning. An overhead electric crane will be positioned to allow for the removal and replacement of the modules.

4.0 SCOPE OF SUPPLY - Typical each boiler.

4.1 Mechanical Equipment, SCR System

QUAN.	ITEM	DESCRIPTION
SCR Reactor and Accessories		
1 Only	**SCR Reactor**	SCR Reactor, fabricated from carbon steel plate, externally stiffened. The Reactor is configured to hold one layer of catalyst. Flow turning, straightening, and mixing vanes are provided to optimize the removal of NO_x and maintain minimum flue gas pressure loss.
4 Only	**Soot Blowers**	Sonic type soot blowers to maintain gas passages through the SCR catalyst system.
60 Only	**SCR Catalyst Modules**	High dust type catalyst. The catalyst material is furnished installed in a steel framework with a nominal size of 1m x 2m plan area and a height of approximately 1.5m. The catalyst pitch is nominally 6.4mm (including 1 wall at 0.8 mm).
1 Lot	**Access**	Access will be provided at each catalyst level, including 2’ x 3’ quick opening doors for internal inspection and larger doors for catalyst removal and replacement.

1	Lot	**Catalyst Handling Equipment**	The SCR Reactor is equipped with a complete set of catalyst handling and hoisting equipment, including carts, air powered hoist, electric hoist, and crane beams that provide a permanently installed method of removing and replacing catalyst blocks. This handling equipment is further described in section 5.
1	Lot	**Ductwork**	1/4” carbon steel ductwork with appropriate stiffening and supports. Ductwork extends from the economizer outlet to the SCR and from the SCR to the air heater.

4.2 Mechanical Equipment, Ammonia System

QUANTITY		**ITEM**	**DESCRIPTION**
Ammonia Injection System and Accessories			
2	Only	**Dilution Fans**	One (1) operating, one (1) spare unit. Dilution air fans taking suction from the air heater hot air discharge and diluting the ammonia vapor 20:1 before injection into the duct.
1	Lot	**Ammonia Vapor Piping**	Ammonia vapor / air mixture piping and distribution from the ammonia storage tank to the duct injection grids. Dilution air duct from the existing hot combustion air duct to the dilution air fans and from the fans to the AIG.
1	Only	**Ammonia Injection Grid and mixer**	Ammonia injection grid in the SCR inlet flue gas duct followed by a flue gas mixer.

4.3 ELECTRICAL Equipment

QUANTITY		ITEM	DESCRIPTION
SCR, Ammonia and Ash Systems			
1	Only	**Field Instruments**	Instrumentation and other related accessories for the operation of the SCR by the Alstom provided PLC system.
1	Only	**PLC and Control Logic**	PLC controller with I/O as needed to control the operation of the SCR. A data highway port will be provided for communication with the owners DCS. PLC cabinet to be located in the owners DCS room. PLC will be provided with Engineering design, drafting, documentation, configuration of controls, and logic diagrams, factory testing of logic, supply of display and control graphics displays for the ALSTOM supplied equipment.
1	Only	**SCR Inlet Gas Analyzer & Monitoring System**	Complete with microprocessor based NO_x, and oxygen analyzers, flow monitors, sampling system, to be housed in the owner's DCS room.

SCOPE BY OTHERS

The following items are not included in the ALSTOM scope and are to be furnished, as required, by others.

1. Existing DCS system (ALSTOM to provide SCR PLC with interface card for communication with DCS)
2. 460V Power feed to Alstom MCC
3. Existing stack CEM to provide SCR with NOx emission value for control of ammonia feed.
4. Existing ammonia storage and unloading facility (ALSTOM to tie in new pipeline to SCR)
5. Subgrade electrical grounding grid.
6. Performance testing
7. Operating personnel and consumables for commissioning and start up.

4.4 List of Major Equipment Suppliers and Subcontractors

MAJOR VENDOR LIST	
PRODUCT	VENDORS
SCR SYSTEM	
Chamber Fabrication	PSP, or equal
Catalyst	Haldor Topsoe or equal
Duct Fabrication	PSP, or equal
Expansion Joints	Effox, or equal
Sootblowing System	Drayton, or equal
AMMONIA SYSTEM	
Storage Tanks	By Others
Vaporizer System	By Others
CONTROLS	
NOx Analyzer	Thermo Electron, or equal

5.0 PERFORMANCE ESTIMATES-SCR SYSTEM

Following the completion of the installation of the proposed equipment and subject to the performance conditions contained in Section 7.1 of this Proposal, ALSTOM estimates the following under steady state conditions as defined in this proposal section 3.2.1:

NO_x removal	90% minimum 24 hour average
Draft Loss	Not to exceed 4 inches of WG, from the economizer outlet to the air heater inlet.
Ammonia Slip	Not to exceed 2 ppm
Catalyst life	8000 hr. of operation, or 12 months from initial operation, whichever occurs first.
SO_3 Oxidation.	Less than 1.2% as measured during the first month of operation.
Ammonia consumption as NH3	Not to exceed 370 lb./hr

5.1 PERFORMANCE CONDITIONS

1. A mutually acceptable test program will determine the estimate testing performance values.
2. Installation of the proposed equipment will be in accordance with ALSTOM's drawings and instructions.
3. Operation and maintenance of the equipment will be in accordance with ALSTOM's instructions and good engineering and operating principles.
4. Performance testing will be conducted with no unusual circumstances. For example, feedwater heaters out of service, no hindrances due to incapacitated FD fans, convection pass dampers, flue gas cleaning equipment, ash handling system, sootblowers, wall blowers, and boiler controls.
5. The fuel fired will fall within the range of the fuel as listed in the specification.
6. Recording devices for operating parameters will be maintained by the Customer and made available to ALSTOM.
7. All replacement parts will be of ALSTOM's manufacture or supply or approved equal.
8. The equipment will be started up in the presence of appropriate ALSTOM personnel.

Documentation

A records system shall be established and maintained to provide documentary evidence of the quality of items and activities affecting quality. ALSTOM will ensure that the following documents, as appropriate, are furnished to GRE:

a) Certificate of Compliance, stating that all equipment and materials furnished comply with the Purchaser's specification.

b) Material Test Reports

c) Material Certifications

d) Foundation Design Drawings

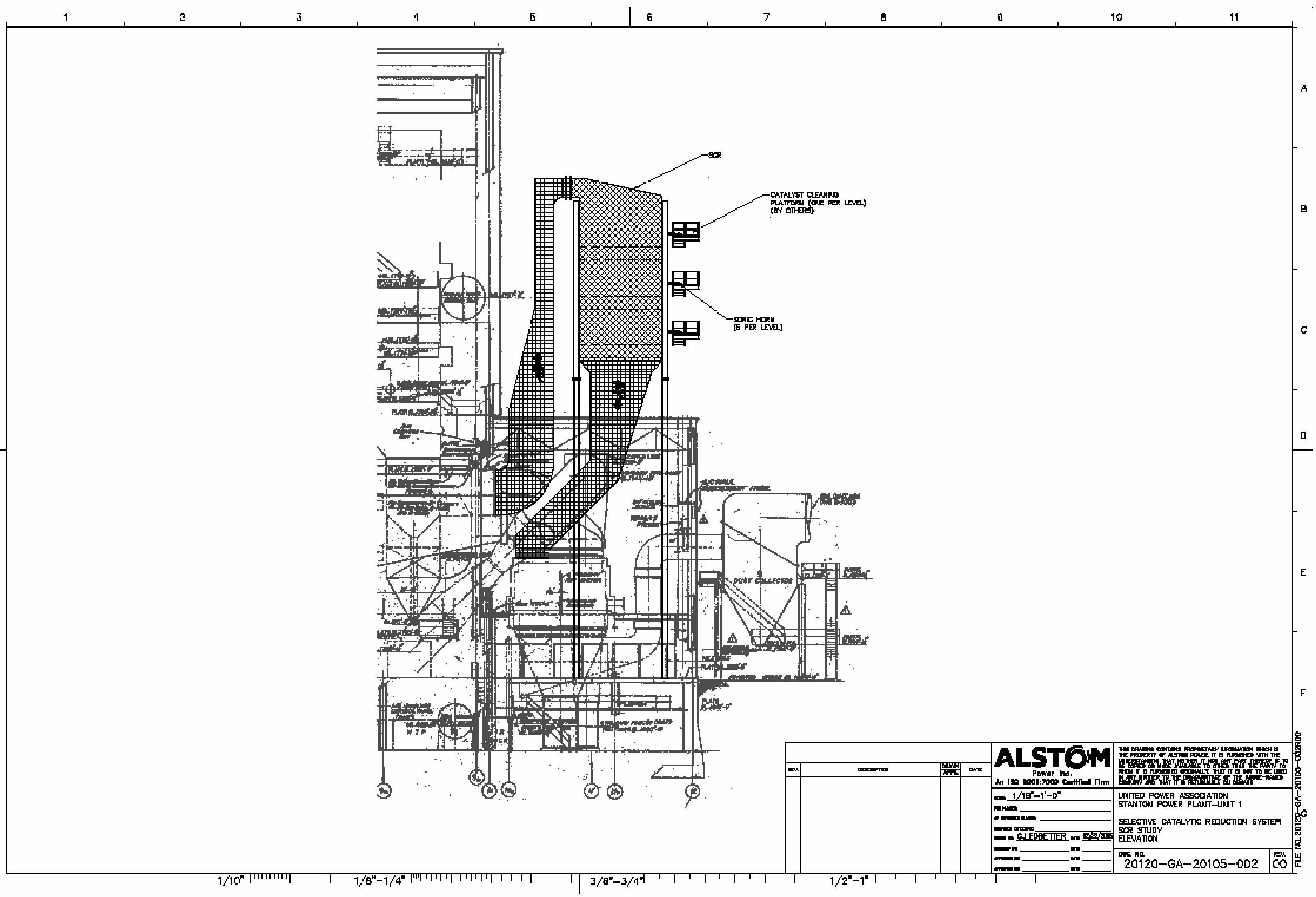
e) Performance Test Results

f) Electrical Test Results and Instrumentation Specifications

g) Documents identifying deviations and their acceptance.

h) Structural Loading Data

APPENDIX 5.6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CATALYST CLEANING PLATFORM (ONE PER LEVEL) (BY OTHERS)
SONIC HORN (5 PER LEVEL)
DUST COLLECTOR
ALSTOM
1/16"=1'-0"
UNITED POWER ASSOCIATION
STANTON POWER PLANT–UNIT 1
SELECTIVE CATALYTIC REDUCTION SYSTEM
SCR STUDY
ELEVATION
20120-GA-20105-002
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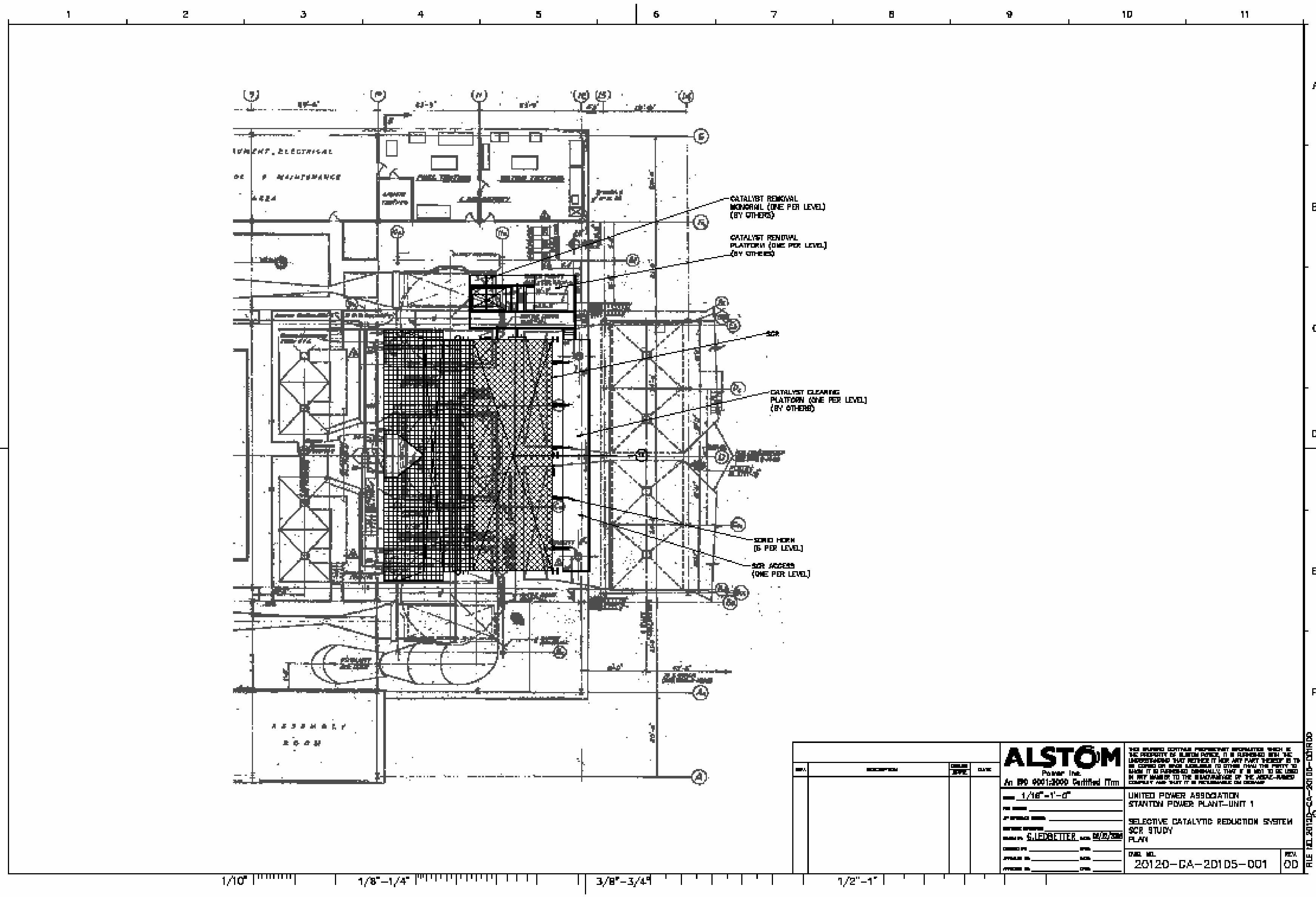

CATALYST REMOVAL MONORAIL (ONE PER LEVEL) (BY OTHERS)
CATALYST REMOVAL PLATFORM (ONE PER LEVEL) (BY OTHERS)
SCR
CATALYST CLEANING PLATFORM (ONE PER LEVEL) (BY OTHERS)
SONIC HORN (6 PER LEVEL)
SCR ACCESS (ONE PER LEVEL)
ALSTOM
Power Inc.
1/16"=1'-0"
G.LEDBETTER
UNITED POWER ASSOCIATION
STANTON POWER PLANT-UNIT 1
SELECTIVE CATALYTIC REDUCTION SYSTEM
SCR STUDY
PLAN
20120-CA-20105-001
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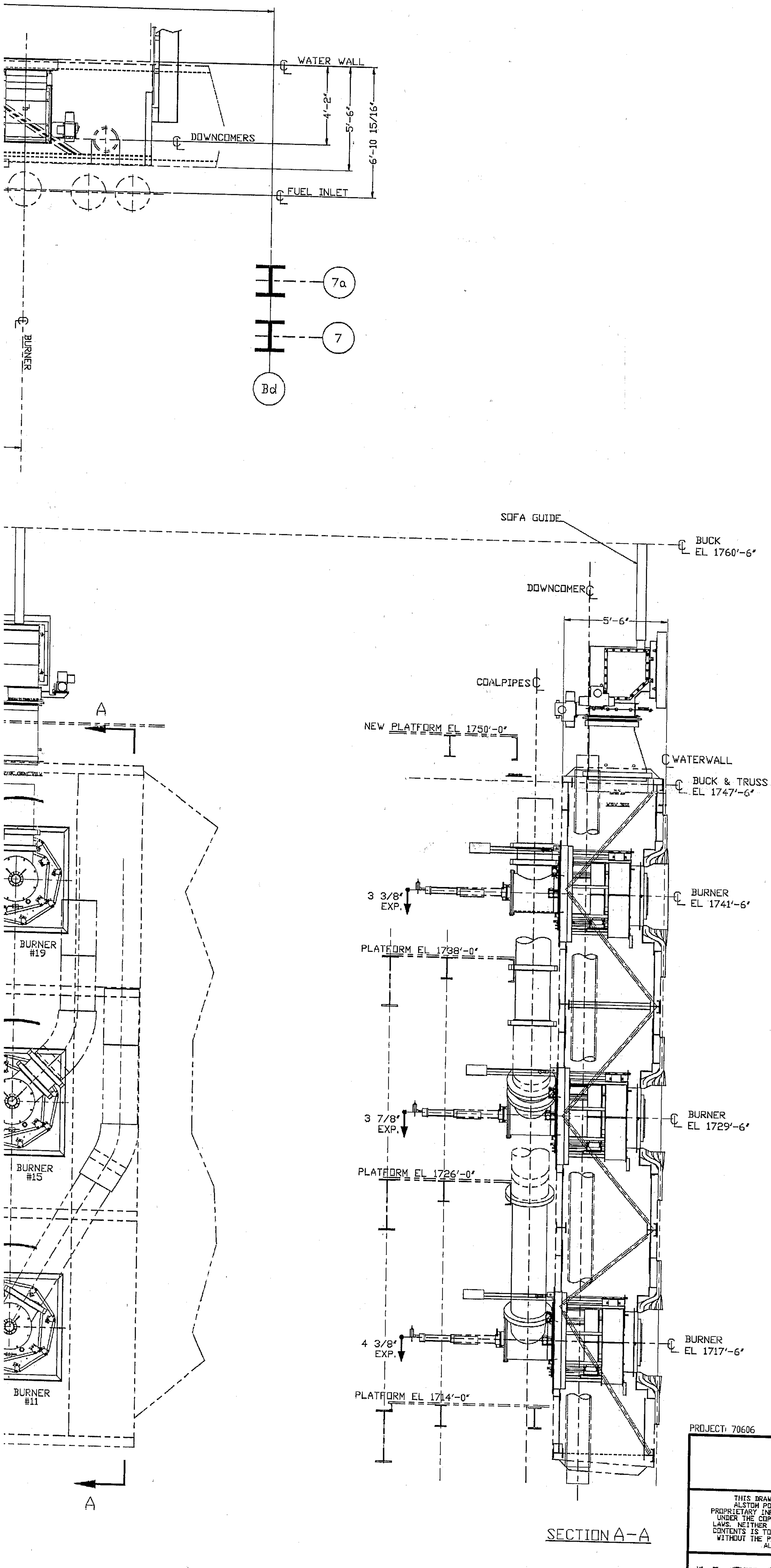
END OF REPORT



SECTION A-A

PROJECT: 70606 ORIGINAL CONTRACT: 76797 UNIT: 1

RSFC BURNER/SOFA GENERAL ARRANGEMENT
GREAT RIVER ENERGY
STANTON STATION
STANTON, ND

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SCALE: NTS
DRAWN BY: J. Lewis DATE: 02/23/06
CHECKED BY: J. Lewis DATE: 02/23/06
APPROVED BY: DATE:
WBS CODE:

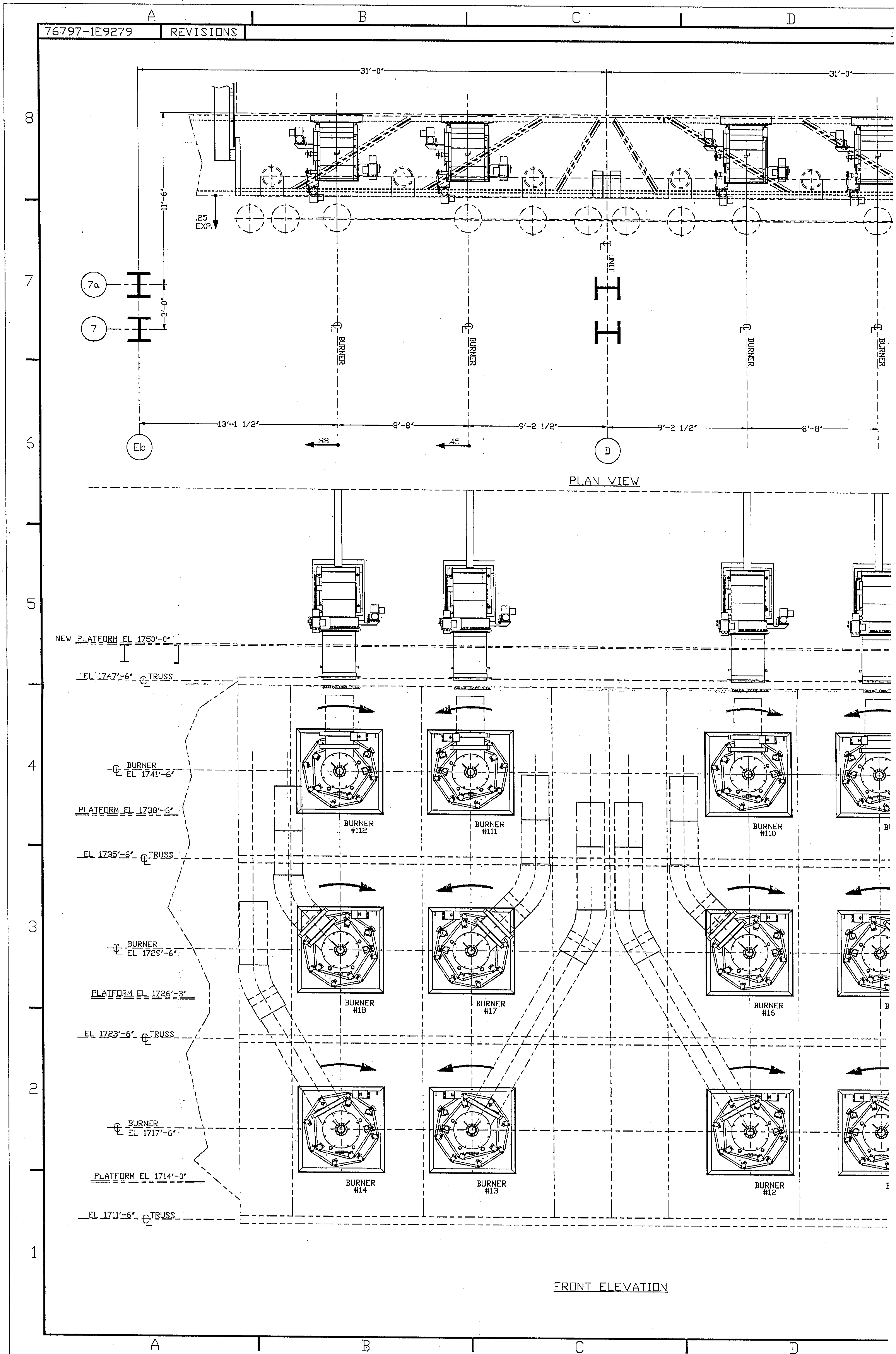
PRELIMINARY

ALSTOM

ALSTOM POWER INC.
2000 DAY HILL RD.
WINDSOR, CONNECTICUT

DRAWING NO. 76797-1E9279 REV. 00

CHECKED


76797-1E9279
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31'-0"
11'-6"
3'-0"
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EXP.
7a
7
UNIT
BURNER
BURNER
BURNER
BURNER
13'-1 1/2"
8'-8"
9'-2 1/2"
9'-2 1/2"
8'-8"
.88
.45
Eb
D
PLAN VIEW
NEW PLATFORM EL 1750'-0"
EL 1747'-6" TRUSS
BURNER EL 1741'-6"
PLATFORM EL 1738'-6"
EL 1735'-6" TRUSS
BURNER EL 1729'-6"
PLATFORM EL 1726'-3"
EL 1723'-6" TRUSS
BURNER EL 1717'-6"
PLATFORM EL 1714'-0"
EL 1711'-6" TRUSS
BURNER #112
BURNER #111
BURNER #110
BURNER #18
BURNER #17
BURNER #16
BURNER #14
BURNER #13
BURNER #12
FRONT ELEVATION

SNCR Feasibility with LNB/OFA

An excerpt from an April 13, 2006 email from Alstom is included below. It describes the technical feasibility of using SNCR in combination with LNB/OFA on Stanton's Unit 1, and includes expected emissions reductions.

