GREAT RIVER
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A Touchstone Energy® Cooperative

Coal Creek Station Units 1 and 2

Best Available Retrofit Technology Analysis

Revised December 12, 2007

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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 Coal Creek Station (CCS) located in Underwood, ND. CCS is a two unit, 1100 megawatt mine-mouth plant. Commercial operation commenced on CCS Unit 1 in 1979 and Unit 2 in 1980. The CCS steam generators are Combustion Engineering Controlled Circulation tangentially fired lignite boilers. Preliminary visibility modeling conducted by the North Dakota Department of Health (NDDH) found that the Coal Creek units 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 the Coal Creek units. The existing pollution control equipment for each unit includes: ESP for particulate matter, low NOx burners (LNB) with a level of separated overfire air (SOFA) for NOx, and partially bypassed wet scrubbing for SO_2. The CALMET/CALPUFF/CALBART dispersion modeling sequence was used to assess the post-BART visibility impacts associated with the proposed BART emission limits. Based on the results of visibility modeling, economic impacts analysis and consideration for other non-air quality energy and environmental factors, GRE proposes the following as BART:

- Particulate matter (PM) emissions will continue to be controlled by the existing ESP for each unit. Additional PM controls, including condensable PM (CPM) controls, would provide little visibility improvement and require significant capital expenditures. Existing and proposed SO_2 controls may provide additional CPM reductions, primarily in the form of sulfuric acid mist (SAM). Therefore, the current PM performance standard of 0.1 lb/MMBtu will be maintained.

- NOx emissions will be reduced to the presumptive BART level of 0.17 lb/MMBtu on a 30-day rolling average. This will be achieved through the installation of an additional level of SOFA.

- SO_2 emissions will be reduced to the presumptive BART level of 0.15 lb/MMBtu on a station wide 30-day rolling average. This will be achieved through the use of coal drying, and the installation of trays or new liquid distribution rings (LDRs) and high flow mist eliminators (MEs)

The proposed BART emission rates will result in an overall visibility improvement of over 50% for Coal Creek Station.

It is GRE's goal to install controls that will meet or perform below the presumptive BART levels for both NOx and SO_2. In an effort to utilize the best available technology at the time of purchase, GRE will continue to evaluate which technology will provide the requisite removal efficiencies to meet presumptive BART emission limits and provide GRE with greatest operational flexibility. GRE was awarded a collaborative agreement for a Lignite Fuel Enhancement project under the Clean Coal Power Initiative DOE Solicitation DE-PS26-02NT41428. Phase I of the DOE project included a 75 ton/hour lignite drying system with a segregator for beneficiation of the fuel was designed and constructed in 2005. The drying system has been performance tested, and an evaluation of the benefits of the drying system was completed. A public version of this evaluation is included in Appendix J. Coal drying results in two major benefits to the station; first is a decrease in lignite moisture content resulting in higher boiler efficiency and a lower flue gas volume, subsequently resulting in increased scrubbing efficiency; and second is a decrease in fuel combustion quantities resulting in lower emissions.

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 subject to BART, 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.

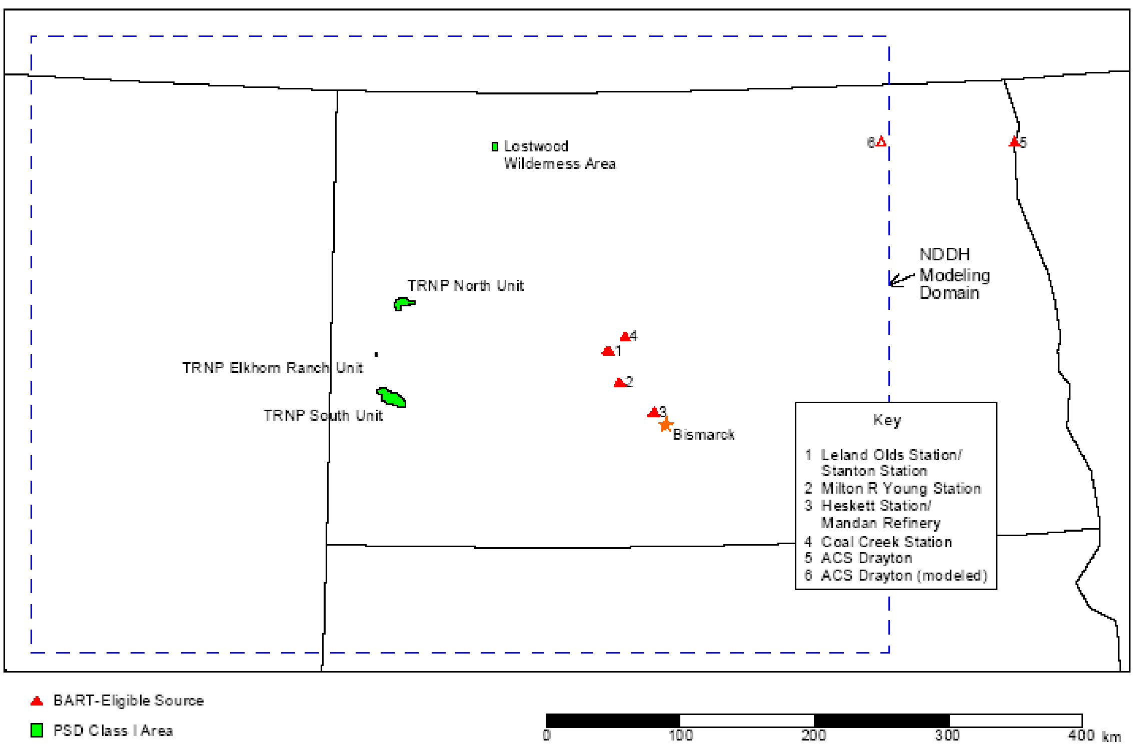

Figure 1-1 North Dakota's BART Geography: The North Dakota SIP will address the 4 PSD Class I Areas and 6 BART Eligible Units illustrated above. (Source *Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota, Final version)*

Expressly, 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

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

conditions. Assuming a uniform rate of progress the default glide path, 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.

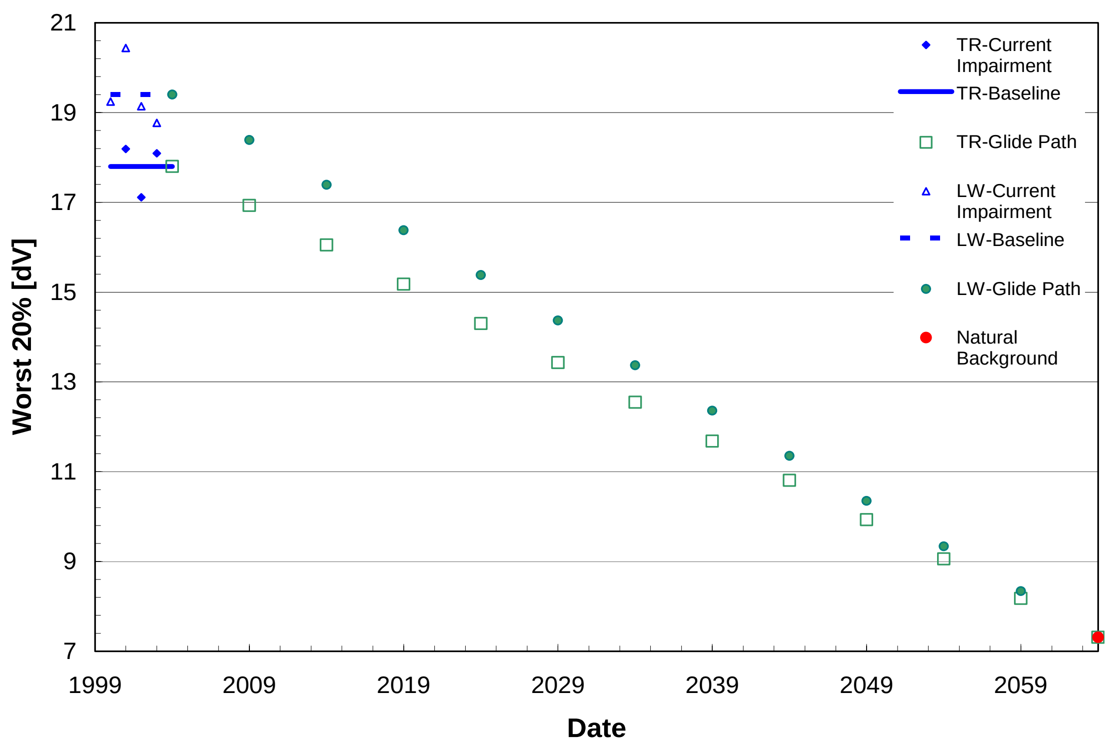

Figure 1-2 Theodore Roosevelt NP and Lostwood WA, ND. Current impairment includes both natural and anthropogenic contributions. (Data from VIEWS database trend analyzer, http://vista.cira.colostate.edu/views/web/AnnualSummaryDev/Trends.aspx DOA 06 Dec 2005)

1.1 BART Eligibility

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 exempt to date from any other CAA requirements.

BART eligibility is established on the basis of 3 criteria. Sources that are BART-eligible must meet all three conditions described below:

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)

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

If emissions from a BART-eligible source cause or contribute to visibility impairment at any Class I area, then that source is subject to BART. Visibility modeling conducted with CALPUFF or another EPA-approved visibility model is necessary to make a definitive visibility impairment determination. 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 BART-eligible source that is not exempt 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 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 finally, 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. Technologies which are determined to be technically infeasible are eliminated from further consideration.

Step 3 - Evaluate Control Effectiveness
In step three, rank the remaining controls based on the control efficiency at the expected emission rate as compared to the emission rate before addition of controls for the pollutant of concern.

Step 4 - Evaluate Impacts and Document Results
The fourth step utilizes an engineering analysis to document the impacts of each remaining control technology option. The economic analysis included in this step includes a dollar per ton of pollutant removed cost for each

[2] 40 CFR 51 Appendix Y

technology in addition to an incremental cost analysis to illustrate the economic effectiveness of one technology in relation to the others evaluated. Step four also 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 proposed BART 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 Coal Creek Station BART Determination

As defined by federal guidance and ND 33-25-25-01, 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 BART eligible sources, including Coal Creek Station, that cause or contribute to visibility impairment in North Dakota.

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

2.1 BART Eligible Units

Great River Energy's (GRE) Coal Creek Station, located in Underwood, ND, contains two main units. Both are tangentially fired lignite boilers with ratings of 6015 and 6022 MMBtu/hr respectively for a combined facility output of 1,100 megawatts. The two units have identical permit emission limits, and for the purpose of this analysis, identical characteristics. The BART analysis for each pollutant has been performed on the basis of a single unit with a rating of 6019 MMBtu/hr, meaning that the total impact with respect to economics or other environmental concerns should be doubled to encompass the entire facility. PM is currently controlled with an electrostatic precipitator (ESP). Low NOx burners (LNB) are used in combination with a level of separated over-fire air (SOFA) for NOx control. Each unit currently controls SO_2 emissions with a wet scrubber, with approximately 25% of the flow bypassing the scrubber. Continued operation of the station is predicted for the long term foreseeable future, therefore the remaining useful life of the source as defined by EPA guidance [4] was not used as an element of impact assessment.

At least three sets of emission parameters must be considered to successfully determine BART. The current Title V permitted emission limits represent the maximum allowable emission rates. The baseline actual emissions represent historical emissions inventories and are used in comparison with design basis emission rates for potential retrofit technologies. This emission rate is the long term (30-day or annual average) average expectation, and is used in the economic analysis. Finally, the pre-BART screening emission rate, which represents the maximum 24-hour average emission rate as mentioned above, is used as a baseline for visibility impacts analysis. Table 2-1 describes these three data parameters for Coal Creek Station.

Table 2-1 Single Unit Emission Bases

Pollutant	Permit Limit	Baseline Actual	BART Screen
PM	0.10 lb/MMBtu 528 lb/hr	0.03 lb/MMBtu 181 lb/hr	0.04 lb/MMBtu 250 lb/hr
NOx	0.4 lb/MMBtu 5,104 lb/hr	0.22 lb/MMBtu 1,294 lb/hr	0.29 lb/MMBtu 1,772 lb/hr
SO_2	1.2 lb/MMBtu 6,336 lb/hr	0.56 lb/MMBtu 3,356 lb/hr	0.95 lb/MMBtu 5,734 lb/hr

The BART analysis, as described in Section 1.2 of this document, will be presented on a pollutant by pollutant basis for the above units 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.

2.2 Other BART Eligible Units

The remaining BART eligible emission units at Coal Creek are exempt from BART analysis because they do not cause or contribute to visibility impairment, and are included under one of the two following categories.

i. *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 Coal Creek and their four year average actual emissions. The limited expected operations of these units makes additional controls economically infeasible, and no further BART analysis is required.

Table 2-2 Coal Creek Station Low Utilization Units

Emission Unit Identification and Description	Fuel	Maximum Heat Input	2001-2004 Average, Actual				
			Hours of Operation	NOx (tpy)	SO_2 (tpy)	PM (tpy)	PM_{10} (tpy)
EUI 3 Auxiliary Boiler No. 91	Fuel oils	172 lb/MMBtu	25	0.06	0.02	4.23E-03	2.96E-03
EUI 4 Auxiliary Boiler No. 92	Fuel oils	173 lb/MMBtu	6	0.10	0.33	1.62E-01	3.23E-02
EUI 5 Emergency Generator	Nos. 1 and 2 fuel oils	3,500 hp	95	2.89	0.27	6.91E-02	4.78E-02
EUI 6 Fire Pump Engine	Nos. 1 and 2 fuel oils	200 hp	14	0.11	0.01	6.06E-03	5.98E-03

ii. Material Handling and Fugitive Sources

All material handling units (EUI 7 through EUI 26), including coal and lime handling operations and fly ash silos, are controlled through the use of fabric filter baghouses. Baghouses are currently recognized as the best available control technology (BACT) for PM emitting sources. No further BART analysis is required for emission units employing BACT or equivalent controls.

In step three of the BART guidance, the Federal Register[4] states, “Fugitive emissions, to the extent quantifiable, must be counted.” The emissions from the sources listed in Table 2-3 consist of PM only, and because sulfates and nitrates are the primary contributors to visibility impairment, PM sources will not significantly contribute to visibility impairment in Class I areas. For this reason, these sources will not be considered further.

Table 2-3 Coal Creek Station Fugitive Sources

Fugitive Source Name
FS 1 Cooling towers No. 91, No. 92, and No. 93
FS 2 Boombelt conveyor (stackout)
FS 3 Conveyor 909 (stackout)
FS 4 Scrubber building flyash silo (stackout)
FS 5 Coal pile maintenance

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

3.0 Particulate Matter (PM) BART Analysis

Historical emissions inventories show that under normal operation, Coal Creek Station units emit PM at less than one third of their permitted limit. The existing ESP provides a great deal of filterable particulate control, and pre-BART modeling showed that the PM contribution to visibility impairment for Units 1 and 2 was almost negligible in comparison to the impairment attributed to sulfates and nitrates. 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 below provides an estimation of CPM and concludes that CPM emissions from Units 1 and 2 do not significantly impact visibility impairment and will be reduced by the proposed SO_2 BART control. As illustrated in Section 7.0, post-BART modeling of Unit 1 alone shows a 1.6 Δ-dV improvement in visibility impairment while particulate controls can provide an improvement of only 0.06 Δ-dV as described in Section 3.5.

3.1 Identify PM Control Options

Table 3-1 lists the available retrofit PM options for Coal Creek Units 1 and 2.

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, typically wires or rigid frames, and grounded collecting electrodes, 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 matter, which falls into hoppers for removal. Collector dust is removed from the precipitator for disposal or recycling.

ESP 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 much 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 Coal

Creek units, making ESP replacement or modification a technically feasible control option.

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, typically wires or rigid frames, and grounded collecting electrodes, 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, WESP's generate wastewater which must be treated to remove suspended particles and dissolved solids.

Since WESP's 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 waster 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 much 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, making it a technically feasible option for the Coal Creek units.

3.2.3 Mechanical Collector

Cyclone separators are designed to remove particles by inducing a vortex as the gas stream enters the chamber, causing 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 waste gas is heavily laden with particulate matter.

According to a report prepared by EPRI[5] on the current controls used for coal-fired only power plants, this technology has only been permitted for use on one similar unit which is not yet operational. Due to the fact that a multiclone has not been successfully demonstrated on a comparable unit, it is infeasible for a retrofit at Coal Creek 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 which 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 collected dust to fall 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.

The main operating limitation of 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, outlet concentrations achieved will depend on the size range and nature of the particles being filtered. Baghouses are commonly used to control particulate

[5] *Status and Performance of Best Available Control Technologies*, EPRI, Palo Alto, CA: 2005. 1008114 (Appendix H)

emissions from coal-fired boilers, making it a viable control option for Coal Creek's BART.

3.3 Evaluate the Effectiveness of Feasible PM Options

Based on the current degree of control being achieved on Units 1 and 2, ESP, WESP and baghouse technologies can only reasonably provide a 50% reduction in actual emissions each from existing emissions. 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[6]	Controlled Emissions lb/MMBtu
Dry ESP	50%	0.015
Polishing WESP	50%	0.015
Baghouse	50%	0.015

3.4 Evaluate the Impacts of Feasible PM Options

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

3.4.1 Economic Impacts

Each technology is expected to provide controlled emissions of roughly 388 tons per year, a 50% improvement from the pre-BART historical baseline. Table 3-3 details the expected costs associated with each technology based on the EPA cost model and site specific information. Due to space considerations, the retrofit of PM controls at Coal Creek Station would require significant additional expenses that were not included in the control cost evaluation below.

Table 3-3 PM Control Cost Summary, per Unit Basis

Control Technology	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)
Polishing WESP	$7.23	$1.92	$4,969
Baghouse	$37.37	$7.67	$19,864
Dry ESP	$38.51	$10.06	$26,056

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

[6] Control efficiency reflects improvement beyond the performance of the existing ESP.

pollution control costs indicate that additional particulate control would involve an excessive investment for only a 50% reduction in already low particulate emissions.

3.4.2 Energy and Environmental Impacts

There are no energy or non-air quality environmental impacts that would discourage the use of an ESP, WESP or baghouse as BART. 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 Coal Creek.

3.5 PM Visibility Impacts

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 visibility improvement of only 0.06 Δ-dV; negligible in comparison to the improvement attributed to SO_2 and NOx control as illustrated in Section 7.0.

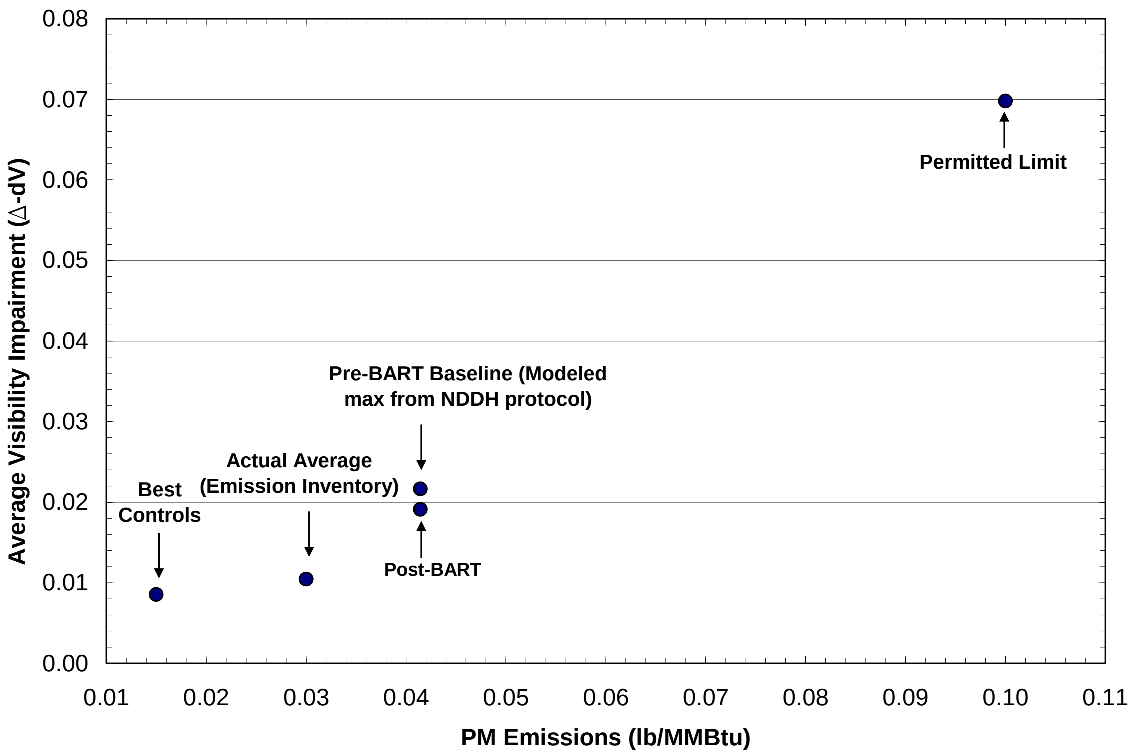

Figure 3-1 PM Visibility Contribution. Four modeled scenarios for Coal Creek Unit 1, modeled year 2002, 98th percentile, illustrate the negligible visibility impacts attributed to particulate matter. All scenarios except for "Pre-BART" were modeled with NOx and SO_2 at the presumptive levels of 0.17 lb/MMBtu and 0.15 lb/MMBtu respectively.

Table 3-4 PM Visibility Modeling Parameters

Scenario	Description			Emission Rate Input									
				Stack Velocity	PM_{10}		$PM_{2.5}$ (fine)	PM (coarse)	SO_2		NOx		
	PM	SO_2/NOx	Units	m/s (ft/s)	% reduction	lb/hr	lb/hr	lb/hr	% reduction	lb/hr	% reduction	lb/hr
0	Pre-BART Protocol		1	25.9 (85)	NA - base	249.2	101.9	147.3	NA - base	5,733.5	NA - base	1,772.3
			1& 2	25.9 (85)	NA - base	465.3	190.3	275.0	NA - base	10,702.8	NA - base	3,594.7
1	Pre-BART Protocol	Presumptive BART [1]	1	25.9 (85)	0%	249.2	101.9	147.3	84%	902.0	42%	1,022.6
			1& 2	25.9 (85)	0%	465.3	190.3	275.0	83%	1,805.0	43%	2,046.3
2	Permit Limit	Presumptive BART	1	25.9 (85)	-141%	601.5	246.0	355.5	84%	902.0	42%	1,022.6
			1& 2	25.9 (85)	-1.6	1,203.7	492.3	711.4	83%	1,805.0	43%	2,046.3
3	Average Actual	Presumptive BART	1	25.9 (85)	28%	180.5	73.8	106.6	84%	902.0	42%	1,022.6
			1& 2	25.9 (85)	22%	361.1	147.7	213.4	83%	1,805.0	43%	2,046.3
4	Best Control	Presumptive BART	1	25.9 (85)	64%	90.2	36.9	53.3	84%	902.0	42%	1,022.6
			1& 2	25.9 (85)	61%	180.6	73.8	106.7	83%	1,805.0	43%	2,046.3

[1] Presumptive levels of 0.15 lb SO_2/MMBtu and 0.17 lb NOx/MMBtu were assumed for modeling purposes.

Table 3-5 PM Modeling, Year 2002

Scenario	Description			Visibility Impairment[1]													
					TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA			
	PM	SO_2/NOx	Units	Avg. PM Contr.	98th % Δ-dV	% PM_{10} [3]	PM_{10} Δ-dV Contr.	98th % Δ-dV	% PM_{10} [3]	PM_{10} Δ-dV Contr.	98th % Δ-dV	% PM_{10} [3]	PM_{10} Δ-dV Contr.	98th % Δ-dV	% PM_{10} [3]	PM_{10} Δ-dV Contr.
0	Pre-BART Protocol		1	0.022	2.559	0.75%	0.019	2.113	1.28%	0.027	1.703	1.03%	0.018	1.814	1.26%	0.023
			1& 2	0.034	4.475	0.73%	0.033	3.557	1.61%	0.057	3.039	0.99%	0.030	3.190	0.53%	0.017
1	Pre-BART Protocol	Presumptive BART [2]	1	0.019	0.749	3.48%	0.026	0.695	3.10%	0.022	0.586	3.16%	0.019	0.536	1.92%	0.010
			1& 2	0.045	1.434	3.27%	0.047	1.338	3.53%	0.047	1.129	5.91%	0.067	1.050	1.80%	0.019
2	Permit Limit	Presumptive BART	1	0.070	0.784	7.99%	0.063	0.731	11.72%	0.086	0.611	7.29%	0.045	0.578	14.93%	0.086
			1& 2	0.135	1.503	8.04%	0.121	1.402	11.81%	0.166	1.181	7.26%	0.086	1.125	14.85%	0.167
3	Average Actual	Presumptive BART	1	0.010	0.742	0.72%	0.005	0.689	2.26%	0.016	0.581	2.31%	0.013	0.533	1.40%	0.007
			1& 2	0.035	1.425	2.56%	0.036	1.328	2.76%	0.037	1.115	4.64%	0.052	1.046	1.40%	0.015
4	Best Control	Presumptive BART	1	0.009	0.733	1.29%	0.009	0.681	1.14%	0.008	0.570	2.32%	0.013	0.529	0.70%	0.004
			1& 2	0.017	1.408	1.29%	0.018	1.311	1.39%	0.018	1.090	2.38%	0.026	1.039	0.70%	0.007

[1] Year 2002 modeled only, to illustrate worst case year in modeling.
[2] Presumptive levels of 0.15 lb SO_2/MMBtu and 0.17 lb NOx/MMBtu were assumed for modeling purposes.
[3] Percentage attributed to PM emissions calculated from model output data (Appendix D).

3.6 Proposed BART for PM

Based on the above analysis and the visibility impacts found in Section 7.0, GRE is proposing the existing ESP and its current PM limit as BART for particulate emissions at Coal Creek's Unit 1 and Unit 2. Current actual emissions reflect a large degree of control and are below the current performance standard of 0.1 lb/MMBtu. A modification to the existing ESP or the retrofit of a baghouse is not cost effective on a dollar per ton basis[7], and additional controls will provide negligible improvement from a visibility standpoint.

[7] Comparisons of the cost guidelines from CAIR, NSPS, WRAP, EPA and court decisions indicates that a cost threshold of under $1500 per ton of pollutant removed is a reasonable estimate for BART (Appendix B).

4.0 Nitrogen Oxides (NOx) BART Analysis

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.

Coal Creek Station's NOx emissions are currently controlled to an average of 0.22 lb/MMBtu through the use of low NOx burners (LNB) with a level of separated overfire air (SOFA).

4.1 NOx Control Options

Table 4-1 lists the available retrofit NOx options for Coal Creek Units 1 and 2.

Table 4-1 Available NOx Control Technologies

NOx Control Options
Combustion Controls
• External Flue Gas Recirculation
• Overfire Air
• Low NOx Burners
Post Combustion Controls
• Selective Catalytic Reduction - High Dust - Low Dust
• Selective Non- Catalytic Reduction - NOxOUT®
• Low Temperature Oxidation - Tri-NOx® - LoTOx
• Non Selective Catalytic Reduction
• Novel Multi-pollutant Controls - Electro-Catalytic Oxidation - Pahlman Process

4.2 Eliminate Infeasible NOx Control Options

4.2.1 Combustion Controls

Various combustion controls exist for NOx reduction from combustion units. A few feasible examples of these controls include overfire air (OFA) and low NOx burners (LNB).

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 Units 1 and 2. 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 lignite-fired boilers and is primarily geared to thermal NOx reductions. 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.

OFA technology is currently used to control NOx emissions on both Coal Creek units. Based on engineering analyses[8] performed on Unit 1, additional levels of separated overfire air (SOFA) are a technically feasible option for further NOx reduction.

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

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[8] *TLN3 System Assessment and Recommendations for Lower NOx Operation*. Foster Wheeler North America Corporation. September 9, 2005 (Appendix F).

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 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 is currently used to control NOx emissions from both Coal Creek units. In combination with SOFA, LNB is a technically feasible option to further reduce emissions. Based on the currently achieved emission rates, reduction in the range of 25%-30% would be expected.

4.2.2 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 of such as vanadium pentoxide on a carrier such as titanium dioxide, and 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.

High-dust SCR (upstream of particulate control) applications typically required soot blowers for catalyst cleaning. Firing lignite coal results in a stream heavily laden with particulate matter containing catalyst poisons such as sodium. The catalyst plugging observed at the lignite-fired boiler at Coyote Station [9] was caused by materials which could not be cleaned by a soot blower system. Due to the likelihood of catalyst surface plugging caused by high sodium concentrations, a high-dust SCR is technically infeasible on both Units 1 and 2. A low-dust SCR (downstream of particulate control), would require reheat to bring the stream temperature back to the effective range after it is cooled for particulate removal, but is a technically feasible option for NOx reduction. Based on current NOx emissions, an SCR could provide additional reduction in the range of 70%-80%.

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 the participation of 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.

SNCR is a technically feasible NOx control option for Units 1 and 2. Based on the current level of NOx control, an emissions reduction of approximately 50% would be expected.

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[9] *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 G)

Low Temperature Oxidation (LTO)

The LTO system utilizes an oxidizing agent such as ozone to oxidize various pollutants including NOx. In the system, the 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 forming sodium nitrate (5) or calcium nitrate. The nitrates are removed from the scrubbing system and discharged to an appropriate water treatment system. Commercially available LTO systems include Tri-NOx® and LoTOx.

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

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

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

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

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

LTO systems represent a technically feasible control option for Units 1 and 2, 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:

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

$$2NaOH + 2NO_2 + \tfrac{1}{2} O_2 \rightarrow 2NaNO_3 + H_2O \qquad (2)$$

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 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, unburdened 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 this condition, 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:

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

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

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, making it infeasible to apply this technology to the lignite-fired boilers at Coal Creek.

Novel Multi-Pollutant Controls

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.

Both ECO and the Pahlman process technologies are still in the testing and development phase. They are therefore not currently considered commercially available and are not considered further.

4.3 Evaluate the Effectiveness of Feasible NOx Options

Based on the current degree of control being achieved on Units 1 and 2, Table 4-2 describes the expected emissions from each of the remaining feasible control options.

Table 4-2 Control Effectiveness of Technically Feasible NOx Control Options

Control Technology	Expected Control Efficiency	Controlled Emissions lb/MMBtu	Controlled Emissions ton/year
LTO	90%	0.022	556
SCR with Reheat	80%	0.043	1,111
SNCR	50%	0.108	2,779
Foster Wheeler SOFA/LNB Option 1	30%	0.15	3,877
Foster Wheeler SOFA/LNB Option 2	21%	0.17	4,394

4.4 Evaluate the Impacts of Feasible NOx Options

As illustrated above in Table 4-2, the five technically feasible options each provide a different level of control. The economic and environmental impacts are presented below.

4.4.1 Economic Impacts

Table 4-3 details the expected costs associated with each technology based on pre-BART historical baseline emissions, the EPA cost model and site specific information. As required by ASTM International designation C618-05, the presence of ammonia in the ash caused by the use of SNCR or SCR would make it ineligible for beneficial use. The cost for SNCR and SCR technologies includes the predicted ash sales revenue losses. The results of the engineering analysis performed by Foster Wheel presented two options with different levels of control for SOFA/LNB control. The detailed cost analysis for each technology is provided in Appendix A.

Table 4-3 NOx Control Cost Summary, per Unit Basis

Control Technology	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)	Incremental Control Cost ($/ton)
LTO	$44.33	$58.07	$11,610	$31,799
SCR with Reheat	$70.36	$40.40	$9,087	$19,862
SNCR	$6.16	$7.28	$2,621	$6,027
Foster Wheeler SOFA/LNB Option 1*	$5.26	$0.66	$395	$868
Foster Wheeler SOFA/LNB Option 2	$2.63	$0.34	$291	NA-Base

The incremental control cost listed in Table 4-3 represents the incremental value of each technology as compared to the technology with the next highest level of control. In this analysis, dominant controls are located on the least cost envelope, as illustrated graphically in Figure 4-1.

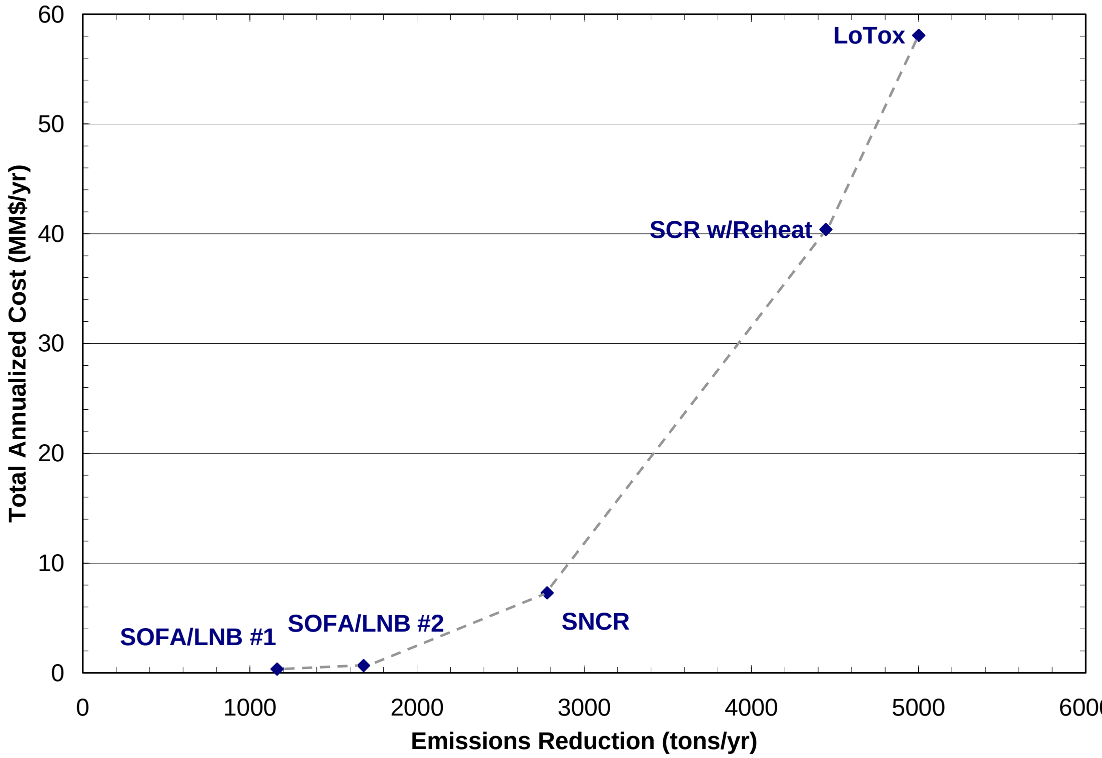

Figure 4-1 Incremental NOx Analysis The remaining feasible technologies are illustrated on the basis of annualized emission reduction in tons per year and total annualized cost in millions of dollars per year.

Based on the BART final rule and other similar regulatory programs like CAIR, cost-effective NOx controls are in the range of $1,300 to $1,800 per ton removed as

* Installation costs revised based on an updated Foster Wheeler proposal. The updated proposal is included in Appendix K.

illustrated in Appendix B. Accordingly, SNCR, SCR with reheat, and LTO should all be precluded from BART consideration on the basis of cost effectiveness. All three technologies represent significant capital investments that are not justified on a cost per ton or incremental cost basis.

4.4.2 Energy and Environmental Impacts

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

Table 4-4 NOx Control Technology Impacts Assessment

Control Option	Energy Impacts	Other Impacts
LTO	- The blower, circulation pump and wastewater discharge require additional electrical usage.	- Additional waste water generated by LTO technologies requires biotreatment.
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 larger natural gas line. - Ammonia slip concerns.
SNCR	- Minimal additional energy impacts.	- Ash would no longer be eligible for beneficial use options. Over $27 million has already been invested in the infrastructure for ash sales. Ash must be landfilled if beneficial use options are not available. - Ammonia slip concerns.
SOFA/LNB	- Minimal energy impacts.	- Potential for tube wastage.

4.5 Proposed BART for NOx

Based on the above analysis and the visibility impacts found in Section 7.0, GRE is proposing an additional level of separated overfire air (SOFA) as BART for NOx emissions at Coal Creek's Unit 1 and Unit 2. A comparison of the visibility modeling results for the two SOFA/LNB control options shows little difference in visibility improvement between the two. Regardless of this fact, the proposed BART will be the more stringent of the two options with a design emission rate of 0.15 lb/MMBtu. While this design emission rate may be achieved on a long term of annual average basis, a shorter term limit of 0.17 lb/MMBtu is required to account for potential variability due to operational conditions.

With tangential firing, the lateral impingement of the horizontally adjacent fuel and air streams produces a furnace vortex with a single flame envelope. The entire furnace acts as the burner; therefore, precise proportioning of fuel and air at each of the individual fuel and air admission points is not required. Locally fuel-rich or air-rich streams are mixed in passing through the furnace, resulting in complete combustion of the fuel. The furnace vortex produces a large amount of internal recirculation of bulk gas, which, couples with the longer residence time for burning, provides a combustion system inherently low in NOx production and virtually eliminates hydrocarbon and CO emissions.

Further reductions of NOx emissions are achieved through the use of close coupled and separated overfire air. Close coupled overfire air compartments are provided as extensions of the windboxes and the separated overfire air compartments are above the windboxes. Overfire reduces NOx formation by reducing the peak and bulk flame temperatures by extending the combustion zone and time necessary for fuel burnout. The close coupled overfire air is directed into the furnace through two elevations of separately tiled windbox registers and the separated overfire air is directed into the furnace through two additional elevations of registers that are separated above the main windbox. Optimum damper and tilt positions are established by field testing.

Current actual emissions reflect a large degree of control and are below the current permit limit of 5,104 lb/hr (0.85 lb/MMBtu) per unit on a 12-month rolling average. The additional level of SOFA/OFA presented in Foster Wheeler’s Option 2 represents a cost effective method of further controlling NOx emissions. As stated above, the installed SOFA will be designed to meet an emission rate of 0.15 lb/MMBtu, but a design basis cannot be directly translated into an operational limit. With consideration for operational variability and potential emission spikes, the proposed BART emissions limit for both Unit 1 and Unit 2 is 0.17 lb/MMBtu on a 30-day rolling average, which corresponds to the presumptive limit established by EPA. The revised Foster Wheeler proposal included in Appendix J states an emission guarantee of 0.17 lb/MMBtu. An optimization study will be performed after the implementation of the full scale coal dryers and the installation of the upgraded NOx control system to determine actual performance levels, but at this time, an emission limit lower than the vendor guarantee will not be proposed.

5.0 Sulfur Dioxide (SO_2) BART Analysis

5.1 SO_2 Control Options

Coal Creek Units 1 and 2 are currently controlled using wet flue gas desulfurization scrubbers that operate at a dry stack condition with approximately 27% of the flue gas bypassing the scrubber. The remaining 73% of the gas from each unit is routed through an existing four-module scrubber with a removal efficiency of approximately 94%. The overall control efficiency for each unit is approximately 68%. Based on the current removal efficiency, only systems that can achieve greater than 68% overall control efficiency are evaluated. Table 5-1 lists the available SO_2 control options for Coal Creek Units 1 and 2.

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.

5.2.1 Pre-Combustion Controls

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, but coal drying was explored and is a viable option. In this process, raw coal is crushed and screened to remove rocks and other impurities. Subsequently, the crushed coal is thermally processed to remove excess moisture. Coal drying is a technically feasible control option, and a full scale DOE project is beginning construction in the spring of 2007 at Coal Creek Station.

The lignite coal supplied to Coal Creek Station by the Falkirk Mining Company typically has a higher heating value of 6200 Btu/lb and a moisture content of 38%. A 75 ton/hour lignite drying system with a segregator for beneficiation of the lignite was designed and constructed in 2005. The drying system utilizes plant waste heat to process the coal at under 200ºF resulting in water evaporation with no additional volatiles production. The prototype dryer was built and tested to determine the final design for the full scale lignite coal drying demonstration project, beginning construction the spring of 2007. The major benefit of drying lignite is a decrease in the lignite moisture content which results in a higher boiler efficiency and a reduction in flue gas volume of up to 30%. Other benefits include reduced SO_2, NOx, CO_2 and Hg emissions (roughly 5%), reduced station power consumption by about 18%, and reduced water used by about 2.5%.

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 powder of slurry, and 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.

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.

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 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%. It should be noted that the maximum expected removal efficiency of this technology (70%) is very close to the existing scrubber removal of 68% for both units. While dry sorbent injection is a technically feasible retrofit option, it will provide only minimal improvement over the existing removal efficiency.

Spray Dry Absorption

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 ($CaSO_3 \cdot 2H_2O$) and calcium sulfate ($CaSO_4$) within the droplets as illustrated by equations 1 and 2 below.

$$SO_2 + CaO + 1/2\ H_2O \rightarrow CaSO_3 \cdot 1/2\ H_2O \qquad (1)$$

$$CaSO_3 + \tfrac{1}{2}O_2 + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O \qquad (2)$$

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. Spray dryer absorption control efficiency is typically in the 70% to 90% range. A spray dry scrubber is a technically feasible retrofit control option.

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. Similarly to the chemistry illustrated above for spray dry absorption, the SO_2 in the gas stream reacts with the lime or limestone slurry to form calcium sulfite ($CaSO_3 \cdot 2H_2O$) and calcium sulfate ($CaSO_4$). Wet lime scrubbing is capable of achieving 98+% control. Wet scrubbing is currently used on approximately 73% of exhaust gas at both Coal Creek units. A new replacement wet scrubber is a technically feasible retrofit option. Modifications to the existing scrubbers in order to improve its capture and/or control efficiency are also technically feasible. Both options, entire replacement of and upgrades to the existing scrubbers, are considered separately in this evaluation.

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 and finally exits through the stack.

This technology has been considered for Coal Creek as a potential method for treating the current scrubber bypass streams from Units 1 and 2. TurboSorp® could provide the benefits of a dry stack and additional particulate control. A booster fan would be required at the outlet to control the gas flow rate, and 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, but TurboSorp® has not been commercially demonstrated in the United States. Though not considered technically feasible due to its lack of commercial availability at this time, TurboSorp® may be considered further in future control technology assessments.

Additional novel controls including ECO and the Pahlman process for NOx and SO_2 are included in Section 4.2.2.

5.3 Evaluate the Effectiveness of Feasible SO_2 Options

Based on the degree of SO_2 emissions control currently achieved at Units 1 and 2, Table 5-2 describes the expected emissions from each of the remaining feasible control options.

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

Control Technology	Expected Control Efficiency	Controlled Emissions lb/MMBtu	Controlled Emissions ton/year
Scrubber Replacement[10]	95%	0.106	2,735.7
Scrubber Modification + Coal Drying	94%	0.128	3,310.2
Spray Dry Baghouse	90.0%	0.212	5,471.4
Existing Scrubber + Coal Dryer	83.1%	0.358	9,263.1
DSI Baghouse	70.0%	0.635	16,414.3

With respect to scrubber modifications, a variety of upgrades have been evaluated for the Units 1 and 2 scrubbers. They range in efficiency from 93.9% to 96.0% as illustrated in Appendix I, and include options that will meet the presumptive SO_2 limit of 0.15 lb/MMBtu. Many of the technically feasible options require the replacement or upgrade of the stacks due to the demands of wet stack conditions. A wet stack is a technically feasible option as illustrated in Appendix E, and the evaluated modifications represent both wet and dry stack options. In addition to being evaluated individually, coal drying was incorporated into some of the evaluated scrubber modification options.Full scale coal drying ~~is~~ will be implemented (see Appendix K for detailed analysis report), and as a results, the volume of the flue gas will be significantly reduced, thus requiring fewer modifications to accommodate the currently bypassed gas flow. Appendix I includes information on scrubber modification options provided by URS Corporation. Other modification options include:

- Replacement/addition of spray headers
- Replacement/addition of nozzles
- Installation of trays or liquid distribution rings (LDRs)
- Addition of a fifth scrubber module
- Expansion of the existing absorbers

Treatment of the existing bypass with a separate control was also considered. All of the modifications will require new mist eliminators in the absorbers and all wet scrubbing options will necessitate stack modifications. These options and the applicable combinations have been evaluated individually, and the economic details are included in

[10] *Survey of State-of-the-Art Emissions Control Systems* (1010762) published in 2006 by EPRI states that new absorbers can achieve control efficiencies of 98+%. However, given the type of coal and necessary retrofit the existing plant, 95% control could be expected from a new scrubber at Coal Creek. (See 2/23/07 letter for additional justification).

Appendix A. For the sake of clarity, the range of control efficiencies and impacts of the eight evaluated modifications are referred to under the classification of "scrubber modifications."

A number of operational variables can affect the performance of SO_2 control technologies. Gas velocities, duct and stack geometry all play a role in determining deposition in the stack and scrubber modules, resulting in varied removal efficiencies. As a result of existing plant configurations, retrofit scrubber modifications may not achieve the optimum velocities and geometries. Therefore, the control efficiencies and emission rates presented above are design rates only and represent best case operational expectations. Coal sulfur content[11], equipment reliability and maintenance will also play a large part in the control of actual emissions.

Due to the fact that Coal Creek Station is a mine-mouth plant, there are limited opportunities for coal blending. SO_2 emissions will depend heavily on mine operations which introduces a high degree of variability. While coal sulfur content may seem to vary little over short periods of time, a change in mining area could produce a drastic and immediate change. On an annual basis, the average may remain low if only one or two months out of twelve have a high sulfur content, but 30-day rolling average limits must account for the potential of a high sulfur content on the short term basis. This variability must be considered when determining an appropriate emission limit. The technology evaluations presented in Section 5.4 are based on recent emission inventories and design removal efficiencies. When compared to more historical or future predicted coal sulfur contents for Falkirk Mine, the recent sulfur content has been in the mid range. Any future SO_2 emission limit needs to account for the higher end of the expected sulfur content, and realistic operational conditions that can result in removal efficiencies lower than the design basis.

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[12].

[11] See section 6.2 and Appendix C for further coal sulfur content and emission rate documentation.
[12] Cost estimates do not represent detailed engineering estimates. Based on market prices and site specific conditions, cost can vary by 20+%.

Table 5-3 SO_2 Control Cost Summary, per Unit Basis

Control Technology	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)	Incremental Control Cost ($/ton)
Scrubber Replacement	$204.72	$30.76	$2,114	$33,498
Scrubber Modification + Coal Drying*	$76.22	$11.52	$824	$281
Spray Dry Baghouse	$181.18	$29.22	$2,472	Inferior
Existing Scrubber + Coal Dryer	$71.20	$9.84	$1,226	NA-Base
DSI Baghouse	$48.75	$12.52	$14,313	Inferior

The incremental control costs listed in Table 5-3 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 5-1.

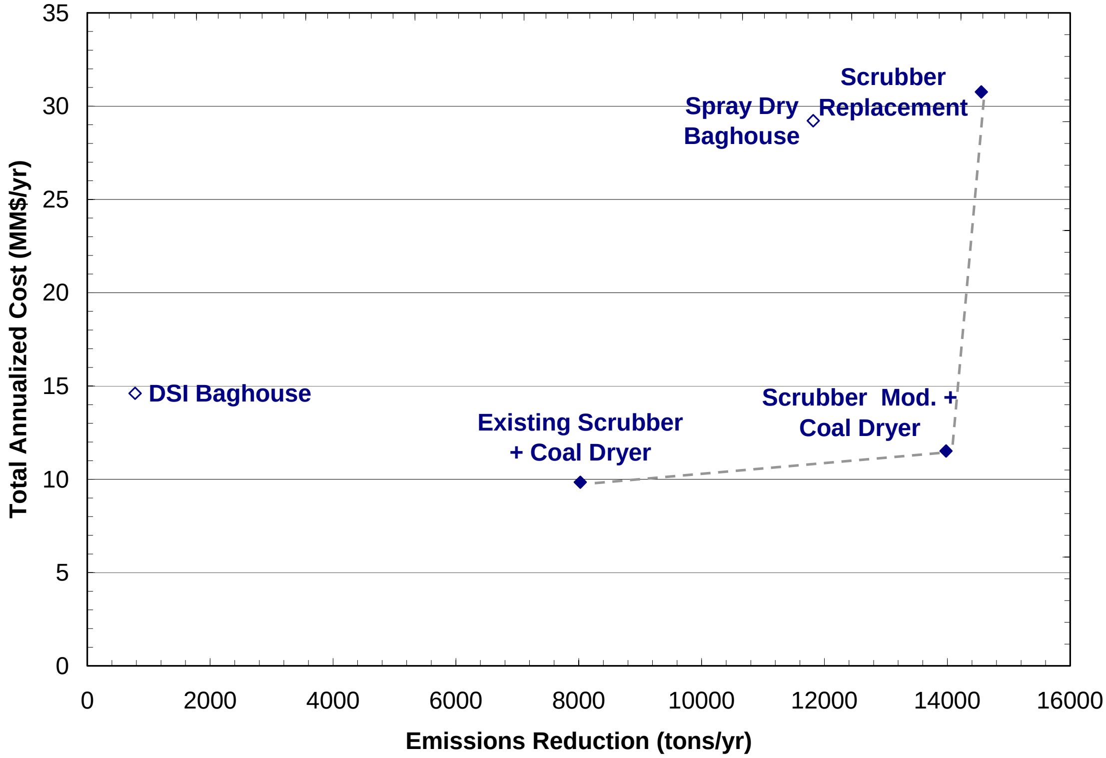

Figure 5-1 Incremental SO_2 Analysis The remaining feasible technologies are illustrated on the basis of emission reduction in tons per year and total cost in millions of dollars per year. Dominant and inferior controls are represented by darkened or empty diamonds respectively. The average cost and emission reduction are show for scrubber modifications.

* Cost of options involving coal drying revised to reflect the installed capital and annualized O&M costs of full scale dryer operation.

Based on the BART final rule and other similar regulatory programs like CAIR, cost-effective SO_2 controls are in the range of $1,000 to $1,300 per ton removed as illustrated in Appendix B. Accordingly, the retrofit options of DSI baghouse, spray dry baghouse, and scrubber replacement should be precluded from BART consideration on the basis of both average cost effectiveness and incremental cost effectiveness. All three technologies represent significant capital investments that are not justified on a cost per ton or incremental cost basis.

5.4.2 Energy and Environmental Impacts

The energy and non-air quality impacts for scrubber replacement and modification, dry scrubbing options, and coal drying are presented in Table 5-4.

Table 5-4 SO_2 Control Technology Impacts Analysis

Control Option	Energy Impacts	Other Impacts
Scrubber Replacement	- Additional blower capacity requires increased energy use.	- Extensive process downtime for installation, requiring replacement power. - Stack modifications required. - Additional water consumption and wastewater generation.
Scrubber Modification with Coal Drying	- Minimal energy impacts.	- Stack modifications required. - Outage/replacement power required for installation. - Additional water consumption and wastewater generation.
Dry Scrubbing (Spray Dry/DSI Baghouse)	- Additional blower capacity requires increased energy use.	- Extensive process downtime for installation, requiring replacement power[13].

5.5 Proposed BART for SO_2

Based on the above analysis and the visibility impacts found in Section 7.0**,** GRE is proposing to eliminate the current bypass and scrub 100% of the flue gas stream, with the potential to maintain wet stack operation. This scenario results in a proposed BART emission limit of 0.15 lb/MMBtu station wide cap per unit on a 30-day rolling average period. Compliance with the proposed BART limit will be demonstrated using the existing continuous emissions monitoring system (CEMS).

The proposed emission limit is intended to account for a short term range of operational conditions and coal sulfur content. On an annual basis, it is likely that both Units will operate below the 0.15 lb/MMBtu limit. The visibility modeling results support the proposed BART on dollar per deciview and total deciview improvement bases. Section 7.3 shows that aside from the addition of a new scrubber which has been ruled out by the factors described in Section 5.4, the proposed BART is the most cost effective

[13] Replacement power is only required for fully retrofit dry controls designed to handle the full flue gas flow. Control options designed to treat only the current scrubber bypass (including TurboSorp) will not have this requirement.

option and provides a large degree of visibility improvement. For the year 2002, the 98th percentile total visibility improvement for the two stations combined will be over 1.8 Δ-dV compared to baseline.

It must be noted that while modifications to the existing scrubber modules can achieve control efficiencies near what is expected from a newly designed scrubber, a number of operational differences still exist. New scrubbers have a great deal of redundancy and flexibility built into their design. For example, multiple levels of spray headers allow operators to put individual spray headers into service or take them out of service as conditions dictate. In contrast, the Coal Creek Station scrubbers have fewer redundancies and are therefore more likely to experience emission spikes caused by operational configuration.

Coal Creek Station requires room for operational changes that may occur between outages. The scrubbers are designed to minimize operational upsets, however all control technologies, including scrubbers, can experience operational degradation between outage opportunities. Examples such as scaling of the mist eliminators, nozzle breakage, and plugging or scaling of spray pumps and lime slurry equipment can all result in a removal efficiency less than the design removal. Additionally, Coal Creek scrubber modification design will be limited by space constraints of the existing module and building, namely, no footprint exists for additional spray pumps. These factors indicate that while the existing modules will be upgraded, their design and resulting operation will not be the same as would typically be expected from a new scrubber. This implies that a design emission rate cannot be directly translated into an operational emission limit.

Based on the results of the coal dryer study (Appendix J), the final SO_2 control strategy for Coal Creek will include coal drying in addition to the installation of trays or new LDRs and high flow MEs. GRE's goal is to meet or operate below BART presumptive levels while maintaining the highest degree of operational flexibility. In an effort to utilize the best available technology at the time of purchase, GRE will continue to evaluate which technology will provide the requisite removal efficiencies to meet the BART presumptive levels and provide GRE with greatest operational flexibility. Coal drying will provide the benefit of reducing the coal moisture content by about 8%. A decreased flue gas volume coupled with the separation of the heavier material in the 1st stage of the drying process has provided evidence of additional pollutant reductions. (CO_2, NOx, Hg) These numbers have been extrapolated from the prototype experiment but the full scale demonstration project will provide the final refined values.

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 Units 1 and 2 at Coal Creek Station. 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. Coal Creek's Title V permit includes a particulate limit for Units 1 and 2 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 1or 2, 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 Coal Creek 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 ($CaSO_3$•$2H_2O$) 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 presents a lower degree of control than will be achieved by the proposed SO_2 BART controls for Coal Creek Station.

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 ($CaSO_3$•$2H_2O$) and calcium sulfate ($CaSO_4$). Coal Creek Station currently uses wet scrubbing for SO_2 control, and modifications to the existing scrubber system are the proposed BART control. Coal Creek's scrubber modifications will also provide a corresponding reduction to CPM.

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 0.29% to 1.21% for Coal Creek Station with an average of 0.63%. 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[14].)

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.

[14] 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[17,18]

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[15] to filterable particulates as measured by EPA Method 5. It is also reflective of recent BACT permit limits[16], 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.

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[15] 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.

[16] CPM information sources for CFB boiler emission limit determinations. Email from Tom Bachman <tbachman@nd.gov> of NDDH, 15 June 2006.

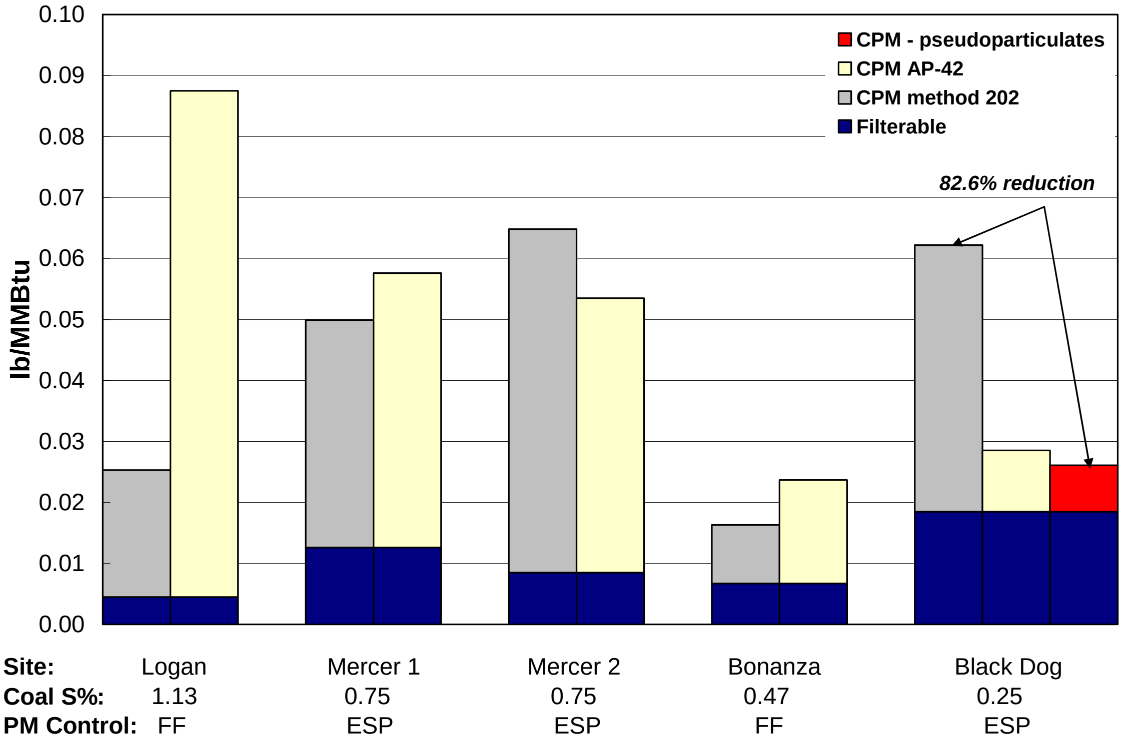

Figure 6-1. Comparison of Method 202 and AP-42. Breakdown of particulate matter is illustrated for 5 power plants[17,18].

Table 6.2 provides CPM estimates using Method 202 and also attempts to correct for pseudo-particulate.

Table 6-3 Annual CPM Emissions Estimate Based on Modified 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)
0.03	799.0 tpy[19]	0.12	0.02	3,196.0 tpy	556.1

6.4 *Evaluate the Impacts of Feasible CPM Options*

Uncontrolled SO_2 emissions for a single unit are calculated to be 56,435 tons per year. As illustrated in Table 6-3 CPM emissions are estimated at approximately

[17] "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.
[18] "Measurement of Condensible Particulate Matter: A Review of Alternatives to EPA Method 202, EPRI, Palo Alto, CA: 1998. Report TR-111327.
[19] Annual emissions are based on past actual operations for Coal Creek Units 1 and 2. 8,856 annual operating hours with a utilization rate of 100%. (0.03 lb/MMBtu x 6019 MMBtu/hr x 8856 hr/yr/2000 = 799.0 tpy)

3,196 tons per year, only 5.7% of the SO_2 emissions. If corrected for pseudo-particulates, CPM emissions may be as low as 556.1 tons per year, or only 1% of the SO_2 emissions. Detailed economic and environmental impacts for the available control technologies have been presented in Section 5.4. With either the corrected or uncorrected value, the incorporation of CPM 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 (0.12 lb/MMBtu) estimated at 4 times filterable PM (0.03 lb/MMBtu), both units are operating only slightly above the filterable emission rate (0.1 lb/MMBtu), which has been modeled and contributes only 0.06 Δ-dV per unit 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. A comparison of Coal Creek's Unit 1 Method 5 results (0.03 lb/MMBtu) and permitted emission rate (0.1 lb/MMBtu) showed a 0.06 Δ-dV 98th percentile addition to visibility impairment. As stated above, it is assumed that total particulate emissions (uncorrected condensable + filterable) will be 5 times the filterable contribution, or in this case, 0.15 lb/MMBtu, given the uncertainties with the methodologies. Extrapolation from the existing data points indicates that the total visibility impairment attributed to CPM is less than 0.08 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. Coal Creek Station will reduce SAM emissions by as much as 98% through proposed scrubber improvements.

7.0 Visibility Impacts Analysis

As indicated in EPA's final BART guidance[20], states are required to consider the degree of visibility improvement resulting from the retrofit technology in combination with other factors, such as economics and technical feasibility, when determining BART for an individual source.

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 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[21] 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, [22] 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 Coal Creek Station as a BART eligible source[23] that does cause or contribute to visibility impairment at the four North Dakota Class I areas. In addition to establishing whether or not a source contributes to impairment on the 98th 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 dV. Finally, the determination of reasonable progress along the predicted glide path can be assessed using the 90th percentile prediction.

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

7.2 Predicting 24-Hour Maximum Emission Rates

Pursuant to verbal guidance from NDDH staff and to be 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 basis.

The highest daily emissions for PM/PM_{10} were maintained from pre-BART modeling. The highest predicted NOx emission rate is based on pre-BART average emission rates and highest day variability. The pre-BART NOx modeled emission rate (0.29 lb/MMBtu) was approximately 30% higher than the average NOx emissions from historical emission inventories (0.22 lb/MMBtu). As illustrated in , the highest expected emission rate for the proposed BART control of an additional level of SOFA was assessed by adding a 20% variability factor to the design emission rate of 0.15 lb/MMBtu.

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

Control Strategy	Design Rate (lb/MMBtu)	30-day Rolling Emission Rate (lb/MMBtu)	24-hour Max. Emission Rate		Basis[24]
			Unit 1 (lb/hr)	Units 1 & 2 (lb/hr)	
Pre-BART Baseline	--	--	1,772.3	3,594.7	Actual emissions data from 2000 – 2002. Represents the highest NOx emission rate per calendar day.
Foster Wheeler SOFA/LNB Option 2	0.17	0.19	1,227.6	2,456.5	Design emission rate with 10% variability for 30-day rolling and 20% variability for 24-hr max.
Foster Wheeler SOFA/LNB Option 1	0.15	0.17	1,083.1	2,167.5	
SNCR	0.11	0.12	776.2	1,553.4	
SCR with Reheat	0.04	0.05	310.5	621.4	
LTO	0.02	0.02	155.2	310.7	

[24] Emission rates for Unit 1 calculated using 6,015 MMBtu/hr rating. Unit 1 & 2 emissions use 12,037 MMBtu/hr combined rating.

SO_2 emission rates are highly dependant on coal sulfur content. Accordingly, an analysis of past actual and future predicted sulfur content is used to determine expected SO_2 emission rates. Figure 7-1 indicates that 2.6 lb/MMBtu is the maximum expected SO_2 emission rate with respect to 30- day block averages.

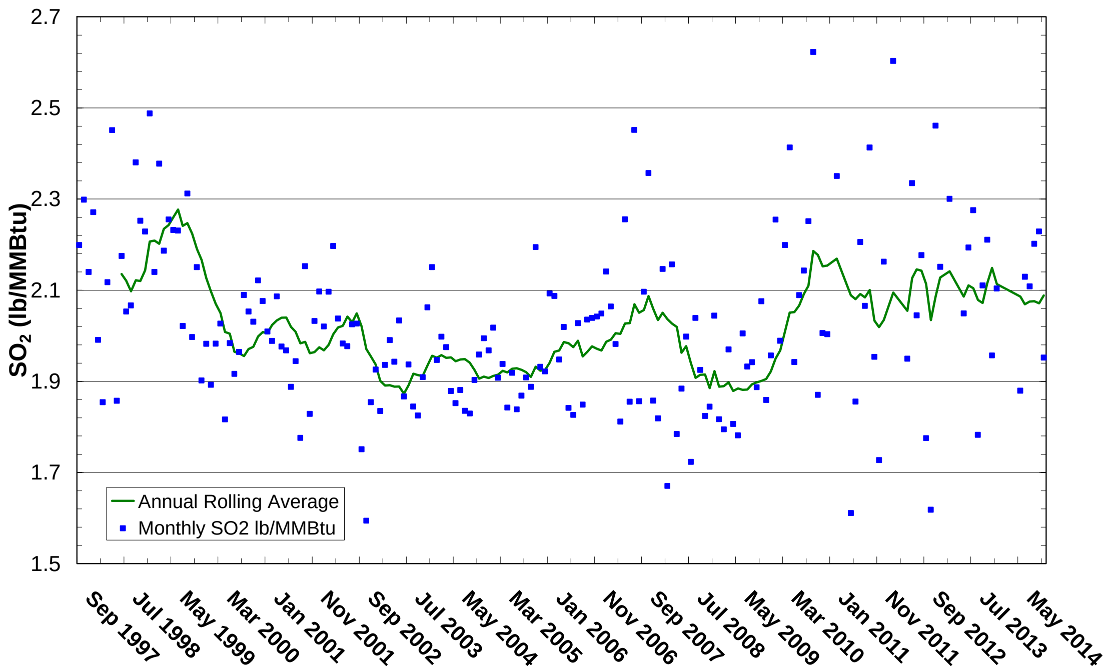

Figure 7-1 Past Actual and Future Predicted Monthly lb SO_2/MMBtu. Coal Creek sampling data is used to determine the 30-day block monthly average sulfur content from 1997 through 2006 and the Falkirk Mine Plan provides monthly predicting for future sulfur content from 2006 through 2014.

A statistical comparison of 30-day block and 30-day rolling past actual data (Appendix C) demonstrates that 14% variability should be used to determine a rolling emission rate based on a block average. This information, in combination with the design emission rates for both a new scrubber and scrubber modifications[25] is used to establish the 30-day rolling emission rates.

Since the SO_2 BART solution will be some modification of the existing scrubber, it is logical to utilize existing operational and maintenance parameters to predict the highest daily emissions. The scrubber is currently cleaned once every 7 days for a period of 4 hours during which time emissions are approximately 1.0 lb/MMBtu. Figure 7-2 illustrates the post-BART operational pattern that will be required to maintain 30-day rolling average emissions of 0.15 lb/MMBtu under current scrubber cleaning conditions. This indicates that under normal operation, the scrubber will be performing below the proposed limit of 0.15 lb/MMBtu.

[25] SO_2 modeling was performed for scrubber replacement and scrubber modifications only because scrubber replacement is the only evaluated SO_2 control which will provide lower emissions than the proposed BART control.

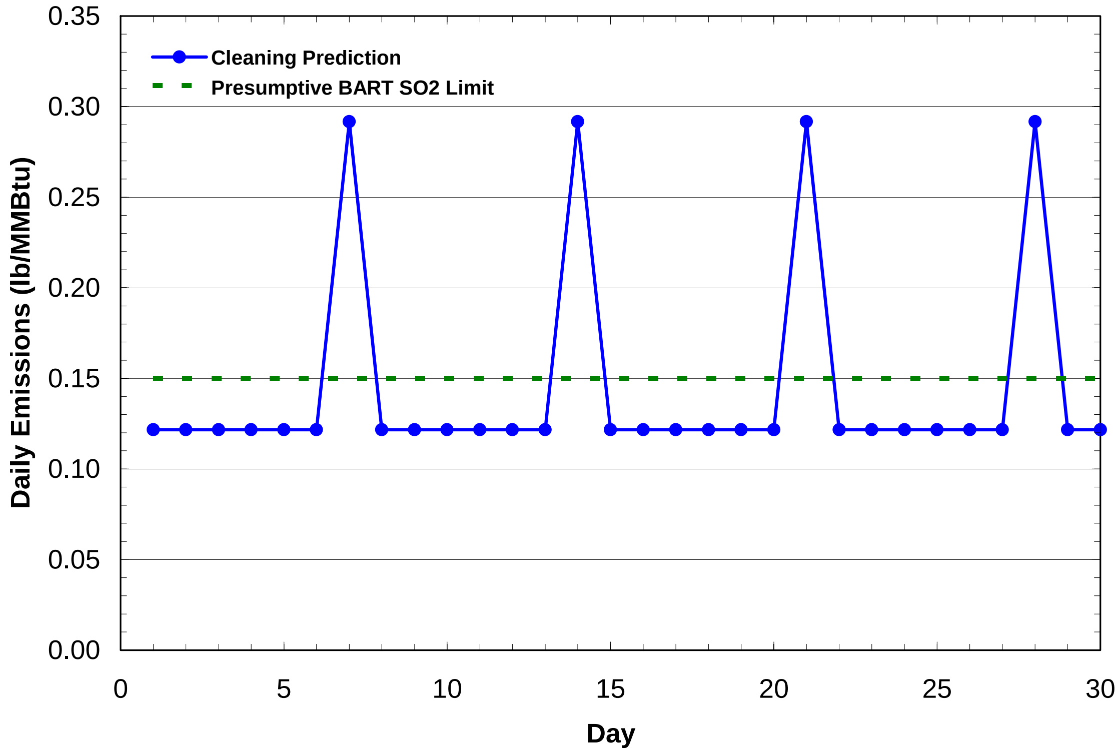

Figure 7-2 Maximum SO_2 Emission Prediction Emissions required to maintain 0.15lb/MMBtu on a 30 day rolling average based on current scrubber maintenance procedures.

A 70% variability was added to the 30-day rolling emission rate for a new scrubber to predict the 24-hour maximum emission rate. This is an engineering estimate based on a comparison of Coal Creek's pre-BART actual annual emissions and 24-hour maximum emissions. Table 7-2 presents a summary of SO_2 emission rates.

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

Control Strategy	Design Reduction	30-day Rolling Emission Rate (lb/MMBtu)	24-hour Maximum Emission Rate Unit 1 (lb/hr)	24-hour Maximum Emission Rate Unit 1 & 2 (lb/hr)	Basis
Pre-BART Baseline	--	--	5,733.5	10,702.8	Actual emissions data from 2000 – 2002. Represents the highest SO_2 emission rate per calendar day.
Scrubber Modification	95.1%[26]	0.06	1,756.4	3,514.8	Resign reduction at 2.6 lb/MMBtu block 30-day sulfur content + 14% variability for 30-day rolling. Individual methods for determining 24-hour max emissions are described above.
Scrubber Replacement	98.0%	0.15	610.8	1,222.4	

Table 7-3 describes the pre and post-BART model input parameters. Other stack parameters such as exit temperature, height, elevation and diameter were not changed and can be found in the protocol[21].

[26] Average percent reduction for evaluated scrubber modifications.

Table 7-3 Visibility Modeling Parameters

Scenario	Description			Emission Rate Input								
				Stack Velocity	PM_{10}		$PM_{2.5}$ (fine)	PM (coarse)	SO_2		NOx	
	SO_2	NOx	Units	m/s (ft/s)	% reduction	lb/hr	lb/hr	lb/hr	% reduction	lb/hr	% reduction	lb/hr
0	Pre-BART Protocol		1	25.9 (85)	NA - base	249.2	101.9	147.3	NA - base	5733.5	NA - base	1772.3
			1& 2	25.9 (85)	NA - base	465.3	190.3	275.0	NA - base	10702.8	NA - base	3594.7
1	Scrubber Modifications	SOFA/LNB #2	1	16.8 (55)	0%	249.2	101.9	147.3	69%	1756.4	31%	1227.6
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	67%	3514.8	32%	2456.5
2	Scrubber Modifications	SOFA/LNB #1	1	16.8 (55)	0%	249.2	101.9	147.3	69%	1756.4	39%	1083.1
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	67%	3514.8	40%	2167.5
3	Scrubber Modifications	SNCR	1	16.8 (55)	0%	249.2	101.9	147.3	69%	1756.4	56%	776.2
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	67%	3514.8	57%	1553.4
4	Scrubber Modifications	SCR	1	16.8 (55)	0%	249.2	101.9	147.3	69%	1756.4	82%	310.5
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	67%	3514.8	83%	621.4
5	Scrubber Modifications	LTO	1	16.8 (55)	0%	249.2	101.9	147.3	69%	1756.4	91%	155.2
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	67%	3514.8	91%	310.7
6	New Scrubber	SOFA/LNB #2	1	16.8 (55)	0%	249.2	101.9	147.3	89%	610.8	31%	1227.6
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	89%	1222.4	32%	2456.5
7	New Scrubber	SOFA/LNB #1	1	16.8 (55)	0%	249.2	101.9	147.3	89%	610.8	39%	1083.1
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	89%	1222.4	40%	2167.5
8	New Scrubber	SNCR	1	16.8 (55)	0%	249.2	101.9	147.3	89%	610.8	56%	776.2
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	89%	1222.4	57%	1553.4
9	New Scrubber	SCR	1	16.8 (55)	0%	249.2	101.9	147.3	89%	610.8	82%	310.5
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	89%	1222.4	83%	621.4
10	New Scrubber	LTO	1	16.8 (55)	0%	249.2	101.9	147.3	89%	610.8	91%	155.2
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	89%	1222.4	91%	310.7

7.3 Modeled Results

Visibility impairment was modeled using the meteorological data for the years 2000, 2001 and 2002 for the predicted post-BART emission scenario. To illustrate the individual in cumulative visibility impacts, Unit 1 alone and Units 1 and 2 in combination were modeled. As indicated by the results, reaction chemistry caused by limited background atmospheric ammonia results in a Δ-dV reduction for Units 1 and 2 together that is less than double the dV reduction for Unit 1 alone. Results for the 90th, 98th and number of days above 0.5 dV at Lostwood Wilderness Area (WA) and Theodore Roosevelt National Park (TRNP) North, South and Elkhorn Ranch units are included in
Table 7-4 through Table 7-6. Additionally, Figure 7-3 illustrates scenarios 1 through 15 on a $/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 7-4 Year 2000 Modeling Results

	Description				Visibility Impairment											
					TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
Scenario	SO_2	NOx	Units	Average Improv-ement [1]	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 Protocol		1	--	24	0.299	1.229	21	0.318	0.941	18	0.212	0.777	37	0.503	1.183
			1& 2	--	41	0.553	2.176	41	0.586	1.836	35	0.401	1.391	58	0.945	2.157
1	Scrubber Modifications	SOFA/LNB #2	1	59%	7	0.125	0.494	6	0.124	0.446	2	0.088	0.314	7	0.215	0.499
			1& 2	78%	7	0.125	0.494	6	0.124	0.446	2	0.088	0.314	7	0.215	0.499
2	Scrubber Modifications	SOFA/LNB #1	1	61%	7	0.119	0.467	6	0.118	0.416	2	0.082	0.300	6	0.207	0.469
			1& 2	79%	7	0.119	0.467	6	0.118	0.416	2	0.082	0.300	6	0.207	0.469
3	Scrubber Modifications	SNCR	1	65%	6	0.106	0.410	6	0.105	0.352	2	0.072	0.270	4	0.180	0.417
			1& 2	81%	6	0.106	0.410	6	0.105	0.352	2	0.072	0.270	4	0.180	0.417
4	Scrubber Modifications	SCR	1	71%	6	0.081	0.338	4	0.097	0.255	2	0.067	0.224	3	0.139	0.371
			1& 2	84%	6	0.081	0.338	4	0.097	0.255	2	0.067	0.224	3	0.139	0.371
5	Scrubber Modifications	LoTOx	1	73%	5	0.073	0.296	4	0.095	0.229	2	0.057	0.220	3	0.128	0.341
			1& 2	86%	5	0.073	0.296	4	0.095	0.229	2	0.057	0.220	3	0.128	0.341
6	New Scrubber	SOFA/LNB #2	1	75%	5	0.081	0.328	3	0.072	0.326	2	0.053	0.186	1	0.134	0.336
			1& 2	86%	5	0.081	0.328	3	0.072	0.326	2	0.053	0.186	1	0.134	0.336
7	New Scrubber	SOFA/LNB #1	1	77%	4	0.076	0.301	2	0.066	0.296	2	0.049	0.174	1	0.124	0.306
			1& 2	87%	4	0.076	0.301	2	0.066	0.296	2	0.049	0.174	1	0.124	0.306
8	New Scrubber	SNCR	1	80%	2	0.062	0.243	1	0.055	0.233	1	0.044	0.147	1	0.106	0.246
			1& 2	89%	2	0.062	0.243	1	0.055	0.233	1	0.044	0.147	1	0.106	0.246
9	New Scrubber	SCR	1	86%	0	0.041	0.157	0	0.042	0.138	0	0.029	0.103	1	0.069	0.166
			1& 2	93%	0	0.041	0.157	0	0.042	0.138	0	0.029	0.103	1	0.069	0.166
10	New Scrubber	LoTOx	1	88%	0	0.034	0.141	0	0.038	0.105	0	0.026	0.086	0	0.060	0.145
			1& 2	94%	0	0.034	0.141	0	0.038	0.105	0	0.026	0.086	0	0.060	0.145

[1] Average improvement represents the 90^{th} percentile comparison to the base case (Scenario 0) averaged for the 4 Class 1 areas.

Table 7-5 Year 2001 Modeling Results

	Description				Visibility Impairment											
					TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
Scenario	SO_2	NOx	Units	Average Improv-ement [1]	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 Protocol		1	--	21	0.251	1.209	27	0.372	1.154	16	0.192	1.056	40	0.503	1.183
			1& 2	--	34	0.466	2.181	46	0.694	2.094	27	0.365	1.949	56	0.945	2.157
1	Scrubber Modifications	SOFA/LNB #2	1	58%	8	0.116	0.509	9	0.142	0.547	8	0.076	0.505	21	0.215	0.499
			1& 2	56%	19	0.230	0.986	25	0.282	1.069	14	0.151	0.984	34	0.215	0.499
2	Scrubber Modifications	SOFA/LNB #1	1	60%	7	0.108	0.482	8	0.136	0.512	6	0.076	0.473	18	0.207	0.469
			1& 2	58%	19	0.214	0.936	24	0.270	1.002	13	0.151	0.923	33	0.207	0.469
3	Scrubber Modifications	SNCR	1	64%	6	0.096	0.437	6	0.127	0.436	4	0.069	0.405	15	0.180	0.417
			1& 2	62%	18	0.194	0.854	20	0.253	0.858	12	0.137	0.793	31	0.180	0.417
4	Scrubber Modifications	SCR	1	70%	2	0.075	0.373	5	0.106	0.353	2	0.058	0.319	13	0.139	0.371
			1& 2	69%	16	0.150	0.730	16	0.212	0.693	11	0.114	0.625	28	0.139	0.371
5	Scrubber Modifications	LoTOx	1	72%	2	0.070	0.356	5	0.101	0.333	1	0.056	0.283	13	0.128	0.341
			1& 2	70%	13	0.139	0.700	15	0.202	0.656	10	0.110	0.557	25	0.128	0.341
6	New Scrubber	SOFA/LNB #2	1	76%	2	0.062	0.340	3	0.079	0.412	1	0.039	0.309	12	0.134	0.336
			1& 2	75%	15	0.123	0.668	13	0.156	0.811	9	0.077	0.602	23	0.134	0.336
7	New Scrubber	SOFA/LNB #1	1	77%	1	0.062	0.310	2	0.075	0.376	1	0.038	0.294	9	0.124	0.306
			1& 2	76%	11	0.123	0.609	12	0.149	0.741	8	0.076	0.573	23	0.124	0.306
8	New Scrubber	SNCR	1	81%	1	0.054	0.248	2	0.069	0.299	1	0.032	0.259	7	0.106	0.246
			1& 2	79%	6	0.108	0.484	9	0.136	0.592	8	0.064	0.509	18	0.106	0.246
9	New Scrubber	SCR	1	86%	0	0.037	0.170	1	0.048	0.184	0	0.027	0.157	5	0.069	0.166
			1& 2	85%	2	0.074	0.335	5	0.098	0.365	1	0.053	0.311	12	0.069	0.166
10	New Scrubber	LoTOx	1	88%	0	0.031	0.149	0	0.044	0.147	0	0.022	0.123	4	0.060	0.145
			1& 2	87%	1	0.062	0.294	5	0.087	0.290	1	0.044	0.242	10	0.060	0.145

[1] Average improvement represents the 90^{th} percentile comparison to the base case (Scenario 0) averaged for the 4 Class 1 areas.

Table 7-6 Year 2002 Modeling Results

Scenario	Description			Average Improv-ement [1]	Visibility Impairment											
					TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
	SO_2	NOx	Units		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 Protocol		1	--	38	0.540	2.559	30	0.385	2.113	23	0.310	1.703	32	0.385	1.814
			1& 2	--	50	0.971	4.475	45	0.706	3.557	42	0.581	3.039	45	0.707	3.190
1	Scrubber Modifications	SOFA/LNB #2	1	57%	22	0.219	1.181	15	0.158	0.987	12	0.136	0.789	13	0.178	0.832
			1& 2	54%	32	0.433	2.218	26	0.313	1.880	18	0.269	1.524	26	0.350	1.601
2	Scrubber Modifications	SOFA/LNB #1	1	59%	20	0.207	1.140	15	0.151	0.918	12	0.129	0.746	13	0.165	0.783
			1& 2	56%	32	0.410	2.145	26	0.298	1.755	18	0.256	1.443	25	0.325	1.510
3	Scrubber Modifications	SNCR	1	64%	20	0.186	1.052	14	0.131	0.813	11	0.118	0.654	11	0.141	0.680
			1& 2	61%	30	0.371	1.991	24	0.260	1.536	17	0.234	1.271	23	0.279	1.318
4	Scrubber Modifications	SCR	1	70%	13	0.160	0.799	11	0.121	0.677	8	0.090	0.515	10	0.114	0.569
			1& 2	68%	25	0.316	1.537	17	0.239	1.290	14	0.180	1.006	23	0.224	1.105
5	Scrubber Modifications	LoTOx	1	72%	11	0.140	0.706	8	0.119	0.632	7	0.084	0.468	8	0.106	0.510
			1& 2	70%	23	0.281	1.364	17	0.235	1.206	14	0.167	0.917	17	0.207	0.992
6	New Scrubber	SOFA/LNB #2	1	74%	13	0.140	0.695	12	0.095	0.727	9	0.088	0.531	9	0.096	0.561
			1& 2	72%	29	0.278	1.344	19	0.188	1.382	17	0.176	1.033	21	0.193	1.088
7	New Scrubber	SOFA/LNB #1	1	76%	11	0.129	0.640	12	0.087	0.675	7	0.085	0.487	9	0.088	0.520
			1& 2	87%	11	0.129	0.640	12	0.087	0.675	7	0.085	0.487	9	0.088	0.520
8	New Scrubber	SNCR	1	80%	8	0.106	0.546	9	0.069	0.529	5	0.073	0.393	2	0.080	0.414
			1& 2	78%	23	0.210	1.057	16	0.137	1.029	11	0.145	0.772	13	0.158	0.812
9	New Scrubber	SCR	1	86%	3	0.070	0.406	2	0.049	0.325	3	0.047	0.250	1	0.059	0.261
			1& 2	85%	11	0.139	0.792	11	0.098	0.627	7	0.093	0.494	9	0.115	0.513
10	New Scrubber	LoTOx	1	26%	32	0.382	2.055	24	0.273	1.601	17	0.243	1.342	24	0.292	1.397
			1& 2	87%	8	0.123	0.651	8	0.092	0.536	7	0.075	0.401	4	0.096	0.444

[1] Average improvement represents the 90^{th} percentile comparison to the base case (Scenario 0) averaged for the 4 Class 1 areas.

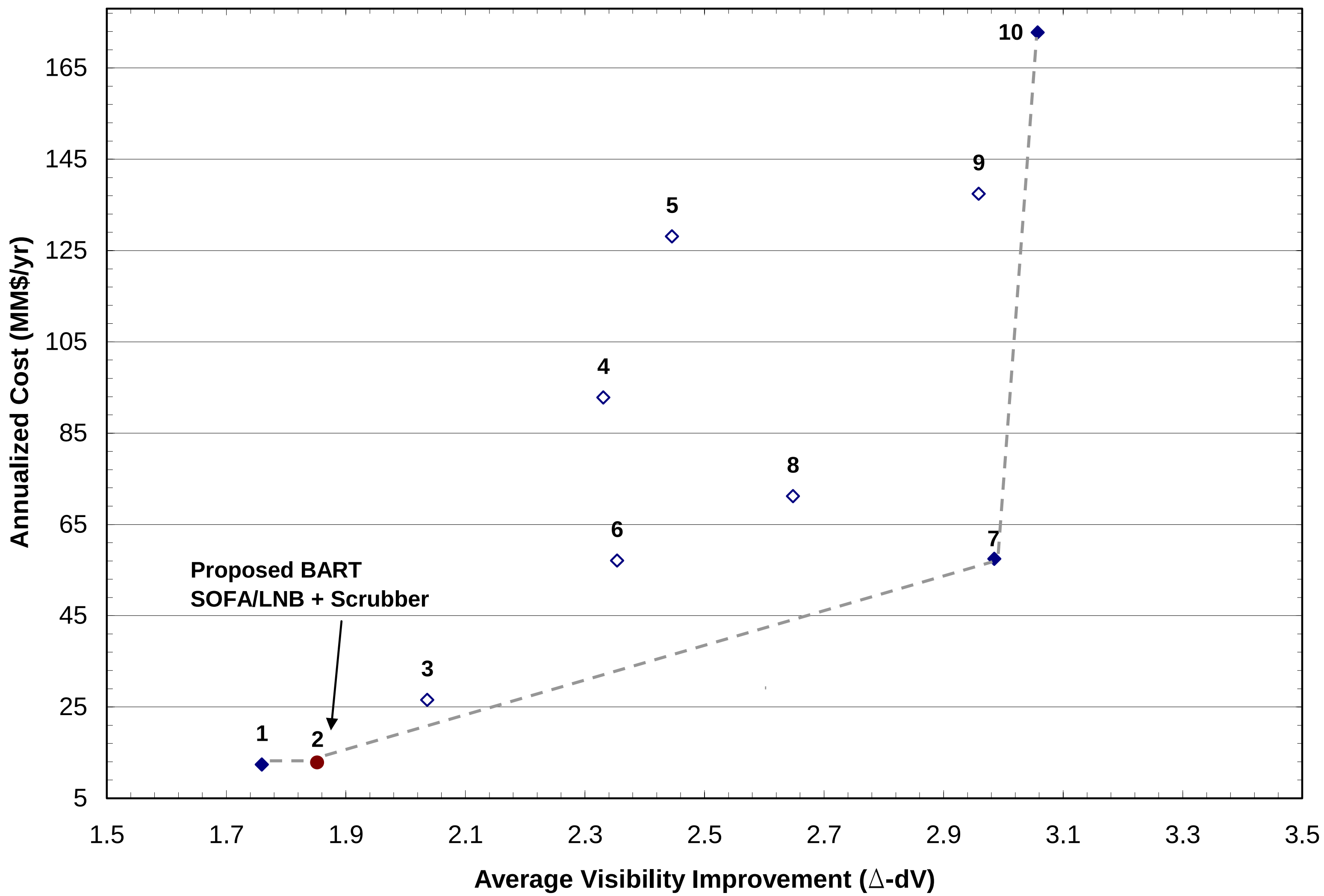

Figure 7-3 Dollar per Deciview Analysis. Scenarios 1 through 10 are plotted for the 98th percentile of 2002 based on the total annualized cost for installation and operation on both Units and the average visibility improvement for the 4 Class 1 areas. Dominant controls are presented as filled icons and inferior controls are represented as empty icons.

As illustrated by the dollar per deciview analysis in Figure 7-3, the proposed BART of scrubber modifications with an additional level of SOFA (Scenario 2) is support by the visibility modeling results. This graph also indicates that a change in NOx emission rate of 0.02 lb/MMBtu (comparison of Scenarios 1 and 2) only results in a change of about 0.1 Δ-dV on a 98th percentile comparison. As noted in Section 5.4.1, scrubber replacement (Scenarios 7 and 10) does not represent a feasible control option, therefore, from a visibility standpoint, Scenario 2 if the next best control.

7.4 Visibility Impacts of the Proposed BART

Scenario 2 represents a significant reduction in modeled visibility impairment in the four Class 1 Areas. As one example, on average, for 2002 98th percentile, the total visibility improvement for the two stations combined will be over 1.8 Δ-dV. Figure 7-4 illustrates the expected visibility improvement for the proposed BART of using current PM_{10} emissions in addition to meeting presumptive NOx and SO_2 limits as compared to the pre-BART baseline (Scenarios 0 and 2). The year 2002 results were used because the highest degree of impairment was demonstrated in that year.

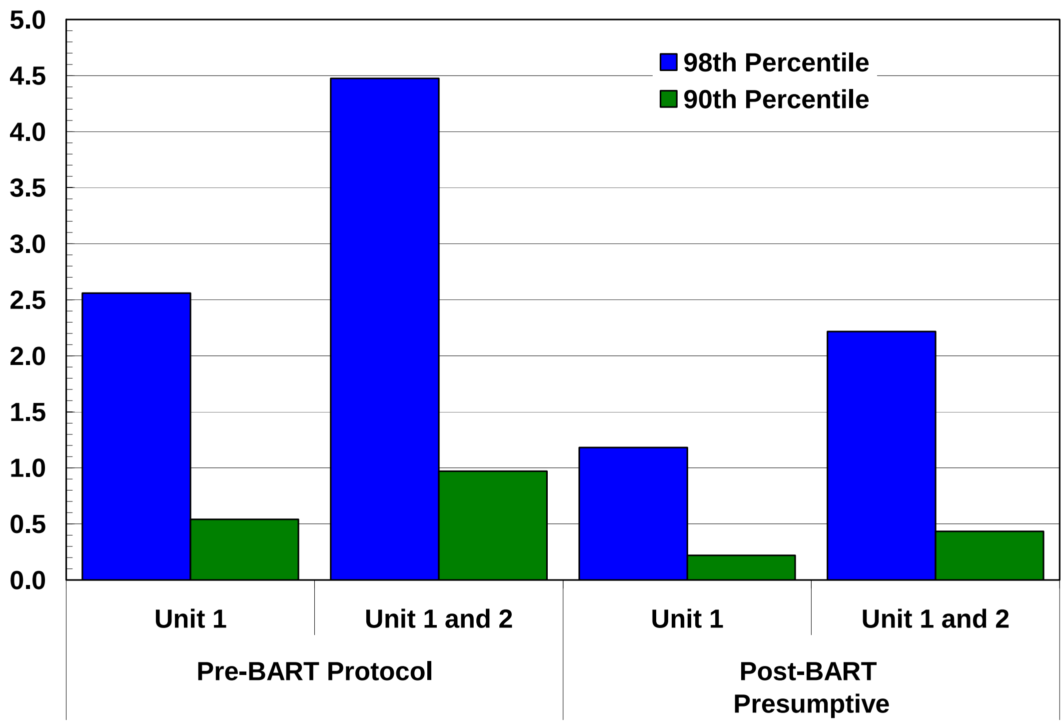

Figure 7-4 Visibility Improvement Predicted visibility improvement at post-BART presumptive emissions illustrated on a 90th and 98th percentile comparison to post-BART emissions at TRNP's South Unit.

8.0 Summary of Proposed BART

Based on the evaluations presented above, Scenario 2 is considered BART for Coal Creek Station. With respect to particulate controls, GRE will maintain the current PM performance standard of 0.1 lb/MMBtu for the existing ESP. The PM analysis presented in Section 3.0 confirms that additional PM controls are not economically justified and would provide negligible deciview reductions in Class 1 areas.

For NOx controls, GRE establishes LNB with and additional level of SOFA as described in Section 4.0. SNCR, SCR and LTO are ruled out on cost per ton bases along with operational, energy and environmental impacts. The LNB/SOFA combination will provide 20% to 30% reduction on a 30-day and annual basis at an emission rate of 0.17 lb/MMBtu.

For SO_2, GRE proposes to modify the existing scrubbers. The proposed emission limit of 0.15 lb/MMBtu on a 30-day rolling average is based on historical and future predicted operation and fuel sulfur content variability. A final decision on the scrubber modifications required to achieve the presumptive BART emission rate of 0.15 lb/MMBtu will be made pursuant to the evaluation of coal drying as applied to Coal Creek Unit 1.

In combination, the proposed BART controls will provide an average visibility improvement of over 1.8 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.

Appendices

Appendix A

Economic Evaluations

Revised Pages September 2007

Great River Energy Coal Creek
BART Emission Control Cost Analysis

Table A-1: Cost Summary
Revised September 2007

PM/PM_{10} Control Cost Summary
Baseline 0.030 lb/MMBtu

Case	Control Technology	Controlled Emissions lb/MMBtu	Control Eff %	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	PM Polishing WESP	0.015	50%	387.6	1	385.9	$7,232,000	$1,917,697	$4,969	D	NA-Base	A-4
2	PM Baghouse	0.015	50%	387.6	--	385.9	$37,370,845	$7,665,813	$19,864	I	NA	A-5
3	Dry ElectroStatic Precipitator (ESP)	0.015	50%	387.6	--	385.9	$38,510,903	$10,055,112	$26,056	I	NA	A-6

SO_2 Control Cost Summary
Baseline 2.12 lb/MMBtu

Case	Control Technology	Designed Emissions lb/MMBtu	Control Eff %	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	Scrubber Replacement	0.106	95%	2735.7	3	14553.4	$204.72	$30.76	$2,114	D	$33,498	A-7
2	Scrubber Mod. + Coal Dryer	0.128	94%	3310.2	2	13978.9	$76.22	$11.52	$824	D	$281	A-8
3	Spray Dry Baghouse	0.212	90%	5471.4	--	11817.7	$181.18	$29.22	$2,472	I	NA	A-9
4	Existing Scrubber + Coal Dryer	0.358	83%	9263.1	1	8026.0	$71.20	$9.84	$1,226	D	NA-Base	A-10
5	DSI Baghouse	0.635	70%	16414.3	--	874.9	$48.75	$12.52	$14,313	I	NA	A-11

NO_x Control Cost Summary
Baseline 0.22 lb/MMBtu

Case	Control Technology	Designed Emissions lb/MMBtu	Control Eff %	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	Low Temperature Oxidation (LoTOx)	0.022	90%	556	3	5001.5	$44.33	$58.07	$11,610	D	$17,283	A-12
2	Selective Catalytic Reduction (SCR) w/Reheat	0.043	80%	1111	--	4445.8	$84.11	$56.15	$12,631	I	NA	A-13 and A-14
3	Selective Non-Catalytic Reduction (SNCR)	0.108	50%	2779	--	2778.6	$19.91	$22.90	$8,240	I	NA	A-15
4	SOFA/LNB #2	0.150	30%	3877	2	1680.1	$5.26	$0.66	$395	D	$629	A-16
5	SOFA/LNB #1	0.170	21%	4394	1	1163.2	$2.63	$0.34	$291	D	NA-Base	A-17

[1] Control Technology Classification- D=Dominant, I=Inferior. Only dominant costs are used to calculate incremental cost effectiveness.

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

Equipment Information: GRE Coal Creek Unit I			6015	MMBtu/hr	590 MW		**Baseline Emis**	
Year	2004	2003	2002	2001	2000	03 -'04 Avg	**Avg Units I & II**	
Hours of Operation	8,480	8,574	7,851	8,546	8,610	8,527	**8,586**	
Fuels Used:								
Quanity of Lignite - Tons	3,927,641	3,966,578	3,602,970	3,979,416	3,920,779	3,947,110	**3,983,234**	
Percent Ash (Coal Only) Average	10.77	10.63	10.93	11.30	11.28	10.70	**10.74**	
Percent Sulfur in Coal Average	0.61	0.61	0.60	0.61	0.62	0.61	**0.61**	
BTU per Unit of Coal Average	6,297	6,261	6,203	6,196	6,201	6,279	**6,257**	
% Sodium in Lignite Ash Average	2.39	2.63	2.66	2.17	2.27	2.51	**2.57**	
Quanity of No. 6 Fuel Oil Gal		76,159	258,263	125,059	87,694	76,159		
Quanity of No. 2 Fuel Oil Gal	190,025	18,593	N/A	N/A		104,309	**189,654**	
Percent Sulfur in Fuel Oil Average	0.04	0.92	1.39	1.32	1.63	0.48	**0.04**	
BTU per Unit of Fuel Oil Average	140,141	151,509	154,030	153,557	152,035	145,825	**147,281**	
Quanity of Used Oil/Solvent on Coal Gal	49,155	21,637	17,327	723	904	35,396	**35,396**	
Percent Sulfur in Used Oil Average	0.47	0.38	0.23	0.38	0.61	0	**0.42**	
BTU per Unit of Used Oil Average	15,893	19,156	19,598	19,350	19,192	17,524	**17,524**	
Heat Input	4.947E+07	4.967E+07	4.470E+07	4.931E+07	4.862E+07	4.957E+07	**4.984E+07**	
MMBtu/hr	5,833	5,793	5,694	5,770	5,647	5,813	**5,805**	
% of Capacity	97.0%	96.3%	94.7%	95.9%	93.9%	96.6%	**96.5%**	
SO2 lb/MMbtu	0.636	0.556	0.533	0.593	0.589	0.596	**0.558**	
PM lb/MMBtu	0.005	0.003	0.058	0.020	0.026	0.004	**0.030**	
NOx lb/MMBtu	0.217	0.204	0.210	0.212	0.214	0.211	**0.215**	
Total Stack Emissions:							**T/yr (1)**	**lb/hr**
Particulate Emitted Tons Per Year:	116.3	72.6	1,305.1	491.6	632.9	94.4	**750.2**	**181.1**
PM10 Emitted Tons Per Year:	78.7	48.6	874.5	329.4	424.1	63.7	**69.5**	**16.8**
PM2.5 Emitted Tons Per Year:	32.2						**32.2**	**7.8**
SO2 Emitted Tons Per Year:	15,741.6	13,816.9	11,910.0	14,630.3	14,331.7	14,779.3	**13,905.9**	**4027.3**
NOx Emitted Tons Per Year:	5,370.1	5,071.8	4,689.6	5,234.6	5,209.7	5,221.0	**5,363.5**	**1294.5**
CO Emitted Tons Per Year:	982.4	991.9	901.4	995.2	980.4	987.1	**996.1**	**240.4**
TOC Emitted Tons Per Year:	78.6	79.4	72.2	79.6	78.4	79.0	**79.7**	**19.2**
Stack Emissions --- Lignite:								
Particulate Rate from Test lb/MMBtu	0.005	0.003	0.058	0.020	0.026	0.004	**0.004**	
SO2 CEM Annual Average lb/MMBtu	0.609	0.538	0.508	0.561	0.563	0.573	**0.543**	
NOX CEM Annual Average lb/MMBtu	0.217	0.204	0.210	0.212	0.214	0.211	**0.215**	

SO2 Scrubber Control Eff
93.7%
Percent Bypass
27%
Overall Control Efficiency
68.4%
Uncontrolled SO2 lb/hr
12,745

(1) Emission rate for 1 unit

Equipment Information: GRE Coal Creek Unit II			6022	MMBtu/hr		
Year	2004	2003	2002	2001	2000	02 -'03 Avg
Hours of Operation	7,963	8,621	8,669	8,028	8,366	8,645
Fuels Used:						
Quanity of Lignite - Tons	3,650,697	4,014,476	4,024,241	3,642,488	3,866,225	4,019,358
Percent Ash (Coal Only) Average	10.80	10.63	10.95	11.28	11.26	10.79
Percent Sulfur in Coal Average	0.60	0.61	0.61	0.61	0.62	0.61
BTU per Unit of Coal Average	6,293	6,260	6,209	6,199	6,201	6,235
% Sodium in Lignite Ash Average	2.38	2.63	2.63	2.18	2.27	2.63
Quanity of No. 6 Fuel Oil Gal		26,179	76,391	139,020	216,520	51,285
Quanity of No. 2 Fuel Oil Gal	189,282	52,291	N/A	N/A		N/A
Percent Sulfur in Fuel Oil Average	0.04	0.42	1.58	1.32	1.62	1.00
BTU per Unit of Fuel Oil Average	140,141	143,194	154,279	153,163	153,839	148,736
Quanity of Used Oil/Solvent on Coal Gal	N/A	N/A	N/A	N/A	N/A	N/A
Percent Sulfur in Used Oil Average	N/A	N/A	N/A	N/A	N/A	N/A
BTU per Unit of Used Oil Average	N/A	N/A	N/A	N/A	N/A	N/A
Heat Input	4.595E+07	5.026E+07	4.997E+07	4.516E+07	4.795E+07	5.012E+07
MMBtu/hr	5,771	5,830	5,765	5,626	5,732	5,797
% of Capacity	95.9%	96.9%	95.8%	93.5%	95.3%	96.4%
SO2 lb/MMbtu	0.499	0.539	0.501	0.517	0.535	0.520
PM lb/MMBtu	0.002	0.003	0.034	0.019	0.023	0.019
NOx lb/MMBtu	0.236	0.221	0.218	0.230	0.222	0.220
Total Stack Emissions:						
Particulate Emitted Tons Per Year:	80.4	120.9	1,267.5	649.1	829.1	694.2
PM10 Emitted Tons Per Year:	54.5	81.0	849.2	434.9	555.6	465.1
PM2.5 Emitted Tons Per Year:	22.3					
SO2 Emitted Tons Per Year:	11,468.8	13,547.3	12,517.7	11,682.5	12,816.5	13,032.5
NOx Emitted Tons Per Year:	5,429.3	5,557.5	5,454.4	5,190.1	5,323.0	5,506.0
CO Emitted Tons Per Year:	913.1	1,003.8	1,006.3	911.0	967.1	1,005.0
TOC Emitted Tons Per Year:	73.1	80.3	80.5	72.9	77.4	80.4
Stack Emissions --- Lignite:						
Particulate Rate from Test lb/MMBtu	0.004	0.005	0.051	0.029	0.035	0.028
SO2 CEM Annual Average lb/MMBtu	0.498	0.533	0.494	0.505	0.531	0.514
NOX CEM Annual Average lb/MMBtu	0.236	0.221	0.218	0.230	0.222	0.220

Adjust Particulate Matter Emissions
Method 5 Average Results
2000 - 2003
0.030 lb PM/MMBtu

Notes
Fuel Oil Use Avg '04 No 2 FO
PM/PM10 Avg Unit 1 '03, '04 & Unit II '03
PM lb/MMBtu Avg Unit 1 '03, '04 & Unit II '03, '04

Uncontrolled PM Emission Rate Using AP-42 - For SW Disposal Rates				
	Total	Filterable	Condensable	
T/yr	214,719	213,950	769	
lb/Hr	50,016	49,837	179	
Filterable PM Emission Factor			107.4	lb/ton coal
Condensable PM Emission Factor			0.031	lb/MMBtu

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

Operating Unit:	Unit 1 or 2	**Study Year**	2005	
Emission Unit Number	NA			
Stack/Vent Number	NA			

Item	Unit Cost	Units	Reference Cost	Year	Data Source	Notes
Operating Labor	37	$/hr	25.86	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Maintenance Labor	37	$/hr	26.25	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	0.79	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 Adsorbers, 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	5.00	$/ton		2005	GRE D Stockdill 2/9/2006	GRE landfill cost for ash
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
Ash Sales	36.00	$/ton	5.00	2006	GRE D Stockdill 4/27/2007	$/ton received for sale of ash; this amount is lost if ash cannot be sold
Chemicals & Supplies						
Lime	90.00	$/ton	72.19	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	0.92	$/lb			GRE per Diane Stockdill	
Nahcolite	233.52	$/ton	195.57	1999	Integrated Air Pollution Control System Program Version 5a, EPA May 1999	
Catalyst & Replacement Parts						
SCR Catalyst	500	$\$/ft^3$			Not used, get vendor quote if needed	
CO Catalyst	650	$\$/ft^3$			Not used, get vendor quote if needed	
Catalyst #3						
Catalyst #4						
Catalyst #5						
Filter Bags	160.00	$/bag	33.71	2002	GRE cost per Steve Smokey	
Tower Packing	100	$\$/ft^3$				
Replacement Parts						
Replacement Parts						
Replacement Parts						
Other						
Sales Tax	0	%			GRE per Diane Stockdill 12/6/05 email	
Interest Rate	5.50%	%			GRE per Diane Stockdill 12/6/05 email	Estimated prime rate plus 3%
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	8,586	Hours			2002 - 2004 Coal Creek Emissions Inventory	
Utilization Rate	100.0%				GRE per Diane Stockdill 12/6/05 email	
Equipment Life	20	yrs				Engineering Estimate
Coal Ash	10.74	wt % ash			2003-2004 Coal Creek Emissions Inventory	
Coal Moisture	37.30	% Coal Moisture Content				
Coal Sulfur	0.73	% Coal Sulfur Content			2003-2004 Coal Creek Emissions Inventory	
Coal Heating Value	6,257	Btu/lb of coal			2003-2004 Coal Creek Emissions Inventory	
Design Capacity	6,019	MMBtu/hr				
ID Fan Flow Rates	No Coal Drying	Coal Drying				
Standardized Flow Rate	965,316	866,294	scfm @ 32º F			
Temperature	330	330	Deg F		GRE per G. Riveland 4/5/06 email	
Moisture Content	15.3%	13.3%			GRE per G. Riveland 4/5/06 email	
Actual Flow Rate	2,488,000	2,234,300	acfm		GRE per G. Riveland 4/5/06 email	
Standardized Flow Rate	1,550,000	1,391,000	scfm @ 330º F		GRE per G. Riveland 4/5/06 email	
Dry Std Flow Rate	1,312,850	1,205,997	dscfm @ 330º F			
	Max Emis	**Baseline Emiss**				
Pollutant	**Lb/Hr**	**lb/MMBtu**				
PM10	180.2	0.030			PM10 99.5% of PM per ND Dept of Health Guidelines (Per Stanton EI)	
Total Particulates	181.1	0.030			2000 - 2002 Coal Creek Emissions Inventory Average Method 5 PM lb/MMBtu and most recent hourly average duty (MMBtu	
Nitrous Oxides (NOx)	1,294	0.215			2002 - 2004 Coal Creek Emissions Inventory	
Sulfur Dioxide (SO_2)	4,027	0.669			2002 - 2004 Coal Creek Emissions Inventory	

Enter this data for each unit
Enter data for this study (applies to all units)

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

Operating Unit: **Unit 1 or 2**

						Chemical Engineering Chemical Plant Cost Index	
Emission Unit Number	NA		Stack/Vent Number	NA		1997	386.5
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F	2005	465
Expected Utiliztion Rate	100%		Temperature	330	Deg F	Inflation Adj	1.20
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%			
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm		
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs						1997		
Purchased Equipment (A)						2005	5,408,000	2,782,609
Purchased Equipment Total (B)	15%	of control device cost (A)						**3,200,000**
Installation - Standard Costs	69%	of purchased equip cost (B)						2,208,000
Installation - Site Specific Costs								NA
Installation Total								2,208,000
Total Direct Capital Cost, DC								5,408,000
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)						1,824,000
Total Capital Investment (TCI) = DC + IC								**7,232,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						832,575
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,085,122
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**1,917,697**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost (6) $/Ton Rem
PM10	180.2	773.5		0.015	lb/MMBtu	387.6	385.9	4,969
Total Particulates	181.1	777.4		0.015	lb/MMBtu	387.6	389.8	4,920
Nitrous Oxides (NOx)	1,294.5	5,557.3				5557.3	-	NA
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1 Total Direct Capital Cost per GRE cost estimate (CCS BART Evaluation.xls). Assumed no indirect capital cost included in estimate.
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 Existing PM emission rate per avg Method 5 test results of 0.030 lb/MMBtu, projected PM emission rate is at typical BACT limit 0f 0.015 lb/MMBtu per RBLC
6 Used an ESP SCA grid factor of 553 ft^2/1000 acfm per GRE, D. Stockdill.
7 Assumed WESP size is 20% of IAPCS model calculated size for electricity and spray water use.
8 Process, emissions and cost data listed above is for one unit.
9 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

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

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**2,782,609**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	278,261
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	139,130
Purchased Equipment Total (B)	15%		**3,200,000**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	128,000
Handling & erection	50%	of purchased equip cost (B)	1,600,000
Electrical	8%	of purchased equip cost (B)	256,000
Piping	3%	of purchased equip cost (B)	96,000
Insulation	2%	of purchased equip cost (B)	64,000
Painting	2%	of purchased equip cost (B)	64,000
Installation Subtotal Standard Expenses	69%		**2,208,000**
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			**2,208,000**
Total Direct Capital Cost, DC			**5,408,000**
Indirect Capital Costs			
Engineering, supervision	20%	of purchased equip cost (B)	640,000
Construction & field expenses	20%	of purchased equip cost (B)	640,000
Contractor fees	10%	of purchased equip cost (B)	320,000
Start-up	1%	of purchased equip cost (B)	32,000
Performance test	1%	of purchased equip cost (B)	32,000
Model Studies	2%	of purchased equip cost (B)	64,000
Contingencies	3%	of purchased equip cost (B)	96,000
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)	**1,824,000**
Total Capital Investment (TCI) = DC + IC			**7,232,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**7,232,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr	39,710
Supervisor	48%	% of Operator Costs.	19,061
Maintenance			
Maintenance Labor	275,173	ft2 grid area, 0.8 $/ft2 of grid area	227,018
Maintenance Materials	1	1% of purchased equipment cost	32,000
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 982 kW-hr, 8586 hr/yr, 100% utilization	426,953
NA	NA		-
Water	0.31	$/kgal, 498 gpm, 8586 hr/yr, 100% utilization	79,467
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization	8,367
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**832,575**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,673
Administration (2% total capital costs)	2%	of total capital costs (TCI)	144,640
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	72,320
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	72,320
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	605,169
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,085,122**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,917,697**

See Summary page for notes and assumptions

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

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		D P in H2O	Efficiency	Hp	kW	
Blower Baghouse & ESP	497,600		4.48			403.5	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.46
	Liq flow	Liquid SPGR	D P ft H2O	Efficiency	Hp	kW	
WESP Pump	2488 gpm	1.000	40	0.5		37.4	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
WESP H2O WW Disch	498 gpm	1.000	40	0.5		7.5	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
SCA Factor	553	ft^2/1000 acfm					
ESP Grid	275,173	ft^2	1.94E-03	kW/ft^2		533.8	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.48
Total						982.3	

Reagent Use & Other Operating Costs					
WESP Pump	497,600 acfm	5	gpm/kacfm	2,488 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 =		498 gpm	

Operating Cost Calculations — **Annual hours of operation:** **8,586** — **Utilization Rate:** **100%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37	$/Hr	1.0	hr/8 hr shift	1,073	39,710	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	48%	of Operator Costs.			NA	19,061	% of Operator Costs.
	Maintenance							
	Maint Labor	275,173	ft2 grid area	0.825	$/ft^2 of grid area		227,018	ft2 grid area, 0.8 $/ft2 of grid area
	Maint Mtls	1	% of purchased equipment cost			NA	32,000	1% of purchased equipment cost
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	982.3	kW-hr	8,433,718	426,953	$/kwh, 982 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	497.6	gpm	256,344	79,467	$/kgal, 498 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatement	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.2	ton/hr	1,673	8,367	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	Mi	0	0	$/ton-mi, 0 Mi, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% 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 Coal Creek
BART Emission Control Cost Analysis
Table A-5: PM Control -Baghouse

Operating Unit: **Unit 1 or 2**

						Chemical Engineering Chemical Plant Cost Index	
Emission Unit Number	NA		Stack/Vent Number	NA			
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F		
Expected Utiliztion Rate	100%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F		

Year		
1997	24,679,400	DC from IAPCS program
2005	29,691,904	Inflation Adjusted DC

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								14,838,533
Purchased Equipment Total (B)	15%	of control device cost (A)						**17,064,313**
Installation - Standard Costs	74%	of purchased equip cost (B)						12,627,591
Installation - Site Specific Costs								NA
Installation Total								12,627,591
Total Direct Capital Cost, DC								29,691,904
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)						7,678,941
Total Capital Investment (TCI) = DC + IC								**37,370,845**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,944,403
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						4,721,410
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**7,665,813**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost (5) $/Ton Rem**
PM10	180.2	773.5		0.015	lb/MMBtu	387.6	385.9	19,864
Total Particulates	181.1	777.4		0.015	lb/MMBtu	387.6	389.8	19,666
Nitrous Oxides (NOx)	1,294.5	5,557.3				5557.3	-	NA
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1 Total Direct Capital Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
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 High control cost is due to the small additional decrease in emissions as compared to existing controls.
6 Existing PM emission rate per avg Method 5 test results of 0.030 lb/MMBtu, projected PM emission rate is at typical BACT limit 0f 0.015 lb/MMBtu per RBLC
7 Process, emissions and cost data listed above is for one unit.
8 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-5: PM Control -Baghouse

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**14,838,533**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,483,853
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	741,927
Purchased Equipment Total (B)	15%		**17,064,313**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	682,573
Handling & erection	50%	of purchased equip cost (B)	8,532,156
Electrical	8%	of purchased equip cost (B)	1,365,145
Piping	1%	of purchased equip cost (B)	170,643
Insulation	7%	of purchased equip cost (B)	1,194,502
Painting	4%	of purchased equip cost (B)	682,573
Installation Subtotal Standard Expenses	74%		**12,627,591**
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			**12,627,591**
Total Direct Capital Cost, DC			**29,691,904**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,706,431
Construction & field expenses	20%	of purchased equip cost (B)	3,412,863
Contractor fees	10%	of purchased equip cost (B)	1,706,431
Start-up	1%	of purchased equip cost (B)	170,643
Performance test	1%	of purchased equip cost (B)	170,643
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	511,929
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	**7,678,941**
Total Capital Investment (TCI) = DC + IC			**37,370,845**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**37,334,469**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 8586 hr/yr	79,421
Supervisor	15%	15% of Operator Costs	11,913
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr	39,710
Maintenance Materials	100%	of maintenance labor costs	39,710
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 4,503 kW-hr, 8586 hr/yr, 100% utilization	1,957,404
NA	NA		-
NA	NA		-
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 8586 hr/yr, 100% utilization	788,176
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization	8,367
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	33.71	$/bag, 795 bags, 8586 hr/yr, 100% utilization	19,702
Total Annual Direct Operating Costs			**2,944,403**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	102,452
Administration (2% total capital costs)	2%	of total capital costs (TCI)	747,417
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	373,708
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	373,708
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	3,124,123
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**4,721,410**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,665,813**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-5: PM Control -Baghouse

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	2	years	
CRF	0.5416		
Rep part cost per unit	33.711	$/bag	
Amount Required	795		
Total Rep Parts Cost	28,140	Cost adjusted for freight & sales tax	
Installation Labor	8,236	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	**36,376**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag
Annualized Cost	**19,702**		

Electrical Use	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	2,488,000		10			4503.3	
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						4503.3	

Baghouse Filter Cost							See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	10,661	ft^2					
Cages	10 ft long	5 in dia	13.42	area/cage ft^2	795 Cages	11.036	$/cage
Bags	1.69	$/ft2 of fabric				22.68	$/bag
Total						33.711	
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:** **8,586**; **Utilization Rate:** **100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37	$/Hr	2.0	hr/8 hr shift	2,147	79,421	$/Hr, 2.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	11,913	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	1,073	39,710	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	39,710	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	4503.3	kW-hr	38,665,162	1,957,404	$/kwh, 4,503 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	2	scfm/kacfm	2,563,436	788,176	$/kscf, 2 scfm/kacfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.2	ton/hr	1,673	8,367	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	33.71	$/bag	795	bags	NA	19,702	$/bag, 795 bags, 8586 hr/yr, 100% 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 Coal Creek
BART Emission Control Cost Analysis
Table A-6: PM Control - Dry ESP

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	100%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F		

Year		
1997	23,864,300	DC from IAPCS program
2005	28,711,254	Inflation Adjusted DC

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								14,949,885
Purchased Equipment Total (B)	15%	of control device cost (A)						**17,192,367**
Installation - Standard Costs	67%	of purchased equip cost (B)						11,518,886
Installation - Site Specific Costs								NA
Installation Total								11,518,886
Total Direct Capital Cost, DC								28,711,254
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)						9,799,649
Total Capital Investment (TCI) = DC + IC								**38,510,903**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						4,472,639
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						5,582,472
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**10,055,112**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost (6) $/Ton Rem
PM10	180.2	773.5		0.015	lb/MMBtu	387.6	385.9	26,056
Total Particulates	181.1	777.4		0.015	lb/MMBtu	387.6	389.8	25,796
Nitrous Oxides (NOx)	1,294.5	5,557.3				5557.3	-	NA
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1 Total Direct Capital Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
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 Existing PM emission rate per avg Method 5 test results of 0.030 lb/MMBtu, projected PM emission rate is at typical BACT limit 0f 0.015 lb/MMBtu per RBLC
6 Used an ESP SCA grid factor of 553 ft^2/1000 acfm per GRE, D. Stockdill.
7 Process, emissions and cost data listed above is for one unit.
8 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-6: PM Control - Dry ESP

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**14,949,885**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,494,988
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	747,494
Purchased Equipment Total (B)	15%		**17,192,367**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	687,695
Handling & erection	50%	of purchased equip cost (B)	8,596,184
Electrical	8%	of purchased equip cost (B)	1,375,389
Piping	1%	of purchased equip cost (B)	171,924
Insulation	2%	of purchased equip cost (B)	343,847
Painting	2%	of purchased equip cost (B)	343,847
Installation Subtotal Standard Expenses	67%		**11,518,886**
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			**11,518,886**
Total Direct Capital Cost, DC			**28,711,254**
Indirect Capital Costs			
Engineering, supervision	20%	of purchased equip cost (B)	3,438,473
Construction & field expenses	20%	of purchased equip cost (B)	3,438,473
Contractor fees	10%	of purchased equip cost (B)	1,719,237
Start-up	1%	of purchased equip cost (B)	171,924
Performance test	1%	of purchased equip cost (B)	171,924
Model Studies	2%	of purchased equip cost (B)	343,847
Contingencies	3%	of purchased equip cost (B)	515,771
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)	**9,799,649**
Total Capital Investment (TCI) = DC + IC			**38,510,903**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**38,510,903**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr	39,710
Supervisor	48%	% of Operator Costs.	19,061
Maintenance			
Maintenance Labor	1,375,864	ft2 grid area, 0.8 $/ft2 of grid area	1,135,088
Maintenance Materials	1	1% of purchased equipment cost	171,924
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 4,687 kW-hr, 8586 hr/yr, 100% utilization	2,037,107
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 25 ton/hr, 8586 hr/yr, 100% utilization	1,069,750
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**4,472,639**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	819,470
Administration (2% total capital costs)	2%	of total capital costs (TCI)	770,218
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	385,109
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	385,109
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	3,222,567
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**5,582,472**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**10,055,112**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-6: PM Control - Dry ESP

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		ΔP ft H2O	Efficiency	Hp	kW	
Blower Baghouse & ESP	2,488,000		4.48			2017.5	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.46
	Liq flow	Liquid SPGR	ΔP 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	1,375,864	ft^2	1.94E-03	kW/ft^2		2669.2	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.48
Total						4686.6	

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: 8,586**; **Utilization Rate: 100%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37	$/Hr	1.0	hr/8 hr shift	1,073	39,710	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	48%	of Operator Costs.			NA	19,061	% of Operator Costs.
	Maintenance							
	Maint Labor	1,375,864	ft2 grid area	0.825	$/ft^2 of grid area		1,135,088	ft2 grid area, 0.8 $/ft2 of grid area
	Maint Mtls	1	% of purchased equipment cost			NA	171,924	1% of purchased equipment cost
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	4686.6	kW-hr	40,239,539	2,037,107	$/kwh, 4,687 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatment	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	24.9	ton/hr	213,950	1,069,750	$/ton, 25 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	Mi	0	0	$/ton-mi, 0 Mi, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% 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 Coal Creek
BART Emission Control Cost Analysis
Table A-7: SO2 Control - Wet Scrubber

Operating Unit: **Unit 1 or 2**

						Chemical Engineering Chemical Plant Cost Index	
Emission Unit Number	NA		Stack/Vent Number	NA			
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F		
Expected Utiliztion Rate	100%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs				DC from IAPCS program		1997	71,051,700	
Purchased Equipment (A)				Inflation Adjusted DC		2005	85,482,640	40,179,854
Purchased Equipment Total (B)	15%	of control device cost (A)						**46,206,833**
Installation - Standard Costs	85%	of purchased equip cost (B)						39,275,808
Installation - Site Specific Costs								103,067,200
Installation Total								142,343,008
Total Direct Capital Cost, DC								188,549,840
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)						16,172,391
Total Capital Investment (TCI) = DC + IC								**204,722,232**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						5,404,793
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						25,357,435
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**30,762,227**

Uncontrolled SO2 Emission Rate	12,745	lb/hr
Scrubber Control Efficiency	95.0%	[7]
Scrubber Bypass	0.0%	

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180	773				773	-	NA
Total Particulates	181	777				777	-	NA
Nitrous Oxides (NOx)	1,294	5,557				5,557	-	NA
Sulfur Dioxide (SO_2)	4,027	17,289	95.0%			2,736	14,553	2,114

Notes & Assumptions

1. Total Direct Capital Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
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 = 20% of circulating water rate
5. Process, emissions and cost data listed above is for one unit.
6. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
7. EPRI, current technology expectation for new scrubber, GRE 3/21/06
8. Per GRE 2/12/07 cost estimate $40/MW-hr, 540 MW
9. Per GRE 2/19/07 demolition cost estimate.