Regarding the NOx reduction using both SOFA and SNCR technologies as a combined/cascade system (SOFA + SNCR):
The general consensus between ALSTOM and Fuel Tech is that for the most part, yes, the two systems should work and should reduce NOx ALMOST to the aggregate of each system capability separately however, with the following exceptions:

1. SNCR technology will work slightly less effectively than it would as a sole NOx reduction system.
2. The combined SOFA and SNCR technologies assumes the upper furnace combustion zone, with SOFA modifications implemented, does not exceed 500ppm CO.
3. ALSTOM has not performed any CFD modeling that would otherwise allow more confident predictions on the effectiveness of SOFA + SNCR cascaded technologies.

	Baseline NOx	Case 1 (w/SOFA + mods)/% red.	Case 1(w/SNCR only)/% red	Case 1 (w/SOFA & mods + SNCR) - % red.
Case 1 (1.1m lb/hr fw 3mills, PRB)	0.38 - 0.40	0.27 - 0.32/20%-29%	0.304/20%	20% - 29% + **18% - 20%** = **38% - 49%** Total
Ammonia slip		5 ppm	5ppm	

Case 2 (.80m lb/hr fw #13 off, PRB)	0.27	0.18 - 0.23/15-33%	**0.23/15%	15 - 33% + 17.5% - 20% = 32.5% - 53% Total
Ammonia slip		5 ppm	5ppm	

** Note: the original evaluation had a target NOx of 0.23, which provided the targeted reduction of 15%. The SNCR process is capable of approx. 20% NOx reduction from the baseline.

Case 3 Total (.9m lb/hr fw Lignite)	0.40	0.27 - 0.32/20 - 33%	0.29/27.5%	20% - 33% + 25% to 27%(20% - 25%)=45% - 60%
Ammonia Slip		10 ppm	10 ppm(5ppm)	

Appendix E

Sulfur Content Statistical Analysis

Coal Sulfur Content Statistical Analysis

Lignite Coal

For the purpose of establishing SO_2 emission rates for Lignite, two sources of data were considered.

1) Historical Stanton coal from the Freedom Mine- For Freedom Mine, the maximum daily sulfur content was 1.55% as reported in the 2001 emission inventory.

,

2) MR Young coal from the Center Mine - Milton R. Young's Unit 1 is a lignite fired boiler that does not currently have a scrubber installed for SO_2 control. Emissions from MR Young Unit 1 indicate that the lignite sulfur content has been higher in recent years (2004 through 2005) than historically recorded at Stanton Station. Based on SO_2 emissions[1] from M.R. Young Unit 1, the daily percent sulfur content for lignite was calculated and is presented in Table 3. The top 10 highest daily coal sulfur contents, as listed in Table 3, confirm that the highest daily sulfur content of 1.57% is not a statistical outlier.

Table 1. Sulfur Content Statistical Analysis

	Date	% Sulfur in Lignite[2]
Average 2004-2005		1.01
Minimum Daily	4/10/2005	0.04
Maximum Daily	7/2/2005	1.57
Average + 2 Standard Deviations		1.31

These data are consistent with North Dakota lignite reserves as could be used by Stanton over the expected life of the plant. Given that the MR Young data is slightly higher than Stanton, it was chosen as a representative daily maximum sulfur percentage for future Stanton lignite combustion. Using the statistical analysis of this data presented in Tables 1 and 2, 1.31% sulfur (2.44 lb/MMBtu) and 1.57% sulfur (2.94 lb/MMBtu) were determined to be representative for a future predicted 30-day rolling average and a 24-hour maximum sulfur content, respectively.

[1] Daily SO_2 emissions data for M. R. Young's Unit 1, years 2004 and 2005 from electronic data records located at <http://www.epa.gov/airmarkets/emissions/raw/index.html> (attached)

[2] % Sulfur in Lignite is calculated based on the SOx emission factor from AP-42 Chapter 1-7, Table 1.7-1. The emission factor is given as 30S lb/ton where S is the weight % sulfur content of wet lignite. To convert to lb/MMBtu the emission factor is multiplied by 0.0625. Therefore, S = lb/MMBtu SO_2/0.0625/30

Table 2. Predicted Emissions Calculations

	30-Day Rolling	24-Hour Maximum
Sulfur %	1.30	1.57
lb/MMBtu	2.44	2.94
Dry Scrubber Control Efficiency	90%	90%
Predicted Emissions	0.24 lb/MMBtu	0.29 lb/MMBtu
	432.0 lb/hr	526.5 lb/hr

Table 3. Top 10 Highest Daily Sulfur Contents

Rank	Date	% Sulfur in LigniteError! Bookmark not defined.
1	7/2/2005	1.57
2	3/9/2005	1.56
3	7/6/2005	1.46
4	12/8/2004	1.45
5	12/6/2005	1.45
6	9/15/2005	1.42
7	12/7/2005	1.41
8	5/18/2005	1.40
9	5/17/2005	1.38
10	7/3/2005	1.36

PRB Coal

Stanton Station is currently permitted to burn both lignite and PRB coals. Currently, Stanton receives coal from the Spring Creek Mine located in eastern Montana. The mine uses a sulfur reject value of 1.2 lb/MMBtu with a contractual guarantee of 0.8 lb/MMBtu. According to the contract, the financial penalty is only the incremental value of SO_2 allowances for any overage from the 0.8 lb/mmbtu value. Although most shipments conform to the 0.8 lb/MMBtu requirement, it is not uncommon to receive shipments with a sulfur content of 1.0 lb/MMBtu as could be expected during a 30-day rolling period. Consequently, for the purpose of establishing a regulatory limit, it is prudent to use the mine's reject value at 1.2 lb/MMBtu.

Given that the existing PRB contract expires in 2009, it is necessary to incorporate sulfur contents from other potential Montana PRB mines. Table 4 presents 3 realistic examples of Montana PRB mines and their average sulfur characteristics.

Table 4. Montana PRB Mine Characteristics[3]

Montana Coal Mine	Average Sulfur Content (%)	HHV (Btu/lb)	SO_2 Emissions (lb/MMBtu)[4]
Spring Creek	0.34	9,350	0.64
Absaloka	0.64	8,750	1.28
Rosebud	0.80	8,750	1.60

Assuming a 90% SO_2 control scenario, an SO_2 limit of 0.15 to 0.16 lb/MMBtu is justified to cover the range of expected PRB fuels as well as possible sulfur variability within a mine. Based on this information, it is clear that a compliance limit set at or slightly above 0.15lb/mmbtu is justified for the life-of-plant.

[3] Coal specification data from BNSF information, included in attachments.
[4] Calculation method in EPA AP-42, Chapter 1: External Combustion Sources.
SO_2 Emissions (lb/MMBtu) = (35 x sulfur content (%)) / HHV (Btu/lb) / 2000 (lb/ton) x 1E6 (Btu/MMBtu)

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
1/1/2004	4792.5	1.57	0.83
1/2/2004	5118.7	1.61	0.86
1/3/2004	5638.5	1.80	0.96
1/4/2004	4758.5	1.59	0.85
1/5/2004	4940.1	1.61	0.86
1/6/2004	5296.3	1.76	0.94
1/7/2004	5510.1	1.89	1.01
1/8/2004	5839.6	1.92	1.02
1/9/2004	6373.4	2.04	1.09
1/10/2004	4750.4	1.76	0.94
1/11/2004	3840.0	1.82	0.97
1/12/2004	4837.5	1.70	0.90
1/13/2004	5263.6	1.86	0.99
1/14/2004	5181.7	1.78	0.95
1/15/2004	4963.6	1.73	0.92
1/16/2004	5020.3	1.70	0.91
1/17/2004	5584.4	1.87	1.00
1/18/2004	4928.0	1.65	0.88
1/19/2004	4946.6	1.64	0.87
1/20/2004	6101.8	2.01	1.07
1/21/2004	6159.7	1.99	1.06
1/22/2004	5745.7	1.85	0.99
1/23/2004	6158.9	2.07	1.11
1/24/2004	6040.5	1.93	1.03
1/25/2004	5677.7	1.75	0.94
1/26/2004	5310.9	1.59	0.85
1/27/2004	5669.3	1.70	0.91
1/28/2004	6489.4	1.91	1.02
1/29/2004	6309.5	1.89	1.01
1/30/2004	6293.0	1.90	1.02
1/31/2004	6696.3	2.04	1.09
2/1/2004	5694.0	1.75	0.93
2/2/2004	5287.7	1.62	0.86
2/3/2004	5692.2	1.74	0.93
2/4/2004	5894.1	1.80	0.96
2/5/2004	5352.3	1.65	0.88
2/6/2004	5537.3	1.71	0.91
2/7/2004	5727.5	1.79	0.96
2/8/2004	5340.2	1.68	0.90
2/9/2004	4513.8	1.41	0.75
2/10/2004	5894.6	1.86	0.99
2/11/2004	5286.3	1.63	0.87
2/12/2004	5791.1	1.77	0.95
2/13/2004	5851.9	1.81	0.97
2/14/2004	6157.5	1.90	1.01
2/15/2004	4827.2	1.62	0.86
2/16/2004	4198.8	1.39	0.74
2/17/2004	4610.2	1.61	0.86
2/18/2004	4988.1	1.74	0.93
2/19/2004	6525.1	2.21	1.18
2/20/2004	5743.8	1.94	1.04
2/24/2004	1287.3	0.80	0.43
2/25/2004	4412.2	1.82	0.97

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
2/26/2004	5775.7	2.13	1.14
2/27/2004	6667.4	2.49	1.33
2/28/2004	6145.6	2.28	1.22
2/29/2004	4917.3	1.84	0.98
3/1/2004	4506.3	1.65	0.88
3/2/2004	5609.9	2.05	1.10
3/3/2004	5237.3	1.91	1.02
3/4/2004	4616.7	1.70	0.91
3/5/2004	5323.2	1.96	1.04
3/6/2004	4651.4	1.71	0.91
3/7/2004	4585.0	1.66	0.89
3/8/2004	4544.9	1.62	0.86
3/9/2004	4882.5	1.77	0.95
3/10/2004	5087.4	1.82	0.97
3/11/2004	5393.8	1.85	0.99
3/12/2004	4756.6	1.73	0.92
3/13/2004	5070.0	1.77	0.95
3/14/2004	4433.4	1.57	0.84
3/15/2004	4668.3	1.68	0.89
3/16/2004	5553.1	2.02	1.08
3/17/2004	5133.7	1.88	1.00
3/18/2004	4915.2	1.79	0.95
3/19/2004	4536.5	1.62	0.87
3/20/2004	5249.9	1.90	1.01
3/21/2004	4427.4	1.63	0.87
3/22/2004	4097.7	1.49	0.79
3/23/2004	5449.5	2.01	1.07
3/24/2004	5300.7	2.01	1.07
3/25/2004	5159.3	1.89	1.01
3/26/2004	5928.2	2.17	1.16
3/27/2004	5558.7	2.04	1.09
3/28/2004	5033.0	1.84	0.98
3/29/2004	4873.2	1.77	0.94
3/30/2004	5395.0	1.93	1.03
3/31/2004	4822.6	1.67	0.89
4/1/2004	4769.8	1.68	0.90
4/2/2004	4943.0	1.74	0.93
4/3/2004	5487.4	1.95	1.04
4/4/2004	4906.3	1.73	0.92
4/5/2004	4504.9	1.59	0.85
4/6/2004	5466.5	1.90	1.01
4/7/2004	5000.2	1.73	0.92
4/8/2004	5192.5	1.77	0.94
4/9/2004	4683.6	1.60	0.85
4/10/2004	4597.3	1.55	0.83
4/11/2004	4672.3	1.63	0.87
4/12/2004	4555.8	1.64	0.87
4/13/2004	4185.8	1.45	0.77
4/14/2004	5752.5	2.11	1.12
4/15/2004	4031.9	1.61	0.86
4/16/2004	3511.1	1.39	0.74
4/17/2004	2666.4	1.38	0.74
4/18/2004	2749.2	1.45	0.77

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
4/19/2004	3490.0	1.41	0.75
4/20/2004	3059.4	1.85	0.99
4/22/2004	5657.8	1.99	1.06
4/23/2004	5601.8	2.05	1.09
4/24/2004	5641.6	2.07	1.10
4/25/2004	5385.6	1.97	1.05
4/26/2004	5280.9	1.94	1.04
4/27/2004	5514.9	2.05	1.09
4/28/2004	6038.0	2.19	1.17
4/29/2004	6647.8	2.43	1.30
4/30/2004	5964.0	2.13	1.14
5/1/2004	5340.0	1.89	1.01
5/2/2004	5468.8	1.95	1.04
5/3/2004	5429.2	1.95	1.04
5/4/2004	4959.2	1.75	0.93
5/5/2004	5203.7	1.83	0.98
5/6/2004	5314.1	1.89	1.01
5/7/2004	5784.0	2.05	1.09
5/8/2004	6672.5	2.31	1.23
5/9/2004	5805.3	2.00	1.07
5/10/2004	5433.4	1.92	1.02
5/11/2004	6427.9	2.19	1.17
5/12/2004	5749.3	1.93	1.03
5/13/2004	5672.6	1.91	1.02
5/14/2004	5590.7	1.87	1.00
5/15/2004	6352.1	2.18	1.17
5/16/2004	5507.9	1.87	1.00
5/17/2004	5125.8	1.75	0.93
5/18/2004	6445.3	2.20	1.17
5/19/2004	6258.1	2.18	1.17
5/20/2004	6757.9	2.49	1.33
5/21/2004	6928.8	2.50	1.33
5/22/2004	6567.7	2.32	1.24
5/23/2004	6189.5	2.21	1.18
5/24/2004	6403.0	2.28	1.22
5/25/2004	6101.4	2.07	1.11
5/26/2004	6202.0	2.12	1.13
5/27/2004	5545.6	1.91	1.02
5/28/2004	5620.3	1.93	1.03
5/29/2004	6024.2	2.07	1.11
5/30/2004	5779.1	2.01	1.07
5/31/2004	5855.5	2.05	1.09
6/1/2004	6010.4	2.08	1.11
6/2/2004	5851.7	2.06	1.10
6/3/2004	5685.4	1.94	1.03
6/4/2004	6070.2	2.07	1.10
6/5/2004	6136.3	2.12	1.13
6/6/2004	5689.5	1.99	1.06
6/7/2004	5655.3	1.93	1.03
6/8/2004	5570.1	1.95	1.04
6/9/2004	5469.0	1.82	0.97
6/10/2004	5480.5	1.81	0.97
6/11/2004	4523.3	1.52	0.81

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
6/12/2004	4082.3	1.45	0.77
6/13/2004	4143.9	1.52	0.81
6/14/2004	4838.9	1.72	0.92
6/15/2004	4686.4	1.64	0.88
6/16/2004	4633.5	1.58	0.84
6/17/2004	4556.2	1.60	0.85
6/22/2004	2802.1	1.53	0.82
6/23/2004	4244.3	1.63	0.87
6/24/2004	4154.3	1.56	0.83
6/25/2004	3651.7	1.51	0.80
6/26/2004	3753.9	1.53	0.82
6/27/2004	3636.5	1.48	0.79
6/28/2004	3512.8	1.43	0.76
6/29/2004	4187.9	1.71	0.91
6/30/2004	4467.1	1.81	0.96
7/1/2004	5114.4	2.07	1.10
7/2/2004	5221.5	2.10	1.12
7/3/2004	5257.8	2.08	1.11
7/4/2004	5115.1	2.06	1.10
7/5/2004	4425.1	1.83	0.97
7/6/2004	4010.5	1.63	0.87
7/7/2004	5493.5	2.16	1.15
7/8/2004	5486.0	2.12	1.13
7/9/2004	5597.2	2.13	1.13
7/10/2004	5435.5	2.06	1.10
7/11/2004	5218.2	2.01	1.07
7/12/2004	4529.4	1.81	0.96
7/13/2004	4928.2	1.94	1.04
7/14/2004	4435.9	1.73	0.92
7/15/2004	4593.2	1.79	0.96
7/16/2004	3966.6	1.52	0.81
7/17/2004	4782.1	1.83	0.97
7/18/2004	4518.5	1.72	0.92
7/19/2004	3926.2	1.50	0.80
7/20/2004	4430.7	1.76	0.94
7/21/2004	5732.8	2.20	1.18
7/22/2004	5742.8	2.22	1.19
7/23/2004	5620.0	2.25	1.20
7/24/2004	5611.4	2.25	1.20
7/25/2004	4796.5	1.97	1.05
7/26/2004	4702.8	1.90	1.02
7/27/2004	5648.5	2.19	1.17
7/28/2004	5375.5	2.12	1.13
7/29/2004	5675.4	2.27	1.21
7/30/2004	5331.5	2.10	1.12
7/31/2004	5608.0	2.21	1.18
8/1/2004	5321.2	2.10	1.12
8/2/2004	5122.1	2.04	1.09
8/3/2004	5313.9	2.10	1.12
8/4/2004	5274.6	2.12	1.13
8/5/2004	5190.4	2.03	1.08
8/6/2004	5239.0	2.06	1.10
8/7/2004	6037.6	2.41	1.29

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
8/8/2004	5121.3	2.07	1.10
8/9/2004	4525.3	1.85	0.99
8/10/2004	5276.4	2.10	1.12
8/11/2004	4326.0	1.68	0.90
8/12/2004	4510.3	1.75	0.93
8/13/2004	5513.9	2.13	1.14
8/14/2004	5444.4	2.09	1.11
8/15/2004	4850.1	1.87	1.00
8/16/2004	4630.8	1.79	0.95
8/17/2004	5308.0	2.03	1.08
8/18/2004	5350.8	2.05	1.09
8/19/2004	5296.6	2.10	1.12
8/20/2004	5515.1	2.08	1.11
8/21/2004	5303.7	2.01	1.07
8/22/2004	4977.1	1.91	1.02
8/23/2004	4658.0	1.80	0.96
8/24/2004	5544.8	2.19	1.17
8/25/2004	5589.3	2.19	1.17
8/26/2004	5426.3	2.16	1.15
8/27/2004	4706.0	1.90	1.01
8/28/2004	5557.0	2.19	1.17
8/29/2004	5197.2	2.06	1.10
8/30/2004	4768.6	1.90	1.01
8/31/2004	4802.4	1.86	0.99
9/1/2004	4834.2	1.89	1.01
9/2/2004	4795.0	1.91	1.02
9/3/2004	5064.2	1.99	1.06
9/4/2004	3918.5	1.71	0.91
9/5/2004	4547.9	1.78	0.95
9/6/2004	4562.5	1.75	0.93
9/7/2004	4273.5	1.69	0.90
9/8/2004	3957.0	1.51	0.81
9/9/2004	4809.0	1.81	0.97
9/10/2004	5462.3	2.10	1.12
9/11/2004	5291.7	2.05	1.10
9/12/2004	4720.1	1.81	0.96
9/13/2004	4417.5	1.68	0.90
9/14/2004	4327.7	1.65	0.88
9/15/2004	4565.2	1.73	0.92
9/16/2004	4666.3	1.77	0.95
9/17/2004	5034.1	1.90	1.01
9/18/2004	4435.6	1.68	0.89
9/19/2004	4279.6	1.63	0.87
9/20/2004	4220.2	1.62	0.86
9/21/2004	5230.0	2.03	1.08
9/22/2004	5481.6	2.09	1.12
9/23/2004	4453.9	1.70	0.91
9/24/2004	4514.8	1.72	0.92
9/25/2004	5174.8	1.98	1.06
9/26/2004	4838.2	1.90	1.01
9/27/2004	4485.8	1.78	0.95
9/28/2004	4511.8	1.73	0.93
9/29/2004	5236.1	1.97	1.05