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

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**40,179,854**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	4,017,985
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	2,008,993
Purchased Equipment Total (B)	15%		**46,206,833**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,544,820
Handling & erection	40%	of purchased equip cost (B)	18,482,733
Electrical	1%	of purchased equip cost (B)	462,068
Piping	30%	of purchased equip cost (B)	13,862,050
Insulation	1%	of purchased equip cost (B)	462,068
Painting	1%	of purchased equip cost (B)	462,068
Installation Subtotal Standard Expenses	85%		**39,275,808**
Site Preparation, as required		Demolition [9]	6,000,000
Buildings, as required		Bypass duct modification	2,200,000
Site Specific - Other		Replacement Power- 6 months (183 days) [8]	94,867,200
Total Site Specific Costs			103,067,200
Installation Total			**142,343,008**
Total Direct Capital Cost, DC			**188,549,840**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,620,683
Construction & field expenses	10%	of purchased equip cost (B)	4,620,683
Contractor fees	10%	of purchased equip cost (B)	4,620,683
Start-up	1%	of purchased equip cost (B)	462,068
Performance test	1%	of purchased equip cost (B)	462,068
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	1,386,205
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	**16,172,391**
Total Capital Investment (TCI) = DC + IC			**204,722,232**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**204,722,232**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr	19,855
Supervisor	15%	15% of Operator Costs	2,978
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr	19,855
Maintenance Materials	100%	of maintenance labor costs	19,855
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 5,189 kW-hr, 8586 hr/yr, 100% utilization	2,255,516
NA	NA		-
Water	0.31	$/kgal, 6,836 gpm, 8586 hr/yr, 100% utilization	1,091,719
NA	NA		-
NA	NA		-
WW Treat Neutralization	1.64	$/kgal, 1,891 gpm, 8586 hr/yr, 100% utilization	1,596,647
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 1,031 lb/hr, 8586 hr/yr, 100% utilization	398,366
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**5,404,793**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	37,526
Administration (2% total capital costs)	2%	of total capital costs (TCI)	4,094,445
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	2,047,222
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	2,047,222
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	17,131,019
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**25,357,435**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**30,762,227**

See Summary page for notes and assumptions

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

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/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		ΔP in H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,488,000		8.55	0.7	-	3,555.5	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**ΔP ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	94,544 gpm	1	60	0.7	-	1,523.4	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	6836 gpm	1	60	0.7	-	110.2	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
Other							
Other							
Other							
Total						5189.1	

Reagent Use & Other Operating Costs					
Caustic Use	1071.22	lb/hr SO2	2.50 lb NaOH/lb SO2	2678.05	lb/hr Caustic
Lime Use	1071.22	lb/hr SO2	0.96 lb Lime/lb SO2	1031.05	lb/hr Lime
Baseline scrubber bypass:		27.0%			
Baseline scrubber efficiency:		93.7%			
Liquid/Gas ratio	38.0	* L/G = Gal/1,000 acf		6836 gpm	
Circulating Water Rate	94,544	gpm			
Water Makeup Rate/WW Disch =		2%	of circulating water rate + evap. loss =		
Evaopration Loss =		72%			

Operating Cost Calculations — **Annual hours of operation:** **8,586**; **Utilization Rate:** **100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37	$/Hr	0.5	hr/8 hr shift	537	19,855	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	2,978	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.5	hr/8 hr shift	537	19,855	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	19,855	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	5189.1	kW-hr	44,553,851	2,255,516	$/kwh, 5,189 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	6,836.1	gpm	3,521,675	1,091,719	$/kgal, 6,836 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	Mscfm	0	0	$/kscf, 0 Mscfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	1,890.9	gpm	974,106	1,596,647	$/kgal, 1,891 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	1031.0	lb/hr	4,426	398,366	$/ton, 1,031 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% 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 Coal Creek
BART Emission Control Cost Analysis
Table A-8: SO2 Control - Option 1, Existing Absorber + Mist Eliminator + Liquid Distribution Ring + Fan Upgrade + Modify Stack + Coal Drying

Operating Unit: **Unit 1 or 2**

						Chemical Engineering Chemical Plant Cost Index	
Emission Unit Number	NA		Stack/Vent Number	NA			
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F		
Expected Utiliztion Rate	100%		Temperature	330	Deg F	2004	442
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj	1.05
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								51,000,000
Purchased Equipment Total (B)	15%	of control device cost (A)						**58,650,000**
Installation - Standard Costs	85%	of purchased equip cost (B)						49,852,500
Installation - Site Specific Costs								32,235,200
Installation Total								82,087,700
Total Direct Capital Cost, DC								55,695,200
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)						20,527,500
Total Capital Investment (TCI) = DC + IC								**76,222,700**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,090,296
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						9,427,172
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**11,517,469**

Uncontrolled SO2 Emission Rate	12,745	lb/hr
Scrubber Control Efficiency	94%	
Scrubber Bypass	0.0%	

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180	773				773	-	NA
Total Particulates	181	777				777	-	NA
Nitrous Oxides (NOx)	1,294	5,557				5,557	-	NA
Sulfur Dioxide (SO_2)	4,027	17,289	94.0%			3,310	13,979	824

Notes & Assumptions

1. Total installed cost per URS Proposal 10/26/04 & Chimney Consultants Proposal 9/22/04
   MM$51 for coal drying addition from Coal Drying Incremental Benefit and Cost Model spread sheet 02/05/2007
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1
3. Liquid/Gas ratio = 10 L/G = Gal/1,000 acf
4. Water Makeup Rate/Wastewater Discharge = 20% of circulating water rate
5. Process, emissions and cost data listed above is for one unit.
6. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
7. Per "Gary's BART analysis" spreadsheet and phone conversation with D. Stockdill 02/14/2006
8. Per GRE 2/12/07 cost estimate $40/MW-hr, 540 MW
9. Installed capital cost per G. Riveland 04/13/06

Great River Energy Coal Creek
BART Emission Control Cost Analysis

Table A-8: SO2 Control - Option 1, Existing Absorber + Mist Eliminator + Liquid Distribution Ring + Fan Upgrade + Modify Stack + Coal Drying

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**51,000,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	5,100,000
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	2,550,000
Purchased Equipment Total (B)	15%		**58,650,000**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	7,038,000
Handling & erection	40%	of purchased equip cost (B)	23,460,000
Electrical	1%	of purchased equip cost (B)	586,500
Piping	30%	of purchased equip cost (B)	17,595,000
Insulation	1%	of purchased equip cost (B)	586,500
Painting	1%	of purchased equip cost (B)	586,500
Installation Subtotal Standard Expenses	85%		**49,852,500**
Option 1 Modifications		Mist Eliminator, Liquid Distrubution Ring, Fan Upgrade [7]	5,020,000
Buildings, as required		Stack Modifications, Installed Cost [9], bypass duct modificatio	12,700,000
Site Specific - Other		Replacement Power - two 14 day outages [8]	14,515,200
Total Site Specific Costs			32,235,200
Installation Total			**82,087,700**
Total Direct Capital Cost, DC			**55,695,200**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	5,865,000
Construction & field expenses	10%	of purchased equip cost (B)	5,865,000
Contractor fees	10%	of purchased equip cost (B)	5,865,000
Start-up	1%	of purchased equip cost (B)	586,500
Performance test	1%	of purchased equip cost (B)	586,500
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	1,759,500
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	**20,527,500**
Total Capital Investment (TCI) = DC + IC			**76,222,700**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**76,222,700**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.3 hr/8 hr shift, 8586 hr/yr	50,700
Maintenance Materials	100%	of maintenance labor costs	50,700
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 2,188 kW-hr, 8586 hr/yr, 100% utilization	951,126
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 2 ton/hr, 8586 hr/yr, 100% utilization	96,370
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 2,437 lb/hr, 8586 hr/yr, 100% utilization	941,400
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**2,090,296**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	NA
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,524,454
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	762,227
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	762,227
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	6,378,264
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**9,427,172**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**11,517,469**

See Summary page for notes and assumptions

Great River Energy Coal Creek

BART Emission Control Cost Analysis

Table A-8: SO2 Control - Option 1, Existing Absorber + Mist Eliminator + Liquid Distribution Ring + Fan Upgrade + Modify Stack + Coal Drying

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/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		D P in H2O	Efficiency	Hp	kW	
Blower, Scrubber	2,488,000		5.38	0.6464	-	2,188.2	Incremental ID fan power increase, GRE G. Riveland 4/5/06 email
	Flow	Liquid SPGR	D 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
Other							
Other							
Other							
Total						2188.2	

Reagent Use & Other Operating Costs					
Caustic Use	0.00	lb/hr SO2	2.50	lb NaOH/lb SO2	0.00 lb/hr Caustic
Lime Use	0.00	lb/hr SO2	0.96	lb Lime/lb SO2	0.00 lb/hr Lime
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		

Operating Cost Calculations — **Annual hours of operation:** **8,586** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8586 hr/yr
Supervisor	15%	of Op.			NA	0	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	1.3	hr/8 hr shift	1,370	50,700	$/Hr, 1.3 hr/8 hr shift, 8586 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	50,700	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	2188.2	kW-hr	18,787,866	951,126	$/kwh, 2,188 kW-hr, 8586 hr/yr, 100% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
SW Disposal	5.00	$/ton	2.2	ton/hr	19,274	96,370	$/ton, 2 ton/hr, 8586 hr/yr, 100% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1 Lime	90.0	$/ton	2436.5	lb/hr	10,460	941,400	$/ton, 2,437 lb/hr, 8586 hr/yr, 100% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1 Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% 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 Coal Creek
BART Emission Control Cost Analysis
Table A-9: SO2 Control - Spray Dryer and Baghouse

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering Chemical Plant Cost Index**	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F		
Expected Utiliztion Rate	100%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs				DC from IAPCS program		1997	55,548,000	
Purchased Equipment (A)				Inflation Adjusted DC		2005	66,830,065	33,398,333
Purchased Equipment Total (B)	15%	of control device cost (A)						**38,408,083**
Installation - Standard Costs	74%	of purchased equip cost (B)						28,421,982
Installation - Site Specific Costs								97,067,200
Installation Total								125,489,182
Total Direct Capital Cost, DC								163,897,265
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)						17,283,637
Total Capital Investment (TCI) = DC + IC								**181,180,902**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						6,709,521
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						22,507,741
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**29,217,263**

Uncontrolled SO2 Emission Rate	12,745	lb/hr
Scrubber Control Efficiency	90.0%	
Scrubber Bypass	0.0%	

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180.2	773.5	0%			773.5	-	NA
Total Particulates	181.1	777.4	0%			777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	0%			5557.3	-	NA
Sulfur Dioxide (SO_2)	4,027.3	17,289.1	90.0%			5,471	11,817.7	2,472

Notes & Assumptions

1 Total Direct Capital Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
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 Process, emissions and cost data listed above is for one unit.
6 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
7 Solid waste disposal cost is only for spent lime.
8 Per GRE 2/12/07 cost estimate $40/MW-hr, 540 MW

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

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**33,398,333**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	3,339,833
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	1,669,917
Purchased Equipment Total (B)	15%		**38,408,083**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	1,536,323
Handling & erection	50%	of purchased equip cost (B)	19,204,042
Electrical	8%	of purchased equip cost (B)	3,072,647
Piping	1%	of purchased equip cost (B)	384,081
Insulation	7%	of purchased equip cost (B)	2,688,566
Painting	4%	of purchased equip cost (B)	1,536,323
Installation Subtotal Standard Expenses	74%		**28,421,982**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Bypass duct modification	2,200,000
Site Specific - Other		Replacement Power- 6 months (183 days) [8]	94,867,200
Total Site Specific Costs			97,067,200
Installation Total			**125,489,182**
Total Direct Capital Cost, DC			**163,897,265**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	3,840,808
Construction & field expenses	20%	of purchased equip cost (B)	7,681,617
Contractor fees	10%	of purchased equip cost (B)	3,840,808
Start-up	1%	of purchased equip cost (B)	384,081
Performance test	1%	of purchased equip cost (B)	384,081
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	1,152,242
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	**17,283,637**
Total Capital Investment (TCI) = DC + IC			**181,180,902**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**181,144,526**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 8586 hr/yr	79,421
Supervisor	15%	15% of Operator Costs	11,913
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr	39,710
Maintenance Materials	100%	of maintenance labor costs	39,710
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 4,503 kW-hr, 8586 hr/yr, 100% utilization	1,957,404
NA	NA		-
Water	0.31	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization	545,860
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 8586 hr/yr, 100% utilization	788,176
WW Treat Neutralization	1.64	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization	2,886,172
NA	NA		-
SW Disposal	5.00	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization	17,971
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 837 lb/hr, 8586 hr/yr, 100% utilization	323,482
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	33.71	$/bag, 795 bags, 8586 hr/yr, 100% utilization	19,702
Total Annual Direct Operating Costs			**6,709,521**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	102,452
Administration (2% total capital costs)	2%	of total capital costs (TCI)	3,623,618
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,811,809
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,811,809
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	15,158,053
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**22,507,741**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**29,217,263**

See Summary page for notes and assumptions

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

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	2	years	
CRF	0.5416		
Rep part cost per unit	33.711	$/bag	
Amount Required	795		
Total Rep Parts Cost	28,140	Cost adjusted for freight & sales tax	
Installation Labor	8,236	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	**36,376**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag
Annualized Cost	**19,702**		

Electrical Use	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	2,488,000		10			4503.3	
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						4503.3	

Baghouse Filter Cost							See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	10,661	ft^2					
Cages	10 ft long	5 in dia	13.42	area/cage ft^2	795 Cages	11.036	$/cage
Bags	1.69	$/ft2 of fabric				22.68	$/bag
Total						33.711	
Lime Use	869.85	lb/hr SO2	0.96	lb Lime/lb SO2		837.23	lb/hr Lime
Water Makeup Rate/WW Disch =	3418 gpm						
Baseline scrubber bypass:	27.0%						
Baseline scrubber efficiency:	93.7%						

	Operating Cost Calculations			**Annual hours of operation:**			**8,586**	
				Utilization Rate:			**100%**	
	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37	$/Hr	2.0	hr/8 hr shift	2,147	79,421	$/Hr, 2.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	11,913	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	1,073	39,710	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	39,710	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	4503.3	kW-hr	38,665,162	1,957,404	$/kwh, 4,503 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	3,418.0	gpm	1,760,837	545,860	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	2	scfm/kacfm	2,563,436	788,176	$/kscf, 2 scfm/kacfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	3,418.0	gpm	1,760,837	2,886,172	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.4	ton/hr	3,594	17,971	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	837.2	lb/hr	3,594	323,482	$/ton, 837 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	33.71	$/bag	795	bags	NA	19,702	$/bag, 795 bags, 8586 hr/yr, 100% 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 Coal Creek
BART Emission Control Cost Analysis
Table A-10: SO2 Control - Existing Wet Scrubber + Coal Drying

Operating Unit: **Unit 1 or 2**

						Chemical Engineering Chemical Plant Cost Index	
Emission Unit Number	NA		Stack/Vent Number	NA			
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F		
Expected Utiliztion Rate	100%		Temperature	330	Deg F	2004	442
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm	Inflation Adj	1.05
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F		
			Dry Std Flow Rate	1,205,997	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			51,000,000
Purchased Equipment Total (B)	15%	of control device cost (A)	**58,650,000**
Installation - Standard Costs	85%	of purchased equip cost (B)	49,852,500
Installation - Site Specific Costs			27,215,200
Installation Total			77,067,700
Total Direct Capital Cost, DC			50,675,200
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	20,527,500
Total Capital Investment (TCI) = DC + IC			**71,202,700**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,037,198
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	8,806,302
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,843,501**

Uncontrolled SO2 Emission Rate	12,745	lb/hr
Scrubber Control Efficiency	92.3%	
Scrubber Bypass	10.0%	

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180	773				773	-	NA
Total Particulates	181	777				777	-	NA
Nitrous Oxides (NOx)	1,294	5,557				5,557	-	NA
Sulfur Dioxide (SO_2)	4,027	17,289	83.1%			9,263	8,026	1,226

Notes & Assumptions

1 Total installed cost per URS Proposal 10/26/04 & Chimney Consultants Proposal 9/22/04.
MM$51 for coal drying addition from Coal Drying Incremental Benefit and Cost Model spread sheet 02/05/2007
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1
3 Liquid/Gas ratio = 10 L/G = Gal/1,000 acf
4 Water Makeup Rate/Wastewater Discharge = 20% of circulating water rate
5 Process, emissions and cost data listed above is for one unit.
6 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
7 Per GRE 2/12/07 cost estimate $40/MW-hr, 540 MW
8 Installed capital cost per G. Riveland 04/13/06

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-10: SO2 Control - Existing Wet Scrubber + Coal Drying

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**51,000,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	5,100,000
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	2,550,000
Purchased Equipment Total (B)	15%		**58,650,000**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	7,038,000
Handling & erection	40%	of purchased equip cost (B)	23,460,000
Electrical	1%	of purchased equip cost (B)	586,500
Piping	30%	of purchased equip cost (B)	17,595,000
Insulation	1%	of purchased equip cost (B)	586,500
Painting	1%	of purchased equip cost (B)	586,500
Installation Subtotal Standard Expenses	85%		**49,852,500**
Site Preparation, as required		Bypass duct modification	2,200,000
Buildings, as required		Stack Modifications, Installed Cost [8]	10,500,000
Site Specific - Other		Replacement Power - two 14-day outage [7]	14,515,200
Total Site Specific Costs			27,215,200
Installation Total			**77,067,700**
Total Direct Capital Cost, DC			**50,675,200**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	5,865,000
Construction & field expenses	10%	of purchased equip cost (B)	5,865,000
Contractor fees	10%	of purchased equip cost (B)	5,865,000
Start-up	1%	of purchased equip cost (B)	586,500
Performance test	1%	of purchased equip cost (B)	586,500
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	1,759,500
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	**20,527,500**
Total Capital Investment (TCI) = DC + IC			**71,202,700**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**71,202,700**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.3 hr/8 hr shift, 8586 hr/yr	50,700
Maintenance Materials	100%	of maintenance labor costs	50,700
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, -235 kW-hr, 8586 hr/yr, 100% utilization	-101,972
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 2 ton/hr, 8586 hr/yr, 100% utilization	96,370
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 2,437 lb/hr, 8586 hr/yr, 100% utilization	941,400
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**1,037,198**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	NA
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,424,054
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	712,027
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	712,027
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	5,958,194
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**8,806,302**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,843,501**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-10: SO2 Control - Existing Wet Scrubber + Coal Drying

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/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		D P in H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,234,300		3.28		-	-234.6	Incremental ID fan power increase, GRE G. Riveland 4/5/06 email
	Flow	Liquid SPGR	D 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
Other							
Other							
Other							
Total						-234.6	

Reagent Use & Other Operating Costs						
Caustic Use	0.00	lb/hr SO2	2.50	lb NaOH/lb SO2	0.00	lb/hr Caustic
Lime Use	0.00	lb/hr SO2	0.96	lb Lime/lb SO2	0.00	lb/hr Lime

Liquid/Gas ratio 0.0 * L/G = Gal/1,000 acf
Circulating Water Rate 0 gpm
Water Makeup Rate/WW Disch = 2% of circulating water rate = 0 gpm

Operating Cost Calculations **Annual hours of operation:** **8,586**
Utilization Rate: **100%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	0	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	1.3	hr/8 hr shift	1,370	50,700	$/Hr, 1.3 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	50,700	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	-234.6	kW-hr	-2,014,276	-101,972	$/kwh, -235 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	2.2	ton/hr	19,274	96,370	$/ton, 2 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	2436.5	lb/hr	10,460	941,400	$/ton, 2,437 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% 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 Coal Creek
BART Emission Control Cost Analysis
Table A-11: SO2 Control - Dry Sorbent Injection and Baghouse

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering Chemical Plant Cost Index**
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F	
Expected Utiliztion Rate	100%		Temperature	330	Deg F	1997 386.5
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%		2005 465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj 1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F	
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F	

Year		
1997	32,195,800	DC from IAPCS program
2005	38,734,921	Inflation Adjusted DC

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			19,357,782
Purchased Equipment Total (B)	15%	of control device cost (A)	**22,261,449**
Installation - Standard Costs	74%	of purchased equip cost (B)	16,473,472
Installation - Site Specific Costs			2,200,000
Installation Total			18,673,472
Total Direct Capital Cost, DC			38,734,921
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	10,017,652
Total Capital Investment (TCI) = DC + IC			**48,752,573**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	6,393,346
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	6,129,094
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**12,522,440**

Uncontrolled SO2 Emission Rate	12,745	lb/hr
Scrubber Control Efficiency	70.0%	
Scrubber Bypass	0.0%	

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180.2	773.5	0%			773.5	-	NA
Total Particulates	181.1	777.4	0%			777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	0%			5557.3	-	NA
Sulfur Dioxide (SO_2)	4,027.3	17,289.1	70.0%			16,414	874.9	14,313

Notes & Assumptions

1 Total Direct Capital Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
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 Process, emissions and cost data listed above is for one unit.
7 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
8 Solid waste disposal cost is only for spent lime.

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-11: SO2 Control - Dry Sorbent Injection and Baghouse

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**19,357,782**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,935,778
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	967,889
Purchased Equipment Total (B)	15%		**22,261,449**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	890,458
Handling & erection	50%	of purchased equip cost (B)	11,130,724
Electrical	8%	of purchased equip cost (B)	1,780,916
Piping	1%	of purchased equip cost (B)	222,614
Insulation	7%	of purchased equip cost (B)	1,558,301
Painting	4%	of purchased equip cost (B)	890,458
Installation Subtotal Standard Expenses	74%		**16,473,472**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Bypass duct modification	2,200,000
Total Site Specific Costs			2,200,000
Installation Total			**18,673,472**
Total Direct Capital Cost, DC			**38,734,921**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,226,145
Construction & field expenses	20%	of purchased equip cost (B)	4,452,290
Contractor fees	10%	of purchased equip cost (B)	2,226,145
Start-up	1%	of purchased equip cost (B)	222,614
Performance test	1%	of purchased equip cost (B)	222,614
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	667,843
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	**10,017,652**
Total Capital Investment (TCI) = DC + IC			**48,752,573**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**48,716,197**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 8586 hr/yr	79,421
Supervisor	15%	15% of Operator Costs	11,913
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr	39,710
Maintenance Materials	100%	of maintenance labor costs	39,710
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 4,503 kW-hr, 8586 hr/yr, 100% utilization	1,957,404
NA	NA		-
Water	0.31	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization	545,860
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 8586 hr/yr, 100% utilization	788,176
WW Treat Neutralization	1.64	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization	2,886,172
NA	NA		-
SW Disposal	5.00	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization	1,330
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 62 lb/hr, 8586 hr/yr, 100% utilization	23,948
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	33.71	$/bag, 795 bags, 8586 hr/yr, 100% utilization	19,702
Total Annual Direct Operating Costs			**6,393,346**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	102,452
Administration (2% total capital costs)	2%	of total capital costs (TCI)	975,051
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	487,526
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	487,526
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	4,076,539
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**6,129,094**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**12,522,440**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-11: SO2 Control - Dry Sorbent Injection and Baghouse

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	2	years	
CRF	0.5416		
Rep part cost per unit	33.711	$/bag	
Amount Required	795		
Total Rep Parts Cost	28,140	Cost adjusted for freight & sales tax	
Installation Labor	8,236	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	**36,376**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag
Annualized Cost	**19,702**		

Electrical Use							
	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	2,488,000		10			4503.3	
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						4503.3	

Baghouse Filter Cost							
							See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	10,661	ft^2					
Cages	10 ft long	5 in dia	13.42	area/cage ft^2	795 Cages	11.036	$/cage
Bags	1.69	$/ft2 of fabric				22.68	$/bag
Total						33.711	
Lime Use	64.40	lb/hr SO2	0.96	lb Lime/lb SO2		61.98	lb/hr Lime
Water Makeup Rate/WW Disch =		3418 gpm					
Baseline scrubber bypass:		27.0%					
Baseline scrubber efficiency:		93.7%					

Operating Cost Calculations — **Annual hours of operation:** **8,586**; **Utilization Rate:** **100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37	$/Hr	2.0	hr/8 hr shift	2,147	79,421	$/Hr, 2.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	11,913	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	1,073	39,710	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	39,710	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	4503.3	kW-hr	38,665,162	1,957,404	$/kwh, 4,503 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	3,418.0	gpm	1,760,837	545,860	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	2	scfm/kacfm	2,563,436	788,176	$/kscf, 2 scfm/kacfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralization	1.64	$/kgal	3,418.0	gpm	1,760,837	2,886,172	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatment	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	266	1,330	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	62.0	lb/hr	266	23,948	$/ton, 62 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	33.71	$/bag	795	bags	NA	19,702	$/bag, 795 bags, 8586 hr/yr, 100% 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 Coal Creek
BART Emission Control Cost Analysis
Table A-12: NOx Control - LoTOx - (Low Temperature Oxidation)

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								9,653,165
Purchased Equipment Total (B)	15%	of control device cost (A)						**11,101,139**
Installation - Standard Costs	98%	of purchased equip cost (B)						10,879,116
Installation - Site Specific Costs								NA
Installation Total								10,879,116
Total Direct Capital Cost, DC								21,980,256
Total Indirect Capital Costs, IC	25%	of purchased equip cost (B)						2,775,285
Total Capital Investment (TCI) = DC + IC								**44,328,337**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						52,548,709
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						5,520,025
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**58,068,734**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180.2	773.5				773.5	-	NA
Total Particulates	181.1	777.4				777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	90%			555.7	5,001.5	11,610
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	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. Check O2 Prices
6. Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART.
7. Flow rate, duty and costs listed above for one unit.
8. Process, emissions and cost data listed above is for one unit.
9. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-12: NOx Control - LoTOx - (Low Temperature Oxidation)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**9,653,165**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	965,316
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	482,658
Purchased Equipment Total (B)	15%		**11,101,139**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	1,332,137
Handling & erection	40%	of purchased equip cost (B)	4,440,456
Electrical	10%	of purchased equip cost (B)	1,110,114
Piping	30%	of purchased equip cost (B)	3,330,342
Insulation	5%	of purchased equip cost (B)	555,057
Painting	1%	of purchased equip cost (B)	111,011
Installation Subtotal Standard Expenses	98%		**10,879,116**
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			**10,879,116**
Total Direct Capital Cost, DC			**21,980,256**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,110,114
Construction & field expenses	10%	of purchased equip cost (B)	1,110,114
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	111,011
Performance test	1%	of purchased equip cost (B)	111,011
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	333,034
Total Indirect Capital Costs, IC	25%	of purchased equip cost (B)	**2,775,285**
Ozone Generator, Installed Cost			**19,572,797**
Total Capital Investment (TCI) = DC + IC			**44,328,337**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**44,328,337**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr	19,855
Supervisor	15%	15% of Operator Costs	2,978
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr	19,855
Maintenance Materials	100%	of maintenance labor costs	19,855
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 15,125 kW-hr, 8586 hr/yr, 100% utilization	6,574,275
NA	NA		-
Water	0.31	$/kgal, 4,976 gpm, 8586 hr/yr, 100% utilization	794,665
Cooling Water	0.27	$kgal, 5,825 gpm, 8586 hr/yr, 100% utilization	806,235
NA	NA		-
NA	NA		-
WW Treat Biotreatement	4.15	$/kgal, 4,976 gpm, 8586 hr/yr, 100% utilization	10,644,316
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Oxygen	15.00	kscf, 261 kscf/hr, 8586 hr/yr, 100% utilization	33,666,674
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**52,548,709**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	37,526
Administration (2% total capital costs)	2%	of total capital costs (TCI)	886,567
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	443,283
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	443,283
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	3,709,366
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**5,520,025**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**58,068,734**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-12: NOx Control - LoTOx - (Low Temperature Oxidation)

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/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		D P in H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,488,000		10	0.7	-	4,158.5	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**D P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	24,880 gpm	1	60	0.7	-	400.9	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	4976 gpm	1	60	0.7	-	80.2	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				10,485	
Other							
Total						15125.0	

Reagent Use & Other Operating Costs							
Ozone Needed	1.8	lb O3/lb NOx	2,330.1	lb/hr O3			
Oxygen Needed	10%	wt O2 to O3 conversion		23,301	lb/hr O2	261,408	scfh O2
LTO Cooling Water	150	gal/lb O3	5,825	gpm			
Liquid/Gas ratio	10.0	* L/G = Gal/1,000 acf					
Circulating Water Rate	24,880	gpm					
Water Makeup Rate/WW Disch =	20%	of circulating water rate =	4976 gpm				
Scrubber Cost	10	\$/scfm Gas	\$9,653,165		Incremental cost per BOC. Need to increase vessel size over standard absorber.		
Ozone Generator	\$350	lb O3/day	\$19,572,797	Installed	Installed cost factor per BOC.		

Operating Cost Calculations — **Annual hours of operation:** **8,586**; **Utilization Rate:** **100%**

	Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37	\$/Hr	0.5	hr/8 hr shift	537	19,855	\$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	2,978	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	\$/Hr	0.5	hr/8 hr shift	537	19,855	\$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	19,855	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	\$/kwh	15125.0	kW-hr	129,863,497	6,574,275	\$/kwh, 15,125 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	\$/kscf	0	scfm	0	0	\$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	\$/kgal	4,976.0	gpm	2,563,436	794,665	\$/kgal, 4,976 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	\$kgal	5,825.2	gpm	3,000,929	806,235	\$kgal, 5,825 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	\$/kscf	0	kscfm	0	0	\$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	\$/kgal	4,976.0	gpm	2,563,436	10,644,316	\$/kgal, 4,976 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	\$/ton-mi	0.0	ton/hr	0	0	\$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	\$/ton	0.0	lb/hr	0	0	\$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	\$/ton	0.0	lb/hr	0	0	\$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	261.4	kscf/hr	2,244,445	33,666,674	kscf, 261 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	\$/ft3	0	ft^3	0	0	\$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	\$/bag	0	bags	0	0	\$/bag, 0 bags, 8586 hr/yr, 100% 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 Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

Chemical Engineering Chemical Plant Cost Index	
1998/1999	390
2005	465
Inflation Adj	1.19

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation		6019	80.0%	0.22		1998	40,904,723
Purchased Equipment (A)							2005	48,771,016
Purchased Equipment Total (B)	0%	of control device cost (A)					SCR Only	**48,771,016**
Installation - Standard Costs	15%	of purchased equip cost (B)					SCR Only	8,778,783
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	**70,360,657**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					SCR + Reheat	34,405,374
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					SCR + Reheat	5,991,799
Total Annual Cost (Annualized Capital Cost + Operating Cost)							SCR + Reheat	**40,397,172**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180.2	773.5				773.5	-	NA
Total Particulates	181.1	777.4				777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	80%			1111.5	4,445.8	9,087
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
3 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.36 -2.43
4 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.32 - 2.35
5 SCR Catalyst Volume per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.18 - 2.24
6 SCR Reactor Size per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.25 - 2.31
7 SCR Catalyst Replacement per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.50 - 2.53
8 SCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.48
9 SCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.46
10 Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART
11 Reheat cost based on 180 F temperature from scrubber exhaust
12 Process, emissions and cost data listed above is for one unit.
13 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			**48,771,016**
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)			**48,771,016**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	2,438,551
Engineerin & Home Office	10%	of purchased equip cost (A)	4,877,102
Process Contingency	5%	of purchased equip cost (A)	2,438,551
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**9,754,203**
Project Contingeny (C)	15%	of (A + B)	**8,778,783**
Total Plant Cost D		A + B + C	**67,304,002**
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))	**1,346,080**
Inventory Capital		Reagent Vol * $/gal	**47,079**
Intial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**68,697,161**
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	1,030,457
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 5,177 kW-hr, 8586 hr/yr, 100% utilization	2,250,322
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Ammonia	0.92	$/lb, 1,387 lb/hr, 8586 hr/yr, 100% utilization	10,958,450
NA	NA		-
SCR Catalyst	500.00	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization	1,391,800
NA	NA		-
Total Annual Direct Operating Costs			**15,631,029**
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	5,748,532
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**5,748,532**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**21,379,562**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

Operating Unit: **Unit 1 or 2**

						Chemical Engineering Chemical Plant Cost Index	
Emission Unit Number	NA		Stack/Vent Number	NA			
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F		
Expected Utiliztion Rate	100%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation		6019	80.0%	0.22		1998	40,904,723
Purchased Equipment (A)							2005	48,771,016
Purchased Equipment Total (B)	0%	of control device cost (A)					SCR Only	**48,771,016**
Installation - Standard Costs	15%	of purchased equip cost (B)					SCR Only	8,778,783
Installation - Site Specific Costs								0
Installation Total								13,750,000
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	**84,110,657**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					SCR + Reheat	49,011,624
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					SCR + Reheat	7,142,389
Total Annual Cost (Annualized Capital Cost + Operating Cost)							SCR + Reheat	**56,154,013**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180.2	773.5				773.5	-	NA
Total Particulates	181.1	777.4				777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	80%			1111.5	4,445.8	12,631
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions
1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
3 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.36 -2.43
4 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.32 - 2.35
5 SCR Catalyst Volume per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.18 - 2.24
6 SCR Reactor Size per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.25 - 2.31
7 SCR Catalyst Replacement per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.50 - 2.53
8 SCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.48
9 SCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.46
10 Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART
11 Reheat cost based on 180 F temperature from scrubber exhaust
12 Process, emissions and cost data listed above is for one unit.
13 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			**48,771,016**
Instrumentation	10%	of control device cost (A)	NA
ND Sales Taxes	0%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**48,771,016**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	2,438,551
Engineering & Home Office	10%	of purchased equip cost (A)	4,877,102
Process Contingency	5%	of purchased equip cost (A)	2,438,551
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**9,754,203**
Project Contingeny (C)	15%	of (A + B)	**8,778,783**
Total Plant Cost D		A + B + C	**67,304,002**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Sunk Capital Investmet (F)		Flyash sales infrastructure loss	**13,750,000**
Pre Production Costs (G)	2%	of (D+E))	**1,346,080**
Inventory Capital		Reagent Vol * $/gal	**47,079**
Intial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**82,447,161**
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	1,236,707
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 5,177 kW-hr, 8586 hr/yr, 100% utilization	2,250,322
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Lost Ash Sales	36.00	$/ton, 47 ton/hr, 8586 hr/yr, 100% utilization	14,400,000
NA	NA		-
Ammonia	0.92	$/lb, 1,387 lb/hr, 8586 hr/yr, 100% utilization	10,958,450
NA	NA		-
SCR Catalyst	500.00	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization	1,391,800
NA	NA		-
Total Annual Direct Operating Costs			**30,237,279**
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	6,899,123
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**6,899,123**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**37,136,403**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

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	12
Replacement Factor	12	Layers replaced per year =		1
Amount Required	8,819	ft^3		
Catalyst Cost	4,409,257			
Y catalyst life factor	3	Years		
Annualized Cost	**1,391,800**			

SCR Capital Cost per EPRI Method			**40,904,723**				
Duty	6,019	MMBtu/hr	Catalyst Area	2,904	ft^2	360	*f* (h SCR)
Q flue gas	2,787,396	acfm	Rx Area	3,339		-24	*f* (h NH_3)
NOx Cont Eff	80%	(as faction)	Rx Height	57.8	ft	-728	*f* (h New) new= -728, Retrofit = 0
NOx in	0.22	lb/MMBtu	n layer	12	layers	Y	Bypass? Y or N
Ammina Slip	2	ppm	h layer	13.1	ft	127	*f* (h Bypass)
Fuel Sulfur	0.67	wt % (as %)	n total	13	layers	25,397,317	*f* (vol catalyst)
Temperature	330	Deg F	h SCR	90	ft		*f* (h SCR)
Catalyst Volume	**105,822**	ft^3	New/Retrofit	N	N or R		

Electrical Use				
Duty	6,019	MMBtu/hr		kW
NOx Cont Eff	80%	(as faction)	Power	5,177.2
NOx in	0.22	lb/MMBtu		
n catalyst layers	13	layers		
Press drop catalyst	1	in H_2O per layer		
Press drop duct	3	in H_2O		
Total				5177.2

Reagent Use & Other Operating Costs			Ammonia Use			
NOx in	0.22	lb/MMBtu	402	lb/hr Neat		
Efficiency	80%		29%	solution	56.0	lb/ft^3 Density
Duty	6,019	MMBtu/hr	1387	lb/hr	185.3	gal/hr
		Volume 14 day inventory	62,270	gal	$47,079	Inventory Cost

Operating Cost Calculations — **Annual hours of operation:** **8,586** — **Utilization Rate:** **100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maintenance Total	1.5	% of Total Capital Investment				1,236,707	% 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	5177.2	kW-hr	44,451,242	2,250,322	$/kwh, 5,177 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gph	0	0	$/kgal, 0 gph, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	36.00	$/ton	46.6	ton/hr	400,000	14,400,000	$/ton, 47 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
7	Ammonia	0.92	$/lb	1387	lb/hr	11,911,359	10,958,450	$/lb, 1,387 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	1,391,800	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% 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 Coal Creek
BART Emission Control Cost Analysis
Table A-14: 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/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		D P in H2O	Efficiency	Hp	kW	
Blower, Thermal	2,488,000		19	0.6		9,218.0	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Blower, Catalytic	2,488,000		23	0.6		11,158.7	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Oxidizer Type	**thermal**	(catalytic or thermal)				9218.0	

Reagent Use & Other Operating Costs Oxidizers - NA

Operating Cost Calculations — **Annual hours of operation:** **8,586**; **Utilization Rate:** **100%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37	$/Hr	0.5	hr/8 hr shift	537	19,855	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	2,978	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.5	hr/8 hr shift	537	19,855	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	19,855	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	9218.0	kW-hr	79,146,091	4,006,731	$/kwh, 9,218 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	4,167	scfm	2,146,725	14,705,069	$/kscf, 4,167 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
2	CO Catalyst	650	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% utilization

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

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-14: 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}	180	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}	369	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	261	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}	1,550,000	scfm - Flow of waste gas
Q_{af}	4,167	scfm - Flow of auxiliary fuel

Year 2005 Inflation Rate 3.0%

Cost Calculations 1,554,167 scfm Flue Gas Cost in 1989 $'s $753,546

Current Cost Using CHE Plant Cost Index $898,458

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 Coal Creek
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	100%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation, 1998 $'s		6019	50.0%	0.22		1998	3,627,729
Purchased Equipment (A)							2005	4,325,369
Purchased Equipment Total (B)	0%	of control device cost (A)						**4,325,369**
Installation - Standard Costs	15%	of purchased equip cost (B)						778,566
Installation - Site Specific Costs								0
Installation Total								13,750,000
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**19,909,069**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						21,231,102
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,665,978
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**22,897,080**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180.2	773.5				773.5	-	NA
Total Particulates	181.1	777.4				777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	50.0%			2778.6	2,778.6	8,240
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1
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
9 Control Efficiency = % reduction needed to meet presumptive BART of 0.29 lb/MMBtu
10 Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART
11 Process, emissions and cost data listed above is for one unit.
12 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-15: 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			**4,325,369**
Instrumentation	10%	of control device cost (A)	NA
ND Sales Taxes	0%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**4,325,369**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	216,268
Engineering & Home Office	10%	of purchased equip cost (A)	432,537
Process Contingency	5%	of purchased equip cost (A)	216,268
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**865,074**
Project Contingeny (C)	15%	of (A + B)	**778,566**
Total Plant Cost D		A + B + C	**5,969,009**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Sunk Capital Investmet (F)		Flyash sales infrastructure loss	**13,750,000**
Pre Production Costs (G)	2%	of (D+E))	**119,380**
Inventory Capital		Reagent Vol * $/gal	**70,680**
Intial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**19,909,069**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**19,909,069**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	15.00	% of Total Capital Investment	2,986,360
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 79 kW-hr, 8586 hr/yr, 100% utilization	34,178
NA	NA		-
Water	0.31	$/kgal, 498 gph, 8586 hr/yr, 100% utilization	1,325
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 47 ton/hr, 8586 hr/yr, 100% utilization	2,003,101
NA	NA		-
NA	NA		-
Lost Ash Sales	36.00	$/ton, 47 ton/hr, 8586 hr/yr, 100% utilization	14,400,000
NA	NA		-
Urea	405.00	$/ton, 1 ton/hr, 8586 hr/yr, 100% utilization	1,806,138
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**21,231,102**
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	1,665,978
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,665,978**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**22,897,080**

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-15: 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	0.22	lb/MMBtu	kW
NSR	1.23		
Power			78.6
Total			78.6

Reagent Use & Other Operating Costs			Urea Use				
NOx in	0.22	lb/MMBtu		519	lb/hr Neat		
Efficiency	50%			50%	solution	71.0	lb/ft^3 Density 50% Solution
Duty	6,019	MMBtu/hr		1039	lb/hr	109.5	gal/hr
			Volume 14 day inventory	36,777	gal	$70,680	Inventory Cost
Water Use	498	gal/hr	Inject at 10% solution				
						10.74	wt % ash
Fuel Use	8.41	MMBtu/hr				37.30	% Coal Moisture Content
						0.73	% Coal Sulfur Content
Ash Generation	144.47	lb/hr				6,257	Btu/lb of coal

Operating Cost Calculations — **Annual hours of operation: 8,586** — **Utilization Rate: 100%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maintenance Total	15	% of Total Capital Investment				2,986,360	% 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	78.6	kW-hr	675,122	34,178	$/kwh, 79 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	497.9	gph	4,275	1,325	$/kgal, 498 gph, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	46.7	ton/hr	400,620	2,003,101	$/ton, 47 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	36.00	$/ton	46.6	ton/hr	400,000	14,400,000	$/ton, 47 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
3	Urea	405	$/ton	0.5194	ton/hr	4,460	1,806,138	$/ton, 1 ton/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% 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 Coal Creek
BART Emission Control Cost Analysis
Table A-16: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #2

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			1,000,000
Purchased Equipment Total (B)	5%	of control device cost (A)	**1,050,000**
Installation - Standard Costs	0%	of purchased equip cost (B)	4,000,000
Installation - Site Specific Costs			NA
Installation Total			4,000,000
Total Direct Capital Cost, DC			5,050,000
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	210,000
Total Capital Investment (TCI) = DC + IC			**5,260,000**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	7,942
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	655,319
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**663,261**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180.2	773.5				773.5	-	NA
Total Particulates	181.1	777.4				777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	30%			3877.2	1,680.1	395
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1 Sept 2005 Cost Estimate from Foster Wheeler, Option 1. Assumed price listed is for one unit. Costs in spreadsheet are for one unit
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 Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4 Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART
5 Process, emissions and cost data listed above is for one unit.
6 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-16: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #2

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**1,000,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	0%	of control device cost (A)	0
Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	50,000
Purchased Equipment Total (B)	5%		**1,050,000**
Installation			
Foundations & supports		of purchased equip cost (B)	0
Handling & erection		of purchased equip cost (B)	0
Electrical	10%	of purchased equip cost (B)	105,000
Piping		of purchased equip cost (B)	0
Insulation	15%	of purchased equip cost (B)	157,500
Painting		of purchased equip cost (B)	0
Installation Subtotal Standard Expenses (1)			**4,000,000**
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			**4,000,000**
Total Direct Capital Cost, DC			**5,050,000**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	52,500
Construction & field expenses	10%	of purchased equip cost (B)	105,000
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	10,500
Performance test	1%	of purchased equip cost (B)	10,500
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	31,500
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	**210,000**
Ozone Generator, Installed Cost			**0**
Total Capital Investment (TCI) = DC + IC			**5,260,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**5,260,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 8586 hr/yr	3,971
Maintenance Materials	100%	of maintenance labor costs	3,971
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			**7,942**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,765
Administration (2% total capital costs)	2%	of total capital costs (TCI)	105,200
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	52,600
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	52,600
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	440,153
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**655,319**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**663,261**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-16: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #2

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/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		D P in H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,488,000		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**D 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: 8,586** — **Utilization Rate: 100%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	0	$/Hr	0.1	hr/8 hr shift	107	0	$/Hr, 0.1 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	107	3,971	$/Hr, 0.1 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	3,971	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% 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 Coal Creek
BART Emission Control Cost Analysis
Table A-17: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #1

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								500,000
Purchased Equipment Total (B)	5%	of control device cost (A)						**525,000**
Installation - Standard Costs	0%	of purchased equip cost (B)						2,000,000
Installation - Site Specific Costs								NA
Installation Total								2,000,000
Total Direct Capital Cost, DC								2,525,000
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)						105,000
Total Capital Investment (TCI) = DC + IC								**2,630,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,942
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						330,042
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**337,984**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180.2	773.5				773.5	-	NA
Total Particulates	181.1	777.4				777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	21%			4394.1	1,163.2	291
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1 Sept 2005 Cost Estimate from Foster Wheeler, Option 1. Assumed price listed is for one unit. Costs in spreadsheet are for one unit
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 Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4 Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART
5 Process, emissions and cost data listed above is for one unit.
6 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-17: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #1

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**500,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	0%	of control device cost (A)	0
Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	25,000
Purchased Equipment Total (B)	5%		**525,000**
Installation			
Foundations & supports		of purchased equip cost (B)	0
Handling & erection		of purchased equip cost (B)	0
Electrical		of purchased equip cost (B)	0
Piping		of purchased equip cost (B)	0
Insulation		of purchased equip cost (B)	0
Painting		of purchased equip cost (B)	0
Installation Subtotal Standard Expenses (1)			**2,000,000**
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			**2,000,000**
Total Direct Capital Cost, DC			**2,525,000**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	26,250
Construction & field expenses	10%	of purchased equip cost (B)	52,500
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	5,250
Performance test	1%	of purchased equip cost (B)	5,250
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	15,750
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	**105,000**
Total Capital Investment (TCI) = DC + IC			**2,630,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**2,630,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 8586 hr/yr	3,971
Maintenance Materials	100%	of maintenance labor costs	3,971
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			**7,942**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,765
Administration (2% total capital costs)	2%	of total capital costs (TCI)	52,600
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	26,300
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	26,300
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	220,077
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**330,042**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**337,984**

See Summary page for notes and assumptions

Great River Energy Coal Creek

BART Emission Control Cost Analysis

Table A-17: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #1

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/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		D P in H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,488,000		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**D 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: 8,586** — **Utilization Rate: 100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	0	$/Hr	0.1	hr/8 hr shift	107	0	$/Hr, 0.1 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	107	3,971	$/Hr, 0.1 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	3,971	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% utilization

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

See Summary page for notes and assumptions

Appendix C

Coal Sulfur Content Variability

Sulfur Content Statistical Variability Analysis

For the purpose of establishing representative SO_2 emission rate predictions, past actual and future predicted coal sulfur content data for Falkirk Mine was analyzed. Table 1 presents an analysis of Coal Creek Station's past actual daily coal sulfur content. The analyzed data set includes 3,136 daily readings covering the time period from September 1997 through mid-May 2006, and is used to illustrate the variability between a 30-day rolling and 30-day block average. Past actual and future predicted mine plan 30-day block data presented in Section 7.2 of the report are recreated below in Figure 1. In order to include at least 98% of expected scenarios and appropriately determine an operational limit on a 30-day rolling average from the 30-day block averages, 14% variability must be assessed. This provides a degree of comfort with the operational limit and expected variability determined from past operational data.

The data presented in Figure 1 is calculated from core samples using a Falkirk mine plan modeling program. The predicted as delivered (AD) pounds of SO_2 per MMBtu is derived from the model. Consequently, the predicted AD pounds of SO_2 per MMBtu will change as the mine plan changes. The mine planning model uses grids generated from drilling and coring data. The in situ sulfur and Btu grids are built using the quality analysis from core samples. Once this is complete, a dilution factor is added in to get the AD sulfur and AD Btu. The dilution factor is needed to account for non-coal (clay) material which is present in the delivered coal as a result of the mining process. The amount of dilution used in the model is periodically adjusted by comparing the model predictions to past actual delivered quality reported by GRE.

The statistical analysis presented in Figure 1 is based on the 2004 mine plan which was available at the time of initial BART analysis submittal. Mine plans are variable in nature, and are therefore used only as an estimation tool, not a definitive statement of future emissions. The individual core sample IDs and characteristics will not be provided as supporting information to this graphic. It is virtually impossible to obtain a representative sample of the coal characteristics using core samples, and this model is only used to plan the mining operation and not to certify the sulfur content or heating values of future coal deliveries. The core samples cannot provide guaranteed estimates for quantities of the coal that will possess the specific characteristics of that core sample; only that some quantity of coal underground has those characteristics. The data provided by the mine plan model is used to incorporate a prediction of future worst case conditions, which in combination with past actual data, assists with the evaluation of SO_2 control technologies.

Table 1. Variability between 30-Day Rolling and 30-Day Block Calendar Month Averages

% Variability	Count	Cumulative %
0%	582	18.6%
1%	666	39.8%
2%	524	56.5%
3%	342	67.4%
4%	284	76.5%
5%	181	82.2%
6%	104	85.6%
7%	74	87.9%
8%	74	90.3%
9%	66	92.4%
10%	70	94.6%
11%	32	95.6%
12%	42	97.0%
13%	25	97.8%
14%	12	98.2%
15%	7	98.4%
16%	8	98.6%
17%	6	98.8%
18%	13	99.2%
19%	6	99.4%
20%	5	99.6%
21%	1	99.6%
22%	1	99.6%
23%	0	99.6%
24%	1	99.7%
25%	1	99.7%
26%	0	99.7%
27%	1	99.7%
28%	0	99.7%
29%	2	99.8%
30%	3	99.9%
31%	3	100.0%

.

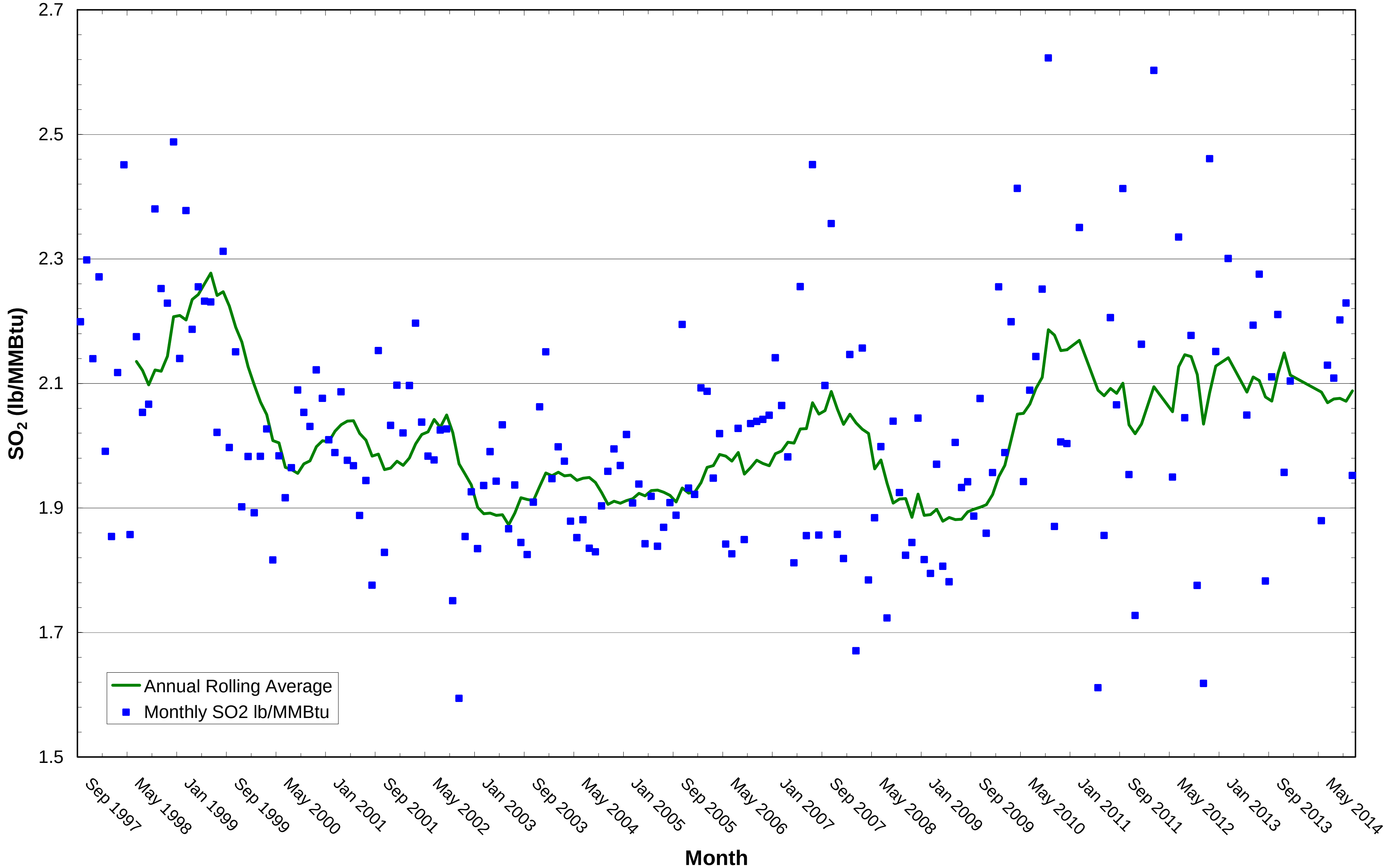

Figure 1. Past Actual and Future Predicted Monthly lb SO_2/MMBtu. Coal Creek sampling data is used to determine the 30-day block monthly average sulfur content from 1997 through 2006 and the Falkirk Mine Plan provides monthly predicting for future sulfur content from 2006 through 2014.

Appendix B

Cost Threshold Documentation

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

Reference	Regulatory Body/Rule	Avg. Expected Values ($/ton)		Limiting/Marginal values ($/ton)		Comments
		SO_2	NOx	SO_2	NOx	
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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GREAT RIVER ENERGY®

17845 East Highway 10 • PO Box 800 • Elk River, Minnesota 55330-0800 • 763-441-3121 • Fax 763-241-2366

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

[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	0.9
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	1222	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 NO_X CONTROLS FOR BART-ELIGIBLE COAL-FIRED UNITS

Unit type	Coal type	Number units nation-wide	National average ($/ton)
Dry-bottom wall-fired	Bituminous	114	1229
	Sub-bituminous	66	576
	Lignite	3	1296
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	599
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 D

Visibility Modeling Output Files

Revised Pages February 2007

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

Ms. Dianne Stockdill
Environmental Coordinator
Great River Energy
2875 Third Street SW
Underwood, ND 58576

Dear Ms. Stockdill:

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 Coal Creek Generating Station Units 1 and 2 are BART-eligible sources. Completed visibility modeling for the Coal Creek Station (Units 1 and 2 combined) indicates that the maximum 98th percentile delta-deciview prediction for the facility exceeds the BART screening threshold of 0.5 deciviews. Therefore, Coal Creek Units 1 and 2 are subject to BART.

Two summaries of modeling results are enclosed. Attachment A provides a summary of 98th percentile predictions for the worst-case meteorological year for all BART-eligible facilities. Attachment B provides more detailed results specific to the Coal Creek Generating Station. 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 appropriate BART control strategies for Coal Creek Units 1 and 2.

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
Coal Creek Station Unit 1 (Scenario 0, Pre-BART) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 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	2.915	5.149	2.234	2000	72	53	107	2.80	68.34	30.91	0.26	0.49
98th %tile Delta-DV	1.229	3.399	2.170	2000	164	51	105	2.50	96.84	1.72	0.53	0.91
90th %tile Delta-DV	0.299	2.405	2.106	2000	214	46	46	2.20	96.52	1.60	0.79	1.08

Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 11
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)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.851	5.085	2.234	2000	74	67	56	2.80	76.95	22.60	0.06	0.39
98th %tile Delta-DV	0.941	3.175	2.234	2000	36	82	71	2.80	60.35	38.73	0.25	0.67
90th %tile Delta-DV	0.318	2.424	2.106	2000	214	82	71	2.20	97.68	1.05	0.31	0.96

Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 7
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)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.918	5.152	2.234	2000	74	90	72	2.80	76.04	23.52	0.06	0.39
98th %tile Delta-DV	0.777	3.010	2.234	2000	54	90	72	2.80	77.58	21.66	0.25	0.51
90th %tile Delta-DV	0.212	2.361	2.149	2000	199	90	72	2.40	92.17	5.82	0.68	1.33

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: 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	3.941	6.216	2.275	2000	47	99	81	2.90	72.86	26.64	0.16	0.33
98th %tile Delta-DV	1.183	3.415	2.232	2000	196	99	81	2.70	89.63	8.06	0.71	1.61
90th %tile Delta-DV	0.503	2.735	2.232	2000	185	99	81	2.70	91.19	7.65	0.34	0.82

Number of days with Delta-Deciview > 0.50: 37
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 0, Pre-BART) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	5.024	7.258	2.234	2000	72	53	107	2.80	66.43	32.84	0.25	0.48
98th %tile Delta-DV	2.176	4.346	2.170	2000	164	51	105	2.50	97.09	1.47	0.53	0.92
90th %tile Delta-DV	0.553	2.680	2.127	2000	100	51	105	2.30	63.30	35.11	0.55	1.04

Number of days with Delta-Deciview > 0.50: 41
Number of days with Delta-Deciview > 1.00: 22
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	4.550	6.783	2.234	2000	74	67	56	2.80	82.48	17.04	0.06	0.42
98th %tile Delta-DV	1.836	4.069	2.234	2000	36	82	71	2.80	58.41	40.68	0.25	0.66
90th %tile Delta-DV	0.586	2.734	2.149	2000	183	82	71	2.40	93.83	4.90	0.41	0.86

Number of days with Delta-Deciview > 0.50: 41
Number of days with Delta-Deciview > 1.00: 19
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	4.813	7.046	2.234	2000	74	90	72	2.80	78.69	20.85	0.07	0.40
98th %tile Delta-DV	1.391	3.497	2.106	2000	265	90	72	2.20	87.87	11.21	0.28	0.64
90th %tile Delta-DV	0.401	2.635	2.234	2000	56	90	72	2.80	74.35	24.92	0.22	0.51

Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 15
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	5.654	7.930	2.275	2000	47	99	81	2.90	86.27	13.15	0.19	0.39
98th %tile Delta-DV	2.157	4.432	2.275	2000	72	97	79	2.90	69.75	29.78	0.16	0.30
90th %tile Delta-DV	0.945	3.177	2.232	2000	204	96	78	2.70	66.55	32.48	0.34	0.63

Number of days with Delta-Deciview > 0.50: 58
Number of days with Delta-Deciview > 1.00: 33
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 1) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 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 Species RECEP	F(RH)	% of Modeled Extinction by %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.383	3.616	2.234	2000	72	53	107	2.80	53.98	43.94	0.70	1.38
98th %tile Delta-DV	0.439	2.673	2.234	2000	75	56	110	2.80	59.78	38.65	0.23	1.34
90th %tile Delta-DV	0.109	2.237	2.127	2000	101	46	46	2.30	51.59	45.04	0.87	2.50

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: 1

TRNP NORTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	% of Modeled Extinction by %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.219	3.452	2.234	2000	74	67	56	2.80	66.62	32.12	0.17	1.10
98th %tile Delta-DV	0.493	2.768	2.276	2000	316	85	114	3.00	55.05	43.38	0.60	0.96
90th %tile Delta-DV	0.117	2.350	2.234	2000	48	82	71	2.80	67.15	32.12	0.12	0.61

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: 1

TRNP ELKHORN RANCH

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	% of Modeled Extinction by %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.292	3.525	2.234	2000	74	90	72	2.80	65.79	32.96	0.18	1.07
98th %tile Delta-DV	0.303	2.537	2.234	2000	69	90	72	2.80	42.73	54.13	1.27	1.86
90th %tile Delta-DV	0.093	2.327	2.234	2000	56	90	72	2.80	64.31	33.68	0.60	1.41

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

LOSTWOOD NWA

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	% of Modeled Extinction by %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.862	4.138	2.275	2000	47	99	81	2.90	61.39	37.26	0.43	0.92
98th %tile Delta-DV	0.486	2.653	2.167	2000	216	97	79	2.40	71.10	25.73	1.32	1.85
90th %tile Delta-DV	0.192	2.359	2.167	2000	215	99	81	2.40	63.48	25.76	4.16	6.60

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: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 1) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 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 Species RECEP	F(RH)	% of Modeled Extinction by %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.620	4.854	2.234	2000	72	53	107	2.80	53.94	44.12	0.65	1.29
98th %tile Delta-DV	0.860	3.094	2.234	2000	75	56	110	2.80	59.84	38.69	0.21	1.25
90th %tile Delta-DV	0.217	2.344	2.127	2000	101	46	46	2.30	51.80	45.04	0.82	2.35

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

TRNP NORTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.302	4.535	2.234	2000	74	67	56	2.80	66.71	32.11	0.15	1.03
98th %tile Delta-DV	0.959	3.235	2.276	2000	316	85	114	3.00	55.14	43.39	0.56	0.90
90th %tile Delta-DV	0.235	2.468	2.234	2000	48	82	71	2.80	67.16	32.15	0.11	0.57

Number of days with Delta-Deciview > 0.50: 16
Number of days with Delta-Deciview > 1.00: 6
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 Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.432	4.666	2.234	2000	74	90	72	2.80	65.88	32.95	0.17	1.00
98th %tile Delta-DV	0.596	2.830	2.234	2000	69	90	72	2.80	42.86	54.21	1.19	1.74
90th %tile Delta-DV	0.186	2.420	2.234	2000	56	90	72	2.80	64.41	33.71	0.56	1.32

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: 1

LOSTWOOD NWA

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	3.470	5.745	2.275	2000	47	99	81	2.90	61.59	37.14	0.41	0.86
98th %tile Delta-DV	0.954	3.121	2.167	2000	216	97	79	2.40	71.27	25.77	1.23	1.73
90th %tile Delta-DV	0.376	2.543	2.167	2000	215	99	81	2.40	64.11	25.79	3.89	6.20

Number of days with Delta-Deciview > 0.50: 28
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
Coal Creek Station Unit 1 (Scenario 2) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.352	3.585	2.234	2000	72	53	107	2.80	48.95	49.31	0.60	1.14
98th %tile Delta-DV	0.494	2.728	2.234	2000	75	56	110	2.80	52.28	46.33	0.21	1.18
90th %tile Delta-DV	0.125	2.274	2.149	2000	184	48	102	2.40	76.35	21.47	0.73	1.44

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: 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	1.227	3.460	2.234	2000	74	67	56	2.80	59.58	39.28	0.14	0.99
98th %tile Delta-DV	0.446	2.679	2.234	2000	36	82	71	2.80	40.08	57.92	0.55	1.45
90th %tile Delta-DV	0.124	2.294	2.170	2000	164	82	71	2.50	68.75	28.23	0.90	2.11

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: 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	1.268	3.502	2.234	2000	74	90	72	2.80	58.36	40.51	0.16	0.97
98th %tile Delta-DV	0.314	2.548	2.234	2000	54	90	72	2.80	60.03	38.06	0.63	1.29
90th %tile Delta-DV	0.088	2.343	2.255	2000	31	90	72	2.90	42.25	55.39	0.74	1.62

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	1.824	4.100	2.275	2000	47	99	81	2.90	53.87	44.94	0.39	0.80
98th %tile Delta-DV	0.499	2.645	2.145	2000	136	99	81	2.30	45.57	51.66	1.01	1.76
90th %tile Delta-DV	0.215	2.447	2.232	2000	208	91	73	2.70	76.27	21.34	0.49	1.90

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 2) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 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	2.558	4.792	2.234	2000	72	53	107	2.80	48.86	49.51	0.56	1.07
98th %tile Delta-DV	0.970	3.203	2.234	2000	75	56	110	2.80	52.37	46.34	0.19	1.10
90th %tile Delta-DV	0.251	2.378	2.127	2000	101	46	46	2.30	45.21	52.12	0.68	1.98

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: 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	2.326	4.560	2.234	2000	74	67	56	2.80	59.64	39.30	0.13	0.93
98th %tile Delta-DV	0.909	3.143	2.234	2000	54	82	71	2.80	51.97	46.47	0.55	1.01
90th %tile Delta-DV	0.245	2.415	2.170	2000	164	82	71	2.50	69.06	28.11	0.84	1.98

Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 6
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	2.419	4.652	2.234	2000	74	90	72	2.80	58.46	40.49	0.15	0.90
98th %tile Delta-DV	0.627	2.733	2.106	2000	265	90	72	2.20	66.05	31.84	0.64	1.46
90th %tile Delta-DV	0.175	2.302	2.127	2000	109	90	72	2.30	18.62	74.81	2.79	3.77

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: 1

LOSTWOOD NWA

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	3.354	5.630	2.275	2000	47	99	81	2.90	54.03	44.86	0.36	0.75
98th %tile Delta-DV	0.983	3.128	2.145	2000	136	99	81	2.30	45.55	51.85	0.95	1.65
90th %tile Delta-DV	0.426	2.571	2.145	2000	247	91	73	2.30	62.84	35.39	0.35	1.42

Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2

CCALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 3) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 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	1.275	3.509	2.234	2000	72	53	107	2.80	52.09	46.06	0.64	1.21
98th %tile Delta-DV	0.467	2.701	2.234	2000	75	56	110	2.80	55.37	43.16	0.22	1.25
90th %tile Delta-DV	0.119	2.247	2.127	2000	101	46	46	2.30	48.00	48.98	0.78	2.25

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: 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	1.172	3.405	2.234	2000	74	67	56	2.80	62.56	36.25	0.15	1.04
98th %tile Delta-DV	0.416	2.649	2.234	2000	36	82	71	2.80	43.05	54.80	0.59	1.56
90th %tile Delta-DV	0.118	2.245	2.127	2000	110	63	52	2.30	14.70	70.78	6.10	8.42

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: 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	1.210	3.443	2.234	2000	74	90	72	2.80	61.37	37.45	0.17	1.02
98th %tile Delta-DV	0.300	2.533	2.234	2000	54	90	72	2.80	62.99	35.00	0.66	1.35
90th %tile Delta-DV	0.082	2.188	2.106	2000	214	90	72	2.20	93.83	1.40	1.72	3.05

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	1.733	4.009	2.275	2000	47	99	81	2.90	56.97	41.78	0.41	0.85
98th %tile Delta-DV	0.469	2.614	2.145	2000	136	99	81	2.30	48.60	48.45	1.07	1.87
90th %tile Delta-DV	0.207	2.440	2.232	2000	204	96	78	2.70	51.65	45.89	0.87	1.58

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 3) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 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 Species RECEP	F(RH)	% of Modeled Extinction by %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.421	4.654	2.234	2000	72	53	107	2.80	52.01	46.26	0.60	1.14
98th %tile Delta-DV	0.918	3.152	2.234	2000	75	56	110	2.80	55.45	43.18	0.20	1.17
90th %tile Delta-DV	0.235	2.363	2.127	2000	101	46	46	2.30	48.18	48.98	0.73	2.11

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

TRNP NORTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.227	4.461	2.234	2000	74	67	56	2.80	62.61	36.27	0.14	0.97
98th %tile Delta-DV	0.860	3.094	2.234	2000	54	82	71	2.80	55.04	43.30	0.58	1.07
90th %tile Delta-DV	0.236	2.406	2.170	2000	164	82	71	2.50	71.56	25.51	0.87	2.05

Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 6
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 Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.313	4.547	2.234	2000	74	90	72	2.80	61.46	37.43	0.15	0.95
98th %tile Delta-DV	0.605	2.711	2.106	2000	265	90	72	2.20	68.57	29.25	0.66	1.52
90th %tile Delta-DV	0.163	2.397	2.234	2000	56	90	72	2.80	60.77	37.41	0.55	1.26

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: 1

LOSTWOOD NWA

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	3.199	5.475	2.275	2000	47	99	81	2.90	57.11	41.71	0.38	0.79
98th %tile Delta-DV	0.924	3.070	2.145	2000	136	99	81	2.30	48.59	48.65	1.01	1.76
90th %tile Delta-DV	0.409	2.641	2.232	2000	204	96	78	2.70	51.88	45.82	0.82	1.49

Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 4) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.113	3.346	2.234	2000	72	53	107	2.80	60.20	37.66	0.74	1.40
98th %tile Delta-DV	0.410	2.644	2.234	2000	75	56	110	2.80	63.24	35.08	0.25	1.43
90th %tile Delta-DV	0.106	2.276	2.170	2000	161	53	107	2.50	88.70	6.94	0.95	3.41

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: 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	1.055	3.288	2.234	2000	74	67	56	2.80	69.91	28.75	0.17	1.16
98th %tile Delta-DV	0.352	2.585	2.234	2000	36	82	71	2.80	51.03	46.42	0.70	1.85
90th %tile Delta-DV	0.105	2.233	2.127	2000	139	82	71	2.30	83.66	12.64	1.27	2.43

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: 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	1.085	3.319	2.234	2000	74	90	72	2.80	68.85	29.83	0.19	1.14
98th %tile Delta-DV	0.270	2.440	2.170	2000	164	90	72	2.50	91.76	4.11	1.41	2.72
90th %tile Delta-DV	0.072	2.306	2.234	2000	56	90	72	2.80	67.76	30.04	0.67	1.52

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	1.539	3.814	2.275	2000	47	99	81	2.90	64.81	33.77	0.46	0.96
98th %tile Delta-DV	0.417	2.692	2.275	2000	72	97	79	2.90	63.51	35.10	0.49	0.90
90th %tile Delta-DV	0.180	2.412	2.232	2000	204	96	78	2.70	59.76	37.40	1.01	1.83

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
Coal Creek Station Unit 1 & Unit 2 (Scenario 4) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 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	2.125	4.359	2.234	2000	72	53	107	2.80	60.15	37.84	0.69	1.31
98th %tile Delta-DV	0.808	3.042	2.234	2000	75	56	110	2.80	63.34	35.10	0.23	1.33
90th %tile Delta-DV	0.210	2.380	2.170	2000	161	53	107	2.50	89.16	6.76	0.88	3.21

Number of days with Delta-Deciview > 0.50: 14
Number of days with Delta-Deciview > 1.00: 6
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	2.015	4.248	2.234	2000	74	67	56	2.80	69.97	28.78	0.16	1.09
98th %tile Delta-DV	0.732	2.965	2.234	2000	36	82	71	2.80	51.18	46.39	0.67	1.76
90th %tile Delta-DV	0.209	2.337	2.127	2000	139	82	71	2.30	83.94	12.59	1.19	2.27

Number of days with Delta-Deciview > 0.50: 14
Number of days with Delta-Deciview > 1.00: 6
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	2.087	4.320	2.234	2000	74	90	72	2.80	68.94	29.82	0.17	1.07
98th %tile Delta-DV	0.552	2.786	2.234	2000	54	90	72	2.80	70.54	27.37	0.69	1.41
90th %tile Delta-DV	0.146	2.380	2.234	2000	56	90	72	2.80	67.97	29.99	0.62	1.41

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: 1

LOSTWOOD NWA

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.864	5.139	2.275	2000	47	99	81	2.90	64.94	33.72	0.43	0.90
98th %tile Delta-DV	0.832	3.108	2.275	2000	72	97	79	2.90	63.65	35.05	0.45	0.84
90th %tile Delta-DV	0.358	2.633	2.275	2000	70	93	75	2.90	48.91	48.48	0.85	1.75

Number of days with Delta-Deciview > 0.50: 26
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
Coal Creek Station Unit 1 (Scenario 5) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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 Species RECEP	F(RH)	% of Modeled Extinction by %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.867	3.101	2.234	2000	72	53	107	2.80	78.22	19.00	0.96	1.82
98th %tile Delta-DV	0.338	2.571	2.234	2000	44	3	3	2.80	67.59	28.69	1.02	2.70
90th %tile Delta-DV	0.081	2.209	2.127	2000	100	51	105	2.30	72.40	21.66	2.06	3.88

Number of days with Delta-Deciview > 0.50: 6
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 Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	0.929	3.035	2.106	2000	247	58	47	2.20	92.96	2.16	1.57	3.30
98th %tile Delta-DV	0.255	2.488	2.234	2000	36	82	71	2.80	70.77	25.70	0.97	2.56
90th %tile Delta-DV	0.097	2.225	2.127	2000	139	82	71	2.30	90.54	5.45	1.38	2.63

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.897	3.130	2.234	2000	74	90	72	2.80	84.12	14.26	0.23	1.40
98th %tile Delta-DV	0.224	2.458	2.234	2000	54	90	72	2.80	84.64	12.66	0.89	1.82
90th %tile Delta-DV	0.067	2.216	2.149	2000	199	90	72	2.40	90.17	3.40	2.17	4.26

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 Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.242	3.517	2.275	2000	47	99	81	2.90	81.56	16.65	0.58	1.21
98th %tile Delta-DV	0.371	2.646	2.275	2000	54	91	73	2.90	81.49	16.23	0.86	1.42
90th %tile Delta-DV	0.139	2.371	2.232	2000	186	91	73	2.70	86.12	6.86	3.09	3.93

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
Coal Creek Station Unit 1 & Unit 2 (Scenario 5) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 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 Species RECEP	F(RH)	% of Modeled Extinction by %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.672	3.906	2.234	2000	72	54	108	2.80	78.35	19.05	0.89	1.71
98th %tile Delta-DV	0.665	2.899	2.234	2000	44	3	3	2.80	67.81	28.72	0.95	2.52
90th %tile Delta-DV	0.161	2.288	2.127	2000	100	51	105	2.30	72.77	21.66	1.93	3.64

Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 6
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 Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.768	3.874	2.106	2000	247	58	47	2.20	93.47	1.95	1.48	3.10
98th %tile Delta-DV	0.533	2.767	2.234	2000	36	82	71	2.80	70.96	25.68	0.93	2.44
90th %tile Delta-DV	0.194	2.321	2.127	2000	139	82	71	2.30	90.82	5.43	1.29	2.46

Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 4
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 Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.739	3.973	2.234	2000	74	90	72	2.80	84.23	14.26	0.21	1.30
98th %tile Delta-DV	0.461	2.695	2.234	2000	54	90	72	2.80	84.86	12.62	0.83	1.70
90th %tile Delta-DV	0.133	2.282	2.149	2000	199	90	72	2.40	90.61	3.37	2.03	3.99

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: 1

LOSTWOOD NWA

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.340	4.615	2.275	2000	47	99	81	2.90	81.69	16.63	0.55	1.13
98th %tile Delta-DV	0.720	2.995	2.275	2000	37	97	79	2.90	69.90	26.17	1.33	2.59
90th %tile Delta-DV	0.277	2.423	2.145	2000	131	91	73	2.30	72.47	22.14	2.41	2.98

Number of days with Delta-Deciview > 0.50: 19
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
Coal Creek Station Unit 1 (Scenario 6) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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 Species RECEP	F(RH)	% of Modeled Extinction by %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.787	3.020	2.234	2000	72	54	108	2.80	86.64	10.29	1.06	2.01
98th %tile Delta-DV	0.296	2.530	2.234	2000	75	56	110	2.80	88.13	9.53	0.35	2.00
90th %tile Delta-DV	0.073	2.200	2.127	2000	113	55	109	2.30	92.72	1.54	1.29	4.46

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	0.919	3.025	2.106	2000	247	58	47	2.20	93.98	1.09	1.59	3.34
98th %tile Delta-DV	0.229	2.335	2.106	2000	239	82	71	2.20	93.17	3.42	1.09	2.31
90th %tile Delta-DV	0.095	2.222	2.127	2000	139	82	71	2.30	93.09	2.79	1.42	2.70

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.835	3.068	2.234	2000	74	90	72	2.80	90.67	7.58	0.24	1.51
98th %tile Delta-DV	0.220	2.475	2.255	2000	11	90	72	2.90	80.94	14.95	1.25	2.85
90th %tile Delta-DV	0.057	2.185	2.127	2000	106	90	72	2.30	60.69	26.13	5.68	7.49

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 Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.143	3.418	2.275	2000	47	99	81	2.90	89.07	8.97	0.64	1.32
98th %tile Delta-DV	0.341	2.616	2.275	2000	54	91	73	2.90	88.73	8.79	0.94	1.54
90th %tile Delta-DV	0.128	2.274	2.145	2000	131	91	73	2.30	81.48	12.11	2.87	3.54

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
Coal Creek Station Unit 1 & Unit 2 (Scenario 6) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.522	3.755	2.234	2000	72	54	108	2.80	86.76	10.36	0.99	1.89
98th %tile Delta-DV	0.587	2.820	2.234	2000	75	56	110	2.80	88.29	9.54	0.32	1.86
90th %tile Delta-DV	0.147	2.380	2.234	2000	48	46	46	2.80	92.18	6.98	0.16	0.68

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: 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	1.753	3.859	2.106	2000	247	58	47	2.20	94.39	0.99	1.49	3.13
98th %tile Delta-DV	0.466	2.700	2.234	2000	36	82	71	2.80	81.42	14.72	1.06	2.79
90th %tile Delta-DV	0.188	2.316	2.127	2000	139	82	71	2.30	93.36	2.78	1.32	2.53

Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 4
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	1.623	3.857	2.234	2000	74	90	72	2.80	90.79	7.58	0.23	1.40
98th %tile Delta-DV	0.439	2.545	2.106	2000	247	90	72	2.20	95.28	0.67	1.58	2.47
90th %tile Delta-DV	0.113	2.241	2.127	2000	106	90	72	2.30	61.01	26.51	5.38	7.10

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 2
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	2.163	4.438	2.275	2000	47	99	81	2.90	89.20	8.96	0.60	1.24
98th %tile Delta-DV	0.681	2.848	2.167	2000	216	97	79	2.40	90.95	5.30	1.56	2.18
90th %tile Delta-DV	0.248	2.481	2.232	2000	204	93	75	2.70	86.22	9.98	1.35	2.46

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 7) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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 Species RECEP	F(RH)	% of Modeled Extinction by %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	0.917	3.151	2.234	2000	72	45	45	2.80	28.92	67.87	1.08	2.13
98th %tile Delta-DV	0.270	2.504	2.234	2000	75	56	110	2.80	34.07	63.36	0.38	2.19
90th %tile Delta-DV	0.072	2.221	2.149	2000	187	46	46	2.40	80.70	14.30	1.67	3.33

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 Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	0.708	2.941	2.234	2000	74	67	56	2.80	40.95	56.81	0.29	1.94
98th %tile Delta-DV	0.316	2.549	2.234	2000	54	82	71	2.80	33.72	63.27	1.05	1.97
90th %tile Delta-DV	0.061	2.231	2.170	2000	164	82	71	2.50	51.38	42.08	1.95	4.59

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 Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.758	2.992	2.234	2000	74	90	72	2.80	40.06	57.75	0.31	1.88
98th %tile Delta-DV	0.178	2.327	2.149	2000	184	90	72	2.40	78.93	12.37	3.25	5.45
90th %tile Delta-DV	0.049	2.176	2.127	2000	97	90	72	2.30	20.64	75.63	0.94	2.79

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 Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.158	3.434	2.275	2000	47	99	81	2.90	35.59	62.16	0.72	1.53
98th %tile Delta-DV	0.292	2.437	2.145	2000	136	99	81	2.30	27.47	67.55	1.83	3.14
90th %tile Delta-DV	0.115	2.326	2.211	2000	171	97	79	2.60	30.54	60.38	3.34	5.74

Number of days with Delta-Deciview > 0.50: 1
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
Coal Creek Station Unit 1 & Unit 2 (Scenario 7) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.776	4.009	2.234	2000	72	45	45	2.80	28.88	68.12	1.01	1.99
98th %tile Delta-DV	0.533	2.767	2.234	2000	75	56	110	2.80	34.13	63.47	0.35	2.05
90th %tile Delta-DV	0.144	2.292	2.149	2000	187	46	46	2.40	80.96	14.36	1.56	3.12
TRNP NORTH UNIT												
Largest Delta-DV	1.366	3.599	2.234	2000	74	67	56	2.80	41.03	56.88	0.27	1.82
98th %tile Delta-DV	0.617	2.850	2.234	2000	54	82	71	2.80	33.92	63.25	0.98	1.85
90th %tile Delta-DV	0.122	2.292	2.170	2000	164	82	71	2.50	51.52	42.37	1.82	4.29
TRNP ELKHORN RANCH												
Largest Delta-DV	1.460	3.693	2.234	2000	74	90	72	2.80	40.14	57.81	0.29	1.76
98th %tile Delta-DV	0.356	2.589	2.234	2000	40	90	72	2.80	24.92	72.66	0.61	1.80
90th %tile Delta-DV	0.097	2.331	2.234	2000	41	90	72	2.80	17.04	78.24	1.56	3.16
LOSTWOOD NWA												
Largest Delta-DV	2.222	4.497	2.275	2000	47	99	81	2.90	35.70	62.19	0.68	1.43
98th %tile Delta-DV	0.575	2.720	2.145	2000	136	99	81	2.30	27.60	67.75	1.71	2.94
90th %tile Delta-DV	0.231	2.441	2.211	2000	171	97	79	2.60	30.65	60.81	3.15	5.40

TRNP SOUTH UNIT

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

TRNP NORTH UNIT

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: 1

TRNP ELKHORN RANCH

Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1

LOSTWOOD NWA

Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 8) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	0.940	3.173	2.234	2000	72	53	107	2.80	25.00	72.44	0.89	1.67
98th %tile Delta-DV	0.328	2.562	2.234	2000	75	56	110	2.80	27.59	70.30	0.31	1.80
90th %tile Delta-DV	0.081	2.208	2.127	2000	110	48	102	2.30	12.91	77.78	3.89	5.41

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

						SEQ	ND					
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	0.768	3.002	2.234	2000	74	67	56	2.80	33.88	64.26	0.23	1.62
98th %tile Delta-DV	0.326	2.580	2.255	2000	11	63	52	2.90	17.96	77.90	1.60	2.55
90th %tile Delta-DV	0.072	2.221	2.149	2000	187	82	71	2.40	81.48	12.31	1.75	4.47

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

						SEQ	ND					
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.805	3.038	2.234	2000	74	90	72	2.80	32.76	65.42	0.25	1.56
98th %tile Delta-DV	0.186	2.292	2.106	2000	265	90	72	2.20	39.37	56.77	1.17	2.69
90th %tile Delta-DV	0.053	2.287	2.234	2000	56	90	72	2.80	32.16	64.85	0.92	2.08

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

						SEQ	ND					
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.221	3.496	2.275	2000	47	99	81	2.90	28.87	69.31	0.59	1.23
98th %tile Delta-DV	0.336	2.612	2.275	2000	44	94	76	2.90	17.39	78.94	1.26	2.41
90th %tile Delta-DV	0.134	2.301	2.167	2000	229	93	75	2.40	13.17	67.57	8.01	11.25

Number of days with Delta-Deciview > 0.50: 1
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
Coal Creek Station Unit 1 & Unit 2 (Scenario 8) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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 Species RECEP	F(RH)	% of Modeled Extinction by %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	1.812	4.046	2.234	2000	72	53	107	2.80	24.93	72.67	0.83	1.57
98th %tile Delta-DV	0.649	2.883	2.234	2000	75	56	110	2.80	27.66	70.38	0.29	1.67
90th %tile Delta-DV	0.161	2.289	2.127	2000	110	48	102	2.30	13.01	78.25	3.66	5.09

Number of days with Delta-Deciview > 0.50: 11
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 Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.486	3.719	2.234	2000	74	67	56	2.80	33.91	64.36	0.22	1.52
98th %tile Delta-DV	0.638	2.892	2.255	2000	11	63	52	2.90	18.07	78.05	1.50	2.39
90th %tile Delta-DV	0.143	2.292	2.149	2000	187	82	71	2.40	82.05	12.12	1.64	4.19

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: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	1.566	3.799	2.234	2000	74	90	72	2.80	32.83	65.48	0.24	1.46
98th %tile Delta-DV	0.370	2.604	2.234	2000	40	90	72	2.80	19.71	78.45	0.45	1.39
90th %tile Delta-DV	0.107	2.341	2.234	2000	56	90	72	2.80	32.33	64.89	0.85	1.93

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	2.300	4.576	2.275	2000	47	99	81	2.90	28.94	69.35	0.56	1.16
98th %tile Delta-DV	0.667	2.942	2.275	2000	72	97	79	2.90	27.86	70.52	0.57	1.05
90th %tile Delta-DV	0.266	2.433	2.167	2000	229	93	75	2.40	13.59	68.13	7.59	10.70

Number of days with Delta-Deciview > 0.50: 16
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 9) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	0.860	3.094	2.234	2000	72	53	107	2.80	27.43	69.76	0.97	1.84
98th %tile Delta-DV	0.301	2.535	2.234	2000	75	56	110	2.80	30.14	67.56	0.34	1.96
90th %tile Delta-DV	0.076	2.225	2.149	2000	187	46	46	2.40	78.07	17.13	1.61	3.19

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	0.710	2.944	2.234	2000	74	67	56	2.80	36.74	61.25	0.25	1.76
98th %tile Delta-DV	0.296	2.551	2.255	2000	11	63	52	2.90	19.77	75.67	1.76	2.80
90th %tile Delta-DV	0.066	2.300	2.234	2000	70	83	112	2.80	22.75	74.87	0.60	1.78

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 ELKHORN RANCH												
Largest Delta-DV	0.743	2.977	2.234	2000	74	90	72	2.80	35.58	62.45	0.28	1.70
98th %tile Delta-DV	0.174	2.280	2.106	2000	265	90	72	2.20	42.17	53.70	1.25	2.88
90th %tile Delta-DV	0.049	2.283	2.234	2000	56	90	72	2.80	34.81	61.94	0.99	2.25

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	1.124	3.399	2.275	2000	47	99	81	2.90	31.51	66.50	0.65	1.34
98th %tile Delta-DV	0.306	2.581	2.275	2000	44	94	76	2.90	19.18	76.78	1.39	2.65
90th %tile Delta-DV	0.124	2.292	2.167	2000	215	99	81	2.40	34.74	48.85	6.36	10.04

Number of days with Delta-Deciview > 0.50: 1
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
Coal Creek Station Unit 1 & Unit 2 (Scenario 9) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 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 Species RECEP	F(RH)	% of Modeled Extinction by %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.664	3.897	2.234	2000	72	53	107	2.80	27.36	70.01	0.91	1.72
98th %tile Delta-DV	0.596	2.829	2.234	2000	75	56	110	2.80	30.21	67.65	0.32	1.83
90th %tile Delta-DV	0.151	2.300	2.149	2000	187	46	46	2.40	78.41	17.09	1.51	2.99

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

TRNP NORTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.378	3.611	2.234	2000	74	67	56	2.80	36.77	61.35	0.24	1.64
98th %tile Delta-DV	0.581	2.836	2.255	2000	11	63	52	2.90	19.89	75.83	1.65	2.63
90th %tile Delta-DV	0.132	2.366	2.234	2000	70	83	112	2.80	22.79	74.99	0.56	1.66

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: 1

TRNP ELKHORN RANCH

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.450	3.684	2.234	2000	74	90	72	2.80	35.65	62.51	0.26	1.59
98th %tile Delta-DV	0.343	2.449	2.106	2000	265	90	72	2.20	42.43	53.69	1.18	2.71
90th %tile Delta-DV	0.099	2.332	2.234	2000	56	90	72	2.80	35.00	61.99	0.92	2.09

Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1

LOSTWOOD NWA

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND Species RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.127	4.403	2.275	2000	47	99	81	2.90	31.59	66.54	0.61	1.26
98th %tile Delta-DV	0.612	2.887	2.275	2000	72	97	79	2.90	30.44	67.79	0.62	1.15
90th %tile Delta-DV	0.245	2.412	2.167	2000	229	93	75	2.40	14.76	65.37	8.24	11.62

Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 10) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 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	0.691	2.924	2.234	2000	72	53	107	2.80	34.47	62.00	1.22	2.31
98th %tile Delta-DV	0.243	2.349	2.106	2000	238	53	107	2.20	69.95	12.40	6.69	10.96
90th %tile Delta-DV	0.062	2.337	2.276	2000	336	47	101	3.00	23.90	70.07	2.59	3.43

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	0.588	2.821	2.234	2000	74	67	56	2.80	44.68	52.87	0.31	2.14
98th %tile Delta-DV	0.233	2.488	2.255	2000	11	63	52	2.90	25.17	69.03	2.24	3.57
90th %tile Delta-DV	0.055	2.161	2.106	2000	238	85	114	2.20	72.69	15.18	4.21	7.93

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

TRNP ELKHORN RANCH

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	0.613	2.846	2.234	2000	74	90	72	2.80	43.44	54.15	0.34	2.07
98th %tile Delta-DV	0.147	2.381	2.234	2000	54	90	72	2.80	44.95	50.91	1.36	2.78
90th %tile Delta-DV	0.044	2.171	2.127	2000	97	90	72	2.30	23.16	72.67	1.06	3.11

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	0.917	3.193	2.275	2000	47	99	81	2.90	39.03	58.51	0.80	1.67
98th %tile Delta-DV	0.246	2.522	2.275	2000	72	97	79	2.90	37.70	59.93	0.83	1.53
90th %tile Delta-DV	0.106	2.446	2.340	2000	350	91	73	3.20	27.28	66.69	1.73	4.30

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
Coal Creek Station Unit 1 & Unit 2 (Scenario 10) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

% of Modeled Extinction by Species

TRNP SOUTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.345	3.578	2.234	2000	72	53	107	2.80	34.42	62.28	1.14	2.16
98th %tile Delta-DV	0.482	2.716	2.234	2000	75	56	110	2.80	37.53	59.81	0.39	2.27
90th %tile Delta-DV	0.127	2.403	2.276	2000	336	47	101	3.00	24.03	70.35	2.42	3.20

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: 1

TRNP NORTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.146	3.380	2.234	2000	74	67	56	2.80	44.73	52.98	0.29	2.00
98th %tile Delta-DV	0.459	2.714	2.255	2000	11	63	52	2.90	25.32	69.23	2.10	3.35
90th %tile Delta-DV	0.109	2.279	2.170	2000	164	82	71	2.50	54.24	39.38	1.91	4.48

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: 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	1.203	3.436	2.234	2000	74	90	72	2.80	43.53	54.22	0.31	1.94
98th %tile Delta-DV	0.292	2.398	2.106	2000	265	90	72	2.20	49.95	45.47	1.39	3.19
90th %tile Delta-DV	0.087	2.215	2.127	2000	97	90	72	2.30	23.21	72.88	0.99	2.92

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

LOSTWOOD NWA

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.751	4.026	2.275	2000	47	99	81	2.90	39.12	58.56	0.75	1.56
98th %tile Delta-DV	0.495	2.770	2.275	2000	72	97	79	2.90	37.84	59.95	0.78	1.43
90th %tile Delta-DV	0.210	2.377	2.167	2000	215	99	81	2.40	40.95	40.87	7.06	11.12

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 0, Pre-BART) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	2.917	5.151	2.234	2001	64	52	106	2.80	77.08	22.59	0.11	0.22
98th %tile Delta-DV	1.209	3.315	2.106	2001	257	48	102	2.20	81.37	17.38	0.44	0.81
90th %tile Delta-DV	0.251	2.378	2.127	2001	131	53	107	2.30	69.04	30.09	0.22	0.65

Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 11
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	3.801	6.034	2.234	2001	64	82	71	2.80	76.74	22.86	0.14	0.26
98th %tile Delta-DV	1.154	3.281	2.127	2001	100	82	71	2.30	78.23	21.40	0.07	0.30
90th %tile Delta-DV	0.372	2.606	2.234	2001	62	82	71	2.80	81.35	18.32	0.08	0.25

Number of days with Delta-Deciview > 0.50: 27
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	2.924	5.157	2.234	2001	64	90	72	2.80	77.73	21.95	0.11	0.22
98th %tile Delta-DV	1.056	3.183	2.127	2001	92	90	72	2.30	58.08	40.84	0.36	0.72
90th %tile Delta-DV	0.192	2.320	2.127	2001	109	90	72	2.30	62.94	35.94	0.28	0.85

Number of days with Delta-Deciview > 0.50: 16
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	4.640	6.916	2.275	2001	64	91	73	2.90	70.40	29.04	0.15	0.41
98th %tile Delta-DV	2.362	4.507	2.145	2001	259	97	79	2.30	85.36	13.84	0.25	0.55
90th %tile Delta-DV	0.522	2.861	2.340	2001	316	93	75	3.20	60.23	38.90	0.36	0.50

Number of days with Delta-Deciview > 0.50: 40
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 0, Pre-BART) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station- 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	5.001	7.235	2.234	2001	64	52	106	2.80	75.58	24.10	0.10	0.22
98th %tile Delta-DV	2.181	4.287	2.106	2001	257	48	102	2.20	80.18	18.59	0.43	0.80
90th %tile Delta-DV	0.466	2.572	2.106	2001	254	45	45	2.20	94.17	3.91	0.58	1.34

Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 21
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	6.322	8.555	2.234	2001	64	82	71	2.80	75.32	24.29	0.13	0.26
98th %tile Delta-DV	2.094	4.221	2.127	2001	100	82	71	2.30	76.82	22.82	0.07	0.29
90th %tile Delta-DV	0.694	2.928	2.234	2001	62	82	71	2.80	80.07	19.61	0.08	0.24

Number of days with Delta-Deciview > 0.50: 46
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 4

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	5.006	7.240	2.234	2001	64	90	72	2.80	76.29	23.40	0.11	0.21
98th %tile Delta-DV	1.949	4.076	2.127	2001	92	90	72	2.30	56.05	42.91	0.35	0.69
90th %tile Delta-DV	0.365	2.493	2.127	2001	109	90	72	2.30	61.06	37.85	0.27	0.82

Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 16
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
LOSTWOOD NWA												
Largest Delta-DV	6.517	8.793	2.275	2001	64	97	79	2.90	82.16	17.18	0.17	0.48
98th %tile Delta-DV	4.038	6.313	2.275	2001	63	91	73	2.90	82.39	17.32	0.08	0.21
90th %tile Delta-DV	0.984	3.151	2.167	2001	232	91	73	2.40	88.98	9.56	0.29	1.17

Number of days with Delta-Deciview > 0.50: 56
Number of days with Delta-Deciview > 1.00: 35
Max number of consecutive days with Delta-Deciview > 0.50: 6

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 1) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.282	3.516	2.234	2001	64	52	106	2.80	59.93	39.24	0.27	0.56
98th %tile Delta-DV	0.509	2.763	2.255	2001	12	48	102	2.90	55.05	43.77	0.45	0.73
90th %tile Delta-DV	0.116	2.244	2.127	2001	148	48	102	2.30	37.78	57.07	2.30	2.85

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

TRNP NORTH UNIT												
Largest Delta-DV	1.696	3.930	2.234	2001	64	82	71	2.80	59.56	39.44	0.34	0.66
98th %tile Delta-DV	0.547	2.675	2.127	2001	109	83	112	2.30	38.76	54.96	2.38	3.90
90th %tile Delta-DV	0.142	2.375	2.234	2001	62	82	71	2.80	66.26	32.87	0.22	0.66

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

TRNP ELKHORN RANCH												
Largest Delta-DV	1.276	3.509	2.234	2001	64	90	72	2.80	60.78	38.40	0.27	0.55
98th %tile Delta-DV	0.505	2.739	2.234	2001	84	90	72	2.80	44.24	53.76	0.69	1.32
90th %tile Delta-DV	0.076	2.182	2.106	2001	224	90	72	2.20	92.65	2.64	1.92	2.79

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

LOSTWOOD NWA												
Largest Delta-DV	2.796	5.136	2.340	2001	326	99	81	3.20	56.42	41.65	0.74	1.19
98th %tile Delta-DV	0.936	3.082	2.145	2001	259	97	79	2.30	70.71	27.12	0.69	1.48
90th %tile Delta-DV	0.227	2.394	2.167	2001	275	93	75	2.40	50.16	44.42	1.81	3.61

Number of days with Delta-Deciview > 0.50: 21
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
Coal Creek Station Unit 1 & Unit 2 (Scenario 1) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station- 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	2.418	4.652	2.234	2001	64	52	106	2.80	59.97	39.26	0.25	0.52
98th %tile Delta-DV	0.986	3.241	2.255	2001	12	48	102	2.90	55.06	43.83	0.42	0.68
90th %tile Delta-DV	0.230	2.357	2.127	2001	148	48	102	2.30	38.00	57.16	2.16	2.68

Number of days with Delta-Deciview > 0.50: 19
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	3.144	5.378	2.234	2001	64	82	71	2.80	59.62	39.45	0.32	0.61
98th %tile Delta-DV	1.069	3.196	2.127	2001	109	83	112	2.30	38.99	55.07	2.26	3.69
90th %tile Delta-DV	0.282	2.516	2.234	2001	62	82	71	2.80	66.27	32.91	0.21	0.61

Number of days with Delta-Deciview > 0.50: 25
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	2.406	4.640	2.234	2001	64	90	72	2.80	60.83	38.40	0.25	0.51
98th %tile Delta-DV	0.984	3.218	2.234	2001	84	90	72	2.80	44.35	53.78	0.64	1.23
90th %tile Delta-DV	0.151	2.257	2.106	2001	224	90	72	2.20	92.95	2.64	1.79	2.61

Number of days with Delta-Deciview > 0.50: 14
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
LOSTWOOD NWA												
Largest Delta-DV	4.932	7.272	2.340	2001	326	99	81	3.20	59.30	38.81	0.73	1.16
98th %tile Delta-DV	1.778	3.924	2.145	2001	259	97	79	2.30	71.32	26.64	0.65	1.39
90th %tile Delta-DV	0.448	2.723	2.275	2001	55	97	79	2.90	30.29	67.67	0.87	1.17

Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 2) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.225	3.459	2.234	2001	64	52	106	2.80	62.92	36.22	0.28	0.58
98th %tile Delta-DV	0.482	2.737	2.255	2001	12	48	102	2.90	58.12	40.63	0.48	0.77
90th %tile Delta-DV	0.108	2.235	2.127	2001	148	48	102	2.30	40.61	53.85	2.47	3.06

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

TRNP NORTH UNIT												
Largest Delta-DV	1.620	3.854	2.234	2001	64	82	71	2.80	62.60	36.34	0.36	0.69
98th %tile Delta-DV	0.512	2.639	2.127	2001	109	83	112	2.30	41.52	51.76	2.54	4.18
90th %tile Delta-DV	0.136	2.369	2.234	2001	62	82	71	2.80	69.12	29.97	0.23	0.69

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

TRNP ELKHORN RANCH												
Largest Delta-DV	1.220	3.454	2.234	2001	64	90	72	2.80	63.75	35.39	0.29	0.58
98th %tile Delta-DV	0.473	2.706	2.234	2001	84	90	72	2.80	47.32	50.54	0.73	1.41
90th %tile Delta-DV	0.076	2.182	2.106	2001	224	90	72	2.20	92.94	2.34	1.92	2.80

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

LOSTWOOD NWA												
Largest Delta-DV	2.677	5.017	2.340	2001	326	99	81	3.20	59.30	38.68	0.78	1.25
98th %tile Delta-DV	0.907	3.053	2.145	2001	259	97	79	2.30	73.08	24.68	0.71	1.53
90th %tile Delta-DV	0.212	2.358	2.145	2001	107	97	79	2.30	32.59	64.27	1.07	2.08

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 2) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	2.316	4.549	2.234	2001	64	52	106	2.80	62.96	36.24	0.26	0.55
98th %tile Delta-DV	0.936	3.191	2.255	2001	12	48	102	2.90	58.13	40.70	0.45	0.72
90th %tile Delta-DV	0.214	2.341	2.127	2001	148	48	102	2.30	40.84	53.96	2.32	2.88

Number of days with Delta-Deciview > 0.50: 19
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	3.012	5.246	2.234	2001	64	82	71	2.80	62.66	36.36	0.34	0.65
98th %tile Delta-DV	1.002	3.129	2.127	2001	109	83	112	2.30	41.75	51.89	2.42	3.95
90th %tile Delta-DV	0.270	2.504	2.234	2001	62	82	71	2.80	69.14	30.01	0.21	0.64