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
9/30/2004	4246.0	1.61	0.86
10/1/2004	4186.8	1.60	0.85
10/2/2004	4289.8	1.66	0.89
10/3/2004	4342.4	1.66	0.88
10/4/2004	4108.1	1.59	0.85
10/5/2004	4809.4	1.82	0.97
10/6/2004	4619.7	1.74	0.93
10/7/2004	5336.1	2.01	1.07
10/8/2004	4650.1	1.75	0.93
10/9/2004	4449.8	1.68	0.90
10/10/2004	4428.6	1.67	0.89
10/11/2004	4329.5	1.65	0.88
10/12/2004	4660.9	1.75	0.93
10/13/2004	4964.7	1.84	0.98
10/14/2004	5416.5	2.04	1.09
10/15/2004	4765.2	1.77	0.95
10/16/2004	5418.4	1.98	1.06
10/17/2004	4368.4	1.65	0.88
10/18/2004	4205.5	1.56	0.83
10/19/2004	4716.0	1.75	0.93
10/20/2004	5731.7	2.11	1.12
10/21/2004	5832.8	2.21	1.18
10/22/2004	5035.7	1.87	1.00
10/23/2004	6204.0	2.34	1.25
10/24/2004	5264.0	1.95	1.04
10/25/2004	4949.1	1.80	0.96
10/26/2004	4873.0	1.80	0.96
10/27/2004	5723.7	2.09	1.11
10/28/2004	4031.5	1.62	0.87
10/29/2004	4687.8	1.91	1.02
11/2/2004	2000.2	1.27	0.68
11/3/2004	4994.6	1.99	1.06
11/4/2004	5373.1	2.12	1.13
11/5/2004	5743.6	2.27	1.21
11/6/2004	5626.0	2.20	1.17
11/7/2004	5326.9	2.06	1.10
11/8/2004	5203.2	2.02	1.08
11/9/2004	5782.5	2.28	1.22
11/10/2004	4551.0	1.84	0.98
11/11/2004	3666.0	1.44	0.77
11/12/2004	3894.7	1.53	0.82
11/13/2004	4933.5	1.94	1.04
11/14/2004	4429.9	1.76	0.94
11/15/2004	4021.4	1.61	0.86
11/16/2004	4501.1	1.82	0.97
11/17/2004	5090.8	1.99	1.06
11/18/2004	4998.1	1.97	1.05
11/19/2004	5263.3	2.03	1.08
11/20/2004	4970.3	1.87	1.00
11/21/2004	4590.3	1.79	0.96
11/22/2004	4625.1	1.73	0.92
11/23/2004	4764.6	1.76	0.94
11/24/2004	6107.9	2.26	1.21

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
11/25/2004	4989.3	1.82	0.97
11/26/2004	5049.0	1.83	0.98
11/27/2004	4840.7	1.79	0.96
11/28/2004	4622.4	1.70	0.91
11/29/2004	4627.5	1.71	0.91
11/30/2004	4559.4	1.67	0.89
12/1/2004	4047.1	1.51	0.81
12/2/2004	4728.8	1.78	0.95
12/3/2004	6441.9	2.40	1.28
12/4/2004	6116.5	2.28	1.22
12/5/2004	4992.3	1.85	0.99
12/6/2004	4513.3	1.64	0.87
12/7/2004	5836.1	2.12	1.13
12/8/2004	6967.8	2.73	1.45
12/11/2004	3428.7	1.93	1.03
12/12/2004	5411.3	2.09	1.12
12/13/2004	5241.7	2.02	1.08
12/14/2004	4612.3	1.77	0.95
12/15/2004	5103.4	1.92	1.02
12/16/2004	4958.7	1.82	0.97
12/17/2004	4729.8	1.74	0.93
12/18/2004	4546.4	1.64	0.88
12/19/2004	4446.7	1.62	0.87
12/20/2004	4166.9	1.54	0.82
12/21/2004	5129.1	1.85	0.99
12/22/2004	4991.6	1.83	0.97
12/23/2004	5434.3	1.99	1.06
12/24/2004	5277.9	1.91	1.02
12/25/2004	4287.0	1.57	0.84
12/26/2004	4592.2	1.63	0.87
12/27/2004	4705.4	1.66	0.89
12/28/2004	5055.1	1.79	0.96
12/29/2004	5059.3	1.81	0.97
12/30/2004	4636.6	1.65	0.88
12/31/2004	5446.7	1.91	1.02
1/1/2005	5276.5	1.87	1.00
1/2/2005	4361.3	1.56	0.83
1/3/2005	4465.2	1.55	0.83
1/4/2005	4162.1	1.41	0.75
1/5/2005	5316.4	1.84	0.98
1/6/2005	5558.9	2.02	1.08
1/7/2005	5362.7	2.04	1.09
1/8/2005	6201.1	2.38	1.27
1/9/2005	4483.1	1.70	0.91
1/10/2005	3974.9	1.48	0.79
1/11/2005	5315.7	1.98	1.06
1/14/2005	5266.0	2.42	1.29
1/15/2005	5066.0	2.05	1.09
1/16/2005	5308.9	2.18	1.16
1/17/2005	4830.4	2.01	1.07
1/18/2005	5983.1	2.21	1.18
1/19/2005	5246.5	1.91	1.02
1/20/2005	4397.7	1.75	0.93

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
1/21/2005	4535.5	1.74	0.93
1/22/2005	5994.5	2.07	1.10
1/23/2005	4786.2	1.89	1.01
1/24/2005	4130.1	1.63	0.87
1/25/2005	5159.4	1.99	1.06
1/26/2005	4910.0	1.93	1.03
1/27/2005	5318.4	2.10	1.12
1/28/2005	5606.8	2.16	1.15
1/29/2005	5555.1	2.11	1.12
1/30/2005	4908.6	1.94	1.03
1/31/2005	4779.2	1.86	0.99
2/1/2005	5429.3	2.07	1.10
2/2/2005	4904.3	1.89	1.01
2/3/2005	5076.2	1.95	1.04
2/4/2005	5475.1	2.10	1.12
2/5/2005	5537.1	2.12	1.13
2/6/2005	4866.6	1.88	1.00
2/7/2005	4415.7	1.63	0.87
2/8/2005	4570.6	1.65	0.88
2/9/2005	5368.8	1.98	1.05
2/10/2005	4573.0	1.69	0.90
2/11/2005	5220.1	1.94	1.03
2/12/2005	4971.6	1.84	0.98
2/13/2005	4223.9	1.64	0.87
2/14/2005	4359.8	1.54	0.82
2/15/2005	5441.7	1.97	1.05
2/16/2005	4925.3	1.80	0.96
2/17/2005	5780.1	2.13	1.14
2/18/2005	6048.1	2.20	1.18
2/19/2005	6140.2	2.25	1.20
2/20/2005	5670.8	2.06	1.10
2/21/2005	5095.0	1.86	0.99
2/22/2005	5139.0	1.92	1.02
2/23/2005	6107.2	2.22	1.18
2/24/2005	4222.6	1.57	0.84
2/25/2005	4500.2	1.62	0.86
2/26/2005	4343.6	1.56	0.83
2/27/2005	5037.9	1.76	0.94
2/28/2005	4487.6	1.65	0.88
3/1/2005	5686.5	2.21	1.18
3/2/2005	5561.6	2.13	1.14
3/3/2005	5103.0	1.99	1.06
3/6/2005	40.2	0.07	0.04
3/7/2005	3331.3	1.62	0.86
3/8/2005	5393.0	2.10	1.12
3/9/2005	6948.3	2.92	1.56
3/10/2005	5126.9	2.03	1.08
3/11/2005	4713.5	1.86	0.99
3/12/2005	4737.8	1.85	0.99
3/13/2005	4665.9	1.87	1.00
3/14/2005	4570.6	1.86	0.99
3/15/2005	4257.2	1.82	0.97
3/16/2005	4790.6	1.93	1.03

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
3/17/2005	5039.7	2.20	1.17
3/18/2005	4035.9	1.82	0.97
3/19/2005	4406.3	1.99	1.06
3/20/2005	4107.9	1.83	0.98
3/21/2005	3925.8	1.70	0.91
3/22/2005	3534.6	1.52	0.81
3/23/2005	5171.2	2.27	1.21
3/24/2005	4237.9	1.88	1.00
3/25/2005	3411.6	1.51	0.81
3/26/2005	3689.3	1.65	0.88
3/27/2005	3415.5	1.52	0.81
3/28/2005	3315.7	1.46	0.78
3/29/2005	3184.0	1.39	0.74
3/30/2005	3092.3	1.36	0.72
3/31/2005	3778.6	1.67	0.89
4/1/2005	3703.0	1.66	0.89
4/2/2005	4027.8	1.78	0.95
4/3/2005	3304.4	1.47	0.79
4/4/2005	3209.5	1.40	0.75
4/5/2005	3849.5	1.68	0.89
4/6/2005	4128.3	1.76	0.94
4/7/2005	4435.3	1.86	0.99
4/8/2005	4369.4	1.91	1.02
4/9/2005	3755.7	1.67	0.89
4/10/2005	2477.9	1.23	0.66
4/11/2005	2932.9	1.37	0.73
4/12/2005	4371.5	2.01	1.07
4/13/2005	3198.1	1.55	0.83
4/14/2005	3269.1	1.64	0.88
4/15/2005	3876.2	1.70	0.91
4/16/2005	4062.1	1.77	0.95
4/17/2005	3616.3	1.60	0.86
4/18/2005	3639.7	1.51	0.80
4/19/2005	4010.9	1.56	0.83
4/20/2005	3766.2	1.46	0.78
4/21/2005	4714.0	1.83	0.98
4/22/2005	4269.7	1.69	0.90
4/23/2005	4135.1	1.65	0.88
4/24/2005	3810.3	1.52	0.81
4/25/2005	3873.7	1.54	0.82
4/26/2005	4999.3	2.00	1.06
4/27/2005	4039.0	1.60	0.86
4/28/2005	4790.9	1.89	1.01
4/29/2005	5117.8	2.01	1.07
4/30/2005	5148.1	2.08	1.11
5/1/2005	4642.2	1.87	1.00
5/2/2005	4070.3	1.65	0.88
5/3/2005	4495.2	1.79	0.96
5/4/2005	4395.0	1.76	0.94
5/5/2005	4070.1	1.62	0.86
5/6/2005	4063.4	1.61	0.86
5/7/2005	3583.1	1.45	0.77
5/8/2005	4113.6	1.61	0.86

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
5/9/2005	4235.8	1.66	0.89
5/10/2005	4338.3	1.71	0.91
5/11/2005	4936.5	1.96	1.05
5/12/2005	4080.7	1.63	0.87
5/13/2005	3759.8	1.49	0.79
5/14/2005	5247.5	2.05	1.09
5/15/2005	4750.8	1.91	1.02
5/16/2005	4351.0	1.76	0.94
5/17/2005	6505.2	2.58	1.38
5/18/2005	6494.3	2.63	1.40
5/19/2005	6176.9	2.50	1.33
5/20/2005	5082.5	2.02	1.08
5/21/2005	5125.0	2.03	1.08
5/22/2005	5171.5	2.06	1.10
5/23/2005	5020.4	2.04	1.09
5/24/2005	4998.0	2.05	1.09
5/25/2005	4768.5	1.99	1.06
5/26/2005	4295.2	1.79	0.96
5/27/2005	4301.3	1.79	0.96
5/28/2005	4546.2	1.90	1.01
5/29/2005	4480.2	1.88	1.00
5/30/2005	4144.4	1.74	0.93
5/31/2005	4172.6	1.74	0.93
6/1/2005	4545.8	1.91	1.02
6/2/2005	4067.7	1.70	0.91
6/5/2005	4600.6	1.89	1.01
6/6/2005	4261.0	1.78	0.95
6/7/2005	4571.6	1.96	1.04
6/8/2005	5116.4	2.13	1.14
6/9/2005	4557.2	1.91	1.02
6/10/2005	5004.3	2.14	1.14
6/11/2005	5572.5	2.41	1.29
6/12/2005	4181.9	1.78	0.95
6/13/2005	4118.5	1.74	0.93
6/14/2005	5363.1	2.31	1.23
6/15/2005	5081.7	2.32	1.24
6/16/2005	4711.9	2.03	1.08
6/17/2005	4886.4	2.13	1.14
6/18/2005	4693.1	2.13	1.13
6/28/2005	3526.2	2.18	1.16
6/29/2005	4581.4	2.26	1.21
6/30/2005	5880.6	2.38	1.27
7/1/2005	5244.0	2.31	1.23
7/2/2005	6599.5	2.94	1.57
7/3/2005	5924.4	2.55	1.36
7/4/2005	5371.9	2.33	1.24
7/5/2005	5654.3	2.44	1.30
7/6/2005	6256.9	2.73	1.46
7/7/2005	4826.1	2.04	1.09
7/8/2005	3991.7	1.70	0.91
7/9/2005	4199.9	1.80	0.96
7/10/2005	4733.1	2.03	1.08
7/11/2005	4682.2	2.01	1.07

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
7/12/2005	4394.7	1.87	1.00
7/13/2005	4773.2	2.04	1.09
7/14/2005	4522.0	1.92	1.02
7/15/2005	4716.2	2.02	1.08
7/16/2005	4394.2	1.90	1.01
7/17/2005	4125.6	1.77	0.94
7/18/2005	3952.8	1.71	0.91
7/19/2005	4144.1	1.78	0.95
7/20/2005	4872.5	2.10	1.12
7/21/2005	4934.6	2.12	1.13
7/22/2005	4748.6	2.06	1.10
7/23/2005	5644.1	2.42	1.29
7/24/2005	4718.3	2.05	1.09
7/25/2005	4695.2	2.02	1.08
7/26/2005	5804.7	2.48	1.32
7/27/2005	5610.1	2.40	1.28
7/28/2005	5189.6	2.20	1.18
7/29/2005	5108.6	2.11	1.12
7/30/2005	5825.1	2.40	1.28
7/31/2005	5284.6	2.20	1.17
8/1/2005	5284.6	2.20	1.17
8/2/2005	5284.6	2.20	1.17
8/3/2005	5992.1	2.45	1.31
8/4/2005	5427.6	2.25	1.20
8/5/2005	5081.7	2.11	1.13
8/6/2005	4143.8	1.71	0.91
8/7/2005	4566.4	1.89	1.01
8/8/2005	4044.4	1.66	0.89
8/9/2005	4007.1	1.63	0.87
8/10/2005	3812.9	1.56	0.83
8/11/2005	3452.1	1.41	0.75
8/12/2005	3706.9	1.56	0.83
8/13/2005	3558.0	1.55	0.83
8/14/2005	3337.9	1.43	0.76
8/15/2005	3379.6	1.41	0.75
8/16/2005	4062.4	1.71	0.91
8/17/2005	4251.2	1.77	0.95
8/18/2005	4144.5	1.73	0.92
8/19/2005	3834.1	1.56	0.83
8/20/2005	3882.8	1.60	0.85
8/21/2005	3742.8	1.56	0.83
8/22/2005	3809.3	1.58	0.84
8/23/2005	4225.0	1.75	0.93
8/24/2005	4554.3	1.89	1.01
8/25/2005	5368.7	2.24	1.20
8/26/2005	4929.6	2.05	1.10
8/27/2005	4547.3	1.95	1.04
8/28/2005	4449.4	1.89	1.01
8/29/2005	4586.2	1.94	1.03
8/30/2005	5449.3	2.31	1.23
8/31/2005	5428.2	2.30	1.23
9/1/2005	5641.5	2.39	1.28
9/2/2005	5220.3	2.21	1.18
9/3/2005	5373.6	2.25	1.20
9/4/2005	5049.4	2.17	1.16
9/5/2005	5007.0	2.11	1.12
9/6/2005	4579.4	1.98	1.06
9/7/2005	4749.4	2.05	1.09
9/8/2005	5115.0	2.23	1.19
9/9/2005	5022.4	2.30	1.22
9/10/2005	4908.3	2.19	1.17
9/11/2005	4760.2	2.10	1.12
9/12/2005	4555.8	2.00	1.07
9/13/2005	4785.8	2.13	1.14
9/14/2005	5308.5	2.37	1.26
9/15/2005	5815.1	2.66	1.42
9/16/2005	5319.2	2.30	1.23
9/17/2005	4478.0	1.95	1.04
9/18/2005	4553.7	1.97	1.05
9/19/2005	4391.2	1.93	1.03
9/20/2005	5523.1	2.37	1.26
9/21/2005	4958.8	2.18	1.16
9/25/2005	2657.2	1.42	0.76
9/26/2005	4506.6	1.99	1.06
9/27/2005	4624.0	2.04	1.09
9/28/2005	5714.8	2.52	1.34
9/29/2005	5596.4	2.38	1.27
9/30/2005	5028.2	2.03	1.08
10/3/2005	3554.2	1.62	0.86
10/4/2005	3793.6	1.60	0.85
10/5/2005	4574.2	1.94	1.03
10/6/2005	4446.7	1.82	0.97
10/7/2005	4629.7	1.94	1.03
10/8/2005	3365.0	1.40	0.75
10/9/2005	3888.5	1.63	0.87
10/10/2005	3938.2	1.66	0.88
10/11/2005	5381.7	2.22	1.18
10/12/2005	4333.7	1.78	0.95
10/13/2005	4134.0	1.69	0.90
10/14/2005	3969.7	1.65	0.88
10/15/2005	4567.5	1.89	1.01
10/16/2005	4270.7	1.78	0.95
10/17/2005	3896.2	1.62	0.86
10/18/2005	4589.6	1.91	1.02
10/19/2005	5457.2	2.30	1.23
10/20/2005	5360.5	2.25	1.20
10/21/2005	5385.4	2.29	1.22
10/22/2005	4629.0	1.94	1.04
10/23/2005	4589.6	1.92	1.03
10/24/2005	4686.4	2.02	1.08
10/25/2005	5740.9	2.46	1.31
10/26/2005	4781.3	2.06	1.10
10/27/2005	5509.1	2.38	1.27
10/28/2005	4992.2	2.16	1.15
10/29/2005	5247.9	2.21	1.18
10/30/2005	4673.6	2.00	1.06

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
10/31/2005	4453.6	1.90	1.02
11/1/2005	4942.9	2.10	1.12
11/2/2005	4861.0	2.06	1.10
11/3/2005	5029.4	2.13	1.13
11/4/2005	5116.6	2.14	1.14
11/5/2005	4747.8	1.98	1.05
11/6/2005	4508.8	1.88	1.00
11/7/2005	4117.3	1.74	0.93
11/8/2005	4448.9	1.85	0.99
11/9/2005	4516.2	1.84	0.98
11/10/2005	4231.8	1.78	0.95
11/11/2005	4805.0	2.00	1.07
11/12/2005	4571.1	1.89	1.01
11/13/2005	4156.9	1.73	0.92
11/14/2005	4368.8	1.80	0.96
11/15/2005	4469.6	1.83	0.97
11/16/2005	4338.1	1.76	0.94
11/17/2005	4557.2	1.86	0.99
11/18/2005	5936.0	2.44	1.30
11/19/2005	4662.5	1.92	1.02
11/20/2005	4971.2	2.03	1.08
11/21/2005	4294.3	1.74	0.93
11/22/2005	4170.8	1.71	0.91
11/23/2005	4326.6	1.77	0.94
11/24/2005	4932.8	1.96	1.05
11/25/2005	4715.5	1.90	1.01
11/26/2005	3619.3	1.46	0.78
11/27/2005	3924.0	1.60	0.85
11/28/2005	3782.2	1.55	0.83
11/29/2005	4901.5	1.98	1.06
11/30/2005	4291.2	1.72	0.92
12/1/2005	5820.1	2.36	1.26
12/2/2005	6072.4	2.47	1.32
12/3/2005	5944.6	2.43	1.29
12/4/2005	5545.1	2.26	1.21
12/5/2005	5811.1	2.35	1.25
12/6/2005	6684.0	2.71	1.45
12/7/2005	6557.5	2.64	1.41
12/8/2005	4806.9	2.17	1.15
12/9/2005	4982.1	2.16	1.15
12/10/2005	5427.1	2.25	1.20
12/11/2005	5367.7	2.22	1.18
12/12/2005	5030.3	2.08	1.11
12/13/2005	5495.2	2.31	1.23
12/14/2005	5545.1	2.29	1.22
12/15/2005	5523.8	2.29	1.22
12/16/2005	5547.6	2.28	1.22
12/17/2005	4776.6	1.92	1.02
12/18/2005	4805.2	1.93	1.03
12/19/2005	4783.9	1.94	1.03
12/20/2005	3787.5	1.54	0.82
12/21/2005	4297.0	1.76	0.94
12/22/2005	4224.9	1.76	0.94

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
12/23/2005	4023.8	1.68	0.90
12/24/2005	3935.9	1.63	0.87
12/25/2005	3873.6	1.65	0.88
12/26/2005	4276.9	1.81	0.96
12/27/2005	3889.8	1.64	0.88
12/28/2005	3253.2	1.36	0.72
12/29/2005	4066.9	1.72	0.92
12/30/2005	4041.0	1.71	0.91
12/31/2005	3687.6	1.58	0.84

2005 dates only with a full 24 hours of records are included.

SPRING CREEK COAL MINE
2002 QUALITY SPECIFICATIONS

Trainload reject parameters: 9000 BTU; 1.2 lbs SO2 per mmbtu

QUALITY PARAMETER	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 95% RANGE -2 STD DEV	+2 STD DEV	TYPICAL DRY VALUE	TYPICAL MOISTURE-ASH FREE VALUE
PROXIMATE						
% Moisture	24.80	0 61	23.58	26.02		
% Ash	3.90	0 33	3.24	4.56	5.19	
% Volatile	32 43	0 81	30 81	34 05	43 13	45 48
% Fixed Carbon	38.54	0.80	36 94	40.14	51.25	54.05
BTU/lb	9360	103	9154	9566	12447	13128
MAFBTU	13128	80 08	12967	13288		
Dry BTU	12447	93.71	12259	12634		
% Sulfur	0 33	0.07	0 19	0 47	0.44	0 46
ULTIMATE						
% Moisture	24 80	0 56	23 68	26 02		
% Carbon	53.88	3.28	47.32	60.44	71.65	75.57
% Hydrogen	3 72	0 23	3 26	4 18	4 95	5.22
% Nitrogen	0 72	0.09	0 54	0 90	0 96	1 01
% Chlorine	0 02	0.01	0 01	0 03	0 03	0 03
% Sulfur	0 33	0 07	0 19	0 47	0 44	0.46
% Ash	3.90	0 33	3 24	4.56		
% Oxygen	12 63	0 70	11 23	14 03	16.80	17 71
SULFUR FORMS						
Pyritic Sulfur (%)	0 05	0.03	0.00	0 11	0 07	0.07
Sulfate Sulfur (%)	0 01	0.015	0.00	0 04	0 01	0.01
Organic Sulfur (%)	0 27	0 06	0 15	0 39	0 36	0 38
Total Sulfur (%)	0 33	0 07	0 19	0 47	0.44	0 46
MINERAL ANALYSIS OF ASH						
% Silicon Dioxide (Silica, SiO2)	30.00	2 78	24 44	35.56	39 89	42 08
% Aluminum Oxide (Alumina, Al2O3)	17.67	1 09	15.49	19.85	23.50	24.78
% Titanium Dioxide (Titania TiO2)	1 21	0 10	1.01	1 41	1.61	1 70
% Iron Oxide (Ferric Oxide, Fe2O3)	4.80	0 47	3.86	5.74	6.38	6.73
% Calcium Oxide (Lime. CaO)	15.98	1 41	13.16	18 80	21 25	22.41
% Magnesium Oxide (Magnesia MgO)	4 42	0 85	2 72	6.12	5.88	6 20
% Potassium Oxide (K2O)	0.63	0 14	0 35	0.91	0.84	0 88
% Sodium Oxide (Na2O)	6.90	2 00	2.90	10 90	9.18	9.68
% Sulfur Trioxide (SO3)	15 09	2 50	10 09	20.09	20 07	21 16
% Phosphorous Pentoxide (P2O5)	0 31	0 06	0 19	0 43	0.41	0 43
% Strontium Oxide (SrO)	0 73	0 22	0 29	1 17	0 97	1.02
% Barium Oxide (BaO)	1 31	0 31	0.69	1 93	1 74	1.84
% Undetermined	0 95	1 00	0.00	2 95	1 26	1 33
Base/Acid Ratio	0.67	0.08	0.51	0.83		
Base Value	32 73	2 20	28 33	37 13		
Acid Value	48 88	3 00	42 88	54 88		
ASH FUSION TEMPERATURES						
Reducing (°F)						
Initial	2078	37	2003	2153		
Softening (H=W)	2109	36	2036	2182		
Hemispherical (H=1/2W)	2126	39	2047	2205		
Fluid	2159	51	2057	2261		
Fluid-Initial Temp Difference	81	40	1	161		
Oxidizing (°F)						
Initial	2349	98	2154	2544		
Softening (H=W)	2394	81	2232	2556		
Hemispherical (H=1/2W)	2423	73	2277	2569		
Fluid	2466	77	2311	2621		
Fluid-Initial Temp Difference	117	60	0	237		

SPRING CREEK COAL MINE
QUALITY SPECIFICATIONS (Continued)

QUALITY PARAMETER	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 95% RANGE -2 STD DEV	+2 STD DEV
ADDITIONAL ANALYSES AND CALCULATED VALUES				
T250 Temperature (^{O}F)	2177	91 88	1993	2361
HGI (at as-received moisture)	54.8	5.6	44	66
HGI % Moisture	22.29	3 88	15	30
Critical Viscosity Temperature (^{O}F)	0	0	0	0
Critical Viscosity (Poises)	0	0	0	0
% Equilibrium Moisture	23.84	0.56	22.72	24.96
Specific Gravity	1.10	0.015	1.07	1 13
%Alkalies NA2O Dry (Total Alkali Content on Coal)	0 379	0 070	0 24	0 52
%Water Soluble Alk - Na2O	0 000	0.000	0.00	0.00
%Water Soluble Alk - K2O	0.000	0.000	0.00	0.00
%Na2O - Dry Coal	0 36	0 03	0 30	0 42
%Na2O As-received Coal	0.27	0 02	0 23	0 31
Silica Value (Silica Ratio)	54.35			
Slag Factor	0.28	0.14	0.00	0.56
Slag factor per Fusion Temperature	2147	85	1977	2317
Dolomite Ratio	62.33	3.25	55.83	68 83
Ash Precipitation Index	4 74	10.1	0 00	24.94
Silica to Alumina Ratio	1 70	0 14	1 42	1 98
Calcium to Silica Ratio	0 53	0 34	0 00	1 21
Iron to Calcium Ratio	0 30	0.07	0 16	0 44
Fouling Factor (Fouling Index)	4 62	1.41	1 80	7 44
SO2/MMBTU	0 71	0.075	0 56	0 86
lbs S/MMBTU	0.35	0 075	0 20	0 50
lbs Sodium/MMBTU	0.288	0.023	0 24	0 33
lbs Ash/MMBTU	4 17	0 5	3 17	5 17

TYPICAL COAL SIZE 2 inch

Size Fraction	Wt. Percent	Cumulative Wt Percent	Wt. Percent Passing Top
+3" RD	0%	0%	100%
3" RD x 2' RD.	4%	4%	100%
2' RD. x 1" RD.	20%	24%	96%
1' RD. x 1/2' RD	28%	52%	76%
1/2" RD. x 4 M	20%	71%	48%
4 M x 60 M	13%	84%	29%
60 M x 0	16%	100%	16%

TRACE ELEMENT SUMMARY

Parts Per Million Whole Coal Dry Basis	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 95% RANGE -2 STD DEV	+2 STD DEV
ANTIMONY (Sb)	0 00	0.00	0.00	0 00
ARSENIC (As)	1 50	1 00	0.00	3 50
BARIUM (Ba)	0 00	0.00	0.00	0.00
BERYLLIUM (Be)	0 21	0 08	0.06	0 36
BORON (B)	0 00	0 00	0 00	0 00
BROMIDE (Br)	0 00	0 00	0.00	0.00
CADMIUM (Cd)	0 18	0 02	0.14	0.22
CHLORINE (Cl)	200 00	55 00	90.00	310.00
CHROMIUM (Cr)	2 40	0 75	0 90	3 90
COBALT (Co)	0 00	0 00	0 00	0 00
COPPER (Cu)	0.00	0 00	0.00	0.00
FLUORINE (F)	41 90	11 00	19.90	63.90
LITHIUM (Li)	0 00	0 00	0 00	0.00
MANGANESE Mn)	16 20	7 90	0 40	32.00
MERCURY (Hg)	0.07	0.03	0 01	0 13
MOLYBDNEUM (Mo)	0.00	0.00	0 00	0 00
NICKEL (Ni)	1 53	1 00	0 00	3 53
LEAD (Pb)	2 60	1 00	0 60	4 60
SELENUIM (Se)	1 20	0 90	0.00	3 00
SILVER (Ag)	0 00	0.00	0.00	0 00
STRONTIUM (Sr)	0 00	0.00	0.00	0 00
THALLIUM (Tl)	0 00	0.00	0.00	0 00
THORIUM (Th)	0 00	0 00	0.00	0 00
TIN (Sn)	0 00	0 00	0.00	0 00
URANIUM (U)	0 00	0 00	0.00	0.00
VANADIUM (V)	0 00	0 00	0.00	0.00
ZIRCONIUM (Zr)	0 00	0 00	0 00	0.00
ZINC (Zn)	0 00	0 00	0 00	0.00

" **All negative numbers were converted to 0.00**

Revised 3/29/2000

Powder River Basin - Montana Mines

Spring Creek Mine - Rio Tinto Energy America

Type of Mine	Surface - dragline operation
Loading Station	Nerco Jct., Montana (Big Horn County) 30 miles northeast of Sheridan, Wyoming
Marketing Contact	Matt Lever - General Manager Sales and Marketing Rio Tinto Energy America 8000 E. Maplewood Avenue Building 5, Suite 250 Greenwood Village, CO 80111 Phone: (720) 377-2043 E-mail: matt.lever@riotinto.com Website: www.rtea.com
Coal Specifications	**Proximate Analysis (as received)** — **Typical** Fixed Carbon — 39 23% Volatile Matter — 31 26% Moisture — 25 60% Ash — 4 32% Sodium as % of Ash — 8 24% Sulfur — 0 34% Btu/lb — 9,350 Size — 2" x 0" Ash Fusion Temp/Reducing Atmosphere: Initial — 2106°F Fluid — 2164°F
Recoverable Reserves	290 million tons
Annual Production	Permitted for 15 million tons/year 2002 – 8.9 million tons 2003 – 8.9 million tons 2004 – 12 0 million tons
Storage Capacity	35,000 tons (barn storage)
Storage Recharge Rate	3,000 tons per hour
Loading & Weighing	Flood loading with belt scale
Loading Rate	4,100 tons per hour
Track Configuration	Loop track holds two unit trains on site

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Powder River Basin - Montana Mines

Absaloka Mine - Westmoreland Coal Co.

Type of Mine	Surface - dragline operation
Loading Station	Kuehn, Montana (Big Horn County) 60 miles southwest of Forsyth, Montana
Marketing Contact	Dave Simpson Westmoreland Resources Inc P. O Box 449 Hardin, Montana 59034 Phone: (406) 342-5241 / Fax: (406) 342-5401 E-mail dws@mcn.net
Coal Specifications	**Proximate Analysis (as received)** — **Typical** Fixed Carbon — 36 27% Volatile Matter — 30 23% Moisture — 24 50% Ash — 9 00% Sodium as % of Ash — 2 00% Sulfur — 0 64% Btu/lb — 8 750 Size — 3" x 0" Ash Fusion Temp/Reducing Atmosphere: Initial — 2130°F Fluid — 2215°F
Recoverable Reserves	70 million tons
Annual Production	Permitted for 7 million tons/year 2002 – 4 0 million tons 2003 – 5 3 million tons 2004 – 4.5 million tons
Storage Capacity	44,000 tons (trough-type storage barn)
Storage Recharge Rate	18,000 tons per day
Loading & Weighing	250-ton surge bin with belt scale
Loading Rate	4,000 tons per hour
Track Configuration	Loop track holds one unit train on site

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Powder River Basin - Montana Mines

Rosebud Mine - Westmoreland Coal Co.

Type of Mine	Surface - dragline operation
Loading Station	Colstrip, Montana (Rosebud County) 35 miles southwest of Forsyth, Montana
Marketing Contact	James Kelly, Vice President Westmoreland Coal Sales Ed DeMeter, Vice President, Westmoreland Coal Sales 2 North Cascade Avenue, 14th Floor Colorado Springs, Colorado 80903 Phone: (719) 442-2600 / Fax: (719) 448-5824 E-mail Jim.Kelly@westmoreland.com E-mail Ed.Demeter@westmoreland.com
Coal Specifications	**Proximate Analysis (as received)** — **Typical** Fixed Carbon 38 33% Volatile Matter 27 72% Moisture 25 50% Ash 8 45% Sodium as % of Ash 0 32% Sulfur 0 80% Btu/lb 8 750 Size 3" x 0" 1" x 0" Ash Fusion Temp/Reducing Atmosphere: Initial 2200°F Fluid 2330°F
Recoverable Reserves	573 million tons
Annual Production	Permitted for 18 million tons 2002 – 10.0 million tons 2003 – 11.0 million tons
Storage Capacity	90,000 tons
Storage Recharge Rate	60 000 tons per day
Loading & Weighing	Rapid-discharge loadout with belt scale
Loading Rate	3,750 tons per hour
Track Configuration	Loop track holds one unit train on site
Information	Rosebud Mine sells most of its production to The Colstrip Station with the remaining tonnage sold to outside utility and industrial markets

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Appendix F

SCR catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals

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FUEL PROCESSING TECHNOLOGY

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SCR catalyst performance in flue gases derived from subbituminous and lignite coals

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Abstract

Lignite and subbituminous coals from the United States of America have characteristics that impact the performance of catalysts used in selective catalytic reduction (SCR) for nitrogen oxide removal and mercury oxidation. Typically, these coals contain ash-forming components that consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. The alkali and alkaline-earth elements are partitioned between reactions with minerals and reactions to form alkali and alkaline-earth-rich oxides during combustion. The particles resulting from the reaction with minerals produce low-melting-point phases that cause a wide range of fireside deposition problems. The alkali and alkaline-earth-rich oxides consist mainly of very small particles (<5 μm) that are carried into the backpasses of the combustion system and react with flue gas to form sulfates, and possibly carbonates. These particles cause low-temperature deposition, blinding, and plugging problems in SCR systems. These coals also contain the very low levels of chlorine that are necessary for mercury oxidation. Slipstream testing was conducted at two selected subbituminous-fired power plants and one lignite-fired power plant to determine the impacts of ash on SCR plugging, blinding, and mercury oxidation. The results indicated a high potential for

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blinding and plugging due to the formation of sulfate-bonded deposits and no evidence for mercury oxidation.
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Keywords: Coal; Selective catalytic reduction (SCR); Blinding; NO_x; Mercury; Oxidation

1. Introduction

Selective catalytic reduction (SCR) for NO_x control and mercury oxidation was investigated using a slipstream reactor at power plants firing subbituminous and lignite coals to determine the potential for ash plugging, catalyst blinding, and mercury oxidation. SCR units lower NO_x emissions by reducing NO_x to N_2 and H_2O. Ammonia (NH_3) is the most common reducing agent used for the SCR of NO_x. The SCR process involves the use of a metal oxide catalyst such as titanium dioxide-supported vanadium pentoxide catalyst (V_2O_5). These units are operated at about 340–370 °C (650–700 °F). Subbituminous and lignitic coals are known for their ability to produce alkali and alkaline-earth sulfate-bonded deposits at low temperature (<1000 °C) in utility boilers. The mechanisms of the formation of low-temperature sulfates have been extensively examined and modeled by the Energy and Environmental Research Center (EERC) in work termed Project Sodium and Project Calcium in the early 1990s [1,2]. Deposit buildup of this type blinds or masks the catalyst, diminishing its reactivity for converting NO_x to N_2 and water and potentially creating increased ammonia slip [3]. Elemental mercury oxidation has been observed in laboratory-, pilot-, and full-scale testing using SCR catalysts [4–6]. In these studies, the metal oxides, V_2O_5 and TiO_2, have been shown to promote the conversion of elemental mercury to oxidized and/or particulate-bound mercury. Full-scale tests in Europe [7] and the United States [8] have indicated that the V_2O_5 and TiO_2 catalyst may promote the formation of oxidized mercury. The ability to oxidize mercury is largely dependent on the composition of the coal [8].

Lignite and subbituminous coals produce ash that plug and blind catalysts [9–12]. The problems currently being experienced on SCR catalysts include the formation of sulfate- and phosphate-based blinding materials on the surface of catalysts and the carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing them on top of the SCR catalysts [3]. The most significant problem that limits the successful application of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates, phosphates, and possibly carbonates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency [3,11–14]. The degree of the ash-related impacts on SCR catalyst performance depends upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design [11–15].

Cichanowicz and Broske [13] conducted tests on a South African and a German Ruhr Valley coal and found that the German Ruhr Valley coal significantly increased the pressure drop across the catalyst because of the accumulation of ash. They found that the German coal produced a highly adhesive ash consisting of alkali (K and Na) sulfates. In addition, they reported that the alkali elements are in a water-soluble form and highly

Table 1
Description of power plants tested

	Baldwin	Columbia	Coyote
Unit #	1	2	1
Utility	Dynegy	Alliant	Otter Tail
Boiler type	Cyclone	T-Fired	Cyclone
Fuel type	Antelope—subbituminous	Caballo—subbituminous	Beulah—Zap lignite
Load	Base	Base	Base
Location	Baldwin, IL	Portage, WI	Beulah, ND
MW	600	520	425

mobile and will migrate throughout the catalyst material, reducing active sites. The water-soluble form is typical of organically associated alkali elements in coals. The German Ruhr Valley coal has about 9.5% ash and 0.9% S on an as-received basis, and the ash consists mainly of Si (38.9%), Al (23.2%), Fe (11.6%), and Ca (9.7%), with lower levels of K (1.85%) and Na (0.85%) [13]. Cichanowicz and Muzio [14] summarized the experience in Japan and Germany and indicated that the alkali elements (K and Na) reduced the acidity of the catalyst sites for total alkali content (K+Na+Ca+Mg) of 8–15% of the ash in European power plants. Licata et al. also found that alkaline-earth elements such as calcium react with SO_3 on the catalyst, resulting in plugging of pores and a decrease in the ability of NH_3 to bond to catalyst sites. The levels of calcium in the coals that caused blinding ranged from 3% to 5% of the ash. Studies conducted on the impact of alkali elements associated with biomass found that, when biomass is fired, poisoning and blinding of SCR catalysts occurred [16,17].

The slipstream reactors were installed at three power plants. Two of the plants were cyclone fired: one with lignite and one with subbituminous coal. The third plant was a pulverized-coal, tangentially fired unit with subbituminous coal. The slipstream reactors were designed to expose SCR catalysts to flue gas and particulate matter under conditions that simulate gas velocities, temperatures, and ammonia injection of a full-scale plant. The control system maintains catalyst temperature, pulse air to remove accumulated deposits, constant gas flow across the catalyst, and records pressure drops and temperatures. The reactor was operated in an automated mode and can be controlled via modem connection. Testing at each power plant was conducted over a 6-month period. The reactor was inspected and cleaned at 2-month intervals, and a catalyst section was removed for analysis. The

Table 2
Key selection criteria

Field test 1—Columbia Station
Tangentially fired boiler to show differences in ash partitioning as compared to cyclone-fired systems. High-potential-blinding coal in Caballo, which can be burned nearly 100% for the entire test.
Field test 2—Baldwin Station
Plant is cyclone fired. Units are already equipped to do slipstream testing. Plant currently fires a blend of Antelope and tires; plant is willing to fire 100% Antelope. High potential blinding coal in Antelope.
Field test 3—Coyote Station
Cyclone-fired with lignite. High potential blinding with high alkali and alkaline-earth elements. Coal can have very high sodium contents and is known to cause significant low-temperature deposition.

Table 3
Ultimate analysis results (dry basis)

	Antelope	Caballo	Beulah
Ash content	7.28	6.59	11.62
Total sulfur	0.33	0.51	1.49
Carbon	69.97	67.88	61.50
Hydrogen	4.77	4.83	3.96
Nitrogen	1.05	1.24	1.08
Oxygen (by difference)	16.61	18.96	20.35

catalysts and associated ash deposits were analyzed to determine the characteristics of the ash on the surface and in the pores. In addition, the mercury speciation in the flue gas upstream and downstream of the catalyst was conducted at 2-month intervals during the testing at the lignite-fired plant. The ability of the SCR catalyst materials to catalyze gaseous elemental mercury (Hg^0[g]) to a more soluble and chemically reactive $Hg^{2+}X(g)$ forms was evaluated, along with the potential increase in particle-associated mercury, Hg(p). Increasing the oxidized and particulate fractions of mercury has the potential to increase the capture efficiency of mercury by conventional control devices such as wet flue gas desulfurization (FGD) scrubbers and electrostatic precipitators (ESPs).

This paper summarizes pressure drop, formation of deposits that blind the surface of the catalyst, and the ability of SCR catalysts to oxidize mercury.

2. Experimental

2.1. Overview of test program and fuel characteristics

A portable SCR slipstream reactor system was designed and constructed to conduct full-scale evaluation of the SCR catalyst ash plugging and blinding and mercury oxidation. A particle-laden flue gas slipstream was isokinetically extracted from the flue gas duct ahead of the air heater at full-scale utilities using an induced-draft fan. Two systems were constructed

Table 4
Ash composition (wt.% equivalent oxide)

Oxide	Antelope	Caballo	Beulah
SiO_2	24.82	26.70	16.50
Al_2O_3	13.55	16.60	13.30
TiO_2	1.39	1.10	0.80
Fe_2O_3	7.52	5.10	16.60
CaO	26.68	25.10	19.50
MgO	7.14	8.00	7.40
K_2O	0.17	0.30	0.20
Na_2O	1.47	1.00	5.20
P_2O_5	0.90	1.70	0.00
SO_3	16.33	14.40	19.80

so that data may be collected simultaneously from two full-scale sites. Testing was conducted at three boilers, including tests on a cyclone boiler firing Powder River Basin (PRB) coal, a lignite-fired cyclone boiler, and a pulverized coal boiler burning PRB. SCR catalysts were exposed to flue gases and combustion-derived fly ash particles for 6-month time periods to study the blinding effect of fly ash and ash deposits on catalyst performance.

The electric utility units selected for testing are shown in **Table 1**. The plants where the SCR slipstream system was installed included Alliant Energy's Columbia Station, Dynegy's Baldwin Station, and Otter Tail Power Company's Coyote Station. **Table 1** describes the plants, and **Table 2** summarizes the characteristics and selection criteria.