Number of days with Delta-Deciview > 0.50: 24
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	2.306	4.540	2.234	2001	64	90	72	2.80	63.79	35.40	0.27	0.54
98th %tile Delta-DV	0.923	3.157	2.234	2001	84	90	72	2.80	47.43	50.56	0.69	1.32
90th %tile Delta-DV	0.151	2.257	2.106	2001	224	90	72	2.20	93.25	2.33	1.80	2.62

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
LOSTWOOD NWA												
Largest Delta-DV	4.773	7.112	2.340	2001	326	99	81	3.20	61.81	36.22	0.76	1.21
98th %tile Delta-DV	1.726	3.872	2.145	2001	259	97	79	2.30	73.65	24.24	0.67	1.44
90th %tile Delta-DV	0.419	2.564	2.145	2001	107	97	79	2.30	32.73	64.33	1.00	1.94

Number of days with Delta-Deciview > 0.50: 33
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 3) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.104	3.337	2.234	2001	64	52	106	2.80	70.29	28.74	0.31	0.65
98th %tile Delta-DV	0.437	2.543	2.106	2001	257	48	102	2.20	73.41	22.87	1.31	2.41
90th %tile Delta-DV	0.096	2.329	2.234	2001	55	46	46	2.80	59.18	39.59	0.28	0.95

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 NORTH UNIT												
Largest Delta-DV	1.459	3.692	2.234	2001	64	82	71	2.80	70.10	28.72	0.40	0.77
98th %tile Delta-DV	0.436	2.564	2.127	2001	109	83	112	2.30	48.87	43.22	3.00	4.92
90th %tile Delta-DV	0.127	2.297	2.170	2001	179	58	47	2.50	86.91	11.36	0.48	1.26

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	1.102	3.335	2.234	2001	64	90	72	2.80	71.03	28.01	0.32	0.64
98th %tile Delta-DV	0.405	2.638	2.234	2001	84	90	72	2.80	55.44	42.04	0.86	1.65
90th %tile Delta-DV	0.069	2.344	2.276	2001	310	90	72	3.00	50.62	43.88	1.02	4.47

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: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	2.418	4.757	2.340	2001	326	99	81	3.20	66.55	31.18	0.87	1.40
98th %tile Delta-DV	0.846	2.991	2.145	2001	259	97	79	2.30	78.65	18.93	0.77	1.65
90th %tile Delta-DV	0.190	2.357	2.167	2001	275	93	75	2.40	60.18	33.32	2.17	4.33

Number of days with Delta-Deciview > 0.50: 15
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
Coal Creek Station Unit 1 & Unit 2 (Scenario 3) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	2.097	4.330	2.234	2001	64	52	106	2.80	70.34	28.76	0.29	0.61
98th %tile Delta-DV	0.854	2.960	2.106	2001	257	48	102	2.20	73.60	22.92	1.23	2.25
90th %tile Delta-DV	0.194	2.428	2.234	2001	55	46	46	2.80	59.19	39.66	0.26	0.89

Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 6
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	2.730	4.964	2.234	2001	64	82	71	2.80	70.16	28.74	0.38	0.72
98th %tile Delta-DV	0.858	2.985	2.127	2001	109	83	112	2.30	49.12	43.39	2.84	4.65
90th %tile Delta-DV	0.253	2.529	2.276	2001	315	82	71	3.00	52.92	44.71	0.91	1.46

Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 6
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	2.093	4.326	2.234	2001	64	90	72	2.80	71.09	28.02	0.30	0.60
98th %tile Delta-DV	0.793	3.027	2.234	2001	84	90	72	2.80	55.57	42.08	0.80	1.55
90th %tile Delta-DV	0.137	2.413	2.276	2001	310	90	72	3.00	50.98	43.86	0.96	4.20

Number of days with Delta-Deciview > 0.50: 12
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
LOSTWOOD NWA												
Largest Delta-DV	4.404	6.744	2.340	2001	326	99	81	3.20	68.33	29.49	0.84	1.34
98th %tile Delta-DV	1.616	3.761	2.145	2001	259	97	79	2.30	79.13	18.60	0.72	1.55
90th %tile Delta-DV	0.373	2.540	2.167	2001	275	93	75	2.40	60.66	33.19	2.06	4.09

Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 15
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 4) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	0.920	3.153	2.234	2001	64	52	106	2.80	85.14	13.69	0.38	0.79
98th %tile Delta-DV	0.373	2.479	2.106	2001	261	48	102	2.20	88.75	8.83	0.76	1.66
90th %tile Delta-DV	0.075	2.351	2.276	2001	330	53	107	3.00	32.34	46.21	9.04	12.41

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.217	3.450	2.234	2001	64	82	71	2.80	85.10	13.47	0.49	0.94
98th %tile Delta-DV	0.353	2.501	2.149	2001	198	86	115	2.40	95.65	1.12	0.95	2.28
90th %tile Delta-DV	0.106	2.340	2.234	2001	62	82	71	2.80	88.65	10.18	0.29	0.88

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.923	3.156	2.234	2001	64	90	72	2.80	85.59	13.26	0.38	0.77
98th %tile Delta-DV	0.319	2.446	2.127	2001	112	90	72	2.30	72.34	22.91	2.12	2.63
90th %tile Delta-DV	0.058	2.164	2.106	2001	255	90	72	2.20	84.03	6.89	2.74	6.34

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	2.008	4.347	2.340	2001	326	99	81	3.20	81.86	15.34	1.07	1.72
98th %tile Delta-DV	0.752	2.898	2.145	2001	259	97	79	2.30	88.81	8.46	0.87	1.86
90th %tile Delta-DV	0.158	2.303	2.145	2001	100	97	79	2.30	88.36	10.59	0.27	0.78

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: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 4) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.761	3.995	2.234	2001	64	52	106	2.80	85.20	13.70	0.36	0.74
98th %tile Delta-DV	0.730	2.836	2.106	2001	261	48	102	2.20	89.11	8.63	0.71	1.55
90th %tile Delta-DV	0.150	2.425	2.276	2001	330	53	107	3.00	32.84	46.92	8.51	11.74

Number of days with Delta-Deciview > 0.50: 16
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	2.300	4.534	2.234	2001	64	82	71	2.80	85.18	13.49	0.46	0.88
98th %tile Delta-DV	0.693	2.842	2.149	2001	198	86	115	2.40	95.92	1.06	0.89	2.13
90th %tile Delta-DV	0.212	2.445	2.234	2001	62	82	71	2.80	88.71	10.20	0.27	0.82

Number of days with Delta-Deciview > 0.50: 16
Number of days with Delta-Deciview > 1.00: 5
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	1.766	4.000	2.234	2001	64	90	72	2.80	85.66	13.26	0.36	0.72
98th %tile Delta-DV	0.625	2.731	2.106	2001	260	90	72	2.20	93.12	4.17	0.97	1.74
90th %tile Delta-DV	0.114	2.220	2.106	2001	255	90	72	2.20	84.61	6.86	2.58	5.96

Number of days with Delta-Deciview > 0.50: 11
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
LOSTWOOD NWA												
Largest Delta-DV	3.766	6.106	2.340	2001	326	99	81	3.20	82.67	14.70	1.01	1.62
98th %tile Delta-DV	1.447	3.593	2.145	2001	259	97	79	2.30	89.13	8.31	0.81	1.74
90th %tile Delta-DV	0.314	2.459	2.145	2001	100	97	79	2.30	88.43	10.59	0.26	0.73

Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 5) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	0.859	3.092	2.234	2001	64	52	106	2.80	91.45	7.29	0.41	0.85
98th %tile Delta-DV	0.356	2.462	2.106	2001	261	48	102	2.20	92.88	4.59	0.80	1.73
90th %tile Delta-DV	0.070	2.176	2.106	2001	255	51	105	2.20	88.34	2.50	3.03	6.13

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.138	3.371	2.234	2001	64	82	71	2.80	91.37	7.10	0.53	1.01
98th %tile Delta-DV	0.333	2.461	2.127	2001	112	85	114	2.30	78.65	14.85	2.97	3.53
90th %tile Delta-DV	0.101	2.377	2.276	2001	332	83	112	3.00	69.10	24.81	2.39	3.70

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.864	3.097	2.234	2001	64	90	72	2.80	91.72	7.04	0.41	0.83
98th %tile Delta-DV	0.283	2.410	2.127	2001	112	90	72	2.30	81.71	12.93	2.40	2.97
90th %tile Delta-DV	0.056	2.162	2.106	2001	255	90	72	2.20	87.06	3.52	2.84	6.57

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	1.867	4.207	2.340	2001	326	99	81	3.20	88.67	8.30	1.16	1.87
98th %tile Delta-DV	0.670	2.946	2.275	2001	63	91	73	2.90	94.45	4.46	0.28	0.81
90th %tile Delta-DV	0.149	2.295	2.145	2001	100	97	79	2.30	93.39	5.50	0.29	0.82

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: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 5) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.649	3.883	2.234	2001	64	52	106	2.80	91.53	7.30	0.38	0.79
98th %tile Delta-DV	0.700	2.806	2.106	2001	261	48	102	2.20	93.15	4.48	0.74	1.62
90th %tile Delta-DV	0.139	2.245	2.106	2001	255	51	105	2.20	88.92	2.48	2.85	5.75

Number of days with Delta-Deciview > 0.50: 13
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	2.158	4.391	2.234	2001	64	82	71	2.80	91.46	7.10	0.49	0.94
98th %tile Delta-DV	0.656	2.784	2.127	2001	112	85	114	2.30	79.04	14.87	2.78	3.31
90th %tile Delta-DV	0.202	2.477	2.276	2001	332	83	112	3.00	69.39	24.91	2.23	3.47

Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 5
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	1.658	3.891	2.234	2001	64	90	72	2.80	91.80	7.04	0.38	0.77
98th %tile Delta-DV	0.557	2.684	2.127	2001	112	90	72	2.30	82.05	12.92	2.24	2.78
90th %tile Delta-DV	0.110	2.216	2.106	2001	255	90	72	2.20	87.65	3.51	2.67	6.17

Number of days with Delta-Deciview > 0.50: 10
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
LOSTWOOD NWA												
Largest Delta-DV	3.534	5.874	2.340	2001	326	99	81	3.20	89.19	7.97	1.09	1.75
98th %tile Delta-DV	1.298	3.574	2.275	2001	63	91	73	2.90	94.52	4.47	0.26	0.75
90th %tile Delta-DV	0.297	2.443	2.145	2001	100	97	79	2.30	93.46	5.50	0.27	0.77

Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 6) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	0.800	3.034	2.234	2001	64	52	106	2.80	34.22	64.43	0.44	0.91
98th %tile Delta-DV	0.340	2.574	2.234	2001	84	52	106	2.80	21.90	75.37	0.98	1.75
90th %tile Delta-DV	0.062	2.211	2.149	2001	190	52	106	2.40	83.61	4.81	4.92	6.66

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.071	3.305	2.234	2001	64	82	71	2.80	33.87	64.49	0.56	1.08
98th %tile Delta-DV	0.412	2.539	2.127	2001	109	83	112	2.30	17.98	73.64	3.17	5.21
90th %tile Delta-DV	0.079	2.228	2.149	2001	195	82	71	2.40	73.96	23.01	0.79	2.24

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: 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	0.790	3.023	2.234	2001	64	90	72	2.80	35.02	63.62	0.45	0.91
98th %tile Delta-DV	0.309	2.415	2.106	2001	261	90	72	2.20	52.12	43.64	1.31	2.94
90th %tile Delta-DV	0.039	2.188	2.149	2001	190	90	72	2.40	86.01	3.12	4.25	6.62

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	1.872	4.211	2.340	2001	326	99	81	3.20	30.73	66.25	1.16	1.86
98th %tile Delta-DV	0.563	2.709	2.145	2001	261	97	79	2.30	34.40	59.13	2.86	3.62
90th %tile Delta-DV	0.154	2.299	2.145	2001	266	91	73	2.30	19.30	74.98	1.43	4.29

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: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 6) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.541	3.774	2.234	2001	64	52	106	2.80	34.25	64.49	0.41	0.85
98th %tile Delta-DV	0.668	2.901	2.234	2001	84	52	106	2.80	21.96	75.49	0.91	1.64
90th %tile Delta-DV	0.123	2.272	2.149	2001	190	52	106	2.40	84.27	4.84	4.62	6.27

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	2.037	4.270	2.234	2001	64	82	71	2.80	33.91	64.56	0.52	1.01
98th %tile Delta-DV	0.811	2.938	2.127	2001	109	83	112	2.30	18.06	74.01	3.01	4.92
90th %tile Delta-DV	0.156	2.305	2.149	2001	195	82	71	2.40	74.14	23.02	0.74	2.10

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 ELKHORN RANCH												
Largest Delta-DV	1.520	3.754	2.234	2001	64	90	72	2.80	35.05	63.67	0.42	0.85
98th %tile Delta-DV	0.602	2.708	2.106	2001	261	90	72	2.20	52.89	43.09	1.24	2.78
90th %tile Delta-DV	0.077	2.226	2.149	2001	190	90	72	2.40	86.65	3.13	3.99	6.23

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: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	3.489	5.828	2.340	2001	326	99	81	3.20	31.47	65.64	1.11	1.77
98th %tile Delta-DV	1.086	3.362	2.275	2001	43	91	73	2.90	32.16	65.65	0.84	1.36
90th %tile Delta-DV	0.303	2.470	2.167	2001	275	93	75	2.40	26.09	66.30	2.54	5.06

Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 7) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	0.740	2.974	2.234	2001	64	52	106	2.80	37.11	61.42	0.48	0.99
98th %tile Delta-DV	0.310	2.543	2.234	2001	84	52	106	2.80	24.08	72.92	1.07	1.93
90th %tile Delta-DV	0.062	2.211	2.149	2001	190	52	106	2.40	84.11	4.24	4.95	6.70

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	0.990	3.224	2.234	2001	64	82	71	2.80	36.79	61.43	0.61	1.17
98th %tile Delta-DV	0.376	2.503	2.127	2001	109	83	112	2.30	19.74	71.06	3.48	5.72
90th %tile Delta-DV	0.075	2.308	2.234	2001	62	82	71	2.80	43.76	54.57	0.42	1.25

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 ELKHORN RANCH												
Largest Delta-DV	0.731	2.964	2.234	2001	64	90	72	2.80	37.94	60.58	0.49	0.98
98th %tile Delta-DV	0.294	2.400	2.106	2001	261	90	72	2.20	54.98	40.54	1.38	3.10
90th %tile Delta-DV	0.038	2.272	2.234	2001	55	90	72	2.80	25.42	72.95	0.40	1.22

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	1.738	4.078	2.340	2001	326	99	81	3.20	33.31	63.41	1.26	2.02
98th %tile Delta-DV	0.526	2.671	2.145	2001	261	99	81	2.30	38.19	54.71	3.12	3.97
90th %tile Delta-DV	0.140	2.286	2.145	2001	266	91	73	2.30	21.22	72.49	1.58	4.72

Number of days with Delta-Deciview > 0.50: 9
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
Coal Creek Station Unit 1 & Unit 2 (Scenario 7) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.429	3.662	2.234	2001	64	52	106	2.80	37.14	61.49	0.45	0.93
98th %tile Delta-DV	0.609	2.843	2.234	2001	84	52	106	2.80	24.14	73.05	1.00	1.80
90th %tile Delta-DV	0.123	2.271	2.149	2001	190	52	106	2.40	84.78	4.26	4.65	6.31

Number of days with Delta-Deciview > 0.50: 11
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	1.889	4.123	2.234	2001	64	82	71	2.80	36.84	61.50	0.57	1.09
98th %tile Delta-DV	0.741	2.869	2.127	2001	109	83	112	2.30	19.82	71.47	3.30	5.40
90th %tile Delta-DV	0.149	2.383	2.234	2001	62	82	71	2.80	43.79	54.66	0.39	1.16

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	1.411	3.644	2.234	2001	64	90	72	2.80	37.98	60.64	0.46	0.92
98th %tile Delta-DV	0.573	2.679	2.106	2001	261	90	72	2.20	55.72	40.05	1.30	2.93
90th %tile Delta-DV	0.076	2.182	2.106	2001	230	90	72	2.20	54.59	29.71	7.02	8.68

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
LOSTWOOD NWA												
Largest Delta-DV	3.266	5.606	2.340	2001	326	99	81	3.20	34.01	62.87	1.20	1.92
98th %tile Delta-DV	1.012	3.157	2.145	2001	261	97	79	2.30	37.61	55.75	2.93	3.70
90th %tile Delta-DV	0.276	2.421	2.145	2001	266	91	73	2.30	21.45	72.61	1.49	4.45

Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 8) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	0.613	2.846	2.234	2001	64	52	106	2.80	45.14	53.08	0.58	1.20
98th %tile Delta-DV	0.248	2.354	2.106	2001	260	46	46	2.20	62.78	31.30	2.16	3.76
90th %tile Delta-DV	0.054	2.182	2.127	2001	131	53	107	2.30	35.39	60.47	1.03	3.11

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	0.818	3.052	2.234	2001	64	82	71	2.80	44.91	52.92	0.74	1.43
98th %tile Delta-DV	0.299	2.427	2.127	2001	109	83	112	2.30	24.87	63.53	4.39	7.21
90th %tile Delta-DV	0.069	2.175	2.106	2001	230	82	71	2.20	74.40	10.30	5.97	9.33

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 ELKHORN RANCH												
Largest Delta-DV	0.606	2.840	2.234	2001	64	90	72	2.80	46.02	52.19	0.59	1.19
98th %tile Delta-DV	0.259	2.365	2.106	2001	258	90	72	2.20	41.54	50.05	3.79	4.62
90th %tile Delta-DV	0.032	2.138	2.106	2001	255	90	72	2.20	52.18	31.61	4.90	11.32

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	1.448	3.787	2.340	2001	326	99	81	3.20	40.59	55.42	1.53	2.46
98th %tile Delta-DV	0.446	2.592	2.145	2001	261	99	81	2.30	45.17	46.44	3.70	4.70
90th %tile Delta-DV	0.111	2.256	2.145	2001	266	91	73	2.30	26.88	65.15	2.00	5.97

Number of days with Delta-Deciview > 0.50: 7
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
Coal Creek Station Unit 1 & Unit 2 (Scenario 8) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.189	3.423	2.234	2001	64	52	106	2.80	45.19	53.15	0.54	1.13
98th %tile Delta-DV	0.484	2.718	2.234	2001	84	52	106	2.80	30.57	65.87	1.27	2.29
90th %tile Delta-DV	0.108	2.236	2.127	2001	131	53	107	2.30	35.47	60.65	0.97	2.91

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 NORTH UNIT												
Largest Delta-DV	1.573	3.806	2.234	2001	64	82	71	2.80	44.98	53.00	0.69	1.33
98th %tile Delta-DV	0.592	2.720	2.127	2001	109	83	112	2.30	24.99	64.04	4.16	6.81
90th %tile Delta-DV	0.136	2.242	2.106	2001	230	82	71	2.20	75.22	10.36	5.63	8.80

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: 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	1.177	3.410	2.234	2001	64	90	72	2.80	46.08	52.25	0.56	1.12
98th %tile Delta-DV	0.509	2.615	2.106	2001	261	90	72	2.20	62.89	32.34	1.47	3.30
90th %tile Delta-DV	0.064	2.191	2.127	2001	144	90	72	2.30	35.75	56.84	2.51	4.90

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
LOSTWOOD NWA												
Largest Delta-DV	2.767	5.107	2.340	2001	326	99	81	3.20	41.22	55.01	1.45	2.32
98th %tile Delta-DV	0.862	3.007	2.145	2001	261	97	79	2.30	44.49	47.67	3.47	4.38
90th %tile Delta-DV	0.219	2.364	2.145	2001	266	91	73	2.30	27.14	65.34	1.88	5.63

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 9) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	0.419	2.653	2.234	2001	64	52	106	2.80	66.57	30.79	0.86	1.78
98th %tile Delta-DV	0.170	2.276	2.106	2001	257	48	102	2.20	66.47	23.84	3.42	6.28
90th %tile Delta-DV	0.037	2.165	2.127	2001	148	48	102	2.30	41.02	42.92	7.17	8.90

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	0.560	2.793	2.234	2001	64	82	71	2.80	66.50	30.29	1.10	2.11
98th %tile Delta-DV	0.184	2.312	2.127	2001	109	83	112	2.30	40.65	40.40	7.18	11.78
90th %tile Delta-DV	0.048	2.324	2.276	2001	315	82	71	3.00	47.74	45.73	2.50	4.03

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	0.418	2.652	2.234	2001	64	90	72	2.80	67.37	30.01	0.87	1.75
98th %tile Delta-DV	0.157	2.391	2.234	2001	84	90	72	2.80	50.35	43.09	2.25	4.32
90th %tile Delta-DV	0.027	2.176	2.149	2001	201	90	72	2.40	85.15	11.16	0.88	2.81

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	0.989	3.329	2.340	2001	326	99	81	3.20	60.84	33.18	2.29	3.69
98th %tile Delta-DV	0.324	2.470	2.145	2001	259	97	79	2.30	73.24	20.29	2.05	4.41
90th %tile Delta-DV	0.073	2.305	2.232	2001	197	91	73	2.70	79.11	12.09	3.92	4.89

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: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 9) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	0.821	3.054	2.234	2001	64	52	106	2.80	66.69	30.85	0.80	1.66
98th %tile Delta-DV	0.335	2.441	2.106	2001	257	48	102	2.20	66.91	23.99	3.20	5.89
90th %tile Delta-DV	0.074	2.201	2.127	2001	148	48	102	2.30	41.43	43.38	6.77	8.41

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	1.088	3.322	2.234	2001	64	82	71	2.80	66.64	30.35	1.03	1.98
98th %tile Delta-DV	0.365	2.493	2.127	2001	109	83	112	2.30	41.00	41.00	6.83	11.17
90th %tile Delta-DV	0.098	2.374	2.276	2001	315	82	71	3.00	47.83	46.01	2.37	3.79

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.818	3.052	2.234	2001	64	90	72	2.80	67.49	30.06	0.81	1.63
98th %tile Delta-DV	0.311	2.544	2.234	2001	84	90	72	2.80	50.58	43.27	2.11	4.05
90th %tile Delta-DV	0.053	2.202	2.149	2001	201	90	72	2.40	85.39	11.17	0.82	2.63

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	1.939	4.279	2.340	2001	326	99	81	3.20	61.39	32.99	2.16	3.46
98th %tile Delta-DV	0.635	2.780	2.145	2001	259	97	79	2.30	73.67	20.27	1.93	4.14
90th %tile Delta-DV	0.145	2.377	2.232	2001	197	91	73	2.70	79.40	12.29	3.69	4.62

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: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 10) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	0.355	2.589	2.234	2001	64	52	106	2.80	78.81	18.08	1.01	2.10
98th %tile Delta-DV	0.149	2.276	2.127	2001	112	51	105	2.30	60.73	27.79	4.96	6.53
90th %tile Delta-DV	0.031	2.137	2.106	2001	254	46	46	2.20	81.62	2.61	4.76	11.01

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	0.475	2.709	2.234	2001	64	82	71	2.80	78.64	17.56	1.30	2.50
98th %tile Delta-DV	0.147	2.274	2.127	2001	98	84	113	2.30	49.30	32.63	7.41	10.66
90th %tile Delta-DV	0.044	2.277	2.234	2001	85	84	113	2.80	49.31	37.83	4.62	8.25

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	0.356	2.589	2.234	2001	64	90	72	2.80	79.39	17.52	1.02	2.06
98th %tile Delta-DV	0.123	2.250	2.127	2001	92	90	72	2.30	59.34	30.16	3.51	6.99
90th %tile Delta-DV	0.022	2.298	2.276	2001	310	90	72	3.00	55.14	27.65	3.20	14.01

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	0.831	3.171	2.340	2001	326	99	81	3.20	72.98	19.85	2.75	4.42
98th %tile Delta-DV	0.292	2.437	2.145	2001	259	97	79	2.30	81.57	11.23	2.29	4.91
90th %tile Delta-DV	0.065	2.232	2.167	2001	275	93	75	2.40	61.71	19.12	6.39	12.78

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 10) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	0.698	2.931	2.234	2001	64	52	106	2.80	78.97	18.12	0.95	1.97
98th %tile Delta-DV	0.294	2.421	2.127	2001	112	51	105	2.30	61.23	27.97	4.66	6.14
90th %tile Delta-DV	0.062	2.168	2.106	2001	254	45	45	2.20	82.59	2.64	4.43	10.34

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	0.927	3.161	2.234	2001	64	82	71	2.80	78.83	17.61	1.22	2.34
98th %tile Delta-DV	0.290	2.417	2.127	2001	109	83	112	2.30	51.83	25.42	8.64	14.12
90th %tile Delta-DV	0.087	2.321	2.234	2001	85	84	113	2.80	49.74	38.15	4.35	7.76

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: 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	0.698	2.932	2.234	2001	64	90	72	2.80	79.56	17.56	0.96	1.93
98th %tile Delta-DV	0.242	2.369	2.127	2001	92	90	72	2.30	59.76	30.38	3.29	6.57
90th %tile Delta-DV	0.044	2.320	2.276	2001	310	90	72	3.00	55.79	27.96	3.02	13.23

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	1.644	3.984	2.340	2001	326	99	81	3.20	73.53	19.74	2.59	4.15
98th %tile Delta-DV	0.572	2.717	2.145	2001	259	97	79	2.30	82.02	11.22	2.15	4.61
90th %tile Delta-DV	0.128	2.295	2.167	2001	275	93	75	2.40	62.46	19.32	6.09	12.13

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 0, Pre-BART) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	4.503	6.737	2.234	2002	78	46	46	2.80	71.11	28.40	0.09	0.39
98th %tile Delta-DV	2.559	4.814	2.255	2002	26	47	101	2.90	64.72	34.53	0.28	0.47
90th %tile Delta-DV	0.540	2.646	2.106	2002	270	53	107	2.20	58.28	40.09	0.61	1.01

Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 3

						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	6.532	8.766	2.234	2002	73	89	118	2.80	66.26	32.91	0.33	0.50
98th %tile Delta-DV	2.113	4.347	2.234	2002	39	67	56	2.80	84.58	14.15	0.33	0.95
90th %tile Delta-DV	0.385	2.512	2.127	2002	152	85	114	2.30	92.22	6.34	0.38	1.06

Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 4

						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	5.501	7.734	2.234	2002	73	90	72	2.80	69.47	29.82	0.26	0.45
98th %tile Delta-DV	1.703	3.978	2.276	2002	336	90	72	3.00	61.77	37.21	0.46	0.57
90th %tile Delta-DV	0.310	2.416	2.106	2002	255	90	72	2.20	88.37	7.70	1.41	2.52

Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3

						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	3.827	6.102	2.275	2002	74	97	79	2.90	72.61	26.86	0.17	0.36
98th %tile Delta-DV	1.814	4.154	2.340	2002	312	99	81	3.20	68.02	30.72	0.27	0.99
90th %tile Delta-DV	0.385	2.531	2.145	2002	247	97	79	2.30	96.31	1.89	0.59	1.21

Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 4

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 0, Pre-BART) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	6.675	8.908	2.234	2002	78	46	46	2.80	79.57	19.89	0.10	0.44
98th %tile Delta-DV	4.475	6.730	2.255	2002	26	47	101	2.90	63.14	36.13	0.27	0.46
90th %tile Delta-DV	0.971	3.077	2.106	2002	270	53	107	2.20	58.87	39.49	0.62	1.02

Number of days with Delta-Deciview > 0.50: 50
Number of days with Delta-Deciview > 1.00: 36
Max number of consecutive days with Delta-Deciview > 0.50: 4

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	10.081	12.314	2.234	2002	73	89	118	2.80	65.93	33.24	0.33	0.49
98th %tile Delta-DV	3.557	5.664	2.106	2002	250	82	71	2.20	89.34	9.05	0.68	0.93
90th %tile Delta-DV	0.706	2.834	2.127	2002	152	85	114	2.30	92.23	6.33	0.38	1.06

Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 4

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	8.644	10.878	2.234	2002	73	90	72	2.80	69.59	29.70	0.26	0.45
98th %tile Delta-DV	3.039	5.315	2.276	2002	336	90	72	3.00	59.83	39.18	0.44	0.55
90th %tile Delta-DV	0.581	2.708	2.127	2002	95	90	72	2.30	56.20	42.67	0.31	0.82

Number of days with Delta-Deciview > 0.50: 42
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	6.332	8.608	2.275	2002	74	97	79	2.90	71.70	27.78	0.17	0.35
98th %tile Delta-DV	3.190	5.487	2.297	2002	29	97	79	3.00	67.24	32.23	0.19	0.34
90th %tile Delta-DV	0.707	2.852	2.145	2002	247	97	79	2.30	96.30	1.90	0.59	1.21

Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 29
Max number of consecutive days with Delta-Deciview > 0.50: 4

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 1) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	2.337	4.570	2.234	2002	78	46	46	2.80	51.48	47.33	0.24	0.95
98th %tile Delta-DV	1.181	3.287	2.106	2002	233	53	107	2.20	67.36	30.47	0.77	1.39
90th %tile Delta-DV	0.219	2.346	2.127	2002	100	6	6	2.30	54.02	43.86	0.56	1.56

Number of days with Delta-Deciview > 0.50: 22
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
TRNP NORTH UNIT												
Largest Delta-DV	3.509	5.742	2.234	2002	73	89	118	2.80	46.16	51.95	0.75	1.14
98th %tile Delta-DV	0.987	3.220	2.234	2002	50	58	47	2.80	38.33	59.46	0.68	1.53
90th %tile Delta-DV	0.158	2.307	2.149	2002	189	58	47	2.40	91.54	3.96	1.57	2.93

Number of days with Delta-Deciview > 0.50: 15
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 ELKHORN RANCH												
Largest Delta-DV	2.763	4.996	2.234	2002	73	90	72	2.80	49.87	48.47	0.59	1.06
98th %tile Delta-DV	0.789	3.022	2.234	2002	78	90	72	2.80	51.41	47.45	0.22	0.92
90th %tile Delta-DV	0.136	2.242	2.106	2002	271	90	72	2.20	49.55	45.09	2.45	2.91

Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 6
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	1.775	4.050	2.275	2002	74	97	79	2.90	53.97	44.76	0.39	0.87
98th %tile Delta-DV	0.832	3.129	2.297	2002	29	97	79	3.00	49.67	49.02	0.47	0.84
90th %tile Delta-DV	0.178	2.453	2.275	2002	69	99	81	2.90	35.74	62.57	0.39	1.30

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 1) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	4.230	6.464	2.234	2002	78	46	46	2.80	51.61	47.27	0.23	0.89
98th %tile Delta-DV	2.218	4.324	2.106	2002	233	53	107	2.20	68.06	29.90	0.73	1.31
90th %tile Delta-DV	0.433	2.560	2.127	2002	100	6	6	2.30	54.10	43.91	0.53	1.46

Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 22
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	6.089	8.323	2.234	2002	73	89	118	2.80	46.36	51.87	0.70	1.07
98th %tile Delta-DV	1.880	4.114	2.234	2002	50	58	47	2.80	38.43	59.50	0.63	1.43
90th %tile Delta-DV	0.313	2.462	2.149	2002	189	58	47	2.40	91.83	3.96	1.47	2.74

Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 15
Max number of consecutive days with Delta-Deciview > 0.50: 4

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	4.916	7.149	2.234	2002	73	90	72	2.80	50.05	48.40	0.55	1.00
98th %tile Delta-DV	1.524	3.757	2.234	2002	78	90	72	2.80	51.44	47.49	0.21	0.86
90th %tile Delta-DV	0.269	2.375	2.106	2002	271	90	72	2.20	50.10	44.85	2.31	2.74

Number of days with Delta-Deciview > 0.50: 18
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
LOSTWOOD NWA												
Largest Delta-DV	3.284	5.559	2.275	2002	74	97	79	2.90	54.07	44.75	0.37	0.82
98th %tile Delta-DV	1.601	3.897	2.297	2002	29	97	79	3.00	49.72	49.05	0.44	0.79
90th %tile Delta-DV	0.350	2.626	2.275	2002	69	99	81	2.90	35.79	62.64	0.36	1.21

Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 2) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	2.217	4.451	2.234	2002	78	46	46	2.80	54.60	44.14	0.26	1.01
98th %tile Delta-DV	1.140	3.246	2.106	2002	233	53	107	2.20	69.96	27.79	0.80	1.44
90th %tile Delta-DV	0.207	2.335	2.127	2002	100	6	6	2.30	57.03	40.72	0.59	1.65

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: 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	3.321	5.554	2.234	2002	73	89	118	2.80	49.26	48.72	0.80	1.22
98th %tile Delta-DV	0.918	3.151	2.234	2002	50	58	47	2.80	41.35	56.27	0.73	1.65
90th %tile Delta-DV	0.151	2.278	2.127	2002	138	82	71	2.30	34.32	60.77	1.96	2.94

Number of days with Delta-Deciview > 0.50: 15
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 ELKHORN RANCH												
Largest Delta-DV	2.620	4.854	2.234	2002	73	90	72	2.80	52.98	45.26	0.63	1.13
98th %tile Delta-DV	0.746	2.979	2.234	2002	78	90	72	2.80	54.51	44.28	0.23	0.98
90th %tile Delta-DV	0.129	2.235	2.106	2002	271	90	72	2.20	52.30	42.04	2.59	3.07

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: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.686	3.961	2.275	2002	74	97	79	2.90	57.08	41.58	0.42	0.92
98th %tile Delta-DV	0.783	3.080	2.297	2002	29	97	79	3.00	52.90	45.71	0.50	0.90
90th %tile Delta-DV	0.165	2.440	2.275	2002	69	99	81	2.90	38.63	59.54	0.42	1.40

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 2) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	4.033	6.266	2.234	2002	78	46	46	2.80	54.71	44.10	0.24	0.94
98th %tile Delta-DV	2.145	4.251	2.106	2002	233	53	107	2.20	70.61	27.27	0.76	1.36
90th %tile Delta-DV	0.410	2.538	2.127	2002	100	6	6	2.30	57.12	40.78	0.56	1.54

Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 20
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	5.800	8.033	2.234	2002	73	89	118	2.80	49.45	48.66	0.75	1.14
98th %tile Delta-DV	1.755	3.988	2.234	2002	50	58	47	2.80	41.45	56.32	0.68	1.55
90th %tile Delta-DV	0.298	2.532	2.234	2002	78	67	56	2.80	51.48	47.35	0.28	0.90

Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 15
Max number of consecutive days with Delta-Deciview > 0.50: 4

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	4.686	6.920	2.234	2002	73	90	72	2.80	53.15	45.20	0.59	1.06
98th %tile Delta-DV	1.443	3.677	2.234	2002	78	90	72	2.80	54.54	44.33	0.22	0.91
90th %tile Delta-DV	0.256	2.362	2.106	2002	271	90	72	2.20	52.84	41.84	2.44	2.89

Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 11
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	3.130	5.406	2.275	2002	74	97	79	2.90	57.18	41.57	0.39	0.86
98th %tile Delta-DV	1.510	3.807	2.297	2002	29	97	79	3.00	52.95	45.74	0.47	0.84
90th %tile Delta-DV	0.325	2.600	2.275	2002	69	99	81	2.90	38.69	59.61	0.39	1.31

Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 3) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.960	4.194	2.234	2002	78	46	46	2.80	62.58	35.97	0.29	1.15
98th %tile Delta-DV	1.052	3.158	2.106	2002	233	53	107	2.20	76.13	21.42	0.87	1.57
90th %tile Delta-DV	0.186	2.419	2.234	2002	51	48	102	2.80	80.77	18.31	0.25	0.66

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: 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	2.913	5.146	2.234	2002	73	89	118	2.80	57.39	40.27	0.93	1.42
98th %tile Delta-DV	0.813	2.919	2.106	2002	250	82	71	2.20	67.27	28.75	1.67	2.31
90th %tile Delta-DV	0.131	2.386	2.255	2002	30	82	71	2.90	69.78	29.39	0.17	0.66

Number of days with Delta-Deciview > 0.50: 14
Number of days with Delta-Deciview > 1.00: 6
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)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.313	4.547	2.234	2002	73	90	72	2.80	60.98	36.99	0.72	1.30
98th %tile Delta-DV	0.654	2.887	2.234	2002	78	90	72	2.80	62.46	36.16	0.27	1.12
90th %tile Delta-DV	0.118	2.246	2.127	2002	95	90	72	2.30	47.77	49.06	0.89	2.28

Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 4
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)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.496	3.771	2.275	2002	74	97	79	2.90	64.95	33.53	0.47	1.05
98th %tile Delta-DV	0.680	2.977	2.297	2002	29	97	79	3.00	61.21	37.18	0.58	1.04
90th %tile Delta-DV	0.141	2.352	2.211	2002	172	97	79	2.60	80.33	10.28	3.11	6.28

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
Coal Creek Station Unit 1 & Unit 2 (Scenario 3) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	3.602	5.835	2.234	2002	78	46	46	2.80	62.68	35.97	0.28	1.08
98th %tile Delta-DV	1.991	4.097	2.106	2002	233	53	107	2.20	76.69	21.02	0.82	1.48
90th %tile Delta-DV	0.371	2.604	2.234	2002	51	48	102	2.80	80.83	18.31	0.23	0.62

Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 20
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	5.159	7.393	2.234	2002	73	89	118	2.80	57.57	40.23	0.87	1.33
98th %tile Delta-DV	1.536	3.642	2.106	2002	250	82	71	2.20	67.80	28.47	1.56	2.17
90th %tile Delta-DV	0.260	2.515	2.255	2002	30	82	71	2.90	69.83	29.39	0.16	0.61

Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 4

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	4.185	6.418	2.234	2002	73	90	72	2.80	61.15	36.96	0.68	1.22
98th %tile Delta-DV	1.271	3.504	2.234	2002	78	90	72	2.80	62.50	36.20	0.25	1.04
90th %tile Delta-DV	0.234	2.362	2.127	2002	95	90	72	2.30	48.03	49.00	0.83	2.14

Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 10
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	2.799	5.075	2.275	2002	74	97	79	2.90	65.05	33.53	0.44	0.98
98th %tile Delta-DV	1.318	3.615	2.297	2002	29	97	79	3.00	61.27	37.22	0.54	0.97
90th %tile Delta-DV	0.279	2.489	2.211	2002	172	97	79	2.60	80.87	10.30	2.92	5.90

Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 4) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.564	3.798	2.234	2002	78	46	46	2.80	80.04	18.11	0.38	1.47
98th %tile Delta-DV	0.799	3.032	2.234	2002	64	57	111	2.80	72.68	23.87	0.96	2.49
90th %tile Delta-DV	0.160	2.394	2.234	2002	49	53	107	2.80	62.71	31.41	1.92	3.96

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: 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	2.273	4.506	2.234	2002	73	89	118	2.80	76.03	20.86	1.23	1.88
98th %tile Delta-DV	0.677	2.783	2.106	2002	250	82	71	2.20	81.34	13.85	2.02	2.79
90th %tile Delta-DV	0.121	2.248	2.127	2002	152	85	114	2.30	91.91	3.47	1.21	3.42

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: 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	1.837	4.071	2.234	2002	73	90	72	2.80	78.69	18.70	0.93	1.68
98th %tile Delta-DV	0.515	2.748	2.234	2002	78	90	72	2.80	79.92	18.31	0.34	1.43
90th %tile Delta-DV	0.090	2.196	2.106	2002	271	90	72	2.20	74.63	17.30	3.69	4.38

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
LOSTWOOD NWA												
Largest Delta-DV	1.208	3.483	2.275	2002	74	97	79	2.90	81.64	16.44	0.60	1.32
98th %tile Delta-DV	0.569	2.908	2.340	2002	312	99	81	3.20	73.42	21.30	1.15	4.13
90th %tile Delta-DV	0.114	2.346	2.232	2002	195	99	81	2.70	65.19	25.04	4.01	5.75

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: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 4) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	2.920	5.154	2.234	2002	78	46	46	2.80	80.14	18.13	0.35	1.38
98th %tile Delta-DV	1.537	3.771	2.234	2002	64	57	111	2.80	72.87	23.91	0.89	2.32
90th %tile Delta-DV	0.316	2.549	2.234	2002	49	53	107	2.80	63.01	31.48	1.80	3.71
TRNP NORTH UNIT												
Largest Delta-DV	4.120	6.354	2.234	2002	73	89	118	2.80	76.24	20.86	1.15	1.75
98th %tile Delta-DV	1.290	3.396	2.106	2002	250	82	71	2.20	81.76	13.73	1.89	2.62
90th %tile Delta-DV	0.239	2.367	2.127	2002	152	85	114	2.30	92.28	3.39	1.13	3.20
TRNP ELKHORN RANCH												
Largest Delta-DV	3.386	5.619	2.234	2002	73	90	72	2.80	78.86	18.70	0.87	1.57
98th %tile Delta-DV	1.006	3.240	2.234	2002	78	90	72	2.80	79.99	18.35	0.32	1.34
90th %tile Delta-DV	0.180	2.286	2.106	2002	271	90	72	2.20	75.15	17.27	3.46	4.12
LOSTWOOD NWA												
Largest Delta-DV	2.287	4.563	2.275	2002	74	97	79	2.90	81.76	16.45	0.56	1.23
98th %tile Delta-DV	1.105	3.445	2.340	2002	312	99	81	3.20	73.62	21.43	1.07	3.88
90th %tile Delta-DV	0.224	2.456	2.232	2002	195	99	81	2.70	65.69	25.10	3.78	5.43

TRNP SOUTH UNIT

Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT

Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH

Number of days with Delta-Deciview > 0.50: 14
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA

Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 5) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.431	3.665	2.234	2002	78	46	46	2.80	88.09	9.88	0.41	1.62
98th %tile Delta-DV	0.706	2.940	2.234	2002	64	57	111	2.80	82.60	13.49	1.09	2.82
90th %tile Delta-DV	0.140	2.373	2.234	2002	83	48	102	2.80	70.99	21.36	2.83	4.82

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: 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	2.056	4.289	2.234	2002	73	89	118	2.80	85.02	11.50	1.38	2.10
98th %tile Delta-DV	0.632	2.738	2.106	2002	250	82	71	2.20	87.41	7.42	2.17	3.00
90th %tile Delta-DV	0.119	2.246	2.127	2002	152	85	114	2.30	93.60	1.70	1.23	3.48

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
TRNP ELKHORN RANCH												
Largest Delta-DV	1.677	3.911	2.234	2002	73	90	72	2.80	86.92	10.20	1.03	1.85
98th %tile Delta-DV	0.468	2.702	2.234	2002	78	90	72	2.80	88.02	10.03	0.38	1.57
90th %tile Delta-DV	0.084	2.317	2.234	2002	75	90	72	2.80	94.58	4.37	0.17	0.89

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
LOSTWOOD NWA												
Largest Delta-DV	1.112	3.388	2.275	2002	74	97	79	2.90	89.07	8.83	0.65	1.44
98th %tile Delta-DV	0.510	2.849	2.340	2002	312	99	81	3.20	82.16	11.93	1.29	4.62
90th %tile Delta-DV	0.106	2.402	2.297	2002	31	97	79	3.00	93.23	5.95	0.16	0.66

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: 1

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 5) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	2.686	4.919	2.234	2002	78	46	46	2.80	88.20	9.89	0.39	1.52
98th %tile Delta-DV	1.364	3.598	2.234	2002	64	57	111	2.80	82.83	13.51	1.02	2.64
90th %tile Delta-DV	0.281	2.514	2.234	2002	83	48	102	2.80	71.36	21.49	2.63	4.52

Number of days with Delta-Deciview > 0.50: 23
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	3.757	5.990	2.234	2002	73	89	118	2.80	85.25	11.50	1.29	1.96
98th %tile Delta-DV	1.206	3.312	2.106	2002	250	82	71	2.20	87.80	7.36	2.03	2.81
90th %tile Delta-DV	0.235	2.362	2.127	2002	152	85	114	2.30	93.93	1.66	1.15	3.26

Number of days with Delta-Deciview > 0.50: 17
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	3.110	5.344	2.234	2002	73	90	72	2.80	87.10	10.20	0.96	1.73
98th %tile Delta-DV	0.917	3.151	2.234	2002	78	90	72	2.80	88.13	10.05	0.35	1.47
90th %tile Delta-DV	0.167	2.401	2.234	2002	75	90	72	2.80	94.63	4.39	0.15	0.83

Number of days with Delta-Deciview > 0.50: 14
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
LOSTWOOD NWA												
Largest Delta-DV	2.115	4.391	2.275	2002	74	97	79	2.90	89.21	8.84	0.61	1.35
98th %tile Delta-DV	0.992	3.332	2.340	2002	312	99	81	3.20	82.44	12.01	1.20	4.35
90th %tile Delta-DV	0.207	2.352	2.145	2002	259	99	81	2.30	87.99	0.33	2.83	8.86

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 6) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.613	3.846	2.234	2002	78	46	46	2.80	26.94	71.27	0.36	1.43
98th %tile Delta-DV	0.695	2.928	2.234	2002	50	48	102	2.80	21.01	76.17	0.78	2.04
90th %tile Delta-DV	0.140	2.267	2.127	2002	95	46	46	2.30	14.22	82.69	0.98	2.12

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
TRNP NORTH UNIT												
Largest Delta-DV	2.578	4.811	2.234	2002	73	89	118	2.80	22.95	74.35	1.07	1.63
98th %tile Delta-DV	0.727	2.961	2.234	2002	39	58	47	2.80	29.46	66.42	1.01	3.10
90th %tile Delta-DV	0.095	2.349	2.255	2002	30	82	71	2.90	33.78	65.06	0.24	0.92

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 ELKHORN RANCH												
Largest Delta-DV	1.947	4.180	2.234	2002	73	90	72	2.80	25.68	71.87	0.87	1.58
98th %tile Delta-DV	0.531	2.765	2.234	2002	78	90	72	2.80	26.89	71.40	0.33	1.38
90th %tile Delta-DV	0.088	2.216	2.127	2002	296	90	72	2.30	14.08	82.49	1.43	2.00

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
LOSTWOOD NWA												
Largest Delta-DV	1.186	3.461	2.275	2002	74	94	76	2.90	28.92	69.13	0.61	1.34
98th %tile Delta-DV	0.561	2.706	2.145	2002	110	91	73	2.30	31.68	65.54	1.03	1.75
90th %tile Delta-DV	0.096	2.393	2.297	2002	13	97	79	3.00	17.53	81.49	0.39	0.60

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 6) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	78	46	46	2.80	26.97	71.35	0.34	1.33
98th %tile Delta-DV	1.344	3.578	2.234	2002	50	48	102	2.80	21.06	76.30	0.73	1.91
90th %tile Delta-DV	0.278	2.512	2.234	2002	91	45	45	2.80	26.14	72.32	0.20	1.34

Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 12
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	4.616	6.850	2.234	2002	73	89	118	2.80	23.04	74.43	1.00	1.53
98th %tile Delta-DV	1.382	3.616	2.234	2002	66	83	112	2.80	17.82	78.26	1.15	2.77
90th %tile Delta-DV	0.188	2.442	2.255	2002	30	82	71	2.90	33.82	65.11	0.22	0.86

Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 12
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	3.569	5.803	2.234	2002	73	90	72	2.80	25.77	71.94	0.82	1.47
98th %tile Delta-DV	1.033	3.139	2.106	2002	250	90	72	2.20	47.14	46.00	2.56	4.31
90th %tile Delta-DV	0.176	2.303	2.127	2002	296	90	72	2.30	14.12	82.68	1.34	1.87

Number of days with Delta-Deciview > 0.50: 17
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	2.247	4.523	2.275	2002	74	94	76	2.90	28.97	69.20	0.57	1.26
98th %tile Delta-DV	1.088	3.233	2.145	2002	110	91	73	2.30	31.79	65.60	0.96	1.64
90th %tile Delta-DV	0.193	2.468	2.275	2002	91	93	75	2.90	11.06	83.75	2.04	3.16

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: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 7) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.484	3.717	2.234	2002	78	46	46	2.80	29.47	68.57	0.40	1.56
98th %tile Delta-DV	0.640	2.746	2.106	2002	233	45	45	2.20	44.01	51.85	1.48	2.66
90th %tile Delta-DV	0.129	2.299	2.170	2002	155	46	46	2.50	42.37	56.75	0.15	0.74

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	2.371	4.605	2.234	2002	73	89	118	2.80	25.22	71.81	1.18	1.79
98th %tile Delta-DV	0.675	2.909	2.234	2002	39	58	47	2.80	31.82	63.73	1.09	3.35
90th %tile Delta-DV	0.087	2.342	2.255	2002	30	82	71	2.90	36.62	62.13	0.26	0.99

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	1.792	4.025	2.234	2002	73	90	72	2.80	28.13	69.19	0.96	1.73
98th %tile Delta-DV	0.487	2.721	2.234	2002	78	90	72	2.80	29.40	68.72	0.36	1.51
90th %tile Delta-DV	0.085	2.191	2.106	2002	271	90	72	2.20	27.48	63.97	3.91	4.64

Number of days with Delta-Deciview > 0.50: 7
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
LOSTWOOD NWA												
Largest Delta-DV	1.091	3.367	2.275	2002	74	94	76	2.90	31.57	66.29	0.67	1.47
98th %tile Delta-DV	0.520	2.817	2.297	2002	29	97	79	3.00	28.07	69.80	0.76	1.37
90th %tile Delta-DV	0.088	2.299	2.211	2002	178	97	79	2.60	82.99	9.58	3.04	4.39

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: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 7) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.484	3.717	2.234	2002	78	46	46	2.80	29.47	68.57	0.40	1.56
98th %tile Delta-DV	0.640	2.746	2.106	2002	233	45	45	2.20	44.01	51.85	1.48	2.66
90th %tile Delta-DV	0.129	2.299	2.170	2002	155	46	46	2.50	42.37	56.75	0.15	0.74

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	2.371	4.605	2.234	2002	73	89	118	2.80	25.22	71.81	1.18	1.79
98th %tile Delta-DV	0.675	2.909	2.234	2002	39	58	47	2.80	31.82	63.73	1.09	3.35
90th %tile Delta-DV	0.087	2.342	2.255	2002	30	82	71	2.90	36.62	62.13	0.26	0.99

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	1.792	4.025	2.234	2002	73	90	72	2.80	28.13	69.19	0.96	1.73
98th %tile Delta-DV	0.487	2.721	2.234	2002	78	90	72	2.80	29.40	68.72	0.36	1.51
90th %tile Delta-DV	0.085	2.191	2.106	2002	271	90	72	2.20	27.48	63.97	3.91	4.64

Number of days with Delta-Deciview > 0.50: 7
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
LOSTWOOD NWA												
Largest Delta-DV	1.091	3.367	2.275	2002	74	94	76	2.90	31.57	66.29	0.67	1.47
98th %tile Delta-DV	0.520	2.817	2.297	2002	29	97	79	3.00	28.07	69.80	0.76	1.37
90th %tile Delta-DV	0.088	2.299	2.211	2002	178	97	79	2.60	82.99	9.58	3.04	4.39

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: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 8) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.207	3.440	2.234	2002	78	46	46	2.80	36.75	60.80	0.50	1.95
98th %tile Delta-DV	0.546	2.653	2.106	2002	233	53	107	2.20	52.29	42.88	1.73	3.10
90th %tile Delta-DV	0.106	2.339	2.234	2002	79	53	107	2.80	31.11	66.09	0.42	2.38

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: 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	1.921	4.154	2.234	2002	73	89	118	2.80	31.87	64.38	1.49	2.26
98th %tile Delta-DV	0.529	2.763	2.234	2002	50	58	47	2.80	25.43	70.35	1.29	2.92
90th %tile Delta-DV	0.069	2.239	2.170	2002	178	85	114	2.50	71.22	22.05	2.60	4.13

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: 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	1.457	3.691	2.234	2002	73	90	72	2.80	35.19	61.46	1.20	2.16
98th %tile Delta-DV	0.393	2.626	2.234	2002	78	90	72	2.80	36.64	61.02	0.45	1.89
90th %tile Delta-DV	0.073	2.243	2.170	2002	178	90	72	2.50	68.13	25.80	2.26	3.81

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
LOSTWOOD NWA												
Largest Delta-DV	0.890	3.165	2.275	2002	74	97	79	2.90	39.17	58.18	0.82	1.82
98th %tile Delta-DV	0.414	2.711	2.297	2002	29	97	79	3.00	35.42	61.90	0.96	1.73
90th %tile Delta-DV	0.080	2.312	2.232	2002	192	91	73	2.70	79.16	9.32	4.66	6.86

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 8) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	2.286	4.519	2.234	2002	78	46	46	2.80	36.80	60.91	0.47	1.82
98th %tile Delta-DV	1.057	3.163	2.106	2002	233	53	107	2.20	52.71	42.75	1.62	2.92
90th %tile Delta-DV	0.210	2.443	2.234	2002	79	53	107	2.80	31.17	66.21	0.39	2.22

Number of days with Delta-Deciview > 0.50: 23
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 NORTH UNIT												
Largest Delta-DV	3.524	5.758	2.234	2002	73	89	118	2.80	31.99	64.50	1.39	2.12
98th %tile Delta-DV	1.029	3.262	2.234	2002	50	58	47	2.80	25.52	70.54	1.21	2.74
90th %tile Delta-DV	0.137	2.307	2.170	2002	178	85	114	2.50	71.58	22.10	2.44	3.87

Number of days with Delta-Deciview > 0.50: 16
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 ELKHORN RANCH												
Largest Delta-DV	2.724	4.957	2.234	2002	73	90	72	2.80	35.30	61.56	1.12	2.02
98th %tile Delta-DV	0.772	3.006	2.234	2002	78	90	72	2.80	36.67	61.14	0.42	1.76
90th %tile Delta-DV	0.145	2.315	2.170	2002	178	90	72	2.50	68.47	25.85	2.12	3.57

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: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.707	3.983	2.275	2002	74	97	79	2.90	39.25	58.28	0.77	1.70
98th %tile Delta-DV	0.812	3.109	2.297	2002	29	97	79	3.00	35.47	62.02	0.90	1.62
90th %tile Delta-DV	0.158	2.390	2.232	2002	192	91	73	2.70	79.81	9.35	4.38	6.46

Number of days with Delta-Deciview > 0.50: 13
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
Coal Creek Station Unit 1 (Scenario 9) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	0.779	3.012	2.234	2002	78	46	46	2.80	58.22	37.91	0.79	3.08
98th %tile Delta-DV	0.406	2.512	2.106	2002	233	53	107	2.20	70.84	22.62	2.34	4.20
90th %tile Delta-DV	0.070	2.197	2.127	2002	100	6	6	2.30	59.27	34.04	1.77	4.92

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

TRNP NORTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	1.211	3.444	2.234	2002	73	89	118	2.80	52.43	41.40	2.45	3.72
98th %tile Delta-DV	0.325	2.431	2.106	2002	250	82	71	2.20	60.14	29.65	4.28	5.94
90th %tile Delta-DV	0.049	2.283	2.234	2002	78	67	56	2.80	54.85	41.30	0.90	2.95

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: 2

TRNP ELKHORN RANCH

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	0.937	3.170	2.234	2002	73	90	72	2.80	56.19	38.45	1.91	3.45
98th %tile Delta-DV	0.250	2.483	2.234	2002	78	90	72	2.80	58.04	38.26	0.71	2.99
90th %tile Delta-DV	0.047	2.280	2.234	2002	66	90	72	2.80	49.08	45.59	0.81	4.53

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

LOSTWOOD NWA

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	0.583	2.858	2.275	2002	74	97	79	2.90	60.72	35.18	1.28	2.82
98th %tile Delta-DV	0.261	2.429	2.167	2002	301	91	73	2.40	47.62	45.46	2.15	4.77
90th %tile Delta-DV	0.059	2.269	2.211	2002	172	97	79	2.60	67.50	9.80	7.51	15.18

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
Coal Creek Station Unit 1 & Unit 2 (Scenario 9) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.502	3.735	2.234	2002	78	46	46	2.80	58.34	38.03	0.74	2.89
98th %tile Delta-DV	0.792	2.898	2.106	2002	233	53	107	2.20	71.29	22.57	2.19	3.95
90th %tile Delta-DV	0.139	2.267	2.127	2002	100	6	6	2.30	59.55	34.18	1.66	4.61

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	2.284	4.518	2.234	2002	73	89	118	2.80	52.67	41.55	2.29	3.49
98th %tile Delta-DV	0.627	2.733	2.106	2002	250	82	71	2.20	60.62	29.77	4.02	5.58
90th %tile Delta-DV	0.098	2.332	2.234	2002	78	67	56	2.80	54.94	41.45	0.85	2.76

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: 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	1.789	4.023	2.234	2002	73	90	72	2.80	56.40	38.58	1.79	3.23
98th %tile Delta-DV	0.494	2.728	2.234	2002	78	90	72	2.80	58.15	38.38	0.67	2.80
90th %tile Delta-DV	0.093	2.220	2.127	2002	95	90	72	2.30	42.39	50.06	2.12	5.43

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	1.134	3.409	2.275	2002	74	97	79	2.90	60.89	35.28	1.19	2.64
98th %tile Delta-DV	0.513	2.681	2.167	2002	301	91	73	2.40	47.85	45.66	2.02	4.47
90th %tile Delta-DV	0.115	2.326	2.211	2002	172	97	79	2.60	68.53	9.97	7.12	14.38

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: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 10) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	0.634	2.868	2.234	2002	78	46	46	2.80	71.98	23.23	0.97	3.81
98th %tile Delta-DV	0.332	2.565	2.234	2002	64	57	111	2.80	62.27	29.25	2.36	6.12
90th %tile Delta-DV	0.062	2.168	2.106	2002	240	49	103	2.20	92.95	3.28	1.33	2.44

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	0.968	3.202	2.234	2002	73	89	118	2.80	66.36	25.84	3.10	4.71
98th %tile Delta-DV	0.277	2.383	2.106	2002	250	82	71	2.20	70.63	17.36	5.03	6.98
90th %tile Delta-DV	0.047	2.174	2.127	2002	152	85	114	2.30	83.50	4.43	3.15	8.93

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

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	0.761	2.995	2.234	2002	73	90	72	2.80	69.77	23.57	2.38	4.28
98th %tile Delta-DV	0.202	2.436	2.234	2002	78	90	72	2.80	71.87	23.55	0.88	3.70
90th %tile Delta-DV	0.038	2.187	2.149	2002	198	90	72	2.40	83.93	3.54	5.44	7.10

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	0.481	2.757	2.275	2002	74	97	79	2.90	73.92	21.09	1.55	3.44
98th %tile Delta-DV	0.226	2.458	2.232	2002	200	93	75	2.70	85.94	7.47	2.42	4.17
90th %tile Delta-DV	0.049	2.195	2.145	2002	247	97	79	2.30	83.85	1.24	4.93	9.98

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
Coal Creek Station Unit 1 & Unit 2 (Scenario 10) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 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	1.230	3.464	2.234	2002	78	46	46	2.80	72.19	23.32	0.92	3.57
98th %tile Delta-DV	0.651	2.884	2.234	2002	64	57	111	2.80	62.64	29.41	2.21	5.74
90th %tile Delta-DV	0.123	2.229	2.106	2002	240	49	103	2.20	93.17	3.31	1.24	2.28

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: 1

TRNP NORTH UNIT												
Largest Delta-DV	1.845	4.078	2.234	2002	73	89	118	2.80	66.72	25.96	2.90	4.42
98th %tile Delta-DV	0.536	2.642	2.106	2002	250	82	71	2.20	71.25	17.46	4.72	6.57
90th %tile Delta-DV	0.092	2.219	2.127	2002	152	85	114	2.30	84.21	4.44	2.95	8.41

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

TRNP ELKHORN RANCH												
Largest Delta-DV	1.464	3.697	2.234	2002	73	90	72	2.80	70.09	23.67	2.23	4.01
98th %tile Delta-DV	0.401	2.634	2.234	2002	78	90	72	2.80	72.06	23.64	0.83	3.46
90th %tile Delta-DV	0.075	2.223	2.149	2002	198	90	72	2.40	84.54	3.67	5.11	6.68

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

LOSTWOOD NWA												
Largest Delta-DV	0.940	3.215	2.275	2002	74	97	79	2.90	74.16	21.17	1.45	3.22
98th %tile Delta-DV	0.444	2.676	2.232	2002	200	93	75	2.70	86.34	7.48	2.27	3.91
90th %tile Delta-DV	0.096	2.263	2.167	2002	220	97	79	2.40	61.77	26.00	5.30	6.93

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
Coal Creek Station Unit 1 (PM Scenario 0, All Pollutants Pre-BART) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	4.503	6.737	2.234	2002	78	46	46	2.80	71.11	28.40	0.09	0.39
98th %tile Delta-DV	2.559	4.814	2.255	2002	26	47	101	2.90	64.72	34.53	0.28	0.47
90th %tile Delta-DV	0.540	2.646	2.106	2002	270	53	107	2.20	58.28	40.09	0.61	1.01

Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 23
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	6.532	8.766	2.234	2002	73	89	118	2.80	66.26	32.91	0.33	0.50
98th %tile Delta-DV	2.113	4.347	2.234	2002	39	67	56	2.80	84.58	14.15	0.33	0.95
90th %tile Delta-DV	0.385	2.512	2.127	2002	152	85	114	2.30	92.22	6.34	0.38	1.06

Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 4

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	5.501	7.734	2.234	2002	73	90	72	2.80	69.47	29.82	0.26	0.45
98th %tile Delta-DV	1.703	3.978	2.276	2002	336	90	72	3.00	61.77	37.21	0.46	0.57
90th %tile Delta-DV	0.310	2.416	2.106	2002	255	90	72	2.20	88.37	7.70	1.41	2.52

Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 13
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
LOSTWOOD NWA												
Largest Delta-DV	3.827	6.102	2.275	2002	74	97	79	2.90	72.61	26.86	0.17	0.36
98th %tile Delta-DV	1.814	4.154	2.340	2002	312	99	81	3.20	68.02	30.72	0.27	0.99
90th %tile Delta-DV	0.385	2.531	2.145	2002	247	97	79	2.30	96.31	1.89	0.59	1.21

Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 4

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (PM Scenario 1, PM at Pre-BART, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.474	3.708	2.234	2002	78	46	46	2.80	40.09	58.18	0.33	1.40
98th %tile Delta-DV	0.749	2.855	2.106	2002	233	53	107	2.20	55.64	40.89	1.25	2.23
90th %tile Delta-DV	0.135	2.263	2.127	2002	100	54	108	2.30	38.72	57.36	1.17	2.75

Number of days with Delta-Deciview > 0.50: 12
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	2.436	4.670	2.234	2002	73	89	118	2.80	34.70	62.54	1.10	1.65
98th %tile Delta-DV	0.695	2.928	2.234	2002	50	58	47	2.80	27.85	69.05	0.95	2.15
90th %tile Delta-DV	0.092	2.240	2.149	2002	198	84	113	2.40	84.80	5.35	3.51	6.34

Number of days with Delta-Deciview > 0.50: 14
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	1.916	4.150	2.234	2002	73	90	72	2.80	38.06	59.46	0.90	1.58
98th %tile Delta-DV	0.586	2.862	2.276	2002	336	90	72	3.00	30.14	66.71	1.41	1.75
90th %tile Delta-DV	0.090	2.196	2.106	2002	271	90	72	2.20	37.58	54.52	3.62	4.29

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	1.188	3.463	2.275	2002	74	97	79	2.90	42.04	56.02	0.62	1.32
98th %tile Delta-DV	0.536	2.833	2.297	2002	29	97	79	3.00	38.20	59.88	0.68	1.24
90th %tile Delta-DV	0.099	2.331	2.232	2002	185	97	79	2.70	21.43	68.70	3.48	6.38

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: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (PM Scenario 2, PM at Permit Limit, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.507	3.741	2.234	2002	78	46	46	2.80	39.14	56.79	0.77	3.31
98th %tile Delta-DV	0.784	2.890	2.106	2002	233	53	107	2.20	53.03	38.97	2.86	5.13
90th %tile Delta-DV	0.143	2.270	2.127	2002	100	54	108	2.30	36.69	54.35	2.66	6.30

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
TRNP NORTH UNIT												
Largest Delta-DV	2.520	4.753	2.234	2002	73	89	118	2.80	33.40	60.20	2.57	3.83
98th %tile Delta-DV	0.731	2.837	2.106	2002	250	82	71	2.20	42.38	45.91	4.96	6.76
90th %tile Delta-DV	0.096	2.351	2.255	2002	30	82	71	2.90	46.56	50.82	0.55	2.07

Number of days with Delta-Deciview > 0.50: 14
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
TRNP ELKHORN RANCH												
Largest Delta-DV	1.977	4.211	2.234	2002	73	90	72	2.80	36.77	57.45	2.10	3.68
98th %tile Delta-DV	0.611	2.887	2.276	2002	336	90	72	3.00	28.85	63.86	3.25	4.04
90th %tile Delta-DV	0.099	2.205	2.106	2002	271	90	72	2.20	33.80	49.03	7.86	9.32

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: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	1.218	3.494	2.275	2002	74	97	79	2.90	40.91	54.52	1.46	3.10
98th %tile Delta-DV	0.578	2.745	2.167	2002	241	91	73	2.40	74.87	10.20	4.86	10.07
90th %tile Delta-DV	0.112	2.345	2.232	2002	185	97	79	2.70	18.81	60.30	7.38	13.52

Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (PM Scenario 3, PM at Average Actual, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.468	3.701	2.234	2002	78	46	46	2.80	40.28	58.46	0.24	1.02
98th %tile Delta-DV	0.742	2.848	2.106	2002	233	53	107	2.20	56.18	41.28	0.91	1.63
90th %tile Delta-DV	0.134	2.368	2.234	2002	91	45	45	2.80	38.80	59.98	0.17	1.04

Number of days with Delta-Deciview > 0.50: 12
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	2.420	4.653	2.234	2002	73	89	118	2.80	34.97	63.02	0.81	1.20
98th %tile Delta-DV	0.689	2.922	2.234	2002	50	58	47	2.80	28.09	69.65	0.69	1.57
90th %tile Delta-DV	0.089	2.323	2.234	2002	78	67	56	2.80	37.73	61.04	0.27	0.96

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 ELKHORN RANCH												
Largest Delta-DV	1.904	4.138	2.234	2002	73	90	72	2.80	38.32	59.87	0.66	1.15
98th %tile Delta-DV	0.581	2.857	2.276	2002	336	90	72	3.00	30.40	67.30	1.03	1.28
90th %tile Delta-DV	0.088	2.194	2.106	2002	271	90	72	2.20	38.41	55.73	2.68	3.18

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	1.182	3.457	2.275	2002	74	97	79	2.90	42.26	56.32	0.45	0.96
98th %tile Delta-DV	0.533	2.830	2.297	2002	29	97	79	3.00	38.40	60.20	0.50	0.90
90th %tile Delta-DV	0.097	2.437	2.340	2002	336	91	73	3.20	16.51	81.04	0.43	2.02

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: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (PM Scenario 4, PM at Best Controls, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	1.459	3.692	2.234	2002	78	46	46	2.80	40.54	58.83	0.12	0.51
98th %tile Delta-DV	0.733	2.839	2.106	2002	233	53	107	2.20	56.90	41.81	0.46	0.83
90th %tile Delta-DV	0.133	2.367	2.234	2002	91	45	45	2.80	39.04	60.35	0.09	0.52

Number of days with Delta-Deciview > 0.50: 12
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	2.398	4.632	2.234	2002	73	89	118	2.80	35.33	63.66	0.41	0.61
98th %tile Delta-DV	0.681	2.915	2.234	2002	50	58	47	2.80	28.41	70.45	0.35	0.79
90th %tile Delta-DV	0.086	2.192	2.106	2002	249	63	52	2.20	31.60	61.47	2.76	4.17

Number of days with Delta-Deciview > 0.50: 13
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	1.889	4.122	2.234	2002	73	90	72	2.80	38.67	60.42	0.33	0.58
98th %tile Delta-DV	0.570	2.676	2.106	2002	250	90	72	2.20	62.68	35.00	0.86	1.46
90th %tile Delta-DV	0.085	2.191	2.106	2002	271	90	72	2.20	39.57	57.41	1.38	1.64

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	1.173	3.449	2.275	2002	74	97	79	2.90	42.56	56.73	0.23	0.48
98th %tile Delta-DV	0.529	2.826	2.297	2002	29	97	79	3.00	38.67	60.62	0.25	0.45
90th %tile Delta-DV	0.096	2.436	2.340	2002	336	91	73	3.20	16.71	82.05	0.22	1.02

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: 2

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (PM Scenario 0, All Pollutants Pre-BART) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	6.675	8.908	2.234	2002	78	46	46	2.80	79.57	19.89	0.10	0.44
98th %tile Delta-DV	4.475	6.730	2.255	2002	26	47	101	2.90	63.14	36.13	0.27	0.46
90th %tile Delta-DV	0.971	3.077	2.106	2002	270	53	107	2.20	58.87	39.49	0.62	1.02

Number of days with Delta-Deciview > 0.50: 50
Number of days with Delta-Deciview > 1.00: 36
Max number of consecutive days with Delta-Deciview > 0.50: 4

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	10.081	12.314	2.234	2002	73	89	118	2.80	65.93	33.24	0.33	0.49
98th %tile Delta-DV	3.557	5.664	2.106	2002	250	82	71	2.20	89.34	9.05	0.68	0.93
90th %tile Delta-DV	0.706	2.834	2.127	2002	152	85	114	2.30	92.23	6.33	0.38	1.06

Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 4

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	8.644	10.878	2.234	2002	73	90	72	2.80	69.59	29.70	0.26	0.45
98th %tile Delta-DV	3.039	5.315	2.276	2002	336	90	72	3.00	59.83	39.18	0.44	0.55
90th %tile Delta-DV	0.581	2.708	2.127	2002	95	90	72	2.30	56.20	42.67	0.31	0.82

Number of days with Delta-Deciview > 0.50: 42
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	6.332	8.608	2.275	2002	74	97	79	2.90	71.70	27.78	0.17	0.35
98th %tile Delta-DV	3.190	5.487	2.297	2002	29	97	79	3.00	67.24	32.23	0.19	0.34
90th %tile Delta-DV	0.707	2.852	2.145	2002	247	97	79	2.30	96.30	1.90	0.59	1.21

Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 29
Max number of consecutive days with Delta-Deciview > 0.50: 4

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (PM Scenario 1, PM at Pre-BART, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	2.755	4.988	2.234	2002	78	46	46	2.80	40.16	58.22	0.30	1.31
98th %tile Delta-DV	1.434	3.540	2.106	2002	233	53	107	2.20	56.13	40.60	1.17	2.10
90th %tile Delta-DV	0.270	2.504	2.234	2002	91	45	45	2.80	38.68	59.77	0.22	1.33

Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 12
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	4.417	6.651	2.234	2002	73	89	118	2.80	34.80	62.63	1.03	1.54
98th %tile Delta-DV	1.338	3.572	2.234	2002	39	82	71	2.80	39.20	57.27	0.97	2.56
90th %tile Delta-DV	0.181	2.329	2.149	2002	198	84	113	2.40	85.40	5.33	3.30	5.96

Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 13
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	3.529	5.763	2.234	2002	73	90	72	2.80	38.17	59.52	0.84	1.48
98th %tile Delta-DV	1.129	3.235	2.106	2002	250	90	72	2.20	61.71	32.39	2.19	3.72
90th %tile Delta-DV	0.181	2.287	2.106	2002	240	90	72	2.20	87.34	10.33	0.82	1.51

Number of days with Delta-Deciview > 0.50: 17
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	2.258	4.533	2.275	2002	74	97	79	2.90	42.10	56.09	0.58	1.23
98th %tile Delta-DV	1.050	3.347	2.297	2002	29	97	79	3.00	38.22	59.98	0.64	1.16
90th %tile Delta-DV	0.197	2.429	2.232	2002	185	97	79	2.70	21.71	69.10	3.22	5.96

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (PM Scenario 2, PM at Permit Limit, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	2.816	5.050	2.234	2002	78	46	46	2.80	39.16	56.77	0.77	3.31
98th %tile Delta-DV	1.503	3.609	2.106	2002	233	53	107	2.20	53.36	38.60	2.88	5.16
90th %tile Delta-DV	0.282	2.410	2.127	2002	100	54	108	2.30	36.58	54.35	2.72	6.35

Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 12
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	4.563	6.796	2.234	2002	73	89	118	2.80	33.43	60.17	2.56	3.84
98th %tile Delta-DV	1.402	3.508	2.106	2002	250	82	71	2.20	42.63	45.57	5.00	6.81
90th %tile Delta-DV	0.195	2.450	2.255	2002	30	82	71	2.90	46.60	50.78	0.55	2.07

Number of days with Delta-Deciview > 0.50: 20
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	3.638	5.871	2.234	2002	73	90	72	2.80	36.81	57.41	2.09	3.68
98th %tile Delta-DV	1.181	3.456	2.276	2002	336	90	72	3.00	28.72	64.01	3.20	4.06
90th %tile Delta-DV	0.198	2.304	2.106	2002	271	90	72	2.20	33.92	48.83	7.89	9.35

Number of days with Delta-Deciview > 0.50: 17
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	2.316	4.591	2.275	2002	74	97	79	2.90	40.92	54.52	1.45	3.10
98th %tile Delta-DV	1.125	3.292	2.167	2002	241	91	73	2.40	75.02	10.13	4.83	10.02
90th %tile Delta-DV	0.226	2.458	2.232	2002	185	97	79	2.70	18.95	60.32	7.26	13.47

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (PM Scenario 3, PM at Average Actual, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	2.746	4.980	2.234	2002	78	46	46	2.80	40.31	58.44	0.24	1.02
98th %tile Delta-DV	1.425	3.531	2.106	2002	233	53	107	2.20	56.54	40.90	0.92	1.64
90th %tile Delta-DV	0.269	2.503	2.234	2002	91	45	45	2.80	38.82	59.98	0.17	1.04

Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 12
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)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	4.397	6.630	2.234	2002	73	89	118	2.80	35.00	62.99	0.81	1.21
98th %tile Delta-DV	1.328	3.562	2.234	2002	39	82	71	2.80	39.51	57.73	0.76	2.00
90th %tile Delta-DV	0.179	2.413	2.234	2002	78	67	56	2.80	37.71	61.06	0.27	0.96

Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 11
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)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	3.514	5.747	2.234	2002	73	90	72	2.80	38.36	59.83	0.65	1.15
98th %tile Delta-DV	1.115	3.221	2.106	2002	250	90	72	2.20	62.54	32.82	1.72	2.92
90th %tile Delta-DV	0.180	2.286	2.106	2002	240	90	72	2.20	87.79	10.39	0.64	1.18

Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 8
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)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.250	4.525	2.275	2002	74	97	79	2.90	42.27	56.32	0.45	0.96
98th %tile Delta-DV	1.046	3.342	2.297	2002	29	97	79	3.00	38.38	60.22	0.50	0.90
90th %tile Delta-DV	0.194	2.533	2.340	2002	336	91	73	3.20	16.50	81.07	0.40	2.03

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

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (PM Scenario 4, PM at Best Controls, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - 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	2.736	4.970	2.234	2002	78	46	46	2.80	40.47	58.90	0.12	0.51
98th %tile Delta-DV	1.448	3.554	2.106	2002	233	53	107	2.20	55.55	43.20	0.45	0.81
90th %tile Delta-DV	0.268	2.438	2.170	2002	178	53	107	2.50	63.03	35.55	0.50	0.92

Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 12
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	4.380	6.613	2.234	2002	73	89	118	2.80	35.17	63.82	0.40	0.61
98th %tile Delta-DV	1.333	3.567	2.234	2002	50	58	47	2.80	28.15	70.71	0.35	0.79
90th %tile Delta-DV	0.179	2.328	2.149	2002	198	84	113	2.40	86.02	10.36	1.29	2.33

Number of days with Delta-Deciview > 0.50: 19
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 ELKHORN RANCH												
Largest Delta-DV	3.505	5.739	2.234	2002	73	90	72	2.80	38.48	60.62	0.33	0.58
98th %tile Delta-DV	1.118	3.224	2.106	2002	250	90	72	2.20	62.37	35.32	0.86	1.46
90th %tile Delta-DV	0.185	2.313	2.127	2002	125	90	72	2.30	30.17	68.80	0.05	0.98

Number of days with Delta-Deciview > 0.50: 17
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	2.234	4.510	2.275	2002	74	97	79	2.90	42.58	56.70	0.23	0.48
98th %tile Delta-DV	1.048	3.345	2.297	2002	29	97	79	3.00	38.27	61.03	0.25	0.45
90th %tile Delta-DV	0.192	2.532	2.340	2002	336	91	73	3.20	16.64	82.14	0.20	1.02

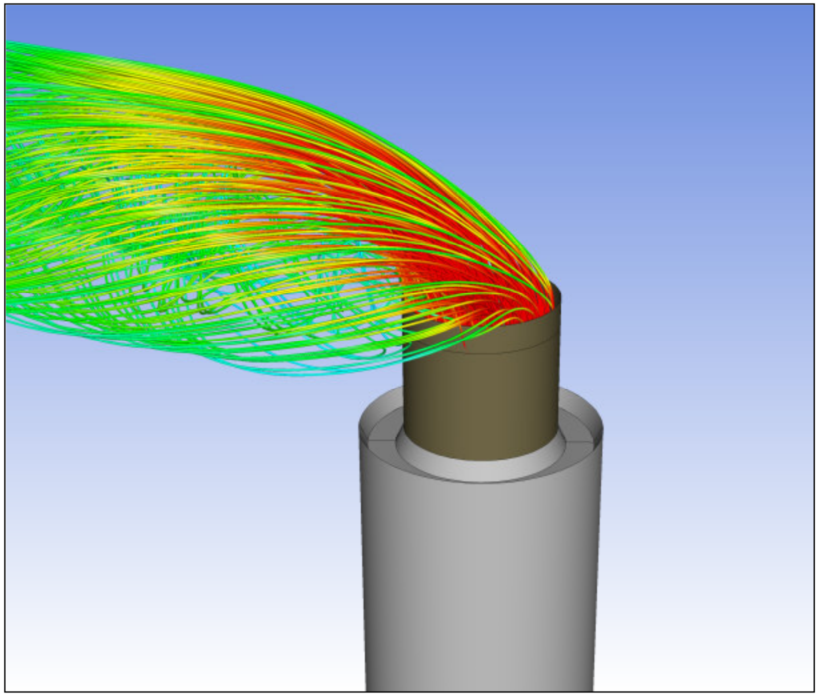
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

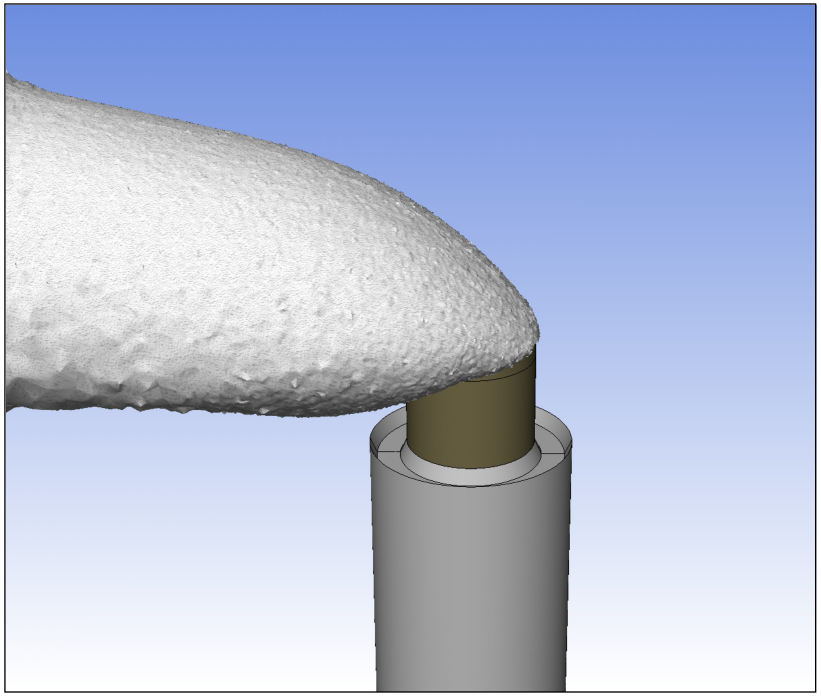
Appendix E

Wet Stack Study

Computational Fluid Dynamics Model of a Wet Stack in North Dakota

590 MW Unit at Full Load





Summary of Results

- The CFD model predicts a bifurcated plume for all cases.
- Predicted plume downwash:
  - 13 Feet Below Top of Liner Extension for 38 MPH wind speed at –7 degree F
  - 16.5 Feet Below Top of Liner Extension for 63 MPH wind speed at –17 degree F
- A 20 foot liner extension is sufficient to prevent stack gas from contacting shell under the worst case met condition.
- The model predicts the potential for ice formation along outer band of plume downwash on liner extension.
- The stack design philosophy is to manage, but not prevent, ice formation.
- Ice formation is managed through the use of an inverted rain cap on the stack shell.
- The model predicts increased vortex shedding in the wake behind the stack for the 63 MPH wind case. This creates additional undulations in the predicted plume shape for the 63 MPH case relative to the 38 MPH case.

CFD Cases

Case 1:
- Wind Speed = 38 MPH at Stack Height
- Ambient Air Temperature = - 7 deg. F

Case 2:
- Wind Speed = 63 MPH at Stack Height
- Ambient Air Temperature = - 17 deg. F

Modeled Flue Gas Conditions (All Cases)

- 1,947,000 acfm at 138 deg. F
- 590 MW at Full Load
- Corresponds to 55 ft/sec gas velocity inside stack
- Effect of buoyancy is included in CFD model

Modeling Assumptions (All Cases)

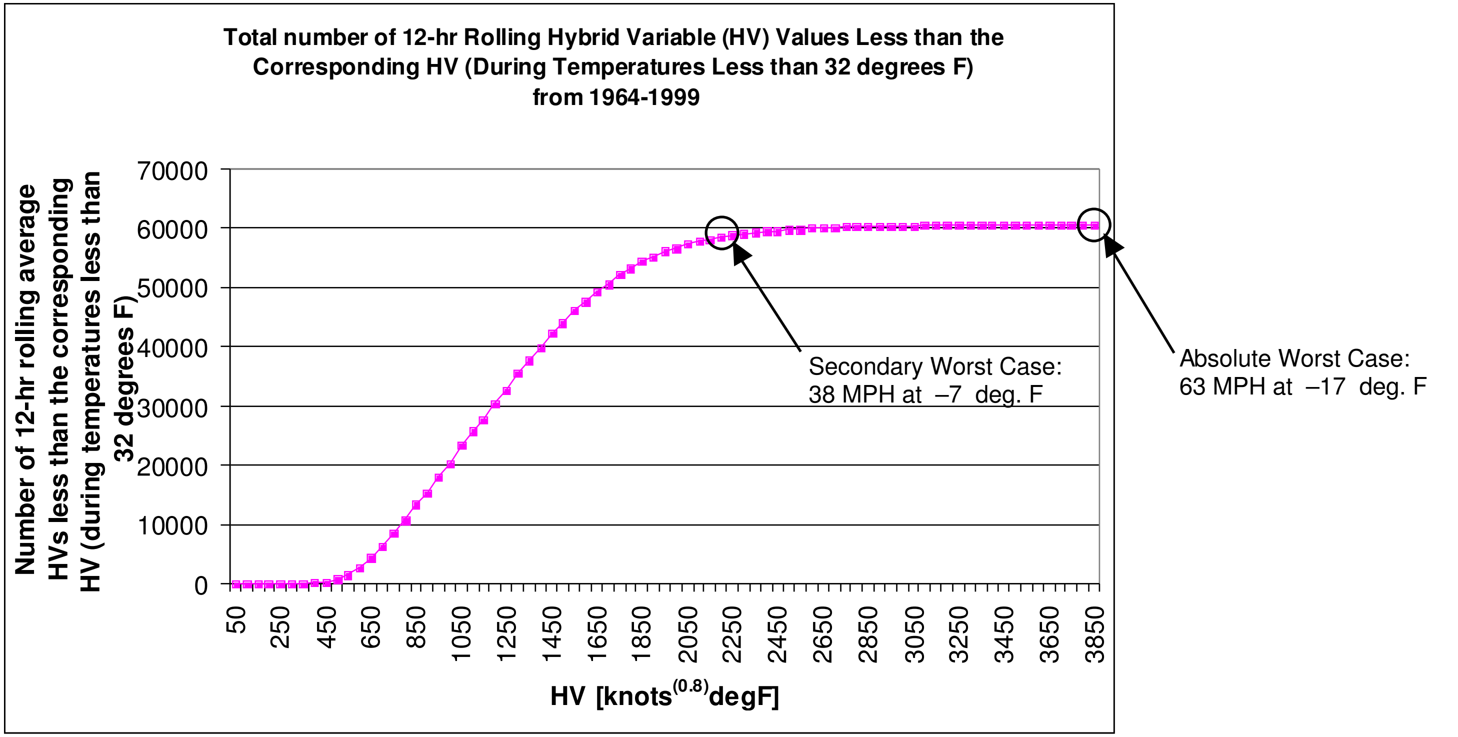
- Plane of symmetry at stack centerline for geometry and boundary conditions
- Liner extension is assumed to be perfectly insulated

URS

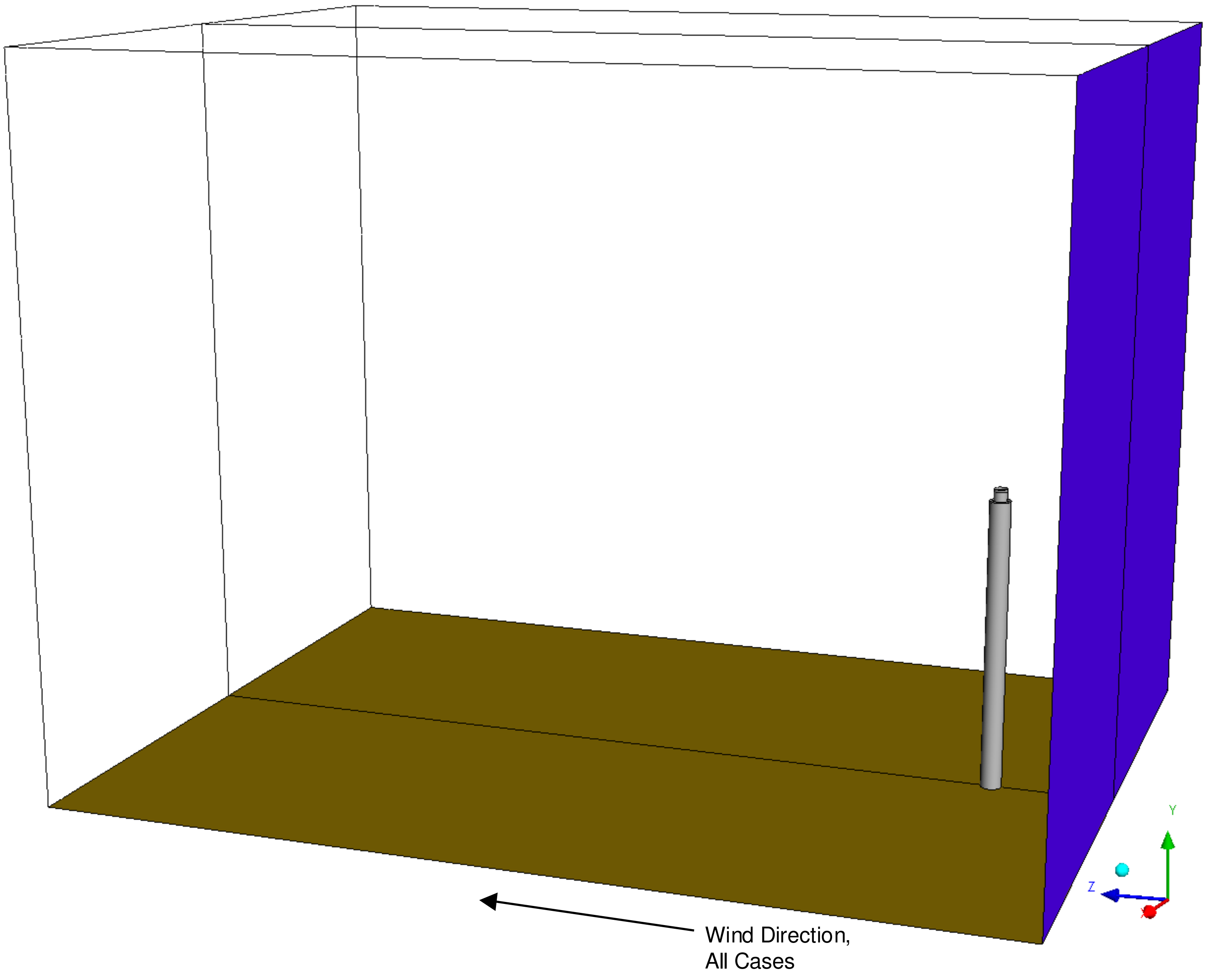
Determination of Worst Case Met Conditions

- Based worst case met condition on wind speed and temperature
  - Reviewed 35 years of Minot met data: 1964 through 1999
  - Computed wind speed at stack height based on wind speed at ground level
  - Heat transfer proportional to [(Wind Speed)$^{0.8}$] * [138 - Temperature] = Hybrid Variable, HV
  - Prepared an occurrence distribution plot of 12 hour rolling average of HV for 35 year period

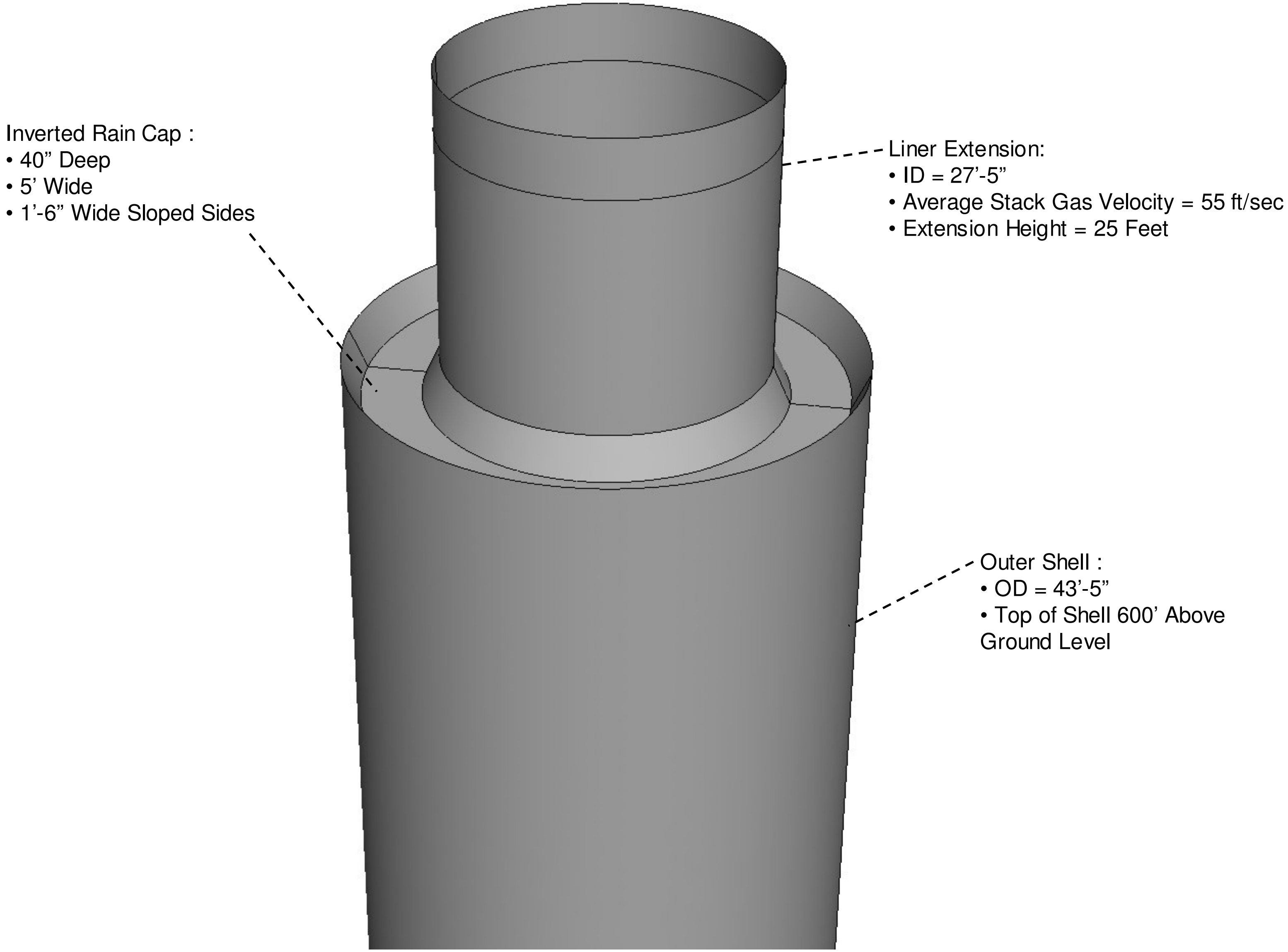
- Identified two met conditions based on 12 hour rolling average Hybrid Variable
  - Absolute worst case for entire 35 year period: Wind Speed at stack height = 63 MPH, Temperature = -17 F
  - Secondary worst case representing 99 % of 35 year period: Wind Speed at stack height = 38 MPH, Temperature = -7 F



CFD Model Geometry

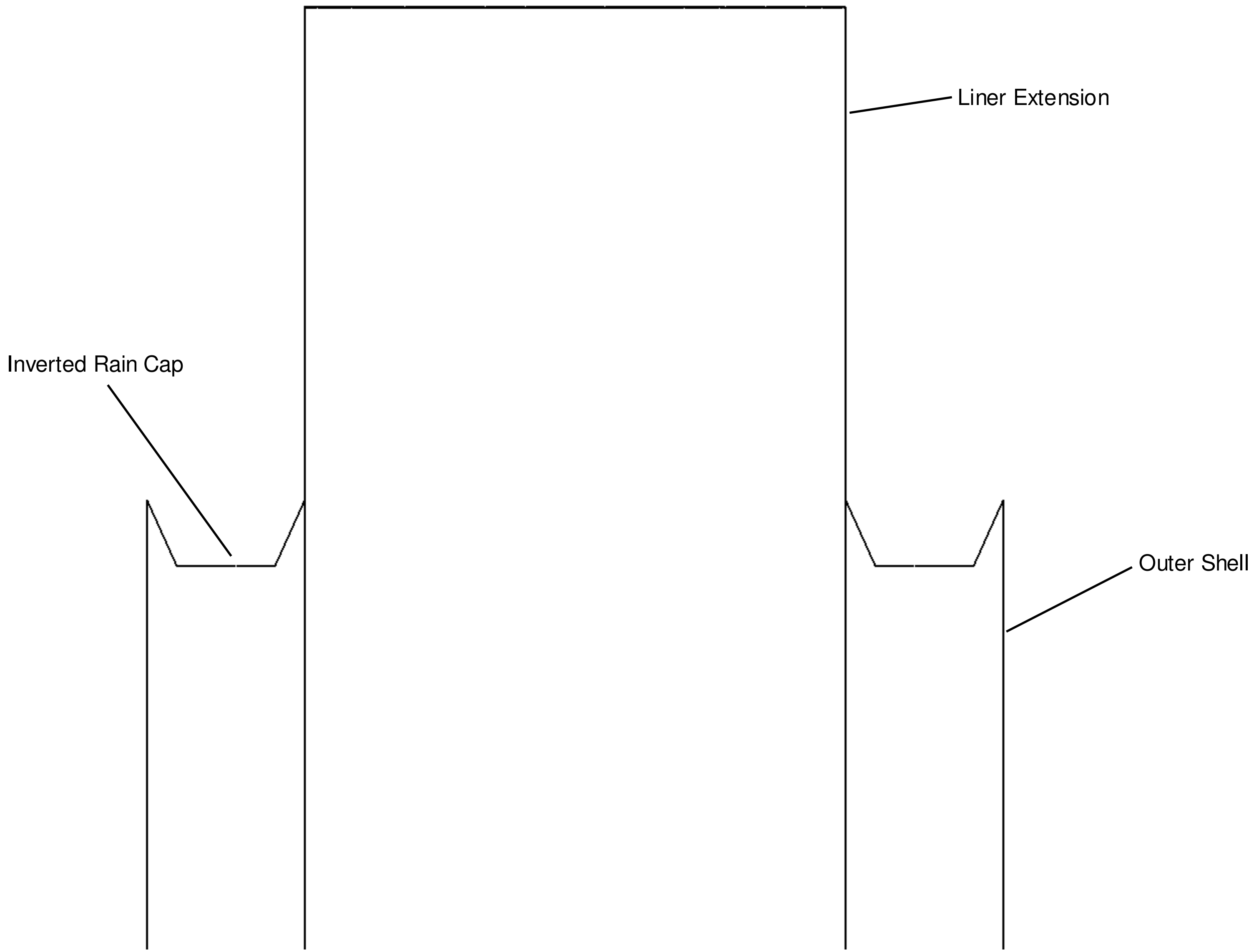


CFD Model Geometry: Top of Stack

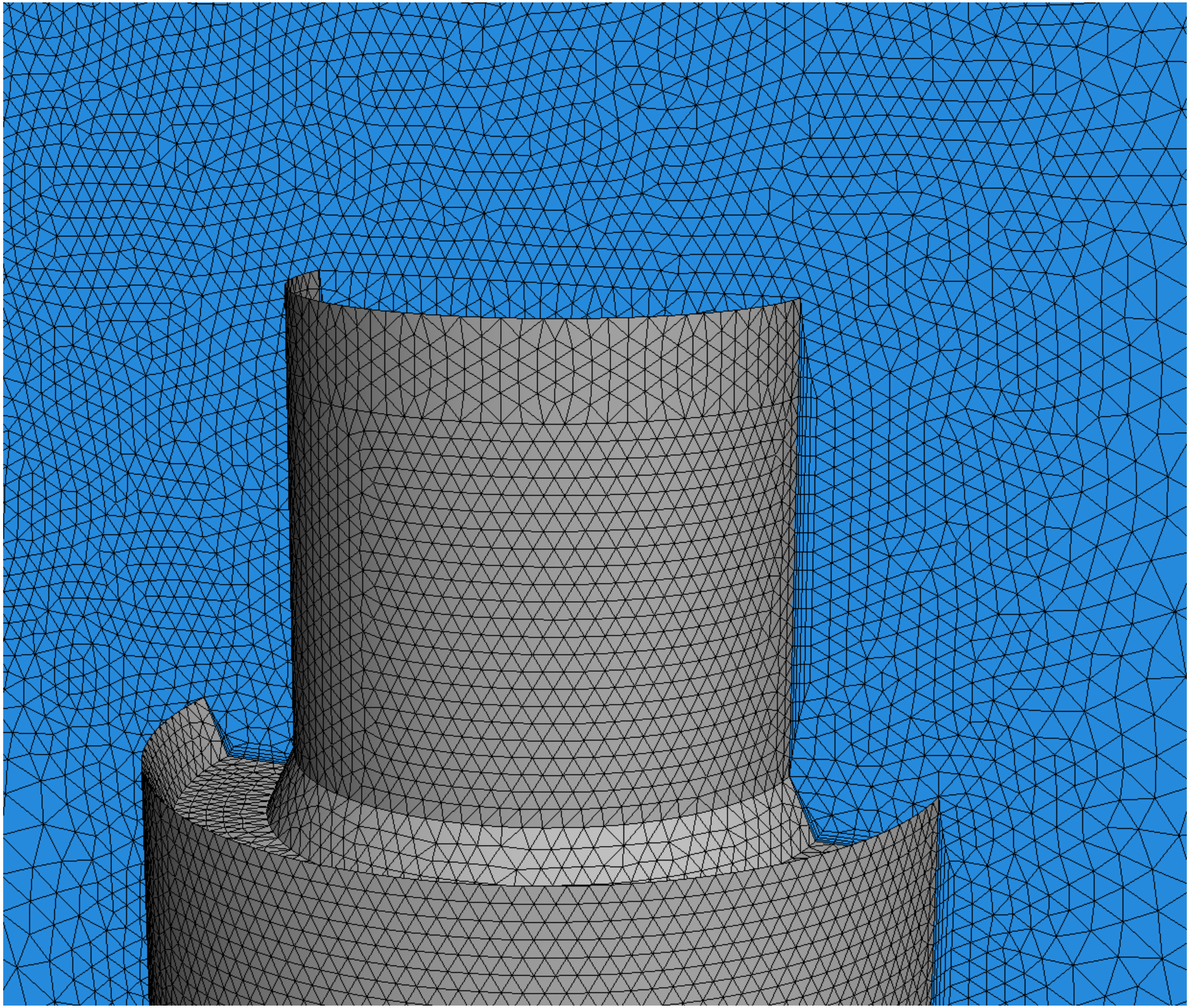


CFD Model Geometry: Top of Stack

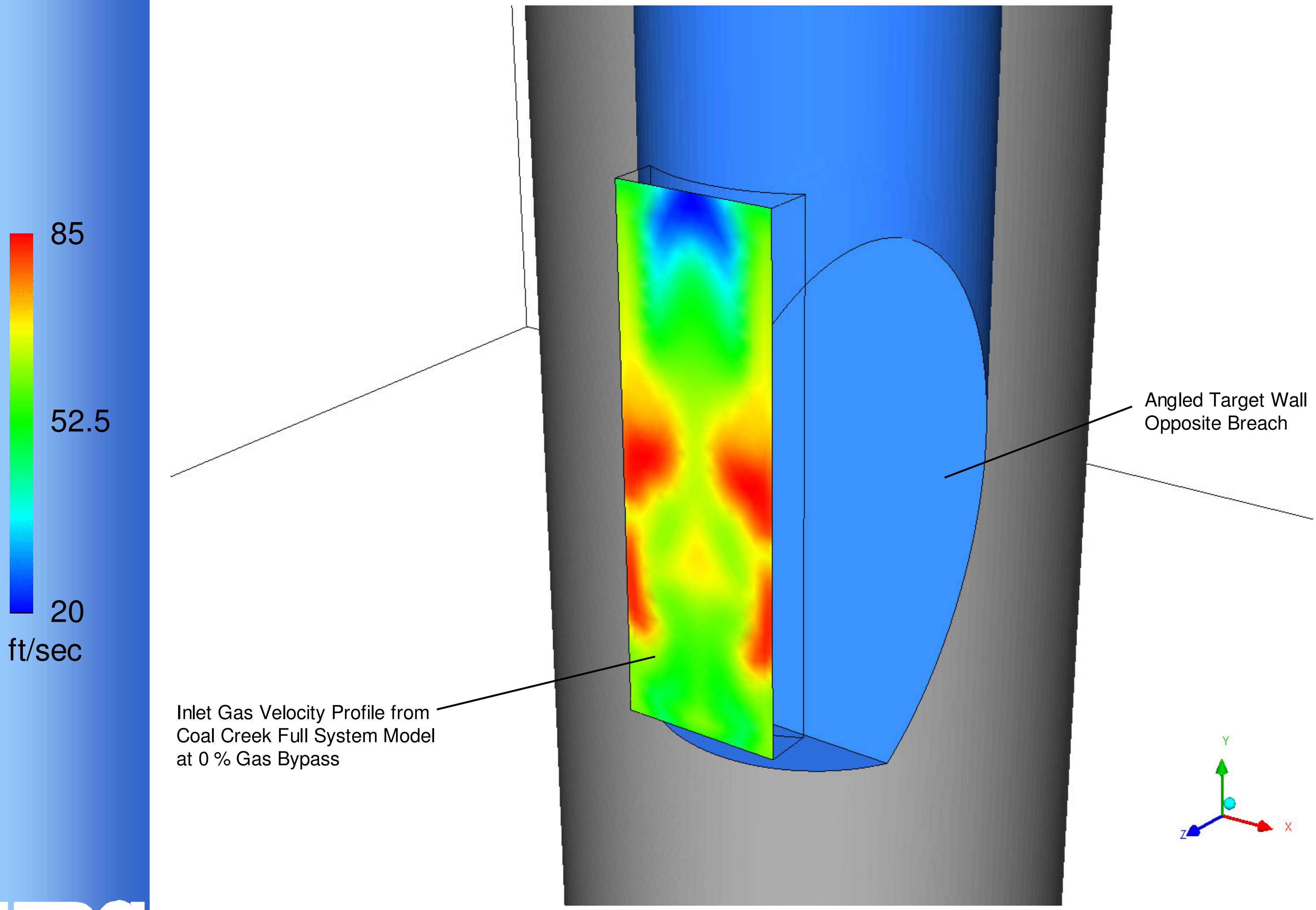
Elevation View



Computational Mesh at Stack Exit – All Cases



CFD Model Geometry: Breach and Liner Floor Details



Gas Streamlines Inside Stack Colored by Gas Velocity Magnitude

Showing Gas Swirl Pattern at Stack Beach, Liner Floor

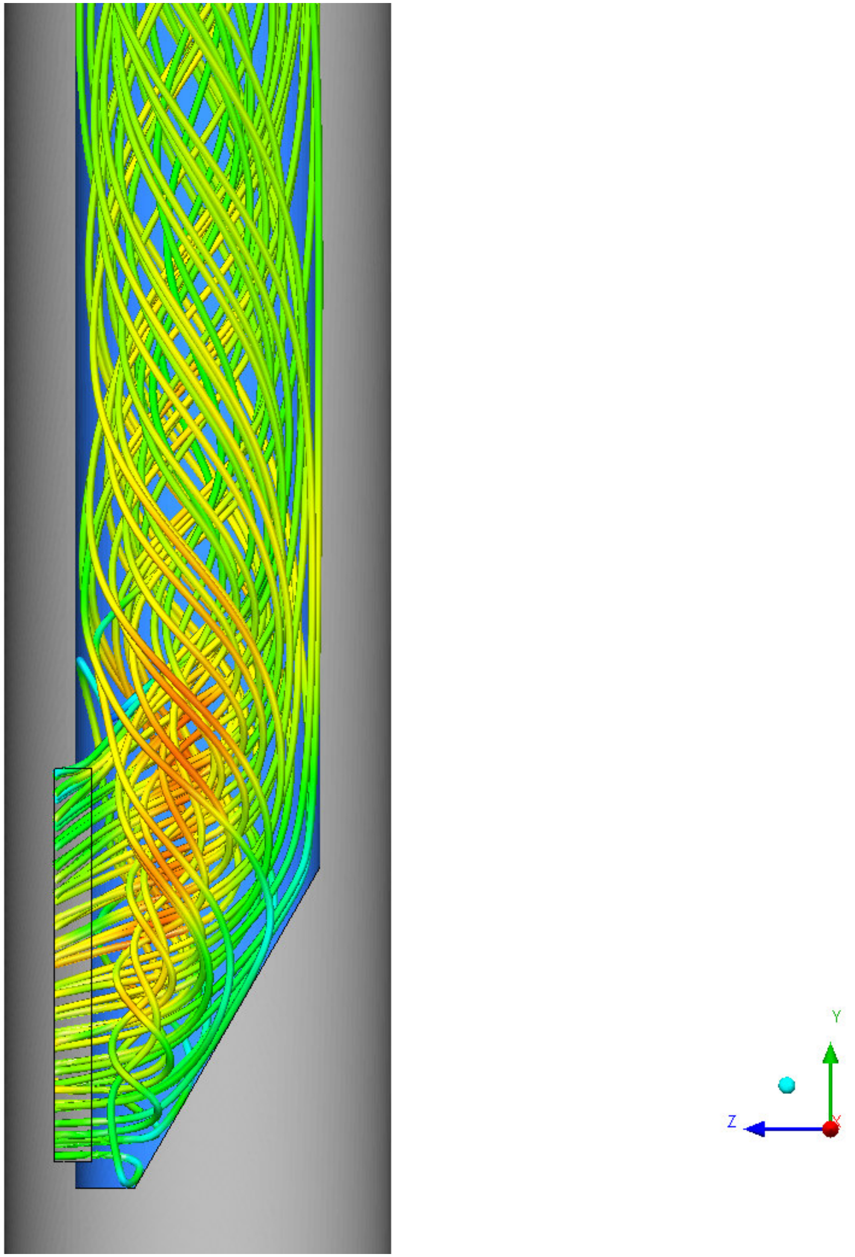
100

50

0

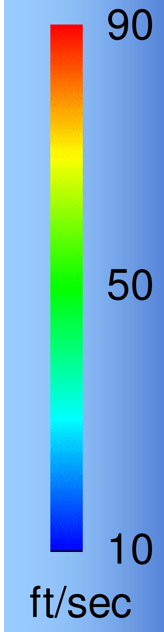
ft/sec

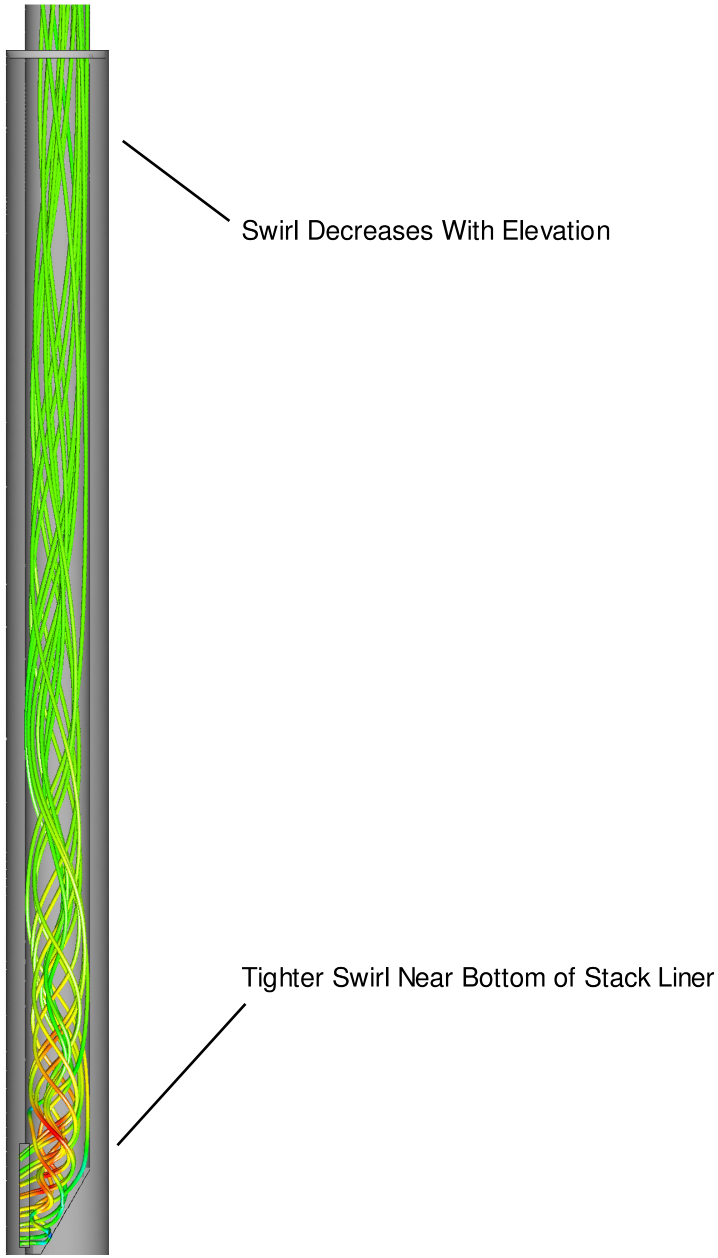
Typical,
All Cases



Gas Streamlines Inside Stack

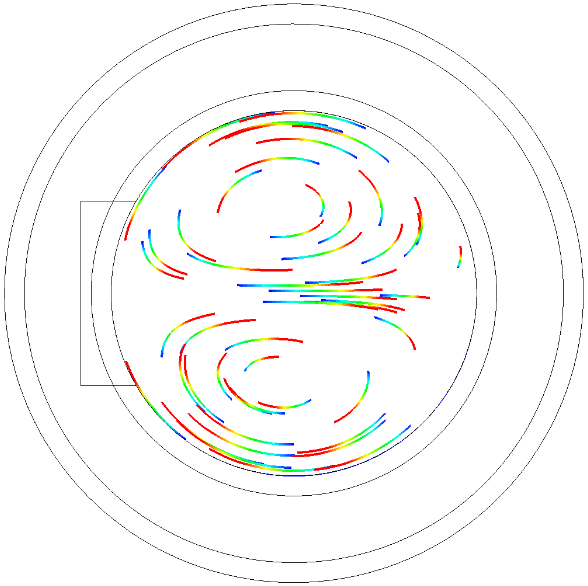
Typical,
All Cases



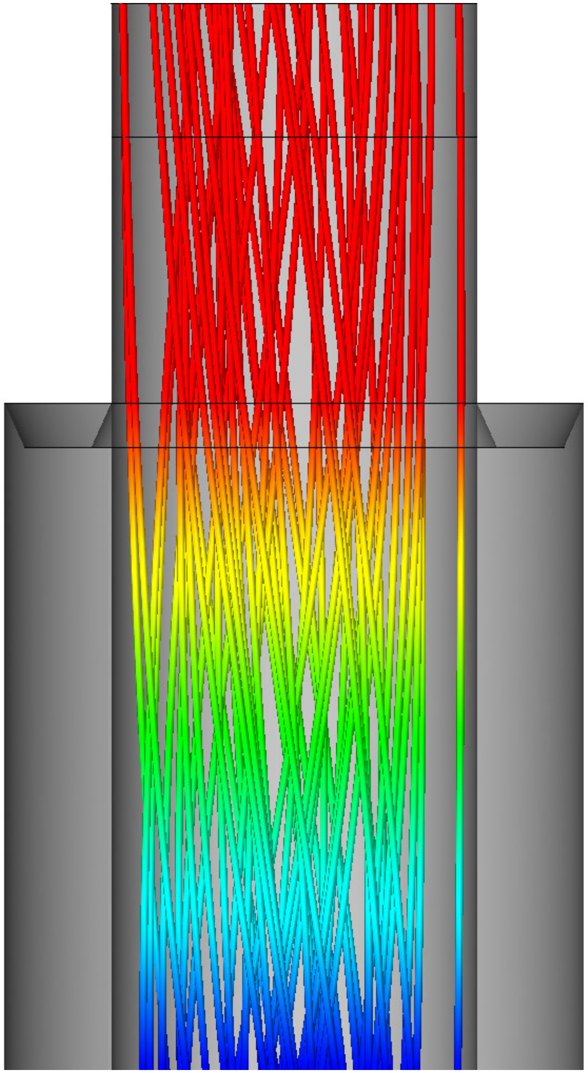


Streamlines Inside Stack: Top 75 Feet of Stack

Typical, All Cases



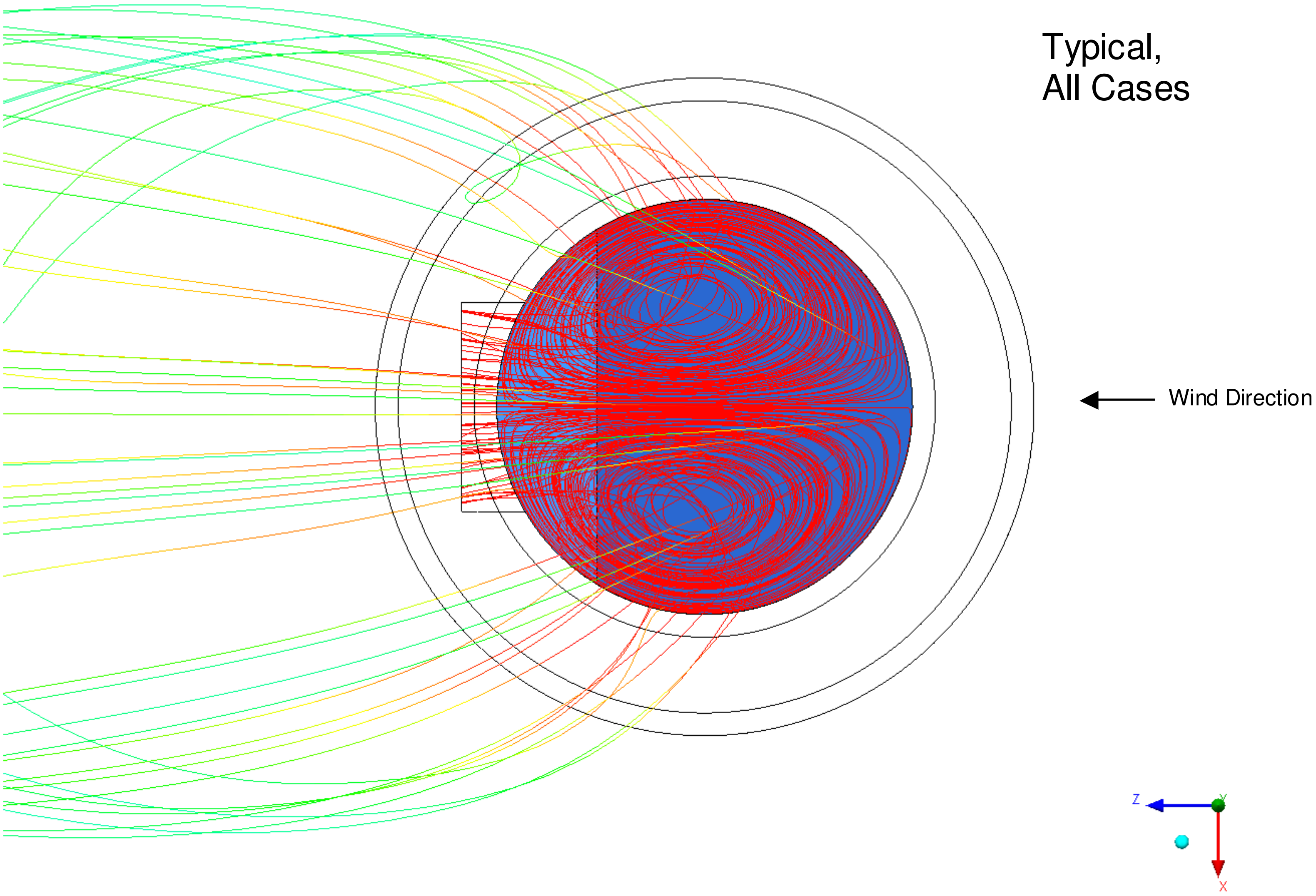
Plan



Side Elevation

Streamlines Along Entire Length of Stack

Plan View



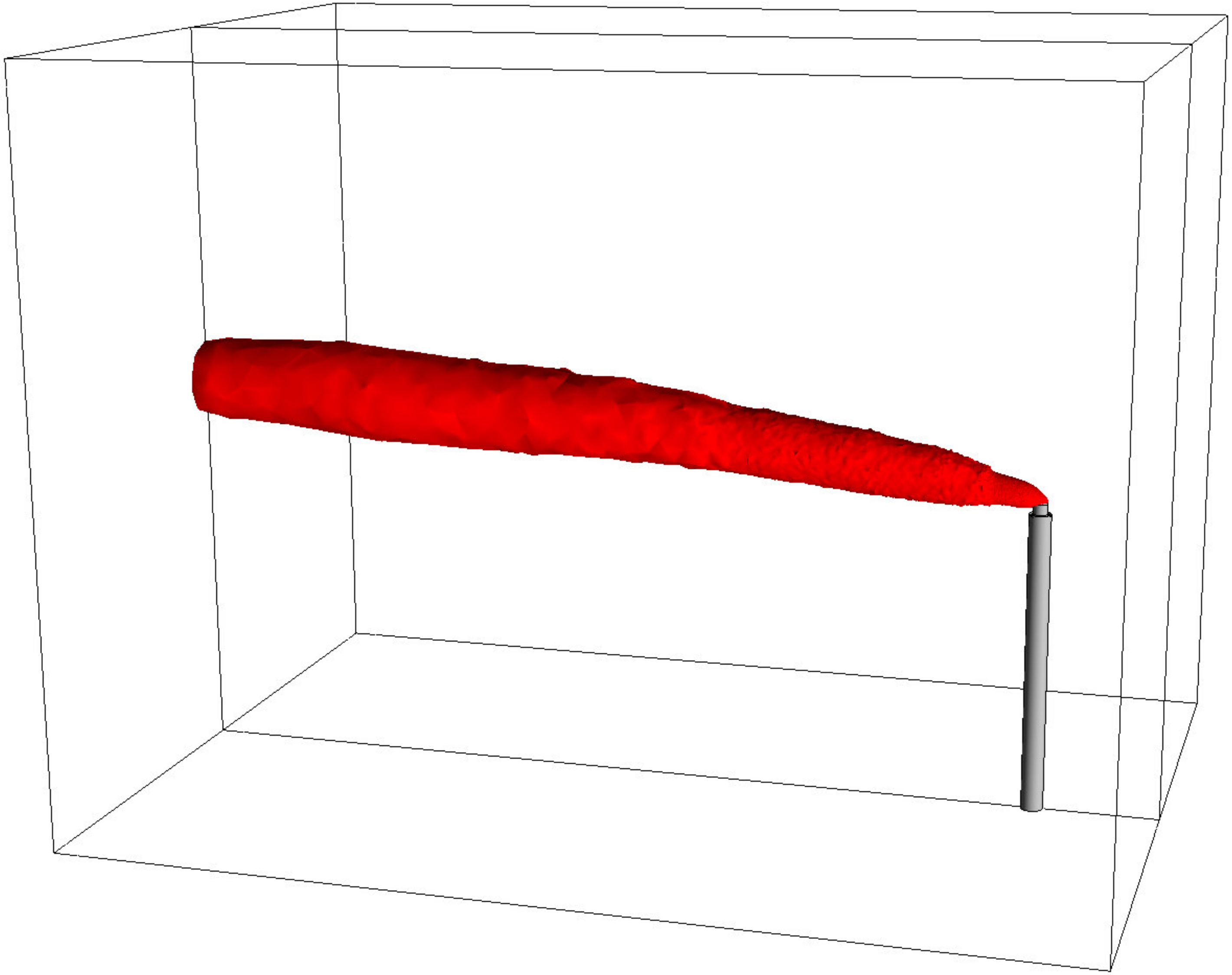
Case 1:

- Wind Speed = 38 MPH at Stack Height
- Ambient Air Temperature = -7 Degrees F

URS

Case 1:
38 MPH
-7 deg. F

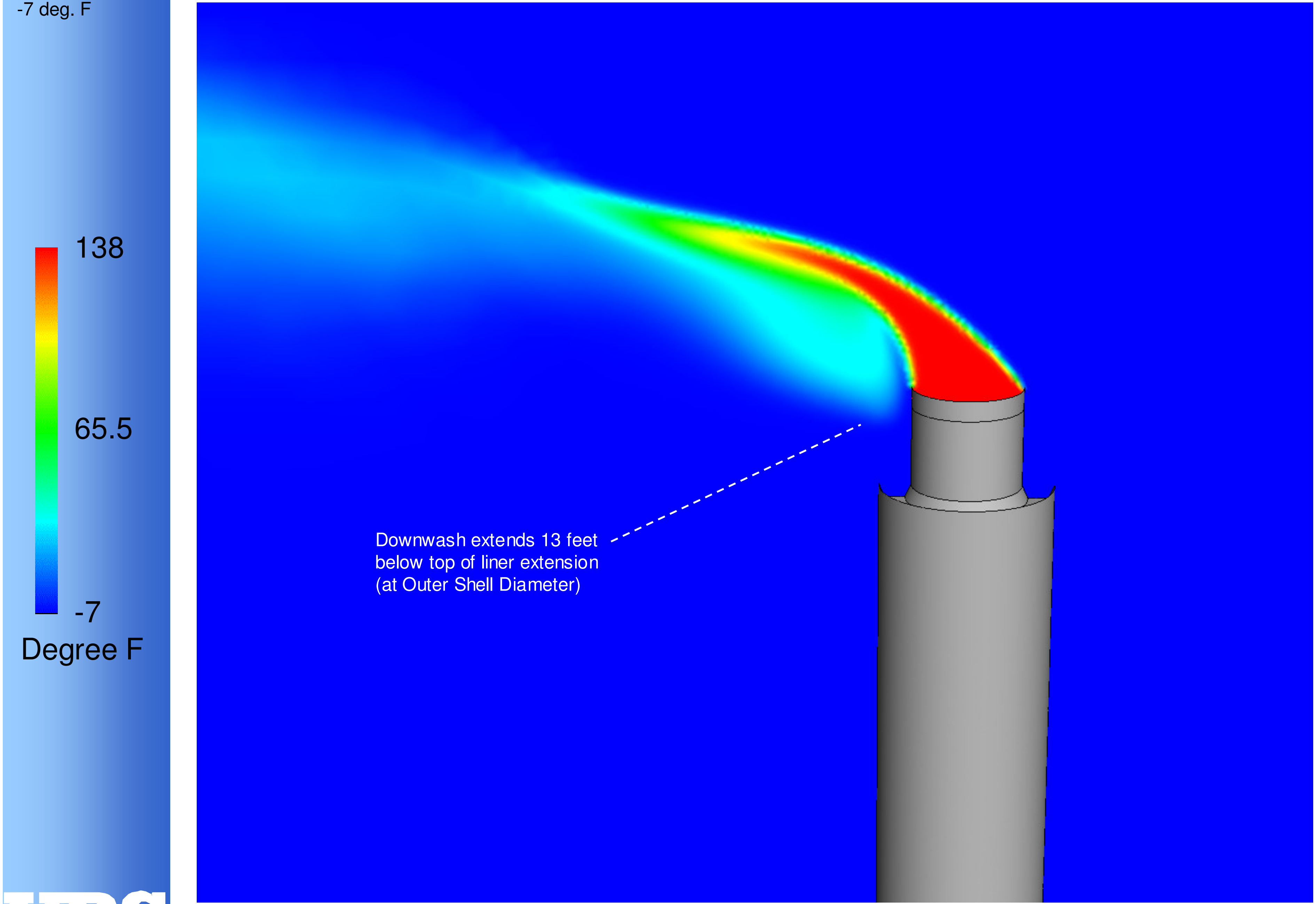
Surface Contour of Constant Temperature = - 6 Degrees F



URS

Case 1:
38 MPH
-7 deg. F

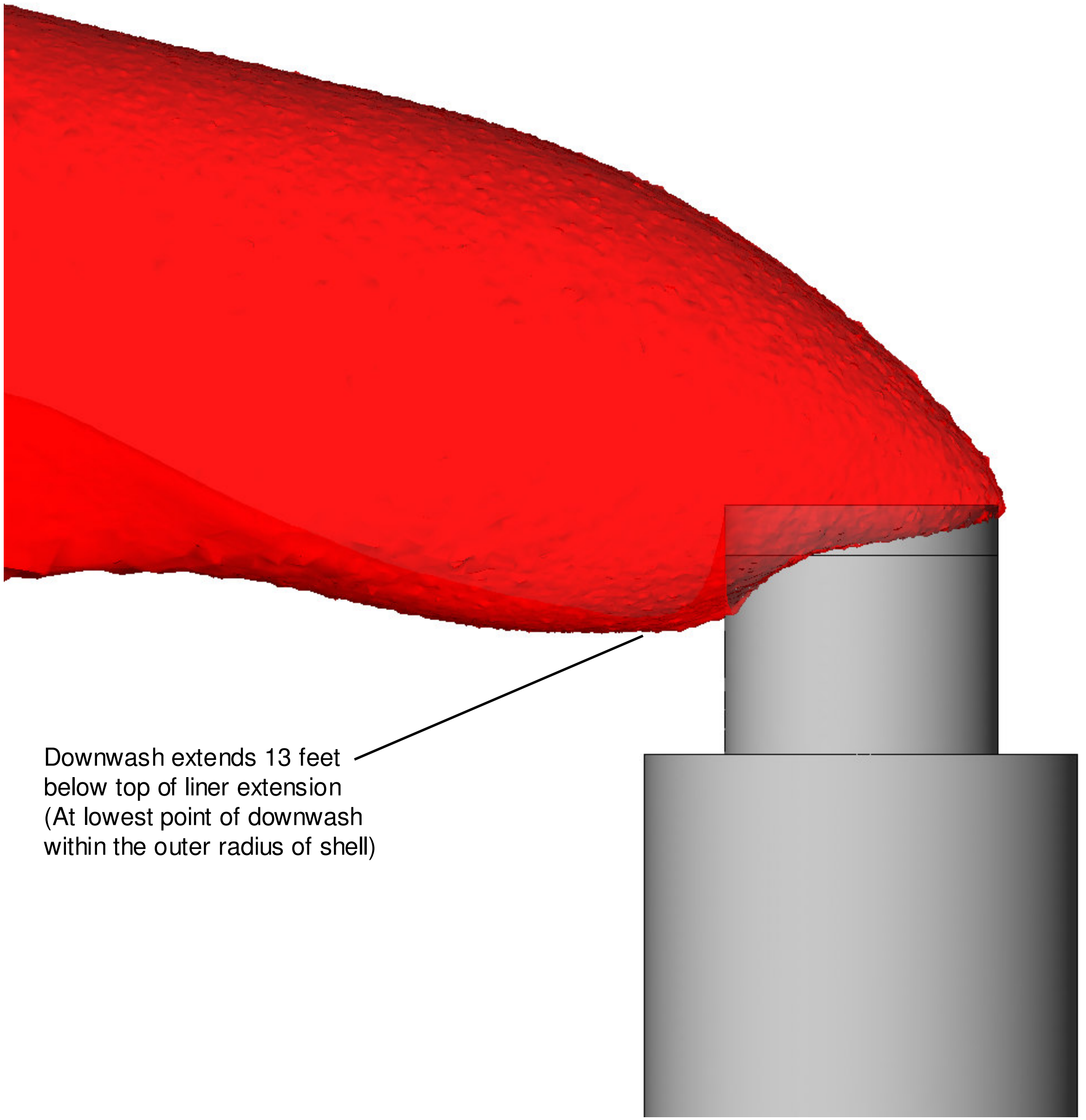
Temperature at Stack Midplane



Case 1:
38 MPH
-7 deg. F

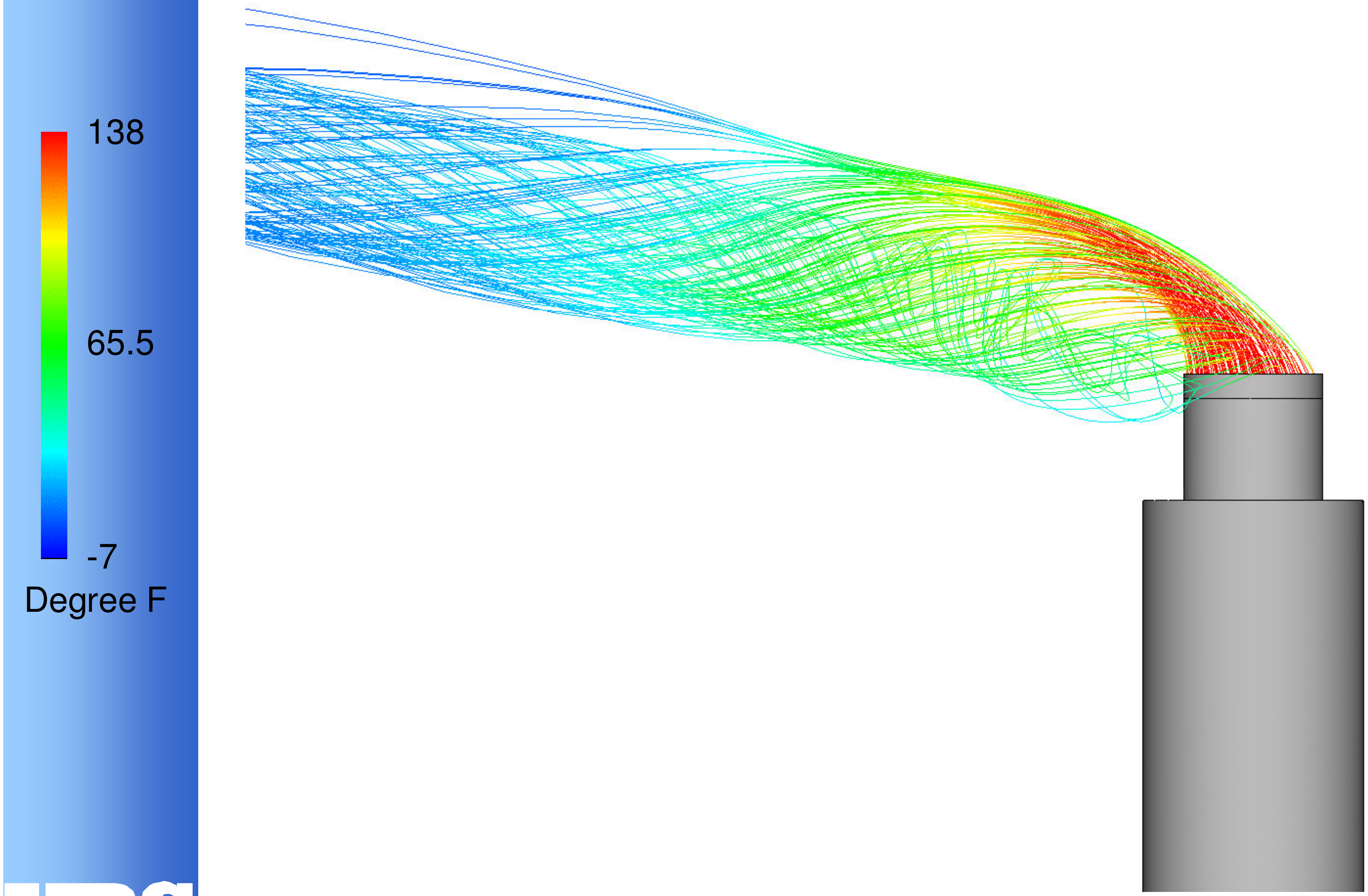
Surface Contour of Constant Temperature = - 6 Degrees F

Surface is Semi-Transparent to Show Liner Extension



Case 1:
38 MPH
-7 deg. F

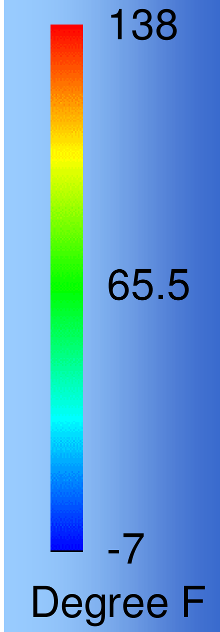
Streamlines Colored by Temperature

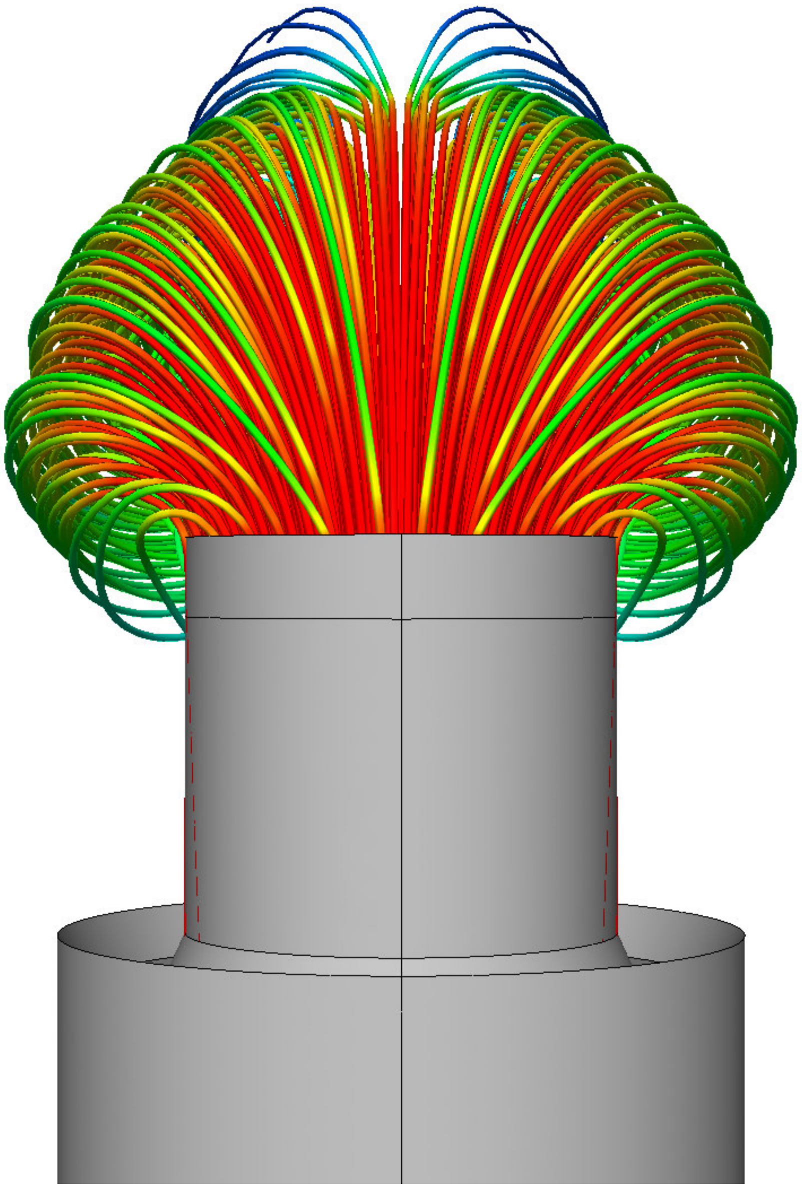


Case 1:
38 MPH
-7 deg. F

Streamlines Colored by Temperature

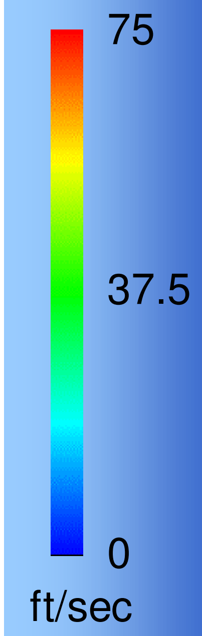
End Elevation View – Looking Downwind

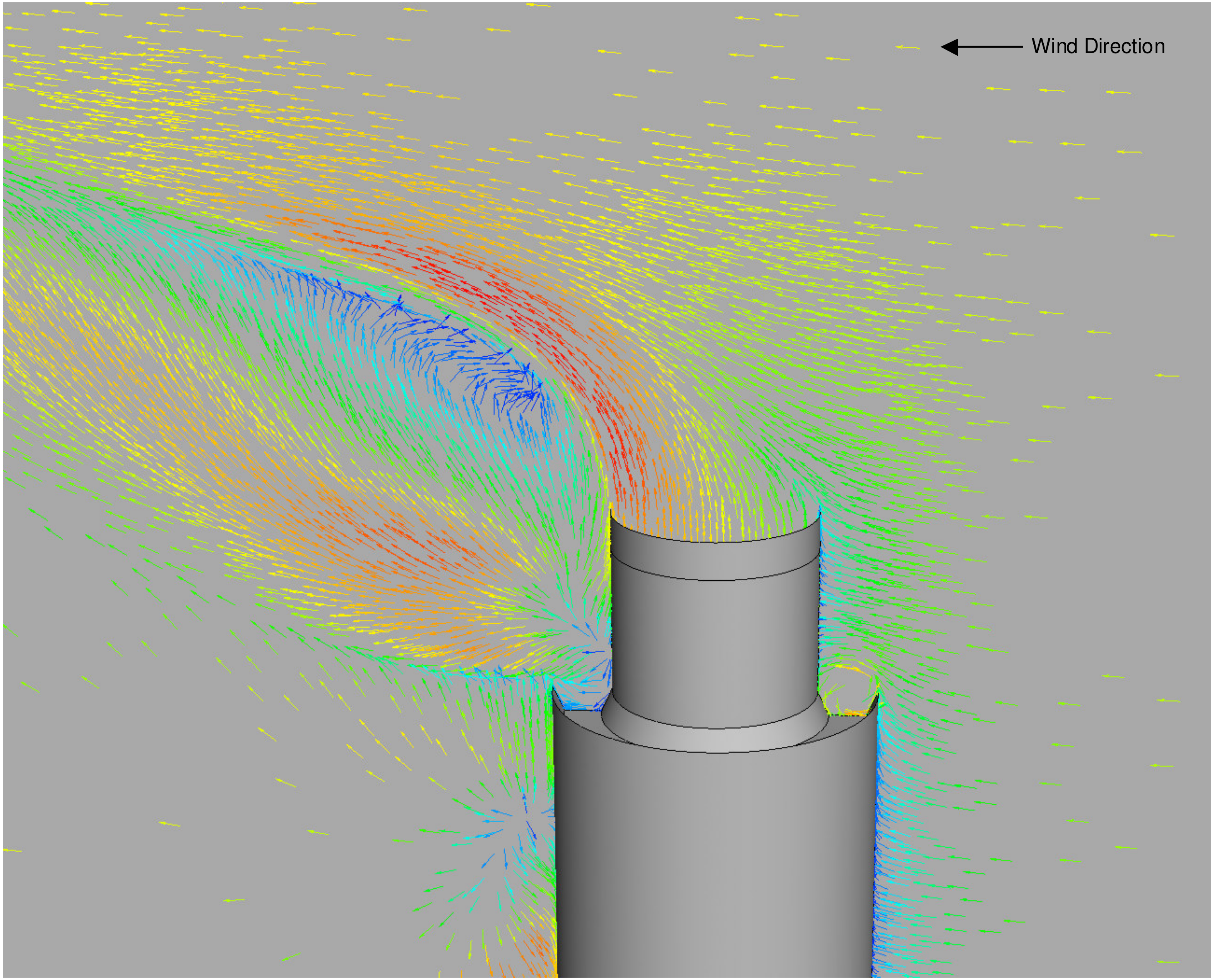




Case 1:
38 MPH
-7 deg. F

Velocity Vectors at Stack Midplane

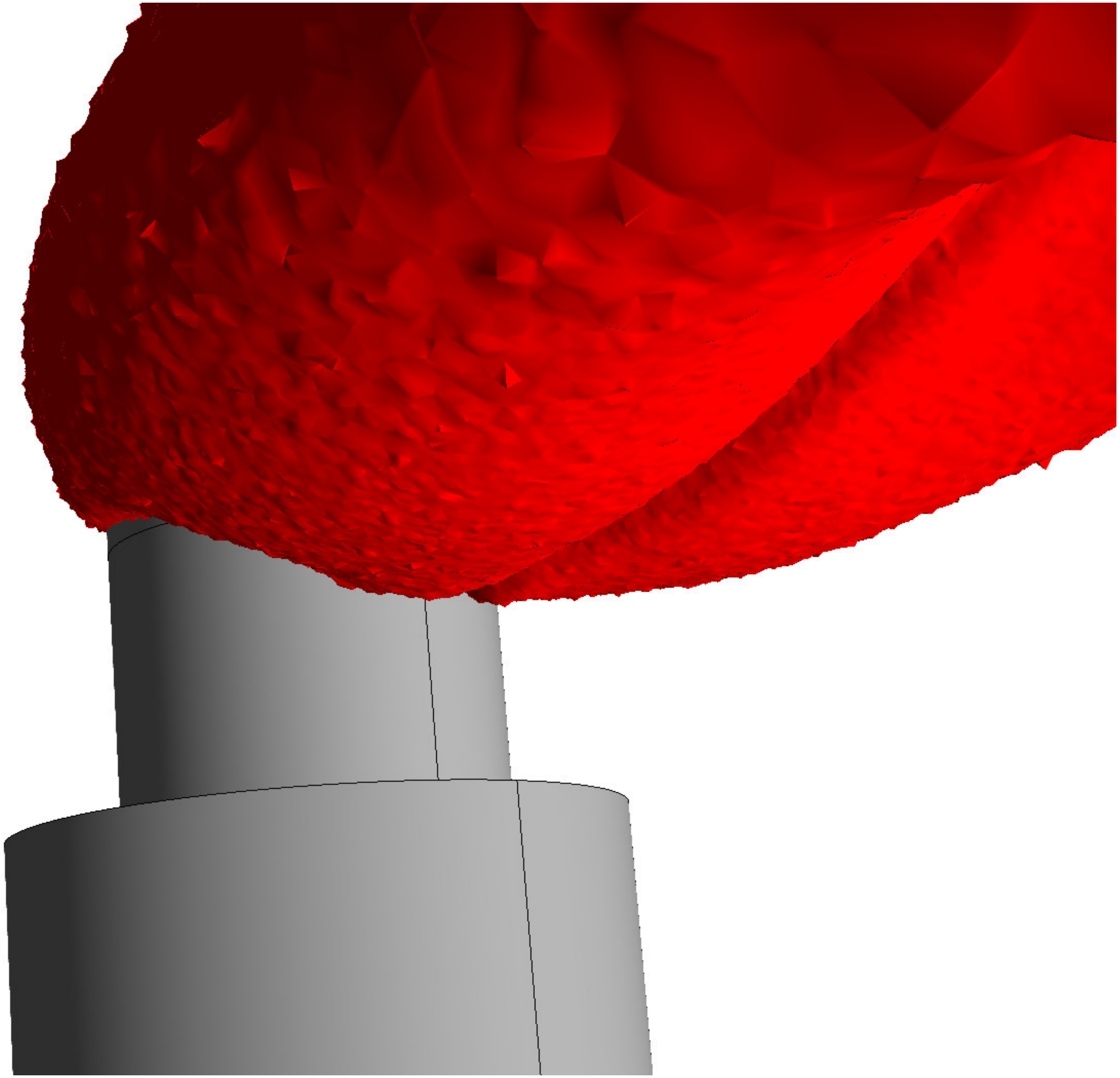




Case 1:
38 MPH
-7 deg. F

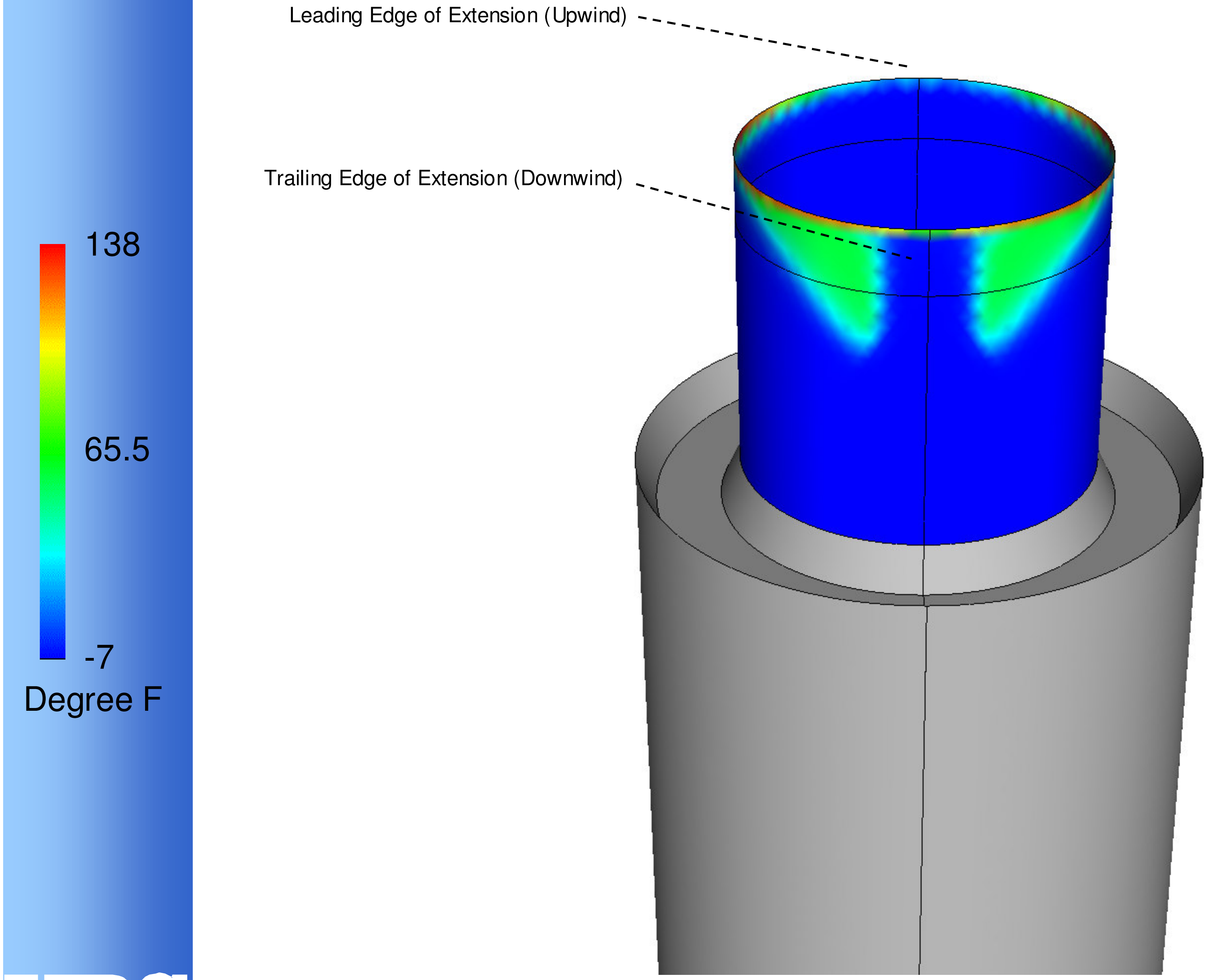
Surface Contour of Constant Temperature = - 6 Degrees F

Showing Bifurcated Plume



Case 1:
38 MPH
-7 deg. F

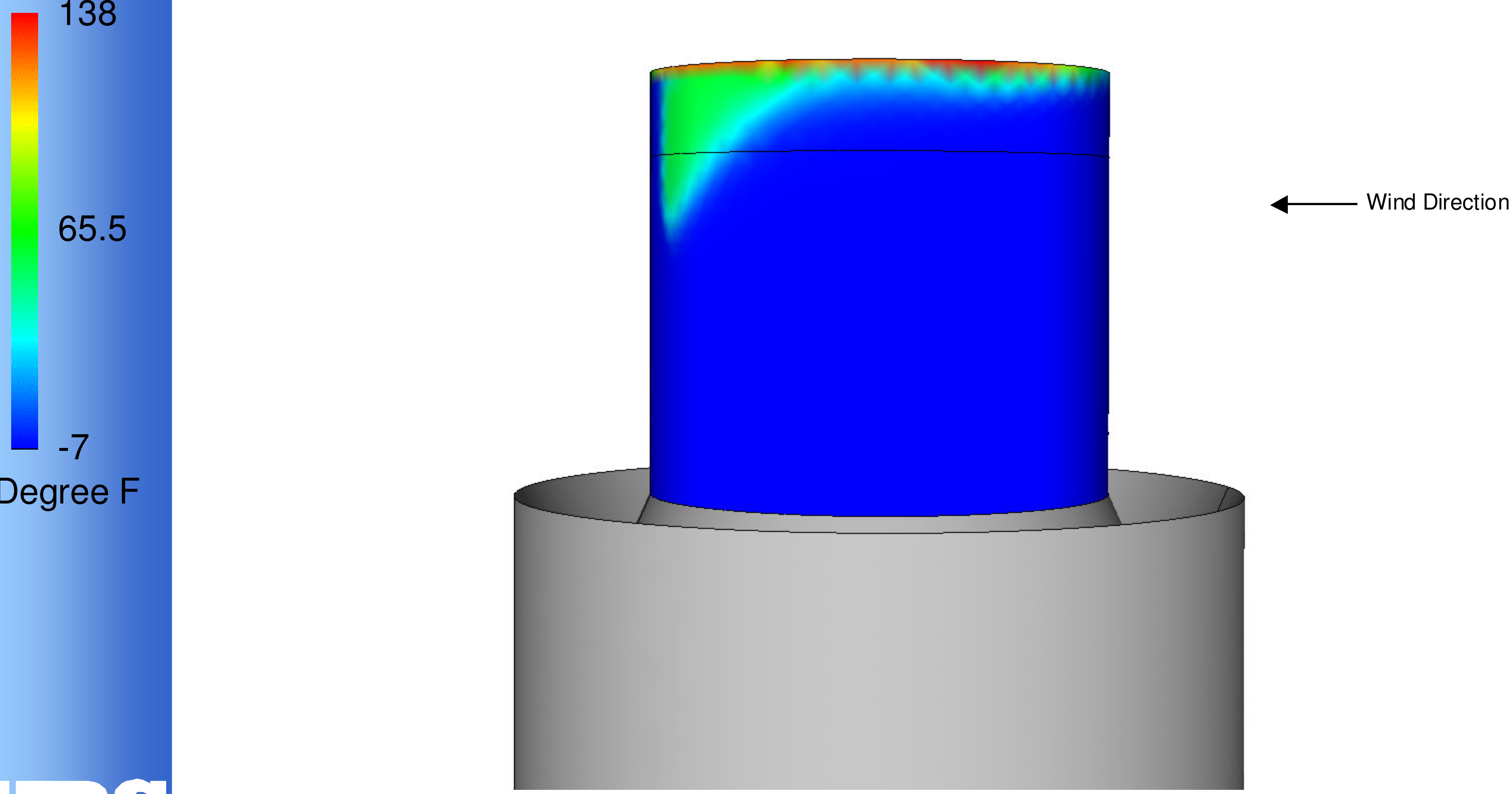
Temperature Adjacent to Liner Extension



URS

Temperature Adjacent to Liner Extension

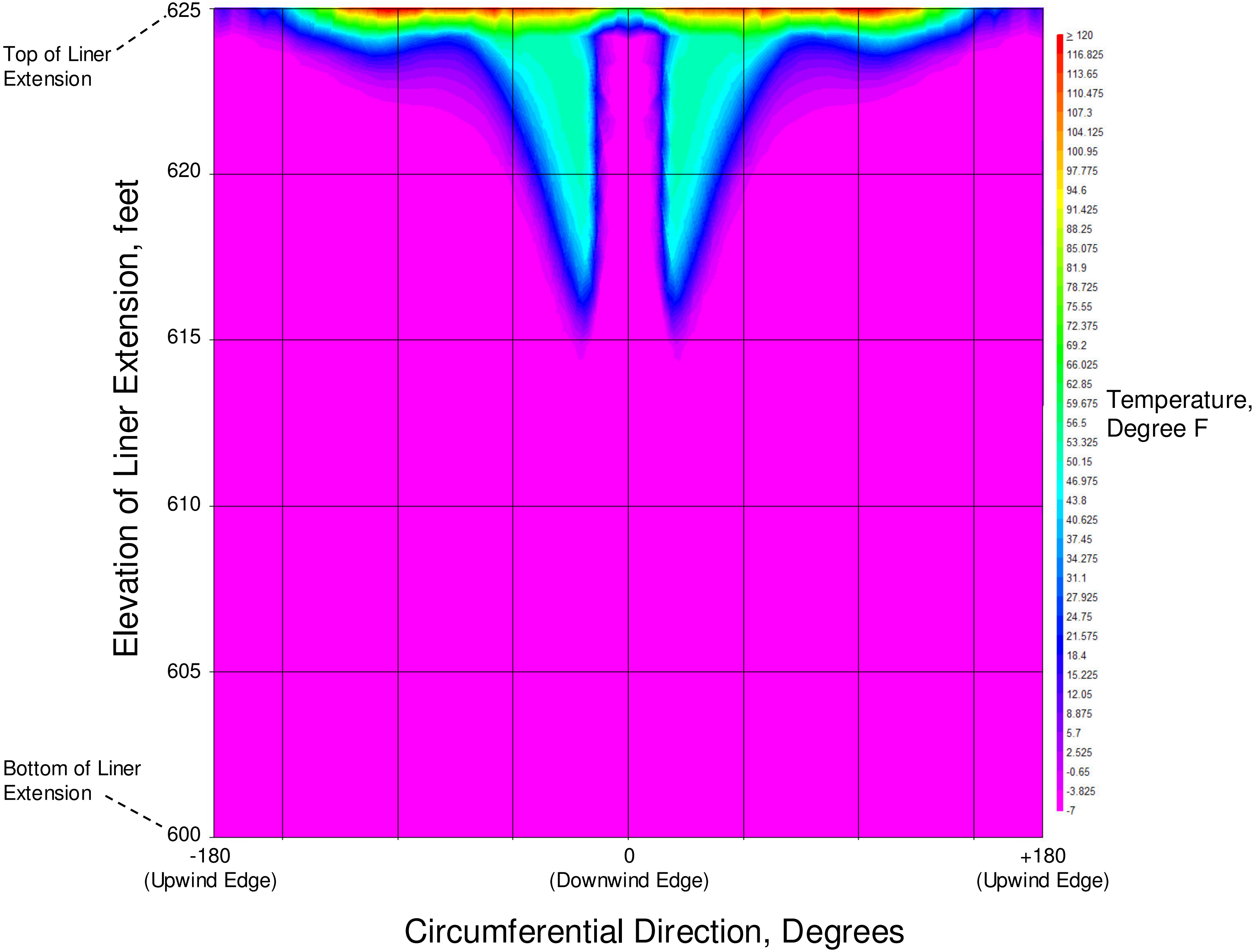
Side Elevation Perspective View



Case 1:
38 MPH
-7 deg. F

Temperature Adjacent to Liner Extension

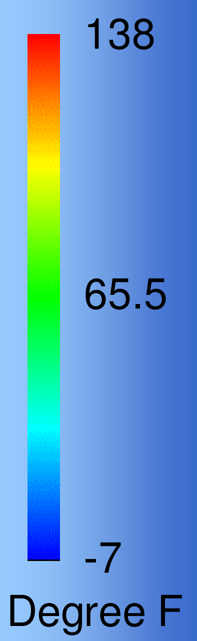
Plotted in Cylindrical Coordinates

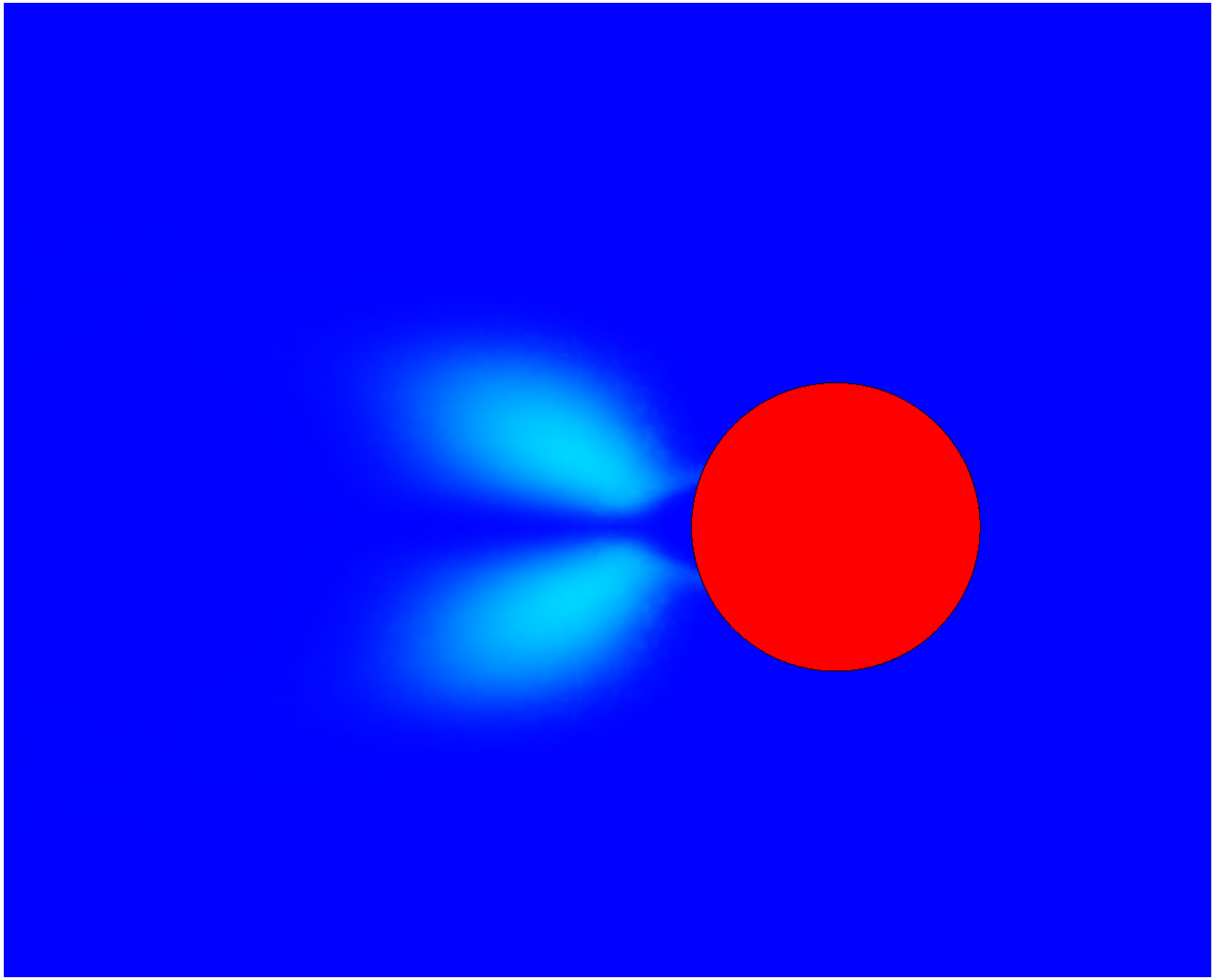


Case 1:
38 MPH
-7 deg. F

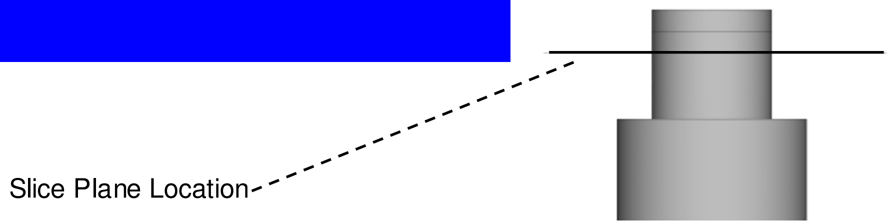
Temperature, 10 Feet Below Top of Liner Extension

Plan View





Wind Direction

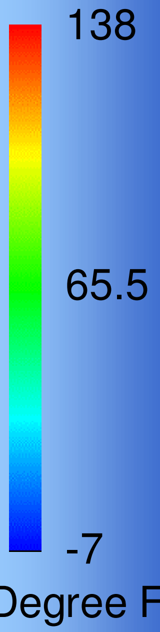


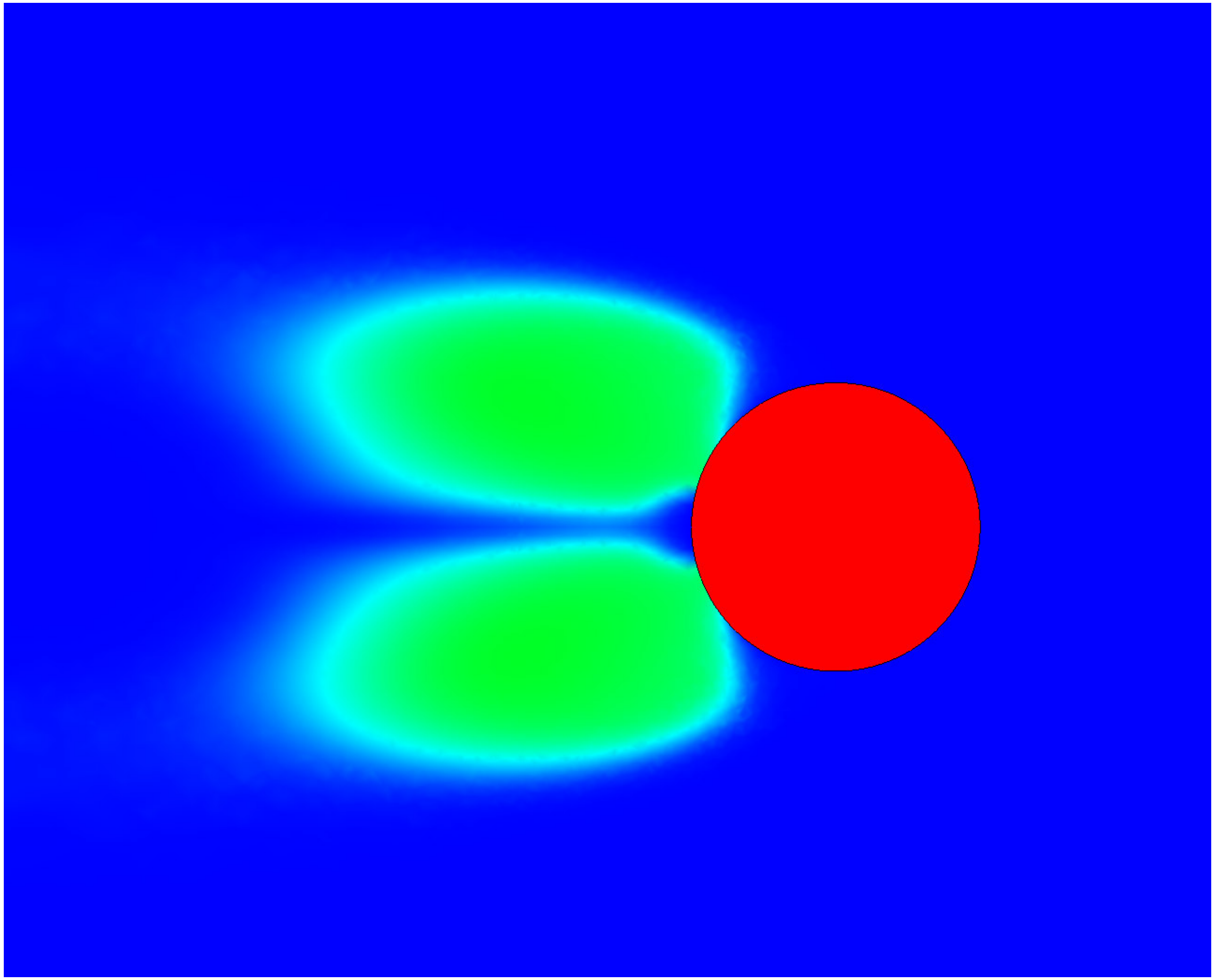
URS

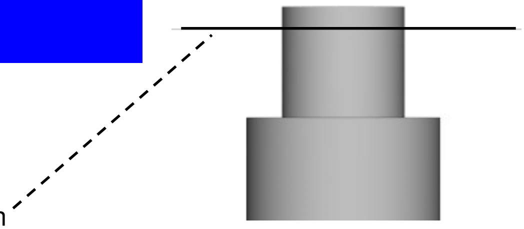
Case 1:
38 MPH
-7 deg. F

Temperature, 5 Feet Below Top of Liner Extension

Plan View



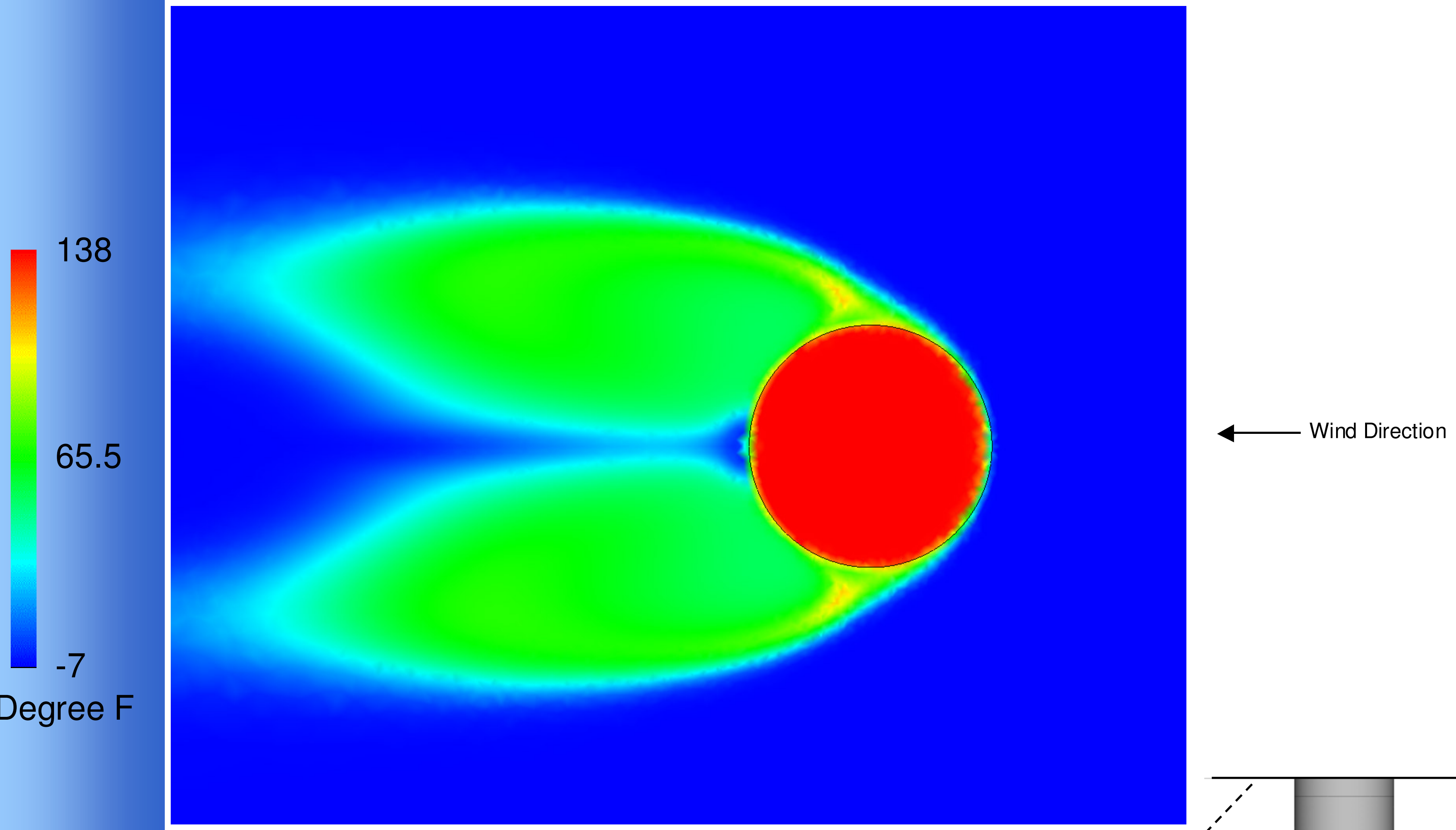


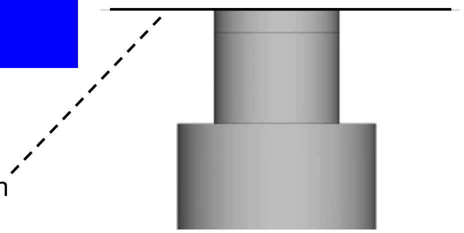


Case 1:
38 MPH
-7 deg. F

Temperature, at Top of Liner Extension

Plan View



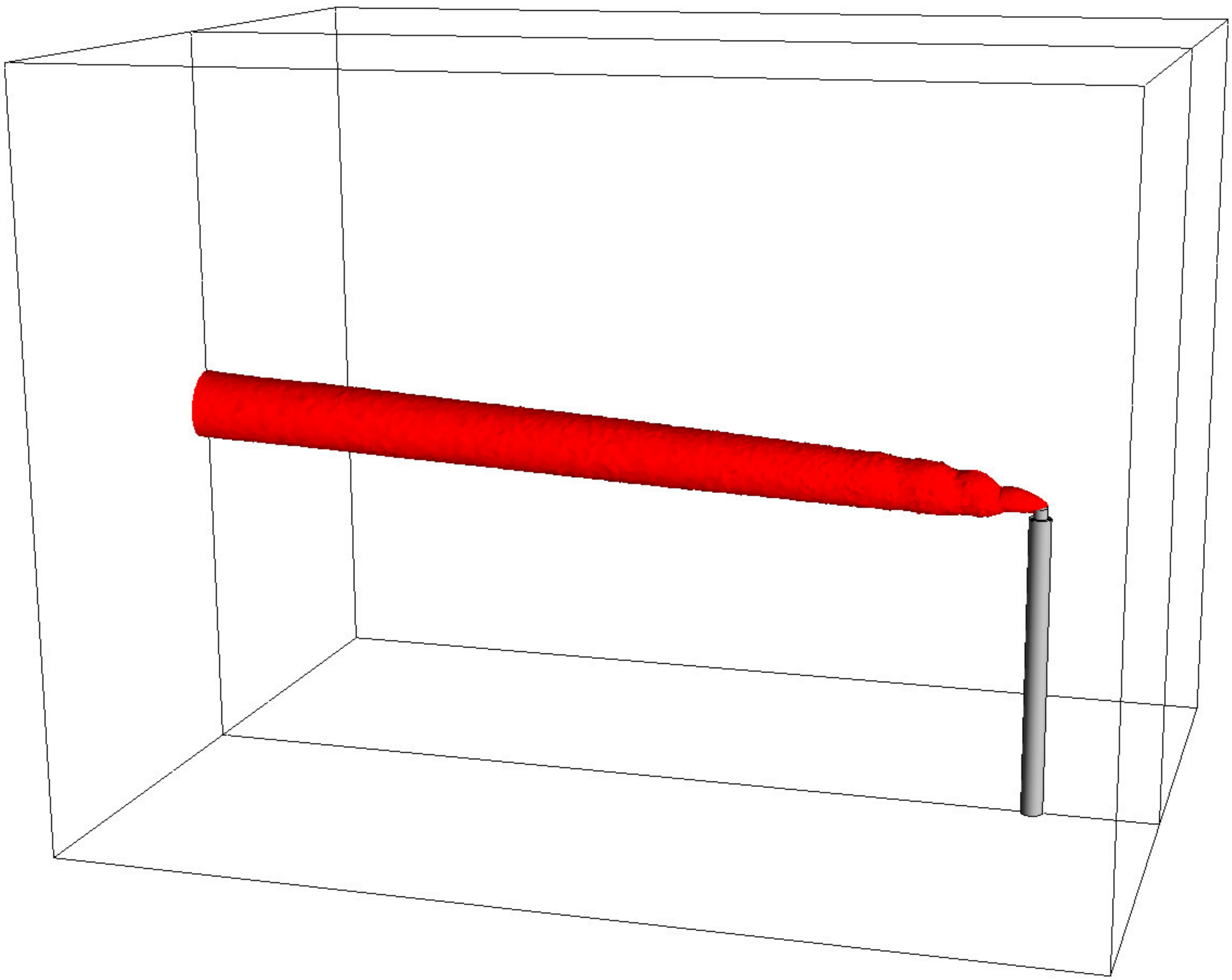


Case 2:

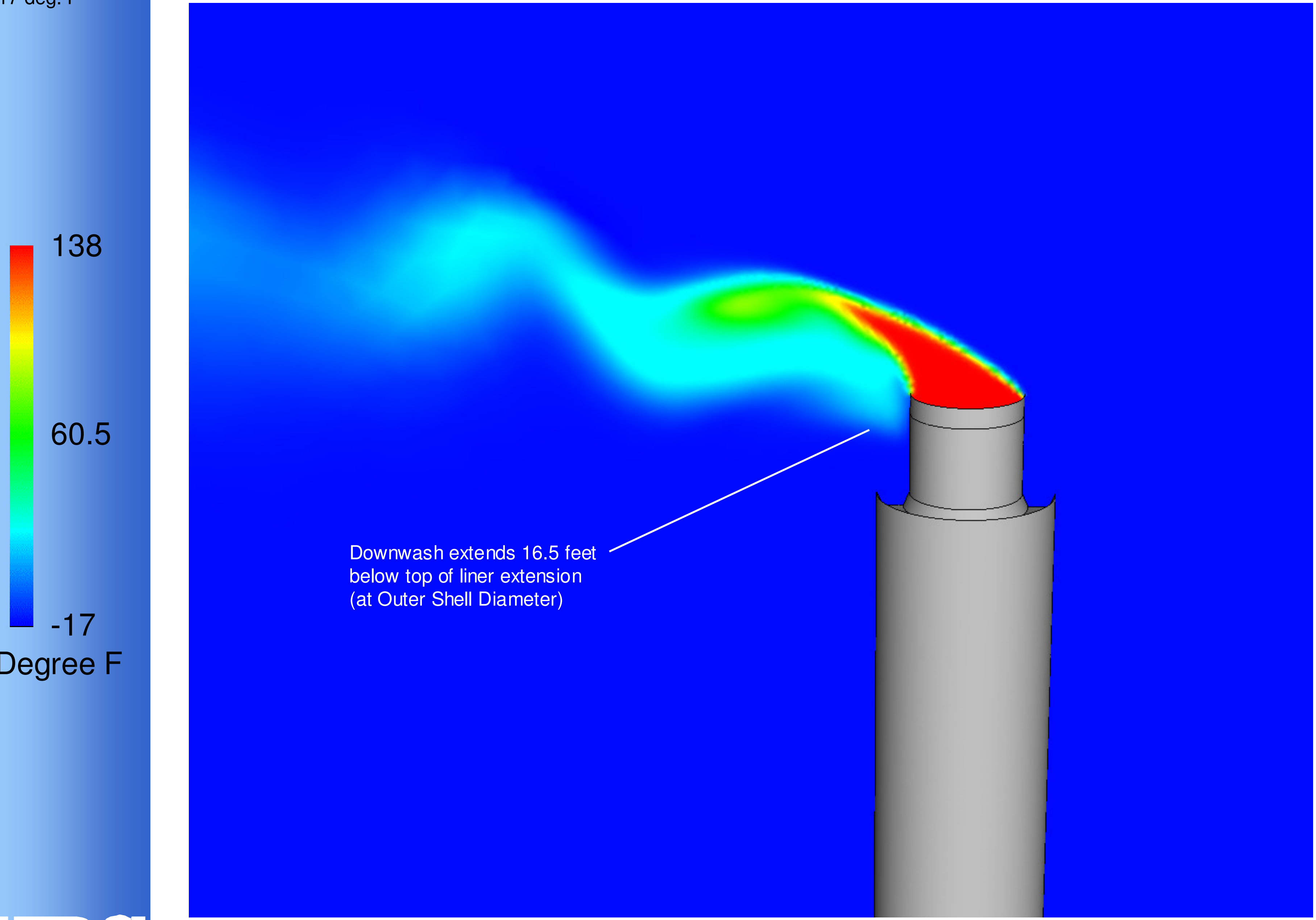
- Wind Speed = 63 MPH at Stack Height
- Ambient Air Temperature = -17 Degrees F

Case 2:
63 MPH
-17 deg. F

Surface Contour of Constant Temperature = - 16 Degrees F



Temperature at Stack Midplane

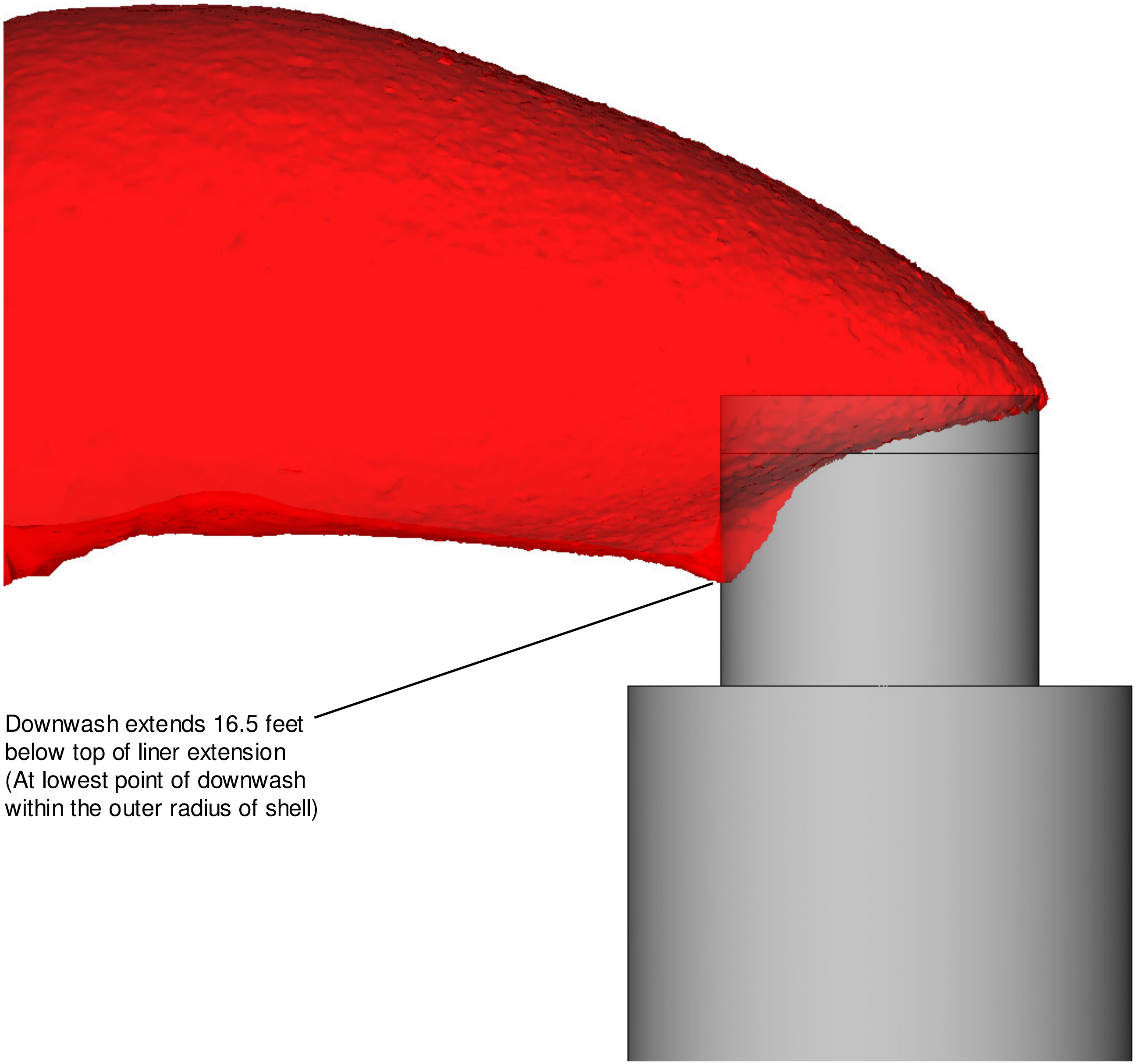


URS

Case 2:
63 MPH
-17 deg. F

Surface Contour of Constant Temperature = - 16 Degrees F

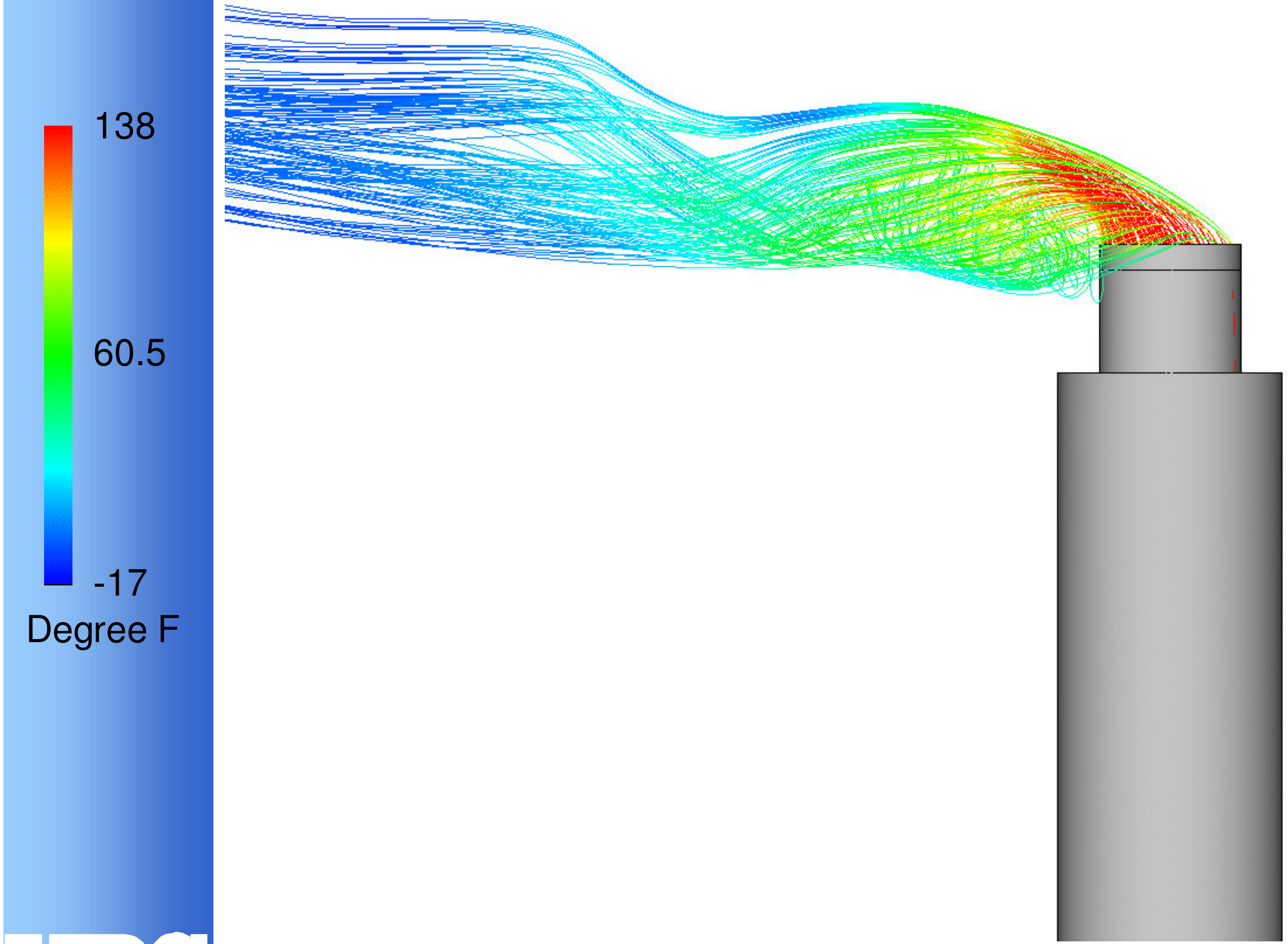
Surface is Semi-Transparent to Show Liner Extension



URS

Case 2:
63 MPH
-17 deg. F

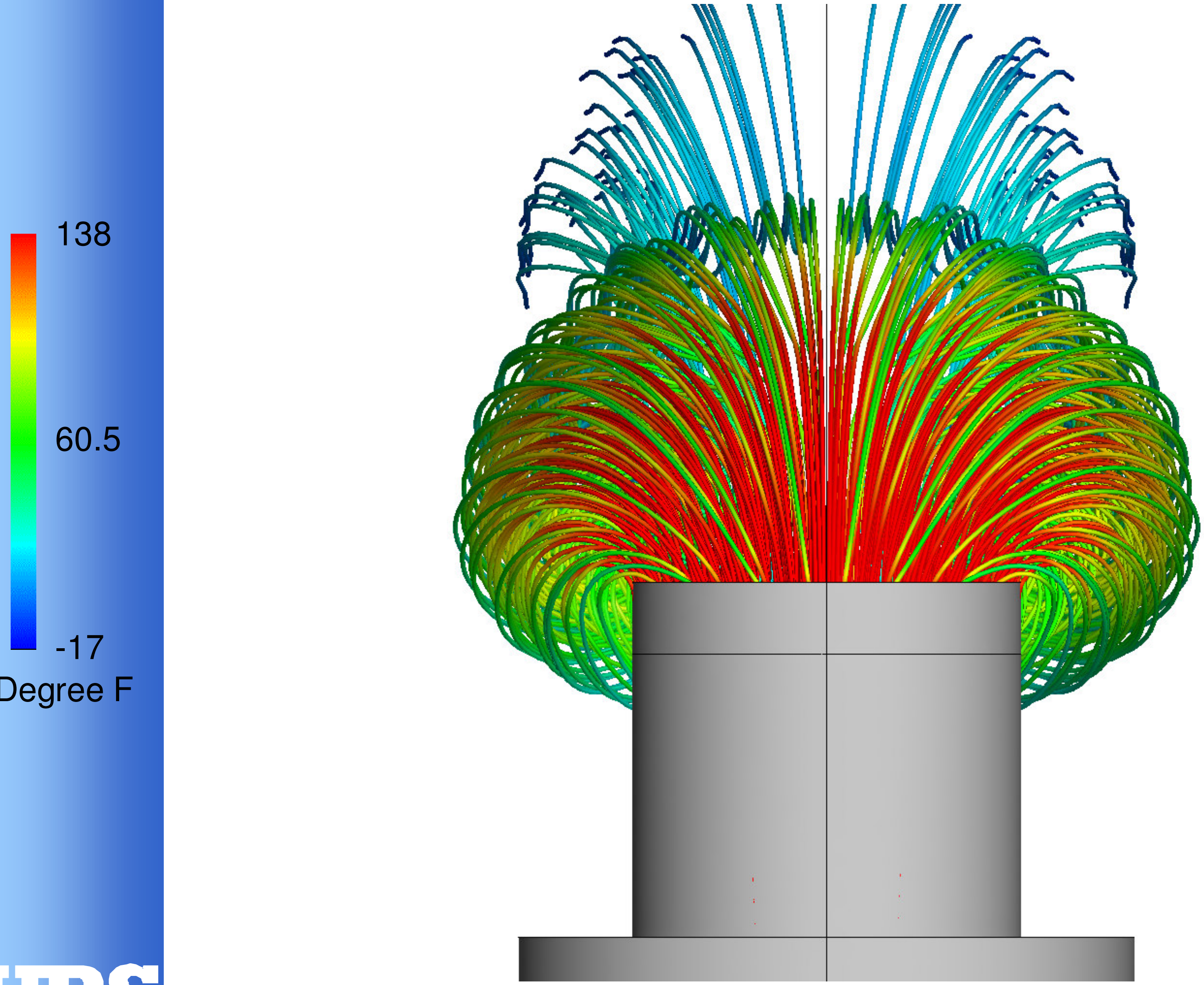
Streamlines Colored by Temperature



Case 2:
63 MPH
-17 deg. F

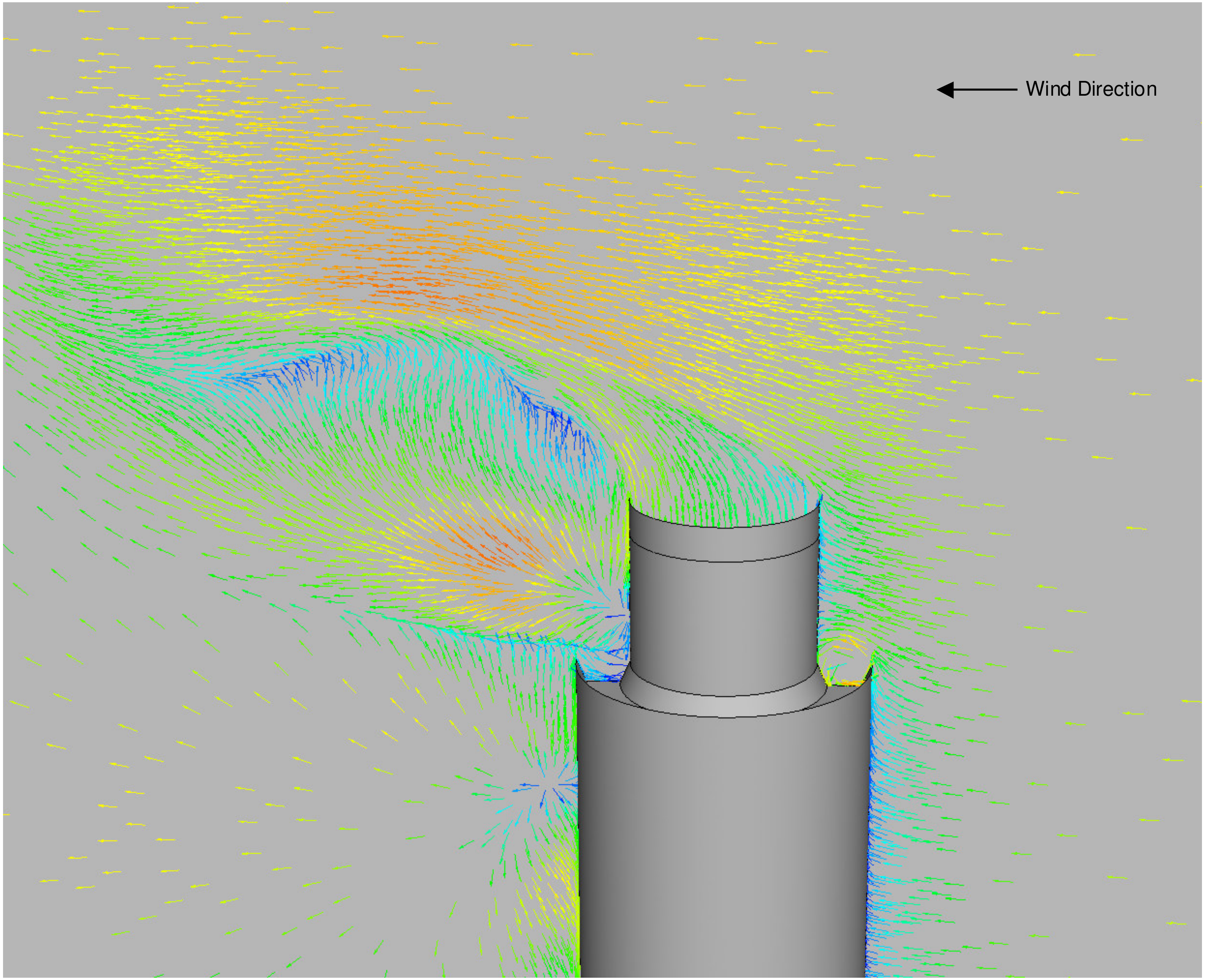
Streamlines Colored by Temperature

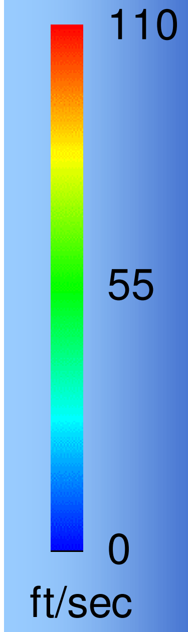
End Elevation View – Looking Downwind



Case 2:
63 MPH
-17 deg. F

Velocity Vectors at Stack Midplane



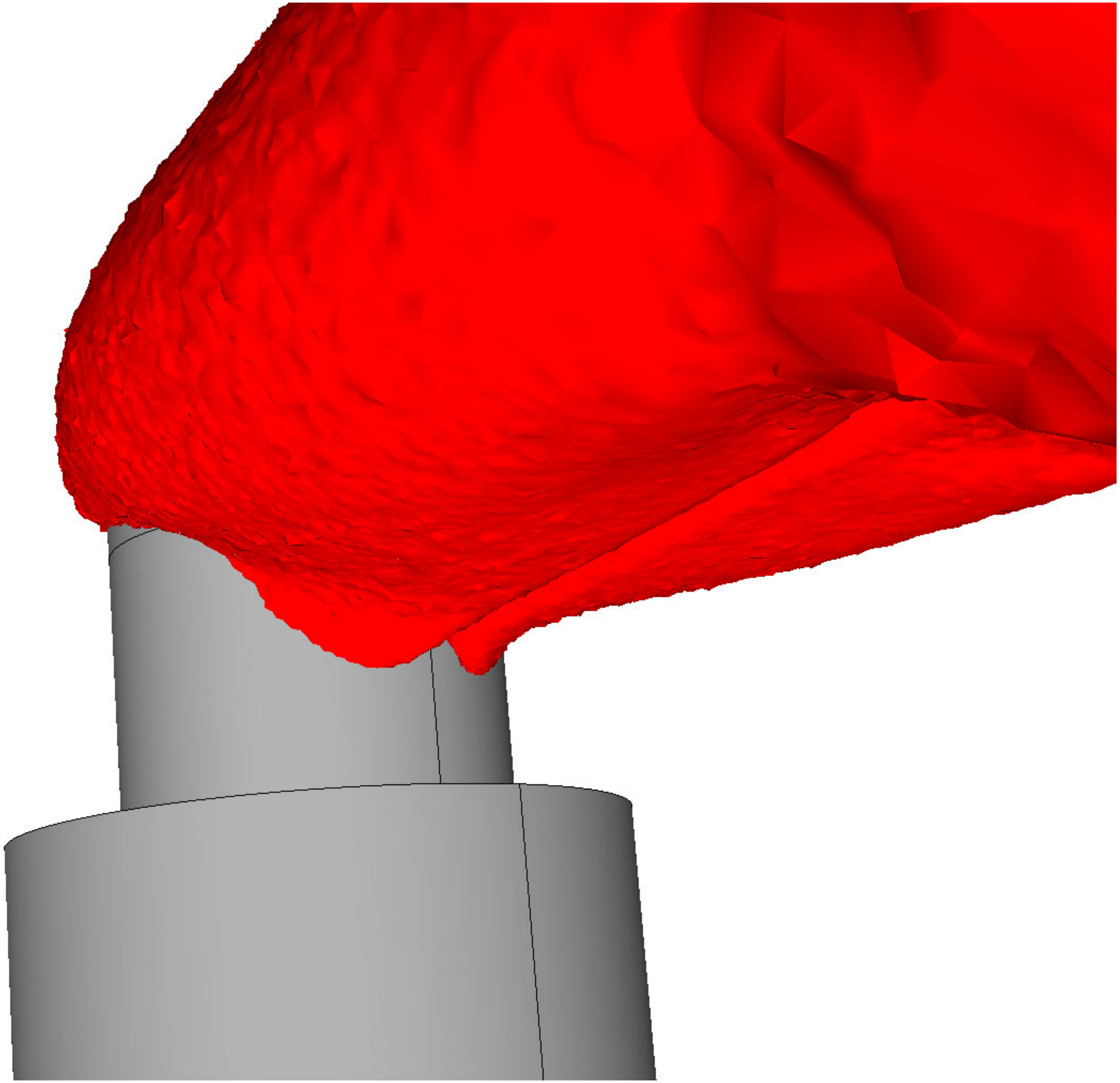


URS

Case 2:
63 MPH
-17 deg. F

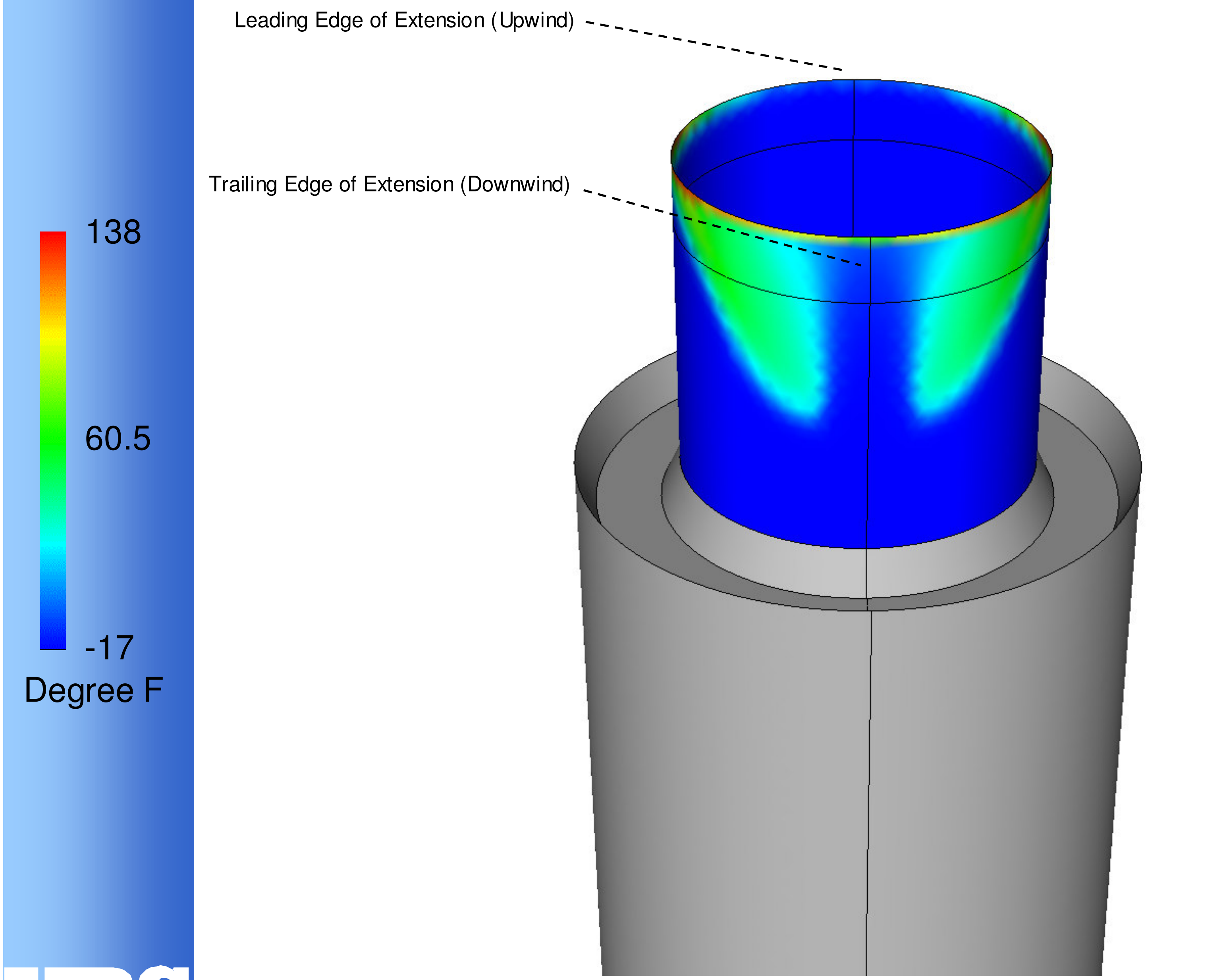
Surface Contour of Constant Temperature = - 16 Degrees F

Showing Bifurcated Plume



Case 2:
63 MPH
-17 deg. F

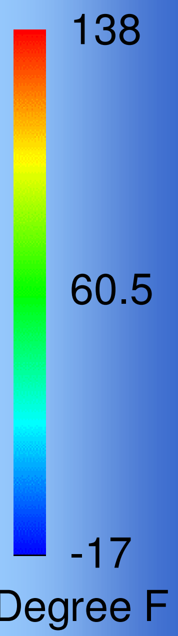
Temperature Adjacent to Liner Extension

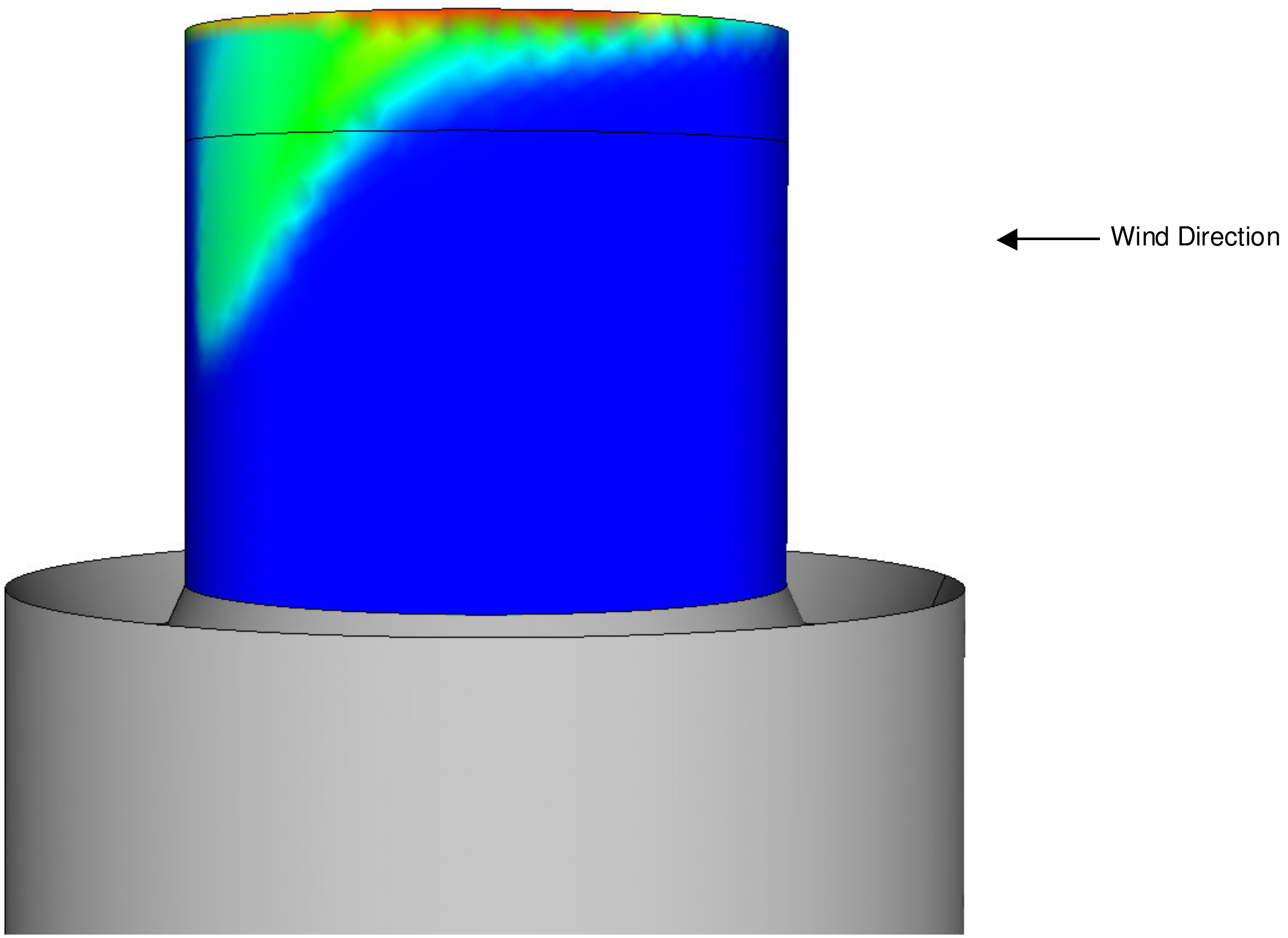


Case 2:
63 MPH
-17 deg. F

Temperature Adjacent to Liner Extension

Side Elevation Perspective View

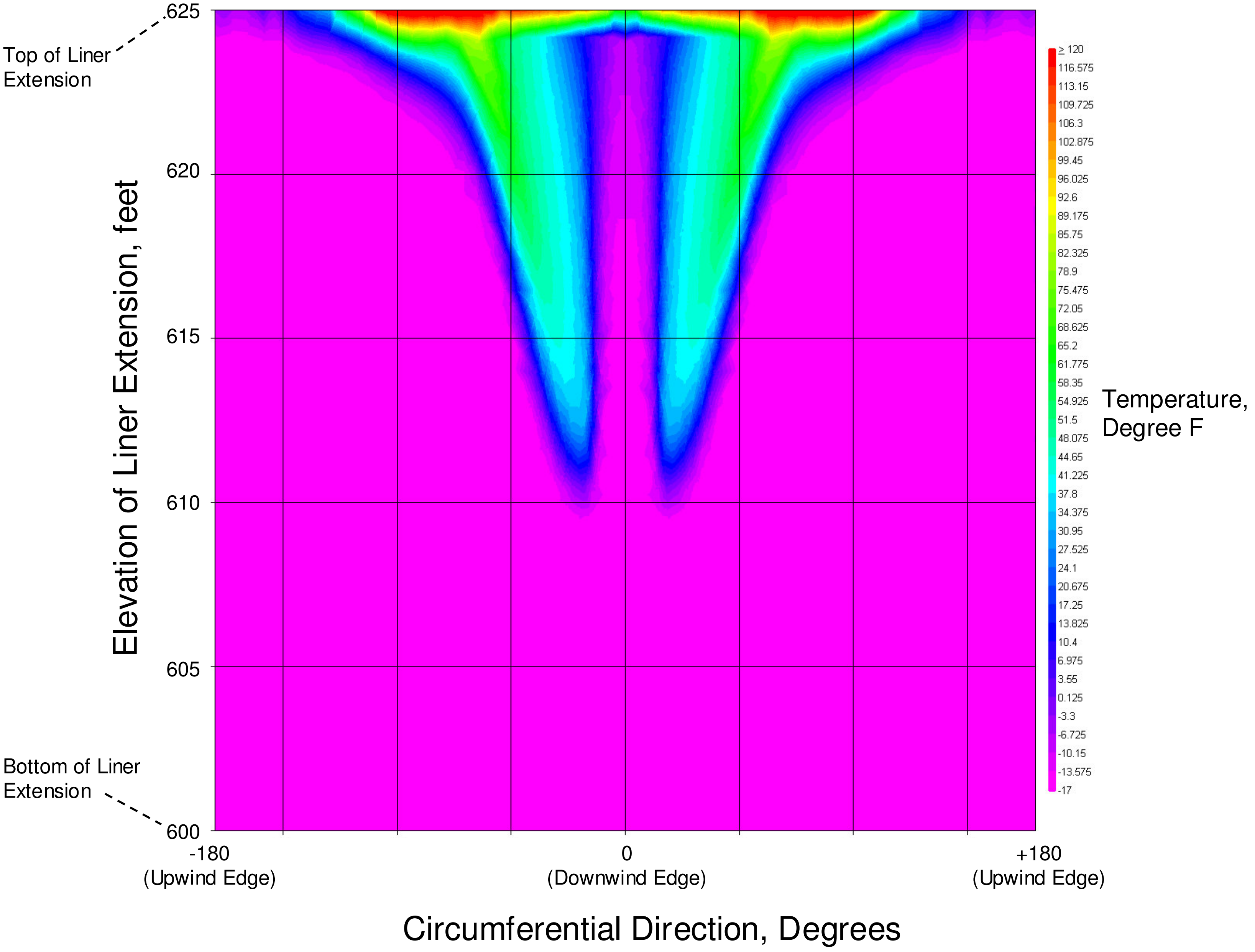




Case 2:
63 MPH
-17 deg. F

Temperature Adjacent to Liner Extension

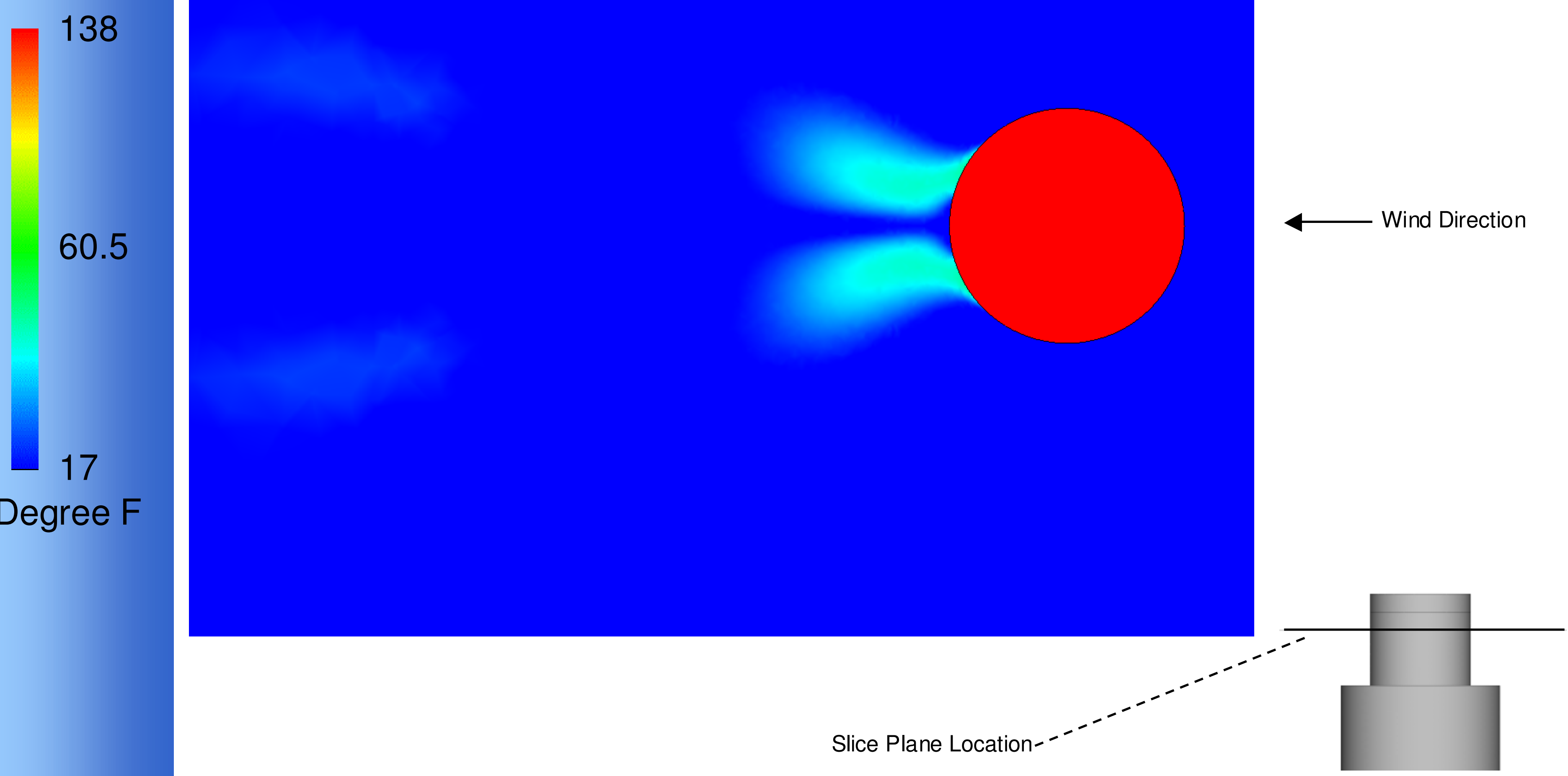
Plotted in Cylindrical Coordinates



Case 2:
63 MPH
-17 deg. F

Temperature, 10 Feet Below Top of Liner Extension

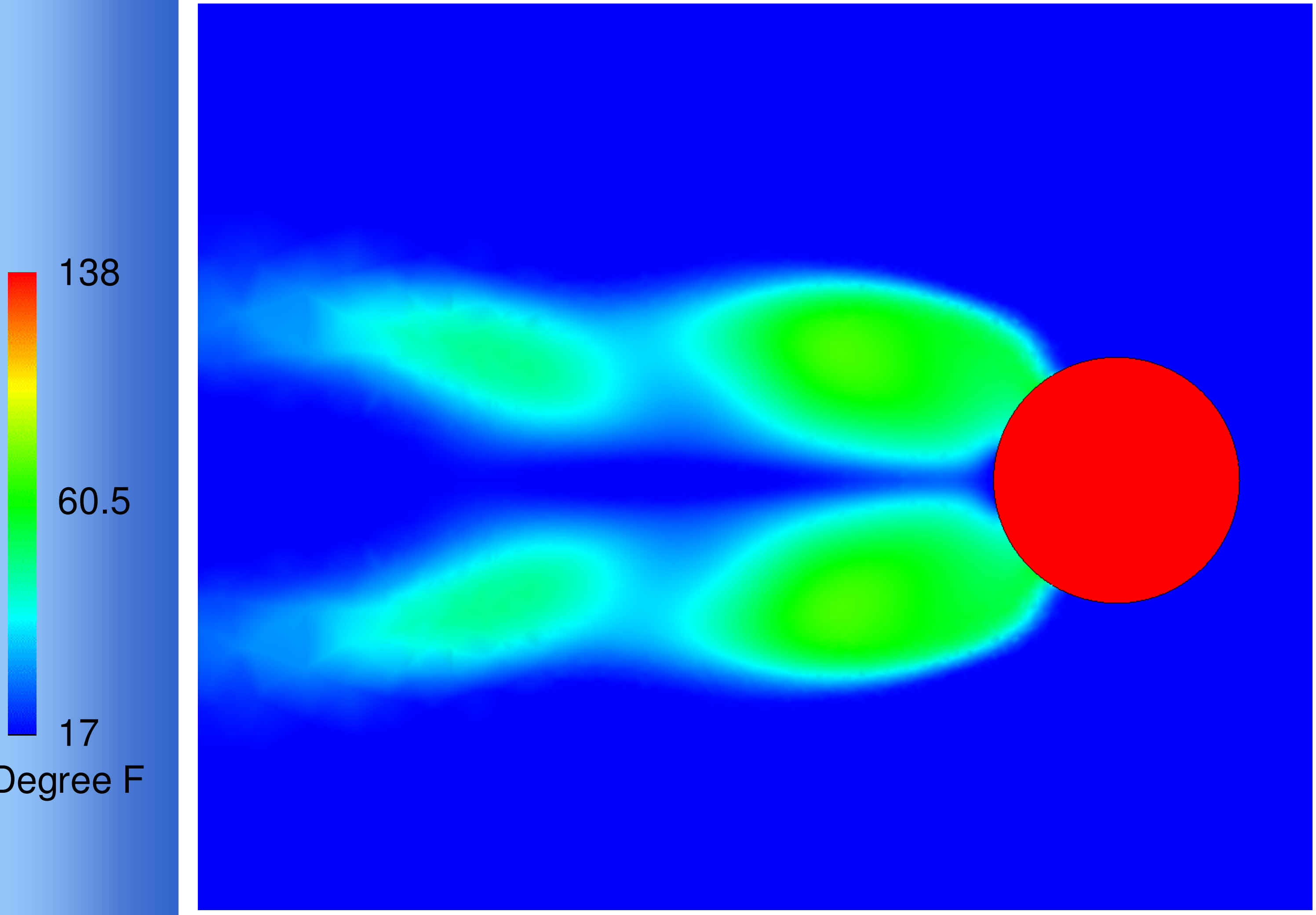
Plan View



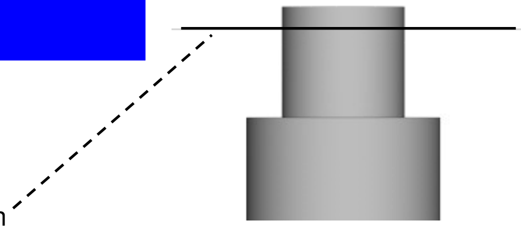
Case 2:
63 MPH
-17 deg. F

Temperature, 5 Feet Below Top of Liner Extension

Plan View

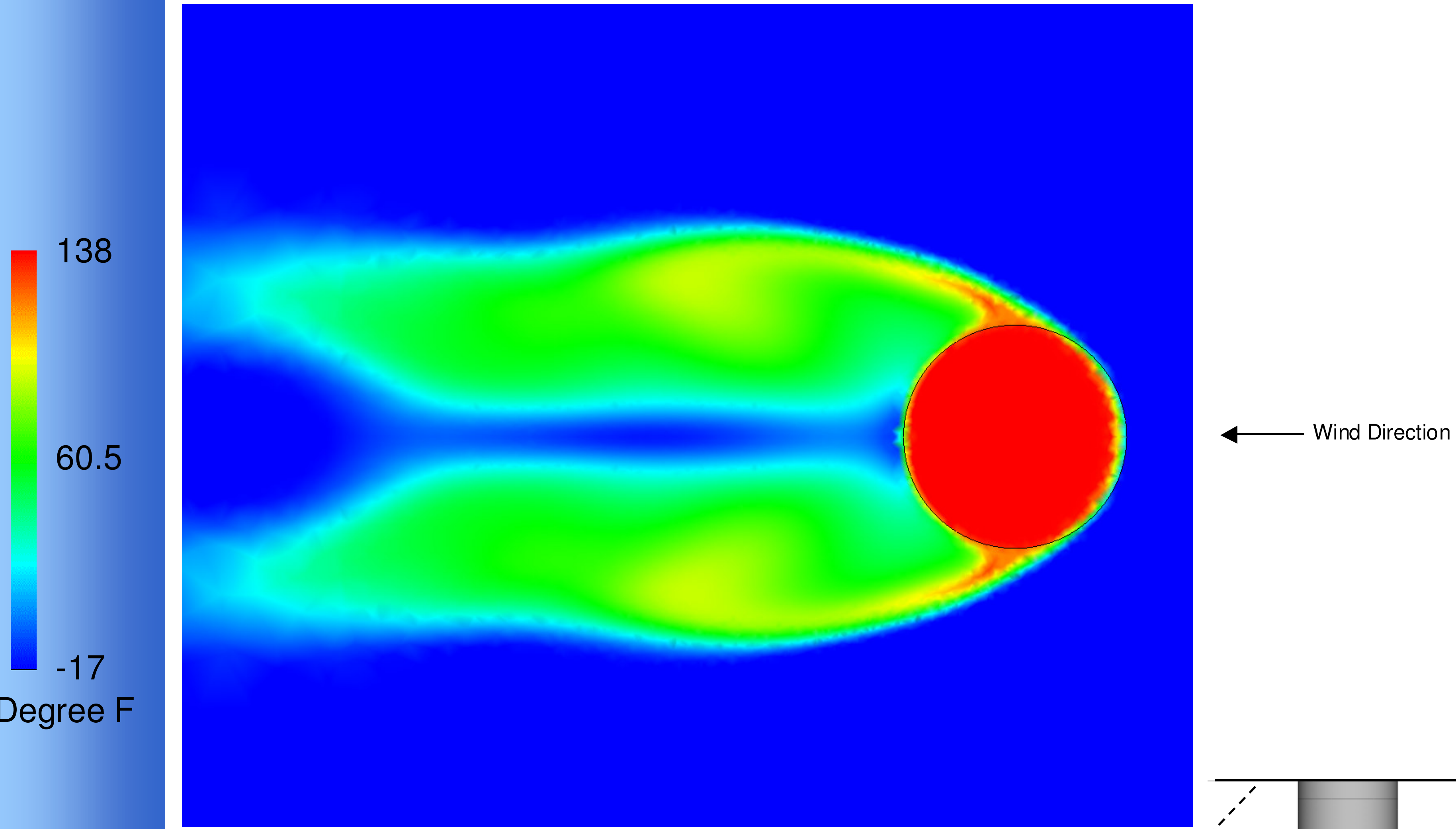


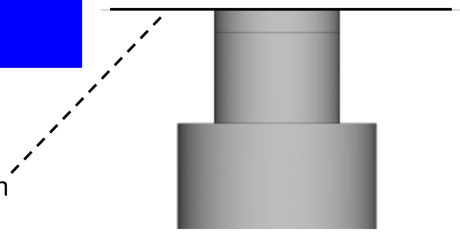
Wind Direction



Temperature, at Top of Liner Extension

Plan View

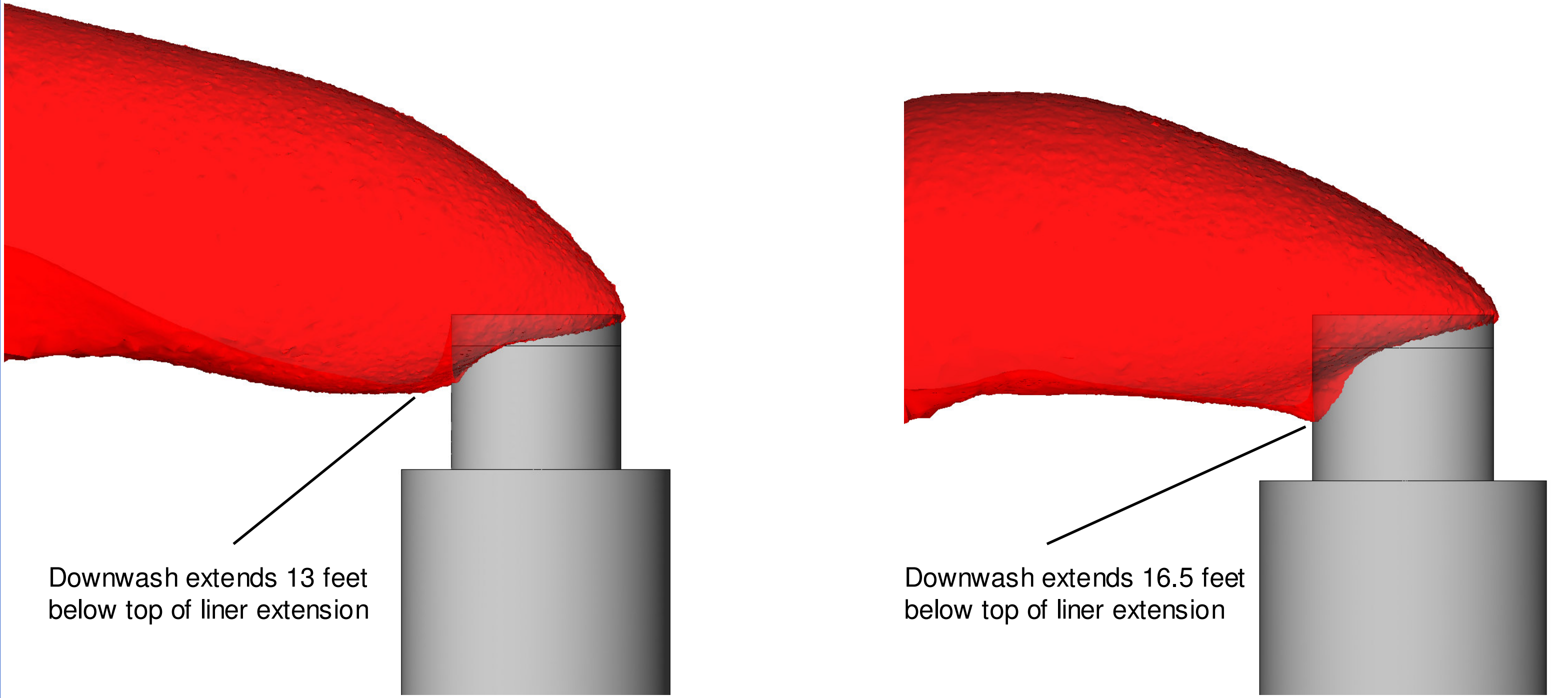




Side by Side Comparison of Both Cases

Surface Contour of Constant Temperature

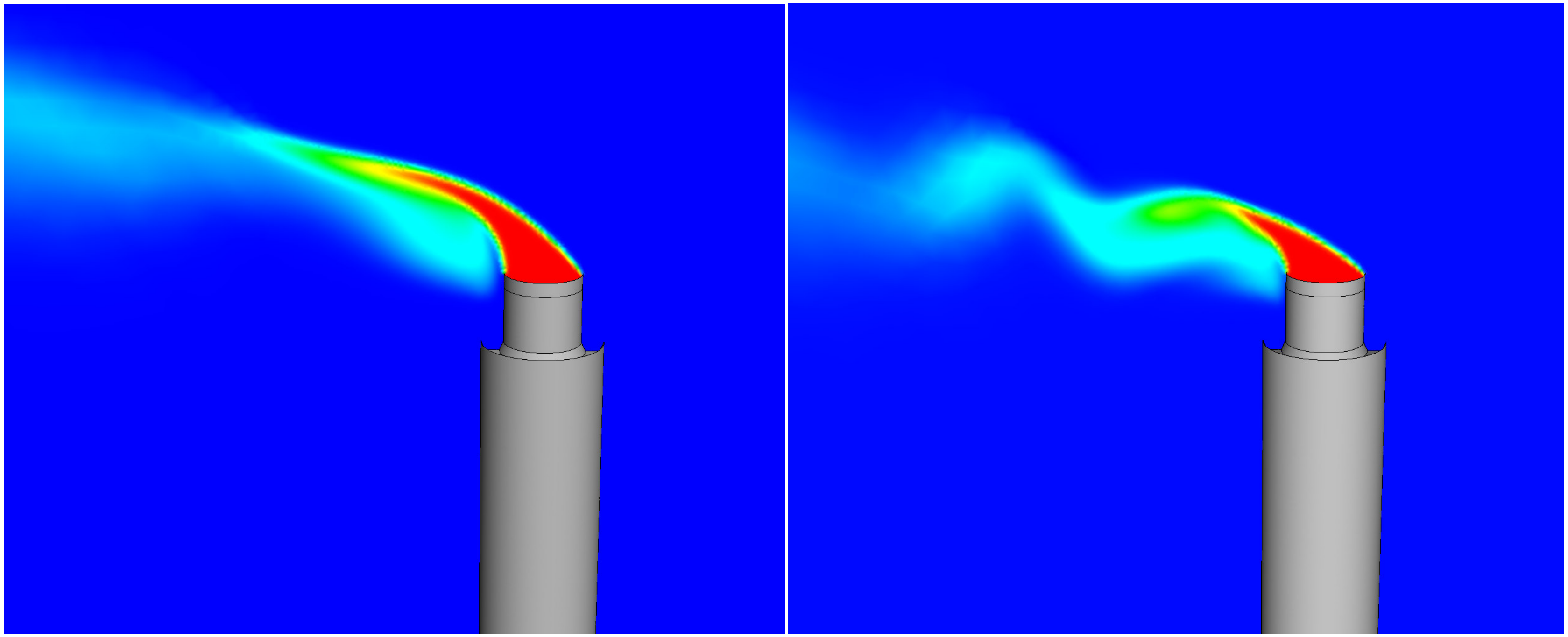
Surface is Semi-Transparent to Show Liner Extension



Case 1: 38 MPH, -7 deg F

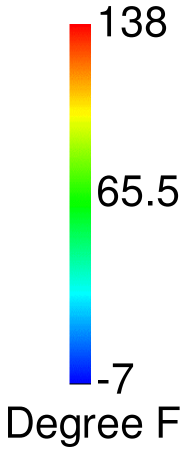
Case 2: 63 MPH, -17 deg F

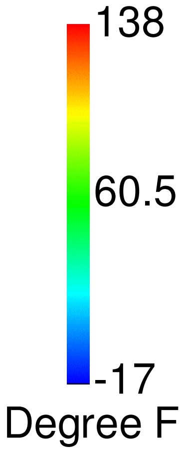
Temperature at Stack Midplane



Case 1: 38 MPH, -7 deg F

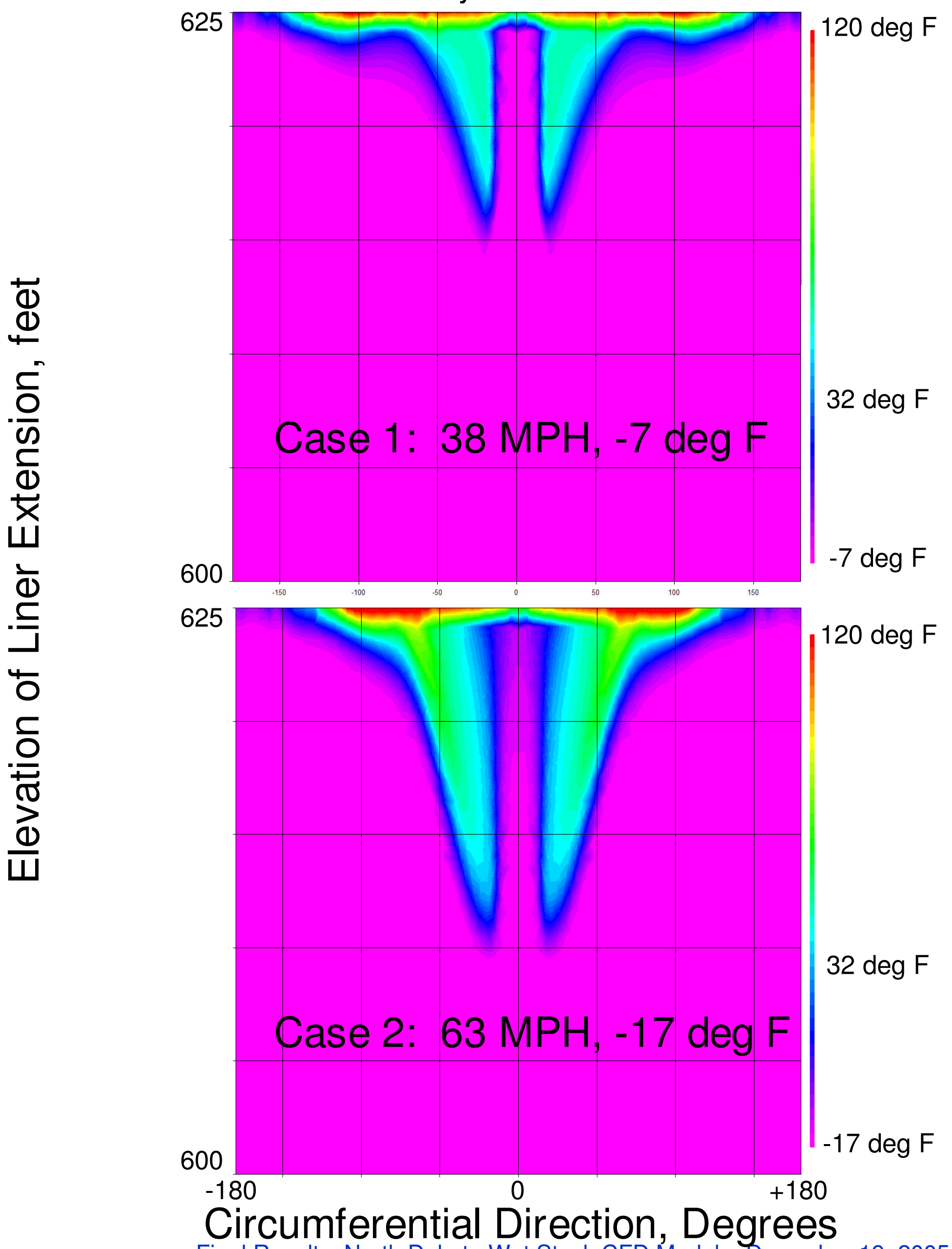
Case 2: 63 MPH, -17 deg F





Temperature Adjacent to Liner Extension

Plotted in Cylindrical Coordinates



Appendix F

Foster Wheeler SOFA/LNB Analysis

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TLN3 SYSTEM ASSESSMENT AND RECOMENDATIONS FOR LOWER NOx OPERATION

GREAT RIVER ENERGY
UNDERWOOD, NORTH DAKOTA
COAL CREEK UNIT 1

FWNAC Contract No. 65-117436
September 9, 2005

Prepared By: Brad Moulton & John Grusha

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Summary:

Foster Wheeler was on site at Great River Energy (GRE) Coal Creek Station August 16-18, 2005 for the purpose evaluating the current TLN3 system performance, for future NOx reduction potential. This consisted of conducting a series of tests that would both identify the effectiveness of various NOx reduction adjustments and subsystems, determine any barriers, and gather data that would help predict and quantify the benefits of specific modifications for additional NOx reduction. Several recommendations are summarized and offered to Great River Energy's for review and consideration.