The units tested were selected based on the fuels fired, boiler type, and availability of the unit for sampling. The average composition of the coals fired during the testing is

Table 5
CCSEM analysis results for Beulah, Antelope, and Caballo (values are wt.% on a mineral basis)

	Caballo	Antelope	Beulah
Total mineral wt % on a coal basis	2.8	3.2	8.4
Quartz	40.4	31.5	11.0
Iron oxide	0.0	2.4	4.4
Periclase	0.0	0.0	0.0
Rutile	2.4	0.3	0.0
Alumina	0.0	0.0	1.1
Calcite	0.0	0.4	0.1
Dolomite	0.0	0.5	0.0
Ankerite	0.0	0.0	0.2
Kaolinite	23.7	17.1	4.9
Montmorillonite	0.4	6.5	6.6
K Al-silicate	0.0	1.6	7.2
Fe Al-silicate	0.0	0.8	9.0
Ca Al-silicate	0.1	1.0	2.6
Na Al-silicate	0.0	0.0	0.1
Aluminosilicate	0.7	3.3	3.2
Mixed Al-silicate	0.0	1.0	5.5
Fe silicate	0.0	0.0	0.0
Ca silicate	0.0	0.4	0.0
Ca aluminate	0.0	0.0	0.0
Pyrite	16.2	0.0	0.8
Pyrrhotite	0.0	4.8	18.4
Oxidized pyrrhotite	0.0	0.5	0.5
Gypsum	0.4	0.0	0.5
Barite	0.8	0.5	3.0
Apatite	0.0	0.2	0.0
Ca Al-P	8.5	13.5	0.1
KCl	0.0	0.0	0.0
Gypsum/barite	0.0	0.1	0.0
Gypsum/Al-silicate	0.1	0.9	4.0
Si-rich	0.3	3.7	4.9
Ca-rich	0.0	0.0	0.0
Ca–Si-rich	0.0	0.1	0.0
Unclassified	3.2	8.7	11.9
Total	100.0	100.0	100.0

listed in **Tables 3 and 4**. The subbituminous coals were typically low ash, nominally 4.5% to 5.5% with very high levels of calcium in the ash. In comparison, the lignite contains higher levels of ash and lower calcium but higher levels of sodium. The alkali and alkaline-earth elements are primarily associated with the organic matrix of the coal as salts of carboxylic acid groups [18]. The portion of the ash-forming components that are associated with the organic matrix of the coal for subbituminous coal ranges from 30% to 60% [18]; for the lignite coal, the portion is about 20% to 40%. The remaining ash-forming components consist of mineral grains. For these coals, the percent organically associated is 29% for the Antelope, 36% for Caballo, and 19% for Beulah. The minerals present in the coals determined by computer-controlled scanning electron microscopy (CCSEM) analyses are listed in **Table 5**. The primary minerals present in the subbituminous coals include quartz and various clay minerals with some pyrite and a mineral that is rich in Ca, Al, and P. This mineral has been identified in some coals as crandalite. The primary minerals found in the Beulah coal include clay minerals (kaolinite), pyrite, and quartz.

2.2. SCR slipstream system

The SCR slipstream system consists of two primary components: the control room and the SCR reactor. The reactor section consists of a catalyst section, an ammonia injection system, and sampling ports for NO_x at the inlet and exit of the catalyst section. The control

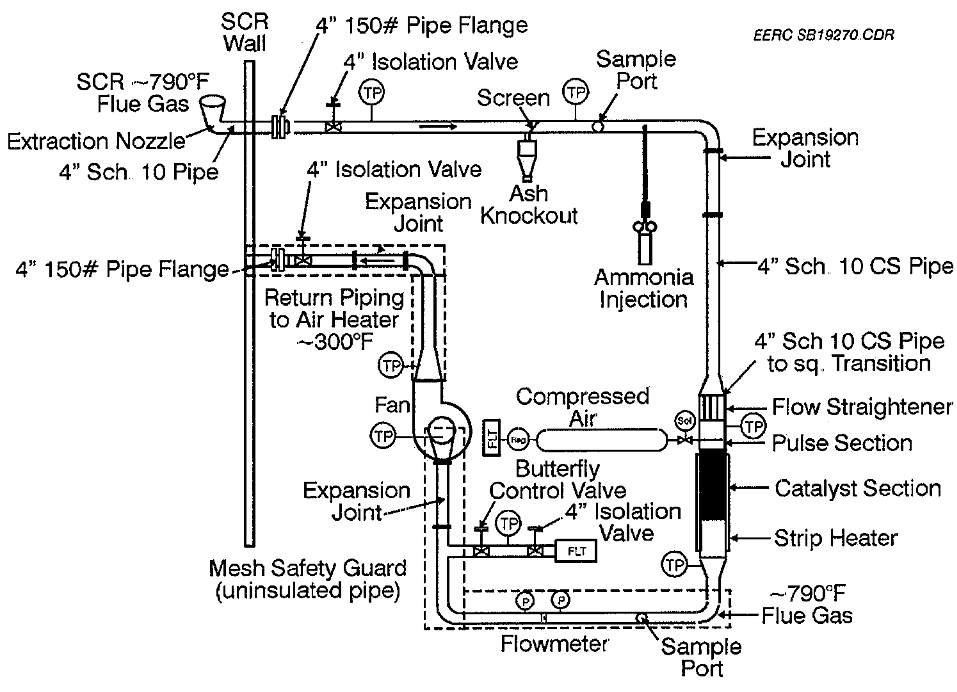

Fig. 1. Schematic diagram of SCR slipstream system.

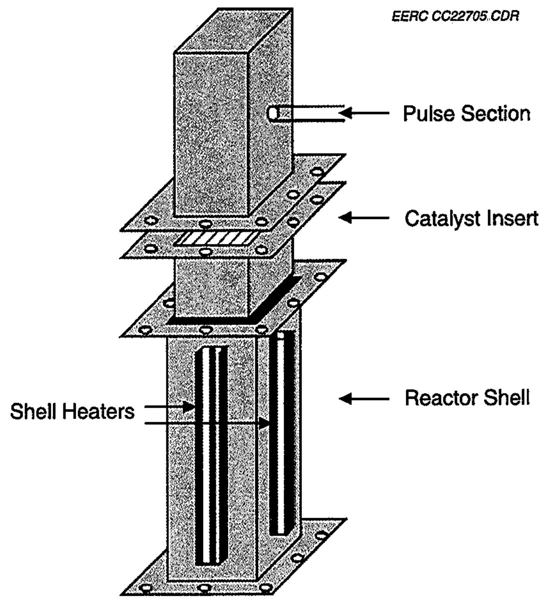

Fig. 2. Diagram of reactor section SCR slipstream system.

room houses a computer system that logs data and controls the gas flow rates, temperatures, pressure drop across the catalyst, and sootblowing cycles. The computer was programmed to maintain constant temperature of the catalyst, gas flow rates, sootblowing cycles, and ammonia injection. The computer is equipped with a modem that

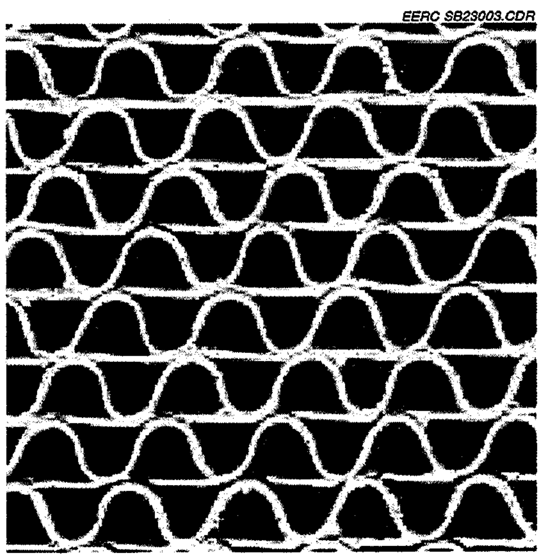

Fig. 3. Haldor Topsoe SCR catalyst showing the gas flow passages.

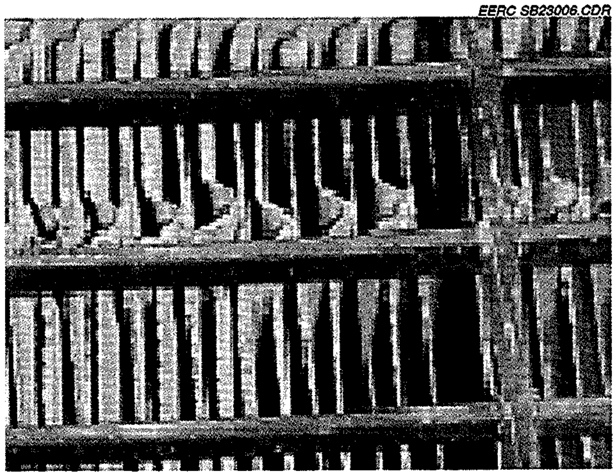

Fig. 4. Babcock Hitachi SCR catalyst showing the gas flow passages.

allowed for downloading of data and modification of the operation of the reactor from a remote computer located at the EERC.

A schematic diagram of the SCR slipstream system is shown in Fig. 1. Flue gas is isokinetically extracted from the convective pass of the boiler upstream of the air heater. The temperature is typically about 790 °F. The flue gases pass through a 4-in. pipe equipped with sampling, thermocouple, and pressure ports. Ammonia is injected into the piping upstream of the reactor section. The reactor consists of a steel housing that is approximately 8.5 in. square and 8 ft long. The reactor section illustrated in Fig. 2 has three components, including a flow straightener, a pulse section or sootblower, and a catalyst test section. A metal honeycomb is used as a flow straightener upstream of the catalyst section and is about 6 in. long. A purge section was installed ahead of the catalyst test section to remove accumulated dust and deposits. The catalyst test section is located downstream of the purge section. The entire catalyst section is insulated and equipped with strip heaters for temperature control. The catalyst test section is 3.28 ft (1 m) in length and houses three catalyst sections. Thermocouple and pressure taps are located in the purge sections for measurements before and after each section.

The induced-draft fan is used to extract approximately 400 acfm (200 scfm) of flue gas from the convective pass of the utility boiler to achieve an approach velocity of 5.2 m/s

Table 6
Selected operating conditions of the SCR catalysts

Plant name	Average SCR inlet temperature (°F)	Average SCR outlet temperature (°F)	Air pulse frequency	Flue gas flow rate (acfm)
Baldwin	645	549	Once per day and on demand	393
Columbia	672	662	Once per day and on demand	385
Coyote	675	667	Once per day and on demand	385

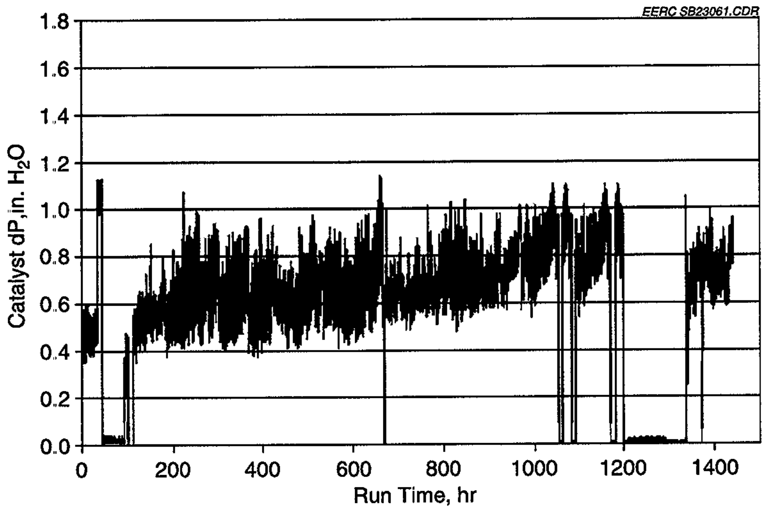

Fig. 5. Catalyst pressure drop at Baldwin Station at 0 to 2 months of operation.

(17.0 ft/s). The total gas flow through the reactor represents a thermal load of approximately 300 kW.

The range of operating conditions for the reactor is listed below:

- Gas temperature: ~700–800 °F
- Gas flow rate: 400–500 acfm
- Approach velocity range: 5.0–5.5 m/s
- Ammonia injection rate: 0.5:1 with NO_x level
- Tempering air for fan: ~50–200 scfm

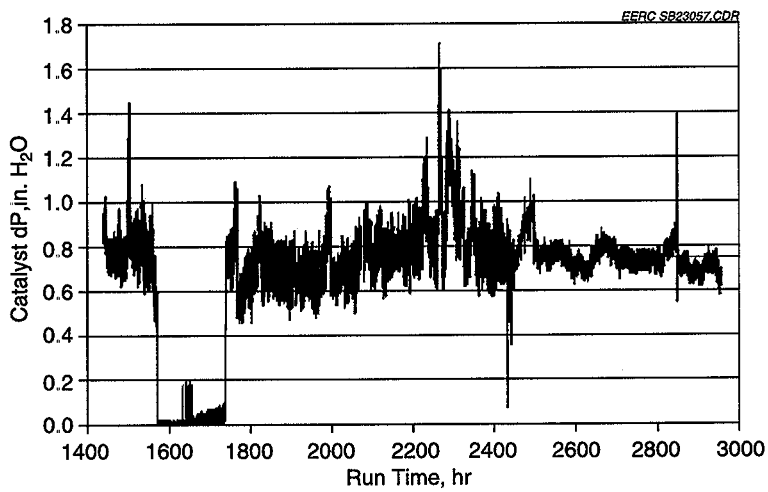

Fig. 6. Catalyst pressure drop at Baldwin Station at 2 to 4 months of operation.

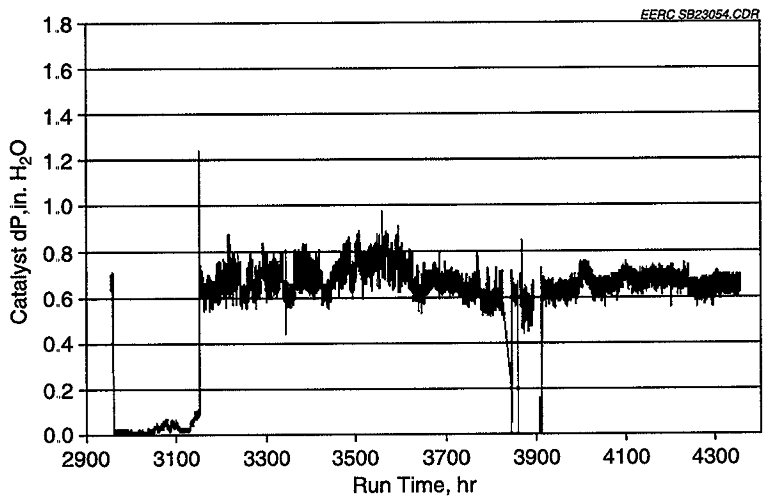

Fig. 7. Catalyst pressure drop at Baldwin Station at 4 to 6 months of operation.

- Catalyst dP: 0.5–1.0 in. water column
- Fan sized for up to 30 in. water column.

2.2.1. SCR catalyst

The catalyst installed at the Baldwin and Coyote Stations was the Haldor Topsoe catalyst. Topsoe's DNX-series of catalysts comprises SCR DENOX catalysts tailored to suit a comprehensive range of process requirements. DNX-series catalysts are based on a corrugated, fiber-reinforced titanium dioxide (TiO_2) carrier impregnated with the active components vanadium pentoxide (V_2O_5) and tungsten trioxide (WO_3). The catalyst is shaped to a monolithic structure with a large number of parallel channels. The unique catalyst design provides a highly porous structure with a large surface area and an ensuing

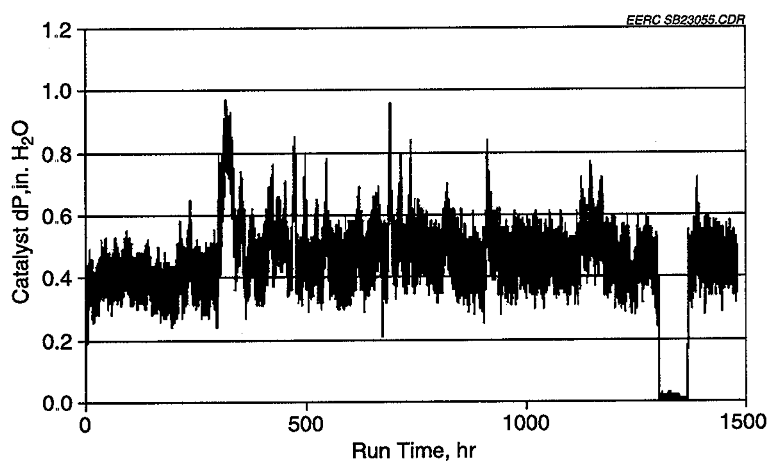

Fig. 8. Catalyst pressure drop at Columbia Station at 0 to 2 months of operation.

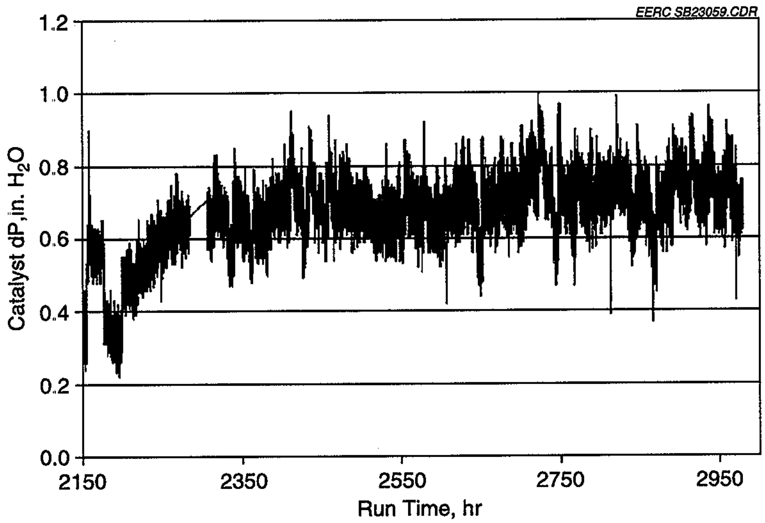

Fig. 9. Catalyst pressure drop at Columbia Station at 2 to 4 months of operation.

large number of active sites. Fig. 3 is an image of the Haldor Topsoe SCR catalyst. The pitch of the catalyst was approximately 6 mm.

The catalyst installed at the Columbia Station was a Babcock Hitachi plate-type catalyst. This catalyst is a TiO_2-based plate catalyst, developed and manufactured by Hitachi. Fig. 4 shows the design of the catalyst. The pitch of the catalyst was approximately 10 mm.

2.2.2. System performance measurement

Upon installation at each utility boiler unit, flue gas temperature, composition, and velocity measurements were obtained using portable equipment. Shakedown testing of the

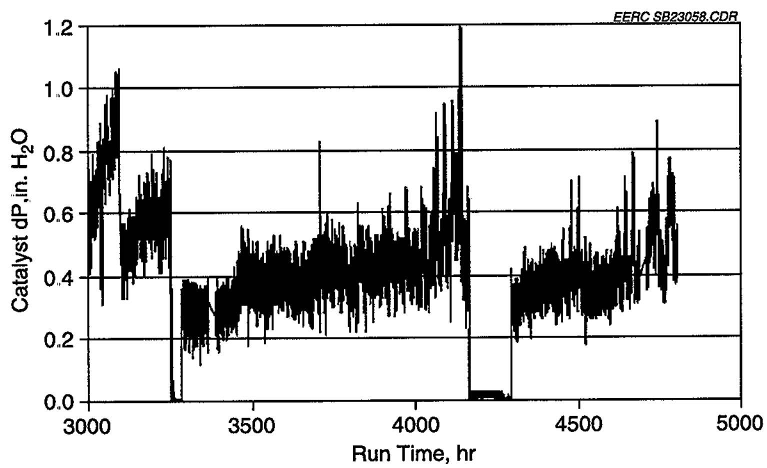

Fig. 10. Catalyst pressure drop at Columbia Station at 4 to 6 months of operation.

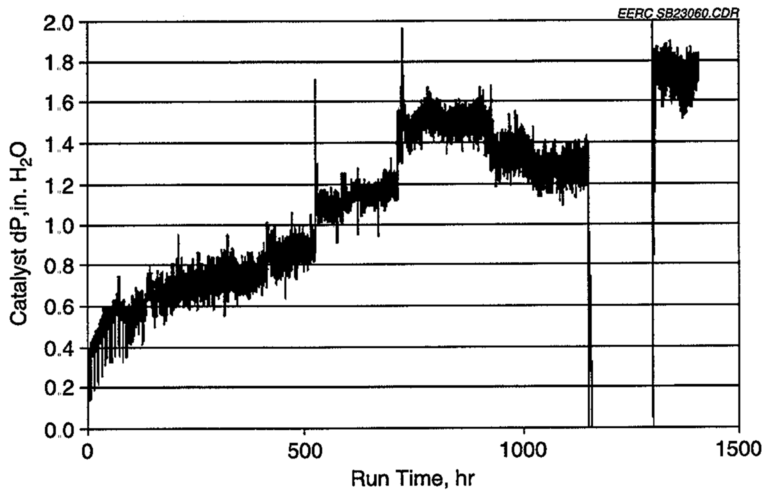

Fig. 11. Catalyst pressure drop at Coyote Station at 0 to 2 months of operation.

unit was conducted to ensure that all components were operating properly and that data were being logged and could be retrieved. After installation and shakedown were completed, the reactor was operated in a computer-controlled, automated mode and monitored on a daily basis to ensure proper operation and data quality. During operation of the SCR slipstream system, catalyst temperature, sootblowing frequency, and pressure drop across the catalyst were monitored and logged. Samples of the exposed SCR catalyst and associated deposits were obtained after exposure to flue gas and particulate for 2, 4, and 6 months. The samples of the catalyst were analyzed to determine the components that were bonding and filling pores, resulting in decreased reactivity.