The primary evaluation tests consisted of the following:

1. Static pressure measurements at the SOFA elevations were taken at varying conditions to determine SOFA flows and the effect on NOx levels.
2. Main windbox/furnace DP was increased to evaluate forcing more air to the SOFA windboxes.

The effect of operating oxygen levels and main burner tilts was not examined however there is potential here.

Separated Overfire Air flow measurements:

Separated overfire air (SOFA or SSAS 13 and 14) static pressure measurements were taken at each corner (both elevations). These readings were used to evaluate current overfire air flow rates versus the initial design and what it takes to increase the flow. Furnace draft measurements were taken at the observation doors near each SOFA corner, to determine the DP across the nozzle tips. Knowing the DP, nozzle tip flow area and k factors, velocity and flow can be determined. The measured overfire air flows are summarized in the following table:

		Corner Flows, lb/hr									
Date/Time	Test	1	2	3	4	5	6	7	8	Total	% Total Air
8/16; 0840	Baseline	109,015	104,905	109,427	112,929	114,412	90,225	114,431	107,919	863,263	17.51
8/16; 1055	SOFA 100%	121,118	108,569	113,245	118,113	114,827	81,526	106,691	121,718	885,808	17.97
8/16; 1306	Wbx 4.5 in	119,979	111,838	121,802	119,880	122,122	95,314	108,675	124,987	924,598	18.75
8/16; 1340	SOFA +25	115,588	110,638	114,176	107,221	114,230	95,461	101,727	118,294	877,334	17.79
8/16; 1430	SOFA horiz.	123,864	115,283	115,938	123,260	116,428	91,897	110,396	123,245	920,312	18.67
8/17; 0749	Base	107,206	103,250	96,452	110,546	115,660	83,842	Bad Data	Bad Data	N/A	N/A
8/17; 0935	SOFA 100%	114,196	105,169	107,891	107,341	108,195	107,836	102,862	121,673	875,161	17.75
8/17; 1110	Wbx 5.0 in	121,789	121,152	120,420	120,075	124,056	104,050	117,717	132,611	961,871	19.51
8/17; 1425	SOFA +25	115,461	104,534	111,151	108,207	109,267	101,874	111,560	112,574	115,461	17.74
8/18; 1322	Check	118,298	111,454	118,373	114,654	109,662	95,774	112,698	121,549	902,461	18.30

Table 1 –Separated Overfire Air Flow Rates for Individual Corners Under Various Conditions

The original overfire air system was designed for 20% at 5.0 in w.c. Some variances exist between corners but overall the current measured flow rates match initial predicted values closely. The first test consisted of raising the windbox/furnace DP from 4.0 to 4.5 in w.c. This increased the SSAS/ SOFA flow from 17.5 to 18.75% (table 1). Further SOFA flow increase was seen at 5.0 in w.c, however at this condition, the main windbox dampers were at their low limit of

10% open. (This is a plant- imposed limit for nozzle tip cooling considerations.) Further closure would have diverted more secondary air to the overfire air.

The next series of test consisted of evaluating SOFA tilt angle versus NOx. The lowest NOx emissions were at a SOFA tilt angle of +12 degrees. Further increasing SOFA tilts to +25 caused an increase in NOx. This was not expected and is suspected to be due to the apparent flow resistance being created by the "up-tilt" of the nozzle tips. Measured flow rates show a slight decrease in overfire air flow.

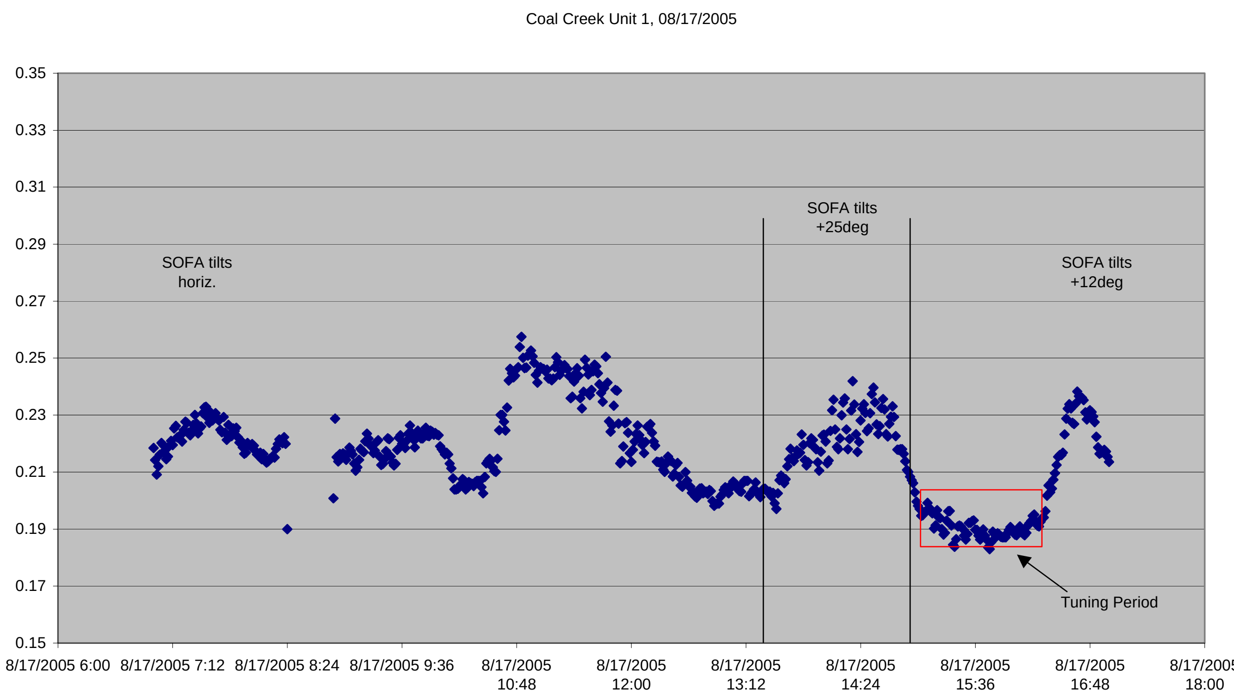

Figure 1: NOx versus Various Operating Conditions

NOx testing/tuning conducted on the last day of the visit (August 18, 2005) showed that opening up the close-coupled overfire air (CCOFA or SAS 11 and 12 compartments) reduced NOx emissions by approximately 0.02 lbs/MBtu.

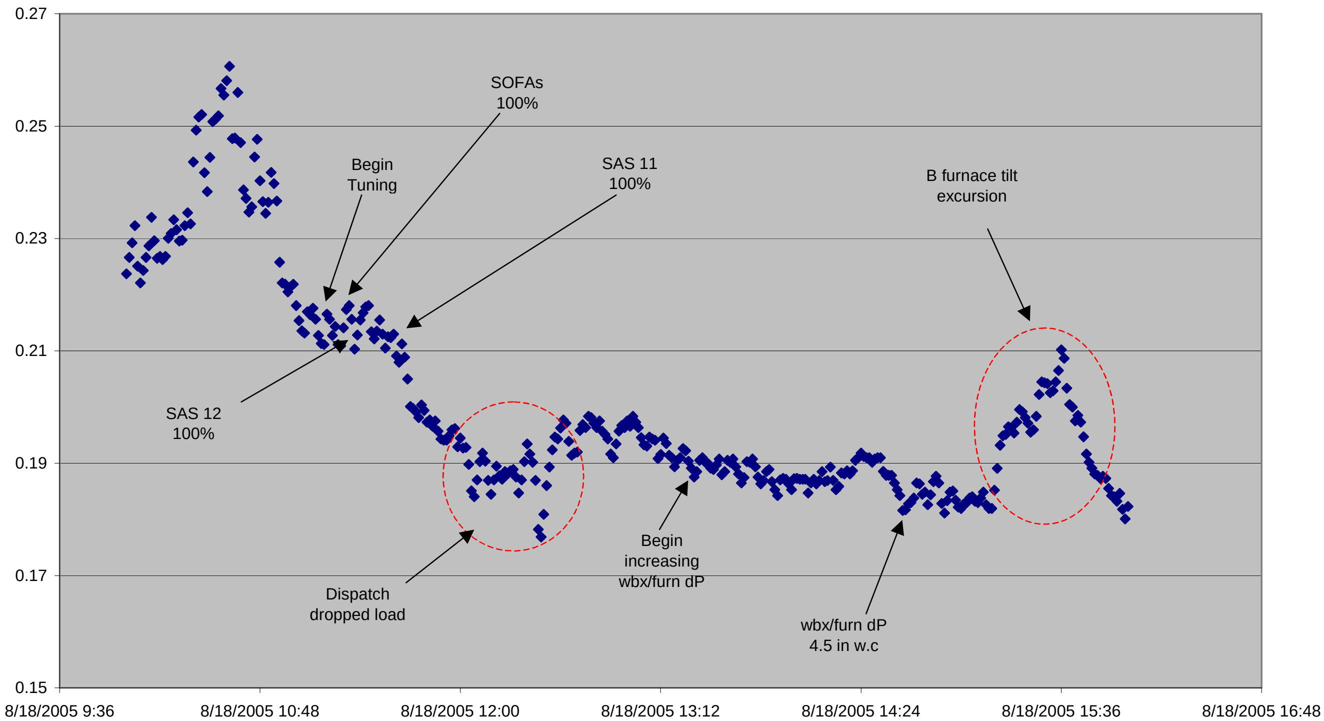

Figure 2. - NOx versus Various Operating Conditions – August 18th

Consistent sub 0.19 lb/MBtu NOx values were achieved with the SOFA and CCOFA compartments at 100% open. As figure 3 shows, only a load disruption and subsequent ramp up caused NOx values above 0.19 lb/MBtu for the better part of the entire afternoon. At these emission levels, main windbox tilts had a pronounced affect on NOx.

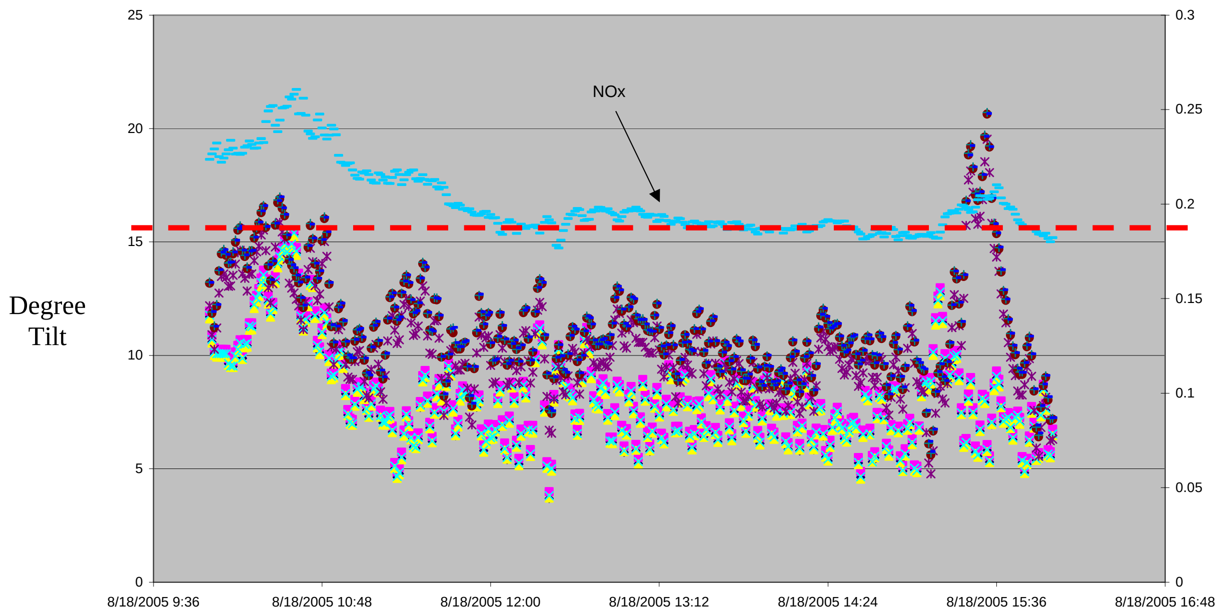

Figure 3. – NOx versus Main Windbox Tilts Over an Extended Period

The above graph shows the NOx and tilts as a function of time. As more overfired air was introduced into the furnace to lower NOx (by opening up the SAS 11 and 12), the main burner tilts were lowered while still controlling steam temperatures. It is clearly evident that fluctuations in NOx coincide with tilt perturbations. The rather drastic increase in NOx around 15:36 was caused by the raising of the A furnace tilts followed by the more marked increase in the B furnace tilts (above 20 degrees).

Recommendations

Based on this evaluation we offer three options that could be applied depending on Great River Energy's short and long-term goals

A. Current Operation:

Based on these evaluation tests, unit #1 should be able to operate at MCR closer to 0.19 lb /MBtu NOx level, with no modification but a few operational changes. This is approximately a 15% reduction from current levels

1. SOFA tilts should be set at + 12 degrees
2. The CCOFA curves (SAS 11 and 12) should be modified so they are 100% open at full load. Specifically they should be optimized to go 100% open at 90 % load, which will match the tested load condition during the time of the Foster Wheeler visit.
3. Further reduction in NOx may be realized by making modifications to the existing steam temperature control logic. Currently, the tilts modulate a fair

amount, which causes fluctuations in NOx of approximately ±0.01 lb/MBtu (over the range observed). (It should be noted that main windbox tilts were not optimized for NOx during this visit.)

4. Lower NOx should be realized with main windbox tilts lower, however some parametric testing would be needed to assess how steam temperatures are affected. Some changes to sootblowing cycles may be warranted to allow lower tilt operation.
5. Operation with a pulverizer out of service would also significantly aid toward maintaining higher overfire air levels. Besides lower NOx emissions it would provide improved DP control and more open auxiliary air dampers.

B. Modifications for 0.17 lbs NOx/MBtu:

Reducing NOx levels closer into the 0.17 levels would require diverting more secondary air to both the CCOFA and SOFA levels. We believe this NOx level could be still be achieved with the current SOFA windboxes and some additional modifications in the main windboxes.

Specifically our model shows that the following changes would be required.

New reduced flow area horizontally adjustable boundary air nozzle tips and new oil nozzle tips would be required. These are required to maintain nozzle tip velocities and nozzle tip cooling being lost due to diverting more secondary air to the SOFA, but also to maintain windbox to furnace DP and damper control. Besides staying cooler, they would also be less prone to slagging for a longer service life. This would be designed to our latest double shroud design standards.

Larger venturi over the coal and auxiliary air dampers would also be required in the main windboxes. These would reduce damper leakage and allow the auxiliary dampers to be at a more open position then current dampers for the same DP. Currently, increased staging is limited by the 10% limit on main windbox auxiliary dampers and the flow restrictions of the existing SOFA nozzle tips.

The following equipment (per unit) would need to be installed:

Item	Quantity	Description
1	Thirty two (32)	Reduced flow area, double shroud front removable section boundary air nozzle tips with full tilt and yaw capability. Matl: 309 SS
2	Twenty four (24)	Reduced flow area, tilting oil nozzle tips. Matl: 309 SS
3	One Hundred Twenty (120)	Venturi damper plates, one for each fuel air and boundary air compartment to further reduce the damper/area tip ratio. Matl. Carbon Steel
4	One lot	Revised SAMA drawings

5	Two Hundred (200) hours	Startup and optimization support for Reevaluating the damper curves regarding impact on the combustion process, furnace slagging, etc. Examination of boiler operational parameters including windbox-furnace DP, boiler O2, fuel/air staging and main burner tilt control.

For budgeting purposes, we estimate approximately $500,000 for the above scope on a D&S basis and approximately another $500,000 for installation.

C. Modifications for 0.15 lbs NOx/MBtu:

From the recent testing and our modeling, long term, NOx levels in the 0.15 lb/MBtu range will not be achieved without substantially increasing separated overfire air flow. At the current 20% SOFA air staging, the lower furnace is bright and free of "sparklers". An additional 10 % staging could be appreciated with minimal boiler performance issues.

To achieve this objective, Foster Wheeler would recommend installing an additional level of SOFA windboxes and associated tube panels, ducts, hanger, etc. The challenge is to get the added SOFA flow, taking into account the high primary air flow percentage with all mills in service. For this we would be looking a duct arrangement that "scoops" secondary air from the secondary air ductwork rather than rely on windbox backpressure through venturi and nozzle tips. We would need to study the take-offs for this and CFD model the design to confirm the expected results.

The objective with this proposed modification is to divert the existing CCOFA air to the new SOFA windboxes. Separated overfired air is nearly twice as effective in reducing NOx as compared to close-coupled overfire air (CCOFA). Because of this fact, the existing CCOFA nozzles would be downsized and venturis added to the CCOFA dampers to achieve this objective.

Specifically, the following equipment (per unit) would need to be installed:

Item	Quantity	Description
1	Eight (8)	Separated SOFA windboxes sized for approximately 10% of total combustion air, with tilting and yawable double shroud nozzle tips and static pressure taps for air flow measurement, etc. Windbox material: Carbon Steel; Nozzle tip material: 309SS.
2	One (1) lot	Complete secondary air duct system for the SOFA system including ducts, hangers expansion joints, flow diverting vanes or scoops, and associated support steel.
3	Sixteen (16)	Reduced flow area, double shroud CCOFA nozzle tips. Matl: 309 SS

4	Sixteen (16)	Venturi damper plates, one for each CCOFA compartment to optimize the damper/area tip ratio. Matl. Carbon Steel
5	One session (1)	CFD modeling of secondary and OFA ducting to optimize duct design
6	Eight (8)	Waterwall tube panels to incorporate SOFA.
7	Five Hundred (500) hours	Startup and optimization support for Reevaluating the damper curves regarding impact on the combustion process, furnace slagging, etc. Examination of boiler operational parameters including windbox-furnace DP, boiler O2, fuel/air staging and main burner tilt control.

For budgeting purposes, we estimate approximately $1,000,000 for the above scope on a D&S basis and approximately another $1,000,000 for installation.

Conclusions:

Lower NOx operation in the range of 0.19 lb/MBtu should be achievable with the current equipment. Only a few operational changes are needed to realize these emission levels. The tilting SOFA nozzle tips have been optimized to produce the lowest NOx possible at +12 degrees with the current equipment.

For NOx emissions, in the range of 0.17 lb/MBtu, it will require additional equipment and operational modifications. Specifically this would include smaller main windbox boundary and oil nozzle tips along with damper venturis. These modifications will allow Coal Creek to “push” more SOFA air, maximizing the modifications within the current constraints of the primary air, existing SOFA ducts and windboxes.

For NOx emissions in the range of 0.15 lb/MBtu, about 10% additional overfire air would be required to reliably achieve these levels. This will require additional separated overfire air by installing an additional level. The objective would be to have the capability of introducing 30% of the total combustion air as separated overfire air.

We hope this information is helpful and are available to discuss this assessment and or other considerations with Great River Energy. Foster Wheeler has thoroughly enjoyed working with the Coal Creek Station and personnel and looks forward to future projects and discussions.

Appendix G

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

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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

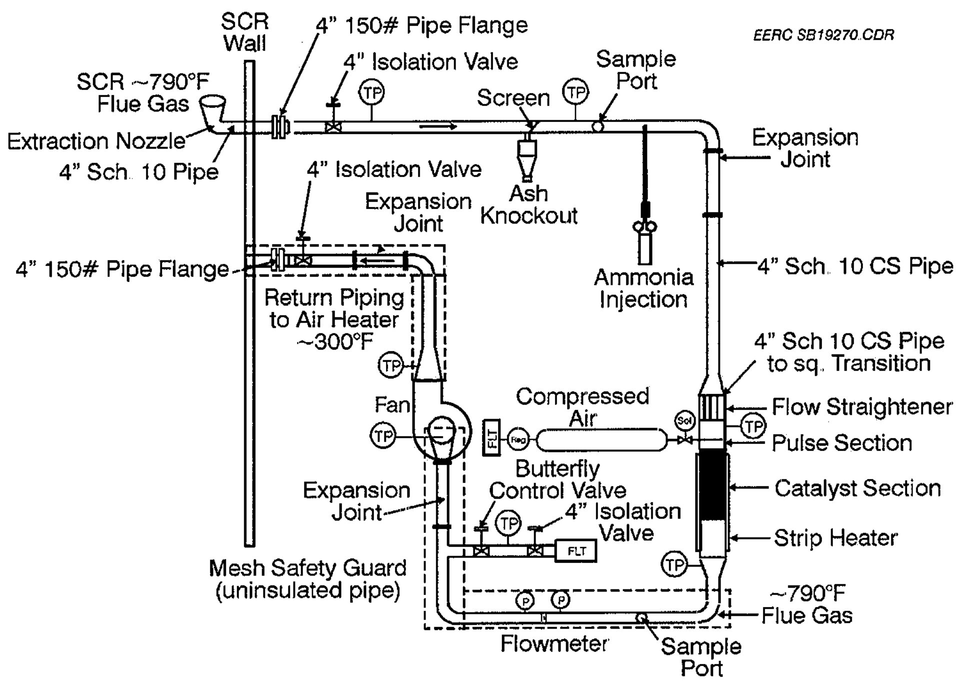

Fig. 1. Schematic diagram of SCR slipstream system.

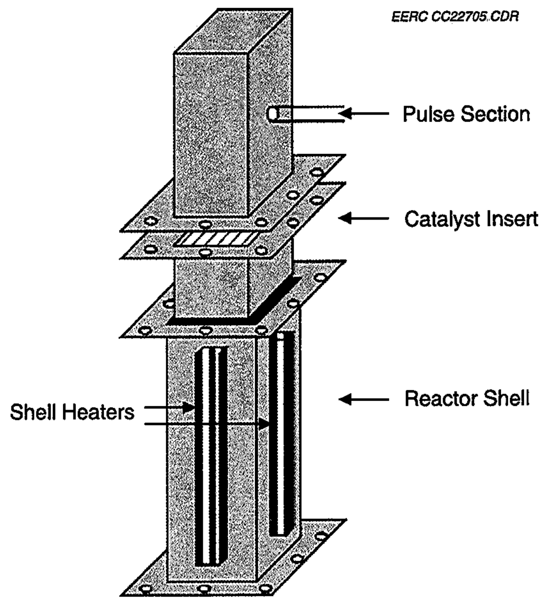

Fig. 2. Diagram of reactor section SCR slipstream system.

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

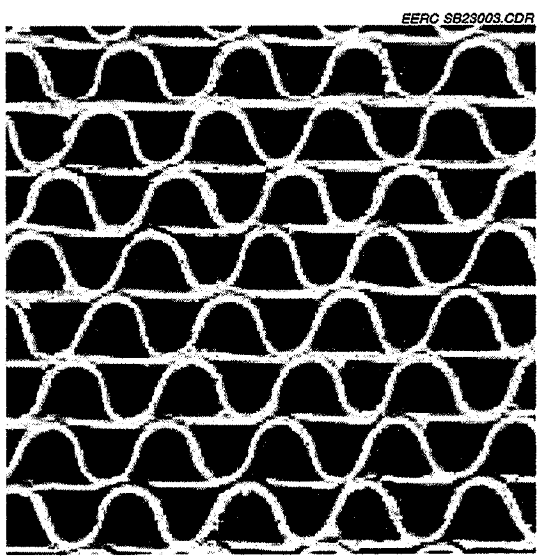

Fig. 3. Haldor Topsoe SCR catalyst showing the gas flow passages.

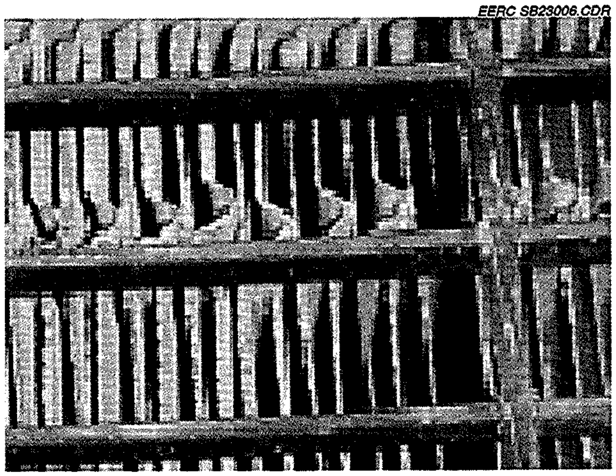

Fig. 4. Babcock Hitachi SCR catalyst showing the gas flow passages.

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

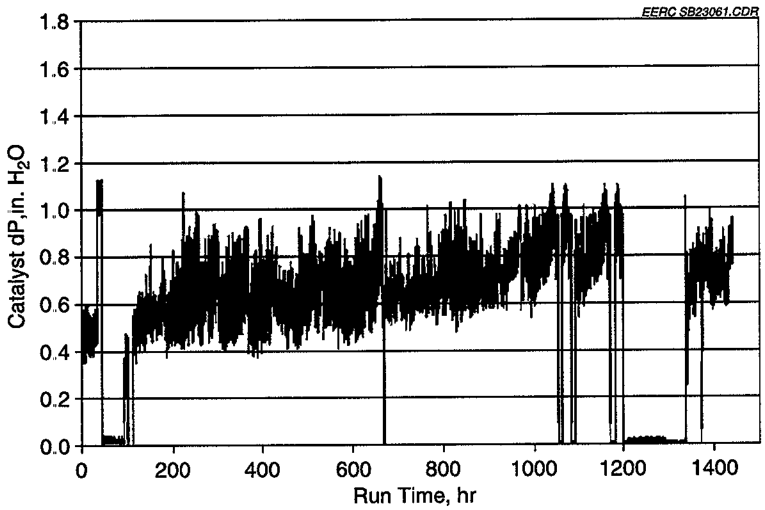

Fig. 5. Catalyst pressure drop at Baldwin Station at 0 to 2 months of operation.

(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

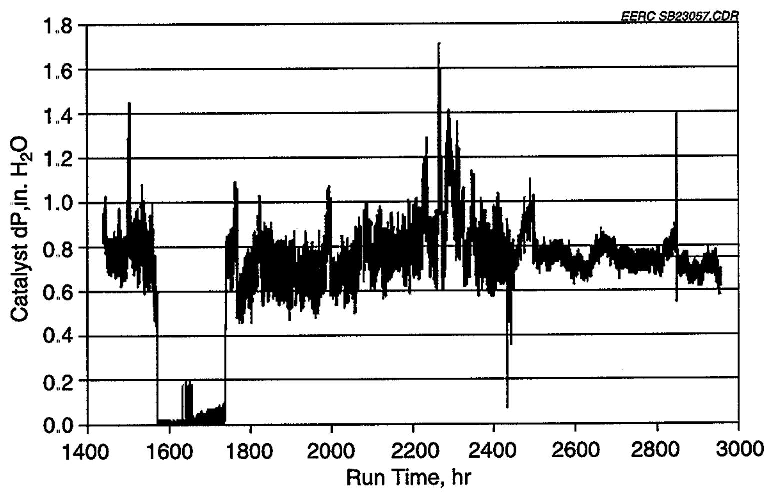

Fig. 6. Catalyst pressure drop at Baldwin Station at 2 to 4 months of operation.

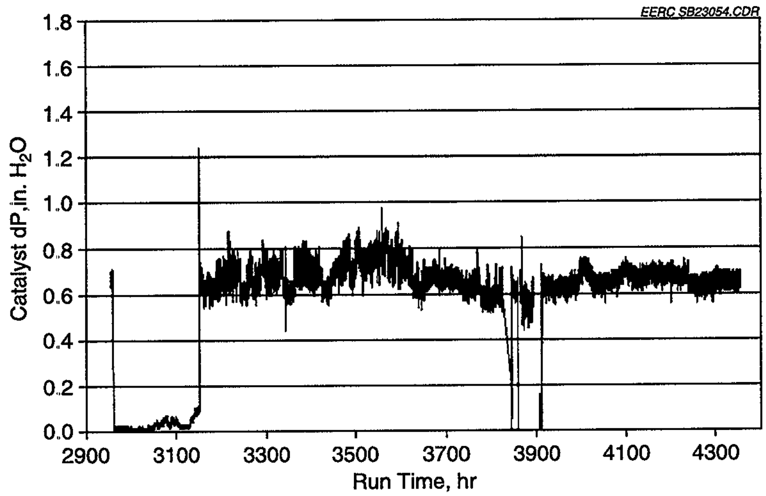

Fig. 7. Catalyst pressure drop at Baldwin Station at 4 to 6 months of operation.

- 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

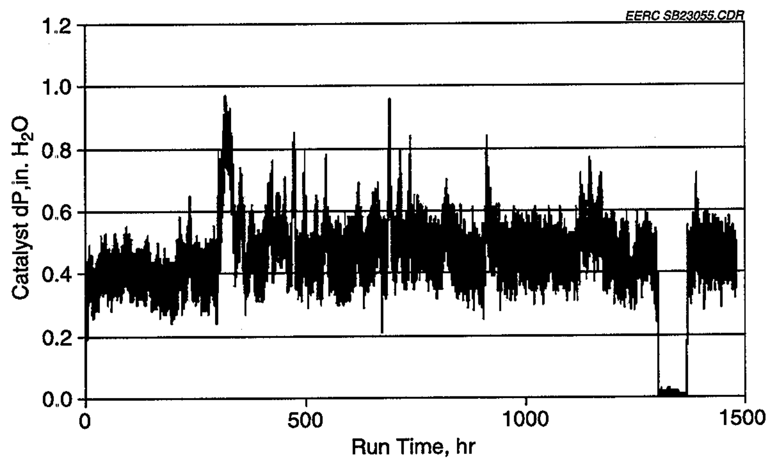

Fig. 8. Catalyst pressure drop at Columbia Station at 0 to 2 months of operation.

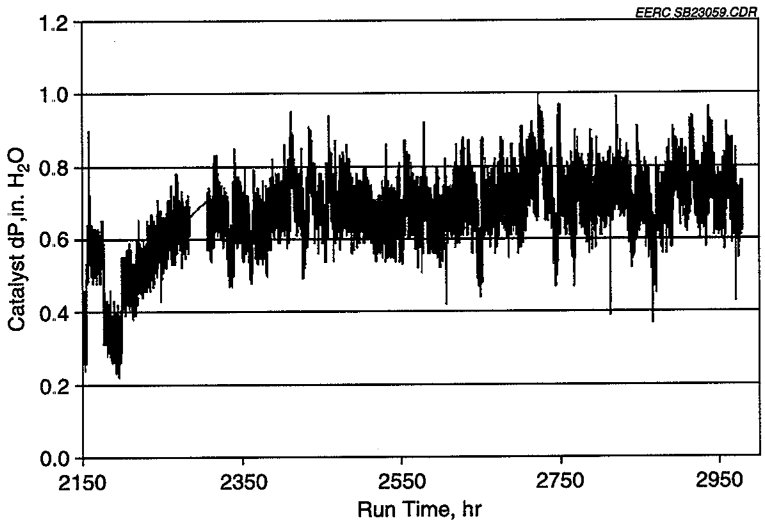

Fig. 9. Catalyst pressure drop at Columbia Station at 2 to 4 months of operation.

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

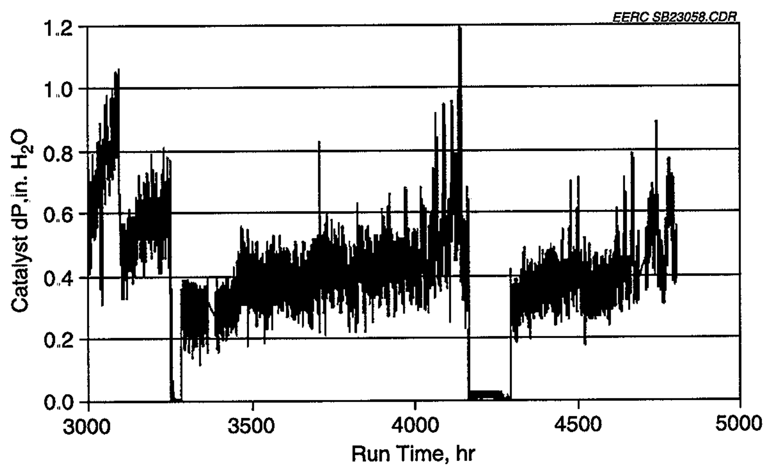

Fig. 10. Catalyst pressure drop at Columbia Station at 4 to 6 months of operation.

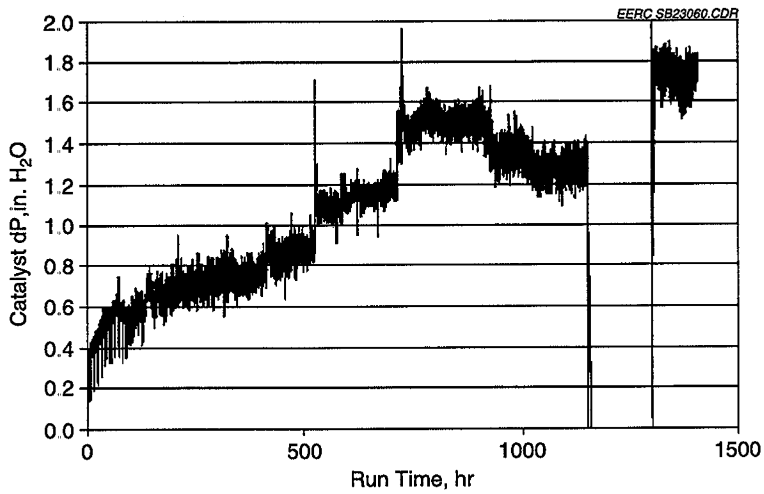

Fig. 11. Catalyst pressure drop at Coyote Station at 0 to 2 months of operation.

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.

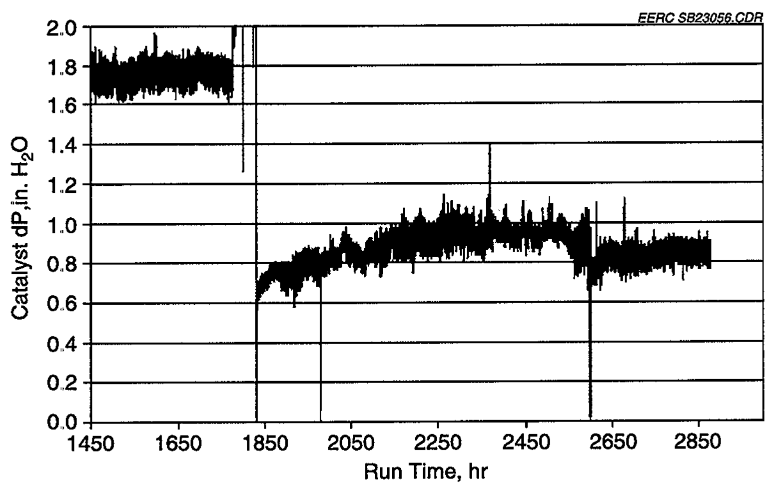

Fig. 12. Catalyst pressure drop at Coyote Station 2 to 4 months of operation.

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

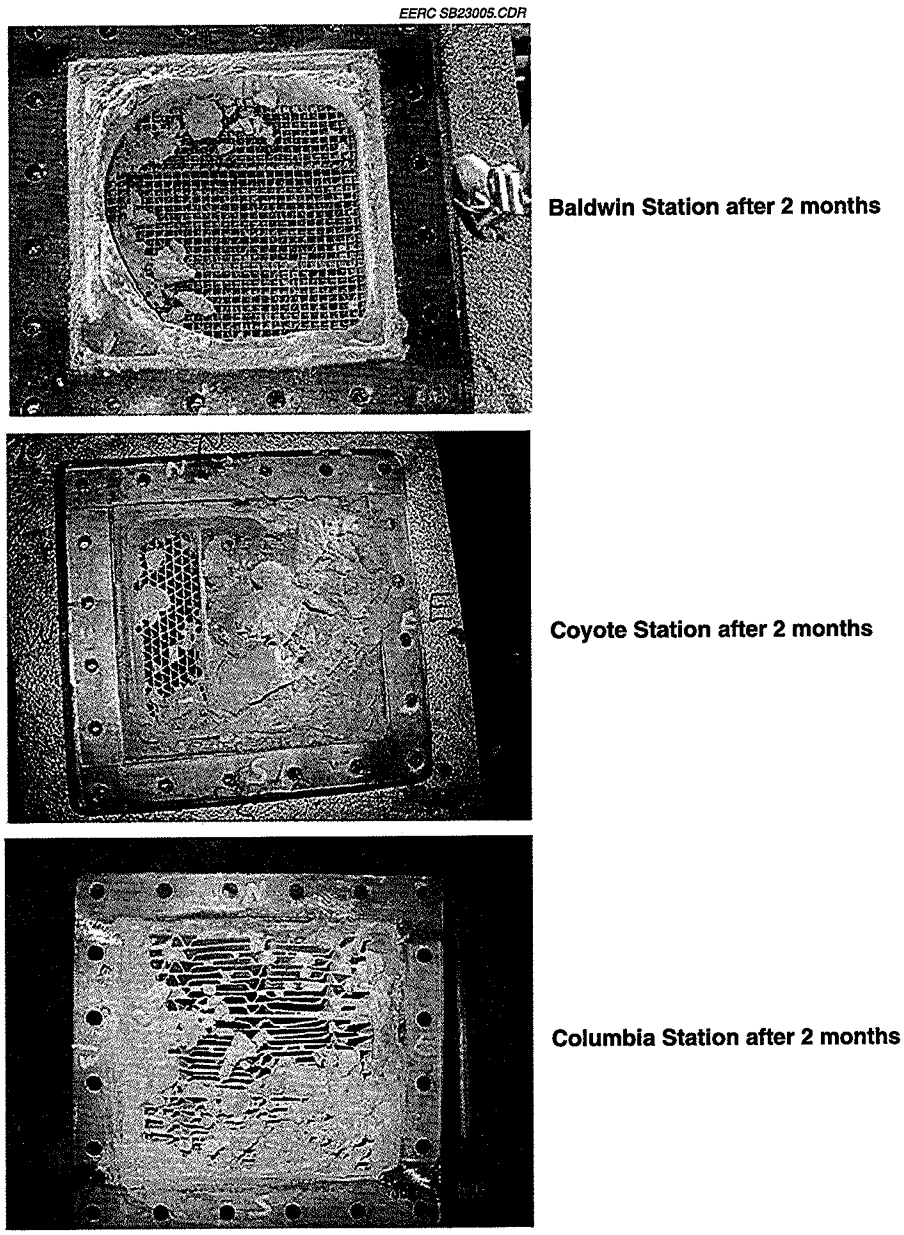

Fig. 13. Pictures of catalyst inlet after about 2 months of testing at each plant.

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].

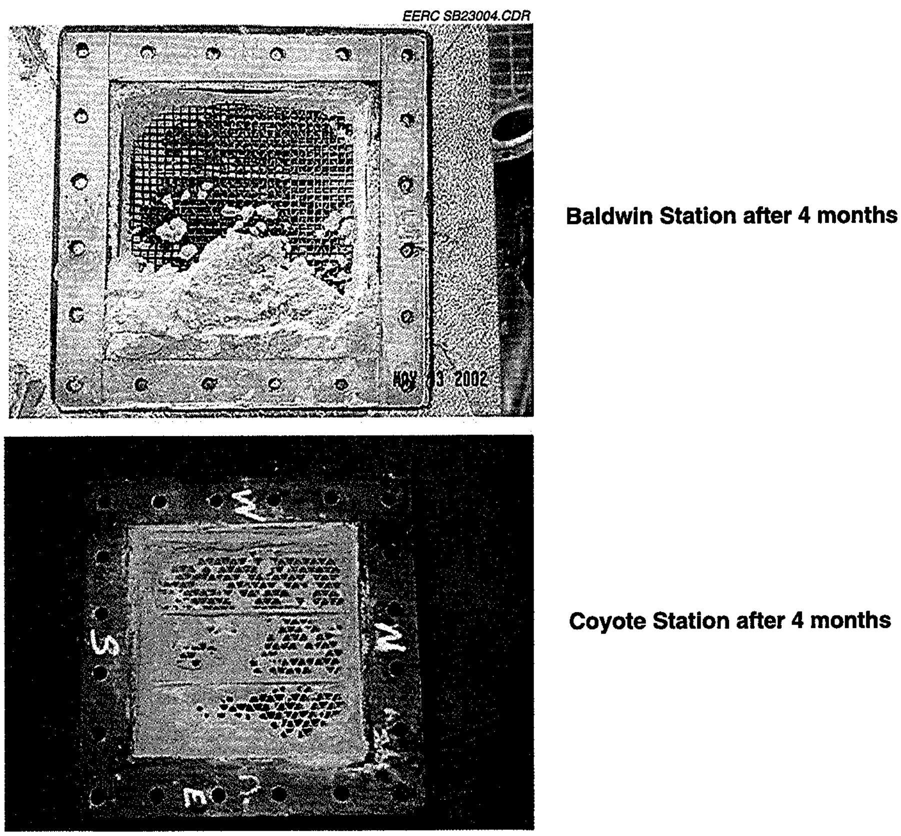

Fig. 14. Pictures of catalyst inlet after about 4 months of exposure to flue gas and particulate.

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

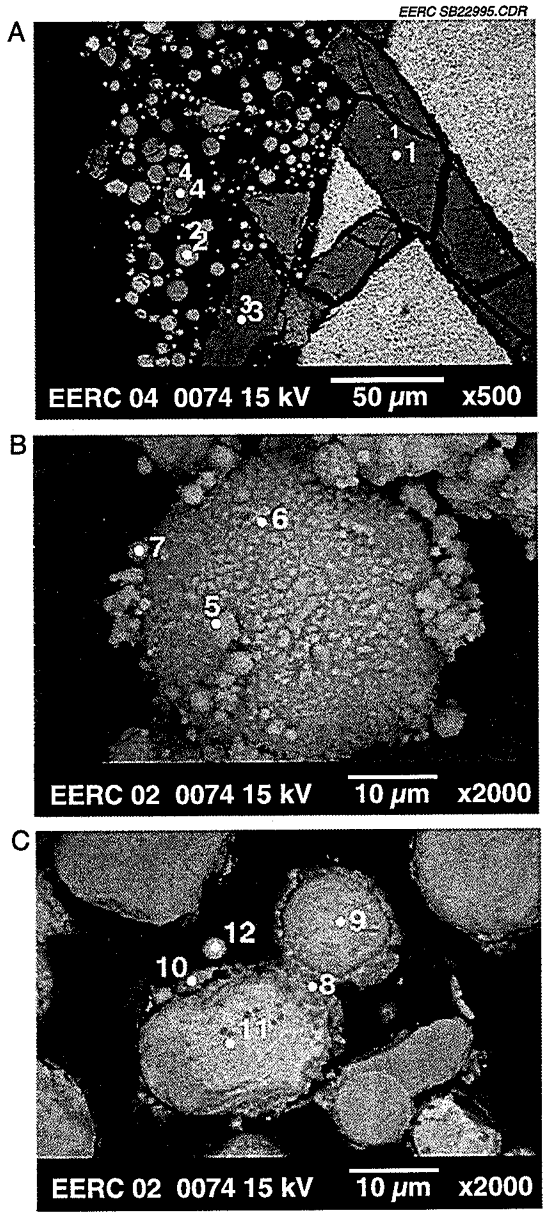

Fig. 15. SEM images of ash collected on catalyst surface at the Baldwin Station after 2 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) high-magnification image of coated ash particle, and (C) high-magnification image of polished cross section showing coatings 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

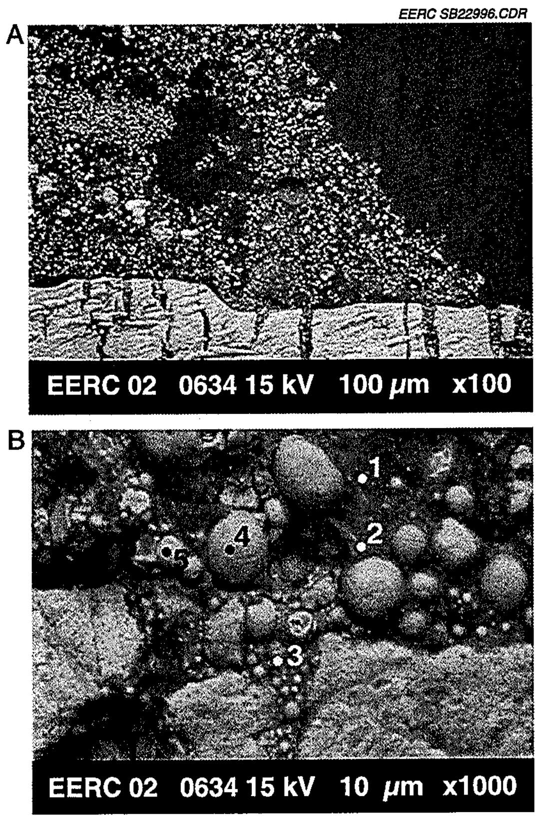

Fig. 16. SEM images of ash collected on catalyst surface at the Baldwin Station after 4 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, and (B) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

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

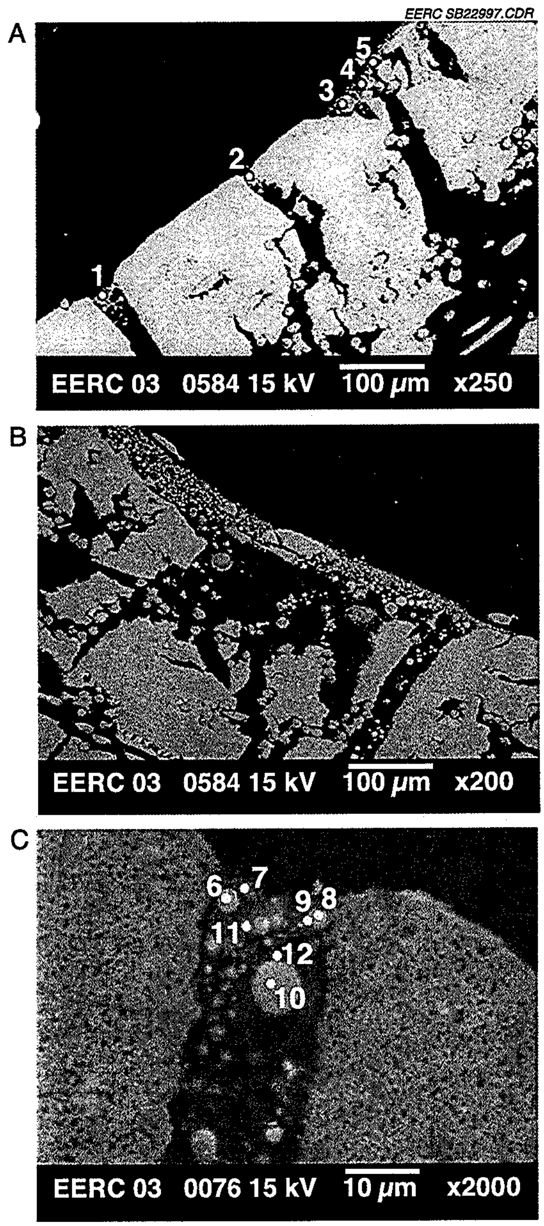

Fig. 17. SEM images of ash collected on catalyst surface at the Baldwin Station after 6 months of exposure. (A and B) Low-magnification images of ash deposit on catalyst surface and (C) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

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

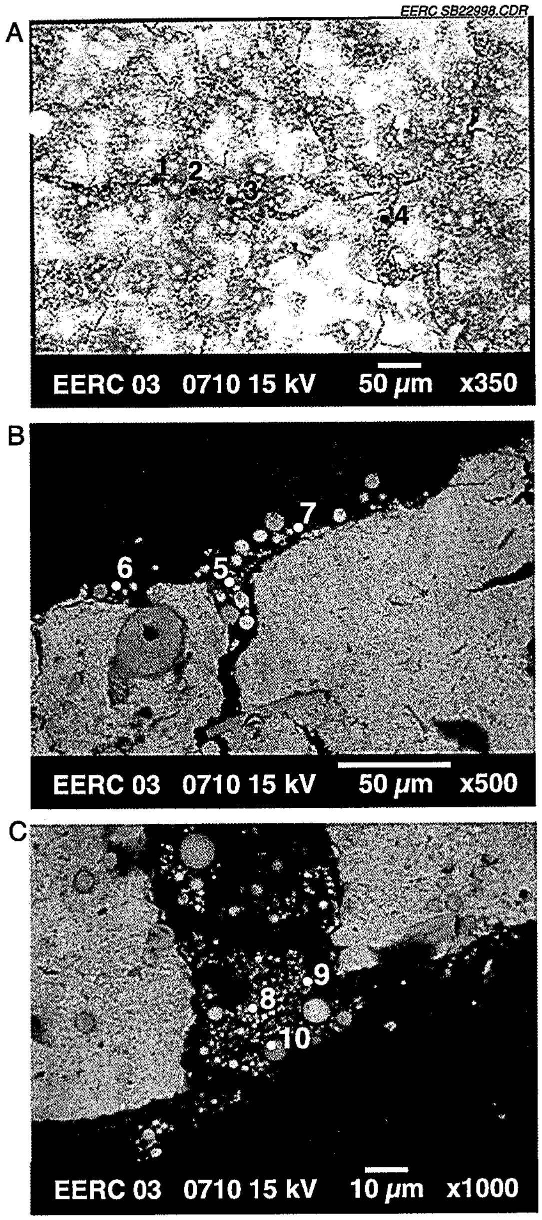

Fig. 18. SEM images of ash collected on catalyst surface at the Columbia Station after 2 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher 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

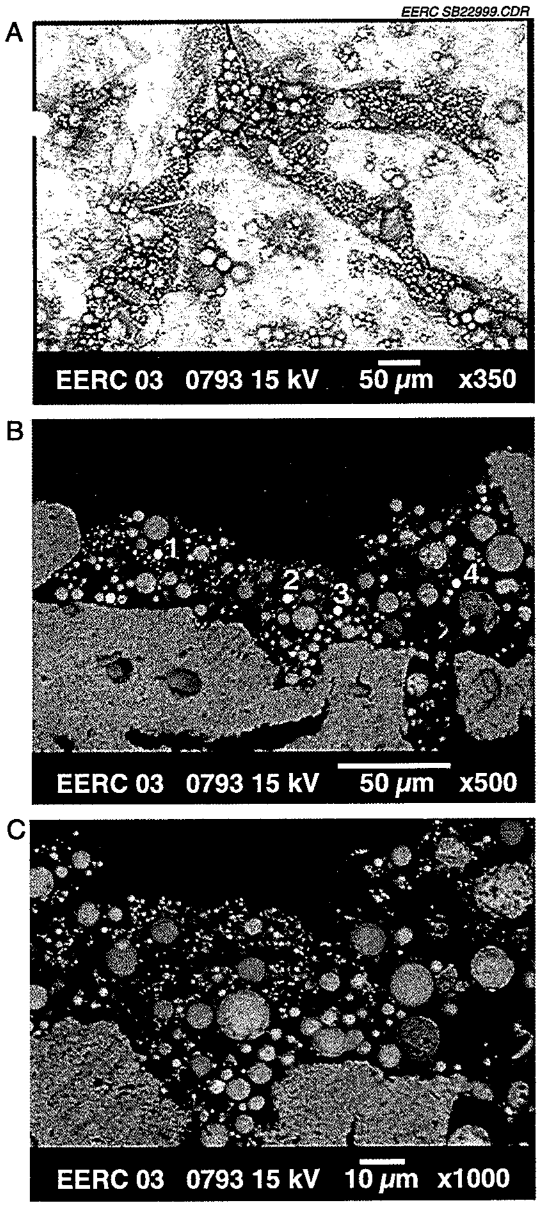

Fig. 19. SEM images of ash collected on catalyst surface at the Columbia Station after 4 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher 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

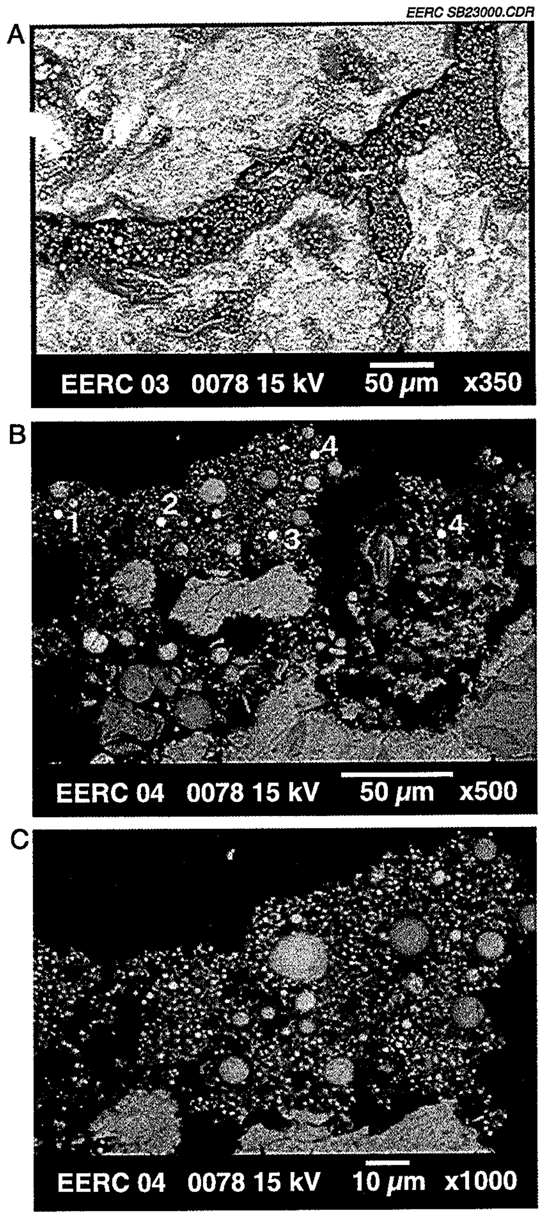

Fig. 20. SEM images of ash collected on catalyst surface at the Columbia Station after 6 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher 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].

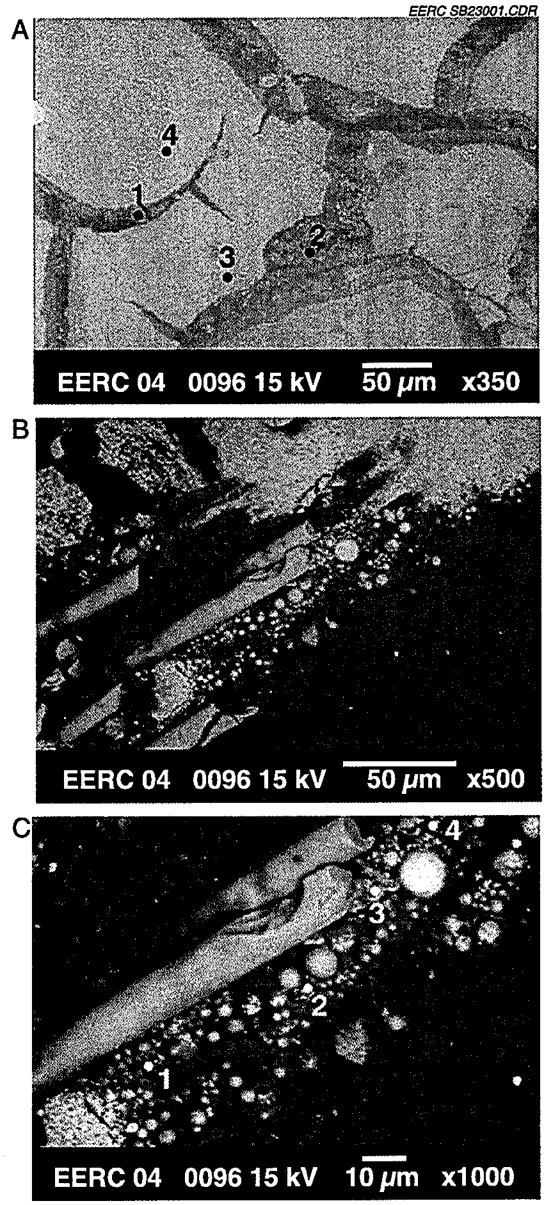

Fig. 21. SEM images of ash collected on catalyst surface at the Coyote Station after 2 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher 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.

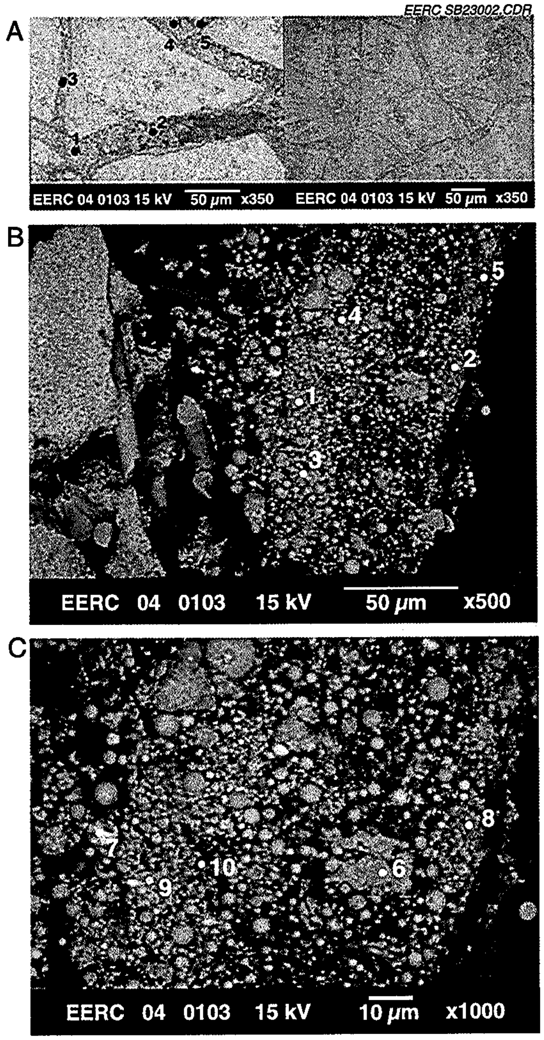

Fig. 22. SEM images of ash collected on catalyst surface at the Coyote Station after 4 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher 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

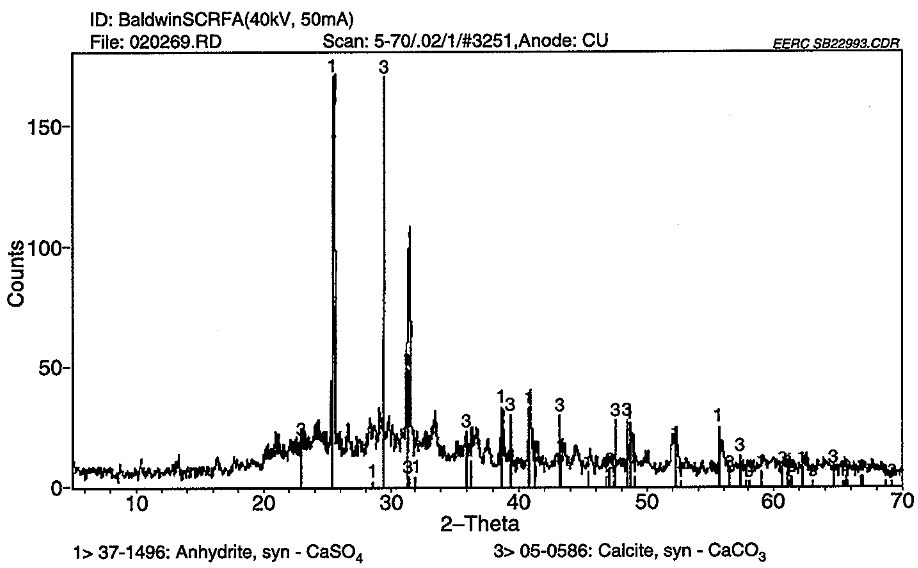

Fig. 23. X-ray diffraction of ash collected on SCR catalyst (1—$CaSO_4$, 2—$Ca_3Mg(SiO_4)_2$, and 3—$CaCO_3$).

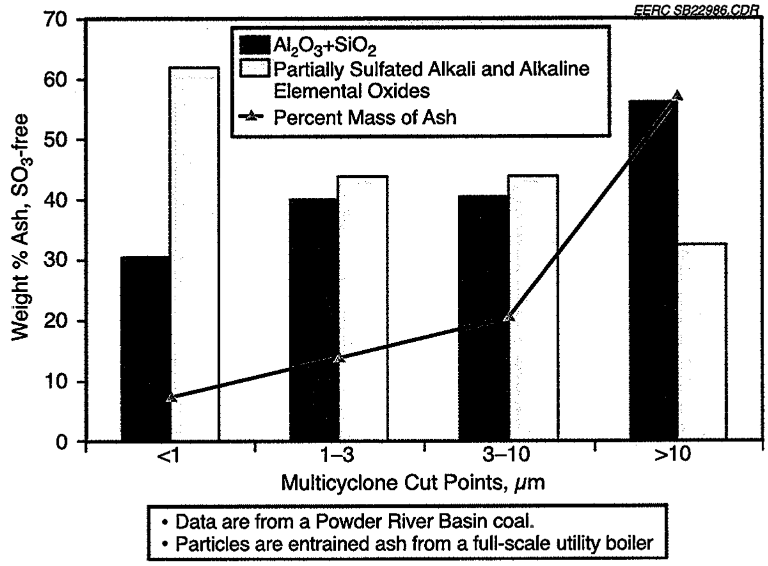

Fig. 24. Simplified illustration of ash partitioning in combustion systems [18].

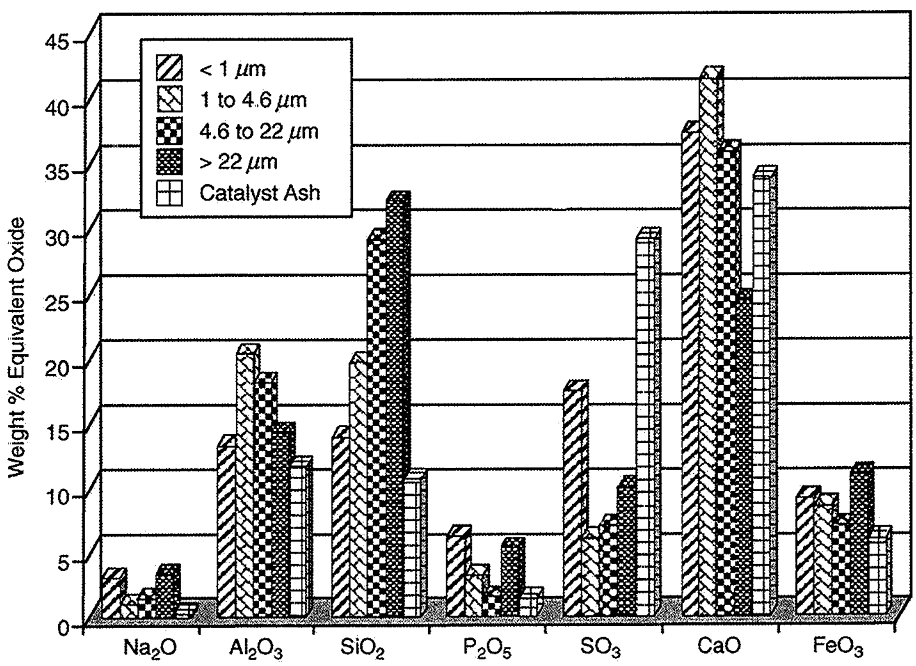

Fig. 25. Comparison of entrained ash and deposited ash on catalyst for Columbia Station.

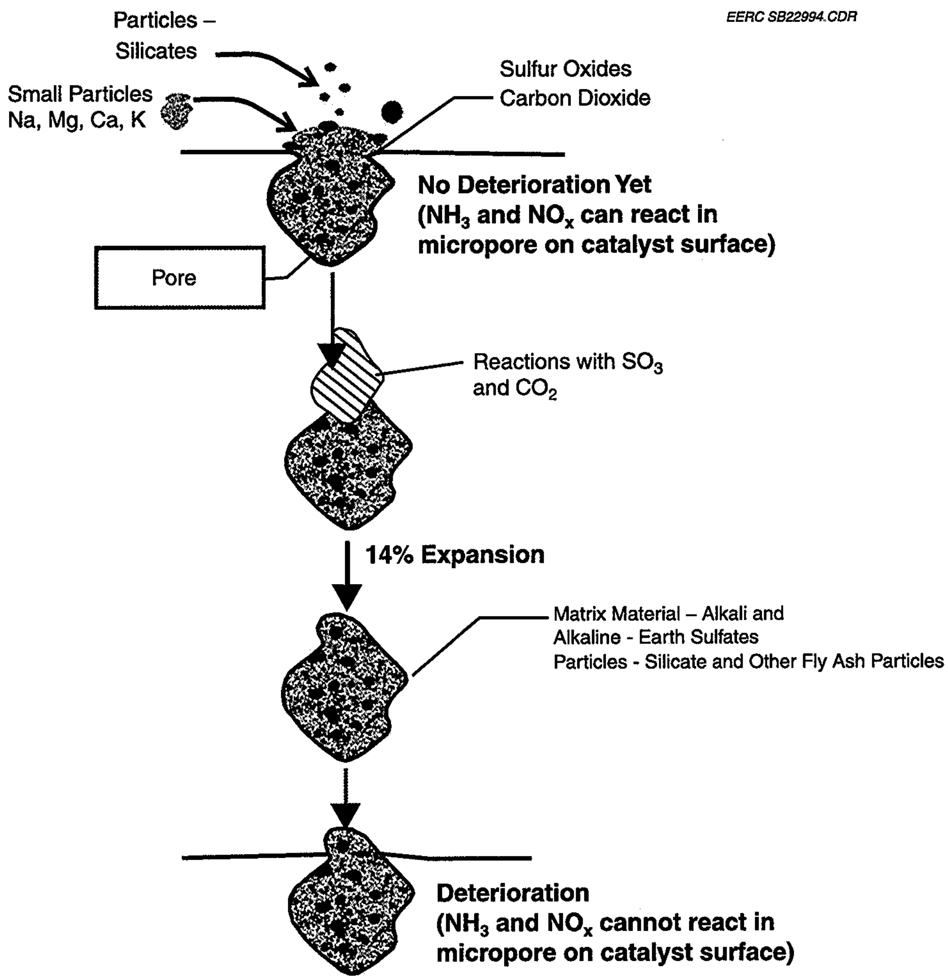

Fig. 26. Mechanism of SCR catalyst blinding via the formation of sulfates and carbonates (modified after Pritchard et al. [35]).

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,

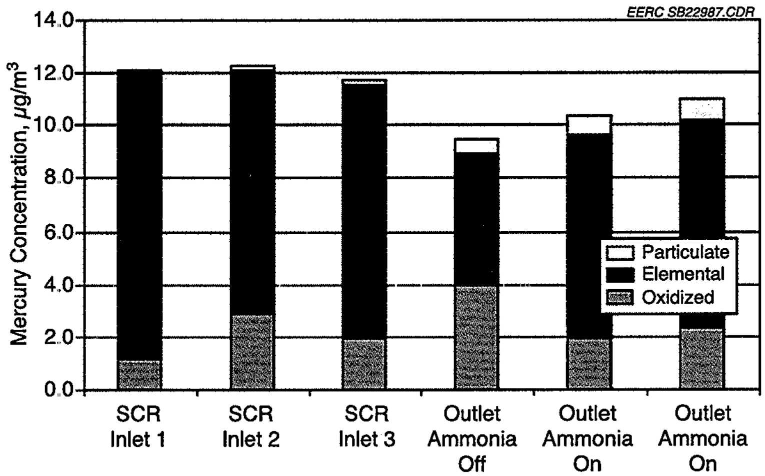

Fig. 27. Mercury speciation measurement at the inlet and outlet of the SCR catalyst upon installation of the catalyst.

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

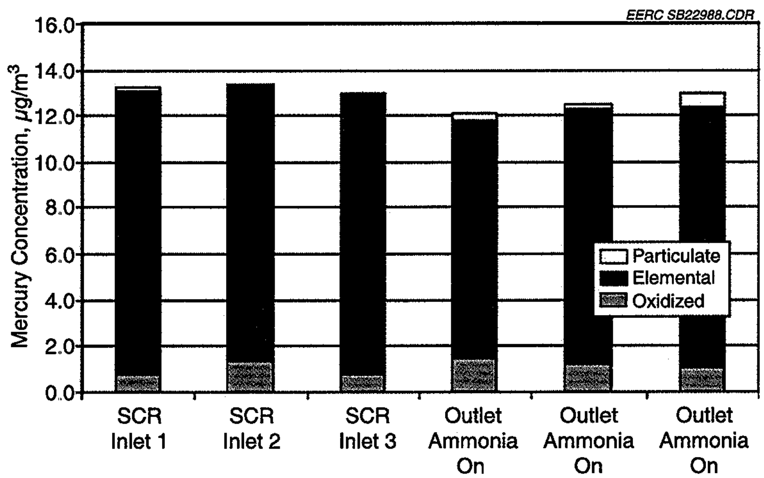

Fig. 28. Mercury speciation measurement at the inlet and outlet of the SCR catalyst after exposure to flue gases and particulate for 4 months.

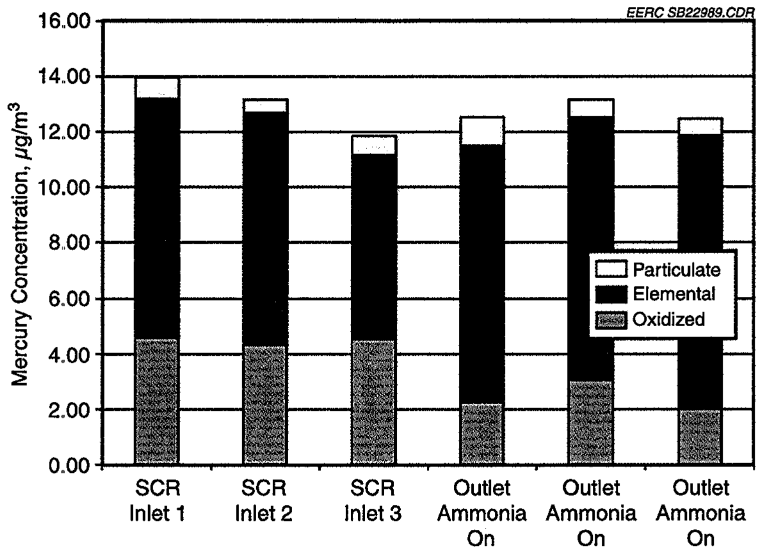

Fig. 29. Mercury speciation measurement at the inlet and outlet of the SCR catalyst after exposure to flue gases and particulate for 2 months.

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 H

EPRI SO_2 Control Support Documentation

EPRI

Status and Performance of Best Available Control Technologies

Technical Report

Status and Performance of Best Available Control Technologies

1008114

Interim Report, March 2005

EPRI Project Manager
C. Dene

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REPORT SUMMARY

This study is intended to provide a better understanding of the best available control technology (BACT) as required today in permits issued for new coal-fired power plants and to document the actual emissions performance of the emission control technologies on new units. The study focused on controls technologies, data reporting, initial test results, and permitting trends.

Background

EPRI has been working with its members to develop a plan that links near-term, tactically-focused work to the ultimate vision of "The Roadmap for the Electricity Sector." A key element of the plan is the development of Near Zero Emissions (NZE) plants that preserve the coal option. Qualitatively, NZE are defined as emissions virtually equivalent to those from gas-fired power plants except for CO_2.

This investigation is intended to provide a better understanding of best available control technology (BACT) proposed today for emission control as well as the performance of the most recently installed equipment on coal-fired power plants. Due to the time lag between permitting of a new coal-fired power plant and initial operation and emissions performance testing, it was necessary to consider units that have been permitted but not yet started up.

Objectives

- To compare the most recent permitted emissions levels to the actual emissions achieved by the newest plants in the generating fleet
- To provide direction for technology development for near zero emission plants by examining the control capabilities of the most recently installed technologies.

Approach

The project team examined the most recent permits that have been issued. It was necessary to examine permits issued as far back as 1997 in order to find plants that had sufficient operating data to examine with respect to initial operation. The focus of this report is on pulverized coal (PC) boilers and circulating fluidized bed (CFB) boilers in Rankine cycle plants. Integrated gasification combined cycle (IGCC) plants have very different needs because they use species capture devices before the addition of combustion air for both process reasons and because of emission constraints.

Results

Various technologies have been installed for SO_2 and NO_X; however, the fabric filter/baghouse is the overwhelming choice for particulate control. SO_2 control technologies were evenly divided between wet and dry technologies. For NO_X control the CFB units were dominated by selective noncatalytic reduction (SNCR), while the majority of PC units are equipped with low NO_x burners (LNBs) and selective catalytic reduction (SCR). Permitting trends for most emissions suggest an increasing tightening of control, and the initial operating experience shows that most of these units were able to achieve the permit limit. There is increasing interest in fine particulates, though little guidance on measurement methods.

EPRI Perspective

This report provides a distillation of available information on emissions control technologies for coal-fired generating stations. It provides a ready source of information on not only permit limits but also the ability to achieve these limits on start-up. Its summary of trends in permit limitation and rundown of recently installed technologies provide some insights into which technologies are appropriate for consideration when examining the development of NZE power stations.

Keywords

Emissions Control Technologies
SO_2 Control
NO_X Control
BACT

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INTRODUCTION

EPRI has been working with its members to develop a Plan that links the near-term, tactically-focused work to the ultimate vision of "The Roadmap for the Electricity Sector". A key element of the plan is the development of Near Zero Emissions (NZE) plants that preserve the coal option. Qualitatively, NZE is defined as being virtually equivalent to emissions from gas-fired power plants, with the exception of CO_2.

The focus is on pulverized coal (PC) boilers and circulating fluidized bed (CFB) boilers in Rankine cycle plants, as integrated gasification combined cycle (IGCC) plants have very different needs because they use species capture devices for both process reasons (before the addition of combustion air) and emission constraints. However, some of the findings and technologies for PC- and CFB-based plants could apply to the final pollution control systems in the stream of devices in IGCC plants. This investigation is intended to provide a better understanding of best available control technology (BACT) proposed today as well as the performance of the most recently installed equipment on coal-fired power plants. Due to the time lag between permitting of a new coal-fired power plant and initial operation and emissions performance testing, it is necessary to consider units which have been permitted but not yet started up.

2
RECENTLY PERMITTED U.S. COAL-FIRED ELECTRIC UTILITY UNITS

The list of units to include in the study was obtained from two sources:

- The RACT/BACT/LAER Clearinghouse (RBLC) database www.epa.gov/ttn/catc
- The National Coal-Fired Utility Projects Spreadsheet http://www.epa.gov/ttn/catc/dir1/natlcoal.xls

For purposes of this study, "recent" permits will be those issued during the calendar year 1997 or thereafter. Advanced queries were run on the RBLC database to find all facilities permitted in 1997 or after and having a Standard Industrial Classification (SIC) code of 4911 "Electric Services". Additionally, the RBLC listed "process" was examined to eliminate any units that were not coal-fired boilers. Added to this basic list were any additional units from the National Coal-Fired Utility Projects Spreadsheet. From this list, all citations for anything other than new coal-fired boilers were eliminated (e.g. modifications to existing boilers were eliminated). Lastly, all units which did not have an issued permit as of February 2005 were eliminated.

To determine the operational status of each unit, the state agency was contacted.

Included Units

Forty-four units at 31 facilities have been identified as meeting the requirements of this study (25 PC units, 19 CFB units). Twelve units are operational and eight of those have been stack tested. Table 2-1 lists the units included in this study. Table 2-2 summarizes each facility and Appendix A describes each facility in detail. Plants that were excluded from the study are listed in Appendix B.

Controls

PC and CFB boilers employ the types of emission control for the various pollutants that are effective for the boiler configuration and operating conditions. Emission controls can be integral to the combustion process or add-on equipment that is installed downstream of the combustion zone. The types of emission control employed for BACT at recently permitted utility boilers are described below. The specific control equipment utilized for each pollutant at each boiler unit identified in Table 2-1 is listed in Tables 2-3 through 2-6.

SO_2

The primary types of SO_2 control for the units in this study are circulating fluidized bed (CFB) combustion, wet flue gas desulfurization, and semi-dry flue gas desulfurization. Flue gas desulfurization (FGD) refers to the treatment of flue gas to remove the SO_2 which has formed during the combustion of fossil fuels. These controls are described in this section, including the prevalence of each type.

In the CFB combustion process, limestone is added to the boiler furnace, resulting in the removal of SO_2 during the combustion process. A grid supports a bed of coal and limestone in the firebox of the CFB boiler. Combustion air is forced upward through the grid, suspending the coal and limestone bed in a fluid-like motion. The sulfur in the coal is oxidized to SO_2 and consequently combines with calcined limestone to form calcium sulfate ($CaSO_4$). The flyash containing the calcium sulfate is collected in the downstream baghouse.

In the wet FGD process, a slurry of finely ground limestone ($CaCO_3$) in water is recirculated through an absorber tower and placed in turbulent contact with the flue gas. The contact between the flue gas and the slurry cools and saturates the gas stream as SO_2 and other acid gasses are absorbed into the slurry droplets. Calcium sulfate (gypsum) and calcium sulfite are formed in the chemical reaction that occurs in the slurry, which is typically dewatered and removed as a solid waste by-product.

Table 2-1
Recently Permitted Coal-Fired Power Plants Included in the Study

Facility	# of Units	Boiler Type	State	Operational Status			
				Permit Issued	Under Construction	Operational	Tested
AES Puerto Rico (Units 1 and 2)	2	CFB	PR	X	Finished	X	X
Corn Belt Energy	1	PC	IL	X	X		
Council Bluffs (Mid America)	1	PC	IA	X	X		
Elm Road Generating Station (WE-Energies) (2 Units)	2	PC	WI	X	X		
Energy Services of Manitowoc	1	CFB	WI	X	X		
EnviroPower IL – Benton (Unit 1 and 2)	2	CFB	IL	X	X		
Hawthorn 5 (KCP&L)	1	PC	MO	X	Finished	X	X
Holcomb Unit #2 (Sand Sage Power, LLC)	1	PC	KS	X			
Indeck-Elwood LLC (Units 1 and 2)	2	CFB	IL	X	X		
Intermountain Power Unit #3	1	PC	UT	X	X		
JEA Northside (1 and 2)	2	CFB	FL	X	Finished	X	X
Kentucky Mountain Power, LLC (EnviroPower), Units 1 and 2	2	CFB	KY	X	X		
Longview Power (GenPower)	1	PC	WV	X			
Plum Point Power Station	1	PC	AR	X	X		
Prairie State (2 units)	2	PC	IL	X			
Red Hills (Choctaw Generation Limited Partnership) Units 1 and 2	2	CFB	MS	X	Finished	X	RATA data only
Rocky Mountain Power (Hardin Generator Project)	1	PC	MT	X			
Roundup (Bull Mountain) (2 units)	2	PC	MT	X			
Santee Cooper/Cross Units 3 and 4	2	PC	SC	X	X		
Sevier Power (Nevco Energy)	1	CFB	UT	X	X		
Seward Reliant Units 1 and 2	2	CFB	PA	X	Finished	X	
Southern Illinois Coop (Marion Generating Station)	1	CFB	IL	X	Finished	X	X
Spurlock (E. KY Power Coop)	1	CFB	KY	X	X		
Thoroughbred (2 units)	2	PC	KY	X			
Toledo Edison Co. Bayshore Plant	1	CFB	OH	X	Finished	X	X
Tucson – Springerville Units 3 and 4	2	PC	AZ	X	X		
Two Elk	1	PC	WY	X			
Whelan Energy Center Unit 2- Hastings	1	PC	NE	X	X		
Wisconsin Public Service - Weston 4	1	PC	WI	X	X		
WYGEN I (Black Hills)	1	PC	WY	X	Finished	X	X
WYGEN II (Black Hills)	1	PC	WY	X			

Table 2-2
Summary of Facilities

Circulating Fluid Bed Plants	NO_x	PM_{10}	SO_2
AES Puerto Rico (2 units)	SNCR	ESP	DFGD, CFB
Energy Services of Manitowoc	SNCR	FF/BH	CFB
EnviroPower IL - Benton (2 units)	SNCR	FF/BH	DFGD, CFB
Indeck-Elwood LLC (2 units)	SNCR	FF/BH	DFGD, CFB
JEA Northside #1 & #2 (2 units)	SNCR	FF/BH	DFGD, CFB
Kentucky Mountain Power, LLC (EnviroPower) (2 units)	SNCR	FF/BH	DFGD, CFB
Red Hills (Choctaw Generation Limited Partnership) (2 units)	CFB	FF/BH	CFB
Sevier Power (Nevco Energy)	SNCR	FF/BH	DFGD, CFB
Seward Reliant (2 units)	SNCR	FF/BH	DFGD, CFB
Southern Illinois Coop (Marion Generating Station)	SNCR	FF/BH	CFB
Spurlock (E. KY Power Coop)	SNCR	FF/BH	DFGD, CFB
Toledo Edison Co. Bayshore Plant	CFB	FF/BH	CFB
Pulverized Coal Plants	**NO_x**	**PM_{10}**	**SO_2**
Corn Belt Energy	SCR, LNB	ESP	WFGD
Council Bluffs (Mid America)	SCR, LNB	FF/BH	DFGD
Elm Road Generating Station (WE-Energies) (2 units)	SCR, LNB	FF/BH	WFGD
Hawthorn 5 (KCP&L)	SCR	FF/BH	DFGD
Holcomb Unit #2 (Sand Sage Power, LLC)	SCR, LNB	FF/BH	DFGD
Intermountain Power Unit #3	SCR, LNB	FF/BH	WFGD
Longview Power (GenPower)	SCR, LNB	FF/BH	WFGD
Plum Point Power Station	SCR, LNB	FF/BH	DFGD
Prairie State (2 units)	SCR, LNB	ESP	WFGD
Rocky Mountain Power (Hardin Generator Project)	SCR	multiclone	WFGD
Roundup (Bull Mountain) (2 units)	SCR, LNB	FF/BH	DFGD
Santee Cooper/Cross #3 & #4 (2 units)	SCR, LNB	ESP	WFGD
Thoroughbred (2 units)	SCR, LNB	ESP, WESP	WFGD
Tucson - Springerville (2 units)	SCR, LNB	FF/BH	DFGD
Two Elk	SCR, LNB	FF/BH	DFGD
Whelan Energy Center Unit 2- Hastings	SCR	FF/BH	DFGD
Wisconsin Public Service - Weston 4	SCR, LNB	FF/BH	DFGD
WYGEN I (Black Hills)	LNB	FF/BH	DFGD
WYGEN II (Black Hills)	SCR, LNB	FF/BH	DFGD

Table 2-3
SO_2 Controls

CFB	Plant Name	Limit lb/MBtu	Test Method	Averaging Time	Notes
	Energy Services of Manitowoc	0.30 (non-BACT)	6, 6A or 6C	30 day rolling	
	Red Hills (Choctaw Generation Limited Partnership) (2 units)	0.25		30 day rolling	
	Southern Illinois Coop (Marion Generating Station)	0.6 (non-BACT)	Method 6 or 19	30 day rolling	
	Toledo Edison Co. - Bayshore Plant	0.6 (non-BACT)		30 day rolling	
CFB-DFGD	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	AES Puerto Rico (2 units)	0.042		30 day	
	EnviroPower IL - Benton (2 units)	0.25	6 or 19	30 day rolling	92% control, if emissions are 0.20 lb/MMBtu or greater. 90% control
	Indeck-Elwood LLC (2 units)	0.10 - 0.15	19	30 day rolling	Illinois coal, washed: 3.51 percent sulfur by weight and 9,965 Btu/lb HHV, uncontrolled SO_2 rate: 7.0 lb/MMBtu, washed coal uncontrolled SO_2 rate: 4.7 lb/MMBtu
	JEA Northside #1 & #2 (2 units)	0.15 (non-BACT)		30 day rolling	
	Kentucky Mountain Power, LLC	0.13	401 KAR 50:015	30 day rolling	
	(EnviroPower) (2 units)				
	Sevier Power (Nevco Energy)	0.022	6, 6A, 6B, 6C	30 day rolling	1.0 lb SO_2 /MMBtu
	Seward Reliant (2 units)	0.6 (non-BACT)		30 day rolling	
	Spurlock (E. KY Power Coop)	0.2		30 day rolling	

PC DFGD-	Plant Name	Limit lb/MBtu	Test Method	Averaging Time	Notes
	Council Bluffs (Mid America)	0.1	6C	30 day rolling	0.625 lb SO_2 /MMBtu
	Hawthorn 5 (KCP&L)	0.12		30 day rolling	1.60 lb SO_2 /MMBtu max at scrubber inlet, 92.5% control
	Holcomb Unit #2 (Sand Sage Power, LLC)	0.12	40 CFR 60.48a	30 day rolling	0.60% on an average annual basis
	Plum Point Power Station	0.16	Method 6C	30 day - NSPS, 3 hour rolling	
	Roundup (Bull Mountain) (2 units)	0.12		30 day average, 24 hour rolling	•1.00% sulfur in coal,9232 Btu/lb, uncontrolled: 2.17 S lb/MMBtu, 94.5% control while burning 1.0% sulfur coal. 90% for 30 day rolling
	Tucson - Springerville (2 units)	0.6 (non-BACT)		30 day rolling	
	Two Elk	0.132	6C	30 day rolling	70% minimum removal efficiency (30 day rolling)
	Whelan Energy Center Unit 2- Hastings	0.12	19	30 day rolling	
	Wisconsin Public Service - Weston 4	0.1	6, 6A or 6C	30 day rolling	1.23 lb S/MMBtu 30 day average
	WYGEN I (Black Hills)	0.17	6	30 day rolling average	
	WYGEN II (Black Hills)	0.10	6C	30 day rolling	70% minimum removal efficiency (30 day rolling)
PC - WFGD	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Corn Belt Energy	0.10 - 0.15	Method 6 or 19	30 day rolling average	3.25%, 6.2 lb S/MMBtu uncontrolled
	Elm Road Generating Station (WE-	0.15	Method 6, 6A or 6C	30 day rolling average	
	Energies) (2 units)				
	Intermountain Power Unit #3	0.09	Method 6, 6A, 6B, 6C	30 day rolling average	
	Longview Power (GenPower)	0.08	30 day rolling average		

	Prairie State (2 units)	0.182	30 day rolling	4% sulfur in raw coal	
	Rocky Mountain Power (Hardin Generator	0.14	30 day rolling average		
	Project)				
	Santee Cooper/Cross #3 & #4 (2 units)	0.6	Method 6 or 6C	30 day rolling average	70% removal efficiency (30-day rolling avg.)
	Thoroughbred (2 units)	0.167		30 day rolling average	

* Secondary averaging period

CFB - circulating fluidized bed boiler

DFGD - semi-dry flue gas desulfurization (either fluidized bed dry scrubber or spray dryer absorber)

PC - pulverized coal boiler

WFGD - wet flue gas desulfurization

Table 2-4
NO_x Controls

CFB	Plant Name	Limit lb/MBtu	Test Method	Averaging Time	Notes
	Red Hills (Choctaw Generation Limited Partnership) (2 units)	0.2 (non-BACT)		30 day rolling	
	Toledo Edison Co. - Bayshore Plant	0.2 (non-BACT)		30 day rolling	
SNCR	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	AES Puerto Rico (2 units)	0.19		30 day	Calculated lb/MMBtu = 2058 tpy x 2000 lb/ton x yr/8760 hr x hr/2461.35 MMBtu
	Energy Services of Manitowoc	0.155 (non-BACT)	7	30 day rolling	In the first month of operation, the average monthly NOx emissions may not exceed the limit of 0.155 pound per million Btu the limit of 0.155 pound per million Btu heat input. After the second month, the average NOx emissions shall be determined to be the total NOx emissions for the last two mo
	EnviroPower IL - Benton (2 units)	0.125 - 0.07	7, 7E or 19	30 day rolling	Evaluation to 0.07 lb/MMBtu
	Indeck-Elwood LLC (2 units)	0.10 (optimization study to 0.08)	19	30 day rolling	
	JEA Northside #1 & #2 (2 units)	0.09	30 day rolling		
	Kentucky Mountain Power, LLC (EnviroPower) (2 units)	0.07	401 KAR 50:015	30 day rolling	The NOX emission limit of 0.07 lbs/MMBTU is waived for the specific SNCR optimization study activity
	Sevier Power (Nevco Energy)	0.1	7, 7A, 7B, 7C, 7D, 7E	30 day rolling	NOx limit listed as 24 hr rolling average, but calculates out to the same limit as a 30 day average (Calculated lb/MMBtu =1066.6 tpy x 2000 lb/ton x yr/8760 hr x hr/2532 MMBtu)
	Seward Reliant (2 units)	0.15		30 day rolling	
	Southern Illinois Coop (Marion Generating Station)	0.2 (non-BACT)	7, 7E or 19	30 day rolling	
	Spurlock (E. KY Power Coop)	0.07		30 day rolling	SNCR optimization study

PC - LNB	Plant Name	Limit lb/MBtu	Test Method	Averaging Time	Notes
	WYGEN I (Black Hills)	0.17 (non-Bact)	40 CFR 60.48a	30 day rolling average	Calculated from limit of 1.6 lb/MWhr (168 lb/hr / 1,014 MMBtu/hr)
PC - SCR	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Hawthorn 5 (KCP&L)	0.08		30 day rolling	evaluation period: NOx limited to 0.12 lbs/MMBtu on a 30-day rolling
	Rocky Mountain Power (Hardin Generator Project)	0.09		30 day rolling	
	Whelan Energy Center Unit 2- Hastings	0.08		30 day rolling	During the first 18 months following initial startup (demonstration period), the Unit 2 Boiler shall not emit NOx exceeding 0.12 lb/MMBtu on a 30-day rolling average instead of 0.08 lb/MMBtu as listed in Table 4
PC –SCR, LNB	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Corn Belt Energy	0.10	7, 7E, or 19	30 day rolling	2 year demonstration period; determine if lower NOx limit (as low as 0.07) may be reliably achieved, 0.12 demonstration / 0.10 or lower at conclusion of demonstration period
	Council Bluffs (Mid America)	0.07	7E	30 day rolling	
	Elm Road Generating Station (WE-Energies) (2 units)	0.07	7	30 day rolling	
	Holcomb Unit #2 (Sand Sage Power, LLC)	0.08	40 CFR 60.48a	30 day rolling	During the first 18 months following initial startup, the unit shall not emit or cause to be emitted any NOx emissions exceeding average, excluding periods of startup, shutdown, and malfunction, in lieu of the 0.08 lb/MMB
	Intermountain Power Unit #3	0.07	7, 7A, 7B, 7C, 7D, 7E	30 day rolling	
	Longview Power (GenPower)	0.08		30 day rolling	NOx limit listed as 24 hr rolling, assumed the same for 30 day rolling
	Plum Point Power Station	0.09	7E	30 day - NSPS, 24 hour rolling	
	Prairie State (2 units)	0.07		30 day rolling	
	Roundup (Bull Mountain) (2 units)	0.07		30 day average, 24 hour rolling	

	Santee Cooper/Cross #3 & #4 (2 units)	0.185	7 or 7E	30 day rolling	
	Thoroughbred (2 units)	0.08		30 day rolling	
	Tucson - Springerville (2 units)	0.15 (non- BACT)	7E	30 day rolling	Calc from NSPS value - Calculated lb/MMBtu = 1.6 lb/MW-hr * 400 MW =640 lb/hr / 4,200 MMBtu/hr = 0.15 lb/MMBtu
	Two Elk	0.09		30 day rolling	
	Wisconsin Public Service - Weston 4	0.07	Method 7, 7E	30 day rolling	
	WYGEN II (Black Hills)	0.07	40 CFR 60.48a	30 day rolling	

* Secondary averaging period

CFB - circulating fluidized bed boiler

LNB - low NOx burner

OFA - over-fire air

PC - pulverized coal boiler

SCR - selective catalytic reduction

SNCR - selective non-catalytic reduction

Table 2-5
PM_{10} Controls

CFB - ESP	Plant Name	Limit lb/MBtu	Test Method	Averaging Time	Notes
	AES Puerto Rico (2 units)	0.03 (f/c)	201, 201A, 202		
CFB FF/BH	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Energy Services of Manitowoc	0.03 (f/c) (non-BACT)	5, 202		
	EnviroPower IL - Benton (2 units)	0.015 (f)	5, or 201, or 201A or 19		
	Indeck-Elwood LLC (2 units)	0.015 (f/c)	5, 201 or 201A, 202	3 hour block	
	JEA Northside #1 & #2 (2 units)	0.011 (f)	201 or 201A	3 hour	
	Kentucky Mountain Power, LLC (EnviroPower) (2 units)	0.015	401 KAR 50:015	3 hour	
	Red Hills (Choctaw Generation Limited Partnership) (2 units)	0.015 (f)	5		
	Sevier Power (Nevco Energy)	0.0154 (f/c)	201, 201A, 202	24 hour rolling	
	Seward Reliant (2 units)	0.01			
	Southern Illinois Coop (Marion Generating Station)	0.011 (f) (non-BACT)	5,or 201, or 201A, or 19		
	Spurlock (E. KY Power Coop)	0.015 (f)	5	3 hour rolling	
	Toledo Edison Co. - Bayshore Plant	0.025 (non-BACT)			

PC - ESP	Plant Name	Limit lb/MBtu	Test Method	Averaging Time	Notes
	Corn Belt Energy	0.02 (f)	5, or 201, or 201A, with 19; 202	3 hour block	
	Prairie State (2 units)	0.035	202 (adapted to prevent bias)	3 hr block	
	Santee Cooper/Cross #3 & #4 (2 units)	0.018 (f/c)	201, 202		
PC – ESP, WESP	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Thoroughbred (2 units)	0.018 (f/c)	5, 9, 201 or 201A, 202	3 hour rolling	
PC – FF/BH	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Council Bluffs (Mid America)	0.025 (f/c)	201A, 202	3 hour rolling	
	Elm Road Generating Station (WE-Energies) (2 units)	0.018 (f/c)	5, 202	3 hour rolling	
	Hawthorn 5 (KCP&L)	0.018 (f/c)	201A, 202		
	Holcomb Unit #2 (Sand Sage Power, LLC)	0.018 (f/c)	40 CFR 60.48a		
	Intermountain Power Unit #3	0.012 (f)	201, 201A, 202	3 hour rolling	
	Longview Power (GenPower)	0.018 (f/c)	201 or 201A , 202	6 hour rolling	
	Plum Point Power Station	0.018 (f/c)	201A, 202		
	Roundup (Bull Mountain) (2 units)	0.015	optimization to 0.012		
	Tucson - Springerville (2 units)	0.055 (f/c)	5, 9, 201 or 201A, and 202	3 hour rolling	
	Two Elk	0.018 (f)			
	Whelan Energy Center Unit 2- Hastings	0.018		3 hour	
	Wisconsin Public Service - Weston 4	0.018 (f/c)	5 or 5B plus 202 or (201A and 202) or CTM039	3 hour rolling	
	WYGEN I (Black Hills)	0.02 (f)	Method 5		

	WYGEN II (Black Hills)	0.012 (f)	40 CFR 60.48a		
Multiclone	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Rocky Mountain Power (Hardin Generator Project)	0.015			

BH - Bag house

CFB - Circulating fluidized bed boiler

ESP - Electrostatic precipitator

(f) - Filterable

(f/c) - Filterable and Condensable

FF - Fabric Filter

PC - Pulverized coal boiler

WESP - Wet electrostatic precipitator

Table 2-6
VOC and CO Controls

All units are controlled by good combustion practices

CO	Plant Name	Limit lb/MBtu	Test Method	Averaging Time	Notes
CFB	EnviroPower IL - Benton (2 units)	0.27	10	30 day rolling	
	Kentucky Mountain Power, LLC (EnviroPower) (2 units)	0.27		30 day rolling	
	Red Hills (Choctaw Generation Limited Partnership) (2 units)	0.2			
	Sevier Power (Nevco Energy)	0.115	10	1 hour	
	Seward Reliant (2 units)	0.15			
	Southern Illinois Coop (Marion Generating Station)	0.15	10	3 hour rolling	
	Spurlock (E. KY Power Coop)	0.15		30 day rolling	
	Toledo Edison Co. - Bayshore Plant	0.13			
	JEA Northside #1 & #2 (2 units)	0.127		24 hour rolling	350 lb/hr / 2,764 MMBtu/hr = 0.127 lb/MMBtu
	Energy Services of Manitowoc	0.15	10	24 hour rolling	BACT
	Indeck-Elwood LLC (2 units)	0.11	10	24 hour rolling	Emission testing shall be conducted for purposes of certification of the continuous emission monitors required by Condition1.9. Thereafter, the NOx, SO2 and CO emission data from certified monitors may be provided in lieu of conducting emissions tests.
	AES Puerto Rico (2 units)	0.1	10	8 hour basis	Emissions of CO shall not exceed 0.10 lb/MMBTU on an eight-hour average basis, 94 ppmdv corrected to 7% oxygen, or 246.1 lb/hour, whichever is more stringent.
CO	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
PC	Prairie State (2 units)	0.12		24 hr block	
	Corn Belt Energy	0.2	10	30 day rolling	
	Council Bluffs (Mid America)	0.154	10	24 hour rolling	

	Hawthorn 5 (KCP&L)	0.16	10		
	Holcomb Unit #2 (Sand Sage Power, LLC)	0.15			
	Intermountain Power Unit #3	0.15	10	30 day rolling	
	Longview Power (GenPower)	0.11	10B	3 hour rolling	
	Plum Point Power Station	0.16	10		
	Rocky Mountain Power (Hardin Generator Project)	0.15			
	Santee Cooper/Cross #3 & #4 (2 units)	0.16	10		
	Thoroughbred (2 units)	0.1		30 day rolling	
	Tucson - Springerville (2 units)	0.15		30 day rolling	
	Two Elk	0.135	10		
	Whelan Energy Center Unit 2- Hastings	0.15	10	3 hour rolling	
	WYGEN I (Black Hills)	0.15	10		
	WYGEN II (Black Hills)	0.15	10		
	Roundup (Bull Mountain) (2 units)	0.15			Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the CO emissions from the two main boilers does not exceed 4,910.4 tons during any rolling 12-month
	Elm Road Generating Station (WE-Energies) (2 units)	0.12	10	24 hour rolling	
	Wisconsin Public Service - Weston 4	0.15	10, 10B	1 day	
VOC CFB	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Energy Services of Manitowoc	0.013	25A and/or 18		
	Kentucky Mountain Power, LLC (EnviroPower) (2 units)	0.0072			
	Red Hills (Choctaw Generation Limited Partnership) (2 Units)	0.0058			
	Seward Reliant (2 units)	0.005			
	Spurlock (E. KY Power Coop)	0.0036	25A	30 day rolling	

	JEA Northside #1 & #2 (2 units)	0.005	18, 25, or 25A	3 hour rolling	14 lb/hr / 2,764 MMBtu/hr = 0.005 lb/MMBtu
	AES Puerto Rico (2 units)	0.0047	25A and 18		Emissions of VOCs shall not exceed based on the average of three 1-hour stack performance tests 7.70 ppmdv corrected to 7% oxygen, 0.0047 lb/MMBTU, or 11.6 lb/hour, whichever is more stringent.
	Southern Illinois Coop (Marion Generating Station)	0.01 (non-BACT)	18, 25, or 25A		Permittee may exclude methane, ethane and other exempt compounds from the results of any VOM test provided that the test protocol to quantify and correct for any such compounds is included in the test plan approved by the Illinois EPA.
	EnviroPower IL - Benton (2 units)	0.007	Method 18, 25, or 25A		Permittee may exclude methane, ethane and other exempt compounds from the results of any VOM test provided that the test protocol to quantify and correct for any such compounds is included in the test plan approved by the Illinois EPA.
	Indeck-Elwood LLC (2 units)	0.004	18 or 25A	3 hour rolling	Permittee may exclude methane, ethane and other exempt compounds from the results of any VOM test provided that the test protocol to quantify and correct for any such compounds is included in the test plan approved by the Illinois EPA.

VOC PC	Plant Name	Limit lb/MBtu	Test Method	Averaging Time	Notes
	Prairie State (2 units)	0.004	3 hr block		
	Corn Belt Energy	0.0065	Method 18 or 25A		
	Council Bluffs (Mid America)	0.0036	Method 25A		
	Elm Road Generating Station (WE-Energies) (2 units)	0.0035	25A and/or 18	24 hour rolling	
	Hawthorn 5 (KCP&L)	0.0036	25		
	Holcomb Unit #2 (Sand Sage Power, LLC)	0.0035			
	Intermountain Power Unit #3	0.0027	25 or 25A		
	Longview Power (GenPower)	0.004	18	3 hour rolling	
	Plum Point Power Station	0.02	25A and/or 18		
	Rocky Mountain Power (Hardin Generator Project)	0.0034			
	Santee Cooper/Cross #3 & #4 (2 units)	0.0024	18, 25 or 25A		

	Thoroughbred (2 units)	0.0072	18 or 25	30 day rolling	
	Two Elk	0.0135	18 and 25		
	Whelan Energy Center Unit 2- Hastings	0.004	25		
	Wisconsin Public Service - Weston 4	0.0036	25A and/or 18	1 day	
	WYGEN I (Black Hills)	0.015	18		
	WYGEN II (Black Hills)	0.01	18 and 25		
	Tucson - Springerville (2 units)	0.06 lb/ton	18 or 25	3 hour rolling	coal
	Roundup (Bull Mountain) (2 units)	0.003			Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the VOC emissions from the two main boilers does not exceed 98.2 tons during any rolling 12-month t

CFB - circulating fluidized boiler

PC - pulverized coal boiler

In the semi-dry FGD process, boiler flue gas is taken from a point downstream of the air heater and introduced into a reactor vessel into which hydrated lime (calcium hydroxide, $Ca(OH)_2$) and water are added. The calcium hydroxide reacts with SO_2 that has been absorbed into the water to form calcium sulfite and calcium sulfate. The heat from the flue gas causes the water to evaporate, cooling the gas and drying the reaction products. The amount of water added to the process is carefully controlled so that the flue gas temperature is maintained safely above the saturation, or dew point, temperature. The reaction product leaves the reactor as fine particles entrained in the flue gas and is collected in the particulate control equipment (usually a baghouse) located downstream of the FGD equipment.

There are two main variants of the semi-dry FGD process: lime spray drying and fluidized bed (or circulating) dry scrubbing. They are differentiated by the type of reactor vessel used and the method in which water and lime are introduced into the reactor. In the lime spray drying process, quicklime (CaO) is slaked with water to form a slurry of calcium hydroxide. The lime slurry is mixed with additional water and sprayed into the reactor as finely atomized droplets. The turbulent mixing of the flue gas and the droplets of slurry promote rapid absorption of SO_2 into the water of the slurry droplets. The flue gas is cooled and humidified as the water evaporates from the droplets, leaving a dry powdered reaction product entrained in the flue gas along with any fly ash that entered the reactor. The entrained particles are collected in an electrostatic precipitator (ESP) or baghouse downstream. To enhance the lime utilization, a portion of the collected product is typically recycled back to the process. It is slurried with water and sprayed into the reactor along with the fresh lime slurry.

In the fluidized bed (or circulating) dry scrubbing process, the flue gas is introduced into the bottom of a reactor vessel at high velocity. The movement of the gas through the reactor suspends particles of fly ash and reaction products from the process that are introduced into the reactor, creating a fluidized bed. Dry, powdered, hydrated lime and/or ash product from the downstream particulate collection device is introduced into the bed within the reactor vessel. Water is sprayed into the reactor near the bottom of the bed under high pressure or mixed with the reagent/ash product before it is added to the reaction vessel. In the moist layer at the surface of the lime particles, calcium hydroxide reacts with the absorbed SO_2 to form calcium sulfite and calcium sulfate. The evaporation of water cools and humidifies the flue gas and maintains the bed in a slightly moist, powdery condition. The continuous motion of the bed prevents solids deposition, and promotes regeneration of the particle surfaces, exposing the lime to additional reaction with SO_2. Particles that are entrained in the flue gas leaving the top of the reactor are collected in an ESP or baghouse downstream. A large portion of the collected particles is recycled to the reactor, sustaining the bed and improving lime utilization.

Five of the 19 recently permitted CFB units identified in this study did not add additional SO_2 controls. The remaining fourteen units employed some variant of semi-dry FGD technology in combination with the SO_2 removal capability of the limestone injection to the CFB boiler.

Thirteen of the 25 recently permitted PC units used semi-dry FGD as their SO_2 control. Wet FGD was used at twelve PC units.

NO_x

The primary types of NO_x control for the units in this study are CFB combustion, selective non-catalytic reduction (SNCR), over-fire air (OFA), low NO_x burners (LNB), and selective catalytic reduction (SCR). These controls are described in this section, including the prevalence of each type.

The CFB combustion process has an inherently low level of NO_x emissions due to the combustion temperature. Combustion in a CFB boiler occurs at relatively low combustion temperatures ranging from 1,500 to 1,800 °F. Because thermal NO_x formation occurs at temperatures greater than 2,000 °F, the lower combustion zone temperatures in a CFB boiler significantly reduces NO_x production.

SNCR is an add-on control technology commonly applied to CFB boilers that utilizes ammonia or urea injection into the flue gas near the furnace exit or in the convective passes. Due to the high temperatures in these zones a catalyst is not needed for NO_x to react with ammonia to form nitrogen gas and water.

Overfire air technology reduces NO_x emissions within the normal combustion zone of the furnace without any chemical additives or alternate fuel. An OFA system reduces the formation of NO_x by inhibiting the immediate availability of oxygen to the fuel. OFA also reduces thermal NO_x by spreading the combustion over a larger volume in the boiler and lowering the combustion temperature in the lower part of the furnace.

An SCR system uses ammonia injected into the flue gas upstream of a catalyst placed downstream of the economizer exit to reduce NO_x to molecular nitrogen and water. The process is termed "selective" because the ammonia preferentially reacts with the NO_x rather than with the oxygen in the flue gas. A catalyst is used to achieve NO_x reduction by chemical reaction with ammonia to form elemental nitrogen and water at appropriate flue gas temperatures. Ammonia for use in an SCR system can come in one of two forms, anhydrous ammonia or aqueous ammonia. Another option is to use a dry urea storage system that generates ammonia on site as needed.

Three of the recently permitted CFB units did not use add on controls for NO_x, while 16 units used SNCR controls.

The controls for PC units were divided up into two groups: SCR, and LNB/ SCR. Three units used SCR, and 24 units used LNB and SCR controls.

PM_{10}

The principal types of PM_{10} control for the units in this study are electrostatic precipitator (ESP), fabric filter/baghouse (FF/BH), and multi clones. These controls are described in this section, including the prevalence of each type.

An electrostatic precipitator (ESP) removes solid or liquid particulate matter from a gas stream by imparting an electrical charge on the individual particle and collecting the charged particle to an oppositely charged surface. Most ESPs used in coal-fired boiler applications are dry, but some high-sulfur coal-fired units are now being permitted with a wet ESP (WESP) located in the saturated flue gas environment down stream of the wet FGD system. The purpose of the WESP is to collect sulfuric acid mist, which is a major component of the condensable fraction of the total particulate emissions. WESPs are not used as the primary particulate control device and either an ESP of a baghouse would be provided upstream of the wet FGD system to remove a majority of the fly ash.

Baghouses collect particulate matter on the surfaces of filter bags. Most of the particles are captured by impaction and sieving on already collected particles, which are present as a dust layer on the bags (dust cake). There are two major types of baghouses: reverse-air and pulse jet. In reverse air baghouse setups, the particulate-laden gas stream enters from the bottom and passes into the inside of the bag. Filtered gas passes through the dust cake on the inside of the bag and is exhausted. In order to clean this type of baghouse, some of the filtered gas is passed in a reverse direction (outside to inside the bag) to remove some of the dust cake. In pulse jet baghouses, the flue gas is passed through the outside of the bags thereby producing the dust cake on the exterior of the bags. These bags are cleaned by injecting a short pulse of compressed air, which removes some of the dust cake.

The multiclone is a mechanical collector sometimes used as a precollector upstream of an ESP, FF, or wet scrubber. These devices can be specified to reduce particle loadings and consequently reduce capital and/or operating costs for downstream equipment.

The primary particulate control technology identified in permits for the 19 recently permitted CFB boilers is a fabric filter (baghouse). Seventeen units used this control. Two CFB units were permitted for an ESP for particulate control.

Fabric filters were also the primary particulate control technology among recently permitted PC boilers, with 17 of the 25 units using this control method. Seven PC units used ESP as the primary particulate controls. ESPs are generally used for high-sulfur coal applications. A multi clone was identified in the permit as the particulate control technology to be used for one unit. Six PC units have been permitted with a WESP for control of the sulfuric acid aerosol downstream of a wet FGD system. Four of these units will use dry ESPs as the primary control upstream of the wet FGD. Two will use a fabric filter.

CO and VOC

VOC and CO emissions at all CFB and PC units are controlled by good combustion practices.

3
EMISSION LIMITS ACHIEVED IN PRACTICE

In order to determine the emissions levels that have been achieved in practice, data was gathered from the Acid Rain data submitted to the EPA.

The data gathered was not sufficient to determine if the pollution control equipment is being operated at its maximum performance level or at a lower level to provide a margin of safety. There are numerous factors that go into such an operating methodology, including the cost (energy, reagents, and maintenance) as well as allowances and compliance averaging periods. Although it seems logical that a "more powerful design" would achieve additional removal at the sacrifice of cost and operational reliability, no concrete data was found to support such a conclusion.

Electronic Data Reporting

The Clean Air Markets division of EPA maintains data from power plants as it is collected from the quarterly electronic data reports (EDRs) submitted by each facility. This database was queried to find the monthly emissions for the units included in this study (http://cfpub.epa.gov/gdm/). Data was pulled for reporting years 2001 through 2003 and is presented in Figures 3-1 through 3-8. The lb/MBtu values for NO_x were provided directly in the retrieved data. The lb/MBtu values for SO_2 were calculated from the retrieved tons SO_2/month and MBtu/month values.

NO_x and SO_2 emission limits that were not given as a 30-day average were converted to a 30-day average using the tpy limits and heat input of the unit. Where a conversion was made, it was noted in the general notes on Tables 2-3 through 2-6 for that facility and pollutant. No Acid Rain data was available for AES Puerto Rico.

Please note that the Acid Rain data is from monthly blocks of data not 30-day rolling averages. This may explain some of the instances where the Acid Rain data shows values higher than the limits.

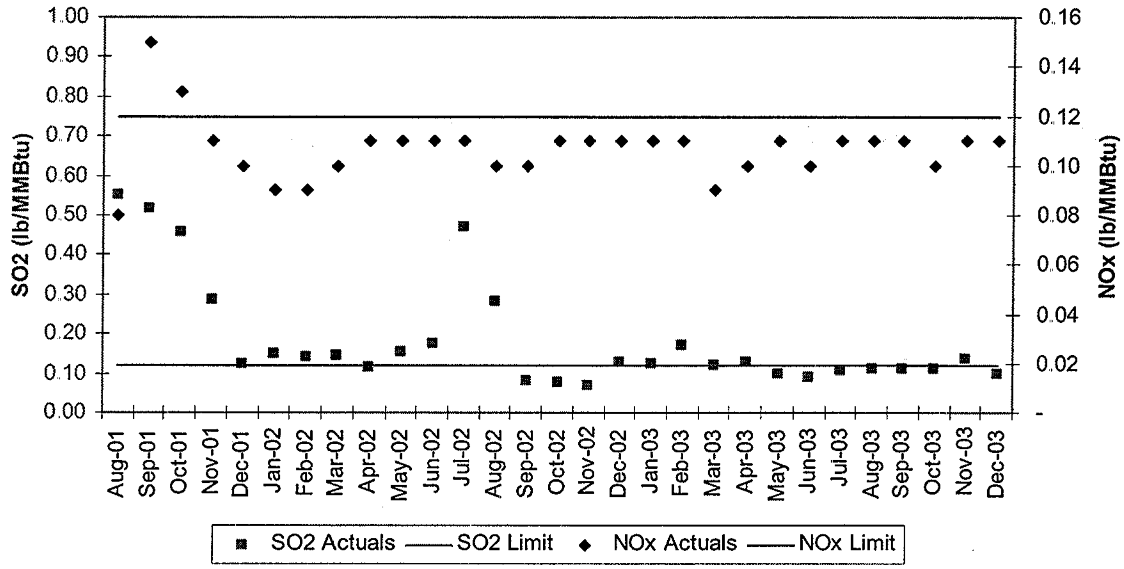


Figure 3-1
Hawthorn 5 Acid Rain Data

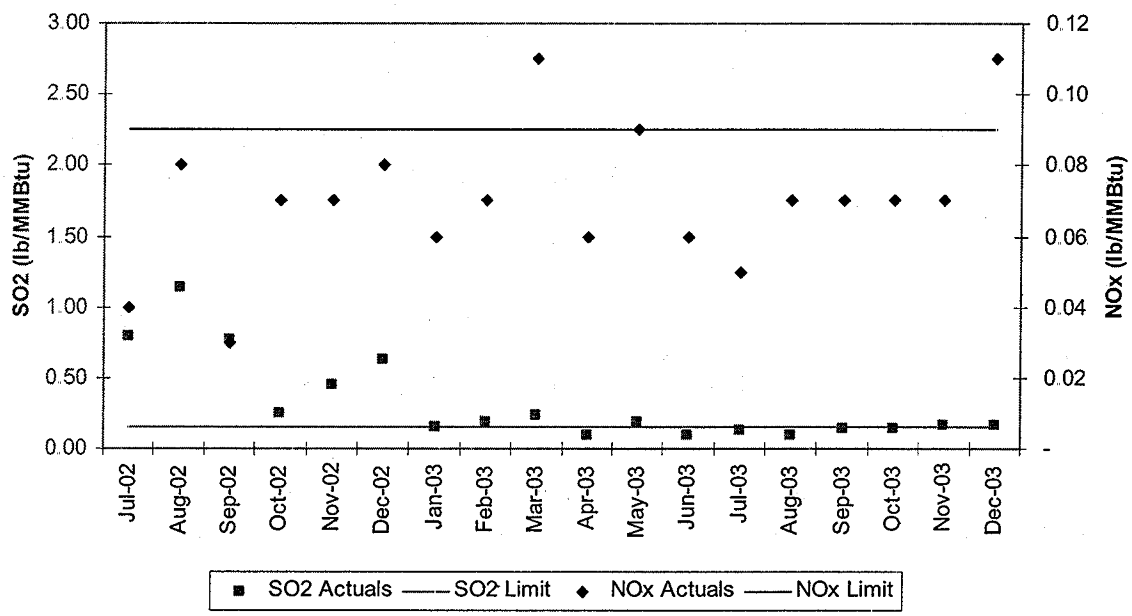


Figure 3-2
JEA Northside Unit 1A Acid Rain Data

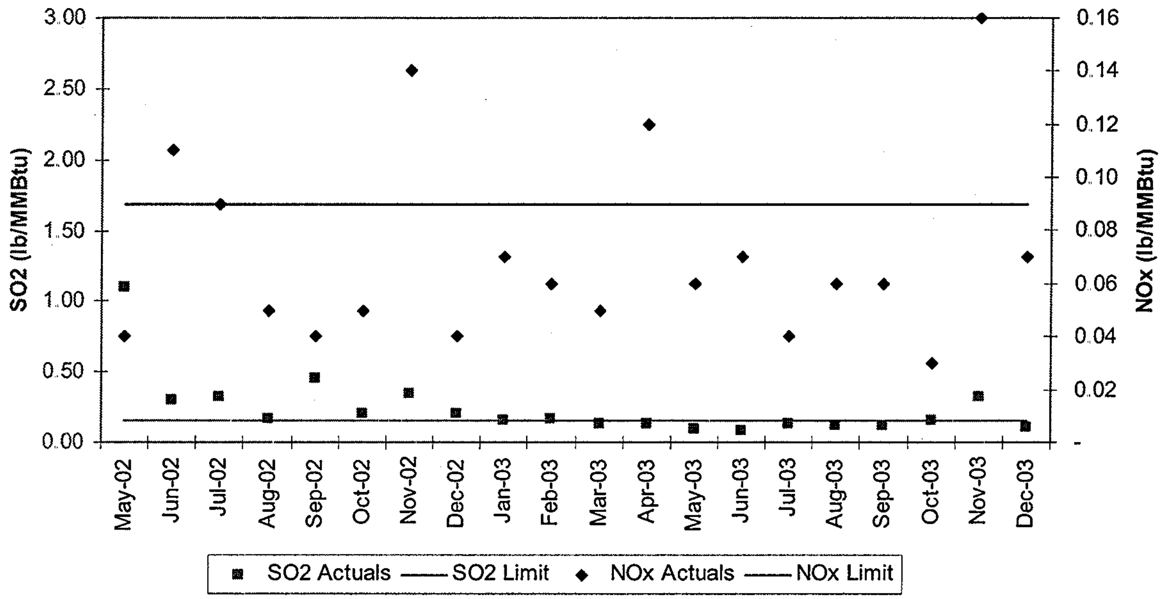


Figure 3-3
JEA Northside Unit 2A Acid Rain Data

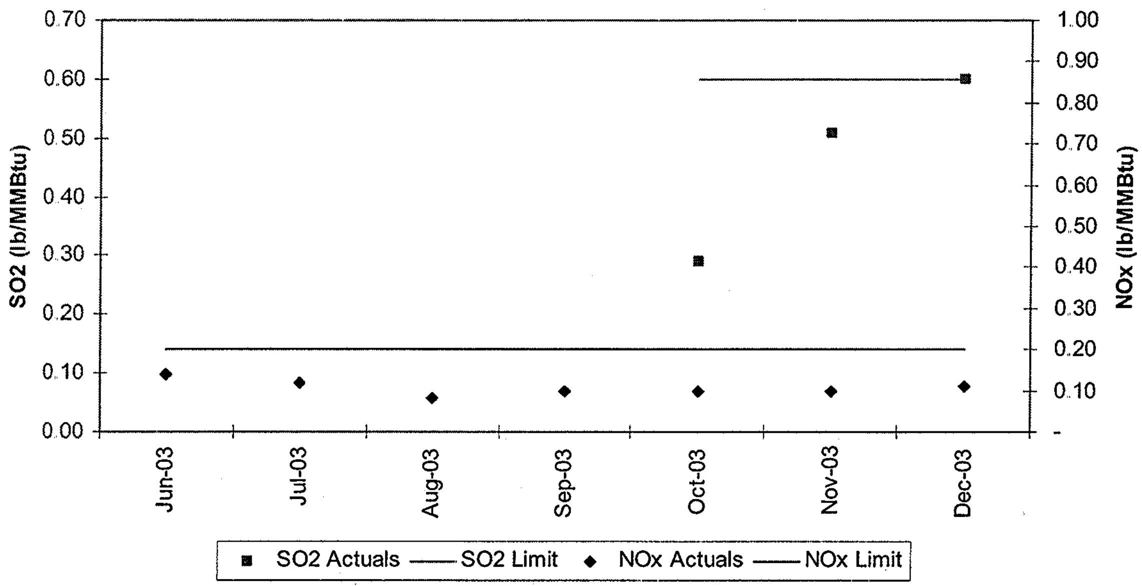


Figure 3-4
Southern Illinois Acid Rain Data

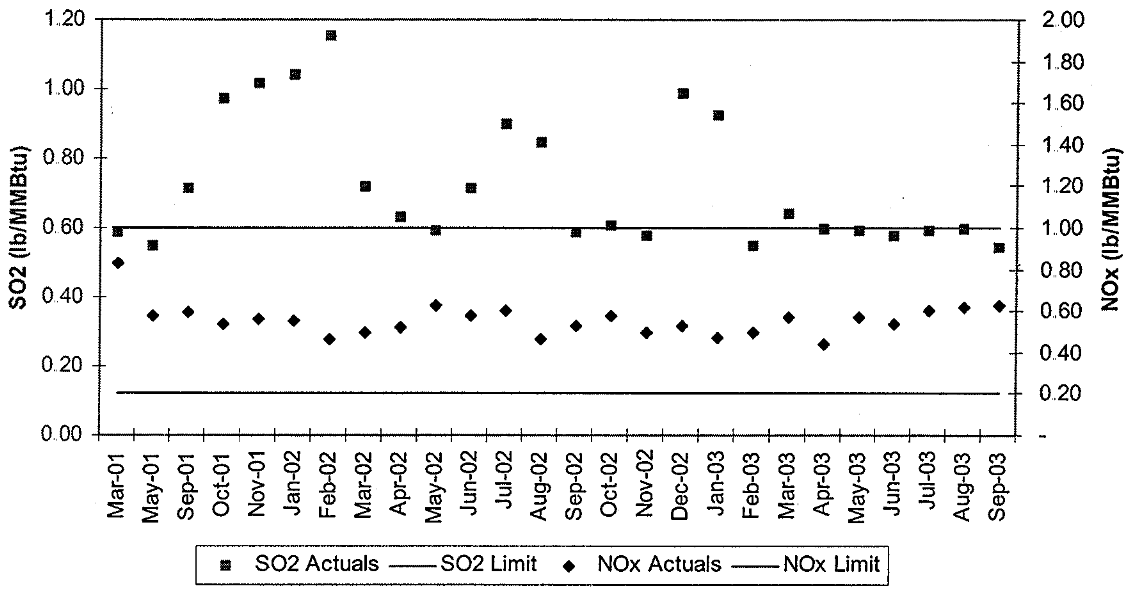


Figure 3-5
Toledo Edison – Bayshore Acid Rain Data

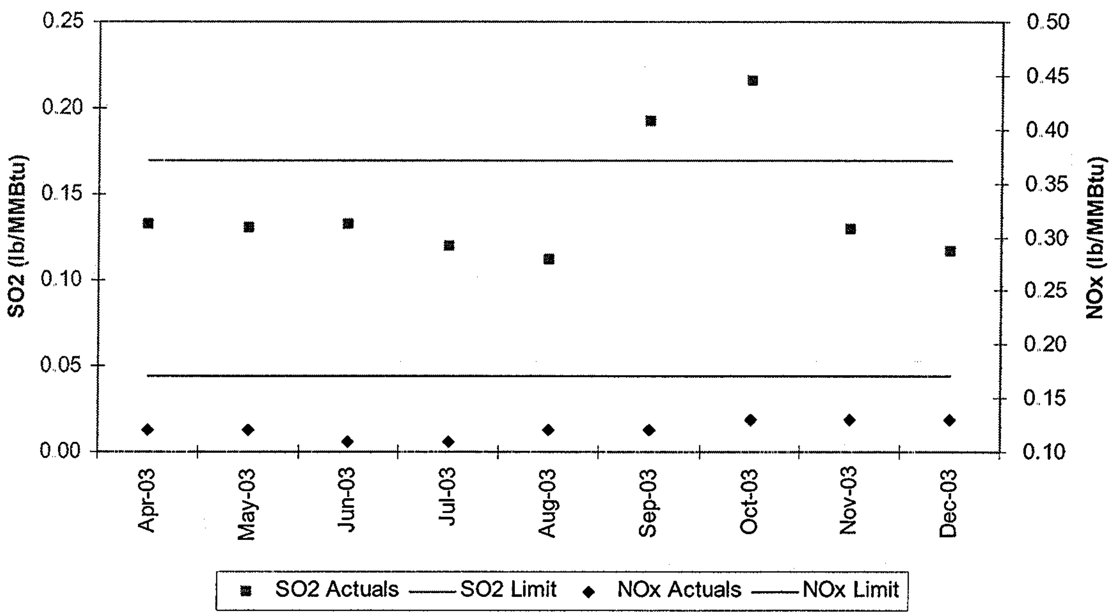


Figure 3-6
Wygen I Acid Rain Data

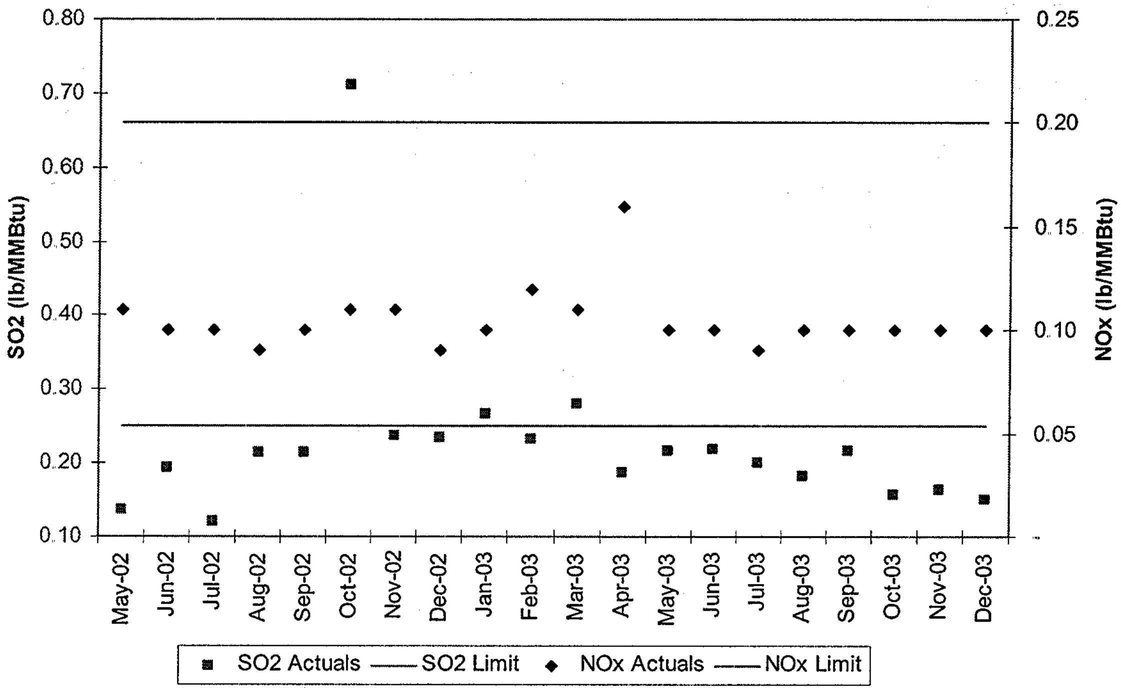


Figure 3-7
Red Hills Unit 1 Acid Rain Data

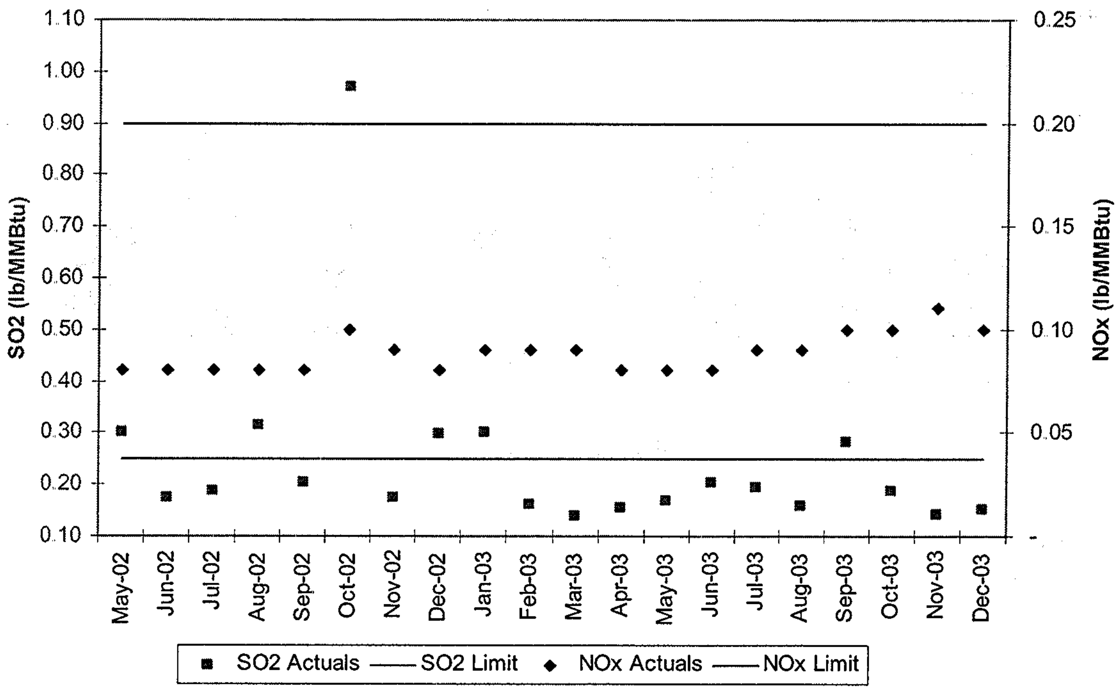


Figure 3-8
Red Hills Unit 2 Acid Rain Data

Initial Test Results

Initial test data was available for eight units, as shown in Table 7. The data was obtained through the state agency or the facility and is for a 3-run average (not a 30-day rolling average). See Figures 3-9 through 3-12. Exceedances are shown for AES Puerto Rico on PM_{10} and TSP; however, results of a repeat stack test were not available from the agency. The limit for AES Puerto Rico was subsequently increased.

Table 3-1
Initial Test Data

Facility	PM/TSP	PM_{10}	CO	VOC
AES Puerto Rico Units 1 and 2	X	X	X	X
Hawthorn	X	X	X	X
JEA Northside Units 1 and 2	X	X	X	X
Southern Illinois	X	X	X	X
Toledo Edison Bayshore		X	X	
Wygen 1	X		X	X

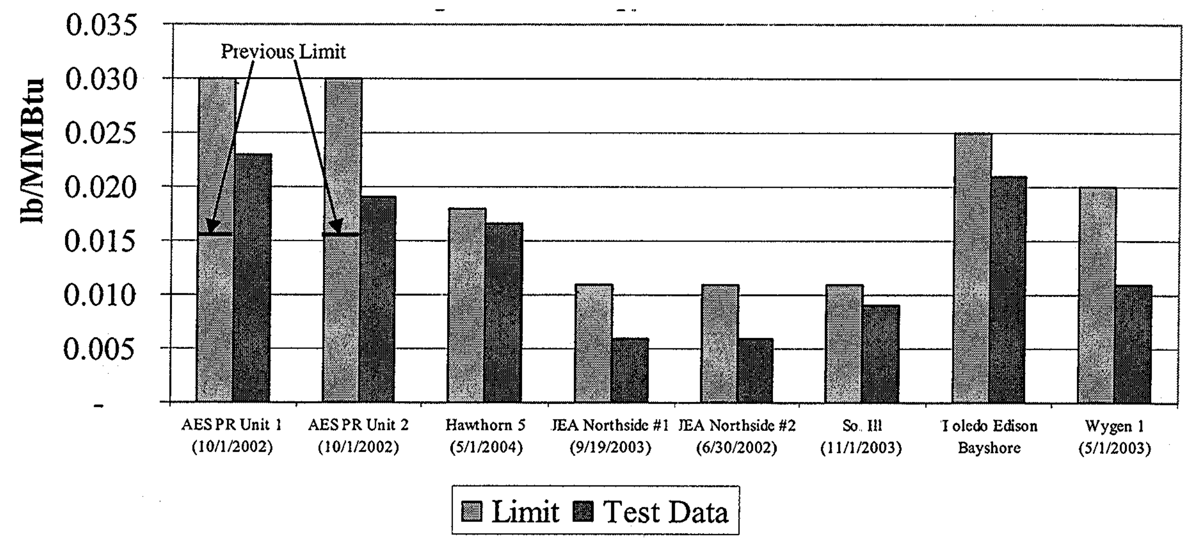


Figure 3-9
PM_{10} Test Data

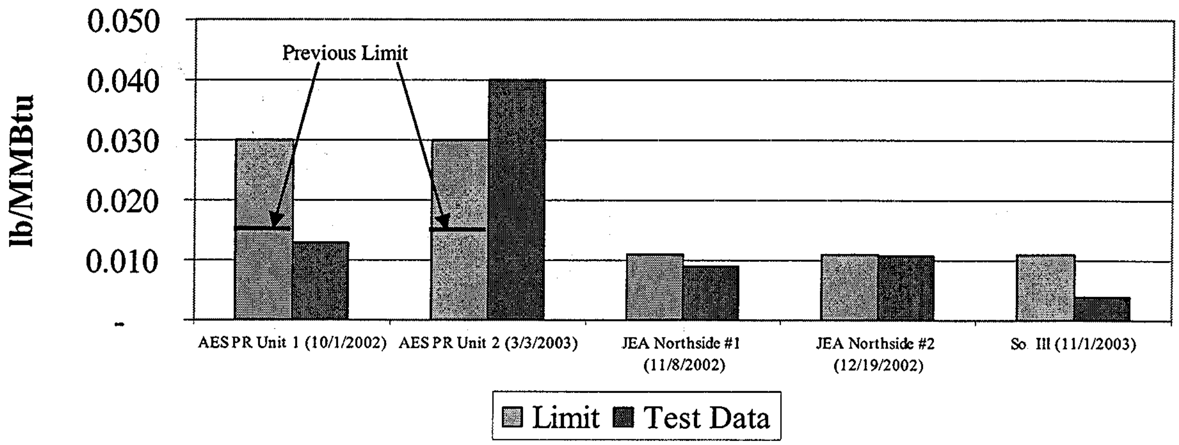


Figure 3-10
TSP Test Data

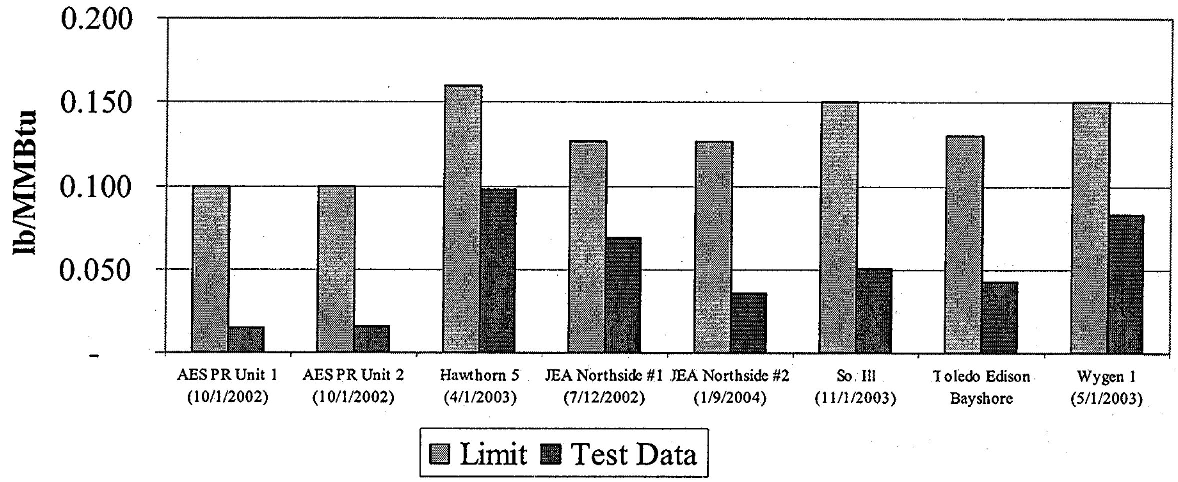


Figure 3-11
CO Test Data

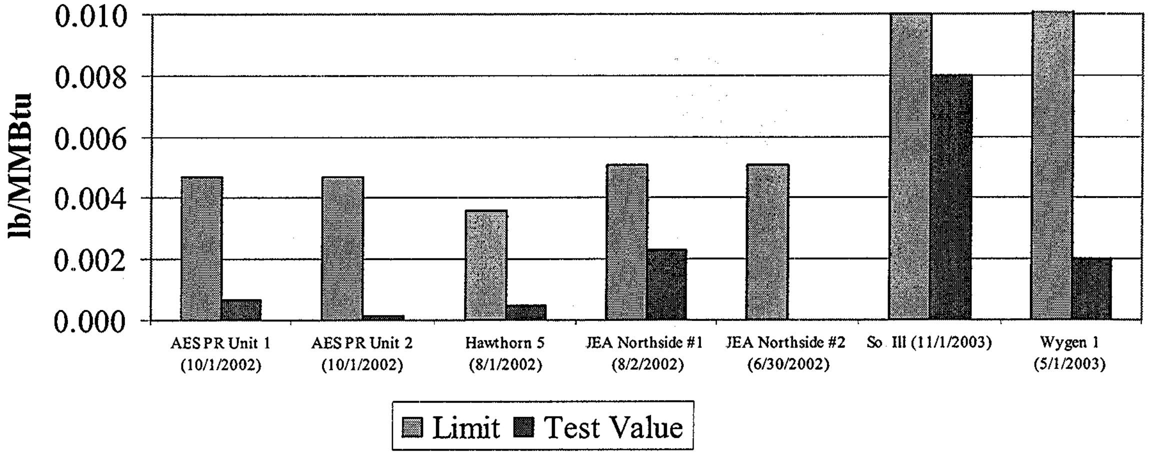


Figure 3-12
VOC Test Data

Permitting Trends

Permitting trends for SO_2, NO_X, and PM_{10} are shown in Figures 3-13, 3-15, and 3-17. These figures were generated to show trends and differences between the permitted emission limits established for units that are operating versus those that are not yet operating. Figures 3-14, 3-16, and 3-18 show trends and differences between permitted emission limits for PC boilers and CFB boilers.

The data in Figures 3-13 through 3-19 is based on permitted emission limits that are based on a Best Available Control Technology (BACT) analysis (i.e. control equipment capabilities). It does not include emission limits that were established from non-BACT criteria, such as the emission limits in NSPS, Subpart Da. For example, pollutants for some of the units replacing existing units did not exceed emission significance thresholds in the netting analysis. Consequently, these pollutants were able to net out of PSD review for those pollutants and be based a less stringent requirement such as NSPS, Subpart Da.

In regards to SO_2, no significant trends or differences between the permitted emission limits established for units that are operating versus those that are not yet operating were found for either CFB or PC units. Figures 3-13 and 3-14 show that the emission limits for operating and not yet operating units are in the same range with most of the emission limits being in the center of the range. CFB boilers have the largest range of limits ranging from 0.022 to 0.25 lb/MMBtu. The emission limits for PC boilers are concentrated around the 0.10 to 0.15 lb/MMBtu range. Both figures show downward trends in the SO_2 emission rates meaning that SO_2 emission limits are becoming more stringent.

In regards to NO_X, no significant trends or differences between the permitted emission limits established for units that are operating versus those that are not yet operating were found for either CFB or PC units. Figures 3-15 and 3-16 generally show that NO_x emission limits for PC units were slightly lower than for CFB boilers (i.e. about 0.08 lb/MMBtu for PC boiler, and about 0.10 lb/MMBtu for CFB boiler). The figures also show a slight downward trend in the NO_x emission limits for both CFB and PC units.

In regards to PM_{10}, no significant trends or differences between the permitted emission limits established for units that are operating versus those that are not yet operating were found for either CFB or PC units. See Figures 3-17, 3-18, and 3-19.

There is an increasing emphasis on speciation between filterable and condensable particulate matter and the appropriate limits for each. Specifying limits as to filterable only or both filterable and condensable is more common in recent years. In fact, the limit for AES Puerto Rico was changed from 0.015 lb/MMBtu to 0.03 lb/MMBtu in order to account for the condensable fraction of the particulate emissions.

Figures 3-18 and 3-19 show emission limits for "filterable" and "filterable and condensable" PM_{10} emissions. There are no distinct trends in the emissions data. With the exception of a couple outliers, the emissions limits for both types of PM_{10} are in the 0.015 to 0.02 lb/MMBtu range.

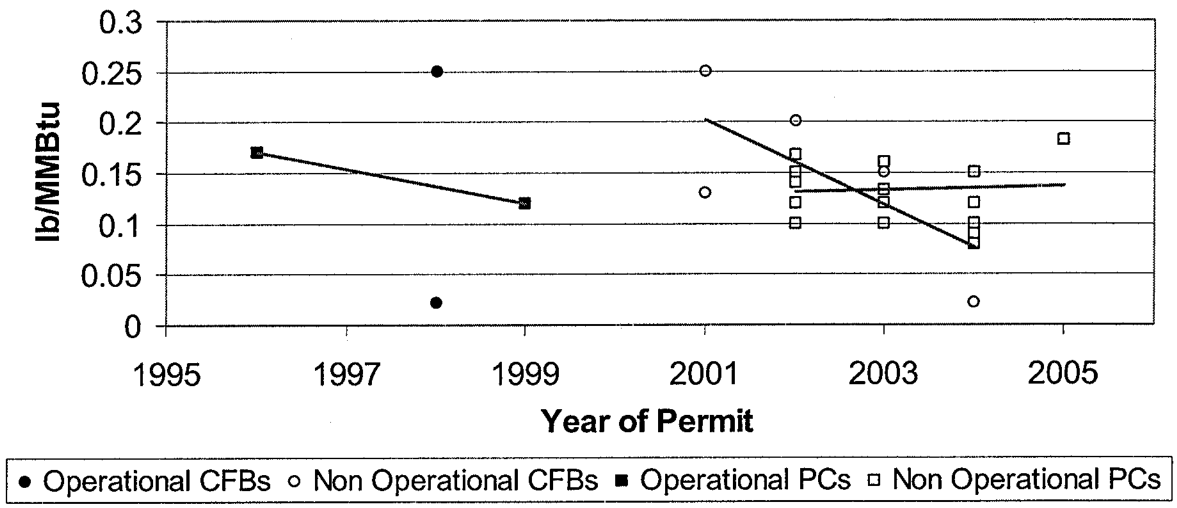


Figure 3-13
SO_2 30 Day Rolling Limits and Operational Status

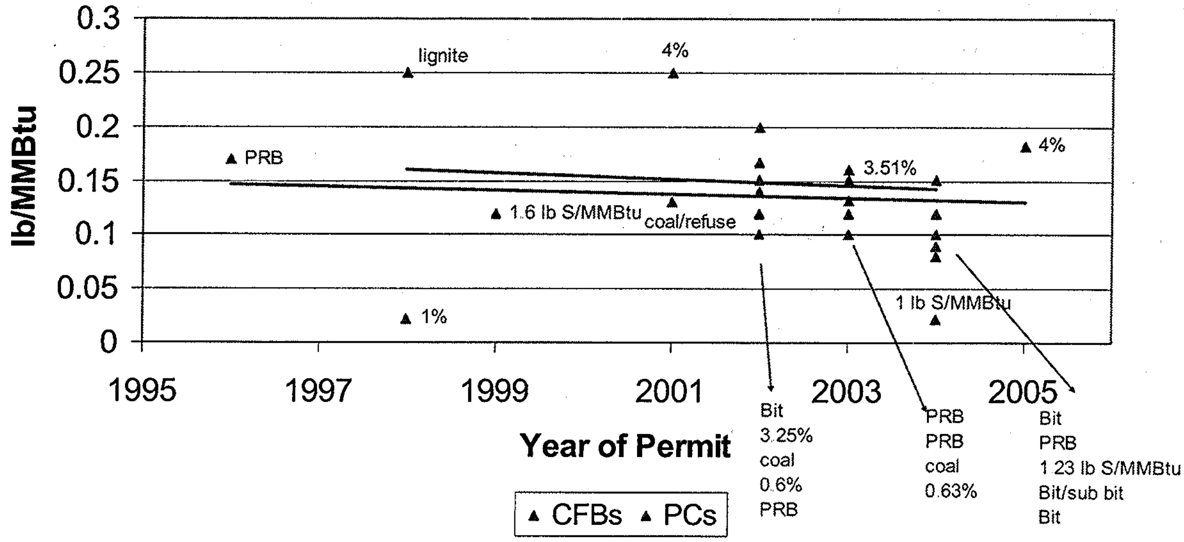


Figure 3-14
SO_2 Permitting Trends

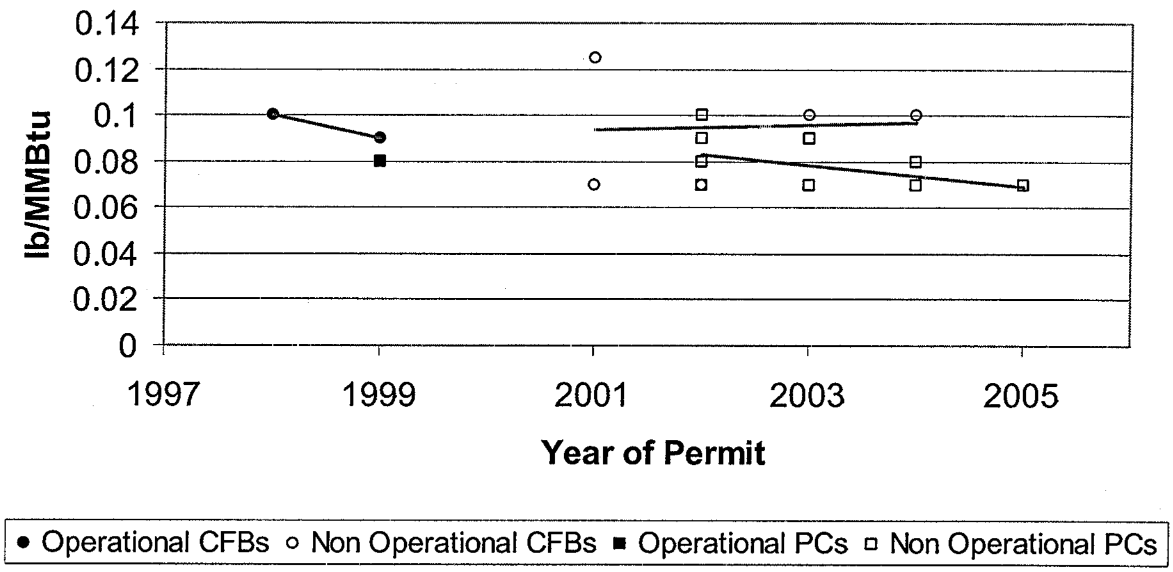


Figure 3-15
NO_x 30-Day Rolling Limits and Operational Status

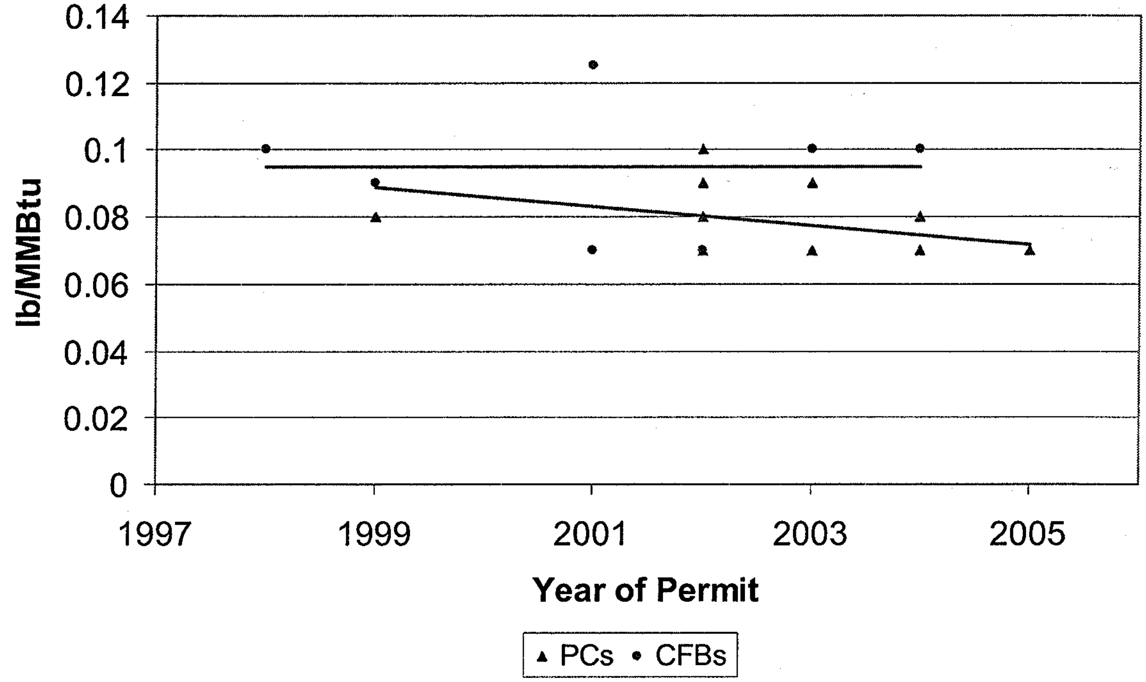


Figure 3-16
NO_x Permitting Trends

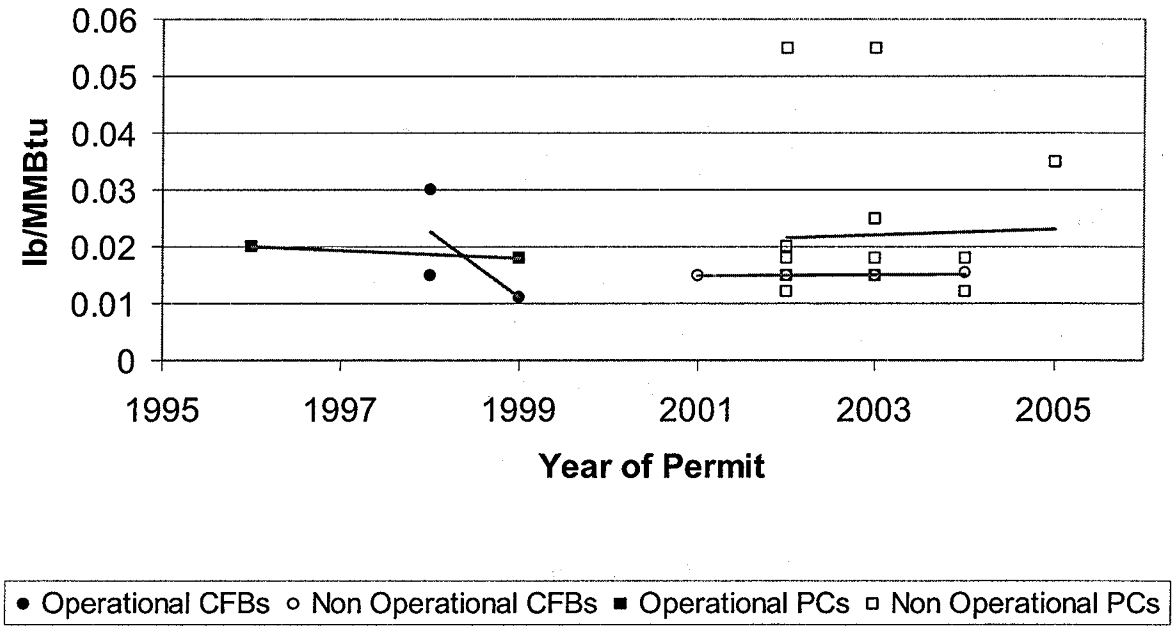
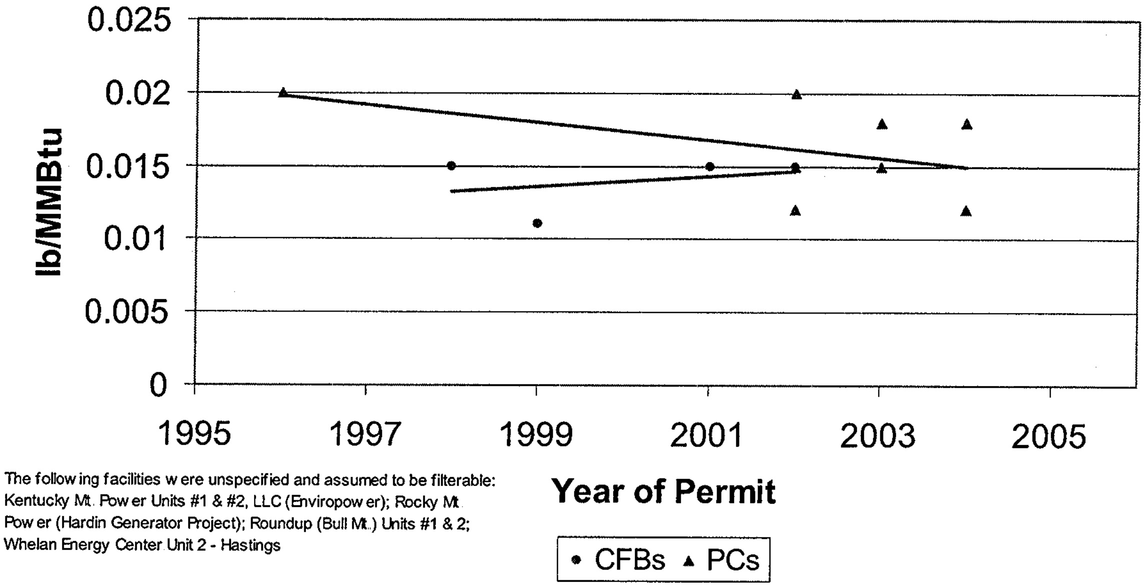


Figure 3-17
PM_{10} Permitting Trends



The following facilities were unspecified and assumed to be filterable: Kentucky Mt. Power Units #1 & #2, LLC (Enviropower); Rocky Mt. Power (Hardin Generator Project); Roundup (Bull Mt.) Units #1 & 2; Whelan Energy Center Unit 2 - Hastings

Figure 3-18
PM_{10} Permitting Trends – Filterable

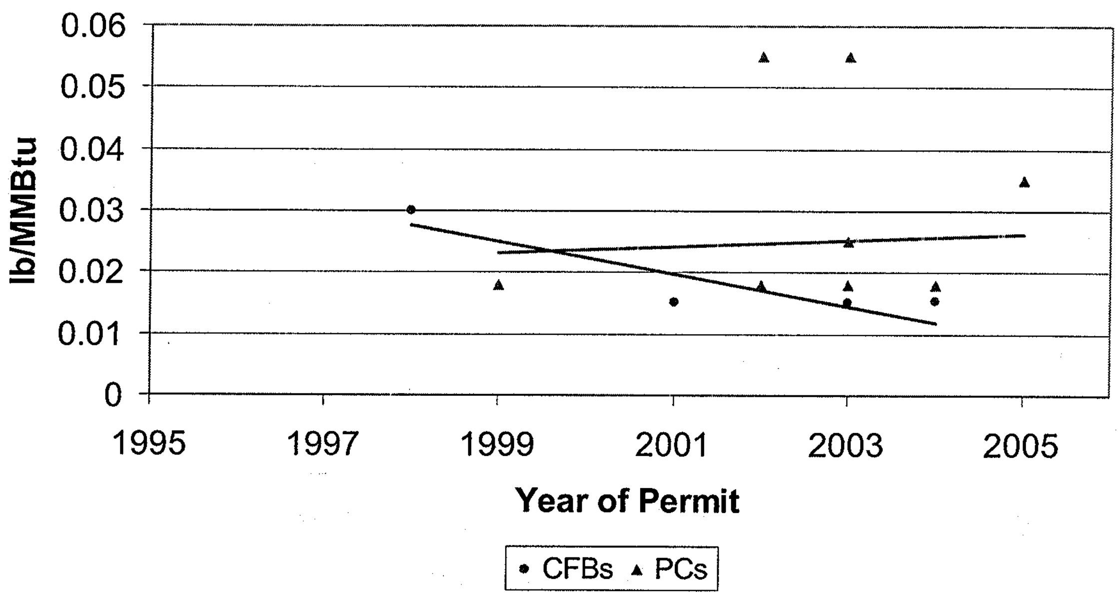


Figure 3-19
PM_{10} Permitting Trends – Filterable and Condensable

4
SUMMARY AND CONCLUSIONS

This investigation is intended to provide a better understanding of the best available control technology (BACT) being required today in permits issued for new coal-fired power plants and to document the actual emissions performance of the air pollution control technologies installed on new units that have recently begun operation. The study focused on four areas: emission controls used, electronic data reporting, initial test results, and permitting trends.

Controls

The types of emission control employed for BACT at recently permitted utility boilers were examined. Permitted SO_2, NO_x, PM_{10}, and CO and VOC controls were compiled from 44 units at 31 facilities. This included 25 PC units and 19 CFB units.

For CFB boilers, 26 percent of the facilities used no additional SO_2 controls. The other 74 percent used some variant of semi-dry FGD technology in combination with the SO_2 removal capability of the limestone injection to the CFB boiler. Semi-dry FGD and wet FGD were the two SO_2 control technologies used at PC facilities, with half of the units using each technology (13 semi-dry and 12 wet).

A majority of CFB units used SNCR to control NO_x emissions and three of the facilities did not use supplemental NO_x controls. Eighty-eight percent of the PC units used LNB and SCR controls, while 12 percent used SCR.

The primary particulate control technology identified in permits for CFB and PC boilers is a fabric filter (baghouse). Out of 44 total units, just seven PC units and two CFB units used ESPs for particulate control and one unit was permitted with a multiclone for particulate control.

VOC and CO emissions at all CFB and PC units are controlled by good combustion practices.

Electronic Data Reporting

Data from power plants as it is collected from the quarterly electronic data reports (EDRs) submitted by each facility was queried to find the monthly emissions for the units included in this study (http://cfpub.epa.gov/gdm/). Monthly data was downloaded for reporting years 2001 through 2003 for the eight operating new units that had data available. In general, the monthly average emissions of SO_2 and NO_x for each unit were consistently below the permit limits for the facilities with the exception of a few outliers.

Initial Test Results

Initial stack test data was available for eight units. The data was obtained through the state agency or the facility and is for a 3-run average (not a 30-day rolling average). All of the facilities met the permit limits for PM_{10}, TSP, CO and VOC, with the exception of the TSP test results dated 3/3/2003 for AES Puerto Rico. This limit was subsequently increased via a permit modification.

Permitting Trends

Permitting trends for SO_2, NO_X, and PM_{10} were generated to show trends and differences between the permitted emission limits established for units that are operating versus those that are not yet operating. Trends and differences between permitted emission limits for PC boilers and CFB boilers were also examined. Data based on permitted emission limits that are based on a Best Available Control Technology (BACT) analysis (i.e., control equipment capabilities) were used.

In regards to SO_2, no significant trends or differences between the permitted emission limits established for units that are operating versus those that are not yet operating were found for either CFB or PC units. The emission limits for operating and not yet operating units are in the same range with most of the emission limits being in the center of the range. CFB boilers have the largest range of limits ranging from 0.022 to 0.25 lb/MBtu. The emission limits for PC boilers are concentrated around the 0.10 to 0.15 lb/MBtu range. The results displayed a downward trend in the SO_2 emission rates meaning that SO_2 emission limits are becoming more stringent.

In regards to NO_X, no significant trends or differences between the permitted emission limits established for units that are operating versus those that are not yet operating were found for either CFB or PC units. The NO_x emission limits for PC units were slightly lower than for CFB boilers (i.e., about 0.08 lb/MBtu for PC boiler, and about 0.10 lb/MBtu for CFB boiler). The results indicated a slight downward trend in the NO_X emission limits for both CFB and PC units.

In regards to PM_{10}, no significant trends or differences between the permitted emission limits established for units that are operating versus those that are not yet operating were found for either CFB or PC units.

There is an increasing emphasis on speciation between filterable and condensable particulate matter and the appropriate limits for each. Specifying limits as to filterable only or both filterable and condensable is more common in recent years. In fact, the limit for AES Puerto Rico was changed from 0.015 lb/MBtu to 0.03 lb/MBtu in order to account for the condensable fraction of the particulate emissions.

There are no distinct trends in the emissions data for "filterable" and "filterable and condensable" PM_{10} emissions. With the exception of a couple outliers, the emissions limits for both types of PM_{10} are in the 0.015 to 0.02 lb/MBtu range.

A
FACILITY INFORMATION

CFB

AES Puerto Rico (2 units)

State: PR *EPA* 2
MW: 2 units at 227 MW each (Net)
MBtu/Hr: 2461.35 MBtu/hr each - 2 units
Operational: yes (& tested)
Number Of Units: 2
Permit Date: 9/18/1998
Permit AES-PRCP
Fuel: bituminous coal
AES-PRCP shall combust the following fuels: Low sulfur coal with a maximum sulfur content of 1.0% by weight.

Energy Services of Manitowoc

State: WI *EPA* 5
MW: 64 MW
MBtu/Hr: 270 MBtu/hr
Operational: no
Number Of Units: 1
Permit Date: 12/3/2003
Permit 02-RV-147
Fuel: coal, petroleum coke, and/or paper pellets
Facility Notes: SO_2, NOx, and PM10 are non-BACT; CO is BACT

EnviroPower IL - Benton (2 units)

State: IL *EPA* 5
MW: 2 units at 250 MW each (nominal net output)
MBtu/Hr: 2,550 MBtu/hr each - 2 units
Operational: no
Number Of Units: 2
Permit Date: 7/3/2001
Permit I.D. #: 055802AAG , Application #: 00080042
Fuel: coal tailings and coal
Coal mine tailings will be taken from the mine tailing piles at the former Old Ben 24 mine site as well as from other sites in southern Illinois.

Indeck-Elwood LLC (2 units)

State: IL *EPA* 5
MW: 2 units at 330 MW each (gross)
MBtu/Hr: 2,900 MBtu/hour each - 2 units
Operational: no
Number Of Units: 2
Permit Date: 10/10/2003
Permit ID #: 197035AAJ, Application #: 02030060
Fuel: coal, petroleum coke, coal tailings
The boilers would be fired on coal as their primary fuel and petroleum coke and coal tailings as supplemental fuels. (The boilers are designed to use coal mixed with up to 20 % petroleum coke and waste coal as their primary fuel.)

JEA Northside #1 & #2 (2 units)
State: FL ***EPA*** 4 ***Operational:*** yes (& tested)
MW: 2 units at 297.5 MW each ***MBtu/Hr:*** 2,764 MBtu/hr each - 2 units ***Number Of Units:*** 2
Permit Date: 7/14/1999 ***Permit*** PSD-FL-265
Fuel: coal, petroleum coke
Facility Notes: SO_2 based on NSPS: other pollutants based on BACT

Kentucky Mountain Power, LLC (EnviroPower) (2 units)
State: KY ***EPA*** 4 ***Operational:*** no
MW: ***MBtu/Hr:*** 2,550 MBTU/hour each - 2 units ***Number Of Units:*** 2
Permit Date: 5/4/2001 ***Permit*** V-00-045
Fuel: coal and coal refuse

Red Hills (Choctaw Generation Limited Partnership) (2 units)
State: MS ***EPA*** 4 ***Operational:*** yes (initial testing waived)
MW: ***MBtu/Hr:*** 2,475.6 MBTU/hr each - 2 units ***Number Of Units:*** 2
Permit Date: 8/25/1998 ***Permit*** 0400-00011
Fuel: lignite
Facility Notes: RBLC indicates NOx is non-BACT; the other pollutants are BACT

Sevier Power (Nevco Energy)
State: UT ***EPA*** 8 ***Operational:*** no
MW: 270 MW ***MBtu/Hr:*** 2532 MBtu/hr ***Number Of Units:*** 1
Permit Date: 10/12/2004 ***Permit*** DAQE-AN2529001-04
Fuel: bituminous coal

Seward Reliant (2 units)
State: PA ***EPA*** 3 ***Operational:*** yes (not tested)
MW: 521 MW (net nominal) ***MBtu/Hr:*** 2,532 MBtu/hr each (nominal), atmospheric CFB - 2 units ***Number Of Units:*** 2
Permit Date: 10/19/2001 ***Permit*** PA-32-040B
Fuel: coal refuse and/or run-of-mine (raw) coal, up to 35% maximum on an annual basis
Facility Notes: non-BACT for SO_2, NOx, PM10; BACT for CO, NSR for VOC

Southern Illinois Coop (Marion Generating Station)
State: IL ***EPA*** 5 ***Operational:*** yes (& tested)
MW: 120 MW ***MBtu/Hr:*** 1402 MBtu HHV/hr ***Number Of Units:*** 1
Permit Date: 6/15/2001 ***Permit*** 00070030- 199856aac
Fuel: coal refuse, coal, petroleum coke
Facility Notes: non-BACT for SO_2, NOx, PM10, and VOC; BACT for CO

Spurlock (E. KY Power Coop)
State: KY ***EPA*** 4 ***Operational:*** no
MW: 270 MW ***MBtu/Hr:*** 2,500 MBTU/hour ***Number Of Units:*** 1
Permit Date: 8/4/2002 ***Permit*** V-97-050 (Revision 1)
Fuel: coal

Toledo Edison Co. - Bayshore Plant
State: OH *EPA* 5 *Operational:* yes (& tested)
MW: *MBtu/Hr:* 1,736 MBtu/hr *Number Of Units:* 1
Permit Date: 10/21/1997 *Permit* 04-01056
Fuel: pet coke, coal CFB boiler fired primarily with petroleum coke (1736 MMBTU/hr rating) and use of coal (1764 MMBTU/hr rating) as a backup fuel
Facility Notes: non-BACT for SO_2, NOx, PM10, VOC; BACT for CO

PC

Corn Belt Energy
State: IL *EPA* 5 *Operational:* no
MW: 91 MW *MBtu/Hr:* 900 MBtu/hr *Number Of Units:* 1
Permit Date: 12/17/2002 *Permit* Application #: 1070028, I.D. #: 107806AAC
Fuel: bituminous coal and coal tailings 10450 btu/lb, , Elkhart Mine Road, Mine-Mouth Project, Elkhart, Logan County
Facility Notes: The project is being pursued by Corn Belt in conjunction with a clean coal combustion grant from the United States Department of Energy (USDOE). 365 day "shakedown" period when only nsps limits apply

Council Bluffs (Mid America)
State: IA *EPA* 7 *Operational:* no
MW: 790 net MW *MBtu/Hr:* 7,675 MBtu/hr *Number Of Units:* 1
Permit Date: 6/17/2003 *Permit* 03-A-425-P
Fuel: PRB

Elm Road Generating Station (WE-Energies) (2 units)
State: WI *EPA* 5 *Operational:* no
MW: 2 units at 615 MW each *MBtu/Hr:* 6180 MBtu/hr each - 2 units *Number Of Units:* 2
Permit Date: 1/14/2004 *Permit* 03-RV-166
Fuel: bituminous coal -washed Eastern United States Pittsburgh #8

Hawthorn 5 (KCP&L)
State: MO *EPA* 7 *Operational:* yes (& tested)
MW: 570 MW *MBtu/Hr:* 6,000 MBtu/hr *Number Of Units:* 1
Permit Date: 8/17/1999 *Permit* 888
Fuel: PRB 8350

Holcomb Unit #2 (Sand Sage Power, LLC)
State: KS *EPA* 7 *Operational:* no
MW: 660 MW *MBtu/Hr:* 6,501 MBtu/hr *Number Of Units:* 1
Permit Date: 10/8/2002 *Permit* Source ID #: 0550087
Fuel: PRB

Intermountain Power Unit #3
State: UT *EPA* 8 *Operational:* no
MW: nominal 950-gross MW (900-net MW) *MBtu/Hr:* 9,050 MBtu/hr *Number Of Units:* 1
Permit Date: 10/15/2004 *Permit* DAQE-AN0327010-04
Fuel: bituminous or blend of bituminous and up to 30% subbituminous

Longview Power (GenPower)
State: WV *EPA* 3 *Operational:* no
MW: 600 MW *MBtu/Hr:* 6,114 MBtu/hr *Number Of Units:* 1

Permit Date: 3/2/2004 *Permit* R14-0024
Fuel: bituminous coal 2.5% sulfur (nominal)

Plum Point Power Station
State: AR *EPA* 6 *Operational:* no
MW: 550-800 MW (nominal) *MBtu/Hr:* 8,897 MBtu/hr *Number Of Units:* 1
Permit Date: 8/20/2003 *Permit* 1995-AOP-R0
Fuel: PRB
Facility Notes: MMBtu/hr for the boiler was found in the predetermination document for Longview

Prairie State (2 units)
State: IL *EPA* 5 *Operational:* no
MW: 1500 MW *MBtu/Hr:* 7,450 MBtu/hr (each) *Number Of Units:* 2
Permit Date: 1/14/2005 *Permit* 189808AAB
Fuel: bituminous coal mine mouth; Illinois coal; 4% sulfur; 8,780 btu/lb

Rocky Mountain Power (Hardin Generator Project)
State: MT *EPA* 8 *Operational:* no
MW: 113 MW (nominal) *MBtu/Hr:* 1,304 MBtu/hr *Number Of Units:* 1
Permit Date: 6/11/2002 *Permit* 3185-00
Fuel: coal coal owned by the Tribe of Crow Indians from the Absaloka Mine. The mine, which is owned by Westmoreland Resources, Inc., is located approximately 30 miles east of Hardin. Using the heat content of 8,700 Btu/lb of Absaloka Mine coal, as provided by Westmoreland Resources, Inc., the coal-firing rate will be approximately 75 ton/hr and 656,500 tpy.

Roundup (Bull Mountain) (2 units)
State: MT *EPA* 8 *Operational:* no
MW: 2 units at 390 MW each (nominal) *MBtu/Hr:* 4,013 MBtu/hr each (Max short term heat input to boiler); 2 units - 3,737 mmBtu/hr each (Max long term heat input to boiler) - 2 units *Number Of Units:* 2
Permit Date: 7/21/2003 *Permit* 3182-00
Fuel: coal Coal for the main boilers will be supplied by the BMP Investments Incorporated coal mine that is located on the adjacent property immediately to the east of the power plant location. (Bull Mountain Mine)

Santee Cooper/Cross #3 & #4 (2 units)
State: SC *EPA* 4 *Operational:* no
MW: 2 units at 600 MW each *MBtu/Hr:* 5,400 MBTU/hr (normal pressure rating), 5,700 „BTU/hr (overpressure rating) each - 2 units *Number Of Units:* 2
Permit Date: 8/5/2004 *Permit* 0420-0030-CI-R1
Fuel: coal, synfuel and petcoke blended up to 30% by weight as fuel coal, including synfuel, and petcoke blended up to 30% by weight as fuel. For this permit, the term "coal" and requirements pertaining to coal shall also include the following synthetic fuel-altered coal (synfuel): - coal with HES binder (petroleum emulsion - MSDS identification AMI-403) - coal with NALCO 9838 binder (water based vinyl polymer)- coal with Dow Latex DL 298NA (latex based emulsion in water) Boilers 03 and 04) The

owner/operator shall maintain daily monitoring of the petcoke blend ratio. This blend shall not exceed 30% by weight blend petcoke. The petcoke blend ratio shall be calculated daily by measuring the weight of the petcoke burned as well as the weight of the entire coal/petcoke mixture. Records of daily petcoke blend ratios shall be submitted to the Manager of the Technical Management Section, Bureau of Air Quality along with the quarterly CEMS reports.

Facility Notes: NOx and SOx are non-BACT, the rest are BACT

Thoroughbred (2 units)

State: KY ***EPA*** 4 ***Operational:*** no, Permit under litigation
MW: 2 units at 750 MW each ***MBtu/Hr:*** 7,446 MBTU/hour each - 2 units ***Number Of Units:*** 2
Permit Date: 10/11/2002 ***Permit*** V-02-001 Revision 1
Fuel: bituminous coal

Tucson - Springerville (2 units)

State: AZ ***EPA*** 9 ***Operational:*** no
MW: 2 units at 400 net MW each ***MBtu/Hr:*** 4,200 MBtu/hr each - 2 units ***Number Of Units:*** 2
Permit Date: 4/29/2002 ***Permit*** 1001554
Fuel: PRB
Facility Notes: Netted for NOx and SO_2, non-BACT for SO_2 and NOx; BACT for PM10, CO and VOC

Two Elk

State: WY ***EPA*** 8 ***Operational:*** no
MW: 280 MW (nominal) ***MBtu/Hr:*** 2,960 MBtu/hr ***Number Of Units:*** 1
Permit Date: 5/29/2003 ***Permit*** CT-1352B
Fuel: PRB

Whelan Energy Center Unit 2- Hastings

State: NE ***EPA*** 7 ***Operational:*** no
MW: 220 MW ***MBtu/Hr:*** 2,211 MBtu/hr ***Number Of Units:*** 1
Permit Date: 3/30/2004 ***Permit*** 58048
Fuel: PRB has a minimum heat content of approximately 8,100 Btu/lb (from NDEQWhelanFactSheet58048f02doc.pdf)

Wisconsin Public Service - Weston 4

State: WI ***EPA*** 5 ***Operational:*** no
MW: 500 MW ***MBtu/Hr:*** 5,173 MBtu/hr ***Number Of Units:*** 1
Permit Date: 10/19/2004 ***Permit*** 03- RV- 248
Fuel: PRB

WYGEN I (Black Hills)

State: WY ***EPA*** 8 ***Operational:*** yes (& tested)
MW: 80 MW ***MBtu/Hr:*** 1,014 MBtu/hr ***Number Of Units:*** 1
Permit Date: 9/6/1996 (5/17/2004) ***Permit*** CT-1236
Fuel: PRB
Facility Notes: Modified Permit CT-1236A reflects the as-build WYGEN 1 facility and to revise the short term SO_2 limit for the PC boiler from a 2 hour block average to a 3 hour block average. The as-built modifications consist of the installation of a boiler baghouse instead of a precipitator, installation of a Spray Dryer Absorber instead of a Circulating Dry Scrubber, and modifications to the material handling dust collectors.

WYGEN II (Black Hills)

State: WY ***EPA*** 8 ***Operational:*** no
MW: 500 MW ***MBtu/Hr:*** 5,145.7 MBtu/hr ***Number Of Units:*** 1
Permit Date: 9/25/2002 ***Permit*** CT-3030
Fuel: PRB

B
PLANTS EXCLUDED FROM THE STUDY

Facility	State	Exclusion Reason
AES Beaver Valley Partners, Inc.	PA	Not a new boiler
AES Hawaii	HI	Not a new boiler
Baldwin Expansion (Dynegy)	IL	Application only
Calla (Estill county)	KY	Not permitted yet
Cash Creek	KY	Application only
Clover, VA	VA	Not a new boiler
Collins Power Plant (Midwest)	IL	Withdrawn
Colstrip Energy Limited Partnership	MT	Not a new boiler
Colstrip Energy Limited Partnership	MT	Not a new boiler
Cottonwood Energy Center	NM	Application only
Deseret Generation & Transmission Company - Bonanza	UT	Not a new boiler
Desert Rock Energy (Steag Power)	NM	Application only
Dominion Resources - Ashtabula County	OH	Application only
Edison Mission Energy	PA	Not a new boiler
Encoal Corporation-Encoal North Rochelle Facility	WY	Pennsylvania NOx budget affected facility.
Franklin Proj. - IL Energy	IL	Application only
Gascoyne Generating Station (Montana Dakota Utilities)	ND	Not permitted yet
Great Plains Weston Bend	MO	Application only
Independence	AR	Not a new boiler
J.K. Spruce II - San Antonio	TX	Application only
Limestone Electric Generating Station (Reliant)	TX	Not a new boiler
Mustang (Peabody) Energy, Mustang Generating Station	NM	Not permitted yet
NorthHampton	PA	Not a new boiler
OPPD - Nebraska City Unit 2	NE	Application only
Orion Power Midwest LP	PA	Not BACT (RACT)
Sandy Creek Energy - LS Power	TX	Application only

Facility	State	Exclusion Reason
SC Elec & Gas Cope, SC	SC	Not a new boiler
Southwest Unit #2 - City Utilities	MO	Application only
Stanton (Orlando), FL (OUC- Orlando utilities)	FL	Not a new boiler
TECO-Big Bend Station	FL	Not a new boiler
TES Filer City Station	MI	Not a new boiler
Thermal Ventures (Martinsville Thermal)	VA	Not a new boiler
Trimble County (LG&E)	KY	Application only
TS Power Plant (Newmount NV)	UT	Application only
UAE Mecklenburg	VA	Not a new boiler
Upshur Energy Center (Dom.)	WV	Withdrawn
W.A. Parish Electric Generating Station (PSD-TX-234)	TX	Not a new boiler
WA Parish Electric Generating Station (PSD-TX-33 M1)	TX	Not a new boiler
WA Parish Electric Generating Station (PSD-TX-901, PSD-TX-902 & -33M1)	TX	Not a new boiler

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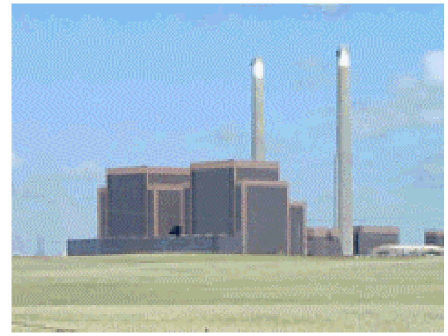
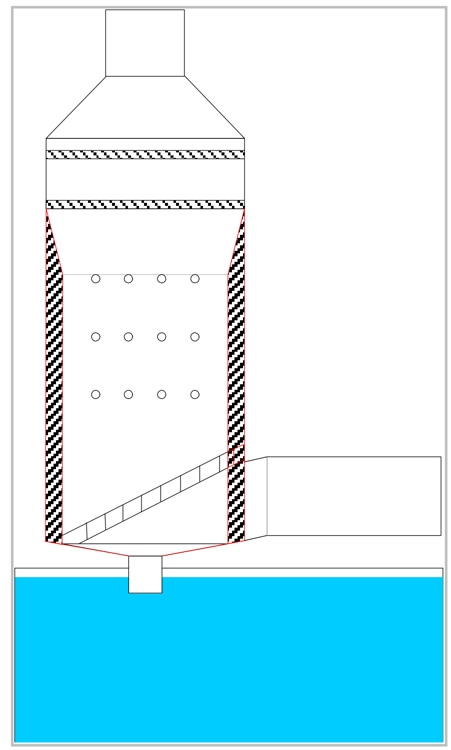
Appendix I

URS SO_2 Control Evaluation

URS



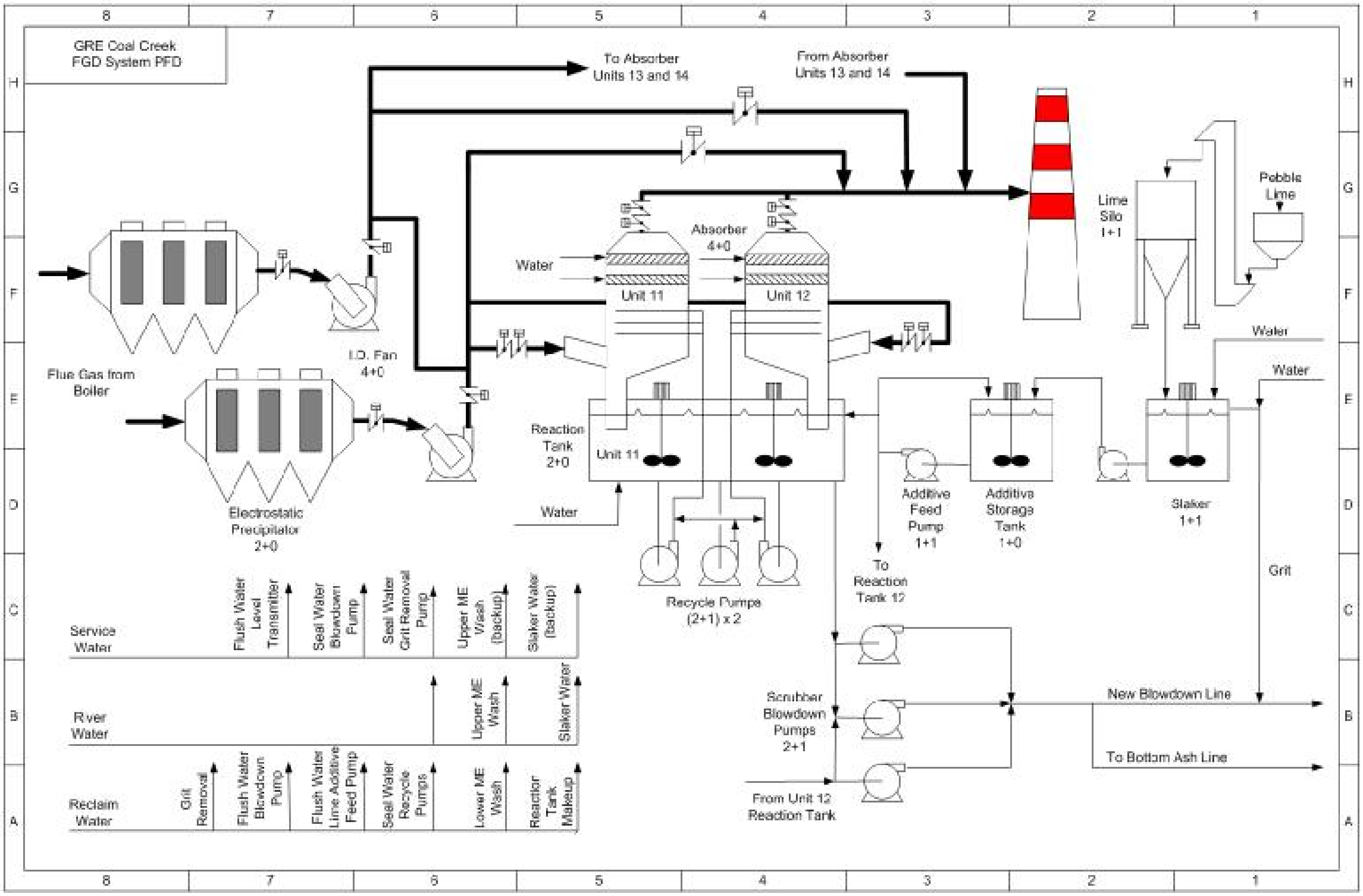


GRE Coal Creek Units 1 & 2

Review of Options to Reduce SO_2 Emissions

October 26, 2004

Process Flow Diagram



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Current Operating Conditions

- Operating data provided by GRE
  - Boiler
  - Fuel
  - Flue gas
- In most cases, the median value was used
  - Data from several months available
  - No significant trends detected in heat rate, flow or sulfur

Boiler & Fuel Characteristics	Units	Current
Unit Load	MW_{gross}	595
Plant Heat Rate	$Btu/KWh)_{gross}$	10,500
Heat Input	MM Btu/hr	6,248
Capacity Factor	percent	85
Coal HHV, Btu/lb	Btu/lb	6,200
Sulfur	percent	0.64
FGD Characteristics		
Absorber Removal	percent	95.0
Bypass	percent	27.0
Plant Removal	percent	69.4
Emissions	TPY	13,817
Allowances	TPY	23,111
Credits	TPY	9,294
Flue Gas Characteristics		
Excess Air, APH Leakage	percent	17.0
APH O_2 Concentration	percent	2.6
APH Flue Gas Flow Rate	scfm	1,485,334
APH SO_2 Concentration		795
ESP, Ductwork Leakage	percent	10.0
Stack O_2 Concentration		4.0
Stack Flue Gas Flow Rate	scfm	1,707,670
Stack SO_2 Concentration		262
Stack Temperature	deg F	191

URS

Determination of Current Bypass

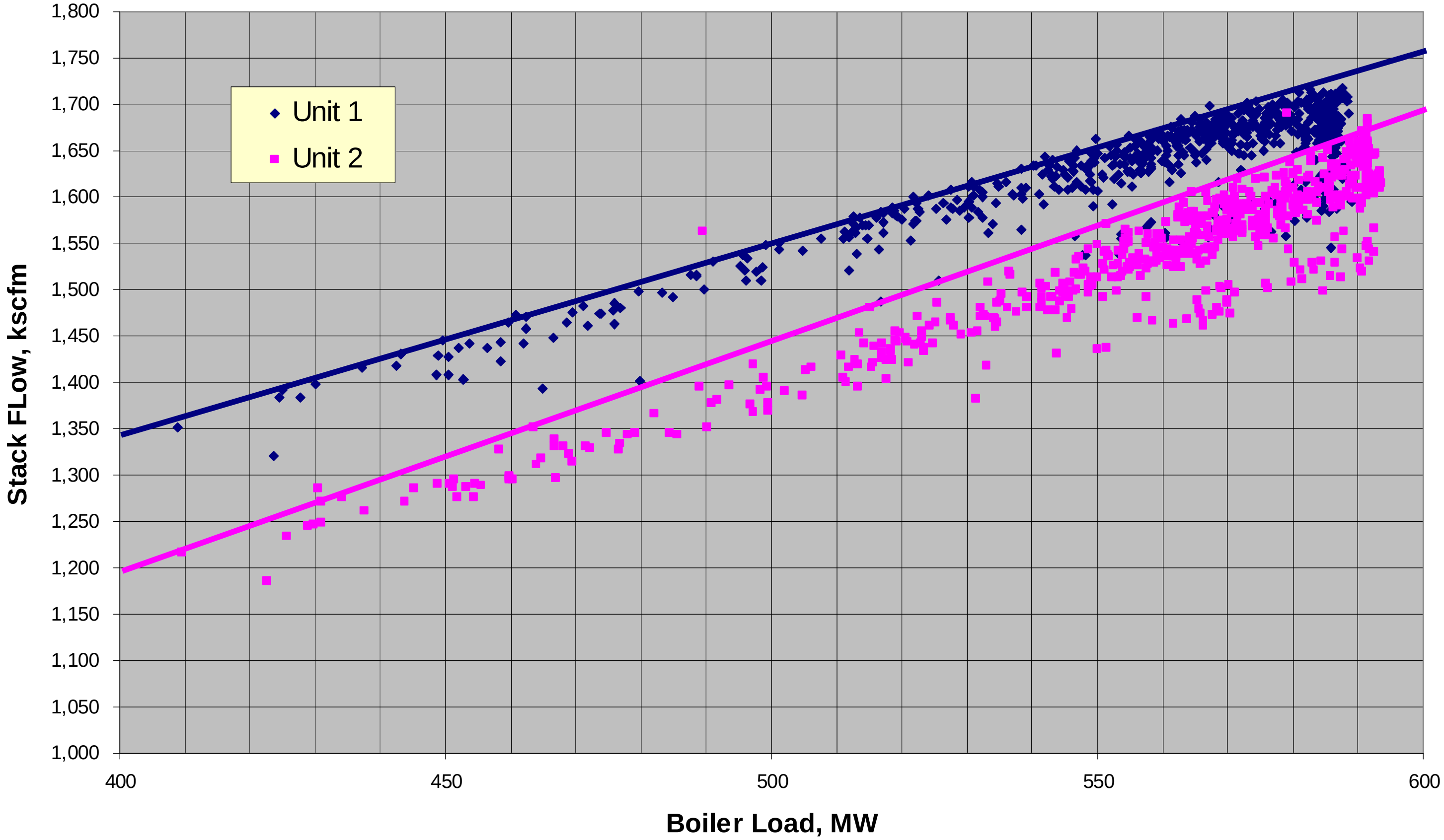
- Current bypass flow was determined using several different methods:
  - ü Historical Emissions
  - ü Stack Temperature

Method	Bypass	Accuracy	Comment
Historical Emissions	27.0	Poor	Annual average
Stack Temperature	28.0	Good	Heat losses hard to estimate
Mass Balance	27.0	Medium	Combo of all parameters
Median	27.0		

Mass Balance, 27% Bypass

GAS COMPOSITION	A Combustion Air	B A APH Outlet	C ESP/FF Outlet	D FGD Bypass	E FGD Inlet	F Forced Oxidation Air	G FGD Outlet	H Stack
N_2	4,270,474	4,276,520	4,777,157	1,289,832	3,487,324	-	3,487,324	4,777,157
O_2	1,309,154	190,200	343,674	92,792	250,882	-	250,474	343,266
CO_2	2,833	1,369,894	1,370,226	369,961	1,000,265	-	1,005,919	1,375,880
Ar	72,972	72,972	81,527	22,012	59,515	-	59,515	81,527
SO_2		11,763	11,763	3,176	8,587	-	429	3,605
HCl		104	104	28	76	-	-	28
HF		5	5	1	4	-	-	1
H_2O	73,521	708,521	716,219	193,379	522,840	-	726,136	919,515
FLY ASH	-	84,644	423	114	309	-	108	222
GAS LB/HR TOTAL	5,728,954	6,629,979	7,300,674	1,971,182	5,329,492	-	5,529,797	7,500,979
TOTAL LB/HR	5,728,954	6,714,622	7,301,098	1,971,296	5,329,801	-	5,529,905	7,501,202
MOLE WT. GAS WET	29.33	28.68	28.69	28.69	28.69		28.06	28.22
MOLE WT. GAS DRY	28.96	30.87	30.67	30.67	30.67		30.65	30.65
TEMPERATURE, deg F	85.0	372.0	340.0	340.0	340.0		138.0	191.1
HUMIDITY, lb/lb	0.013	0.120	0.109	0.109	0.109		0.151	0.140
DRAFT, in.H2O	26.0	-20.6	-10.0	4.0	4.0		2.0	1.0
FLOW RATE, acfm	1,217,479	2,465,374	2,540,009	662,430	1,791,014		1,427,014	2,100,586
FLOW RATE, scfm	1,254,890	1,485,334	1,635,195	441,503	1,193,693		1,266,167	1,707,670
SO_2, ppm actual	-	795	722	722	722		34	212
SO_2, ppm dry	-	958	856	856	856		43	262
SO_2, lbs/MM Btu	-	1.88	1.88	0.51	1.37	-	0.07	0.58
SO_2, tpy		43,794	43,794	11,824	31,969		1,598	13,423
PARTICULATE, grains/acf	0.000	4.006	0.019	0.020	0.020		0.009	0.012
PARTICULATE mg/Nm3	0.0	16,353	74.3	74	74		25	37
PARTICULATE lbs/MM Btu	-	13.55	0.07	0.02	0.05	-	0.02	0.04
PARTICULATE, tpy	-	315,128	1,576	425	1,150		403	828
OXYGEN, percent	20.9	2.6	4.2	4.2	4.2		4.0	4.04
CO_2, percent	0.0	13.5	12.2	12.2	12.2		11.6	11.76

Flue Gas Flow Rate



1,750 kscfm used as maximum flow

URS

Mass Balance, 0% Bypass

GAS COMPOSITION	A Combustion Air	B A APH Outlet	C ESP/FF Outlet	D FGD Bypass	E FGD Inlet	F Forced Oxidation Air	G FGD Outlet	H Stack
N_2	4,270,474	4,276,520	4,777,157	-	4,777,157	-	4,777,157	4,777,157
O_2	1,309,154	190,200	343,674	-	343,674	-	343,116	343,116
CO_2	2,833	1,369,894	1,370,226	-	1,370,226	-	1,377,971	1,377,971
Ar	72,972	72,972	81,527	-	81,527	-	81,527	81,527
SO_2		11,763	11,763	-	11,763	-	588	588
HCl		104	104	-	104	-	-	-
HF		5	5	-	5	-	-	-
H_2O	73,521	708,521	716,219	-	716,219	-	994,706	994,706
FLY ASH	-	84,644	423	-	423	-	148	148
GAS LB/HR TOTAL	5,728,954	6,629,979	7,300,674	-	7,300,674	-	7,575,065	7,575,065
TOTAL LB/HR	5,728,954	6,714,622	7,301,098	-	7,301,098	-	7,575,213	7,575,213
MOLE WT. GAS WET	29.33	28.68	28.69	0.00	28.69		28.06	28.06
MOLE WT. GAS DRY	28.96	30.87	30.67	#DIV/0!	30.67		30.65	30.65
TEMPERATURE, deg F	85.0	372.0	340.0	340.0	340.0		138.0	138.0
HUMIDITY, lb/lb	0.013	0.120	0.109	0.000	0.109		0.151	0.151
DRAFT, in.H2O	26.0	-20.6	-10.0	4.0	4.0		2.0	1.0
FLOW RATE, acfm	1,217,479	2,465,374	2,540,009	0	2,453,444		1,954,814	1,959,608
FLOW RATE, scfm	1,254,890	1,485,334	1,635,195	#DIV/0!	1,635,195		1,734,475	1,734,475
SO_2, ppm actual	-	795	722	-	722		34	34
SO_2, ppm dry	-	958	856	-	856		43	43
SO_2, lbs/MM Btu	-	1.88	1.88	-	1.88	-	0.09	0.09
SO_2, tpy		43,794	43,794	0	43,794		2,190	2,190
PARTICULATE, grains/acf	0.000	4.006	0.019	0.000	0.020		0.009	0.009
PARTICULATE mg/Nm3	0.0	16,353	74.3	0	74		25	25
PARTICULATE lbs/MM Btu	-	13.55	0.07	-	0.07	-	0.02	0.02
PARTICULATE, tpy	-	315,128	1,576	0	1,576		551	551
OXYGEN, percent	20.9	2.6	4.2	0.0	4.2		4.0	3.97
CO_2, percent	0.0	13.5	12.2	#DIV/0!	12.2		11.6	11.60

URS

Gas Velocities

- Design Flow
  - Absorber Inlet Duct
    - Potential increase in erosion
    - Elevated pressure drop
    - Flue gas maldistribution
  - Absorber Mist Eliminator
    - High liquid loading
    - Scaling
    - Carryover
- Low Flow
  - No issues

Area	Units	Design Flow Flue Gas Bypass		
		0.00	10.00	27.00
Inlet Plenum	fps	75.61	68.05	55.2
Bypass Duct	fps	0.00	15.80	57.6
Absorber Inlet Duct	fps	67.4	60.7	48.5
Absorber Inlet	fps	67.4	60.7	48.5
Absorber	fps	19.2	17.3	13.8
Mist Eliminator	fps	~~16.0~~	~~14.4~~	~~11.5~~
Absorber Outlet Duct	fps	67.2	60.5	48.4
Stack Breach	fps	48.3	49.6	51.9
Stack Bottom	fps	53.7	55.1	57.7
Stack Top	fps	85.9	88.2	92.3

Area	Units	Low Flow Flue Gas Bypass		
		0.00	10.00	27.00
Inlet Plenum	fps	62.8	56.5	45.8
Bypass Duct	fps	0.0	13.1	47.8
Absorber Inlet Duct	fps	56.0	50.4	40.3
Absorber Inlet	fps	56.0	50.4	40.3
Absorber	fps	15.9	14.3	11.5
Mist Eliminator	fps	~~13.3~~	~~12.0~~	~~9.6~~
Absorber Outlet Duct	fps	55.8	50.2	40.2
Stack Breach	fps	40.1	41.2	43.1
Stack Bottom	fps	44.6	45.7	47.9
Stack Top	fps	71.3	73.2	76.6

URS

Available Options - Design

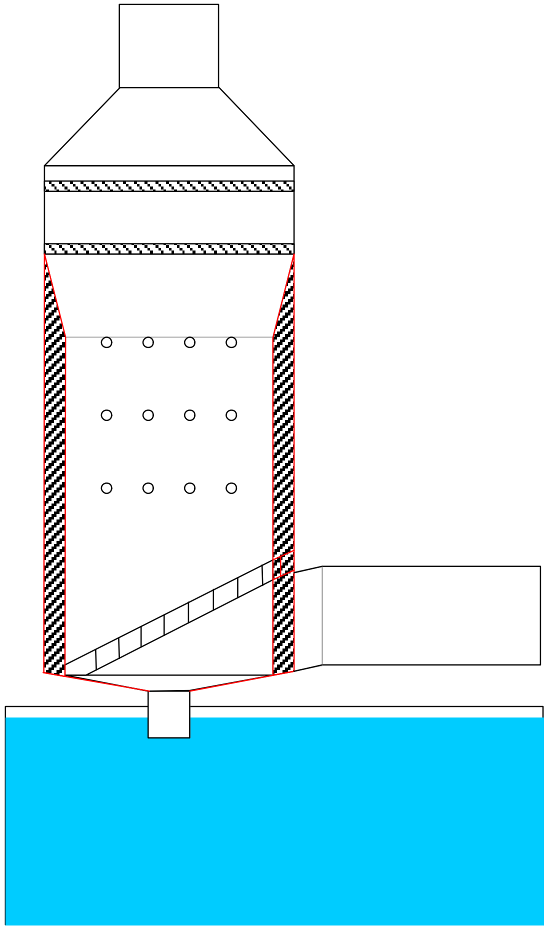
- Design, 10% Bypass
  1. Gas Velocity at 17 fps
  2. New mist eliminator
  3. Liquid Distribution Rings
  4. Duct and stack condensation traps
  5. Fan upgrade
     1. 2.4" increase in pressure drop
     2. Tip the fan
     3. New motor?
  6. Evaluate if DBA system is required to control scaling
     1. If scaling continues to be a problem – not expected

- Design, 0% Bypass
  1. Expand current towers or install a fifth module
     1. Reduce velocity from 18.9 fps to 15.4 modified
     2. Reduce pressure drop increase from 4.3" to 1.4"
  2. New mist eliminator
  3. Liquid Distribution Rings
  4. Fan upgrade
     1. 1.4" increase in pressure drop
     2. Within the capability of the existing fan?
  5. Duct and stack condensation traps
  6. **Stack upgrade or new stack**
  7. Evaluate if DBA system is required to control scaling
     1. If scaling continues to be a problem – not expected

URS

Expand Current Absorber Modules

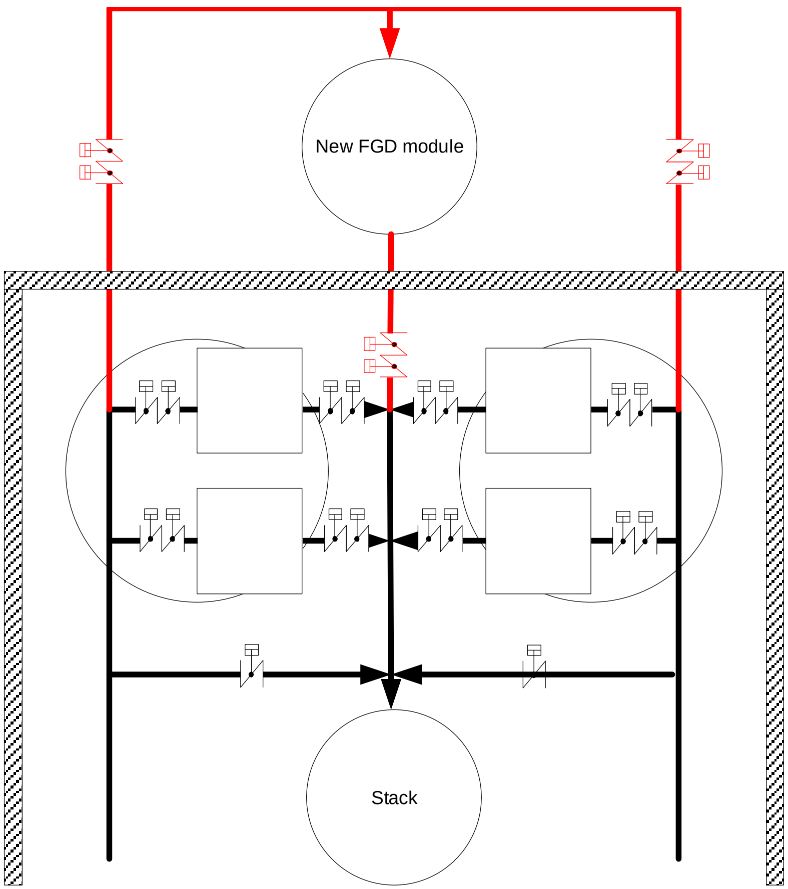
- Concept
  - Upgrade to straight sides
  - Pros
    - Complete utilization of ME area
    - 20 percent reduction in gas velocity
    - No changes in:
      - Foundation
      - Building
      - Electrical
      - Process etc
      - Equipment (pumps etc)
  - Cons
    - Module outages required
      - Can be completed over several regular scheduled outages
    - Substantial field work



URS

New Fifth Absorber Module

- Concept
  - Install a fifth absorber module
  - Pros
    - 20 percent reduction in gas velocity
    - Limited impact on operation
  - Cons
    - Considerable plant impact
      - Building expansion
      - Foundation
      - Electrical
      - Process (pumps, piping)
      - Ductwork
      - Dampers
      - Flow balancing



Lime Slaker Capacity

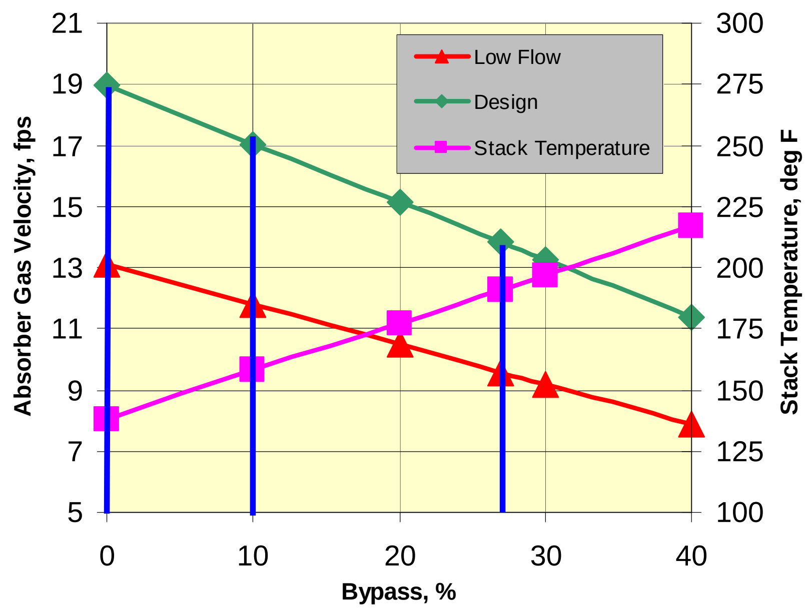
- Lime Consumption
  - Current: 4.7 tph
  - 10% bypass
    - 4.7 tph
    - One slaker required
  - 0% bypass:
    - 6.4 tph
    - Two slakers required
- Byproduct Blowdown
  - Current 234 gpm
  - Future 288 to 320 gpm
  - Sufficient capacity for all conditions

Bypass percent	Lime Consumption tph	Blowdown Rate gpm
0	6.4	325
10	5.8	292
20	5.2	260
27	4.7	237
30	4.5	227
6+4 tph slaker capacity		
2 x 300 gpm blowdown pump capacity		

Mist Eliminator and Stack

- Maximum gas velocity in the Spray Zone and ME

Bypass %	Design fps	Low Flow fps
0	18.9	15.9
10	17.0	14.3
20	15.2	12.8
27	13.8	11.6



- Issues from higher gas velocity
  - Higher liquid loading potentially leading to carryover
  - Increased alkalinity on the ME vanes potentially leading to scaling
  - Potentially higher wall sneakage leading to lower SO_2 removal
  - Reduced L/G leading to lower SO_2 removal

- Stack temperature
  - 158 ^{o}F at 10 percent bypass
    - May not be sufficient during winter
  - 138 ^{o}F at 0 percent bypass
    - Wet stack or reheat?