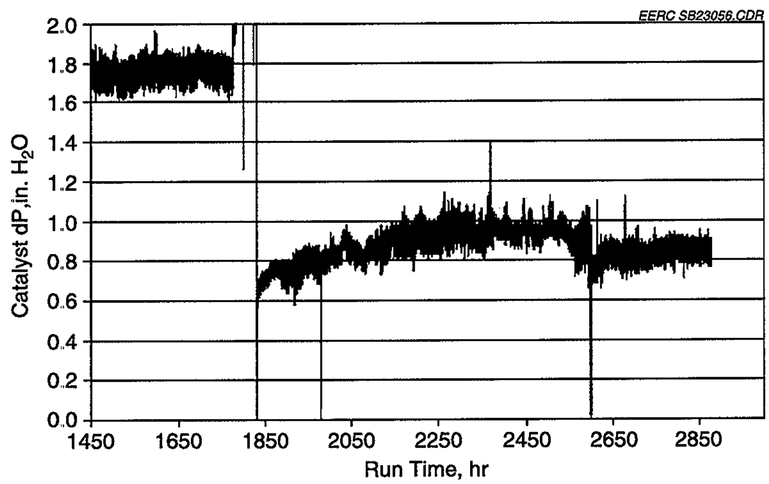

Fig. 12. Catalyst pressure drop at Coyote Station 2 to 4 months of operation.

The characteristics of ash that accumulated on the catalyst were examined using SEM–X-ray microanalysis and X-ray diffraction (XRD) [18]. Correlations between the physical and chemical characteristics of any ash deposits on the SCR test section and entrained-ash sample collected at the chamber inlet and the coal inorganic composition will be made to

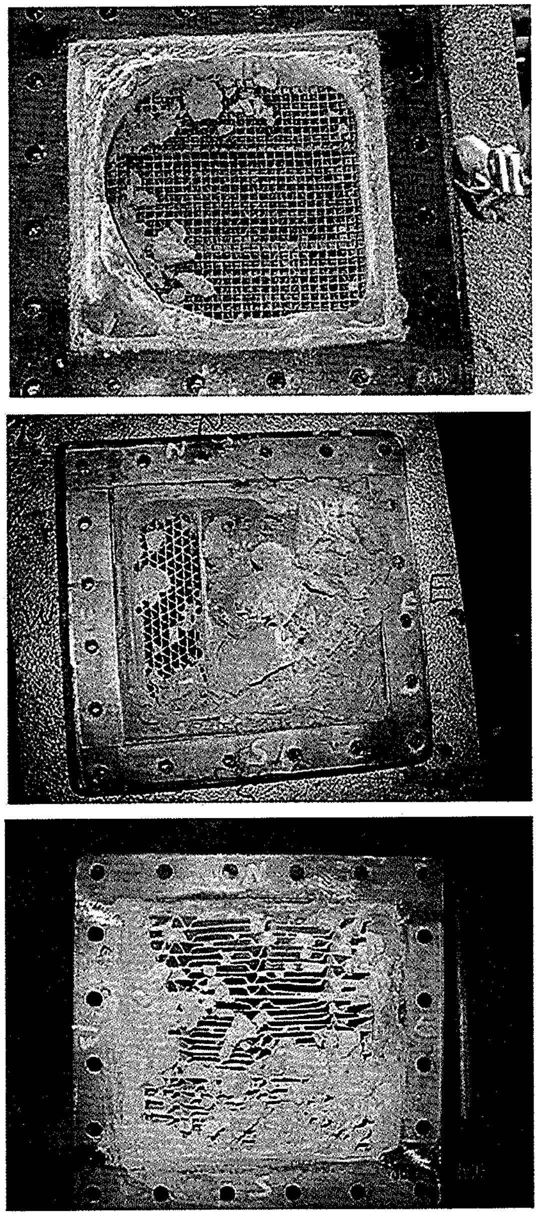

Fig. 13. Pictures of catalyst inlet after about 2 months of testing at each plant.

discern mechanisms of SCR blinding. Entrained ash was collected at Columbia Station only and characterized to composition and size.

2.3. Analysis of flue gas constituents across the catalyst—Ontario Hydro method for mercury speciation

At the Coyote Station, the Ontario Hydro (OH) mercury speciation sampling train was used to determine mercury forms across the SCR test section. The OH extractive mercury speciation sampling technique was used to measure potential mercury conversion across the SCR system over a period of several hours after fresh installation of the SCR test chamber and again just prior to removal of SCR catalyst sections.

The procedure used to conduct the mercury speciation sampling was American Society for Testing and Materials (ASTM) Method 06784-02 entitled "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" [19].

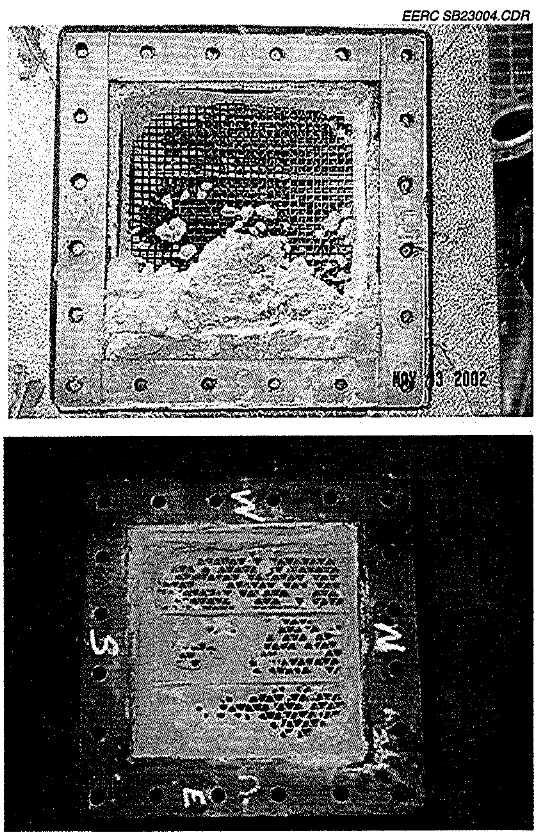

Fig. 14. Pictures of catalyst inlet after about 4 months of exposure to flue gas and particulate.

The OH method follows standard EPA methods for isokinetic flue gas sampling (EPA Methods 1–3 and EPA Method 5/17). A sample is withdrawn from the flue gas stream isokinetically through the filtration system, which is followed by a series of impingers in

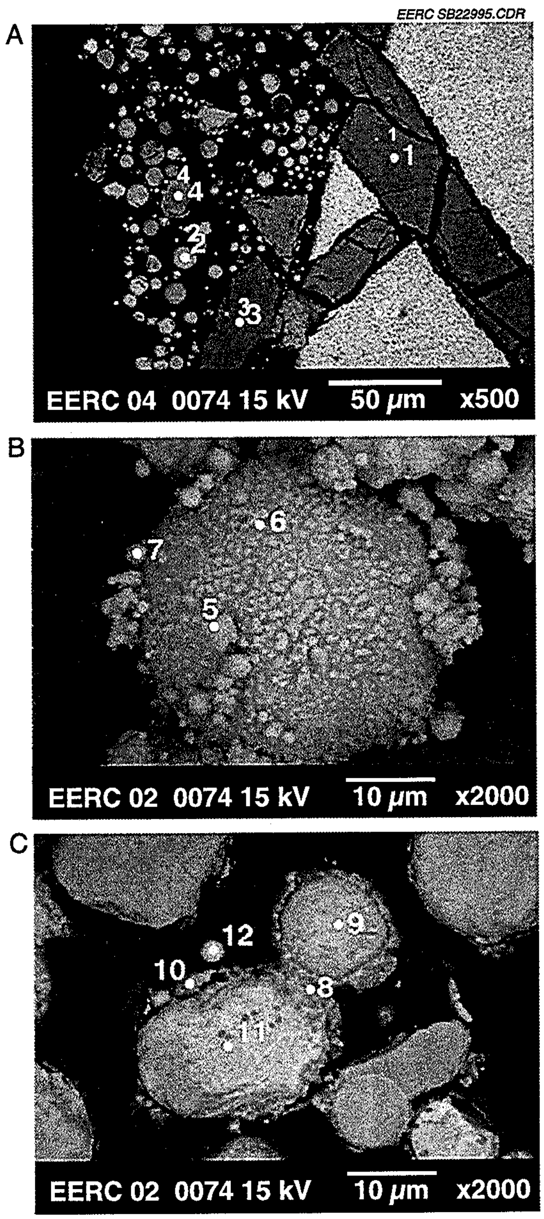

Fig. 15. SEM images of ash collected on catalyst surface at the Baldwin Station after 2 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) high-magnification image of coated ash particle, and (C) high-magnification image of polished cross section showing coatings on particles.

an ice bath. Particulate-bound mercury is collected on the filter; Hg^{2+} is collected in impingers containing 1 N potassium chloride solution; and elemental mercury is collected in one impinger containing a 5% nitric acid and 10% peroxide solution and in three impingers containing a solution of 10% sulfuric acid and 4% potassium permanganate. An impinger containing silica gel collects any remaining moisture. The filter media is quartz fiber filters. The filter holder is glass or Teflon-coated. An approximate 2-h sampling time was used, with a target sample volume of 1 standard cubic meter.

3. Results and discussion

3.1. Pressure drop

3.1.1. Testing at the Baldwin Station

The reactor was installed at the Baldwin Station and operated for a 6-month time period on the Haldor Topsoe catalyst. The information obtained from testing included pressure drop, sootblowing cycles, and reactor temperatures. Table 6 summarizes the operating conditions of the reactors during the testing periods at all plants. Figs. 5–7 show the pressure drop across the catalyst test periods from 0 to 2 months, 2 to 4 months, and 4 to 6 months, respectively. During the first 2 months of operation, the pressure shown in Fig. 6 was about 0.5 in. of water; at the end of 2 months, the pressure drop was about 0.8 in. of water, indicating plugging had occurred. The air was pulsed a minimum of every 8 h in an attempt to maintain cleanliness. The reactor was monitored on a daily basis, and adjustments in pulsing cycles were made in order to minimize deposit accumulation. However, for the first 2 months, the pressure drop steadily increased. There are several periods where the unit was taken off-line; during those times, the temperature of the catalyst was maintained. At 2-month intervals, a section of catalyst was removed and replaced with a new one.

Table 7
Chemical composition of selected points and areas in Fig. 15

Element (wt.%)												
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
Na_2O	0.2	0.0	0.2	2.3	2.5	3.0	3.6	0.7	0.6	1.6	0.4	0.9
MgO	0.0	6.3	0.0	3.1	3.0	1.3	1.6	2.5	4.5	3.0	3.6	3.5
Al_2O_3	3.6	17.9	6.9	29.6	8.4	5.5	4.4	5.4	22.7	12.2	21.2	14.2
SiO_2	92.1	5.9	86.5	39.9	3.4	53.2	15.7	3.4	16.1	1.0	8.1	2.3
P_2O_5	0.1	0.4	0.0	0.0	1.8	0.0	1.5	0.3	0.5	2.3	0.0	4.6
SO_3	3.3	0.4	5.2	0.1	51.8	18.1	52.4	53.0	0.0	46.4	0.0	19.7
K_2O	0.0	0.0	0.0	0.6	0.4	0.5	0.7	0.2	0.0	0.1	0.0	0.0
CaO	0.0	49.4	0.1	18.6	16.4	14.6	13.0	28.8	41.5	27.1	51.1	39.2
TiO_2	0.7	4.5	0.4	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fe_2O_3	0.0	14.6	0.7	3.6	12.3	3.8	7.1	5.7	14.2	6.5	15.6	15.6
BaO	0.0	0.6	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	100	100	100	100	100	100	100	100	100	100	100	100

For Months 2 through 4, the pressure drop was highly variable initially but was about 0.8 in. of water. From Months 4 through 6, the pressure drop was maintained between 0.6 and 0.8 in. of water. This is due to the installation of a fresh catalyst section and leaving two thirds of the catalysts in place that partially plugged. The gas velocity in the single section of new, clean catalyst was high because of channeling, and the result of the high gas flow was less deposition and accumulation. Gas velocity has a significant impact on the potential for deposits to form. However, at high gas velocity, low NO_x conversion is likely.

3.1.2. Testing at Columbia

The reactor was installed at the Columbia Station and operated for a 6-month period of time for the Babcock Hitachi catalyst. The information obtained from the testing included pressure drop information, sootblowing cycles, and reactor temperature. Table 6 shows the reactor temperature, air-pulsing cycles, and airflow rates. Figs. 8–10 show the test periods from 0 to 2 months, 2 to 4 months, and 4 to 6 months, respectively. The pressure drop across the SCR upon installation was about 0.4 in. of water and increased to an average of

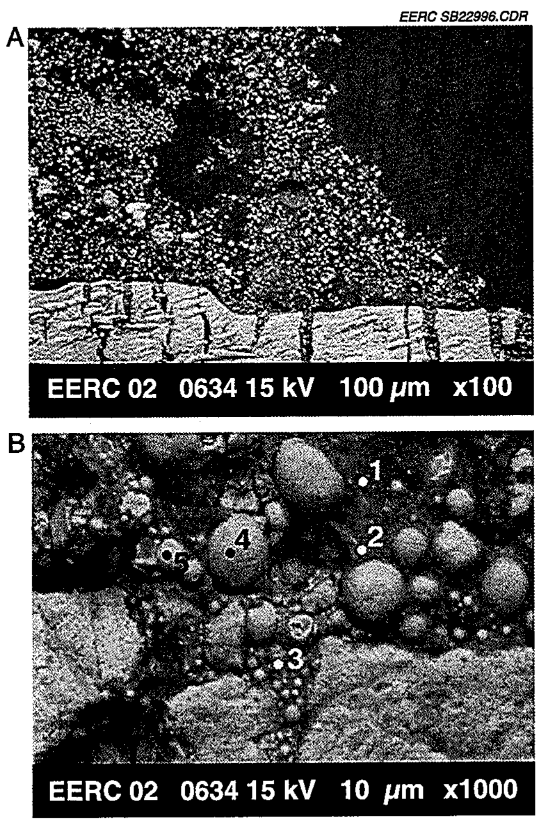

Fig. 16. SEM images of ash collected on catalyst surface at the Baldwin Station after 4 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, and (B) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

about 0.5 in. of water, but ranged from less than 0.4 to greater than 0.8 in. of water. **Fig. 9** shows the pressure drop for Months 2 to 4. The pressure drop increased from about 0.5 to 0.7 in. of water because of accumulation of ash. **Fig. 10** shows a rapid increase in pressure drop across the catalyst at about 3000 h of operation, and aggressive pulsing brought it down to 0.4 in. of water until the catalyst section was changed out at about 3200 h. After cleaning the reactor and replacing one catalyst section, the pressure drop was about 0.3 but increased to over 0.6 in. of water up to about 4100 h. There was an outage at the plant, and aggressive pulsing of the reactor was conducted; the pressure drop was brought back down to 0.3 but rapidly increased to over 0.5 in. of water within 500 h.

3.1.3. Testing at Coyote

The same reactor that was installed at the Baldwin Station was moved and installed at the Coyote Station. In addition, the same Haldor Topsoe catalyst was used in the reactor. The cleaning cycles, temperatures, and gas flow rates are listed in **Table 6**. The reactor was operated for a 6-month period of time. **Figs. 11 and 12** show the test periods from 0 to 2 months and 2 to 4 months. As this paper is being prepared, the reactor is still operating on-site. The pressure drop across the catalyst upon installation was about 0.4 in. of water. After only 750 h, the pressure drop was 1.5 in. of water, indicating significant plugging. Very aggressive air pulsing was conducted, with little success in removing the deposits. The pressure drop for the catalyst was over two times greater than the pressure drop observed for the Baldwin Station utilizing the same reactor and same catalyst. At about 1700 h, the reactor was cleaned, and a section of catalyst was removed for characterization. The pressure drop after cleaning was about 0.8 to 1.0 in. of water. The pressure drop did not increase as rapidly because of the higher velocities through the clean section of the catalyst.

3.1.4. Visual observations of deposit characteristics

The tops of the catalysts were photographed during inspection and sampling of the catalyst sections. **Fig. 13** shows the ash materials that accumulated on the catalyst inlet after 2 months of operation. The most significant accumulation was noted for the Coyote

Table 8
Chemical composition of selected points and areas in Fig. 16

Element (wt.%)					
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5
Na_2O	1.7	2.3	0.0	0.3	1.0
MgO	5.9	3.0	1.2	1.8	3.8
Al_2O_3	3.7	2.5	3.3	5.7	6.3
SiO_2	9.7	31.5	13.3	70.0	18.5
P_2O_5	3.1	2.7	0.8	0.0	2.6
SO_3	48.1	31.0	35.8	0.0	32.1
K_2O	0.5	0.7	0.0	1.5	0.0
CaO	22.0	8.8	38.0	13.9	14.7
TiO_2	1.8	10.8	4.1	1.6	15.1
Fe_2O_3	2.1	6.6	3.4	4.2	5.9
BaO	1.4	0.0	0.0	0.9	0.0
Total	100	100	100	100	100

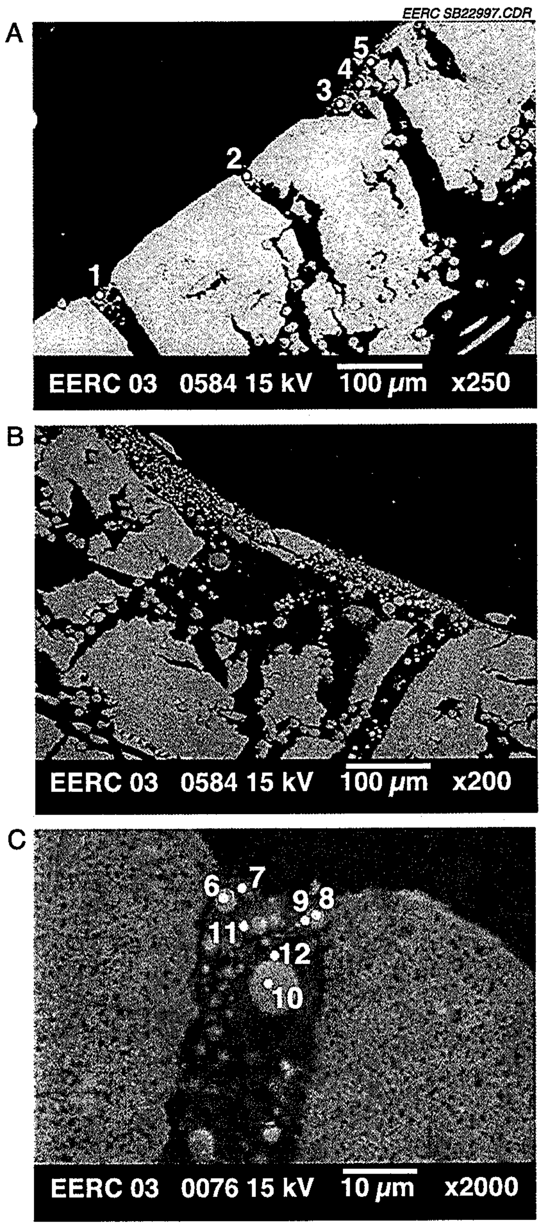

Fig. 17. SEM images of ash collected on catalyst surface at the Baldwin Station after 6 months of exposure. (A and B) Low-magnification images of ash deposit on catalyst surface and (C) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

Station, followed by Columbia and Baldwin. The Coyote Station had some larger pieces of ash deposit material on the surface as well as plugging of the catalyst passages. The Baldwin Station showed some obvious deposition along the walls of the reactor and some accumulation on the inlet sections. The Columbia Station showed more significant accumulation and plugging than the Baldwin Station.

After 4 months, the tops of the catalysts were photographed during inspection and sampling of the catalyst sections, as shown in Fig. 14. The most significant accumulation was noted for the Coyote Station and some accumulation for the Baldwin Station.

3.2. Deposit characteristics

The characteristics of the ash materials that collected on the catalyst surfaces and pores were characterized by SEM and X-ray microanalysis and, in selected cases, XRD was used to determine the crystalline phases present. The catalysts were sampled after 2, 4, and 6 months. The sections were sampled, and approximately 2.5-cm squares were mounted for SEM analysis on double-stick tape and in epoxy resin. The double-stick tape samples allowed for characterization of the external morphology of the particles and catalyst surface. The samples mounted in resin were cross-sectioned and polished, which allowed for more detailed and quantitative analysis of the bonding materials and materials that accumulated in the pores of the catalyst.