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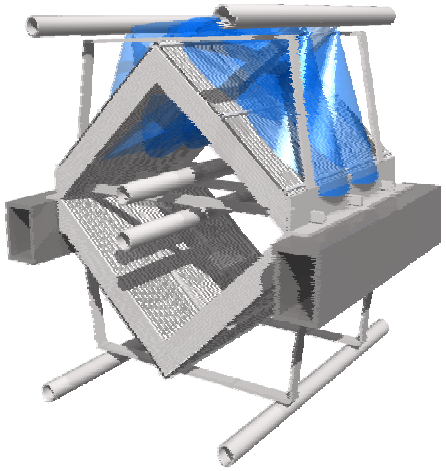
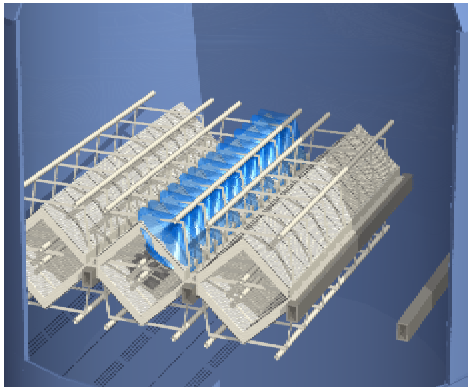
Achieve Required ME Performance

- New High Velocity Mist Eliminator
  - Munters DV 210 Plus
    - Single layer, diamond shape ME
    - Increased disengagement zone
    - Ideal for rectangular tower designs
    - High velocity, up to 25 fps continuous flow
    - Can handle flue gas mal-distribution up to 29 fps
  - Change wash water to 50/50 mixture of ash/service water



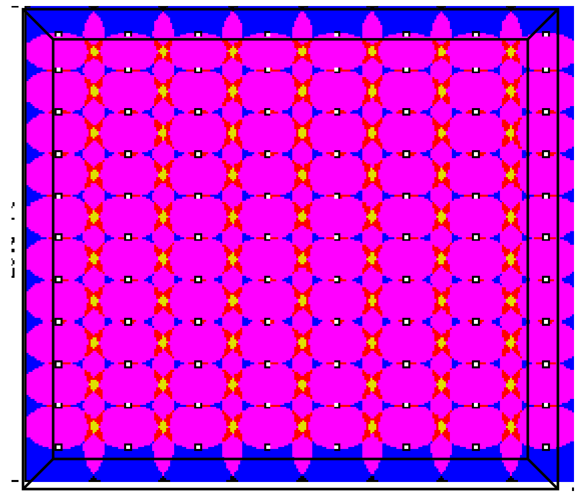


ME Wash System Guidelines

- Wash intensity – 1.5 gpm/ft2
- Wash pressure - >40 psi
- Spray nozzle – 90 degree, full cone
- Wash coverage – 200% overlap
- Distance from tip of wash nozzle to ME surface – 18” to 36”
- Wash duration – 90 to 120 seconds
- Wash frequency – 1st stage and front side of 2nd stage every 2 to 3 hours
- Backside of 2nd stage every 4 to 8 hours
- Wash water - < 50% saturated

Eliminate Wall Sneakage

- Liquid Distribution Rings
  - improve gas distribution
  - eliminate wall sneakage
  - increase SO_2 removal



Conditions		Design		Low Flow	
		Absorber	Station	Absorber	Station
As is	0	89.9	89.9	90.1	90.1
	10	90.9	81.8	92.3	83.1
	27	93.7	68.4	96.0	70.1
with LDR	0	94.0	94.0	94.1	94.1
	10	94.6	84.6	95.4	85.4
	27	96.2	69.2	97.6	70.6

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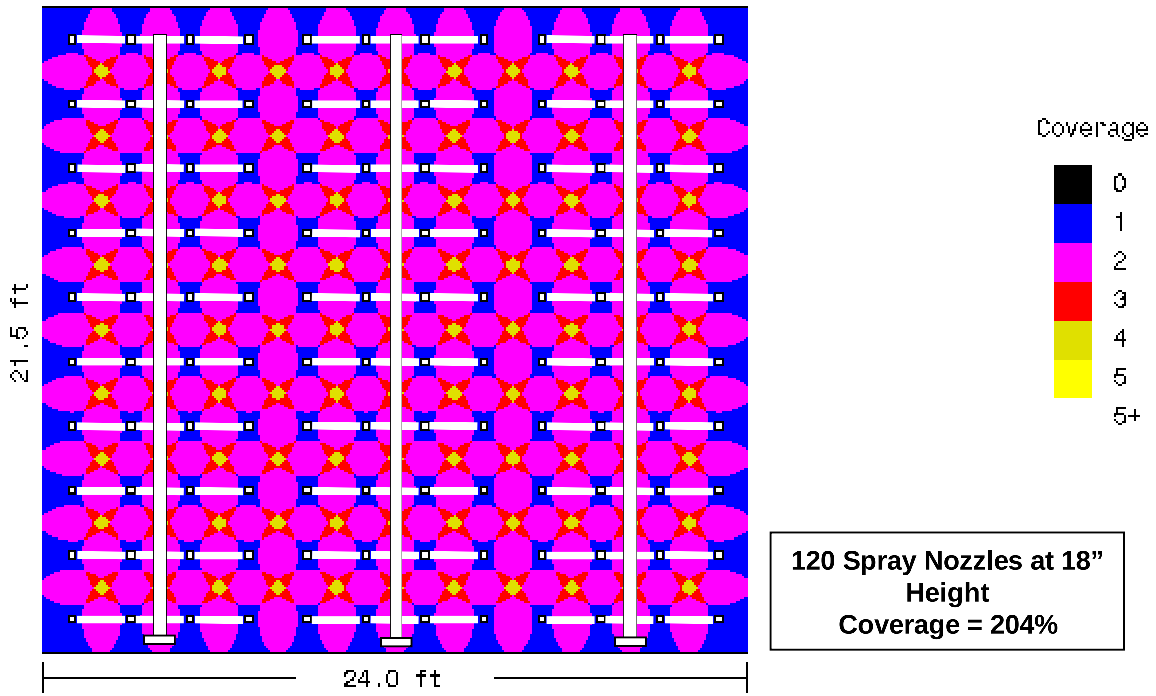
Proposed Nozzle Layout

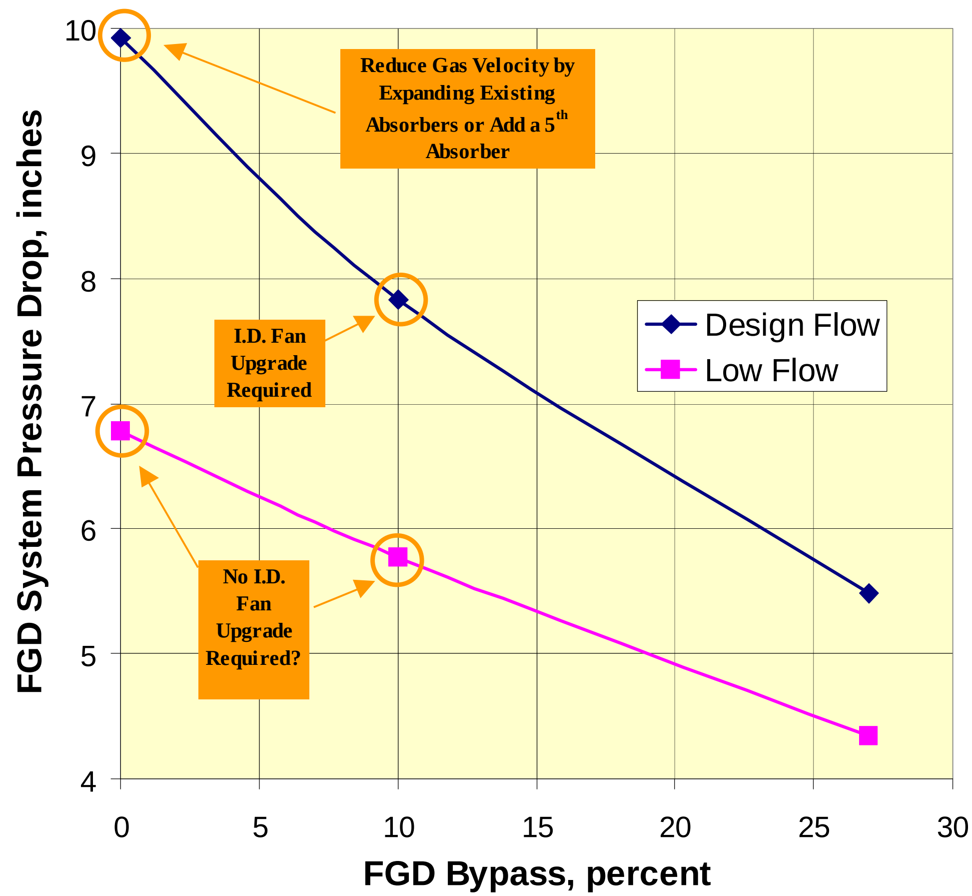


120 Spray Nozzles at 18" Height
Coverage = 204%

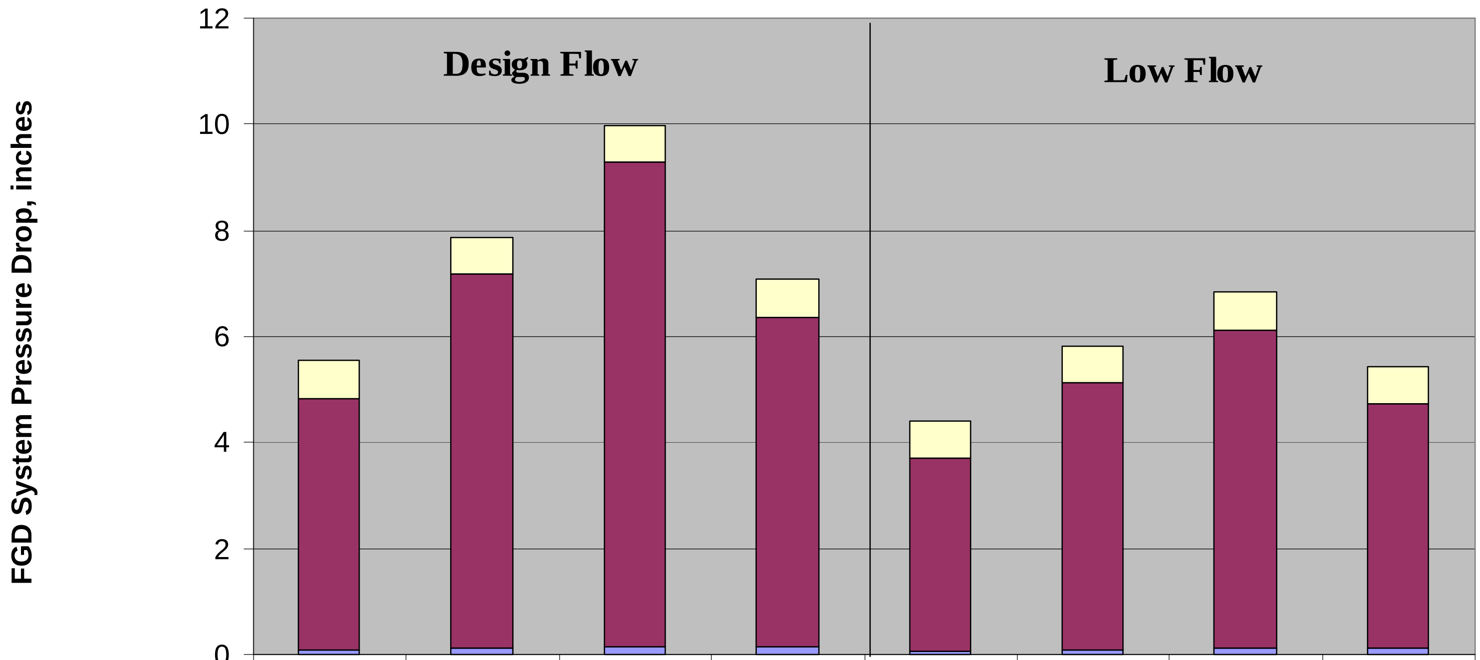
Figure 3: Proposed Nozzle Layout and Wash Coverage for Intermediate Wash Levels

Fan Capacity – Pressure Drop

- No Absorber Mods Implemented
  - Design
    - 5.5” at 27% bypass
    - 7.8” at 10% bypass
    - 9.9” at 0% bypass
  - Low Flow
    - 4.2” at 27% bypass
    - 5.7” at 10% bypass
    - 6.8” at 0% bypass
- Fan upgrade required and/or
- Reduction in gas velocity



Pressure Drop Prediction



	27%	10%	0%	O% Modified	27%	10%	0%	O% Modified
Outlet Ducts	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Absorber	4.74	7.05	9.12	6.22	3.63	5.03	6.01	4.62
Inlet Ducts	0.10	0.13	0.16	0.16	0.07	0.10	0.12	0.12

Remaining Issues – Path Forward

- Is partial bypass permissible
  - Costly stack modifications or a new stack can possibly be avoided
- Does zero bypass require a dry stack or is a wet stack feasible
  - Can the existing stack be upgraded to accommodate new conditions
- Can the existing fans be upgraded to provide the required head
  - Is the fan motor capacity sufficient
- Study gas distribution inside absorber modules and associated duct work using CFD to reduce overall pressure drop
- Select upgrade option/options, validate design assumptions and fine tune cost estimates

Summary

- Stack uses other than condensation traps excluded from study
- If permissible, partial bypass (10%) is clearly the low cost option
- Reducing flue gas flow is very cost effective option
- If zero bypass is required, expanding the current absorber modules is the low cost and least intrusive approach
- URS has the experience and know-how to provide the required absorber modifications

URS

Appendix J

Revised Foster Wheeler Proposal

Added February 2007

FOSTER WHEELER NORTH AMERICA CORPORATION
Perryville Corporate Park
Clinton, NJ 08809-4000, USA

TANGENTIAL LOW NOx COMBUSTION SYSTEM EMISSIONS PERFORMANCE UPGRADE

GREAT RIVER ENERGY

COAL CREEK
UNITS 2

Proposal No. 65-120220-00 rev01

October 6th, 2006

PROPIETARY AND CONFIDENTIAL INFORMATION

The Foster Wheeler North America Corporation Services Management Commitment

Foster Wheeler is committed to being the vendor of choice for our utility and industrial clients by continually supplying products and services that meet their need for improved profitability. We will accomplish this through open communication and measurable performance objectives and by being fiercely focused on cost.

Foster Wheeler is uniquely qualified to support the mission of Great River Energy with over a century of experience with design, fabrication, erection, commissioning, and rehabilitation of steam generating equipment. We have over 150,000 MW of installed equipment. Our mission is to provide our clients the best low NOx technology in the world. The experience we have gained through over 200 million hours of operation of our equipment and our sophisticated simulation models allow us to accurately predict how your unit will operate as a result of changes intended to increase performance, reliability, and operational flexibility, regardless of the OEM. As a subsidiary of Foster Wheeler Limited, we have the financial clout to stand behind our performance guarantees. We have the project managers, engineers, procurement and financial specialists and the manufacturing, erection, and commissioning capability to meet your needs regardless of complexity. Our list of repeat, satisfied customers is long and growing. We would like to continue our relationship with Great River Energy with this challenging project and look forward to the opportunity to work with you.

Sincerely,

Ed Dean

Executive Vice President, Services Division

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

Foster Wheeler North America Corporation is pleased to submit to Great River Energy our proposal for the engineering and material supply of a TLN3 System for Coal Creek Units 1 & 2. Foster Wheeler has enjoyed the successful relationship we have and look forward to serving Great River Energy in this and future projects. Foster Wheeler believes this proposal is a high value solution with many unique features and capabilities that will benefit the long-term emission performance, operation and maintenance of these units.

The original TLN3 system supplied by Foster Wheeler in the late 1990s was designed to reduce NOx below 0.35 lb/MBtu. After installation and optimization, even lower NOx levels were achieved. Great River Energy is planning to install a coal drying system to reduce the coal moisture from current levels of 35 – 38%. After this system is on-line, the primary air will be greatly reduced from current levels of over 50%. This primary air reduction will result in more secondary air available for staging as well as introduction into the main windboxes.

The new TLN3 System is based on increasing the size of the SOFA windboxes and ducts to allow more overfire air and thereby lower NOx levels. In addition, the main windbox damper venturi system will be modified to accommodate the increased amount of secondary air.

Primary Scope of Supply

Our base scope of supply includes all the necessary components to achieve the requested 0.17 lb/MBtu NOx levels.

a) The proposed TLN system(s) will be based on a single level of separated overfire air (SOFA) including all necessary waterwall tube panel openings and secondary air ducting. The new, larger SOFA windboxes will be located in the same location as the current windboxes. The SOFA ductwork is larger to allow more flow, but is less tortuous to provide less pressure drop.

b) Larger damper venturis will be provided to allow operators with enhanced air-staging capability. It also improves windbox-to-furnace and secondary air damper control over a greater unit load range.

c) Foster Wheeler patented Double Shroud "Boundary" auxiliary air nozzles will be provided to direct air in "multiple directions" versus just "concentrically", to reshape the fireball for control of slagging, emissions, as well as oxygen and temperature profiles.

Other typical features of the Foster Wheeler TLN Systems

a.) Our separated overfire air systems are designed to reduce installation time and costs including minimal, or no buckstay modifications, minimal tube cuts, etc.

b.) All nozzle tips, windbox components and upgrades are 100% compatible and inter-changeable with existing windbox equipment.

c.) We provide a full line of tilt, damper and other related tangential firing equipment upgrades to compliment your TLN retrofit.

Our vision is to provide our clients with the best low NOx coal fired technologies in the world. We believe we have achieved this goal. As part of this goal we provide user-friendly, low NOx systems that not only meet your long-term emission and boiler performance objectives, but also minimize retrofit and long-term operating costs. We look forward to continuing our relationship with Great River Energy with this project.

2. INTRODUCTION TO FOSTER WHEELER NORTH AMERICA CORPORATION

In 1927, Foster Wheeler Corporation was formed when Wheeler Condenser and Engineering Company of Carteret, New Jersey merged with Power Specialty Company of Dansville, New York. Innovators in the field of superheaters and condensers, the two companies, operating as Foster Wheeler Corporation, went on to form other subsidiary companies to specialize in different facets of the steam generation and process plants industries.

Foster Wheeler Corporation grew and subdivided into Foster Wheeler Ltd., Foster Wheeler International Corporation, and Foster Wheeler Equipment, Process Plants and Fired Heater Divisions. In 1973, Foster Wheeler Energy Corporation (FWEC) was established by joining the FWC Equipment, Process Plants and Fired Heater Divisions.

In 1985, Foster Wheeler Energy Corporation transferred the assets of the Process Plants and Fired heater Division to form Foster Wheeler USA Corporation. Foster Wheeler Constructors, Inc. was formed in 1987 to provide construction services for both FWEC and FWUSA. In 2001, Foster Wheeler Corporation organized and adopted the name Foster Wheeler Ltd. Today, Foster Wheeler Ltd. is an internationally operating company addressing the needs of clients through two operating groups. They are the Engineering & Construction and Energy Equipment Groups.

Foster Wheeler Power Corporation (FWNAC) is the wholly owned subsidiary of Foster Wheeler Power Group, Inc. (FWPGI) in the United States of America. FWPGI provides products and services in steam generation and process plant markets throughout the world.

With the acquisitions of Zack Power and Industrial and Alhstrom Pyropower in 1995, Foster Wheeler Power Group Inc. now offers greater capabilities within our range of products and services. Operations have expanded and include engineering and construction services, manufacturing, research and development, aftermarket customer service and project management. Our equipment includes pulverized coal, oil and gas boilers (both utility and industrial), fluidized bed boilers (bubbling and circulating), condensers, feedwater heaters, tubular air heaters, wall, tangential and arch fired burners, pulverizers and other related equipment.

The scope of FWNAC Services includes, but is not limited to, engineered unit retrofits, increase in unit efficiency and availability, test and performance engineering, inspection services, engineering and life extension studies, alternative fuel firing, options and analysis, and replacement parts. This full-service operation ranges from conceptual analysis through manufacturing and construction for all boiler types, regardless of size, fuel or original design.

3. TECHNICAL DISCUSSION

3.1 Unit Description

Coal Creek Units 1 & 2 are 560 MWG, controlled circulation, radiant, reheat, balanced draft, and divided furnace, Combustion Engineering (CE) generating units. Each unit was originally designed for a maximum continuous rating (MCR) for superheat and reheat steam flow of 3,730,000 lbs/hr and 3,325,000 lbs/hr, respectively. Steam conditions at the superheater outlet are 1,005°F and 2620 psig. Reheat outlet temperature of 1,005°F is controlled by fuel nozzle tilt and superheat outlet temperature is controlled by two desuperheating spray valves (one for each furnace half).

The unit is designed to fire North Dakota Lignite from the nearby Falkirk mine, through eight (8) 1043 RP mills with hydraulics into eight elevations of tilting tangential fuel nozzles. Each of the 1043 RP pulverizers were designed to pulverize 136,8000 lbs/hr coal flow with a Hardgrove Grindability Index (HGI) of 35, while producing coal fineness output of 65% through 200 Mesh and 2% on 50 mesh screens. The moisture of the coal was specified for design as 36.6%, but typically varies between 35 and 42%. The design airflow through these 1043 RP mills was 255,000 lbs/hr.

In the early 1990's, the 1043 RP mills were retrofitted with ABB-CE vane wheels to increase airflow. Currently, these mills operate at 350,000 lbs/hr airflow in order to keep the mill outlet temperatures above 145 °F. At mill outlet temperatures below 145 °F, these pulverizers have the tendency to load up and/or plug up.

In the late 1990's, Foster Wheeler designed and supplied the current TLN3 low NOx system. It was designed to achieve NOx emission levels of 0.35 lb/MBtu. Further reduction with the Foster Wheeler TLN3 System was achieved after tuning and optimization. Currently, NOx emissions range between 0.18 – 0.30 lb/MBtu.

3.2 Technical Evaluation of Current Unit Operation

We believe that it is very important, when designing a low NOx firing system retrofit, that the designers understand the current unit operation including fuel effects, equipment limitations and client requirements. Each boiler windbox arrangement is simulated with our proprietary Windbox Simulation Program to assure proper flow distribution for staging and air jet penetration for optimal fuel air mixing. We also look at the boiler design and arrangements, fuel ranges and constituents, pulverizer air, coal and fineness, burner zone heat release rates, etc. We also compare each proposed design to other similar units that we have retrofit, further assuring successful post-retrofit performance.

Foster Wheeler was last on site to perform some unit optimization in August 2005. Some highlights of this evaluation are presented below. FWNAC believes that such on-site evaluations and discussions with operations personnel allow the designer to provide a low NOx system custom tailored for the unit.

- Overall, this unit currently operates at average NOx levels compared to units of similar vintage and size firing similar coals. NOx emissions at full load range from 0.18 to 0.30 lb/MBtu. The EPA website data shows the NOx averaging 0.22 to 0.24 lb/MBtu at full load. The higher NOx values are attributed (most likely) to a function of main windbox burner tilt location, excess air levels and manual, non-adjusted control of main windbox air dampers. During the August optimization, NOx levels were maintained at 0.18 lb/MBtu for extended periods.
- Main burner tilts operate above horizontal position between 5 to 12 degrees
- CO levels are not measured on these units.
- UBC is reportedly below 0.5%
- Mill fineness is reported as 65% though 200 mesh and 98% through 50 mesh.
- Windbox-to-furnace differential pressure averages 4.0 – 4.5 In. H_2O at 100% MCR.
- Superheat and reheat temperatures were 1000 °F and 1003 °F respectively.
- Boiler O_2 averaged 2.5% during optimization with side to side values measuring ±0.2% from average.
- All pulverizers were evenly loaded during the testing.

3.3 Foster Wheeler's Tangential Low NOx (TLN) Systems

3.3.1 Design Philosophy

Foster Wheeler North America Corp's (FWNAC) Tangential Low NOx (TLN) Combustion Systems provide industrial and utility boiler owners with an alternative solution to their NOx compliance needs. Our philosophy is to provide our clients with the highest value low NOx system.

- Our systems are designed to maximize NOx reduction efficiency while minimizing the impact on combustion performance or unit operation. Our combined wall and tangential-fired combustion expertise gives FWNAC a unique perspective no other combustion equipment supplier can claim. An extensive support team of experienced technical and project specialists backs our commitment.

- We focus on designing systems that minimize changes to the furnace and/or the boiler house. This reduces installation time and costs for the owner.

- We believe each TLN application should compliment the unit's operational capabilities as well as the range of current and future fuels.

- We believe that each TLN system should provide years of reliable service. All tangential-fired windbox components are manufactured in either our own facilities or per our specifications by high quality suppliers.

- A team of experienced and qualified tangential firing engineers, project managers, service engineers and suppliers, supports each project. Our goal is to make each of your TLN retrofits your most favorable project.

Our system technology is supported by a continuous commitment to improve performance and reliability. For example, our on-line, real-time, ECT coal flow distribution, velocity and particle size monitoring technology combined with our CADM system allows fuel and air to be more balanced for lower CO and higher combustion efficiency.

3.3.2 FWNAC’s TLN Systems

Foster Wheeler’s Tangential Low NOx (TLN) firing systems are based on the application of secondary air staging technology commonly referred to as “overfire air”. Both in-windbox and separated secondary air-staging arrangements are applied depending on current windbox configurations and the desired level of NOx reduction. Staging of secondary combustion air has been well documented throughout the international boiler industry to be the single most effective technique for reducing NOx emissions from tangentially fired boilers. By redirecting a portion of the combustion air above the upper fuel elevation, fuel nitrogen conversion and thermal NOx production is reduced. Control of this staging process through proper nozzle and damper design is critical in order to maximize combustion efficiency and component longevity. Depending on the unit configuration and required NOx reductions, Foster Wheeler can offer several high value options. These include the TLN1, TLN2 and TLN3 arrangements, which are shown below in **Figure 1.**

FWNAC’s **TLN1** arrangement is an “in-windbox” secondary air staging system. It consists of reconfiguring the tangential windbox fuel and air nozzle arrangement to provide the required air staging effect. The TLN1 arrangement requires lowering existing upper coal elevations in the windboxes to make provision for “in- windbox secondary air staging, or overfire Air. Depending on the specific windbox arrangement, these systems can provide up to approximately 250 ppm (corrected to 3% O_2) of NOx reduction.

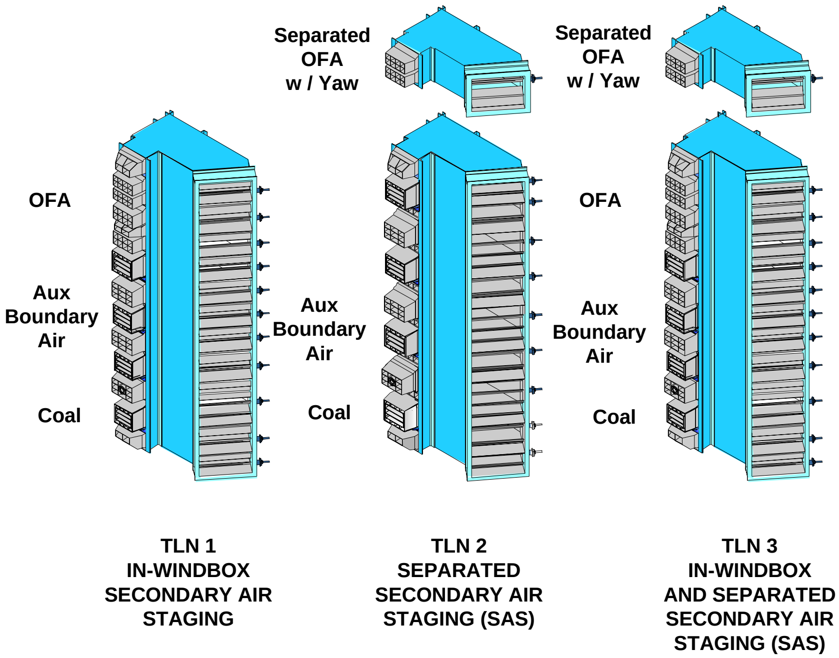


Figure 1 - FWNAC Tangential Low NOx (TLN) Configurations

Alternatively, for units that already have in-windbox/CCOFA compartments installed, the TLN1 installation would involve installing High Efficiency (HE) type CCOFA and top end air nozzle tips. These provide up to an additional 30% more flow area than the original tips. By utilizing the existing manual tilt capabilities in the CCOFA compartments, separation can be obtained between the CCOFA and the main combustion zone. In addition, the flow areas in the bottom end air, auxiliary air, and coal elevations would be optimized to bias air flow to the top end air / CCOFA elevations and nozzle tips would be re-sized to maintain design outlet velocities.

The TLN1-HE arrangement can also be upgraded to a TLN3 System in the future with minimal main windbox modifications

FWNAC also offers more aggressive NOx control arrangements using Separated Overfire Air (SOFA), including the TLN2 and the TLN3 systems. Increased separation between the upper most coal elevation and overfire Air level results in greater NOx reduction. Depending on the unit design and fuel, these arrangements are capable of NOx reductions exceeding 70%.

FWNAC's **TLN2** system consists of adding an additional level of overfire Air above the main firing zone to provide the required air staging effect. Because of increased spacing from the upper coal elevation, these arrangements generally provide higher NOx reduction efficiencies compared with in-windbox arrangements.

FWNAC's **TLN3** system consists of adding single level of separated overfire Air to units that already have an in-windbox OFA. This system is best suited for both post-NSPS or unit units previously retrofit with in-windbox overfire Air arrangements. Other applications of the TLN3 arrangements are units where interferences do not permit placement of an adequate single overfire Air windbox. According to our experience, the reduction efficiencies of the TLN3 systems are similar to TLN2 systems.

It should be noted that applying more levels of overfire air results in a limitation of furnace residence time for carbon particle burnout; therefore careful design consideration is required to minimize UBC losses.

3.4 Typical TLN Components and System Features

3.4.1 Separated Overfire Air Systems

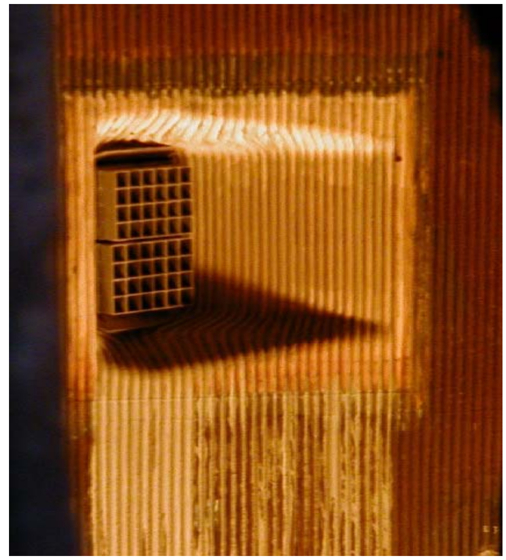
The advantages of the FWNAC Separated Overfire Air (SOFA) system over other suppliers are its compact, yet performance efficient, design. This reduces the physical changes within the boiler house, thereby reducing installation time and cost. See **Figure 2** below for typical SOFA windbox and nozzle assembly**.**

Figure 2 - TLN Separated Overfire Air Windbox with Horizontal Yaw and Vertical Tilt Control

Introduction of staged secondary air, as “overfire air” is the single most important NOx performance component in any tangential low NOx system retrofit. Whether it is located in the main windbox or separated, it should provide the highest NOx reduction efficiency. The FWNAC SOFA systems provide the following specific features:

1. Compact separated windbox design that minimizes installation costs associated with tube panels, buckstay or other boiler house modifications.
2. Optimum vertical and horizontal placement assures highest NOx reduction efficiency and maximizes fuel/air mixing during this critical stage in the combustion process.
3. SOFA placement considers minimizing tube cuts and welds.
4. Adjustment capability is provided for maximizing fuel/air mixing through horizontal yaw, velocity, tilt and flow control.
5. Separated staging windboxes are fitted with turning vanes. The associated connecting duct designs are laid out to minimize system resistance, reducing auxiliary power requirements.
6. A minimal number of nozzle tips and linkages are applied to improve reliability and reduce long-term maintenance.
7. No refractory SOFA ports, only proven adjustable stainless nozzle tips with directional control are used.
8. Pressure taps in each compartment provide air distribution information and are used in the optimization process.
9. All components are designed and fabricated for long-term reliability.
10. For more aggressive NOx control, Foster Wheeler offers ours ECT and CADM systems, which allow for real-time quantified coal pipe distribution, velocity and particle size as well as air distribution.
11. Pressure taps in each compartment provide air distribution information and are used in the optimization process.
12. All components are designed and fabricated for long-term reliability.
13. For more aggressive NOx control, Foster Wheeler offers ours ECT and CADM systems, which allow for real-time quantified coal pipe distribution, velocity and particle size as well as air distribution.

Foster Wheeler SOFA Windbox with two "double shroud" nozzle tips



Installed TLN SOFA System

Figure 3 - Foster Wheeler Separated Overfire Air Windbox

14. Pressure taps in each compartment provide air distribution information and are used in the optimization process.

15. All components are designed and fabricated for long-term reliability.

16. For more aggressive NOx control, Foster Wheeler offers ours ECT and CADM systems, which allow for real-time quantified coal pipe distribution, velocity and particle size as well as air distribution.

3.4.2 Coal Nozzle Tips and Nozzle Assemblies

All Foster Wheeler coal nozzle tips and coal nozzle assemblies are designed to match coal characteristics and pulverizer performance. This is key to preventing future pluggage or burn-back problems that reduce component life and inhibit unit long-term emission performance. All are designed to provide localized air staging, complimenting the overfire air based TLN system. Each Foster Wheeler coal nozzle assembly offers the following features:

1. All coal nozzle tips are designed to maintain high temperature structural integrity. This includes the mechanical design aspect as well as radiation protection for the internal sections. Foster Wheeler's new "Double Shroud" (DS) coal nozzle tips (US

Patent No. 6,260,491) are standard on most TLN retrofits. This design can offer even greater high temperature thermal resistance over conventional designs. See **Figure 4** below.

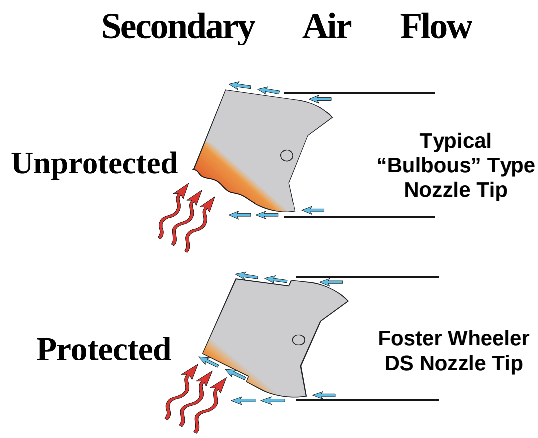


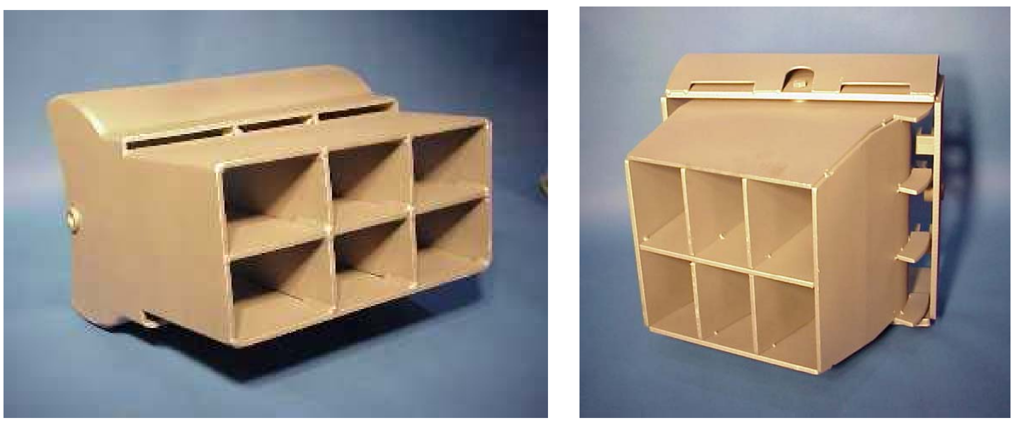
Figure 4 - Foster Wheeler's Double Shroud Coal Nozzle Tip

2. The new DS style coal nozzle tips are available in either single piece or two-piece stainless steel construction. Most Foster Wheeler DS style coal nozzle tips are capable of being replaced from the furnace side without removing the stationary coal nozzle assembly. This feature also allows coal nozzle tip side clearance adjustment without having to remove the complete stationary coal nozzle assembly. This feature saves 80 to 100 man-hours per coal nozzle.
3. Contoured outer radiation shrouds provide laminar air flow around the tips for added cooling and directional control of the air.
4. All nozzle tips are designed to maintain structural integrity due to thermal stresses.
5. All Foster Wheeler coal nozzle tip assemblies are <u>100% compatible and interchangeable</u> with all existing windbox tilt linkages and other windbox internals.
6. The leading edges of splitter plates are hard surfaced for increased erosion resistance.
7. *Optional* coal nozzle tips are also available without seal plates.
8. *Optional* coal nozzle and tip assemblies are available with added wear resistant hard-surfacing and or materials.

3.4.3 Auxiliary, Boundary and Overfire Air Nozzle Tips

Typical windbox changes, associated with a TLN retrofit, consist of replacing many of the nozzle tips and associated hardware. Replacing particular nozzle tips is required primarily for performance reasons and secondly for reducing long-term maintenance costs. Foremost, it allows the system designer to redistribute the air properly in order to achieve the desired staging for NOx reduction. Secondly, it maximizes the air velocity leaving the air nozzle to ensure the highest degree of fuel/air mixing in the main firing zone. Thirdly, is assures adequate nozzle tip film cooling is maintained. Consequently, service life of individual nozzle tips is noticeably increased through proper nozzle sizing. Significant maintenance cost reductions can be realized in these cases.

All FWNAC air nozzle tips are designed for high temperature structural integrity. Each is available either as a single or two-piece design fabricated from a 309 stainless steel for high temperature oxidation resistance. Other specific materials are available upon request. Where applicable, the new "Double Shroud" (US Patent No. 6,260,491) design is provided for all air nozzle tips. See **Figure 5**.



(a) Tilting ***(b) Boundary Air***

Figure 5 - FWNAC's Double Shroud Air Nozzle Tips

The configuration of each newly provided nozzle tip consists of a contoured inlet for more laminar flow under tilted conditions as compared to the current equipment. An optional two-piece design allows replacement from the furnace side should it ever become necessary.

Foster Wheeler's "Boundary Air" nozzles direct secondary air tangent to two or more imaginary circles within the furnace. The air tips in each corner are set independently to direct air from a given corner at a significantly different angle from the air coming from another corner or other corners. These range from one corner being aimed directly at the center of the furnace for instance, to another directing air along the furnace waterwall, etc. This variable positioning allows further control of the fireball shape to provide more even flue gas conditions exiting the combustion zone. These tips are provided only when required to reduce furnace waterwall slagging and/or any localized corrosion. This is usually a one-time adjustment that is set during post-retrofit system optimization. See **Figure 6** following.

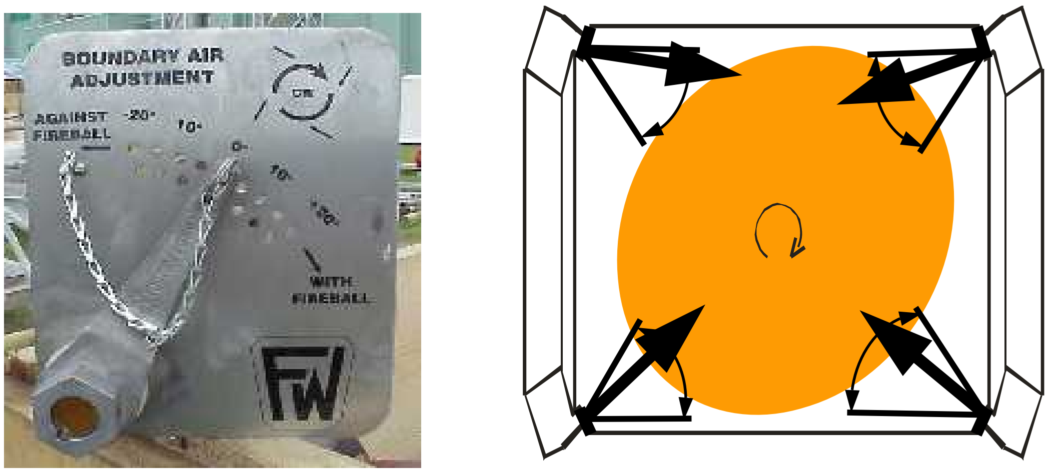


Figure 6 - Boundary Air Direction Control

The FWNAC SOFA nozzle tips include a similar feature that provides horizontal yaw adjustments. The nozzles from each individual SOFA windbox can be aimed, in unison, to direct the overfire air as required to maximize fuel/air-mixing momentum in this final phase of the combustion process. This adjustment is key for controlling exit CO emissions. This is a manual adjustment that usually requires only an initial adjustment during optimization. See **Figure 7** following.

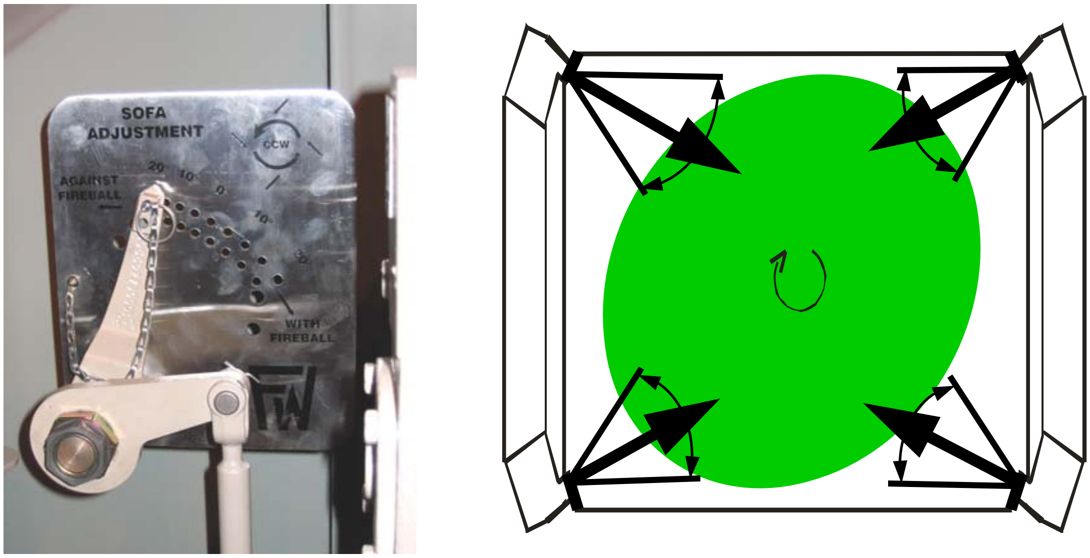


Figure 7 - SOFA Direction Control

3.4.4 Damper Venturi Inserts

FWNAC includes damper venturi inserts on most TLN retrofits. This upgrade, available for either existing or new damper systems, re-establishes windbox differential pressure control over the load range, lost due to the addition of overfire Air. It also insures that dampers operate in a controllable range. Another application is older tangential-fired units. These units tend to lose some windbox differential pressure control due to increasing furnace in leakage or other increased differential pressure requirements. Venturi damper inserts help re-establish this control.

The upgrade consists of installing venturi plates around existing damper blades or with new windbox dampers. It is an aerodynamic solution to increase the damper to nozzle tip flow ratio, providing improved air flow control and increased windbox to furnace differential control over a greater load range. A typical damper venturi installation is shown in **Figures 8 and 9.**

For information on the Optional Full Windbox Damper Upgrade, see “Design Update Bulletin No. 114.

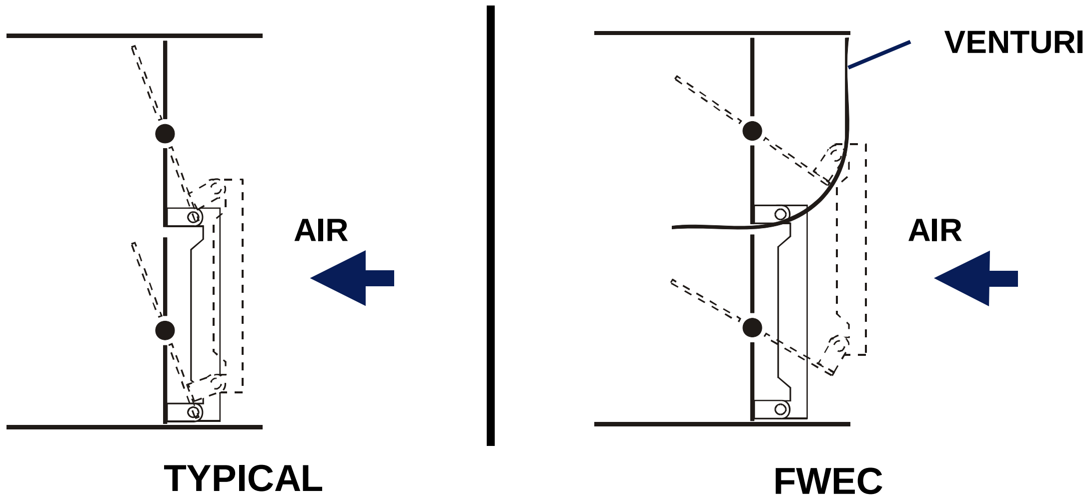


Figure 8 - FWNAC Damper Venturi Inserts

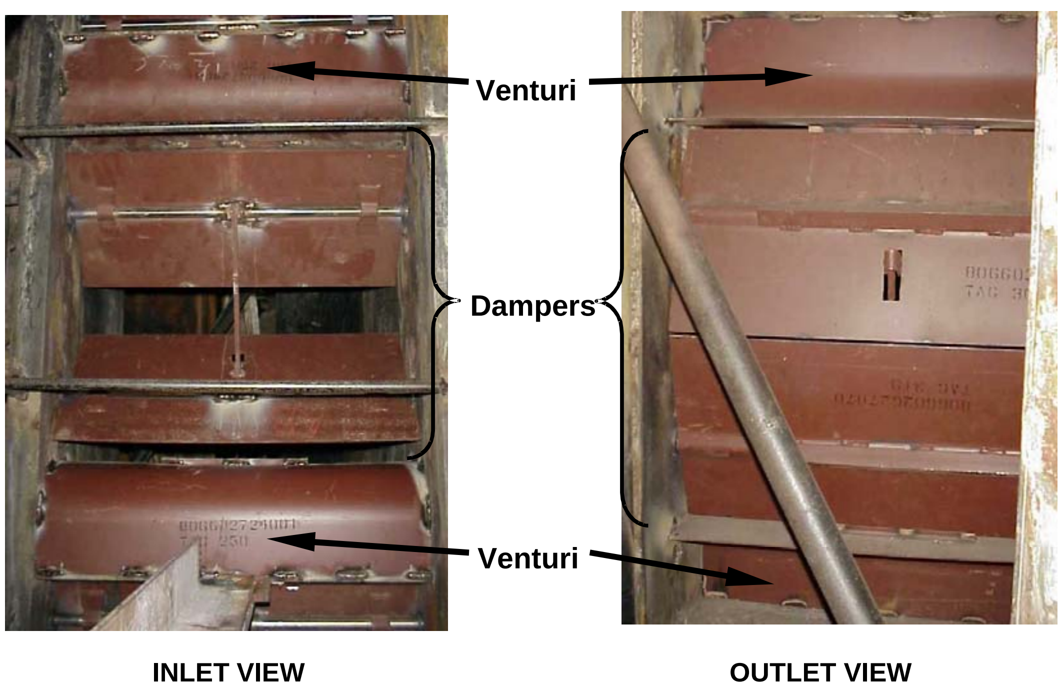
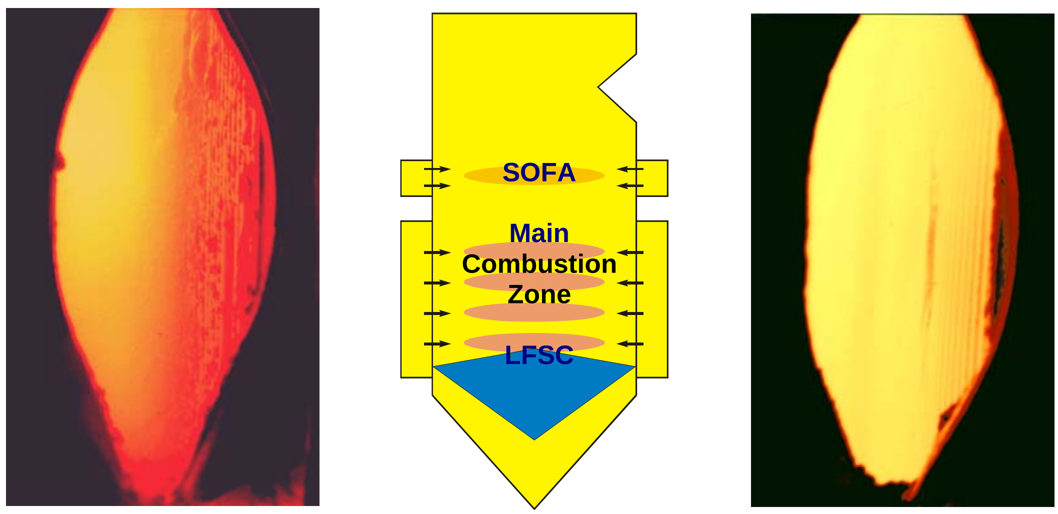


Figure 9 - Typical Damper Venturi Installation

3.4.5 Lower Furnace Stoichiometry Control (LFSC)

FWNAC's Lower Furnace Stoichiometry Control was developed to help control the lower furnace hopper conditions created during deep staged low NOx combustion. Specifically, this FWNAC unique feature was developed to manage the fuel rich, smoky conditions as well as slag buildup in the lower furnace. Dark lower furnace /hopper conditions are common on many tangential-fired units equipped with competitor's tangential low NOx systems. LFSC includes nozzle tips (sometimes) and linkage modifications (always) to independently direct a percentage of secondary combustion air into the furnace hopper. Besides reducing the dark lower furnace conditions, FWNAC's experience with the LFSC system has also seen NOx benefits. The lower furnace concept is depicted as **Figure 10**.



Original Firing Arrangement

TLN System With LFSC

Figure 10 - Comparison of Lower Furnace Conditions Without & With FWNAC's TLN System

3.4.6 Windbox Secondary Air Biasing

In order to efficiently achieve the lowest NOx levels from tangential-fired units, some degree of secondary air flow biasing, is usually recommended as part of every TLN retrofit. Depending on what air biasing capability exists presently, FWNAC may recommend some or all of the following biasing controls:

- Corner-to-corner auxiliary air biasing.
- Hot and cold corner fuel and auxiliary air biasing (8 corner units).
- Front-to-rear and/or side-to-side secondary air biasing.

- Elevation air biasing.
- Furnace-to-furnace air biasing.
- Individual compartment air flow control.

Many tangential-fired units have oblong "fireballs" due to the aspect ratios associated with this type of firing system. These conditions, especially under deeply-staged low NOx firing conditions, if left uncontrolled, could lead to high CO emissions, increased corner slag buildup, furnace oxygen imbalance, etc. Such limitations could become barriers to achieving the lowest possible NOx emissions. FWNAC's experience with air biasing shows that by selective air biasing, these conditions can be lessened and a rounder fireball shape can be achieved.

3.4.7 On-Line Conduit Coal Flow Measurement System (ECT)

Older vintage NOx reduction systems were capable of achieving moderate reductions in NOx at best. With the current emphasis on ultra low NOx emissions, these levels of reduction are no longer sufficient. Knowing and controlling the fuel and air distribution in a modern ultra low NOx combustion system is now key to achieving reliable long-term air staged operation without excessive CO or UBC formation. This fact has become evident, as more units are required to achieve very low emission levels. Without balance, high CO levels, unburned carbon, unequal oxygen profiles and temperature splits, etc. limit the reduction potential of low NOx systems. As a result, Foster Wheeler recommends the Electric Charge Transfer (ECT) system to provide operators with on-line, real time indication of coal flow conduit mass distribution, velocity and/or coal particle size.

ECT On-line Measurement of Coal Flow

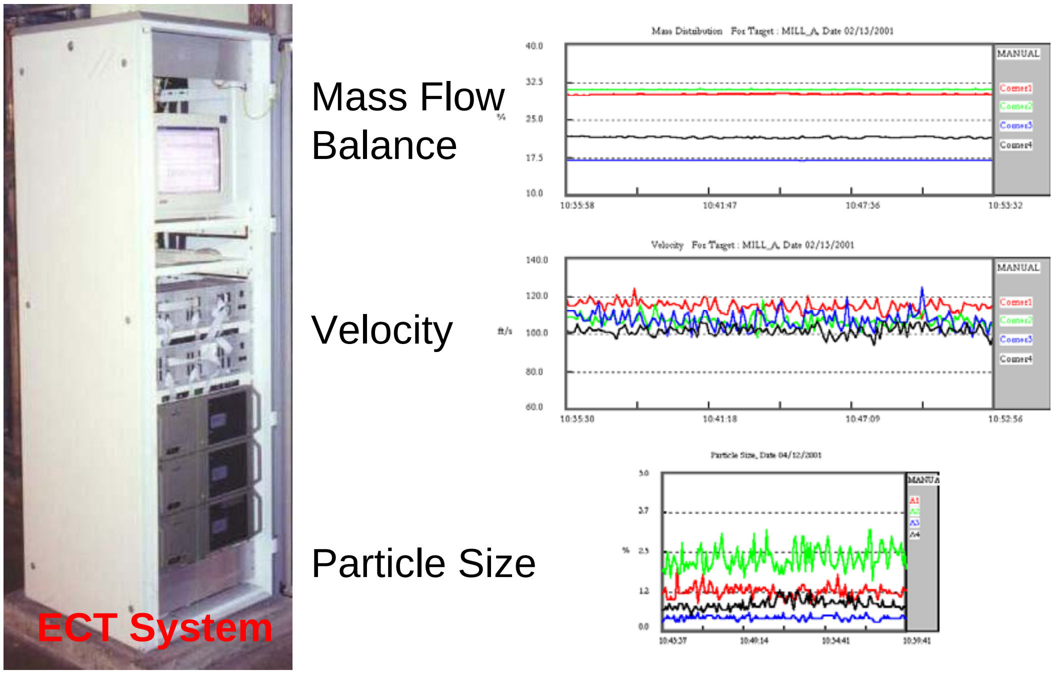


Figure 11 - ECT System and Features Measured

Due to aggressive CO requirements in typical specifications, Foster Wheeler commonly offers a system that monitors both the coal flow, velocity and/or particle size in each coal conduit as well as windbox air flow distribution in real time.

The ECT measurement, coupled with individual windbox compartment static air pressure measurements further enhances and accelerates the combustion optimization process. This type of information and control technology is well suited for application with Boiler Optimization Software. Additional information on the ECT System is presented in Attachments.

3.4.8 Compartment Air Distribution Monitoring (CADM) System

As mentioned previously, it is becoming more apparent in the low NOx power industry that in order to achieve ultra low NOx levels, air and coal flow distribution must be simultaneously monitored and controlled. This is analogous to the automobile industry changing from carburetors to fuel injection. Foster Wheeler is taking the lead in the industry with this Fuel Injection approach for pulverized coal-fired units.

Combined ECT/CADM are available as a fully automatic DCS controlled system. This is Foster Wheeler's Fuel Injection (FI) system. Coal flow through each coal nozzle is measured in real-time along with secondary air flow through each windbox compartment. Comparisons are made and the DCS is instructed to adjust secondary air balancing the air to match the coal floe distribution entering the furnace. Besides NOx and other gas profile benefits, results have shown extremely low CO levels under ultra low NOx operating conditions. **Figure 12** shows typical benefits data obtained from combined ECT/CADM System.

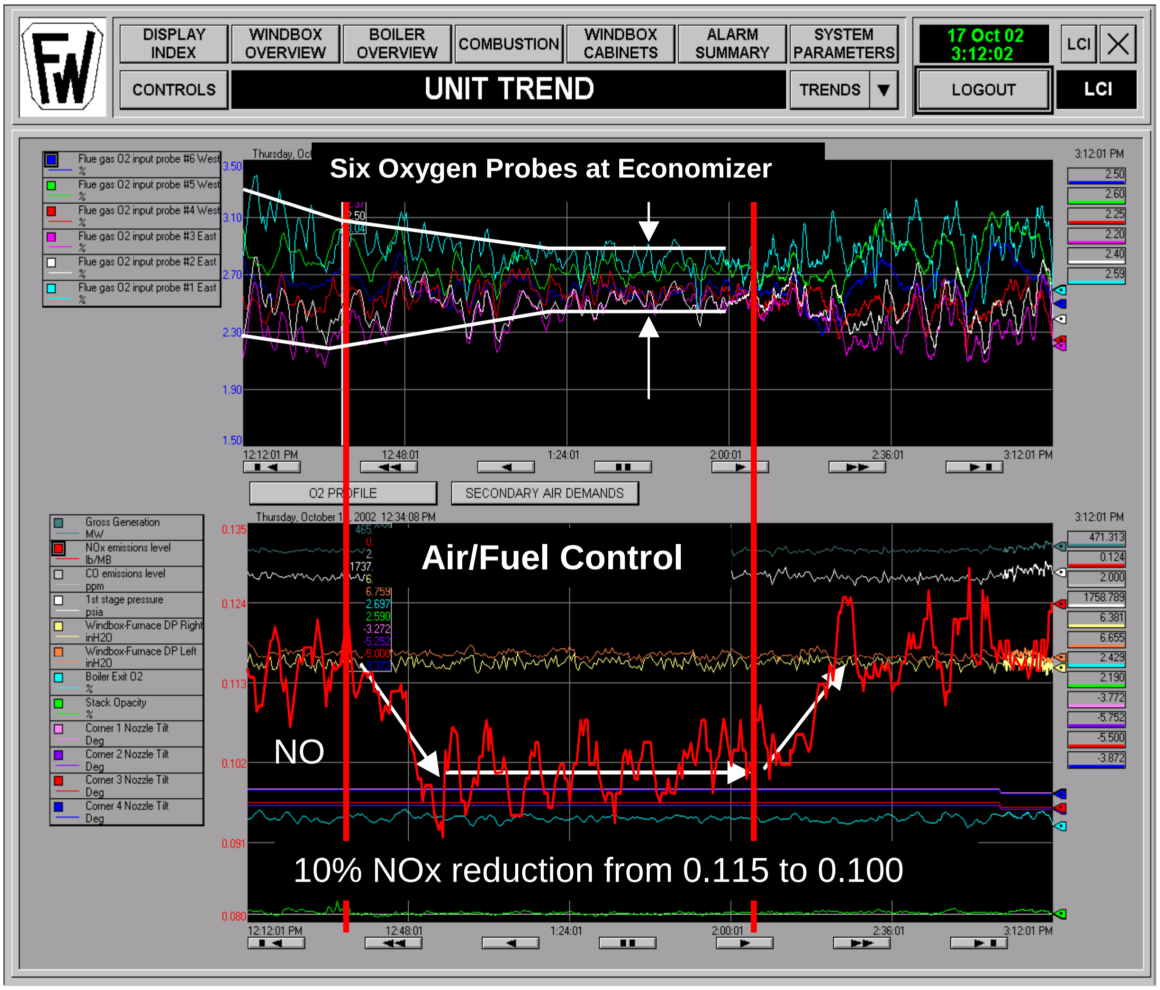


Figure 12 - NOx Reduction and O_2 Profile Improvement Results from 480 MW Unit Firing PRB Coal and Equipped with a TLN3 and both ECT and CADM operating under DCS Control

4. DESCRIPTION OF PROPOSED FWNAC TLN3 SYSTEM

4.1 Proposed TLN3 System for Coal Creek Units 1 & 2

Based on Great River Energy's requirements and FWNAC's evaluation of the current unit operation, FWNAC is proposing an "expanded" TLN3 System. Foster Wheeler's approach is to increase the amount of SOFA to each corner by installing larger SOFA windboxes and ducts, while staying between the existing buckstays, thereby reducing installation time and costs.

The descriptions of Foster Wheeler modifications are the same for both units. This will allow for design interchangeability.

The proposed FWNAC modifications to Coal Creek Units 1 & 2 are shown on FWNAC proposal drawings attached in the Appendices.

a) A SINGLE level of new separated SOFA windboxes will be provided as part of the FWNAC TLN3 system. This would consist of four (4) new, larger SOFA windboxes. To minimize physical changes to the boiler house, the new overfire air windboxes would be installed where the existing SOFA windboxes are. The new, larger SOFA windboxes are wider but maintain the same height so as to fit between the buckstays. The SOFA windboxes would be designed to supply an increased amount of combustion air as overfire air. Each new windbox will be provided along with new waterwall panels and the necessary larger, connecting ductwork, hangers, expansion joints and steel modifications to interface with the secondary air ducts. The new SOFA duct arrangement will eliminate the "S-shaped" bends to the inner corner windboxes, thereby providing less pressure drop. Each windbox will be fitted with nozzle tips, turning vanes, access doors, air control dampers and electric actuators and static pressure taps to provide total overfire air control. Manual "set and forget" horizontal yaw and vertical tilt capability would be provided in the SOFA to help control CO as well as back end gas temperature and oxygen profiles. The yaw linkage, manual tilt gearbox and damper drives will be accessible from the sides of each windbox.

b) On the rear waterwall, at the inside corners, there is an existing economizer valve that will need to be relocated. This is noted on the proposal drawing and will be detailed during the engineering and design phase. Currently, this relocation is anticipated as a simple matter of moving the valve down an elevation. (Note: there are several wall blowers one elevation above this valve).

c) Platform and structural steel modifications are not needed.

d) New Double Shroud "Boundary" auxiliary air nozzle tips for the (non-oil) 19 ¼" compartments. These nozzle tips are designed to provide the necessary velocity, air flow distribution and direction control to benefit NOx emissions, fireball shaping while maximizing combustion efficiency.

e) All CCOFA, coal and auxiliary air windbox compartments will be modified with FWNAC's larger damper venturi plates to improve air flow distribution control over a larger load range.

5. PROPOSED SCOPE OF SUPPLY

The Scope of Supply for the Foster Wheeler TLN3 System is listed below. Due to the similarities between Coal Creek Units 1 & 2, components are interchangeable. Quantities listed are for one (1) unit only.

5.1 TLN3 Engineering Scope

Item	Quantity	Description
1	One (1) lot	Engineering and design analysis for new TLN3 System.
2	One (l) lot	Engineering arrangement drawings to incorporate TLN equipment and unit modifications, including Bill of Materials.
3	One (l) lot	SAMA control diagrams to describe the desired control SOFA dampers, (see Appendix for typical SAMA drawings).
4	One (l) set	Listing of all required I/O

5.2 TLN3 Equipment Scope

Item	Quantity	Description
1	Eight (8)	Separated SOFA windbox; 32” wide furnace channel by approx. 56” high, complete with an appropriate number of compartments, including turning vanes, yaw and tilt mechanisms and 48” wide opposed blade damper assemblies. Damper blades will be carbon steel with stainless steel damper shafts. Damper bearings will be stainless steel except for the outboard damper bearings that will be self-aligning graphite. Two (2) Hagan pneumatic drives, and all mounting brackets and hardware are provided with each SOFA windbox (16 total). Each compartment will be fitted with an individual static air pressure tap. A rear access door is also provided.
2	One (1) lot	Complete secondary air duct system for SOFA. Includes structural steel check for proposed hanger assemblies.

3	Four (4)	Waterwall tube panels to incorporate SOFA. Rifled/ribbed tubes of material similar to existing water wall.
4	Two (2)	Duct scoops to direct secondary air into the overfire air ducts.
5	Thirty-two (32)	“Boundary” air nozzles for each of the 19 ¼” auxiliary air (non-oil) compartments. Includes quadrants.
6	Sixty-four (64)	Air deflector plates (3” high) for installation in each of the 19 ¼” auxiliary air (non-oil) compartments. Replaces the current 2” high deflector plates. Material: 309 SS
7	One Hundred Twenty (120)	Flow controlling damper venturi plate sets for all coal and auxiliary air compartment dampers. Material: Corten.
8	Fourteen (14)	Fabric Expansion joints with welded flange joints.
9	One (1) lot	Hanger rod assemblies
10	One (1) lot	Spare pins and hardware for installation support as determined by FWNAC.
11	Ten (10)	Operating instruction manuals with parts lists.
12	One (1)	Three (3) day Operator Training Sessions and ten (10) Training Manuals (prior to startup).

5.3 Technical Field Support

1		Technical support of FWNAC service engineer time covering pre-outage, outage and post-outage time frame. Billed on a Per Diem rate presented in the Appendix.

5.4 Scope NOT Included

The following work will be performed or furnished and installed by others:

a) Installation.

b) Asbestos removal.

c) Instrumentation and control equipment or modifications, except as expressly specified by FWNAC. Great River Energy is required to incorporate FWNAC provided SAMA control logic into their DCS as part of the TLN retrofit.

d) Any new/additional neural network inputs.

e) Electrical wiring, cable trays/modifications and conduit.

f) Pneumatic and control system additions or modifications, including relocation of existing pneumatic piping.

g) Insulation and lagging. Insulation removed for fitting SOFA system or for other work proposed by FWNAC is not included.

h) Material for removal or relocating sootblower (other than the required pipe material), downcomers, economizer valves, refractory replacement, material to limit spray arc of sootblowers etc. Material for relocating cable trays, fire water, service air piping is not included.

i) Structural steel or modifications to the existing steel is by others except where specified by Foster Wheeler.

j) Temporary office space or trailer with telephone and electricity at the jobsite for use by FWNAC Service Engineer(s) should be provided by Great River Energy and is not included in FWNAC scope.

k) Repair or replacement of damaged components discovered during TLN outage.

l) Fuel, ash sampling and lab analysis is not included in FWNAC scope of supply.

m) If coal flow balancing is required during baseline testing and/or optimization, FWNAC scope does not include procuring and installing coal pipe sampling ports and any subsequent corrections.

n) Provision and installation of the necessary ports and sampling probes at the economizer outlet for system optimization is not included.

5.5 Terminal Points

The FWNAC terminal points for this scope will be as shown on the attached proposal drawings and are further identified by the material listed in Section 5 under “Scope of Supply”.

A) OFA System:

Ductwork termination points are at the connecting point to the existing air ducts and at the register. The ductwork includes expansion joints, hangers and support steel only as required to attach to existing steel. The termination point is the connection at the existing steel. The register includes the tube openings and seal boxes. Termination points are the tube ends of the panels.

B) Windbox Material:

Material to replace identified tilting nozzle tips is included. Termination points are at the windbox front channel and the windbox damper frame. Plate work and hardware as required to modify the windbox is included. Any additional material required to return the existing windbox shell or internal structural components to a structurally sound and dimensionally true condition is not included in FWNAC's scope.

C) Electrical and Controls:

All electrical, pneumatic and control interface points are the field device termination points of the identified field devices.

D) Control System:

Seller will provide SAMA drawings.

5.6 Post-Retrofit System Tuning/Optimization

The objective of this phase is to optimize the newly installed TLN system for the required emissions performance and unit operation. The unit's Continuous Emission Monitoring System (CEMS) will be used as the basis for assessing NOx. It will again be the client's responsibility to ensure the accuracy of the CEMS system through proper calibration and maintenance procedures. To evaluate and confirm long-term emission performance, FWNAC estimates approximately a one (1) to four (4) week period for optimization to establish and confirm long-term reliable operating set points.

To ensure a technically proper evaluation of the low NOx burner performance, it will be necessary to have steady state system operating conditions during evaluation of individual settings.

a) The unit's Continuous Emission Monitoring System (CEMS) will be used as the basis for assessing NOx. A multi-point gas sampling grid at the economizer outlet, which can be provided by FWNAC, to measure exit gas NOx, CO and O_2 on a per point basis can be utilized as well. This has been proven to reduce optimization time and costs. FWNAC will provide an Engineer to conduct the optimization program. Great River Energy should also provide an air-conditioned test facility for the test instrumentation during optimization. Supply utilities such as electric power and air at sampling locations are also required by client.

b) FWNAC will request that Great River Energy make preparations for supplying and firing a coal within the guarantee range.

c) If coal fineness is suspect, Great River Energy may be requested that coal fineness be taken on a mill basis.

d) Normal unit board data, furnace slag profiles and temperature measurements, etc. necessary for proper boiler performance evaluation, will be taken.

e) Great River Energy shall perform any required station instrumentation calibration, if necessary and assist if requested in making control room data available to FWNAC.

f) FWNAC will provide an optimization plan prior to commencement of the TLN3 system.

g) FWNAC will provide a Service Engineer for unit testing. The extension of field testing service time and/or schedules for reasons beyond the control of FWNAC, shall be considered extra work assignments and be billable at the standard FWNAC service rates (see Appendices for standard rates).

5.7 Post-Retrofit Performance Testing

a) Prior to guarantee testing, FWNAC will conduct preliminary “dry-runs” of guarantee testing.

b) Foster Wheeler will notify Great River Energy when the unit is ready to be tested. Individual testing will be conducted at MCR steam flow (3,730,000 lbs/hr) over a four (4) hour period. FWNAC will work with Great River Energy to establish the final post-retrofit test plan, following engineering submittal.

c) Guarantee testing will consist of a four (4) hour test period conducted under steady-state NORMAL OPERATING CONDITIONS as identified under guarantee requirements.

d) To ensure a technically proper evaluation of the TLN system performance it will be necessary to have a four (4) hour test period with normal, non-transient, boiler operation and consistent fuel supply with confirmation of fineness levels. Any periods of unit upsets or if unplanned transient conditions occur, additional time will be required.

e) Unit should be fuel seasoned for at least two (2) days of MCR operation. Great River Energy is requested to provide coal fineness from each mill.

f) FWNAC site representative may request changes in the sootblowing procedures as required for fuel changes and / or performance requirements.

Post-Retrofit Performance Testing will be conducted under FWNAC guidance. FWNAC will assign an engineer to participate in witnessing the test program. If the allotted Service time has been exceeded, additional service time above those listed in the Scope of Supply will be considered as extra work assignments.

FWNAC will accept post-retrofit testing using the plant CEMS equipment and standard fly ash sampling methods with the following provision.

Note: For optimization FWNAC may elect to install probes into existing economizer outlet gas duct taps. The probes will be provided by Great River Energy. It is assumed this unit is already equipped with economizer outlet taps that are in good shape.

5.8 FWNAC Outage Support

FWNAC can furnish one qualified service representative to assist in installation and commissioning activities for erection coverage. It is estimated that this individual would be required for four weeks of the scheduled outage. Pricing is based up an eight hour day for six days a week for four weeks. If activities extend beyond the anticipated time or allotted hours, service engineer's time will be billed on a per diem basis at the agreed upon rates.

6. PREDICTED PERFORMANCE

The Tangential Low NOx Operating System offered in this proposal is designed for current operating conditions. The system is designed with enough flexibility for 7/8 mills in service (pre-drying system) and for 6/8 mills in service (post-drying system) to achieve 3,730,000 lbs/hr of main steam flow. Fuel analyses provided by Great River Energy were utilized in the design.

Note: The following projections are not to be construed as guarantees.

6.1 NOx Emissions

Foster Wheeler predicts the following NOx emissions at the customer defined MCR load point for the TLN3 proposed within this document:

- The TLN3 system is designed with the potential to produce 0.15 lb/MBtu NOx emissions at full load MCR.

Figure 13 shows the current NOx performance been achieved on the Coal Creek boilers (2nd quarter 2006 EPA data) and the predicted NOx levels that will be achieved post-retrofit on these boilers.

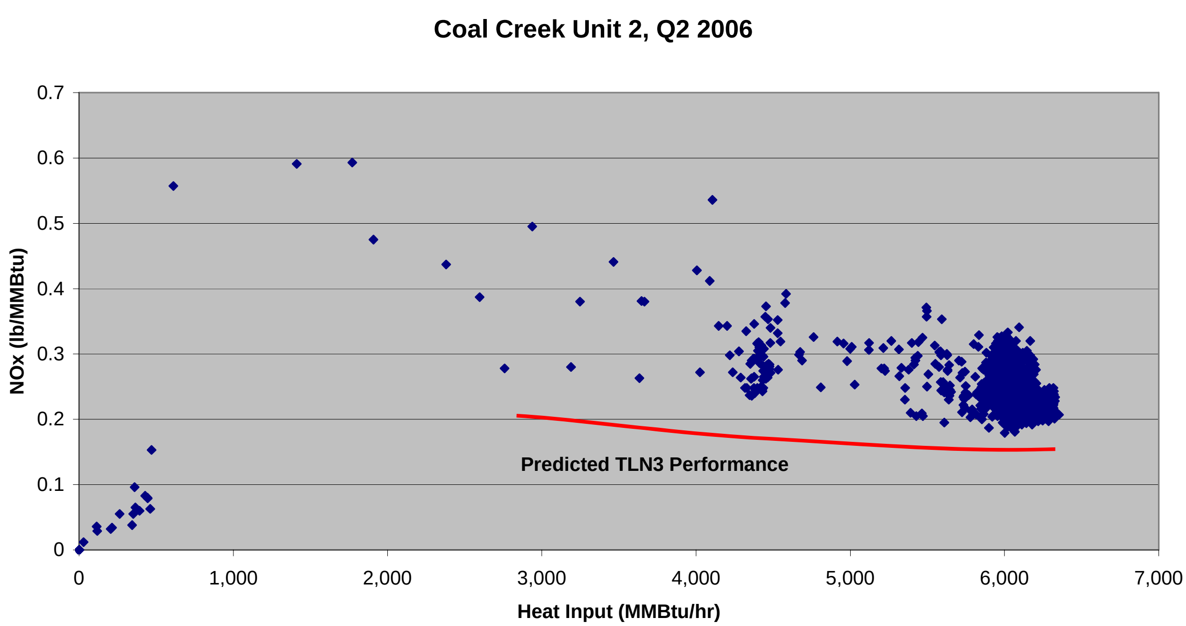


Figure 13 - Predicted NOx Performance on Coal Creek Boilers

Notes

1.) All full load predictions are based on ideal boiler operating conditions and 7/8 mills in service (pre-drying system) or 6/8 mills in service (post-drying system). They are also based on the assumption that burner tilts are no higher than the horizontal position.

Low load NOx performance is very unit specific. Since the reduction of heat input into the furnace inhibits the NOx formation, NOx emissions should decrease with reduced loads unless excess air increases. However, the actual amount of reduction also depends on other boiler operating parameters such boiler excess O_2 and actual levels of boiler in-leakage. In addition, nozzle tilts are often brought above horizontal to maintain steam temperature at lower loads, thereby decreasing furnace residence time. Therefore, the appropriate SOFA flows at various points in the load range will be determined during post-retrofit tuning to maintain Low NOx operation.

Current data gathered from the EPA website for Coal Creek No. 2 indicates that as unit load is decreased, NOx emissions is reduced.

See **Figure 13** for low load NOx predictions.

Note:

NOx emissions are not directly affected by variances in mill fineness levels. Values lower than 65% through 200 mesh will most likely result in higher percentages on the 50 mesh and this will indirectly cause NOx emissions to increase by virtue of reducing staging to control UBC levels. Fineness on it’s own has no direct impact on NOx formation.

6.2 Unburned Carbon (UBC) in Flyash

As with the NOx emissions, Foster Wheeler's predictions for the Coal Creek boilers are based on past experience with these types of fuel and unburned carbon levels.

Foster Wheeler predicts that the UBC levels for the proposed TLN3 system will be as follows:

- Less than 0.5% when firing the design coal at MCR.

Improved fineness levels and coal/air distribution can help reduce the UBC in fly ash levels. Current predictions are based on a minimum fineness of 65% through 200 mesh and 1.5% on the 50 mesh.

Fuel related impacts on unburned carbon are much higher than on NOx. Therefore, any future changes in actual fuel characteristics might necessitate revision of the above predictions.

UBC does not significantly increase when firing lignite fuels under staged conditions, again due to its relatively high reactivity. However, as with all other performance parameters, the unburned carbon is negatively impacted by up-tilt on the burners. High tilt positions on tangential-fired units result in poor fuel/air interaction leading to higher UBC and CO. Thus, it will be important to maintain the tilts at or below horizontal to ensure high levels of burnout.

6.3 Steam Temperature Performance

Foster Wheeler predicts that steam temperatures will remain near current levels following the TLN3 retrofit. Our experience with at Coal Creek and with tangential-fired units firing similar fuels to that being fired on the Coal Creek boilers is that a more balanced or uniform temperature profile will result following the TLN3 retrofit. After the first Foster Wheeler TLN retrofits, the Coal Creek units experienced cleaner waterwalls in the firing zone. Foster Wheeler predicts no change in steam temperatures from current values.

6.4 Effects of Excess Air (Boiler O_2 levels)

Excess air is an important parameter that affects NOx, steam temperatures, boiler efficiency, etc. Maintaining proper boiler O_2 levels is key to low NOx combustion. Too much O_2 at the burner can create high NOx as well as contribute to lower boiler efficiencies due to stack losses. However, too little O_2 can lead to unacceptable UBC and CO values as well as lowered steam temperatures. FWNAC evaluates each of these parameters to determine the optimum post-retrofit excess air level. The TLN3 will be designed to operate at or near current O_2 levels. However, the effects of excess air levels will be investigated during the optimization/tuning phase.

6.5 Effects of Nozzle Tilt Angle

In order to maintain steam temperatures, main burner nozzle tilt angle is typically modulated. Through the tilt range, various combustion effects are reflected through fluctuating NOx, CO, and UBC levels. A downward tilt angle will provide increased residence time for greater carbon burnout, hence lower UBC levels. Increased residence time also helps NOx emissions. CO effects are typically unit and fuel specific. It is predicted that the burner tilt positions at MCR conditions will remain unchanged (or possibly lower with more SOFA flow) following the TLN3 retrofit.

6.6 Effects of Coal

Coal properties play a very important role in operation of any low NOx combustion system. For both NOx and UBC, fuel reactivity plays the key role. FC/VM, HHV(daf), as well as fuel nitrogen loading are the primary parameters. Ash constituents also are important as they effect the furnace thermal environment that affects NOx and UBC.

7. PERFORMANCE GUARANTEES

7.1 Performance Guarantees

The following Performance Guarantees contained in sections 7.2 through 7.5 are the **exclusive performance guarantees** offered by FWNAC relating to the equipment supplied by FWNAC. Any graphs, stated performance values, predictions or discussions in other sections of the proposal shall not be construed as performance guarantees.

- The guarantee will be considered met, if the average of the guarantee value, over the test period meets the guarantee values offered below by FWNAC.
- All performance conditions, test methods, and referenced fuels/ranges of fuels as defined in Section 7.2 of this proposal are considered a prerequisite for the guarantees. All sampling must ensure that a representative average of the flue gas emissions and fly ash sample is taken.

7.1.1 NOx Guarantee

- **NOx will average less than or equal to 0.170 lb NOx/MBtu** at 100% MCR (3,730,000 lbs/hr steam)

7.2 Performance Condition Requirements

To ensure a technically proper evaluation of the low NOx system performance, it is necessary to have normal, non-transient unit operating conditions. The following requirements are the basis for the post-retrofit performance period (cold/hot commissioning, optimization and performance guarantee test):

a) <u>Unit Operation</u> - Operation of the unit should be in accordance with the manufacturer's instructions and the direction of Foster Wheeler's site representative. Adjustable parameters include O_2, mill sequencing, mill biasing, windbox-to-furnace differential pressure, damper and yaw settings, load ramping rates, sootblowing and others. Boiler and steam cycle equipment must be operated in a manner similar to baseline conditions including normal design temperatures, flow, pressures, etc. tests. Boiler should be seasoned to the fuels being fired. Any modifications to boiler heat transfer equipment (i.e., SH, economizer, air preheaters) or changes in system operation (such as feedwater heaters out of service) prior to the retrofit outage will require alterations of guarantees.

NOTE: All emission and steam temperatures guarantees are subject to maintaining the same baseline main steam flow and pressure, reheat flow and pressure, feedwater temperature and cold reheat inlet temperature following retrofit. This will assure a fair evaluation basis for both Great River Energy and Foster Wheeler to evaluate the TLN3 system performance.

b) The NOx guarantees are based on the post-retrofit coal being within the shaded qualifying region shown on **Figures 14** and within the ranges from **Table 1.** Should the coal fall outside that region the appropriate NOx emission corrections shall apply.

c) For the performance guarantee test, coal fineness levels on a per mill basis will be no coarser than 1.5% on Mesh 50, 88% passing Mesh 100, and 65% passing Mesh 200.

d) All pulverizers are to be operated in accordance with the manufacturer's instruction and the Buyer is responsible for ensuring that coal pipe riffle elements and orifices are in good condition prior to optimization. Primary air flow must be in accordance with the associated pulverizer airflow curves. Foster Wheeler has designed the system to accommodate the current 350 klb/hr primary air flow and the expected future (post-drying system) 255 klb/hr primary air flow. Coal flow imbalance between coal conduits should not exceed the normal industry standard of ± 20% from average on an elevation basis. It is assumed that the pulverizers are operating in accordance with the OEM's air flow and temperature criteria. Primary air flow between coal conduits should be within the normal industry standard of ± 10% from average on an elevation basis.

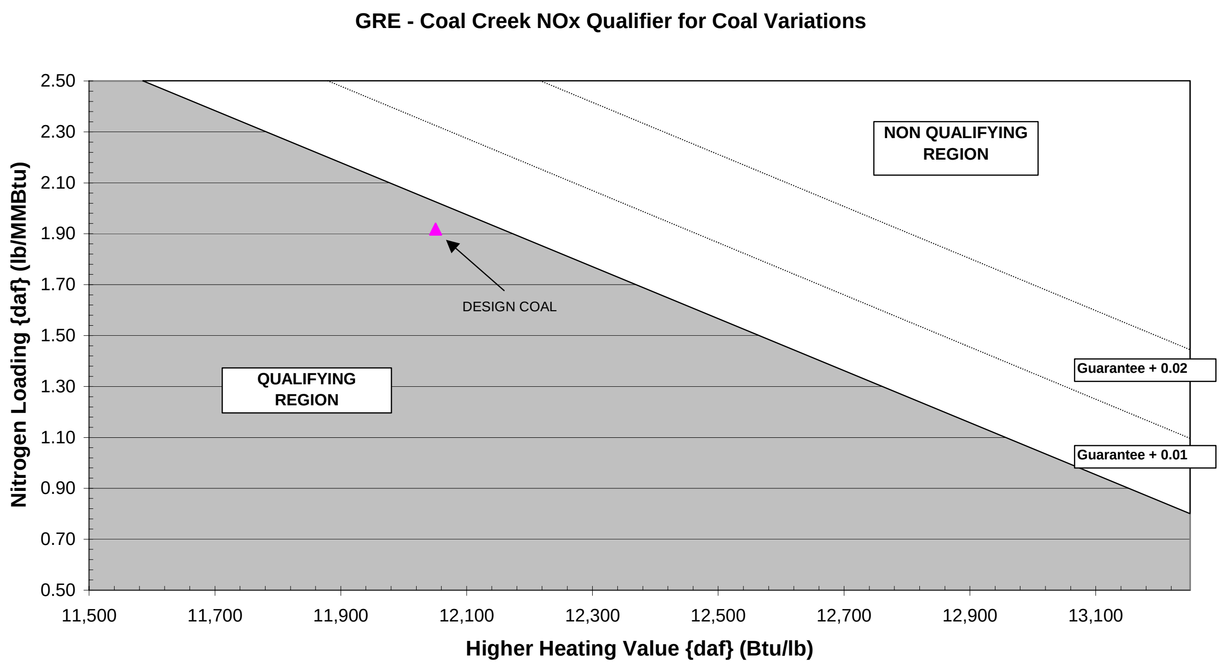


Figure 14 - NOx Fuel Qualifier Curve for HHV (daf) and Nitrogen Loading (daf)

e) A qualified Foster Wheeler Technical Services representative will recommend the final O_2 operating level during the start-up and optimization of the low NOx firing system. The actual level of excess oxygen will be adjusted to simultaneously optimize NOx, CO, and UBC. The low NOx firing system will be designed for a target average excess oxygen level of 2.5 %.

f) All performance guarantee testing shall be conducted under standard plant operating conditions at steady-state loads of 3,730,000 lbs/hr (100% MCR) steam flow with no feedwater heaters out of service, no hindrances due to incapacitated FD or ID fans, flue gas cleaning equipment, coal feeders, pulverizers, ash handling system, sootblowers, wall blowers and burner controls.

g) It is assumed that all other existing related windbox structure, linkage, hardware and nozzle tips not supplied under this proposal are in good operating condition.

h) All guarantee parameters measured during the performance test will be an average over the four (4) hour test period.

i) The CEMS shall be used to determine the NOx emission levels during all performance tests. If the guarantee testing fails to demonstrate the guaranteed emissions, EPA methods 3A, 7E, and 10 and isokinetic testing shall be used at a grid in the economizer outlet to determine excess O_2, NOx and CO during a second performance guarantee test. This data is the determining data.

j) Economizer O_2 must be maintained within a ± 0.20% range from set-point.

Fuel - Coal characteristics play a major role in determining achievable emission as well as combustion efficiency. For both NOx and UBC, fuel reactivity plays the key role. FC/VM, HHV (daf), as well as fuel nitrogen loading are the primary parameters. Ash constituents also are important as they effect the furnace thermal environment that affects NOx and UBC. These are listed below. Foster Wheeler has taken all these parameters into consideration in offering our guarantees. Consequently, all guarantees are based on firing the following fuel consistent with fuel parameters identified below. Coals outside the qualification ranges in **Figure 14** and **Table 1** below do not qualify as fuels that meet the performance conditions. During optimization and testing, coal loaded in various bunkers must be kept consistent, i.e. same coal in same bunkers. Prior to commencing any testing, the boiler must be properly seasoned with the design fuel that will be burned during the test.

LOW NOX SYSTEM DESIGN COAL AND ALLOWABLE RANGE		
Fuel Parameter	**Design**	**Allowable Range**
Volatile Matter, as rec. (VM), %	25.2	See FC/VM
Fixed Carbon as rec., (FC), %	26.5	See FC/VM
FC/VM Ratio	1.05	Max: 1.2
Moisture, total %	36.3	38.0
Ash, as rec. %	11.9	8.0 – 14.0
HHV, as rec. Btu/lb	6,241	See Figure 14
Carbon, as rec. %	37.0	Max: 39.0
Hydrogen, as rec. %	6.5	-
Nitrogen, as rec. %.	0.6	Max: 0.7
Sulfur, as rec. %.	0.7	Max: 0.9
Oxygen, as rec. %	7.0	-
Fe2O3 in ash, as rec. %	6.7	Max: 8.5
Na2O in ash, as rec. %	2.2	Max: 5.0

Table 1.Design Coal

Furnace In-Leakage - The furnace in leakage shall be less than 8%. Should the furnace fail to meet the in-leakage requirement, emissions and combustion efficiencies will be affected and thus the related performance guarantees will have to be adjusted accordingly.

Slagging - Furnace slagging should be controlled in accordance with normal industry practice.

8. COMMERCIAL OFFERING

8.1 Project Schedule

The project schedule is very aggressive. Based upon current shop loadings and space availability, equipment delivery to support the March 15, 2007 outage start date can be achieved. FWNAC will monitor shop space during the engineering phase of the project and alert GRE to any changes to shop space availability. A preliminary schedule can be found in the Appendices.

8.2 Pricing & Payment Terms

8.2.1 Engineering and Material Supply:

FWNAC offers to perform the scope of work contained in Sections 5.1 and 5.2 FOB jobsite, exclusive of taxes, subject to availability of shop space:

One Million Six Hundred and Fifty Thousand Dollars
US $ 1,650,000

8.2.2 Outage Support

FWNAC offers to provide technical outage support in accordance with Section 5.3

Forty Thousand Dollars

US $40,000

8.2.3 Commissioning and Optimization

FWNAC offers to provide technical support for the Commissioning and Optimization of the equipment on a per diem rate of $1200 for each eight hour day Monday through Friday plus Travel and Living expenses. Travel and Living expense will be invoiced at cost. Additional hours per day, weekends and Holidays would be billed at a rate of $225/ hour. The estimated **budget** cost for two Service Engineers for approximately four weeks for sixty hours per week plus Travel and Living expenses is $96,000.

8.2.4 Terms and Conditions

FWNAC offers to perform the above scope of work in accordance with the attached Standard FWNAC Terms and Conditions of Sale Material Only.

If the equipment fails to achieve the Guaranteed NOx level in Section 7, FWNAC will perform additional tuning and optimization of the equipment with a maximum cost of $30,000. Performing the additional tuning and optimization and expenditure of this money shall be in full settlement of all liabilities of FWNAC for failure to meet the Performance Guarantee.

A written notification of award setting forth the basis of the award including the agreed upon Terms and Conditions is required by FWNAC prior to starting work. In the event Great River Energy would like work to proceed prior to agreement on Terms and Conditions, FWNAC would do so in accordance with and upon receipt of the executed “Authorization to Begin Work” form included with this proposal.

8.2.5 Validity of Proposal

The prices tendered with this proposal are subject to acceptance by Great River Energy within a period of thirty (30) days from the date hereof, except Foster Wheeler North America Corp. shall have the right to withdraw its proposal at any time before formal acceptance by Great River Energy and receipt of written approval by an officer of Foster Wheeler North America Corp.

The proposed schedule is contingent upon receipt of an acceptable purchase order and full release to proceed by an award date of October 16, 2006. It is also contingent upon availability of vendor shop space at the time of material/equipment procurement.

8.2.6 Progress Payment Terms

The payment to Foster Wheeler North America Corp. shall proceed by the following schedule:

5% of Contract Value upon Award/Release

10% of Contract Value upon Drawing Submittal

30% of Contract Value upon Purchase of Major Material and Equipment

45% of Contract Value upon Delivery of Material and Equipment

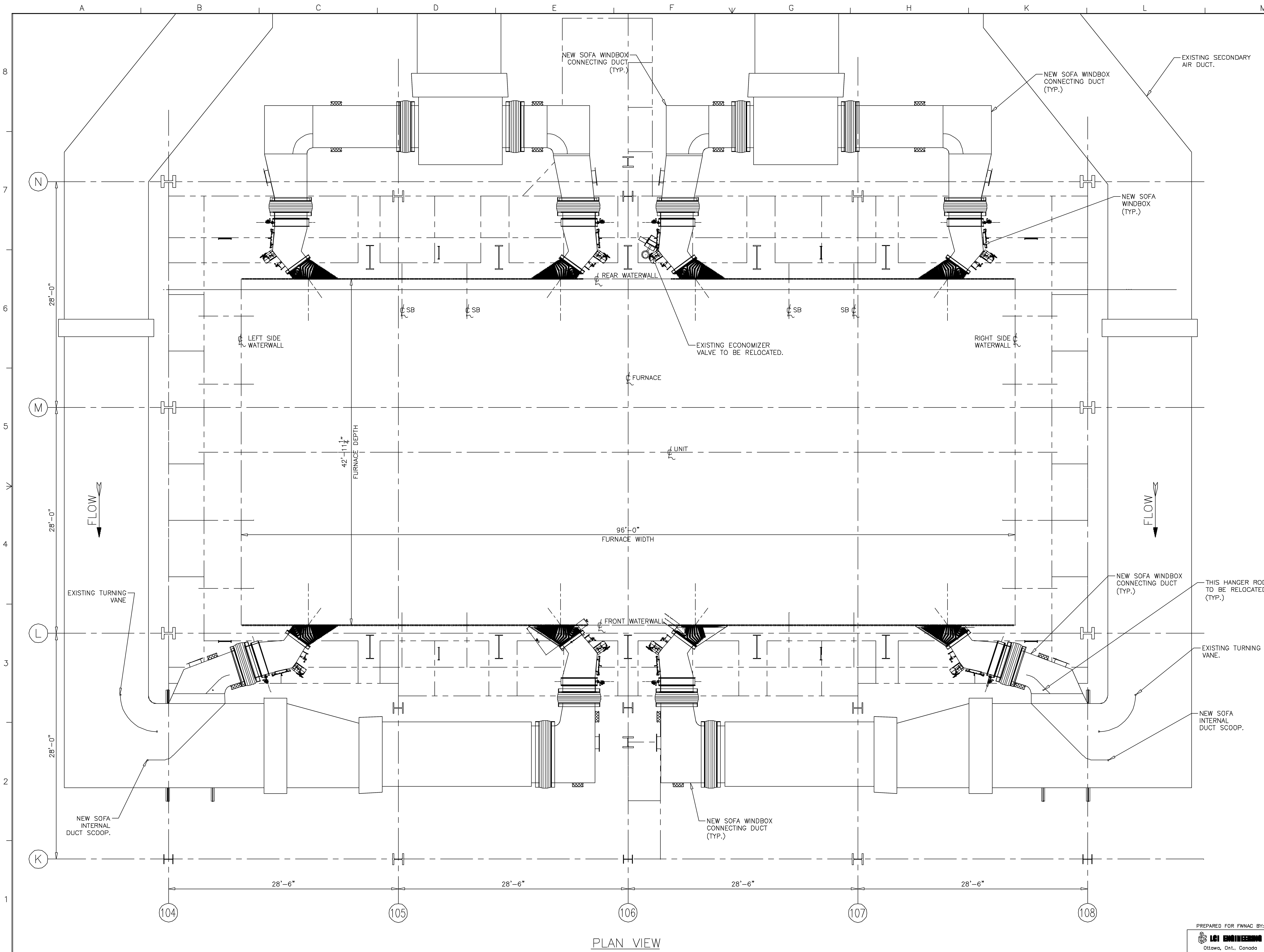
10% of Contract Value upon Successful Achievement of Performance Guarantee or Six Months after delivery whichever is sooner.

APPENDICES

A. Drawings

Drawing No.	Description
D-001	Proposed Tangential Low NOx SOFA System Arrangement
D-002	Proposed Tangential Low NOx SOFA Air System General Arrangement – Plan View
D-003	Proposed Tangential Low NOx SOFA Air System General Arrangement – Front & Side Views
D-004	Proposed Tangential Low NOx SOFA Air System General Arrangement – Isometric Views

B. Preliminary Schedule



LEGEND OF SYMBOLS

- CENTRELINE
- INSULATION
- DUCT ACCESS DOOR
- FABRIC (CLOTH) EXPANSION JOINT
- DAMPER

REFERENCE DRAWINGS

1) GENERAL ARRG'T FRONT VIEW ____ D-003
2) GENERAL ARRG'T ISOMETRIC VIEWS ____ D-004

REV.	DATE	DR. INIT.	DESCRIPTION
A	09/13/06	R.D.	FIRST ISSUE

REVISIONS

PROPOSED TANGENTIAL LOW NOx
SOFA AIR SYSTEM
GENERAL ARRANGEMENT–PLAN VIEW

FOR: GREAT RIVER ENERGY
COAL CREEK UNIT NO.1
UNDERWOOD, ND.

FWNAC CONTRACT NUMBER:

DRAWING NUMBER	SCALE:	REVISION
D–002		A

DRAWN BY	R.D.	09/13/06
CHECKED BY		
APPROVED BY		

PREPARED FOR FWNAC BY:
LCI ENGINEERING
Ottawa, Ont., Canada
LCI Contract no. 2006077

THIS DRAWING IS THE PROPERTY OF THE
FOSTER WHEELER NORTH AMERICA CORP.
CLINTON, N.J.

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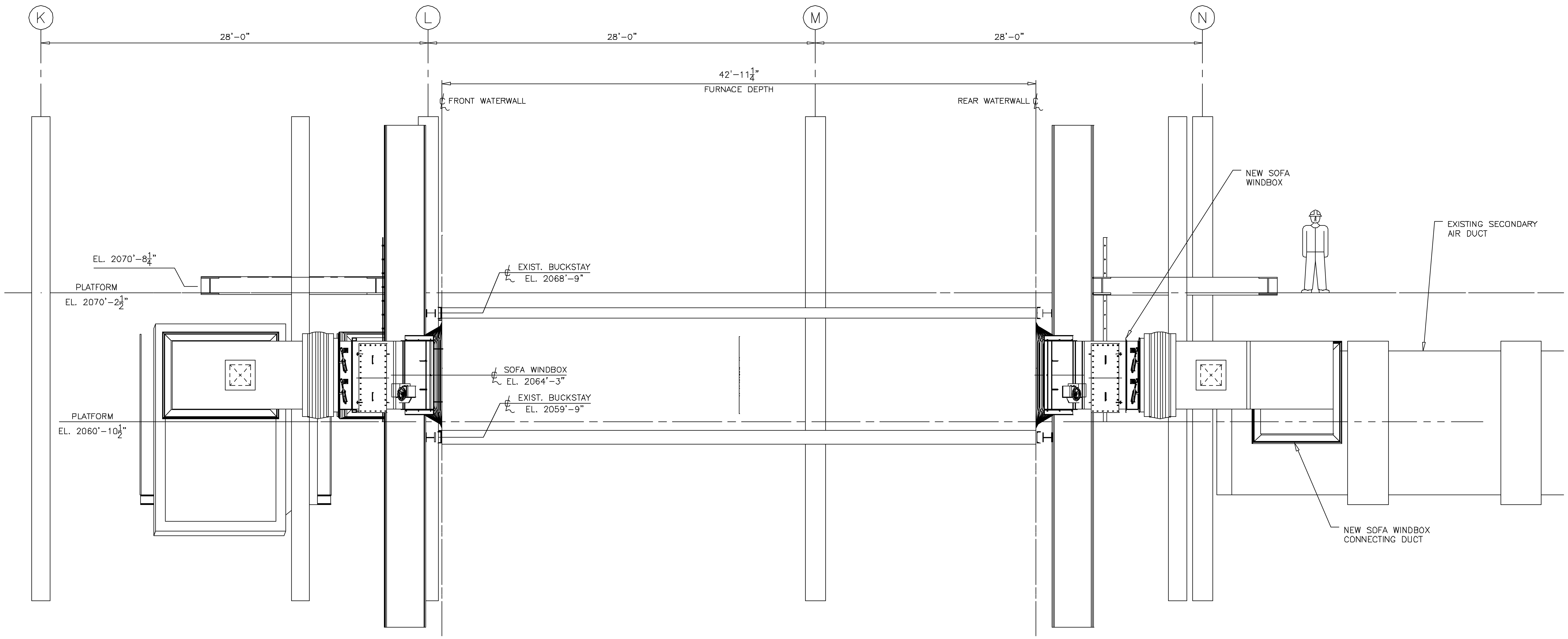
SECTIONAL FRONT ELEVATION



SECTIONAL SIDE ELEVATION

REFERENCE DRAWINGS

1) GENERAL ARRG'T PLAN VIEW — D-002
2) GENERAL ARRG'T ISOMETRIC VIEW — D-004

REV.	DATE	DR. INIT.	DESCRIPTION
A	01/13/06	GF	FIRST ISSUE

REVISIONS

PROPOSED TANGENTIAL LOW NOx
SOFA AIR SYSTEM
GENERAL ARRG'T– FRONT & SIDE VIEWS

FOR: GREAT RIVER ENERGY
COAL CREEK UNIT NO.1
UNDERWOOD, ND.

FWNAC CONTRACT NUMBER:

DRAWING NUMBER: D-003 | SCALE: | REVISION: A

DRAWN BY	R.D.	09/13/06
CHECKED BY		
APPROVED BY		

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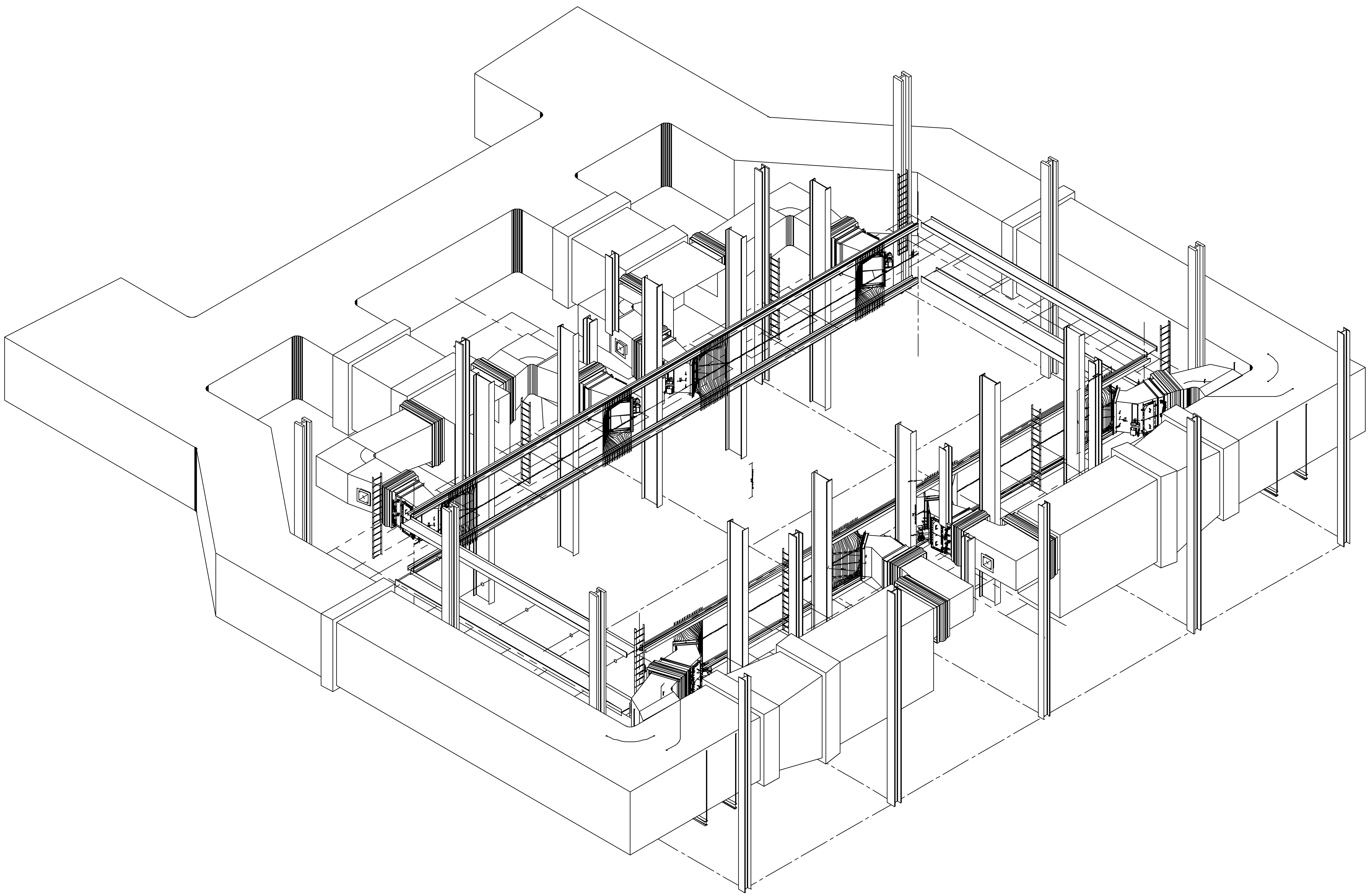


REFERENCE DRAWINGS
1) GENERAL ARRG'T PLAN VIEW ______ D-002
2) GENERAL ARRG'T FRONT & SIDE VIEWS ______ D-003

REV.	DATE	DR. INIT.	DESCRIPTION
A	01/13/06	GF	FIRST ISSUE

REVISIONS

PROPOSED TANGENTIAL LOW NOx
SOFA AIR SYSTEM
GENERAL ARRANGEMENT– ISOMETRIC VIEWS

FOR: GREAT RIVER ENERGY
COAL CREEK UNIT NO.1
UNDERWOOD, ND.

FWNAC CONTRACT NUMBER:

DRAWING NUMBER: D–004
SCALE:
REVISION: A

DRAWN BY	R.D.	09/13/06
CHECKED BY		
APPROVED BY		

FILENAME: PARRGT.dwg

AUTHORIZATION TO BEGIN WORK

Great River Energy hereby authorizes Foster Wheeler North America Corporation to perform the work described in its Proposal No. 65-120220-00 rev01 dated October 6, 2006 the rates and/or prices stated therein. Foster Wheeler North America Corporation is to commence the work in accordance with the Terms and Conditions of the proposal. It is understood that Great River Energy reserves the right to request changes in the Terms and Conditions and in the event that mutual agreement cannot be reached regarding the requested changes, we shall have the right to direct Foster Wheeler North America Corporation to stop work, in which case Foster Wheeler North America Corporation shall be paid for all materials as well as all work performed and Foster Wheeler North America Corporation shall have no further obligation to Great River Energy.

It is understood that a formal contract or purchase order will be prepared confirming this Authorization and or agreements regarding the work.

Great River Energy

By:_________________________

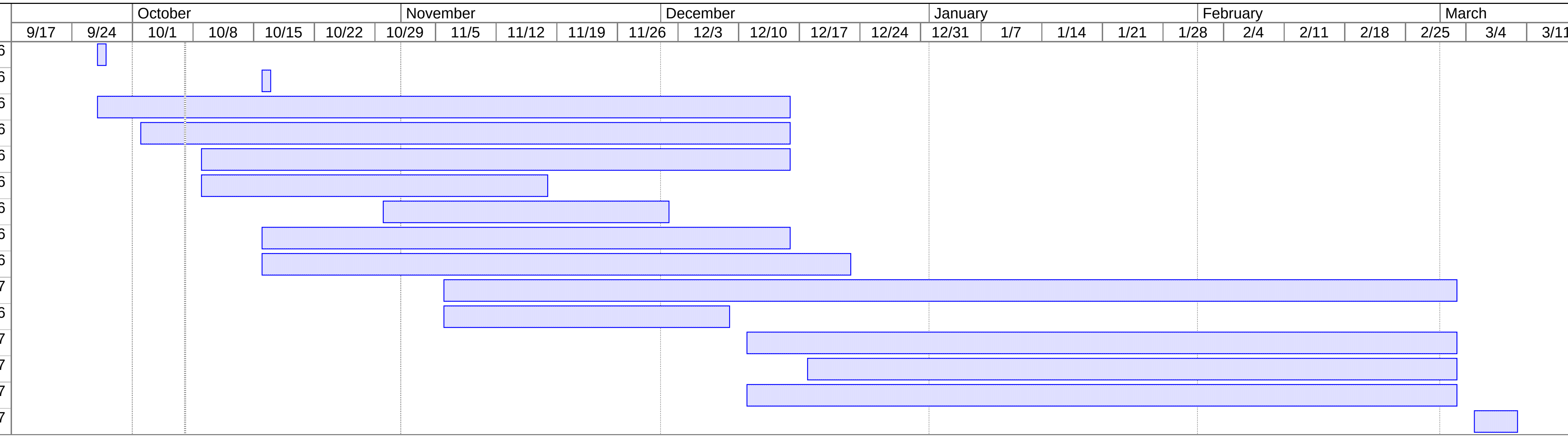
Signature (Authorized Representative)

Printed or Typed Signature

Date:________________________

GREAT RIVER ENERGY COAL CREEK TLN RETROFIT

ID	Task Name	Start	Finish
1	**ENGINEERING CONTRACT AWARD**	Wed 9/27/06	Wed 9/27/06
2	**MATERIAL CONTRACT AWARD**	Mon 10/16/06	Mon 10/16/06
3	**ENGINEERING**	Wed 9/27/06	Fri 12/15/06
4	GA Drawings	Mon 10/2/06	Fri 12/15/06
5	SOFA Duct Design	Mon 10/9/06	Fri 12/15/06
6	Pressure Part Design	Mon 10/9/06	Fri 11/17/06
7	Platform/Structural Design	Mon 10/30/06	Fri 12/1/06
8	SOFA Boxes, Tips	Mon 10/16/06	Fri 12/15/06
9	**MAT'L / EQUIP. PROCUREMENT**	Mon 10/16/06	Fri 12/22/06
10	**FABRICATION**	Mon 11/6/06	Fri 3/2/07
11	Tubing	Mon 11/6/06	Fri 12/8/06
12	SOFA Boxes Tips	Mon 12/11/06	Fri 3/2/07
13	SOFA Port Panels	Mon 12/18/06	Fri 3/2/07
14	Structural Steel & Ductwork	Mon 12/11/06	Fri 3/2/07
15	**SHIPMENT**	Mon 3/5/07	Fri 3/9/07



Project: GRE Coal Creek 2 TLN
Date: Sat 10/7/06

Task	Progress	Summary	External Tasks	Deadline
Split	Milestone	Project Summary	External Milestone	

Appendix K

Coal Drying Study

Added February 2007

(Revised 2/6/07)

LIGNITE FUEL ENHANCEMENT

Final Technical Report: Phase 1

Reporting Period: July 9, 2004 to August 1st, 2006
DOE Award Number: DE-CF26-04NT41763
Date Report Issued: November 30, 2006

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DISCLAIMER

ACKNOWLEDGEMENT

The authors wish to acknowledge the contributions and support provided by various project managers: Dr. Sai Gollakota (DOE), Matt Coughlin (Barr), Dave Rian (Barr), John Wheeldon (EPRI), Tony Armor (EPRI), Dr. Ed Levy (Lehigh), Dr. Nedad Sarunac (Lehigh), and Mark Ness (GRE).

ABSTRACT

U.S. lignites have moisture contents ranging from 25 to 40 percent. This results in lower heating value, higher fuel flow rate, higher stack flue gas flow rate and stack loss, higher station service power, lower plant efficiency, and higher mill, coal pipe and burner maintenance requirements compared to that of the Eastern bituminous coals. Despite problems associated with their high-moisture content, lignite and sub-bituminous coals from the Western U.S. are attractive due to their low cost and emissions, and high reactivity.

A process that uses low-grade heat rejected from the steam condenser and waste heat from the flue gas leaving the boiler to evaporate a portion of the fuel moisture from the lignite feedstock in a fluidized bed dryer ("FBD") was developed in the U.S. by a team led by Great River Energy ("GRE"). The research is being conducted with Department of Energy ("DOE") funding under DOE Award Number: DE-CF26-04NT41763.

The objective of GRE's Lignite Fuel Enhancement project is to demonstrate a 5 to 15 percentage point reduction in lignite moisture content (about ¼ of the total moisture content) by using heat rejected from the power plant. This will significantly enhance the value of lignite as a fuel in electrical power generation power plants. Although current lignite power plants are designed to burn wet lignite, the reduction in moisture content will increase efficiency, reduce pollution, and improve plant economics.

The benefits of reduced-moisture-content lignite are being demonstrated at GRE's Coal Creek Station (CCS). A phased approach is used. In Phase 1 of the project, a full-scale prototype coal drying system, including a fluidized bed coal dryer, was designed, constructed, and integrated into Unit 2 at Coal Creek.

The prototype coal drying system at CCS has been in almost continuous, fully automatic operation since February 2006. Performance of the prototype dryer and the effect of partially dried coal on unit performance and emissions were determined from a series of paired performance tests that were conducted at carefully controlled test conditions. In addition, dryer performance during regular operation was determined.

According to the test results, at the baseline feed rate of 75 tons per hour, the prototype coal dryer easily meets the performance goals and specifications established for the project. The maximum continuous feed rate to the dryer is 101 t/hr. Further increases in feed rate are prevented by limitations on the coal conveying system throughput and dust collector fan power limits.

A commercial coal drying system, consisting of four fluidized bed dryers will be designed, built, installed, and tested at CCS during Phase 2 of the project. With four dryers in service it will be possible to reduce moisture content of the total coal feed to Unit 2 at Coal Creek to a target level of 29.5 percent. This will allow determination of boiler and unit efficiency improvements and emissions reductions, and evaluation of the effects of partially dried coal on unit operation and maintenance requirements.

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LIST OF FIGURES *(continued)*

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LIST OF FIGURES *(continued)*

LIST OF FIGURES *(continued)*

LIST OF TABLES

LIST OF TABLES *(continued)*

1. INTRODUCTION

U.S. low-rank coals have moisture contents ranging from 15 to 30 percent for sub-bituminous coals and from 25 to 40 percent for lignites. When high-moisture coals are burned in utility boilers, about seven percent of the fuel heat input is used to evaporate fuel moisture. The use of high-moisture coals results in higher fuel flow rate, higher stack flue gas flow rate, higher station service power, lower plant efficiency, and higher mill, coal pipe and burner maintenance requirements compared to that of the Eastern bituminous coals. Despite problems associated with their high-moisture content, lignite and sub-bituminous coals from the Western U.S. are attractive due to their low cost and emissions.

Countries with large resources of high-moisture low-quality coals are developing coal dewatering and drying processes. However, thermal processes developed thus far are complex and require high-grade heat to remove moisture from the coal. This significantly increases process cost, which represents a main barrier to industry acceptance of the new technology. A review of thermal drying technology is presented in [1].

A process that uses low-grade heat rejected from the steam condenser and waste heat from the flue gas leaving the boiler to evaporate a portion of fuel moisture from the lignite feedstock in a fluidized bed dryer (FBD) was developed in the U.S. by a team led by Great River Energy (GRE). The research was conducted with Department of Energy (DOE) funding under DOE Award Number: DE-CF26-04NT41763.

The objective of GRE's Lignite Fuel Enhancement project is to demonstrate a 5 to 15 percentage point reduction in lignite moisture content (about ¼ of the total moisture content) by incremental drying using heat rejected from the power plant. This will significantly enhance the value of lignite as a fuel in electrical power generation power plants. Although current lignite power plants are designed to burn wet lignite, the reduction in moisture content will increase efficiency, reduce pollution, and improve economics.

The benefits of reduced-moisture-content lignite are being demonstrated at GRE's Coal Creek Station. A phased approach is being used. In Phase 1, a full-scale prototype coal dryer was designed, constructed, and integrated into Unit 2 at Coal Creek. Dryer performance was tested at the baseline coal feed rate of 75 tons per hour. Field experience, dryer performance, and the effects of burning a lower moisture coal on unit performance, emissions, and operations are described in this report.

An additional four full-scale coal dryers will be designed, built, installed, and tested during Phase 2 of the project. With four dryers in service it will be possible to reduce the moisture of the total coal feed to Unit 2 at Coal Creek. This will allow determination of the efficiency improvement and emissions reduction for a unit operating on partially dried coal. Also, the effects of burning coal with reduced moisture content on unit operation will be evaluated.