3.2.1. Plugging deposit characteristics

3.2.1.1. Baldwin Station deposits. Samples of catalyst were removed from the Baldwin Station after exposure to flue gases and particulate after 2, 4, and 6 months. Fig. 15 shows the characteristics of the ash deposit material on the SCR catalyst after 2 months of exposure. This is a polished cross section of a deposit on the surface of the catalyst. Fig. 15A shows particles on the surface of the catalyst that range in size from <1 to 15 μm. The larger particles range from oxides of solely silicon and iron to complex mixtures rich in

Table 9
Chemical composition of selected points and areas in Fig. 17

Element (wt.%)												
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
Na_2O	0.6	1.0	2.1	0.3	0.5	2.7	1.7	0.4	0.5	2.2	1.3	1.7
MgO	4.3	2.5	6.3	0.7	1.6	7.6	4.5	6.4	5.9	5.0	3.4	6.4
Al_2O_3	14.8	16.0	15.6	15.5	14.7	0.9	5.0	2.4	3.0	19.2	10.8	3.8
SiO_2	3.3	7.8	18.8	57.7	7.7	47.3	8.4	18.4	18.5	31.0	17.9	16.7
P_2O_5	2.3	2.1	0.5	0.6	1.8	0.0	1.8	0.9	1.0	0.0	1.7	1.2
SO_3	30.7	20.4	17.7	0.0	29.0	0.8	37.9	1.7	5.3	0.0	22.5	13.9
K_2O	0.7	0.0	1.0	0.4	0.9	0.9	0.4	0.0	0.0	0.9	0.8	0.0
CaO	28.8	28.7	28.1	22.5	34.9	28.4	31.4	52.6	49.0	28.9	30.6	45.4
TiO_2	2.0	7.2	2.2	0.3	1.3	1.1	1.9	6.9	7.4	2.4	2.0	1.1
Fe_2O_3	11.4	12.9	6.2	0.0	7.6	7.9	7.1	5.7	6.0	6.3	6.1	6.5
BaO	1.1	1.4	1.4	2.0	0.0	2.5	0.0	4.6	3.5	4.2	2.9	3.3
Total	100	100	100	100	100	100	100	100	100	100	100	100

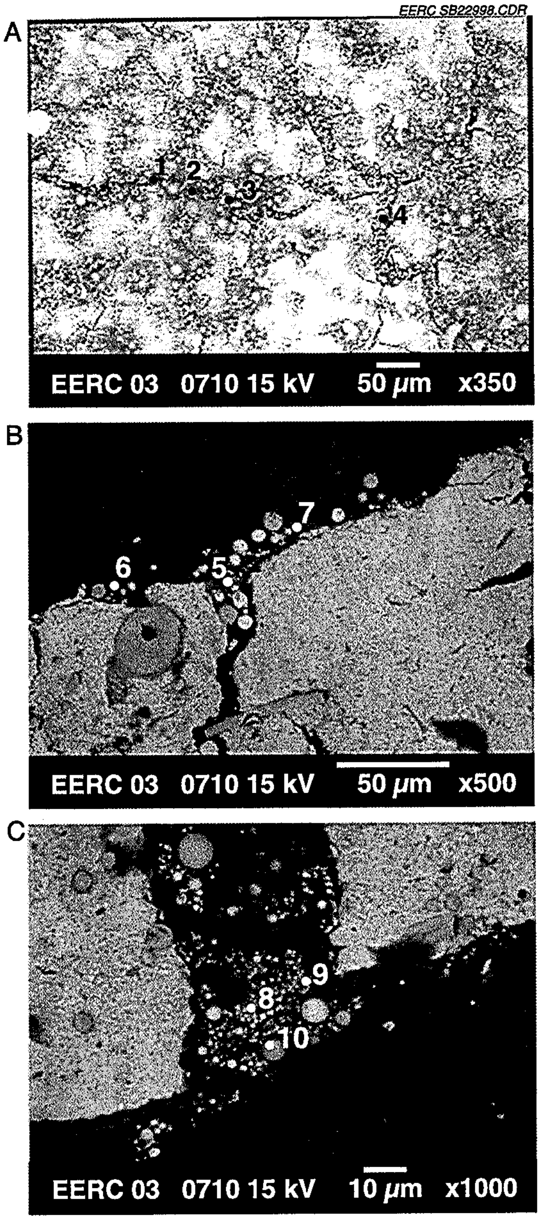

Fig. 18. SEM images of ash collected on catalyst surface at the Columbia Station after 2 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

aluminum and calcium; aluminum, silicon, and calcium; aluminum, calcium, and iron; and sodium, calcium, aluminum, and silicon. Chemical analysis of selected particles is summarized in Table 7. The samples of ash mounted on double-stick tape allow for the characterization of the external surfaces of the particles. The surface of a typical particle that is accumulating on the surface of the catalyst is shown in **Fig. 15B**. The blebs on the surface are composed of calcium and sulfur, with some iron and minor amounts of sodium and potassium. **Fig. 15C** shows a cross section of the deposited particles showing calcium- and aluminum-rich particles bonded together with a calcium- and sulfur-rich phase. This phase is in the form of calcium sulfate based on XRD analysis conducted on the deposited ash samples.

The 4-month sample from the Baldwin Station showed more extensive sulfation of the alkaline-earth elements present in the deposits. **Fig. 16** shows the images of a polished cross section of an ash deposit on the surface of the catalyst. The deposit formed both on the surface of the catalyst and within the catalyst pores as shown in **Fig. 16A**. **Fig. 16B** shows a higher magnification view of the deposit on the catalyst surface. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical composition of selected points shown in **Table 8** shows high levels of calcium and sulfur. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample.

The 6-month sample from the Baldwin Station showed extensive sulfation of the alkaline-earth elements present in the deposits. **Fig. 17A and B** shows regions of the catalyst where all the pores were blocked and a minimal amount of deposit on the surface of the catalyst. **Fig. 17C** shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical compositions of selected points that indicate the presence of high levels of calcium and sulfur are listed in **Table 9**. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample. In addition, there are some regions of high levels of calcium, aluminum, and sulfur present. The calcium aluminum materials are likely derived from the calcium aluminum phosphate minerals found in the coal fired at this plant.

Table 10
Chemical composition of selected points and areas in Fig. 18

Element (wt.%)										
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6	Point 7	Point 8	Point 9	Point 10
Na_2O	0.0	0.9	1.3	0.1	0.3	0.0	0.6	1.0	0.5	1.8
MgO	0.7	1.5	3.2	3.9	0.9	0.0	1.5	2.9	1.4	0.7
Al_2O_3	12.2	17.6	20.9	12.2	5.9	5.5	12.4	13.6	9.0	20.7
SiO_2	10.8	4.1	23.3	7.3	6.3	9.4	6.1	15.4	7.9	61.8
P_2O_5	0.9	0.1	0.0	1.4	2.6	1.2	0.6	1.7	3.1	0.2
SO_3	15.2	17.6	16.8	17.1	32.3	33.3	22.0	19.5	30.7	0.0
K_2O	0.2	0.0	0.5	0.0	0.1	0.0	0.0	0.1	0.2	2.5
CaO	14.1	43.1	25.0	42.0	34.9	44.1	48.5	34.1	38.3	4.4
TiO_2	44.8	2.8	1.1	10.5	5.2	0.5	4.4	2.4	2.6	2.2
Fe_2O_3	1.1	12.3	3.9	5.5	11.5	3.1	2.3	6.0	6.3	4.4
BaO	0.0	0.0	4.2	0.0	0.0	2.8	1.6	3.3	0.0	1.3
Total	100	100	100	100	100	100	100	100	100	100

3.2.1.2. Columbia Station deposits. The 2-month sample from the Columbia Station showed particles adhering to the surface and filling pores in the catalyst, as shown in Fig. 18. Fig. 18A shows the external morphology of the catalyst surface showing

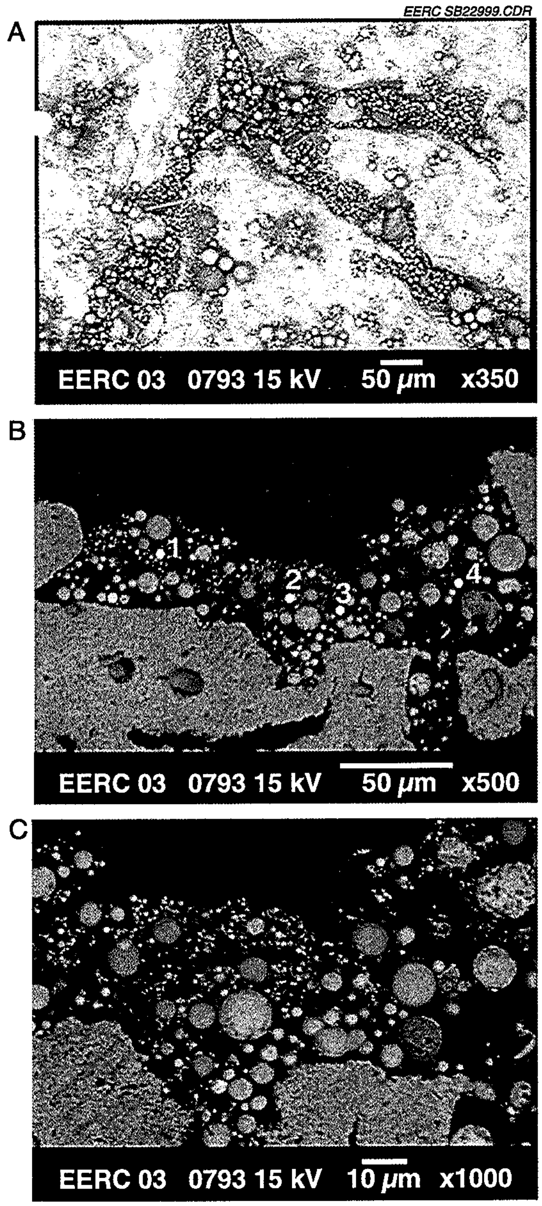

Fig. 19. SEM images of ash collected on catalyst surface at the Columbia Station after 4 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in Table 10. The 2-month sample shows significant evidence of sulfation after only 2 months of exposure. It appears to be more significant than that observed for the Baldwin 2-month sample. Fig. 18B and C shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate.

The 4-month sample from the Columbia Station showed particles adhering to the surface and filling pores in the catalyst, as shown in Fig. 19. Fig. 19A shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in Table 11. It appears to be more significant than that observed for the Baldwin 2-month sample. Fig. 19B and C shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate.

The 6-month sample from the Columbia Station showed particles adhering to the surface and filling pores in the catalyst as shown in Fig. 20. Fig. 20A shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in Table 12. Fig. 20B and C shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The 6-month samples show the most extensive degree of sulfation of the Columbia Station samples.

3.2.1.3. Coyote Station deposits. The 2-month sample from the Coyote Station showed particles adhering to the surface and filling pores in the catalyst as shown in Fig. 21. Fig. 21A shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in Table 13.

Table 11
Chemical composition of selected points and areas in Fig. 19

Element (wt.%)				
Oxide	Point 1	Point 2	Point 3	Point 4
Na_2O	0.5	0.0	0.6	0.3
MgO	3.3	1.9	3.2	2.4
Al_2O_3	13.1	10.2	13.0	6.3
SiO_2	12.4	8.4	8.4	3.6
P_2O_5	1.3	0.5	2.1	0.6
SO_3	27.7	29.9	32.2	47.4
K_2O	0.2	0.6	0.1	0.8
CaO	32.1	38.1	28.9	33.2
TiO_2	1.0	2.7	1.3	0.0
Fe_2O_3	6.3	6.3	7.6	2.6
BaO	2.0	1.4	2.5	2.6
Total	100	100	100	100

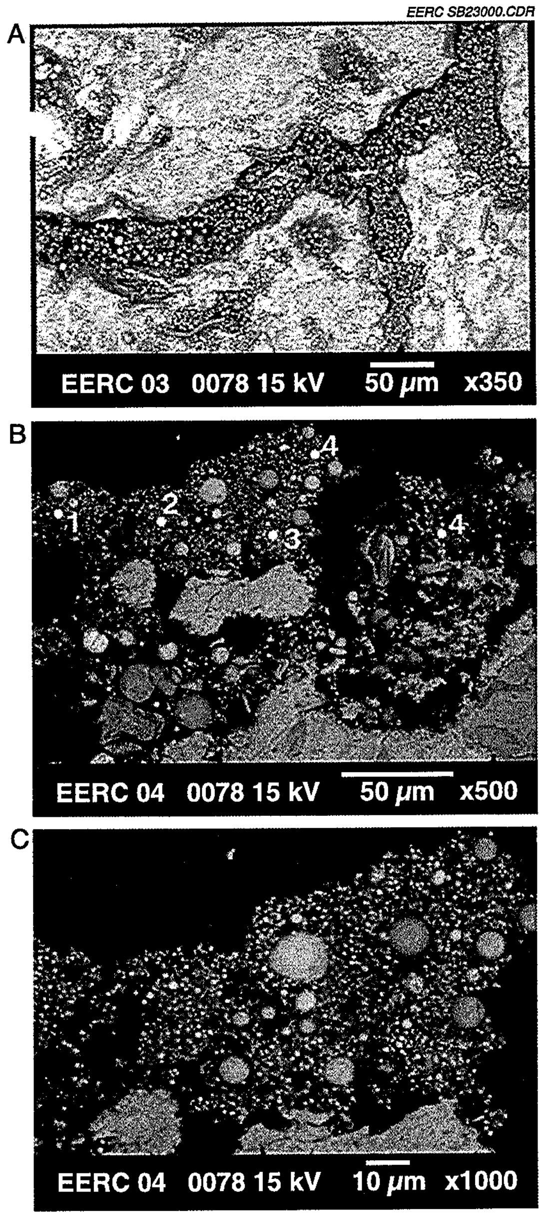

Fig. 20. SEM images of ash collected on catalyst surface at the Columbia Station after 6 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

The 2-month sample shows significant evidence of sulfation after only 2 months of exposure and was much more pronounced than the 2-month samples for the Baldwin and Columbia Stations that are fired on PRB coals. Fig. 21B and C shows a higher

Table 12
Chemical composition of selected points and areas in Fig. 20

Element (wt.%)				
Oxide	Point 1	Point 2	Point 3	Point 4
Na_2O	0.1	0.0	0.3	0.6
MgO	1.8	0.7	1.7	2.2
Al_2O_3	10.9	9.6	6.2	11.3
SiO_2	13.1	11.3	12.4	19.5
P_2O_5	3.9	4.8	0.2	2.1
SO_3	27.6	34.0	35.5	30.0
K_2O	0.5	0.3	0.1	1.2
CaO	33.0	25.9	39.8	25.8
TiO_2	0.8	2.5	1.6	3.3
Fe_2O_3	6.1	9.7	1.9	2.9
BaO	2.1	1.2	0.0	1.1
Total	100.00	100.00	100.00	100.00

magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The presence of sodium enhances the bonding and sulfation of the particles to form a strongly bonded matrix.

The 4-month sample from the Coyote Station showed particles adhering to the surface and completely filling and masking the pores in the catalyst as shown in **Fig. 22**. **Fig. 22A** shows the external morphology of the catalyst surface showing the masking of the catalyst surface. Chemical compositions of selected points are shown in **Table 14**. The 4-month sample shows more sulfation than the 2 months of exposure samples. **Fig. 22B and C** shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of sodium-, calcium-, and sulfur-rich material, likely in the form of calcium sulfate. The presence of sodium and potassium enhances the bonding and sulfation of the particles to form a strongly bonded matrix. Significant sodium was found in the deposits, as shown in **Table 14**.

3.2.2. Deposit formation mechanisms

The mechanism for the formation of deposits that blind SCR catalysts involves the transport of very small particles rich in alkali and alkaline-earth elements, the surface of the catalyst, and reactions with SO_2/SO_3 to form sulfates. The formation of SO_3 from SO_2 is catalyzed by the SCR; this, in turn, increases the reaction rate of SO_3 to form sulfates. In some cases, the alkali and alkaline-earth elements will also react with CO_2 to form carbonates. XRD analysis shown in **Fig. 23** identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements including sodium, magnesium, calcium, and potassium, in addition to mineral phases. The primary minerals present in these coals include quartz, clay minerals, carbonates, sulfates, sulfides, and phosphorus-containing minerals [18].

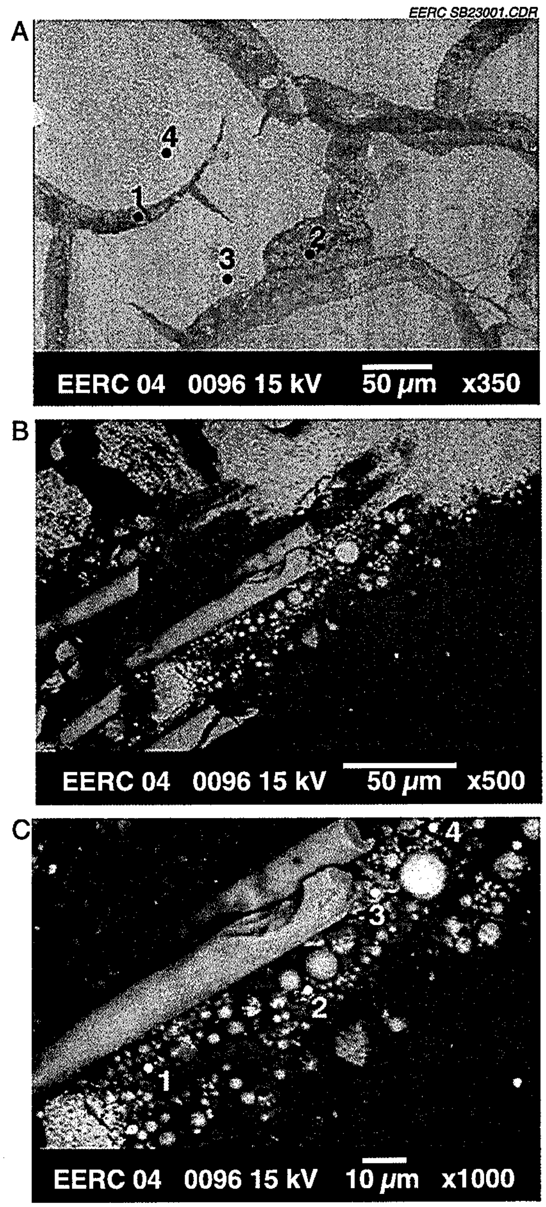

Fig. 21. SEM images of ash collected on catalyst surface at the Coyote Station after 2 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component, their association in the coal, and combustion system design and operating conditions. There has been

Table 13
Chemical composition of selected points and areas in Fig. 21

Oxide	Point 1	Point 2	Point 3	Point 4
Na_2O	0.9	0.7	1.2	1.0
MgO	5.0	1.6	5.6	1.7
Al_2O_3	12.3	5.8	11.9	5.5
SiO_2	24.6	3.1	21.1	2.6
P_2O_5	0.7	0.0	0.5	0.0
SO_3	23.5	44.0	17.4	31.8
K_2O	0.5	0.3	0.8	0.4
CaO	14.9	36.4	19.6	46.9
TiO_2	7.2	1.9	8.0	2.1
Fe_2O_3	9.2	5.5	11.8	6.9
BaO	1.3	0.7	2.1	1.1
Total	100	100	100	100

significant research conducted on ash formation mechanisms and relationships to impacts on power plant performance [18–34]. Typically, during combustion the inorganic components associated with western subbituminous and lignite coal are distributed into various size fractions of ash, as shown in Fig. 24. The results shown in Fig. 24 were obtained from isokinetic sampling and aerodynamically size-fractionating ash particles from a full-scale pulverized-coal-fired boiler firing subbituminous coal and analyzing each size fraction. The results show that the smaller size fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. These ash particles are largely derived from the organically associated cations in the coal. The larger size fraction has higher levels of aluminum and silicon derived from the mineral fraction of the ash-forming component of the coal. Entrained ash was extracted from the Columbia Station at the point of the inlet to the SCR reactor and was aerodynamically classified and analyzed. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst, as shown in Fig. 25. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-μm size fraction. The deposited material shows significantly more sulfation than the entrained-ash size fraction, indicating that the sulfation process occurs after the particles are deposited in the catalyst.

The mechanism of SCR catalyst blinding when firing lignite or subbituminous coals is shown in Fig. 26 [35]. The requirements for the formation of deposits that blind SCR catalyst include firing a coal that produces significant levels of <5-μm-sized particles. The particles are transported into the pores of the catalyst and subsequently reacted with SO_3 to form sulfates. The sulfate forms a matrix that bonds other ash particles. The SCR catalyzes the formation of SO_3 and thereby increases the rate of sulfation [9,15]. The sulfation of CaO increases the molar volume, resulting in the filling of the pore. For coals that have high sodium contents, formation of low-melting-point phases such as pyrosulfates are possible [36]. Pyrosulfate materials can melt at temperatures as low as 535 °F in coal-fired power systems.

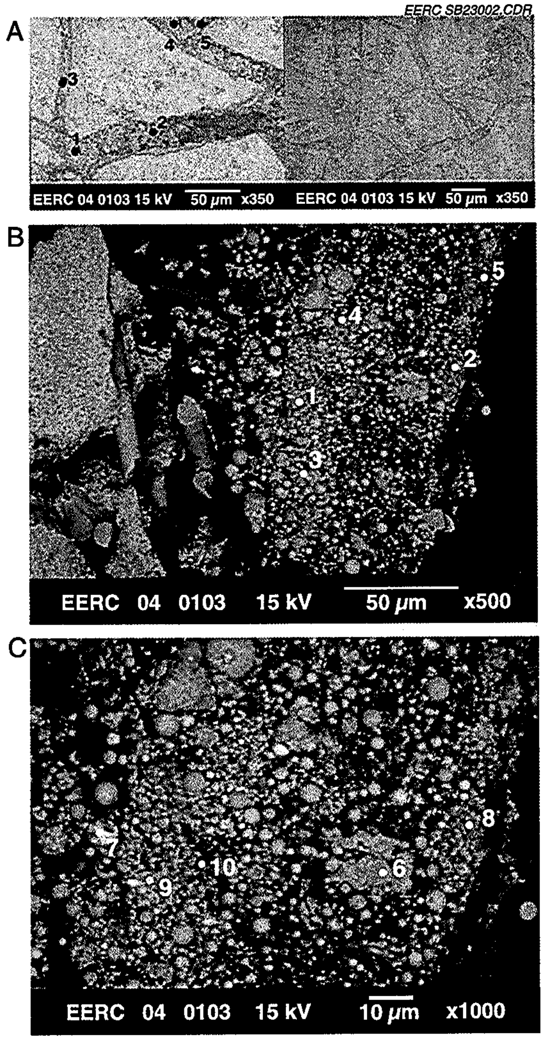

Fig. 22. SEM images of ash collected on catalyst surface at the Coyote Station after 4 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

3.3. Flue gas measurements

3.3.1. Mercury transformations

The ability of mercury to be oxidized across the SCR catalyst was investigated at the Coyote Station. The Coyote Station is fired on North Dakota lignite, and the flue gases are dominated by elemental mercury. Measurement of mercury speciation was conducted using the OH method at the inlet and the outlet of the SCR catalyst. The measurements were made upon installation of the catalyst and after 2 and 4 months of operation. The

Table 14
Chemical composition of selected points and areas in Fig. 22

Element (wt.%)										
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6	Point 7	Point 8	Point 9	Point 10
Na_2O	6.7	1.9	7.1	6.2	3.1	9.5	2.6	10.4	8.9	4.4
MgO	1.1	1.7	1.1	2.6	3.2	1.2	1.9	1.3	3.0	3.7
Al_2O_3	2.6	8.8	4.0	4.8	10.5	2.6	8.6	4.2	4.9	10.6
SiO_2	7.0	21.1	11.3	5.6	32.2	6.3	18.2	10.5	5.0	28.9
P_2O_5	0.2	2.4	0.0	0.2	0.9	0.1	1.9	0.0	0.1	0.7
SO_3	54.7	38.5	56.4	57.5	30.4	41.8	28.4	44.9	44.5	23.4
K_2O	2.0	2.8	0.7	2.8	2.4	3.2	4.3	1.2	4.4	3.8
CaO	18.0	3.4	15.8	9.3	2.3	24.5	4.4	22.5	12.8	3.1
TiO_2	0.6	0.8	1.1	1.3	1.5	0.6	0.8	1.3	1.5	1.8
Fe_2O_3	5.8	5.1	2.1	6.5	9.8	7.7	6.6	2.9	8.9	13.2
BaO	1.4	13.5	0.5	3.4	3.6	2.4	22.3	0.9	5.9	6.3
Total	100	100	100	100	100	100	100	100	100	100

results of the mercury speciation measurement at the inlet and outlet of the SCR catalyst conducted upon installation are shown in Fig. 27. The inlet and outlet measurements were repeated three times and are shown in Fig. 27. The level of elemental mercury at the inlet was approximately 76% to 92%, with the remaining in the oxidized form ranging from 8% to 24%. Very little was in the form of particulate mercury at the inlet. Measurement of mercury speciation was conducted with the ammonia on and off. The results with the ammonia off showed an increase in the oxidized mercury to 43% of the total mercury occurring across the SCR catalyst. However, when the ammonia was introduced into the

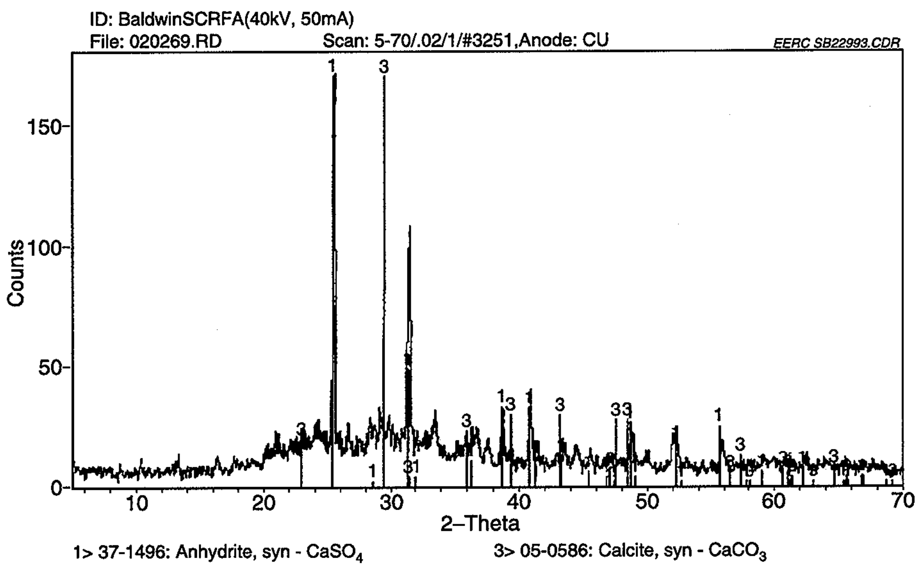

Fig. 23. X-ray diffraction of ash collected on SCR catalyst (1—$CaSO_4$, 2—$Ca_3Mg(SiO_4)_2$, and 3—$CaCO_3$).

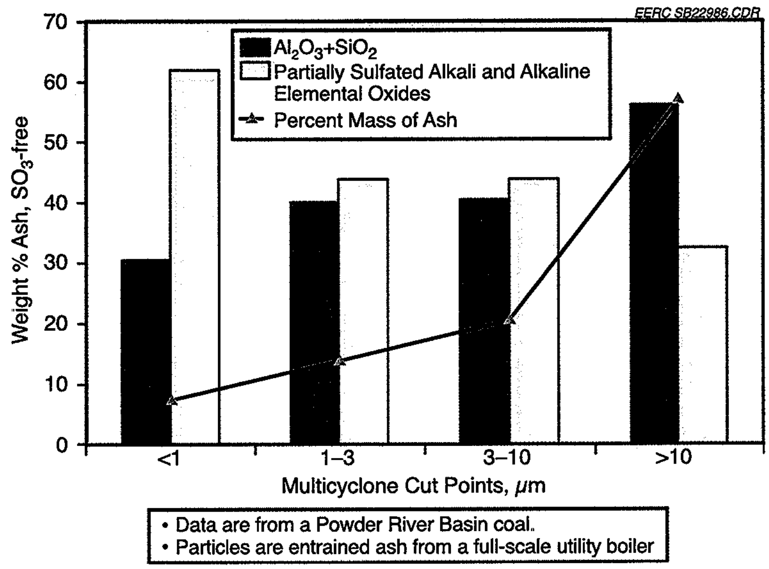

Fig. 24. Simplified illustration of ash partitioning in combustion systems [18].

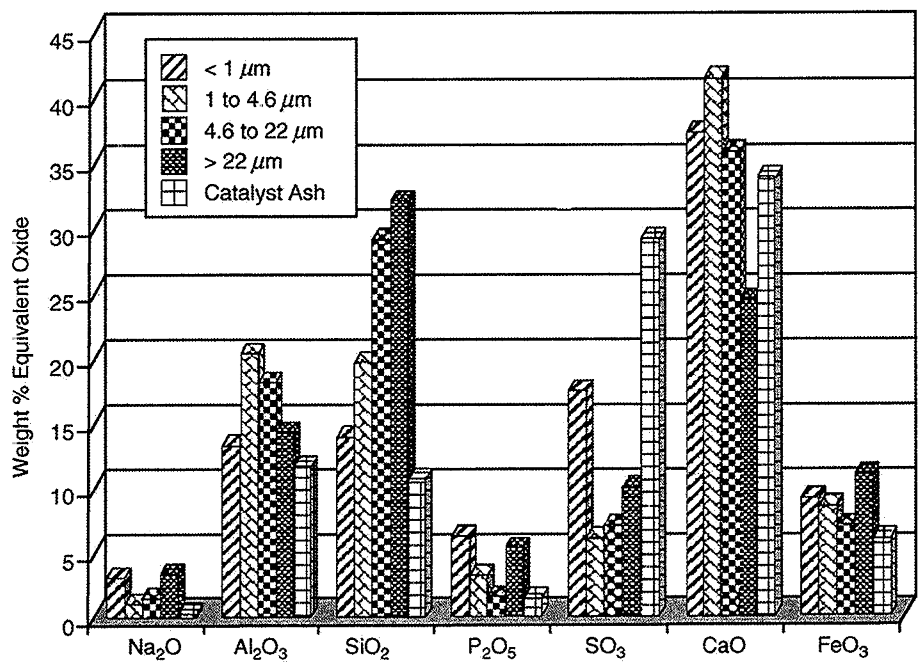

Fig. 25. Comparison of entrained ash and deposited ash on catalyst for Columbia Station.

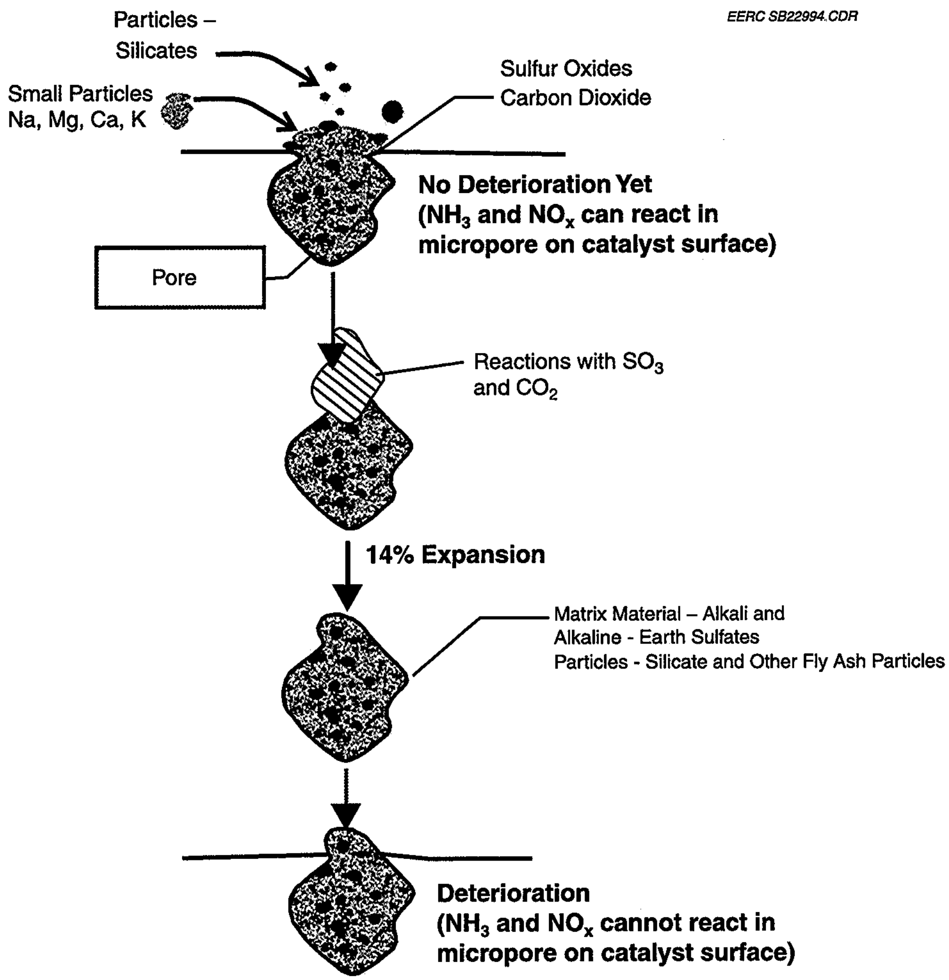

Fig. 26. Mechanism of SCR catalyst blinding via the formation of sulfates and carbonates (modified after Pritchard et al. [35]).

SCR catalyst, the amount of mercury oxidation decreased from 43% to 19%. There was an increase in the particulate mercury from 1.0% to 7.2%.

The mercury oxidation after the SCR catalyst was exposed to flue gas and particulate for 2 months is shown in Fig. 28. The level of oxidized mercury at the inlet ranges from 7.5% to 11.1% of the total mercury. The level of oxidized mercury at the outlet ranged from 7.6% to 14% of the total mercury. The level of particulate mercury increased from a negligible level to 3% of the total mercury at the outlet.

The results of mercury oxidation across the SCR catalyst after 4 months of exposure to flue gases and particulate are shown in Fig. 29. The results show a higher level of oxidized mercury at the inlet as compared to testing conducted at installation and after 2 months. The level of oxidized mercury at the inlet ranges from 32% to 38% of the total,

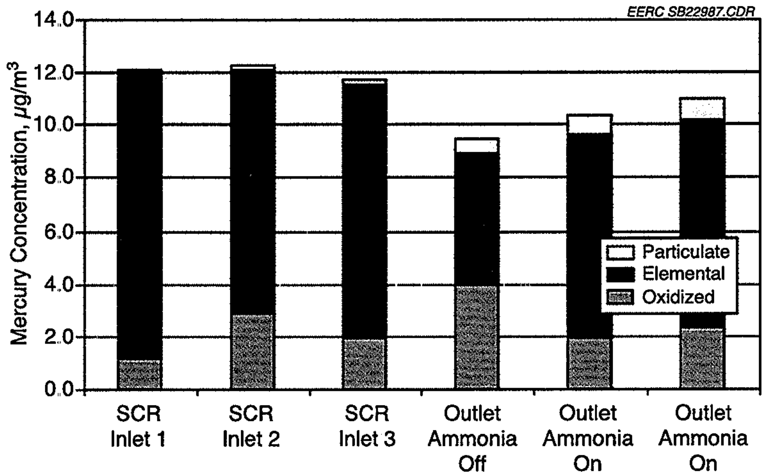

Fig. 27. Mercury speciation measurement at the inlet and outlet of the SCR catalyst upon installation of the catalyst.

with about 5% of the total in the particulate form. The outlet levels of oxidized mercury decrease after passing through the catalyst to about 20% of the total. The level of particulate mercury remained about the same across the catalyst.

4. Conclusions

A slipstream reactor is designed to expose SCR catalyst to coal combustion-derived flue gases and particulate. The system is computer-controlled and operates in an automated

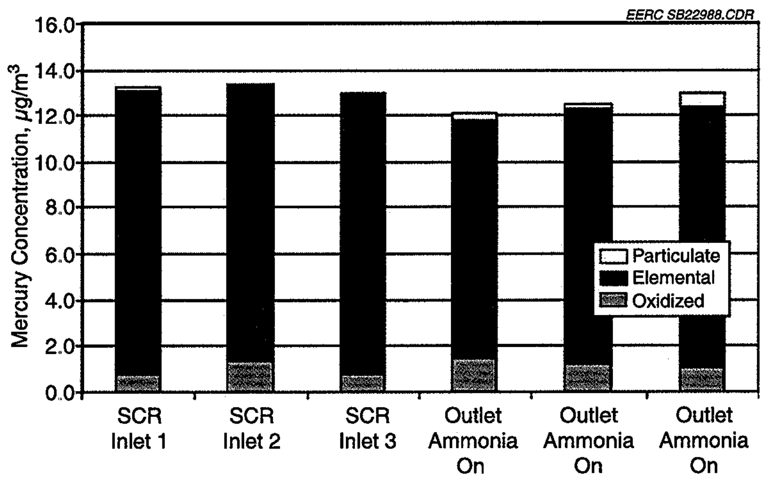

Fig. 28. Mercury speciation measurement at the inlet and outlet of the SCR catalyst after exposure to flue gases and particulate for 4 months.

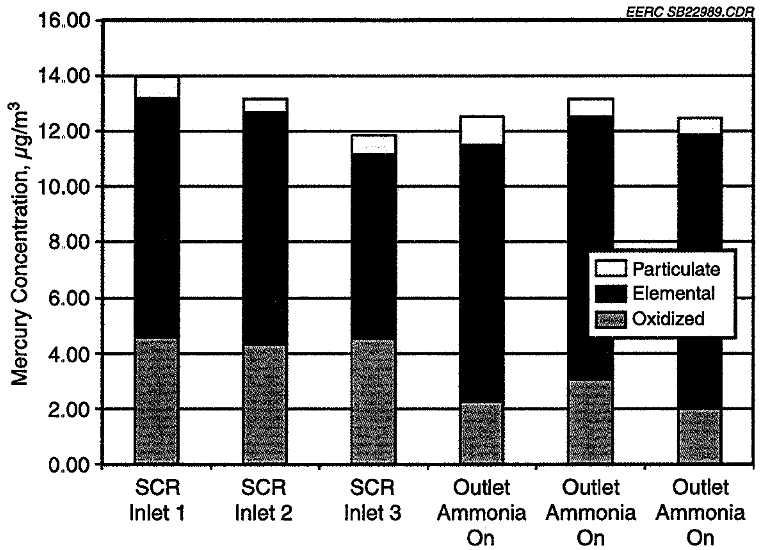

Fig. 29. Mercury speciation measurement at the inlet and outlet of the SCR catalyst after exposure to flue gases and particulate for 2 months.

mode. The system can be operated and monitored remotely through a modem connection. SCR catalyst testing was conducted at two subbituminous-fired plants and one lignite-fired plant. The boiler configurations for the subbituminous-fired plants included a cyclone- and a tangentially fired boiler. The boiler configuration for the lignite plant was a cyclone-fired system.

The pressure drop across the catalyst was found to be the most significant for the lignite-fired plant as compared to the subbituminous-fired plants. Both coals had significant accumulations of ash on the catalyst, on both macroscopic and microscopic levels. On a macroscopic level, there were significant observable accumulations that plugged the entrance as well as the exit of the catalyst sections. On a microscopic level, the ash materials filled pores in the catalyst and, in many cases, completely masked the pores within 4 months of operation.

The deposits on the surfaces and within the pores of the catalyst consisted of mainly alkali and alkaline-earth element-rich phases that have been sulfated. The mechanism for the formation of the sulfate materials involves the formation of very small particles rich in alkali and alkaline-earth elements, transport of the particles to the surface of the catalyst, and reactions with SO_2/SO_3 to form sulfates. XRD analysis identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements, including sodium, magnesium, calcium, and potassium in addition to mineral phases. During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component and their association in the coal and combustion system design and operating conditions. The results of this testing found that the smaller size fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-μm size fraction.

The ability of mercury to be oxidized across the SCR catalyst was investigated at the Coyote Station. The Coyote Station is fired on North Dakota lignite, and the flue gases are dominated by elemental mercury. Measurement of mercury speciation was conducted using the OH method at the inlet and the outlet of the SCR catalyst. These results show limited oxidation of mercury across the SCR catalyst when firing lignite coals. The reasons for the lack of mercury oxidation include the following: no or low chlorine present in the coal and flue gas to catalytically enhance the oxidation of Hg^0, high levels of alkali and alkaline-earth elements acting as sorbents for any chlorine present in the flue gas, and low levels of acid gases present in the flue gas.

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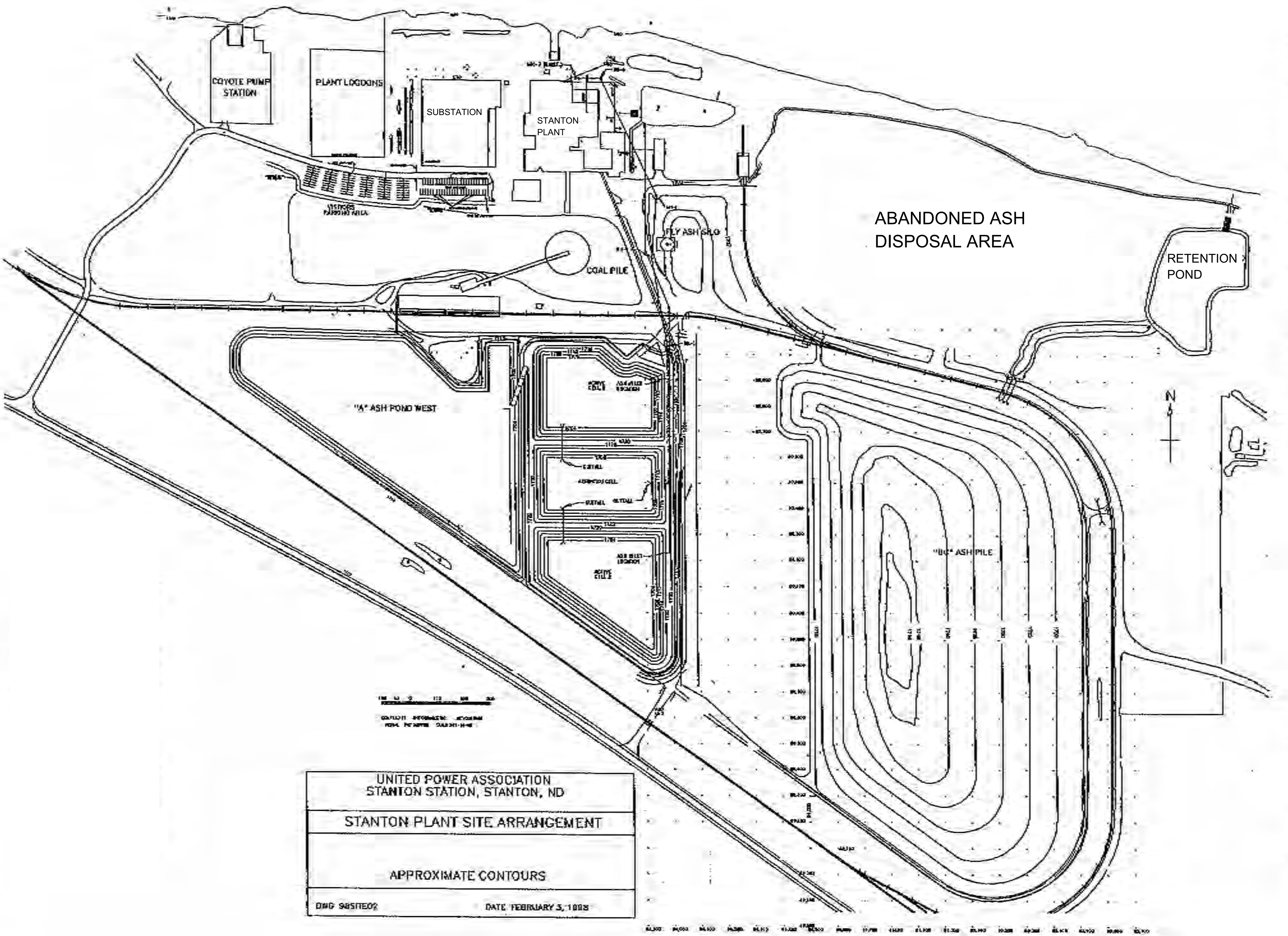
Appendix G

Stanton Station Site Plan


COYOTE PUMP STATION
PLANT LOGGINS
SUBSTATION
STANTON PLANT
ABANDONED ASH DISPOSAL AREA
RETENTION POND
FLY ASH SILO
COAL PILE
"A" ASH POND WEST
N
UNITED POWER ASSOCIATION
STANTON STATION, STANTON, ND
STANTON PLANT SITE ARRANGEMENT
APPROXIMATE CONTOURS
DWG 98SITE02
DATE FEBRUARY 3, 1998