A fluidized bed coal dryer ("FBD") was selected for this project due to its good heat and mass transfer characteristics which result in a much smaller dryer, compared to a fixed bed design. The FBD size, flow rate of fluidizing air and the power required to drive the fluidizing air fan are strongly influenced by the FBD operating conditions, such as coal size, bed depth, fluidizing air temperature, maximum allowed bed temperature, heat transferred to the fluidized bed by the in-bed heat exchanger, desired moisture level in the dried coal leaving the dryer, and amount of waste/rejected heat that could be used for drying. Higher dryer temperatures result in a smaller dryer size but require a more expensive heat exchanger system, working at higher temperature levels.

EXECUTIVE SUMMARY

A process which uses low-grade heat rejected from the steam condenser and waste heat from the flue gas leaving the boiler to evaporate a portion of fuel moisture from the lignite feedstock in a FBDwas developed in the U.S. by a team led by Great River Energy (GRE). The research was conducted with Department of Energy (DOE) funding under DOE Award Number: DE-CF26-04NT41763. The objective of GRE's Lignite Fuel Enhancement project is to demonstrate a 5 to 15 percentage point reduction in lignite moisture content by incremental drying using heat rejected from the power plant.

The benefits of reduced-moisture-content lignite are being demonstrated at GRE's Coal Creek Station (CCS). A phased approach is used. In Phase 1 of the project, a full-scale prototype coal drying system, including a fluidized bed coal dryer, was designed, constructed, and integrated into Unit 2 at Coal Creek.

The prototype coal drying system at CCS has been in almost continuous fully automatic operation since February 2006. Performance of the prototype dryer, and the effect of partially dried coal on unit performance and emissions, was determined in a series of paired performance tests that were conducted at carefully controlled test conditions. In addition, dryer performance during regular operation was determined as well.

According to the test results, the prototype coal dryer easily meets the performance goals and specifications established for the project, while operating at the baseline feed rate of 75 tons per hour. The maximum continuous feed rate to the dryer is 101 t/hr. Further increases in feed rate were prevented by limitations on the coal conveying system throughput and dust collector fan power limits. With a coal feed rate of 101 t/hr, a moisture reduction in the 7 to 9 percentage point range (20 to 26 percent on a relative basis) was achieved in the prototype coal dryer. The corresponding improvement in higher heating value (HHV) was in the 875 to 1,280 Btu/lb range, or 14 to 21 percent.

The plant performance parameters are summarized in Table E-1. For the total coal feed moisture reduction of 1.14 percent that was achieved with one coal dryer in service, boiler efficiency was improved by 0.37 percentage points. The improvement in net unit heat rate was 40 Btu/kWh, or 0.37 percent.

Table E-1

Effect of Partially Dried Coal on
Plant Performance Parameters Determined From Parametric Tests

Paired Performance Tests					
Parameter	**Units**	**Wet Coal**	**Partially Dried Coal**	**Absolute Change WRT Wet Coal**	**Relative Change WRT Wet Coal [%]**
Dried Coal	**% of total**	**0.00**	**14.12**	**14.1**	
Total Coal Flow Rate	klbs/hr	971	953	**-17.8**	**-1.8**
Total Coal Moisture	**%**	**37.06**	**35.92**	**-1.14**	**-3.1**
Coal HHV	**BTU/lb**	**6,299**	**6,402**	**103**	**1.64**
Gross Unit Load	MW	590	590	**0**	**0.0**
Throttle Steam Temperature	^{o}F	989	988	**-0.1**	**0.0**
Reheat Steam Temperature	^{o}F	1,002	1,002	**0.3**	**0.0**
SHT Desuperheating Spray Flow Rate	klbs/hr	45	51	**5.5**	**12.2**
Mill Power	kW	4,176	4,037	**-140**	**-3.3**
FD Fan Power with IGV	kW	2,049	2,056	**7**	**0.4**
ID Fan Power with ID	kW	11,782	11,613	**-169**	**-1.4**
PA Fan Power with IGV	kW	6,618	6,989	**371**	**5.6**
Total Fan and Mill Power	kW	24,624	24,694	**70**	**0.3**
Flue Gas Flow Rate at Scrubber Inlet	klbs/hr	7,140	7,101	**-39**	**-0.55**
Boiler Efficiency	**%**	**78.07**	**78.44**	**0.37**	**0.47**
Net Unit Heat Rate	**BTU/kWh**	**10,688**	**10,648**	**-40**	**-0.37**
FD Fan Power with VSD	kW	2,049	2,037	**-12**	**-0.6**
ID Fan Power with VSD	kW	11,782	11,430	**-351**	**-3.0**
PA Fan Power with VSD	kW	6,618	6,923	**305**	**4.6**
Total Fan and Mill Power with VSD	kW	24,624	24,427	**-197**	**-0.8**
Net Unit Heat Rate	**BTU/kWh**	**10,693**	**10,639**	**-54**	**-0.50**

With four driers in service, it would be possible to partially dry 100 percent of coal feed to the boiler. Performance predictions for a target moisture removal level of 8.5 percent are summarized in Table E-2. The results show that reducing the coal moisture content from 38.5 to 30 percent, would improve boiler efficiency by 1.70 percentage points. The improvement in net unit heat rate would be 219 Btu/KWh, or 2.05 percent.

Table E-2

Predicted Performance Improvement for Target Coal Moisture Removal of 8.5 Percent

Predicted Performance					
Parameter	**Units**	**Wet Coal**	**Partially Dried Coal**	**Change WRT Wet Coal**	**Percent Change WRT Wet Coal**
Dried Coal	% of total	0.00	100	100	
Total Coal Flow Rate	klbs/hr	971	837	-134	**-13.8**
Total Coal Moisture	%	37.06	28.56	-8.50	**-22.9**
Coal HHV	BTU/lb	6,299	7,150	851	**13.5**
Mill Power	kW	4,176	3,100	-1,076	**-25.8**
FD Fan Power with VSD	kW	2,049	1,928	-120	**-5.9**
ID Fan Power with VSD	kW	11,782	10,551	-1,231	**-10.5**
PA Fan Power with VSD	kW	6,618	8,305	1,687	**25.5**
Total Fan and Mill Power with VSD	kW	24,624	23,884	-740	**-3.0**
Flue Gas Flow Rate at Scrubber Inlet	klbs/hr	7,140	6,864	-276	**-3.9**
Boiler Efficiency	**%**	**78.07**	**79.77**	1.70	**2.18**
Net Unit Heat Rate	**BTU/kWh**	**10,688**	**10,469**	-219	**-2.05**

The effect of the prototype coal drying system on plant emissions is summarized in Table E-3. As the test results show, firing of partially dried coal has resulted in reduced NO_x, SO_x, CO_2, and mercury emissions.

Table E-3

Effect of Partially Dried Coal on Plant Emissions Determined From Parametric Tests

Paired Performance Tests		Segregated Stream Mixed with Product Stream				Segregated Stream not Mixed with Product Stream		
Parameter	Units	Wet Coal	Partially Dried Coal	Absolute Change WRT Wet Coal	Percent Change WRT Wet Coal	Partially Dried Coal	Absolute Change WRT Wet Coal	Percent Change WRT Wet Coal
NOx Emissions	lbs/hr	1,469	1,359	-111	**-7.5**			**-7.5**
CO_2 Emissions (due to HR Improvement)	klbs/hr	848	844.5	-3.2	**-0.37**			**-0.37**
SO_x Emissions (all 16 paired tests)	lbs/hr	3,670	3,641	-30	**-0.81**			**-1.8 to -2.5**
SO_x Emissions (first 12 paired tests)	lbs/hr	3,692	3,621	-71	**-1.93**			**-2.0 to -2.7**
Mercury Emissions					**-0.37**			**-2.2 to -3.9**

With the current design of the prototype coal drying system at CCS, the segregated and product streams are mixed. The segregated stream is mostly comprised of the non-fluidizable material discharged from the first dryer stage, and contains 3 to 3.5 times more sulfur and mercury compared to the product and feed streams. If the segregated stream were not mixed with the product stream, the mass flow rates of sulfur and mercury to the boiler would be reduced, resulting in lower emissions of these pollutants.

The predicted reduction in emissions for a target value of moisture reduction of 8.5 percent, is summarized in Table E-4 for the cases where the segregated stream and product streams are mixed, and for the case where the segregated stream is further processed and not mixed with the product stream. The results show the potential for significant reductions in SO_x and mercury emissions.

Table E-4

Predicted Emission Reduction for Target Coal Moisture Removal of 8.5 Percent

Predicted - Fanroom Coil in Service		**Segregation Stream Mixed with Product Stream**				**Segregation Stream not Mixed with Product Stream**		
Parameter	**Units**	**Wet Coal**	**Partially Dried Coal**	**Absolute Change WRT Wet Coal**	**Percent Change WRT Wet Coal**	**Partially Dried Coal**	**Absolute Change WRT Wet Coal**	**Percent Change WRT Wet Coal**
NOx Emissions					**> -7.5**			**> -7.5**
CO_2 Emissions (due to HR Improvement)					**-2.4**			**-2.4**
SO_x Emissions					**> -2**			**-12 to -17**
Mercury Emissions					**-15**			**-25 to -35**

The predicted reductions in SO_x and Hg emissions due to the sulfur and Hg removal from the feed stream in the first dryer stage are affected by the accuracy of the measured sulfur and Hg concentration levels in the feed, segregated, and product streams, and the segregated stream flow rate. The actual reductions in SO_x and Hg emissions will be determined when the commercial coal drying system at CCS is operating at 100 percent capacity.

A commercial coal drying system, consisting of four fluidized bed dryers will be designed, built, installed, and tested at CCS during Phase 2 of the project. With four dryers in service it will be possible to reduce the moisture content of the total coal feed to Unit 2 at Coal Creek to a target level of 29.5 percent. This will allow determination of the resulting efficiency improvement and emissions reduction and evaluation of the effects of partially dried coal on unit operation and maintenance requirements.

2. DESCRIPTION OF COAL CREEK STATION

Coal Creek Station (CCS) is a 1,200 MW lignite-fired power plant located in Underwood, North Dakota. The plant supplies electricity to 38 member cooperatives in

Minnesota. Two tangentially fired CE boilers supply steam to two single reheat GE G-2 turbines rated at 560 MW each. The units are designed for 1,005°F main steam and reheat steam temperature at a 2,520 psi throttle pressure. Three mechanical draft cooling towers are used to reject heat to environment. The boiler fires lignite coal from the nearby Falkirk mine. The coal that has a HHV of 6,200 Btu/lb and total moisture content of approximately 38 percent. An aerial photograph of Coal Creek Station is presented in Figure 1-1.

Figure 1-1: Aerial Photograph of Coal Creek Station

A schematic representation of heat flows for the CCS is given in Figure 1-2. For full unit load (gross power output of 576.7 MW (546 MW nameplate)) and fuel containing 40 percent moisture, the heat input with the fuel (Q_{fuel}) is approximately 5,670 MBtu/h. The boiler loss (Q_{loss}), including dry stack loss (Q_{stack}) and fuel moisture evaporation loss (Q_{evap}) is approximately 1,090 MBtu/h, or 19.2% of the fuel heat input. This gives a boiler efficiency of 80.78%. The dry stack loss is 436 MBtu/h, which represents 7.7 percent of the fuel heat input. The loss due to evaporation of fuel moisture is 370 MBtu/h (approximately 6.6 percent of fuel heat input). Thermal energy

(Q_T) transferred to the working fluid in the boiler is about 4,580 MBtu/h. The thermal efficiency of the steam turbine cycle is approximately 43 percent, which gives rejected heat of approximately 2,600 MBtu/h (46 percent of the fuel heat input). The gross unit efficiency is approximately 34.7 percent, with a gross unit heat rate of 9,825 Btu/kWh.

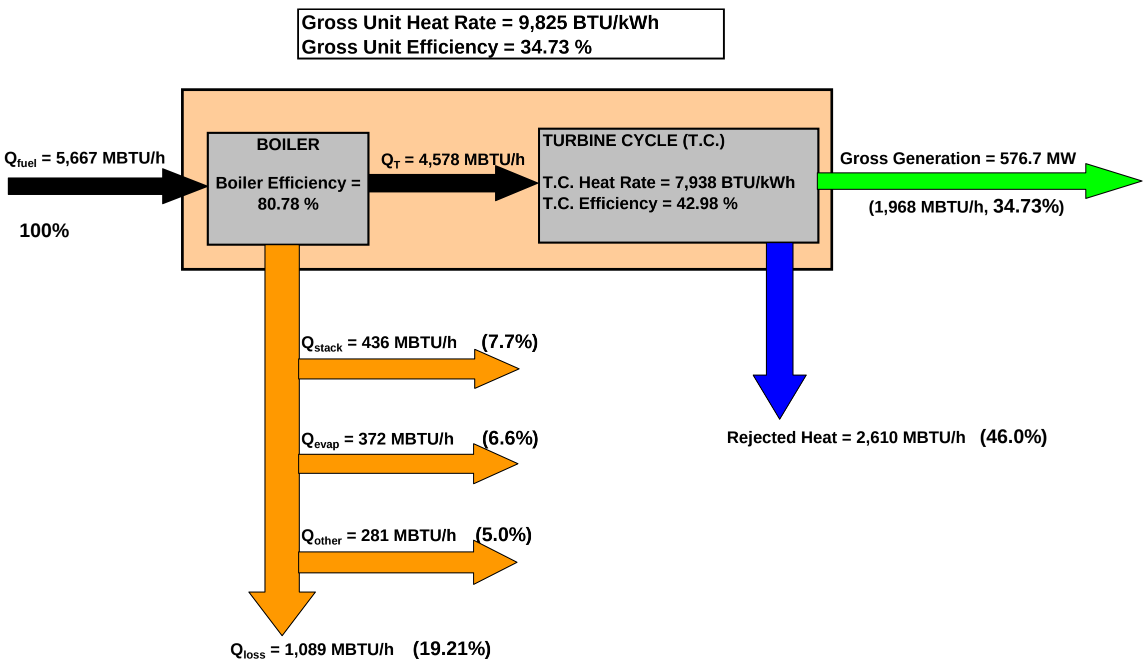

Figure 1-2: Coal Creek Unit Heat Flow Schematic – One Unit

2.1: <u>Sources and Magnitudes of Waste Heat</u>

Thermal energy in the flue gas leaving the plant represents waste heat. For one unit of the Coal Creek Station with a lignite feed containing 40 percent moisture, the waste heat in the flue gas is approximately 440 MBtu/hr. Engineering analyses show that using waste heat in flue gas to remove 5 percent of coal moisture would decrease the stack temperature by approximately 30°F.

Heat rejected in the main steam condenser represents another large source of waste heat. For one unit of the Coal Creek Station, heat rejection in the condenser is approximately 2,600 MBtu/hr (about 46 percent of the fuel heat input). The cooling water leaving the Coal Creek condenser has a temperature of approximately 120°F. This warm cooling water is then cooled in the cooling towers to approximately 90°F and is circulated back to the condenser. Engineering analyses show that, at full unit load, approximately 2 percent of the heat rejected in the condenser/cooling tower would be needed to decrease the coal moisture content by 5 percent. The cooling water circuit is constructed of pipes, which makes the access to this waste heat source relatively easy.

3. PREVIOUS WORK

During the 1990's the engineering staff at CCS began investigating alternative approaches to dealing with future emission regulations. Conventional approaches included changing fuels and/or adding environmental control equipment. This approach often results in lowering emissions at the expense of increases in unit heat rate and operating and maintenance costs. Higher heat rate results in higher required fuel heat input, higher CO_2 emissions, higher flow rate of flue gas leaving the boiler and lower plant capacity. Lower capacity is due to higher station service power requirements or limited equipment capacity. Also, increased flue gas flow rate requires a larger size of environmental control equipment, higher equipment cost and station service power.

A theoretical analysis was performed by the Lehigh University's Energy Research Center (ERC) in 1997-98 to estimate the magnitude of performance improvement that could be achieved by firing coal having lower moisture content [2]. The results showed that a decrease in fuel moisture would have a large positive effect on unit performance, Figure 1-3.

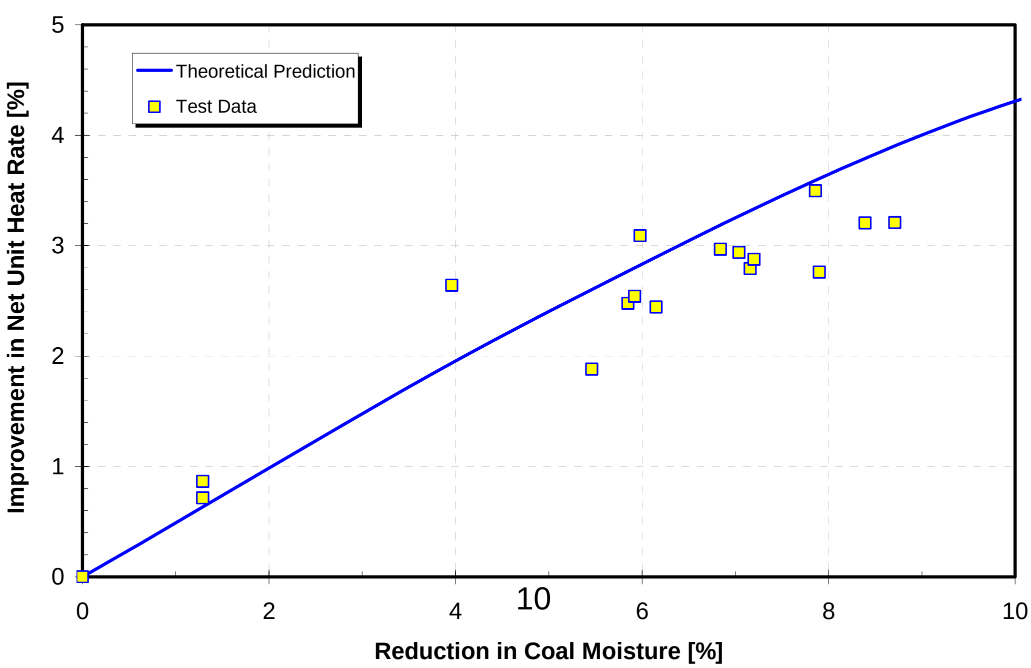

Figure 1-3: Effect of Fuel Moisture on Unit Performance

Based on these theoretical results, CCS personnel performed test burns with partially dried lignite in 2001 to confirm whether the boiler and coal handling system could handle the partially dried lignite. Except for dust in the transfer hoppers, no other fuel handling problems were encountered. Also, test results confirmed the theoretical performance improvement predictions [3].

After demonstrating the benefits of firing dried fuel, a technology for coal drying needed to be selected. Based on laboratory testing conducted at the ERC in 2002, a FBD was selected as the best technology due to its high heat and mass transfer coefficients and compact size.

GRE submitted an application to DOE in 2002 under the Clean Coal Power Initiative (CCPI) to develop a prototype fluidized bed coal dryer and develop and install a commercial coal drying system on one unit at CCS. GRE, ERC, EPRI, Barr Engineering and Falkirk Mining Company participated in the proposal development. The project was negotiated with DOE for funding under the CCPI in July 2004. Previous work and project activities are summarized in Table 1-1.

Table 1-1

Previous Work

Time Period	**Activity**
1997-1998	Preliminary studies and concept development.
1999	Lignite-drying tests using low-temperature fixed-bed dryer.
2000	CCS Boiler modeling. Laboratory lignite drying tests. Full-scale test burns using 20,000 tons of lignite dried using low-temperature air.
2001	Fixed bed dryer designed. Fluidized bed dryer selected for coal drying due to higher efficiency, smaller size, and lower cost. Application for funding under the PPI initiative was filed but turned down. Laboratory-scale FB drying tests at ERC.
2002	Application filed with DOE under the Clean Coal Power Initiative (CCPI)
2003	Application selected for negotiation with DOE. Pilot FBD built at CCS. Pilot FBD testing.
2004	Contract signed with DOE. Design of the prototype coal dryer and associate equipment.

2005	Construction of prototype coal dryer begins.
2006	Prototype dryer checkout and start-up. Prototype dryer performance testing. Unit performance testing. Maximum capacity testing. Data analysis and project report. August: Phase 1 milestone.

The project is divided into two phases. The first phase involved design, construction, installation and testing of a prototype coal drying system at CCS consisting of one FBD. The prototype coal drying system was designed in 2004. The construction began in 2004 and was finished in February 2006. The system checkout tests were conducted in February and March 2006. Performance testing was performed in March and April. Maximum capacity tests were performed in June 2006.

The second phase of the project involves installation of a commercial drying system at CCS capable of drying 500 tons/hr of wet lignite fuel.

3.1: Pilot Coal Dryer

Prior to DOE Project selection, and with funding from the North Dakota Industrial Commission (NDIC), GRE designed and constructed a 2 ton/hr pilot dryer at CCS in 2003 to provide operating experience and design scalability data for the DOE project. The pilot dryer is depicted in Figure 1-4. Field testing was conducted over a range of FBD operating conditions. A methodology for analyzing test data and determining FBD performance was developed [4].

The pilot coal dryer was operated for a 12-week period beginning in September 2003. The pilot dryer dried 150 tons of coal in 38 tests reducing the moisture content of the lignite by 24 to 60 percent, Figure 1-5. Moisture-free heating values for the feed and product streams indicated that no appreciable carbon oxidation took place during the drying process.

A buildup of the non-fluidizable material on the distributor plate, close to the coal feed point, was observed during testing. This was especially evident in the final days of testing when non-fluidizable material was cleaned out between tests, and its mass was measured. It was realized that accumulation of non-fluidizable material on a distributor plate could be used to segregate out ash, pyrites, and other impurities from the coal.

Analysis of collected samples confirmed that the non-fluidizable material on the bed bottom exhibited very high concentrations of ash, sulfur, and mercury. Depending on the feed material, it is likely that removal of this material from the feed stream would create a relatively minor energy loss, while causing a significant reduction in ash sulfur and mercury. It is possible that removal of the concentrated bed bottom material could result in SO_2 and mercury reductions of greater than 20 percent as was seen in several tests.

The pilot dryer field results were also compared to the predictions obtained by a FBD Simulation Code, developed under DOE Award Number DE-FC26-03NT41729 by ERC researchers [5] and [6]. Comparison between measured and predicted values is given in Table 1-2. A very good agreement between measurements and predictions was achieved.

Figure 1-4: Pilot Fluidized Bed Dryer at CCS

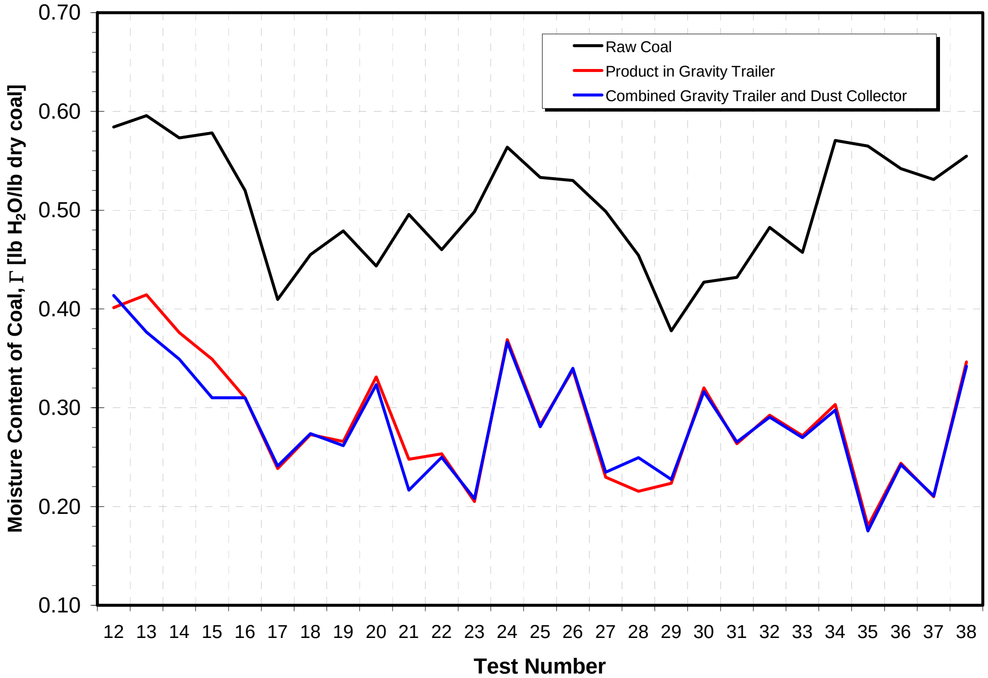

Figure 1-5: Pilot Test Results

Table 1-2

Comparison Between Pilot Test Results and FBD Simulation Code Predictions

Test Number	$\Delta\Gamma$ [lb/lb dry coal]		Outlet Air Temp. [°C]		RH of Outlet Air [%]	
	Measured	Predicted	Measured	Predicted	Measured	Predicted
4	0.175	0.151	25.5	26	72.5	69
20	0.134	0.217	33.5	36.7	86.9	70
23	0.300	0.335	36.9	37.8	66.7	67
30	0.107	0.150	30.2	33.3	86.1	72

The FBD simulation code was used to design a prototype coal dryer and, later on, the commercial coal dryers at CCS. The technical approach and results are described in [7] and [8].

PART 1: PROTOTYPE COAL DRYER AND ITS PERFORMANCE

4. COAL CREEK PROTOTYPE COAL DRYING SYSTEM

The prototype coal drying system employed at Coal Creek is based on using waste heat from the steam condenser and the hot flue gas to heat the fluidizing air used for coal drying. These two waste heat sources are also used to provide heat within the freeboard region of the FBD to provide an additional drying of the coal. The prototype coal drying system and FBD were designed by a design team assembled by GRE.

Coal feed for the dryer is supplied from existing coal bunker No. 28 (Figure 1-6). The wet coal (feed stream) is fed by a vibrating coal feeder (Figure 1-9) to a coal crusher and crushed and sieved to -1/4". The crushed coal is screened by a vibrating screen (Figure 1-7) and conveyed to the dryer inlet hopper. Two rotary coal feeders (air locks) feed coal to the first stage of the FBD. The screen bypass flow (i.e., the larger particles separated out by the screen that were not therefore dried in the dryer) is mixed with a product stream leaving the dryer employing a bypass conveyer. Mixing of the two streams takes place downstream of the coal sampling location.

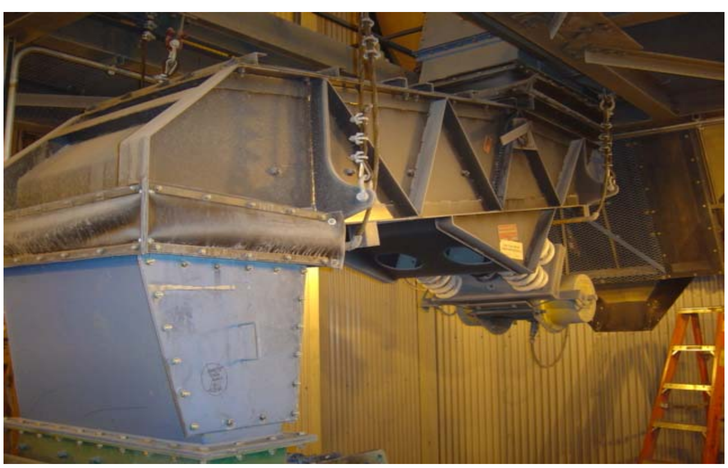

Figure 1-6: Coal Feeder

Figure 1-7: Vibrating Screen

The dried coal (product stream) leaving the dryer is stored in coal bunker No. 26, feeding coal mill 26. A coal conveyor and bucket elevator are used to transport dried coal to the No. 26 bunker. As product stream is transported from the dryer to the bunker, it cools down, and its temperature drops by approximately 10°F.

The coal-drying system was designed in modular fashion to allow incremental drying of the coal. Each coal-drying module will dry a portion of the total coal flow and will also include environmental controls (baghouse for dust control). With all four coal-drying modules in service it will be possible to dry 100% of the coal feed.

The commercial coal drying system design will provide redundancy whereby coal dryers will be able to supply dried product to any coal mill. This will provide backup in the event of the equipment problem. This redundancy will also extend from Unit 1 to Unit 2 and vice versa.

Also, in the commercial coal drying system, the segregated stream will not be combined with the product stream. This will have a significantly positive effect on SO_x and mercury emissions.

4.1: Fluidized Bed Coal Dryer

A fluidized bed dryer is a good choice for drying coal to be burned at the same site where it is dried. The coal dryer can be of single-stage or multiple-stage design, with the stages contained in one or more vessels. The multi-stage design allows maximum utilization of fluidized bed mixing, segregation and drying characteristics.

A two-stage fluidized bed dryer design, where the bed volume is divided into two parts, is employed at Coal Creek. The dryer was manufactured by Heyl & Patterson, Inc. and is comprised of two stages, packaged into a single vessel. The first stage occupies approximately 20 percent of the dryer volume.

In the first stage, the coal is preheated and partially dried (a portion of surface moisture is removed). Non-fluidizable particles segregate out, thereby forming the segregated stream. The first dryer stage accomplishes the following functions: separates the fluidizable and non-fluidizable material, pre-dries and preheats the coal, and provides uniform flow of coal to the second stage.

The fluidizable material flows over the weir to the second stage of the dryer, where the coal is heated and dried to a desired outlet moisture level. The product stream from the second stage is discharged over the discharge weir into the discharge hopper. From the discharge hopper, the product stream is fed to the product stream conveyor through three rotary coal feeders (air locks) (Figure 1-8). Although the second stage can also be used to further separate ash and other impurities from the coal, this option was not employed at CCS.

Figure 1-8: Dried Coal is Discharged through Three Rotating Coal Feeders

Fluidization and heating of coal and removal of coal moisture is accomplished within the fluidized bed by hot fluidization air. The air stream is cooled and humidified as it flows upwards through the coal bed. The quantity of moisture, which can be removed from the bed of fluidized coal, is limited by the drying capacity of the fluidization air stream. The drying capacity of the fluidization air stream can be increased by supplying additional heat to the bed by the in-bed heat exchanger. The in-bed heat exchanger not only increases drying capacity of the fluidizing air stream but it also reduces the quantity of drying air required to accomplish a desired degree of coal drying.

Five in-bed heat exchangers (bed coils), employing finned tubes, are used to supply additional heat to the coal: one in the first dryer stage, with the other four in the second stage. Different designs and materials were used for each bed coil tested in the prototype dryer. The best performing design will be used in the additional four dryers that will be built in Phase 2 of the project.

The prototype dryer design data are summarized in Table 1-3. As the data in Table 1-3 show, the heat transfer area for individual bed coils, depending on their design, varies from 1,144 to 1,982 ft^2. The average heat transfer coefficient for finned tubes of 18 Btu/hr-ft^2-°F was determined experimentally by GRE and Barr engineers.

Table 1-3

Prototype Dryer Design Data

Prototype Coal Dryer Parameter	Units	Prototype Value
Distributor Area	ft^2	**308**
First Stage Fluidizing Air Flow	klbs/hr	**55**
Second Stage Fluidizing Air Flow	klbs/hr	**250**
Expanded Bed Depth	"	**38 to 40**
In-Bed Heat Exchanger No. 1 HT Area	ft^2	**1,982**
In-Bed Heat Exchanger No. 2 HT Area	ft^2	**1,696**
In-Bed Heat Exchanger No. 3 HT Area	ft^2	**1,982**
In-Bed Heat Exchanger No. 4 HT Area	ft^2	**1,832**
In-Bed Heat Exchanger No. 5 HT Area	ft^2	**1,144**
Total In-Bed Heat Exchnager Area	**ft^2**	**8,636**
Total Exchanged Heat, In-Bed HXE	MBTU/hr	**16.53**
Average Heat Transfer Coefficient	BTU/hr-ft^2-°F	**18.08**
Total Water Flow Through the In-Bed Heat Exchangers, Actual	gpm	**1,588**
Total Water Flow Through the In-Bed Heat Exchangers, Indicated	gpm	**1,363**

In order to achieve maximum drying, the drying air stream would need to leave the fluidized bed at saturation conditions (i.e., with 100 percent relative humidity). This is, however, undesirable since condensation would occur in the freeboard region of the dryer. To prevent this, the CCS prototype coal dryer was designed for an outlet air relative humidity less than 100 percent.

Alternatively, reheat surfaces in the freeboard region of the bed or duct skin heating can be used to increase the temperature and lower the relative humidity of the air leaving the dryer and prevent downstream condensation. This option was not implemented at CCS.

The particle control equipment, consisting of a dust collector (baghouse) and discharge fan, is used to remove elutriated fines from the moist air stream leaving the dryer. Collected particulate matter is mixed with the coal product stream, and clean particle-free moist air is discharged through a stack to the atmosphere, as presented in Figure 1-9.

Figure 1-9: Clean Moist Air Stream Leaving Dust Collector is Discharged into the Atmosphere

4.2: **<u>Instrumentation</u>**

The prototype coal drying system tested at CCS was instrumented to allow determination of dryer performance. Plant instrumentation was used to determine boiler efficiency and plant heat rate.

Measured variables include: coal feed rate, crusher power, inlet and outlet air lock (rotary feeder) loading, temperature of feed stream, temperature of coal in the No. 26 bunker, CO level at the dryer outlet and in the bunker, dust collector fan power, moisture in product stream, moisture in fluidizing air stream leaving the dryer and dust collector, temperature of fluidizing air stream at the dryer inlet, cold and hot PA temperatures, flow rate of fluidizing air into the first and second dryer stage, circulating water flow and inlet and outlet temperature, pressure of fluidizing air in the plenum, above the bed and other state points including dust collector inlet and outlet, and flow rate of the bypass and scrubbing air. An array of thermocouples is used to measure the coal and freeboard temperature in the dryer. Thermocouple arrangement in the dryer is presented in Figure 1-10. Process values, measured during dryer testing will be presented later.

It has to be noted that the on-line instrument for coal moisture measurement is not providing representative information since it measures surface moisture. A very poor correlation was found between coal moisture values measured by the on-line instrument and determined from the laboratory analysis of coal samples. Therefore, the on-line measurement of coal moisture content was not used in the data analysis.

The relative humidity of fluidizing air stream leaving the dust collector (baghouse) was usually in the 99 to 100 percent range. Its value was not affected by changes in dryer operating conditions. It is believed that this measurement, although correct, is not representative of the dryer outlet conditions. In addition, as elutriated coal particles are collected on a bag wall, they form a layer (cake) of wet coal. This layer is dried by the air flowing through the bags. Engineering analyses suggest that the air leaving the cake is saturated.

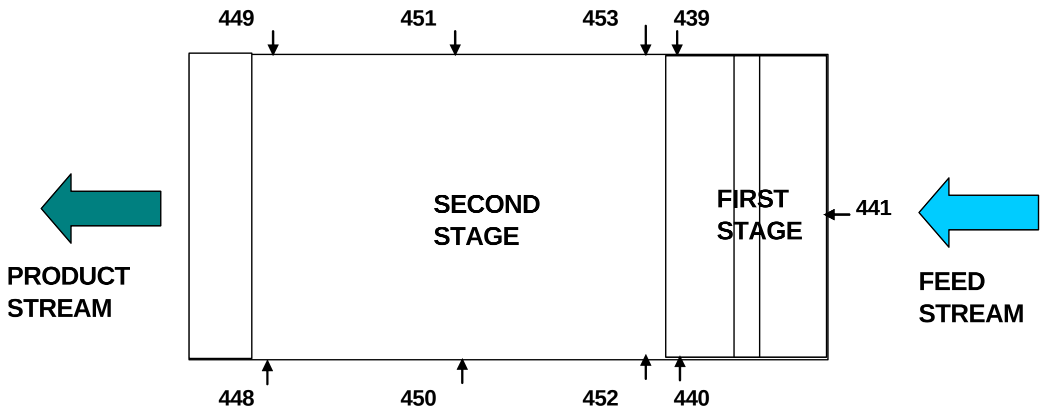

Figure 1-10a: Thermocouple Locations and Numbers in First and Second Stages of a Prototype Coal Dryer at CCS

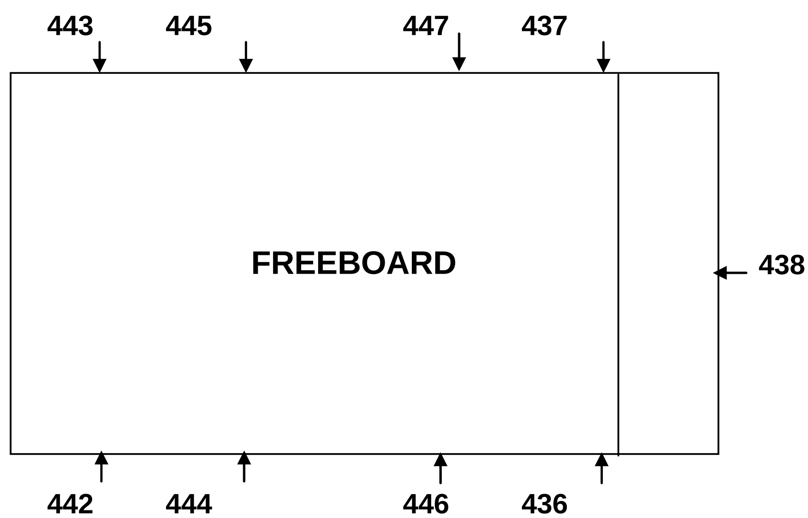

Figure 1-10b: Thermocouple Locations and Numbers in the Freeboard Region of a Prototype Coal Dryer at CCS

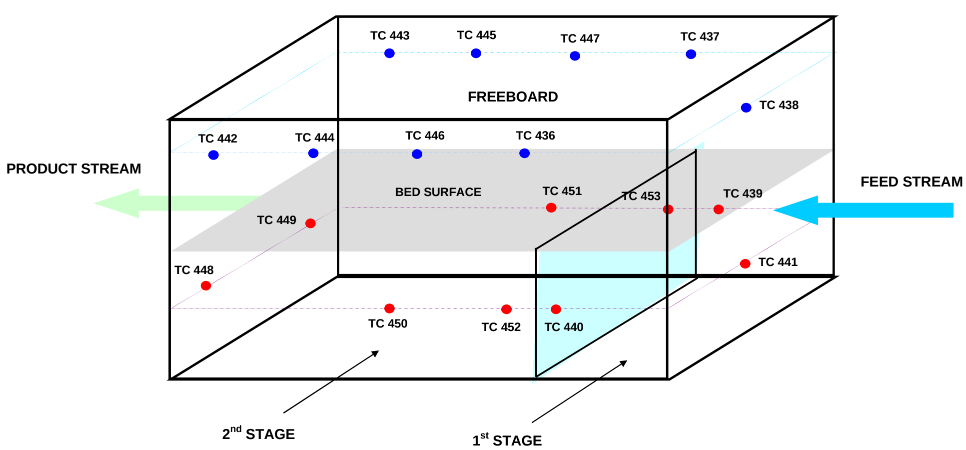

Figure 1-10c: Thermocouple Locations in First and Second Stagesand in a Freeboard Region of a Prototype Coal Dryer at CCS Isometric View

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The second instrument for air moisture measurement, located at the dryer outlet, upstream of the dust collector was, unfortunately, not working properly. Therefore, no measured values of dryer outlet air moisture are available for analysis and comparison with theoretical predictions.

Two automatic coal samplers were used to collect samples of the feed and product streams. The feed coal sampler, located on the feed conveyer, is presented in Figure 1-11.

Figure 1-11: Automatic Coal Analyzer: Feed Conveyer

The automatic coal sampler for the product stream is located on the product conveyer after the product stream leaving the dryer is mixed with the segregated stream and elutriated coal particles collected by the dust collector. This introduces an uncertainty in product moisture and dryer performance. Manual coal samples were also taken from the segregated stream conveyer to determine composition of the segregated stream.

4.3: Process Control

Operation of the prototype coal drying system at CCS is completely automated, including the startup, shutdown, and emergency shut down procedures. Heat input to the dryer is controlled by adjusting the input flow rates of the waste heat sources to match the heat input required to accomplish the desired degree of drying.

Heat input to the dryer, Q_1, is defined as:

$$Q_1 = Q_{air} + Q_{Circulating\ water} \qquad \text{Eqn. 1-1}$$

where:

Q_{air}	Heat input with the air stream
$Q_{Circulating\ Water}$	Heat supplied to the in-bed heat exchanger

The required heat input to the dryer, Q_2, is defined as:

$$Q_2 = M_{coal}\ \Delta TM\ h_{fg} + \Delta Q_{Coal\ Sensitive} \qquad \text{Eqn. 1-2}$$

where:

M_{coal}	Coal feed flow rate
ΔTM	Required (desired) absolute reduction in total coal moisture content
h_{fg}	Latent heat of evaporation of coal moisture
$\Delta Q_{Coal\ Sensitive}$	Change in sensitive heat of coal

As long as $Q_1 < Q_2$, during the dryer startup or transient operation when coal feed rate to the dryer is increased, the control algorithm increases the hot air flow rate until the heat input supplied to the dryer matches the required heat input.

When the coal feed flow rate is reduced, or a lower reduction of coal moisture content is required, $Q_2 > Q_1$, the control algorithm reduces the flow rate of hot air flow until $Q_1 = Q_2$. This simple control algorithm works very well in practice.

5. DRYER PERFORMANCE

5.1: Factors Affecting Dryer Performance

Performance of a fluidized bed dryer is affected by many operating and design parameters. The most important include: flow rate and inlet moisture content of coal, flow rate, temperature and humidity of drying/fluidizing air, bed depth, coal residence time, and heat input by the in-bed heat exchanger. The latter is directly proportional to the heat transfer surface area and the average difference in temperature between the heat exchanger tube surface area and fluidized coal particles.

5.2: First and Second-Stage Dryer Performance

As discussed earlier, a two-stage dryer design offers several advantages, compared to a single-stage design. The most important advantage is segregation of coarse and non-fluidizable material which is collected at the bottom of the first stage and discharged from the dryer and scrubbing boxes. The fluidizable material flows over the weir separating the first and second dryer stages and enters the second stage. After passing through the second stage, dried coal is discharged into the outlet hopper over the discharge weir. The function of the discharge weir is to maintain the bed height.

The calculated variations of the bed temperature and coal moisture content along the length of the prototype dryer are presented in Figures 1-12 and 1-13 for a feed rate of 75 t/hr of wet Falkirk mine lignite, a fluidization air temperature at 170°F and an average bed coil temperature of 210°F are required. Calculations were performed with an inlet coal moisture content of 37.08 percent on a wet coal basis, corresponding to $\Gamma = 0.589$ lb moisture/lb dry coal.

The results presented in Figures 1-12 and 1-13 show that the main functions of the first and second dryer stages are very different. The incoming coal is preheated in the first dryer stage from the inlet temperature to a temperature corresponding to approximately 90 percent of the maximum coal temperature leaving the dryer. The reduction in coal moisture content in the first stage is small -- less than 10 percent of the total coal moisture is removed in the first stage. By contrast, the increase in bed temperature in the second dryer stage is very small -- only about 10 percent of the total temperature increase in coal dryer. However, the second dryer stage removes more than 90 percent of the total moisture removed from the feed stream.

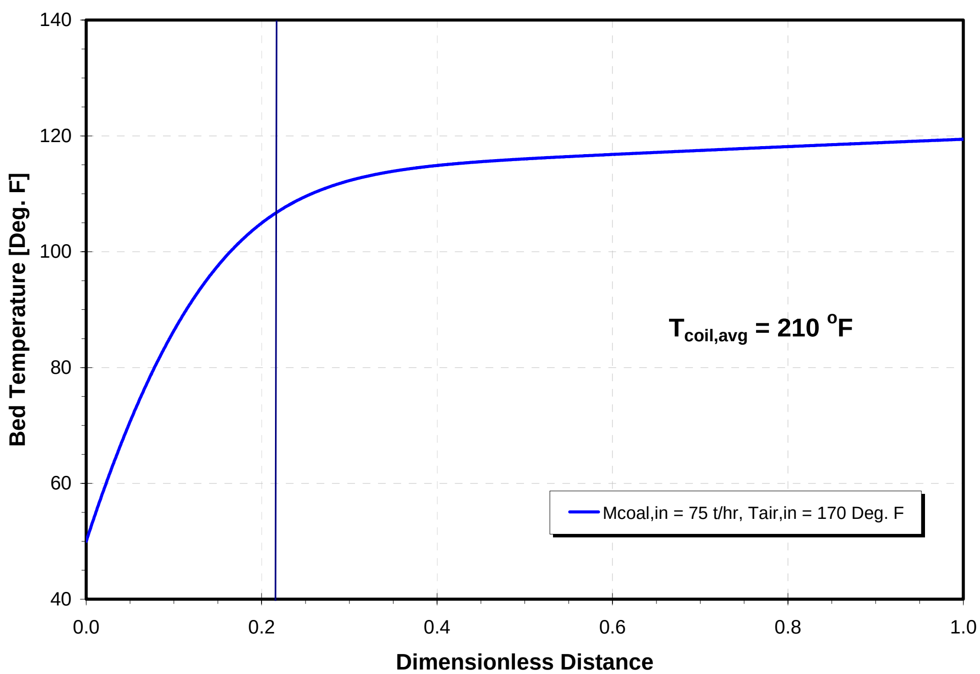

Figure 1-12: Variation of Bed Temperature Along the Dryer Length

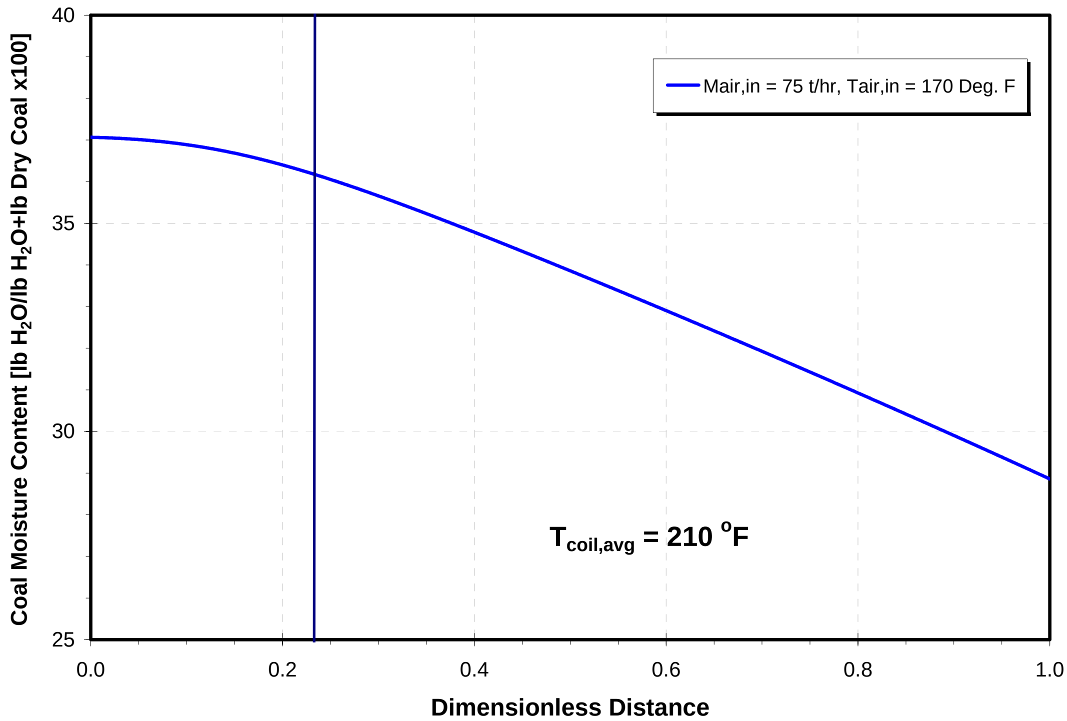

Figure 1-13: Variation of Coal Moisture Content Along the Dryer Length

6. TEST RESULTS

6.1: Operation Under Controlled Conditions

Performance tests were conducted under controlled conditions to determine dryer performance and the effect of firing dried coal on boiler efficiency and unit performance. As suggested by Dr. Moen, a paired-test approach was used where two consecutive performance tests were run per day: one with the prototype dryer in operation, the other with the prototype dryer off. The order of tests, i.e., dry and wet, or wet and dry, was determined randomly. Such an approach minimizes or eliminates the effects of bias errors, i.e., day-to-day differences/variations in plant operating conditions, and other uncontrollable variables.

Statistics was used to determine the number of required tests. The test uncertainty, i.e., random error vs. number of tests relationship presented in Figure 1-14, shows that the benefit of running more than 12 tests is very small. This is because test uncertainty is inversely related to the square root of the number of tests. The random error in Figure 1-14 was normalized with respect to the best estimate of standard deviation S. The absolute value of random error can be determined by multiplying values from Figure 1-14 by the numerical value of S.

Test uncertainty (random error) is defined as:

$$RE = \frac{tS}{\sqrt{N}} \qquad \text{Eqn. 1-3}$$

where:

RE	Random error (test uncertainty)
t	Student (W. Gosset) variable, where t = f(N, Confidence Level)
S	Best estimate of standard deviation σ

$$S = \sigma\sqrt{\frac{N}{N-1}} \qquad \text{Eqn. 1-4}$$

Standard deviation is calculated from the test data. Based on the statistical analysis, it was decided to conduct 16 paired performance tests.

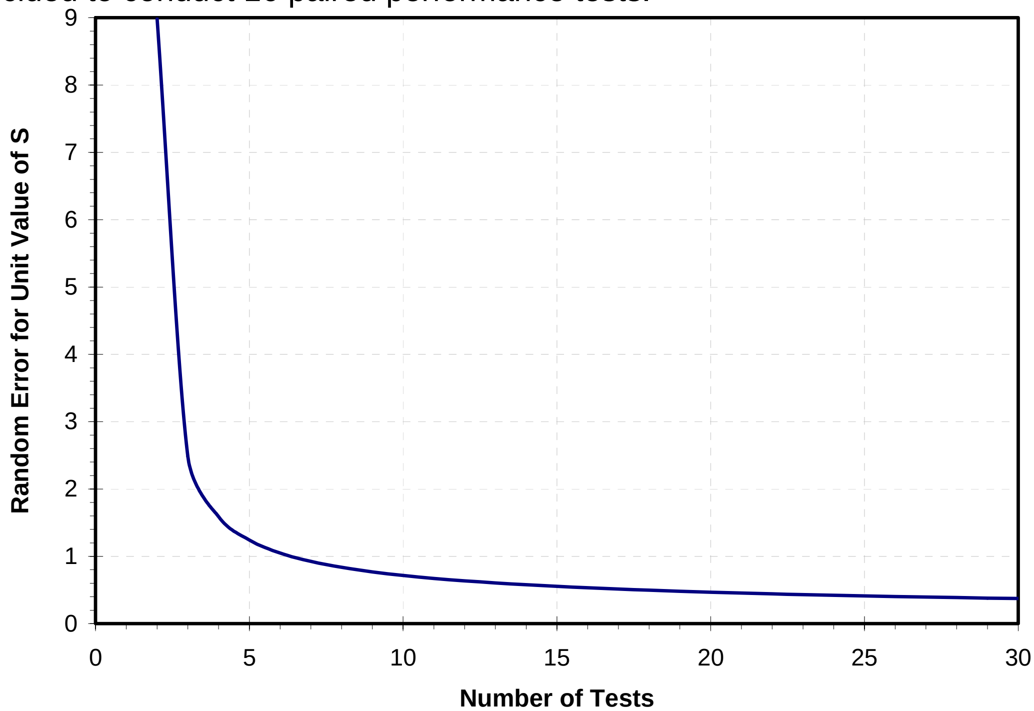

Figure 1-14: Normalized Random Error vs. Number of Tests Relationship

Statistics also provides information regarding the minimum detectable difference. The minimum detectable difference is the smallest statistically significant difference between two sets of measurements -- in this case between two sets of performance tests conducted with dried and wet coals. For sixteen performance tests, the minimum statistically significant difference in boiler efficiency that can be measured is in the 0.025 to 0.125 range, depending on the precision of the measurement. Assuming an S of 0.10 gives the minimum statistically significant difference in boiler efficiency of 0.096 (Figure 1-15). Since the theoretical difference in boiler efficiency, for the expected reduction in coal moisture content of feed coal is in the 0.35 percentage point range, the test results will be statistically significant.

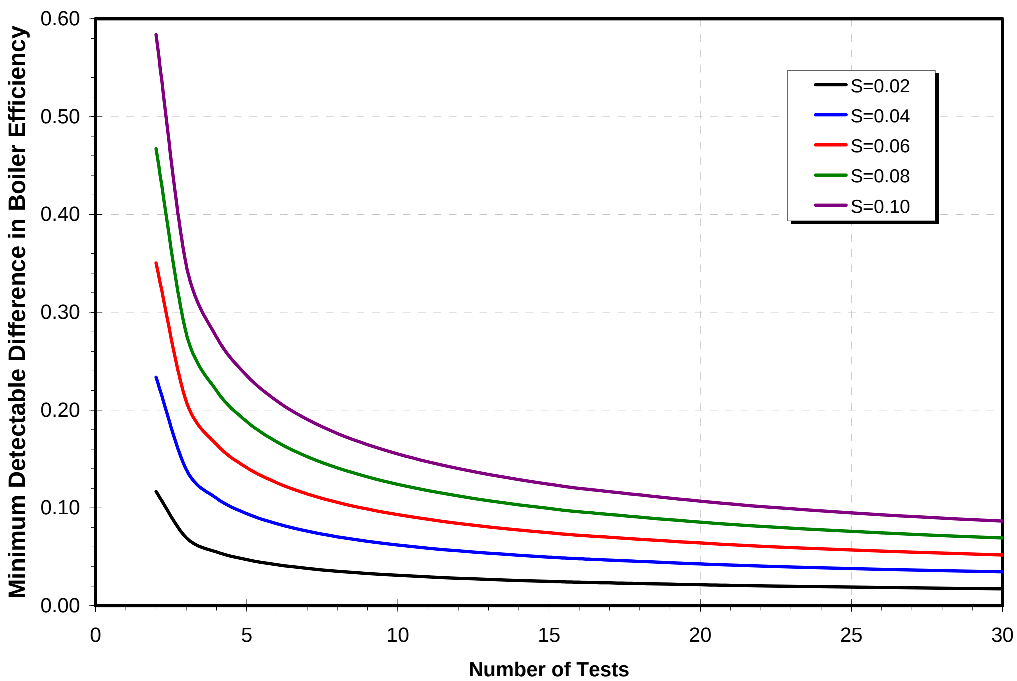

Figure 1-15: Minimum Statistically Significant Difference in Boiler Efficiency vs. Number of Performed Tests

Sixteen dryer performance tests were performed during time period from March 22nd to May 12th 2006, under controlled conditions with a baseline coal feed rate of 75 t/hr, fluidization air temperature in the 165 to 190°F range, and average bed coil temperature of 210°F. Under these operating conditions, in-bed heat input to the dryer was in the 15 to 16 MBtu/hr range.

A comparison of measured and predicted (simulated) dryer performance is presented in Figures 1-16 and 1-17. The total moisture content measured in the product stream is presented in Figure 1-16 as a function of fluidization air temperature. Dryer simulation results are represented by a solid line. As Figure 1-16 shows, there is a very good agreement between the measured and predicted product moisture contents. The results also show that the prototype dryer was operated with a relatively low fluidization air temperature. Increasing the fluidization temperature will have a positive effect on dryer performance.

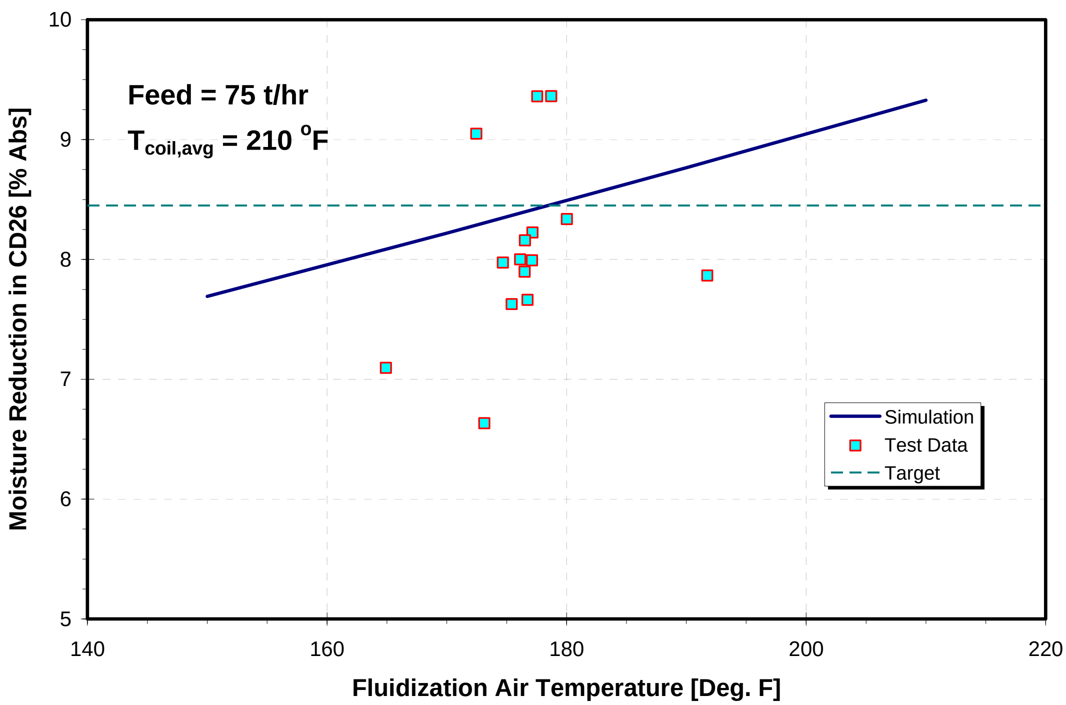

Figure 1-16: Measured and Predicted Dryer Performance: Total Moisture

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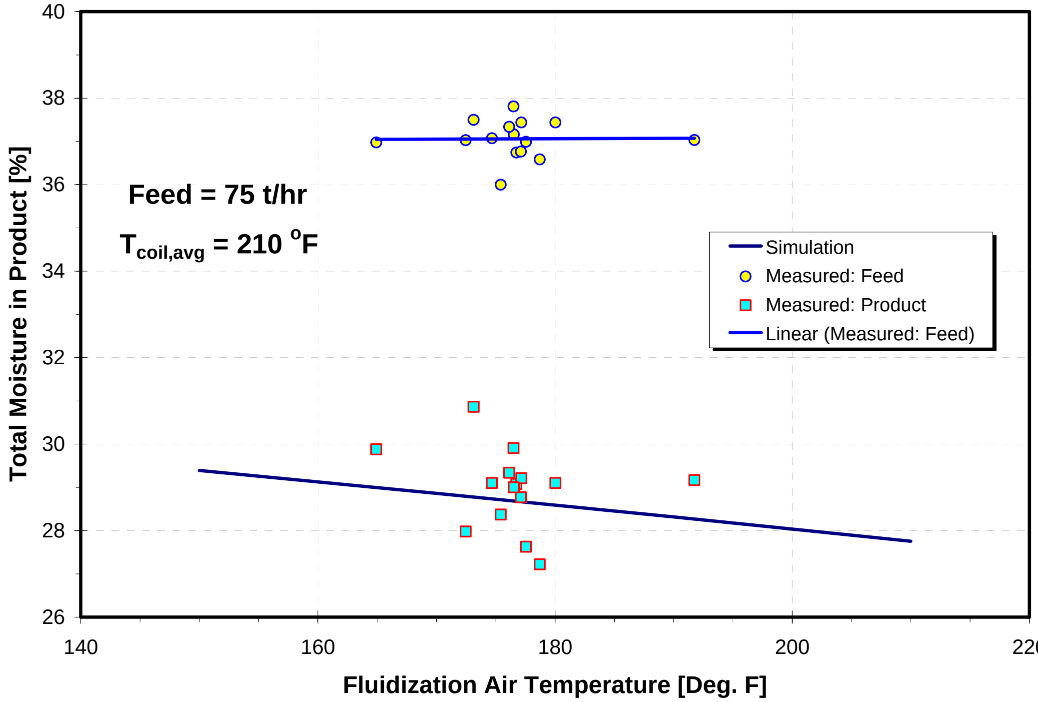

Figure 1-17: Measured and Predicted Dryer Performance: Moisture Reduction

Figure 1-17 compares the measured and predicted coal moisture reduction in the prototype dryer. Except for a few test points, there is very good agreement between the measurements and simulation. The target moisture removal level of 8.45 percent was easily reached by operating the prototype dryer with fluidization temperature at or above 180°F.

The total coal moisture (TM) and higher heating value (HHV) measured in the feed and product streams during the controlled dryer tests are summarized in Table 1-4 and presented in Figures 1-18 and 1-19. The Test 16 results show a much lower TM content and higher HHV value compared to the other tests and were, therefore, not included in the statistical analysis of data. The results show that average moisture reduction was 8.08 ± 0.42 percent. The HHV was on average improved by 727 ± 62 Btu/lb. The random error in Table 1-4 represents the 95 percent confidence interval. The variation in TM and HHV during the controlled tests is presented in Figures 1-41 and 1-19. The improvement in HHV and reduction in total coal moisture content are presented in Figure 1-20.

Table 1-4

Dryer Performance Tests: Coal Moisture and HHV

CD 26 Test Number	TM [%] Product	TM [%] Feed	TM [% Abs] Reduction	Dry Coal Flow % of Total	HHV [BTU/lb] Product	HHV [BTU/lb] Feed	ΔHHV [BTU/lb] Difference
1	27.98	37.03	9.05	14.28	6,871	6,203	668
2	29.08	36.74	7.66	14.28	6,746	6,148	598
3	29.21	37.44	8.22	13.79	7,069	6,392	677
4	28.77	36.76	7.99	13.91	7,037	6,292	745
5	30.87	37.50	6.63	13.32	7,028	6,172	857
6	27.22	36.58	9.36	13.84	7,212	6,214	997
7	29.10	37.44	8.34	14.28	7,162	6,392	770
8	27.63	36.99	9.36	14.29	6,947	6,337	610
9	29.88	36.98	7.09	14.26	7,033	6,489	544
10	29.10	37.07	7.97	14.14	7,109	6,361	748
11	28.37	36.00	7.63	14.29	7,084	6,270	814
12	29.00	37.16	8.16	14.29	7,035	6,340	695
13	29.34	37.34	8.00	14.29	7,060	6,285	775
14	29.17	37.03	7.86	14.29	6,854	6,176	679
15	29.91	37.81	7.90	14.29	7,145	6,415	730
16	21.19	37.47	16.28	13.90	7,499	6,440	1,059
Average	**28.98**	**37.06**	**8.08**	**14.12**	**7,026**	**6,299**	**727**
Std.Dev	0.92	0.44	0.75	0.29	125	102	112
St.Error	0.24	0.11	0.19	0.07	32	26	29
Random Error	**0.51**	**0.24**	**0.42**	**0.16**	**69**	**56**	**62**

Note: The data from Test 16 are considered outliers and are not included in the calculated average and standard deviation values.

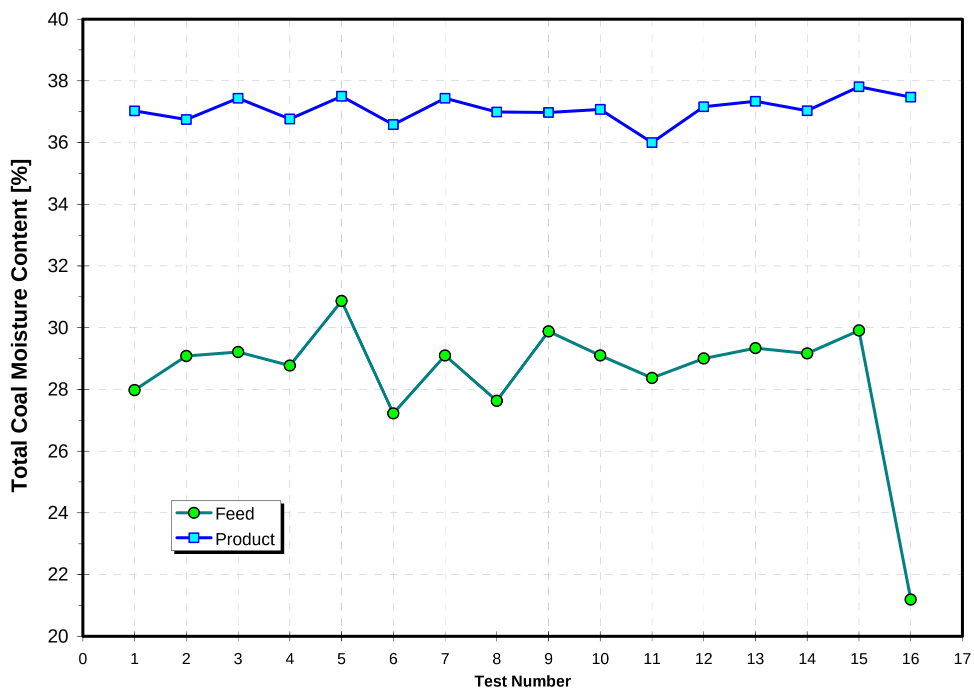

Figure 1-18: Total Coal Moisture Content in Feed and Product Streams Measured During Dryer Performance Tests

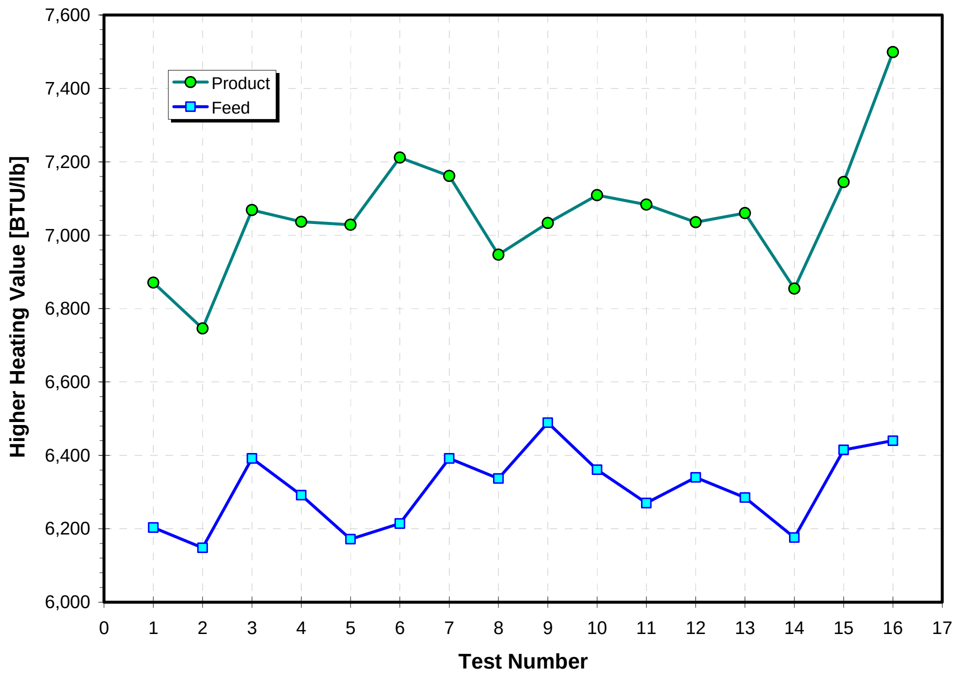

Figure 1-19: Higher Heating Value in Feed and Product Streams Measured During Dryer Performance Tests

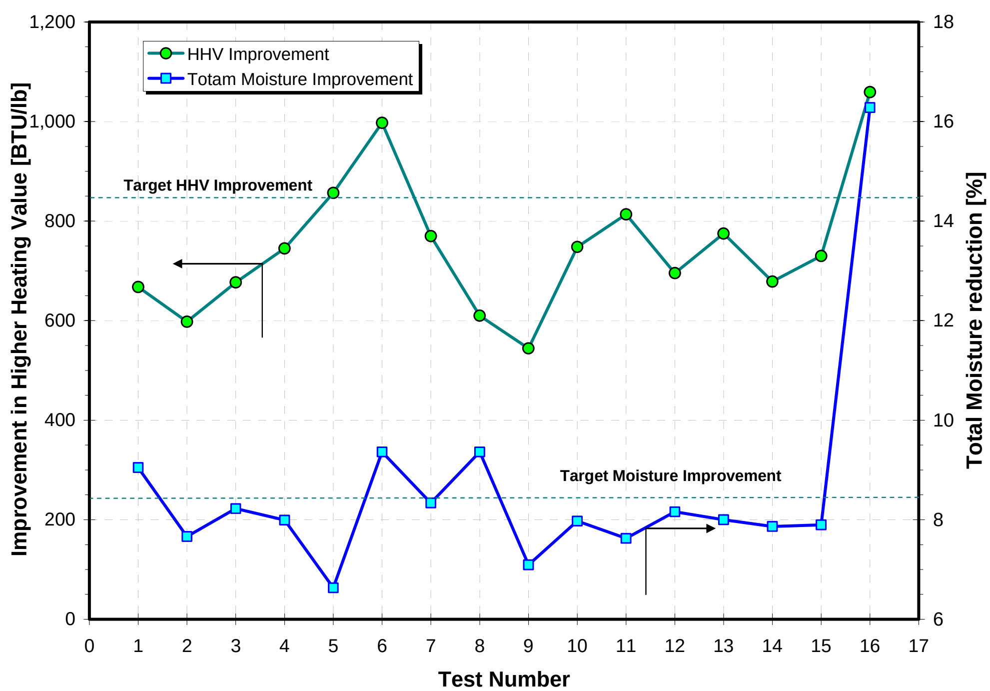

Figure 1-20: Improvement in HHV and Reduction in Total Moisture Measured in Dryer Performance Tests

6.2: Regular Dryer Operation

Coal quality data were collected during regular dryer operation for the time period from March to April, 2006. Results are presented in Table 1-5 and Figures 1-21 and 1-22.

Table 1-5

Regular Dryer Performance: Coal Moisture and HHV

Parameter	Feed TM %	Product TM %	Change TM % Abs	Change TM % Rel
Average Total Moisture, TM	36.78	28.55	8.23	22.4
Std. Deviation	1.26	1.00	1.07	
Std. Deviation of the Mean	0.34	0.27	0.30	

Parameter	Feed HHV [BTU/lb]	Product HHV [BTU/lb]	Change HHV [BTU/lb]	Change HHV [%]
Average HHV	6,290	7,043	752	12.0
Std. Deviation	159	121	131	
Std.Deviation of the Mean	43	33	37	

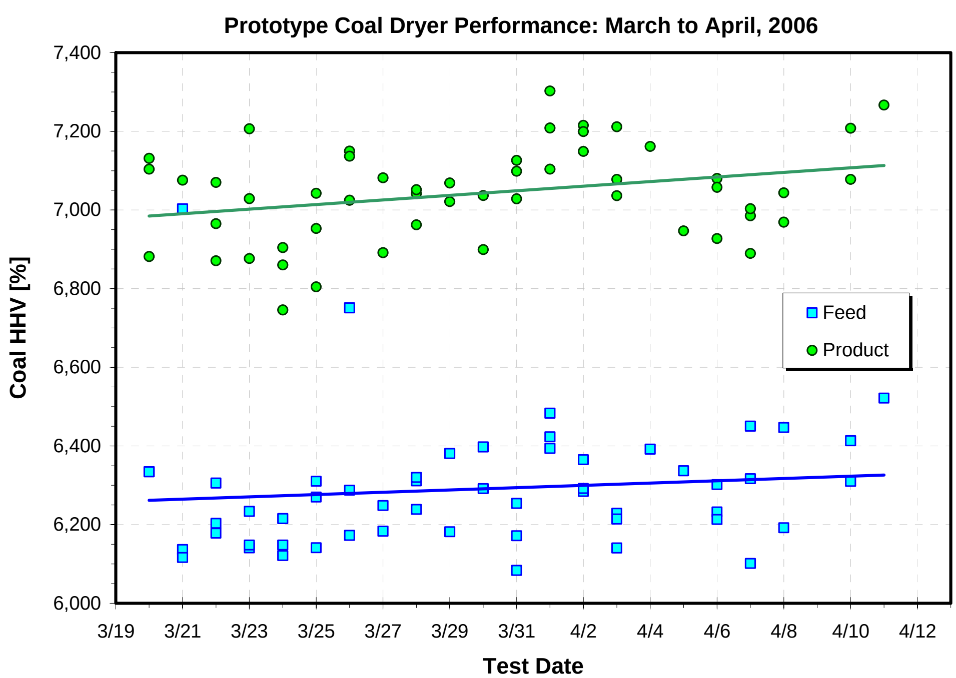

Figure 1-21: Coal Moisture in Feed and Product Streams Measured During Regular Dryer Operation

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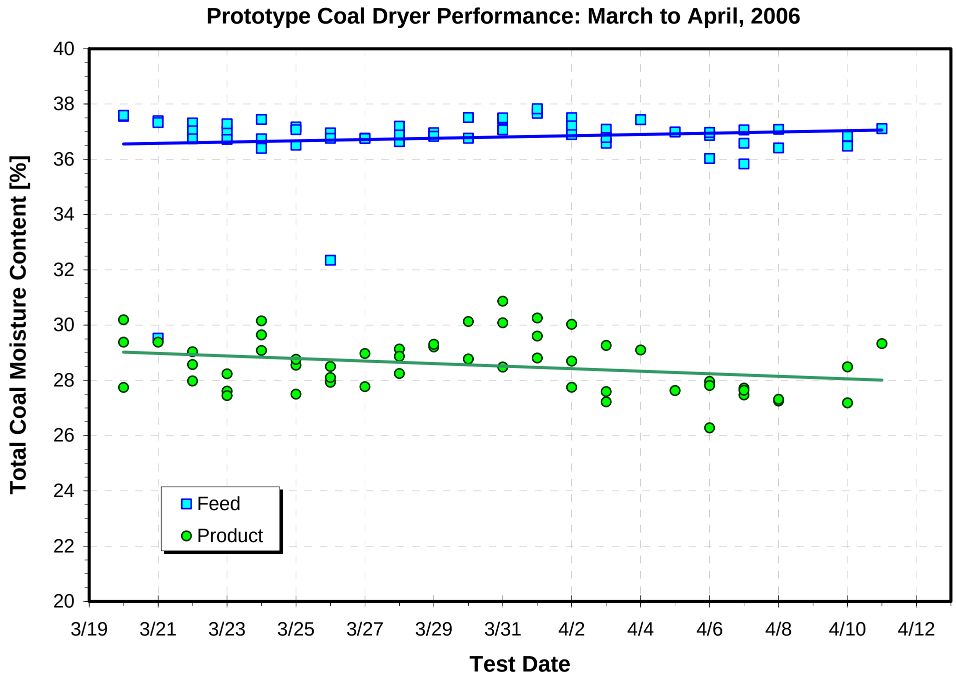

Figure 1-22: Higher Heating Value for Feed and Product Streams Measured During Regular Dryer Operation

The average moisture reduction, achieved during regular dryer operation, was 8.23 ± 0.6 percent. This is almost identical to the total moisture reduction achieved during the controlled performance tests. The improvement in HHV during regular dryer operation was 752 ± 74 Btu/lb. Within the accuracy of the data, this is the same improvement in HHV achieved during the controlled dryer performance tests. In conclusion, this means that dryer performance, measured during the controlled tests, is sustainable over the long-term [9].

6.3: <u>Dryer Performance at Maximum Coal Feed Rate</u>

6.3.1: Maximum Capacity Tests

The maximum design coal feed rate for the prototype dryer is 112.5 tons per hour. With four dryers in service, each operating at the maximum feed rate, it would be possible to dry the total full-load coal feed for Unit 2 at Coal Creek (450 t/hr).

Three maximum capacity tests (CT1, CT2, and CT3) were performed from June 21 to 23, 2006, wherein coal feed rate was increased from the baseline value of 75 t/hr first to 90 t/hr, and finally to the maximum value of 101 t/hr. The coal conveying system and dust collector fan power imposed a limit on the maximum coal feed rate, which fell short of the design value by 10 percent.

The maximum capacity test data are summarized in Tables 1-6 to 1-8. Operating conditions of the dryer, presented in Table 1-6, show that inlet temperatures of fluidizing air and circulating water were increased above the baseline values to accommodate higher coal feed to the dryer. With the maximum coal feed rate at 101 t/hr, fluidization air temperature was 40°F higher compared to baseline operation, while the circulating water temperature was 20°F higher. With the feed rate at 101 t/hr, the dried coal represented 21 percent of the total coal feed to the boiler.

Table 1-6

Maximum Capacity Tests: Dryer Operating Conditions

Test	Date	Test Duration	Dryer Coal Feed	Total Coal Flow	Dried Coal	Fluidization Air Flow	Fluidization Temperature	Circulating Water Inlet Temperature	Circulating Water Outlet Temperature	In-Bed Heat Transfer
		hours	t/hr	t/hr	% of Total	klbs/hr	°F	°F	°F	MBTU/hr
1	6/21/2006	4	**90**	494.0	**18.2**	301	188	219	200	15.1
2	6/22/2006	4	**90**	484.5	**18.6**	291	214	233	211	16.4
3	6/23/2006	2	**101**	480.5	**21.0**	288	220	236	214	16.9

Table 1-7

Maximum Capacity Tests: Coal Moisture Reduction

Test	Coal Feed	Feed Moisture	Coal Dryer			Coal Feed to the Boiler	
			Product Moisture	Moisture Reduction	Moisture Reduction	Average Coal Moisture	Moisture Reduction
	t/hr	%	%	% Abs	% Rel	%	% Abs
1	90	35.2	27.9	**7.3**	**20.7**	33.9	**1.3**
2	90	36.8	27.4	**9.4**	**25.5**	35.1	**1.7**
3	101	36.4	29.1	**7.3**	**20.1**	34.9	**1.5**

Table 1-8

Maximum Capacity Tests: Improvement in HHV

Test	Coal Feed	Feed HHV	Coal Dryer			Coal Feed to the Boiler		
			Product HHV	HHV Increase	HHV Increase	Average Coal HHV	HHV Improvement	HHV Improvement
	t/hr	BTU/lb	BTU/lb	BTU/lb	%	BTU/lb	BTU/lb	%
1	90	5,895	6,886	991	16.8	6,076	181	3.1
2	90	6,198	7,074	876	14.1	6,361	163	2.6
3	101	6,116	7,393	1,277	20.9	6,384	268	4.4

The reduction in coal moisture, achieved in the maximum capacity tests, is summarized in Table 1-7. The results show that the coal moisture reduction in the 7 to 9 percentage point range (20 to 26 percent relative) was achieved. The average coal moisture in the coal feed to the boiler (blend of dried and wet coal), was in the 1.3 to 1.7 percent range.

The coal HHV improved as moisture was removed from the coal in the prototype coal dryer (Table 1-8). The achieved HHV improvement was in the 875 to 1,280 Btu/lb range, or 14 to 21 percent. The improvement in the HHV of the boiler coal feed was in the 160 to 270 Btu/lb range, or from 2.6 to 4.4 percent.

Computer simulations were performed using operating conditions corresponding to the dryer capacity tests. Measured and predicted values are presented in Figures 1-23and 1-24. The comparison between measured and predicted moisture reduction values are presented in Figure 1-46.

An excellent agreement was achieved between measurements and predictions for capacity tests 1 and 3 (CT 1 and CT3). The measured value of moisture reduction for CT2 was approximately one percentage point higher compared to the predictions. This disagreement could be due to an error in coal analysis or a mislabeling of coal samples that were sent to the plant coal analysis laboratory.

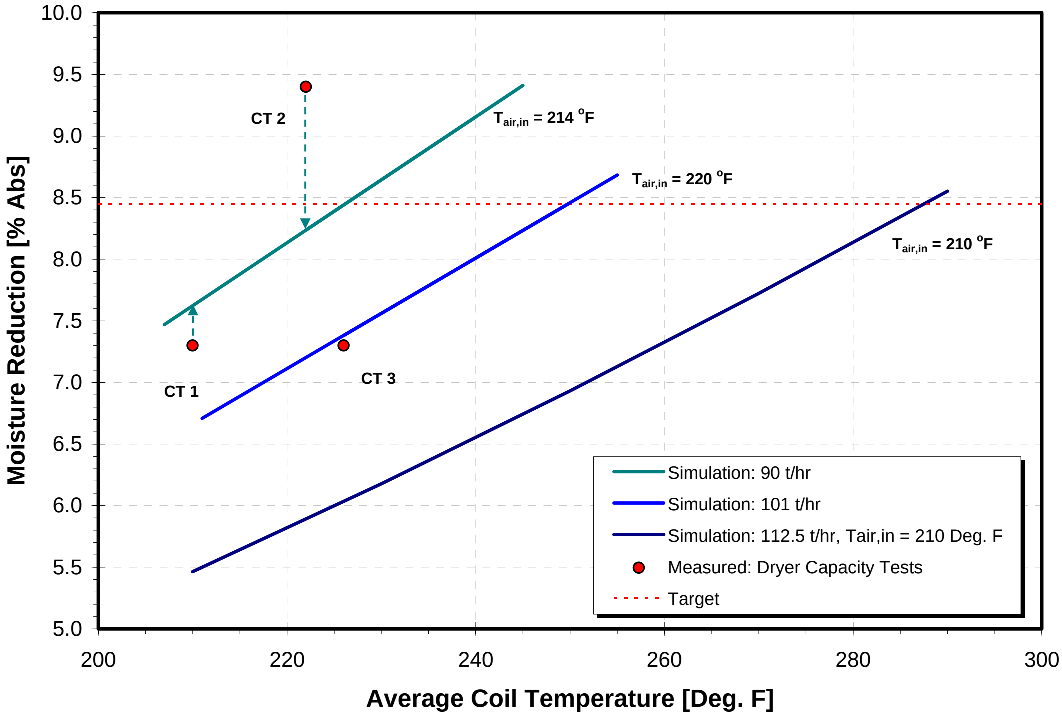

Figure 1-23: Maximum Capacity Tests - Measured vs. Predicted Values of Moisture Reduction

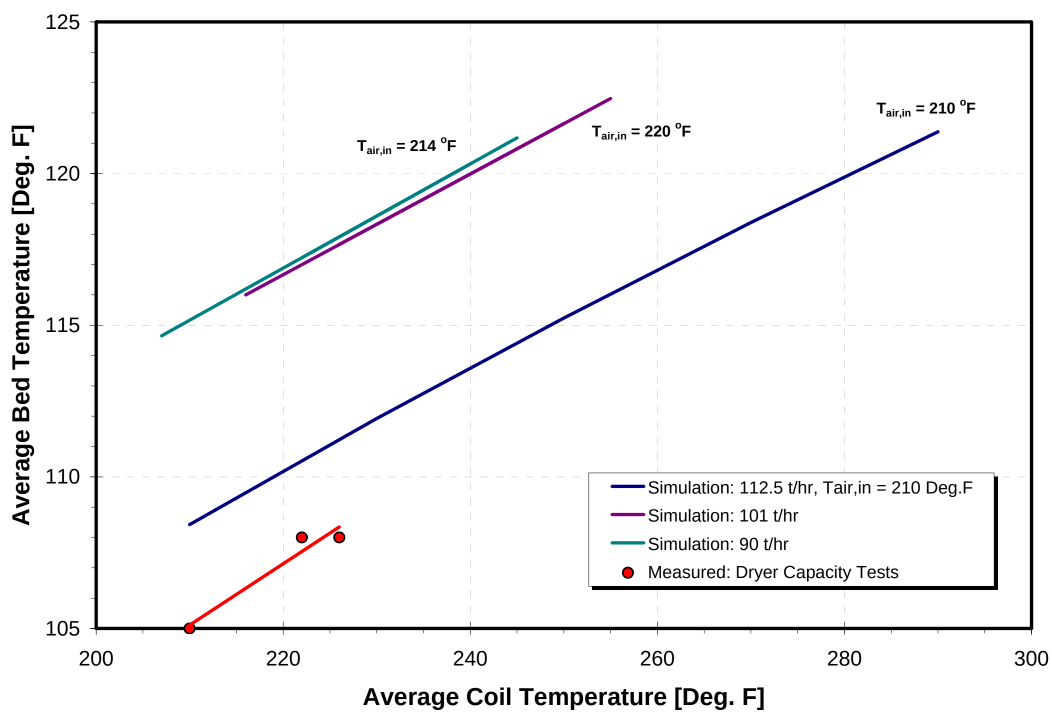

Figure 1-24: Maximum Capacity Tests - Measured vs. Predicted Values of Average Bed Temperature

The results also show that with a feed rate at 90 t/hr and an inlet air temperature at 214°F, the target moisture reduction can be achieved by increasing the average coil temperature to 227°F. With a feed rate at 101 t/hr and a fluidization air temperature at 220°F, the average coil temperature needs to be increased to 250°F. Predictions are also given for the maximum design coal feed at 112.5 t/hr and fluidizing air temperature at 210°F. It has to be noted that the average coil temperature is, for practical purposes, equal to the average of the circulating water inlet and outlet temperatures.

Predicted and measured values of the average bed temperature are presented in Figure 1-24. The results show that the predicted values followed the same trend as measurements, with measured values being, on average, 9°F lower. Considering locations of the in-bed thermocouples and uncertainties in bed temperature measurement, this represents a very good agreement.

6.4: First-Stage Segregation

The non-fluidizable material is removed from the dryer as the segregated stream by a patent pending system. Samples were taken from the segregated stream and analyzed to determine its composition. Results are presented in Tables 1-9 and 1-10 and in Figures 1-25 to 1-28 for baseline coal feed flow rate.

The total moisture, sulfur, and mercury content, and HHV of the feed, product, and segregated streams, determined from samples that were collected during the May-June time period, are summarized in Table 1-9. While the total moisture content of the product stream is significantly lower and its HHV higher compared to the feed stream, the moisture content and HHV of the segregated stream are similar to the feed stream. These experimental findings are in agreement with the dryer simulation results that show that only 10 percent of the total moisture removed in the dryer is removed in the first stage.

Table 1-10 presents the sulfur, mercury, and HHV of the segregated stream as percentages of the feed stream. The results show that approximately 30 percent of sulfur and mercury in the feed stream entering the dryer are removed in the first stage and discharged as the segregated stream. The segregated stream also contains approximately 10 percent of the inlet HHV. Additional processing of the segregated stream is needed to further concentrate sulfur and mercury and reduce the HHV content. Segregated stream processing will be incorporated into the commercial coal drying system.

The segregated stream samples were also collected during the maximum dryer capacity tests.

Table 1-9

Composition of Feed, Product and Segregated Streams (May-June, 2006)

Test	Feed Stream				Product Stream				Segregation Stream			
	HHV	TM	Sulfur	Hg	HHV	TM	Sulfur	Hg	HHV	TM	Sulfur	Hg
	BTU/lb	%	% AR	ppm AR	BTU/lb	%	% AR	ppm AR	BTU/lb	%	% AR	ppm AR
1	6,359	38.1	0.61	614	7,477	28.1	0.60	498	6,631	35.7	1.37	1,347
2	6,303	37.2	0.69	700	7,448	27.1	0.60	380	6,263	35.3	2.00	1,853
3	6,271	38.1	0.63	500	7,363	25.3	0.62	463	6,097	33.9	2.16	2,290
4	6,324	37.3	0.66	648	7,565	23.2	0.60	615	6,504	37.2	1.39	1,509
5	6,370	37.8	0.58	495	7,840	23.2	0.67	493	6,696	37.1	1.13	1,246
6	6,115	37.3	0.55	616	7,796	21.0	0.61	555	6,223	35.0	1.97	2,237
7	6,085	36.8	0.61	748	7,434	25.1	0.60	553	6,267	34.7	1.71	1,839
8	6,236	37.0	0.61	625	7,583	28.6	0.55	457	6,389	36.0	1.58	1,970
9	6,421	38.1	0.57	604	7,303	28.3	0.63	536	6,427	35.9	1.85	2,537
10	6,303	38.2	0.69	591	7,335	28.8	0.65	606	6,558	36.1	1.89	2,121

Table 1-10

Sulfur and Mercury Removed by the
First Stage and HHV Content of the Segregated Stream

Segregated Stream			
Test	**S**	**Hg**	**HHV**
	% of Feed	% of Feed	% of Feed
1	22.5	21.9	10.4
2	29.3	26.5	9.9
3	34.5	45.8	9.7
4	21.2	23.3	10.3
5	19.4	25.2	10.5
6	36.0	36.3	10.2
7	28.2	24.6	10.3
8	25.7	31.5	10.2
9	32.5	42.0	10.0
10	27.4	35.9	10.4
Average	**27.7**	**31.3**	**10.2**

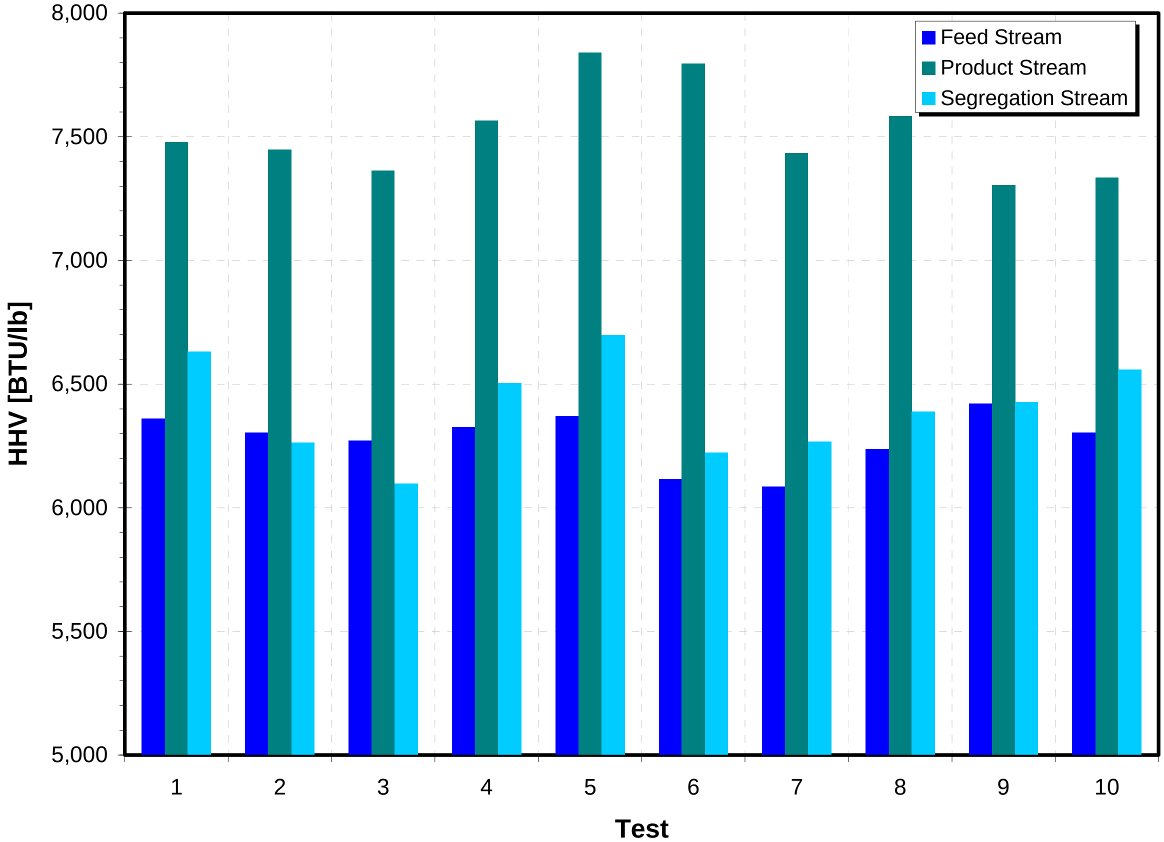

Figure 1-25: HHV of the Feed, Product and Segregated Streams

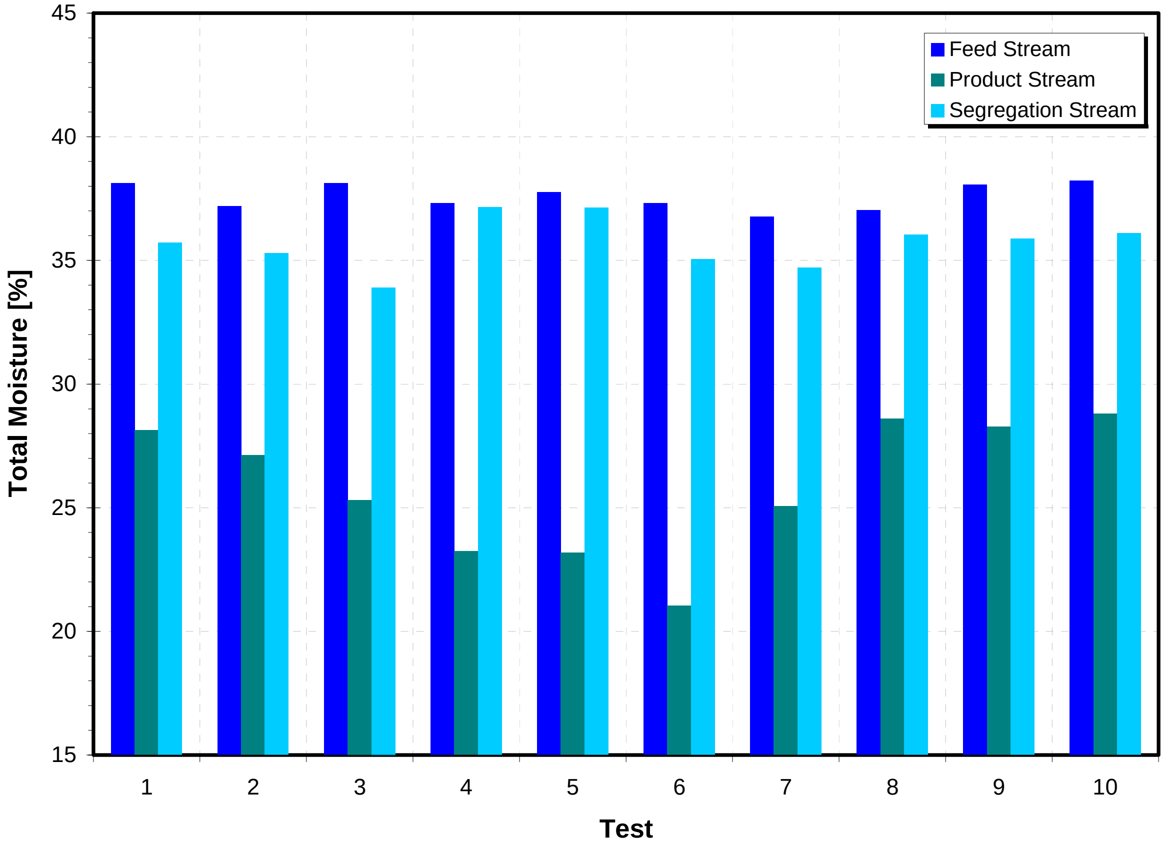

Figure 1-26: Total Moisture in the Feed, Product and Segregated Streams

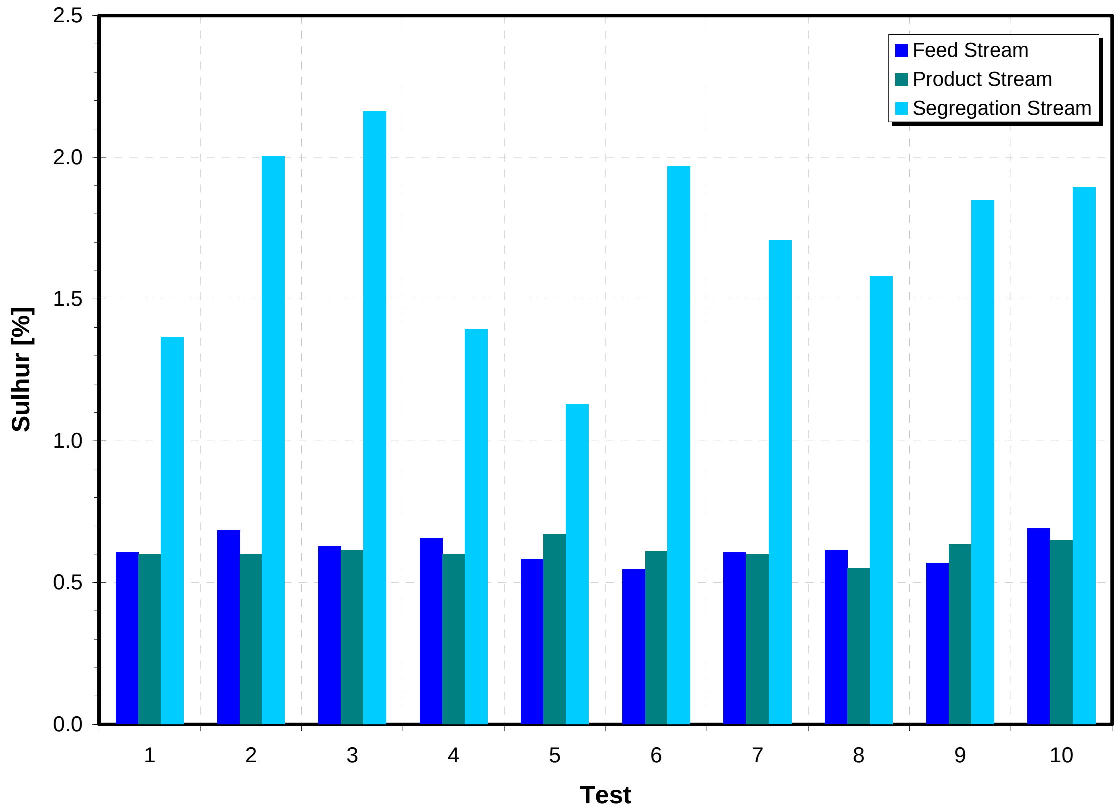

Figure 1-27: Sulfur in the Feed, Product, and Segregated Streams

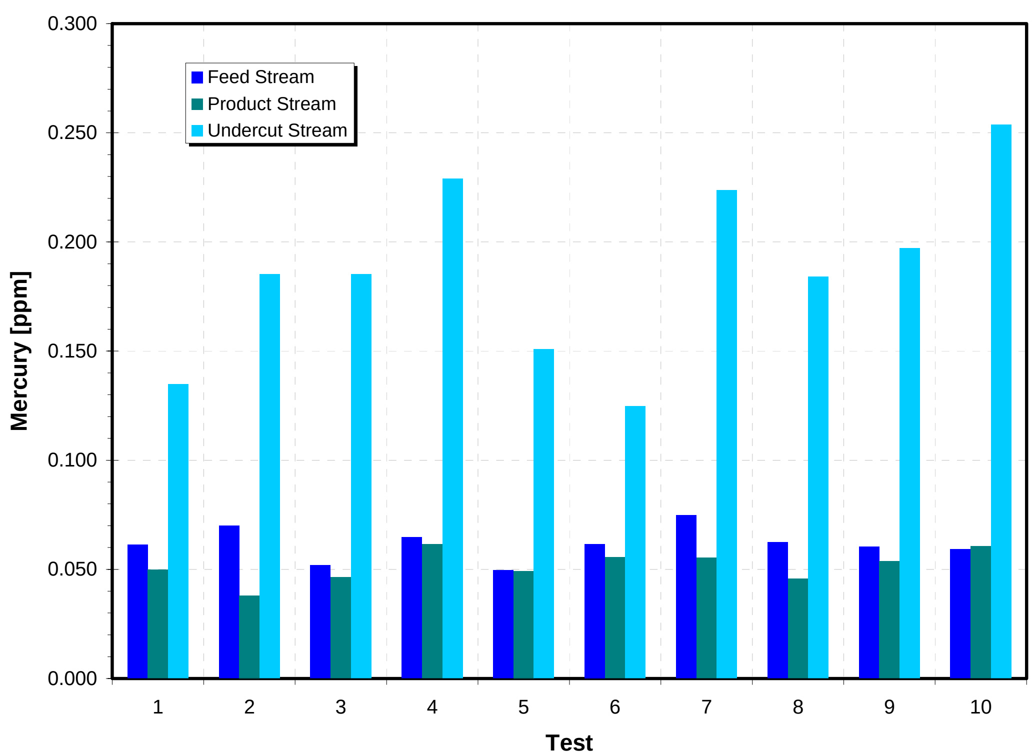

Figure 1-28: Mercury in the Feed, Product, and Segregated Streams

The S, Hg and HHV content of the segregated stream, expressed as percentage of feed, are summarized in Table 1-13 and Figure 1-29 as functions of feed rate. The results show that mercury content of the segregated stream increased as feed rate increased, while sulfur and HHV contents remained approximately constant.

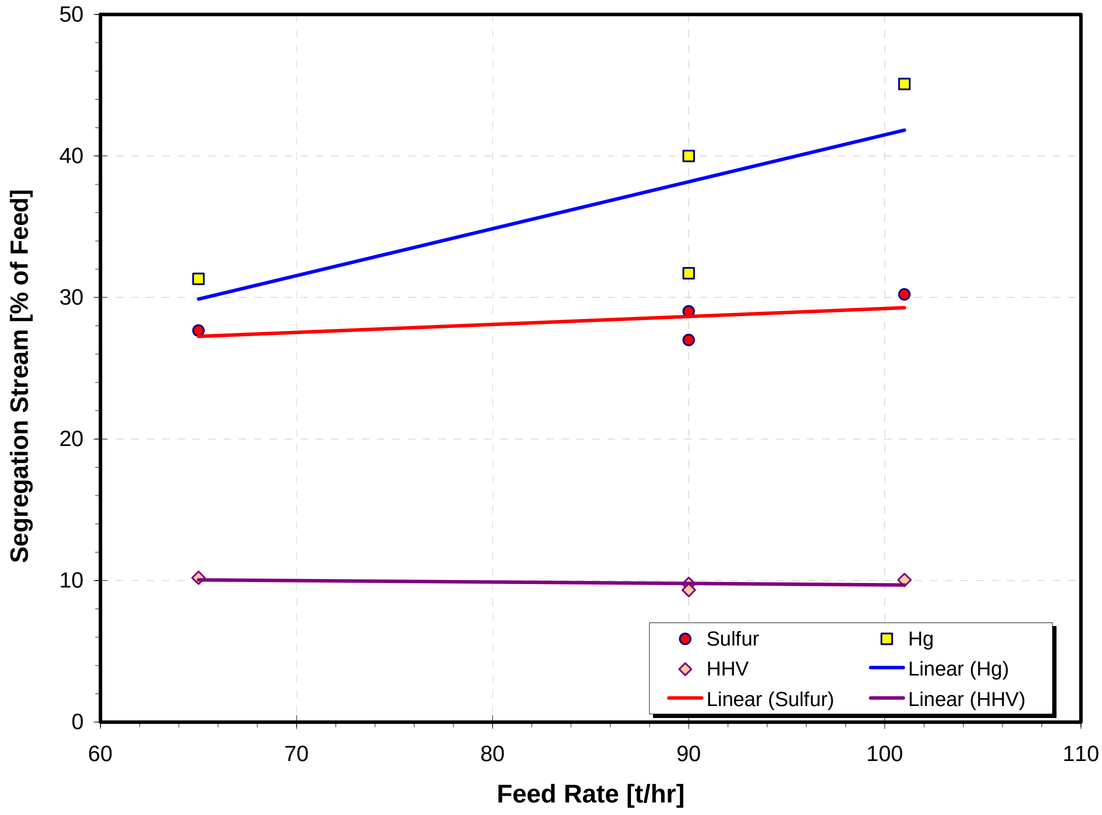

Figure 1-29: Sulfur, Mercury, and HHV Content of Segregated Stream vs. Feed Rate

PART 2: UNIT PERFORMANCE AND EMISSIONS

7. UNIT PERFORMANCE

As discussed in Section 6.1 (Operation Under Controlled Conditions), performance tests were conducted under carefully controlled conditions to determine the effect of firing dried coal on boiler efficiency and unit performance. A paired-test approach was used where two performance tests were run per day: one with the prototype dryer in operation, the other with the prototype dryer out of service. Such an approach minimizes or eliminates the effects of bias errors, i.e., day to day differences in plant operating conditions, variation in uncontrollable variables, and calibration drift of coal feeders.

Plant operating parameters such as main and reheat steam temperature, main steam and desuperheating spray flow rates, coal feeder flow rate, mill and fan power, flow rates of primary air to the mills, temperature of air and flue gas at a number of state points, and plant emissions were measured and recorded by the plant data acquisition system. Coal composition and HHV were determined from coal samples that were collected manually and by automatic coal samplers.

As predicted by theoretical calculations and confirmed in test burns, firing of partially dried coal in the boiler has a positive effect on boiler and unit efficiency, and stack emissions. The improvement in performance and reduction in emissions were determined for a series of 16 paired dryer tests.

In the current arrangement of a prototype coal drying system at CCS, the prototype coal dryer supplies dried coal to coal mill No. 26. With the prototype coal dryer in service and operating at a nominal coal feed of 75 t/hr, dried coal represents approximately 14 percent of the total coal flow rate supplied to the boiler (Figure 2-1).

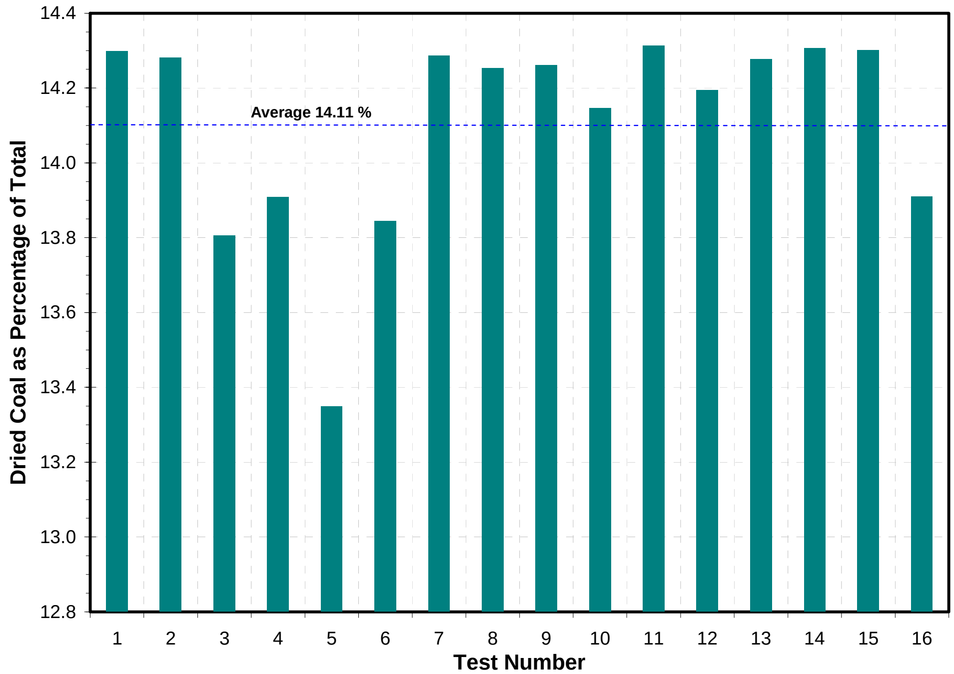

Figure 2-1: Dried Coal as Percentage of Total Coal Feed

Coal composition, HHV, and fuel heat input, determined for 16 pairs of coal dryer performance tests, are summarized in Table 2-1. With the prototype coal dryer (CD26) in service, the properties of the dried and wet coal streams were mass-averaged to determine properties of the coal blend fired in the boiler. The composition and HHV of the coal blend were determined from the following expression:

$$X_{Mass\text{-}Average} = X_{Blend} = X_{Dry}\, M_{Dry}/M_{Total} + X_{Wet}\, M_{Wet}/M_{Total} \qquad \text{Eqn. 2-1}$$

where:

X_{Blend} Composition or HHV of blended coal
X_{Dry} Composition or HHV of dried coal out of the CD26
X_{Wet} Composition or HHV of wet coal
M_{Dry} Flow rate of dried coal out of the CD26
M_{Wet} Flow rate of wet coal to the boiler
M_{Total} Total coal flow rate, where:

$$M_{Total} = M_{Dry} + M_{Wet} \qquad \text{Eqn. 2-2}$$

Table 2-1

Properties of Blended and Wet Coals

Description	Units	Mass-Average Dry	Average Wet	% Change WRT Wet	Absolute Change WRT Wet
C	% by weight	39.55	39.00	1.4	0.6
S	% by weight	0.68	0.66	1.6	0.0
H	% by weight	3.34	3.35	-0.1	0.0
N	% by weight	0.54	0.53	1.4	0.0
O	% by weight	8.55	8.26	3.5	0.3
Moisture	**% by weight**	**35.92**	**37.06**	**-3.1**	**-1.14**
Ash	% by weight	11.42	11.14	2.5	0.3
Total	**% by weight**	100.00	100.00		
HHV	**BTU/lb**	**6,402**	**6,299**	**1.63**	**103**
TOTAL FEEDER COAL FLOW RATE	**klbs/hr**	**953**	**971**	**-1.83**	
Total heat input	**MBTU/hr**	**6,102**	**6,117**	**-0.24**	
MAF-Basis HHV	**BTU/lb**	**12,157**	**12,160**	**-0.03**	**-4**

The results show that, with CD26 in service, the total moisture of the coal blend was reduced by 1.14 percentage points, or 3.1 percent on a relative basis, Figures 2-2 and 2-3. The improvement in HHV was 103 Btu/lb, or 1.63 percent, Figures 2-4 and 2-5. As expected, the coal HHV, expressed on a moisture-and-ash-free (MAF) basis, remained constant.

With the prototype coal dryer in service, the total coal flow rate, measured by the mill feeders, was reduced by 1.83 percent, Figures 2-6 and 2-7. The measured and theoretically predicted reductions in total coal flow rate are compared in Figure 2-8. The results show an excellent agreement between the calculated and measured values. For a target value of coal moisture reduction of 8.5 percent, the predicted decrease in coal flow rate is approximately 14 percent. This decrease is due to the higher HHV of the partially dried coal and improved boiler and unit performance.

The reduction in unit heat rate, due to the improvement in HHV and reduction in total coal flow rate, resulted in a 0.24 percent lower fuel heat input to the boiler, Table 2-2.

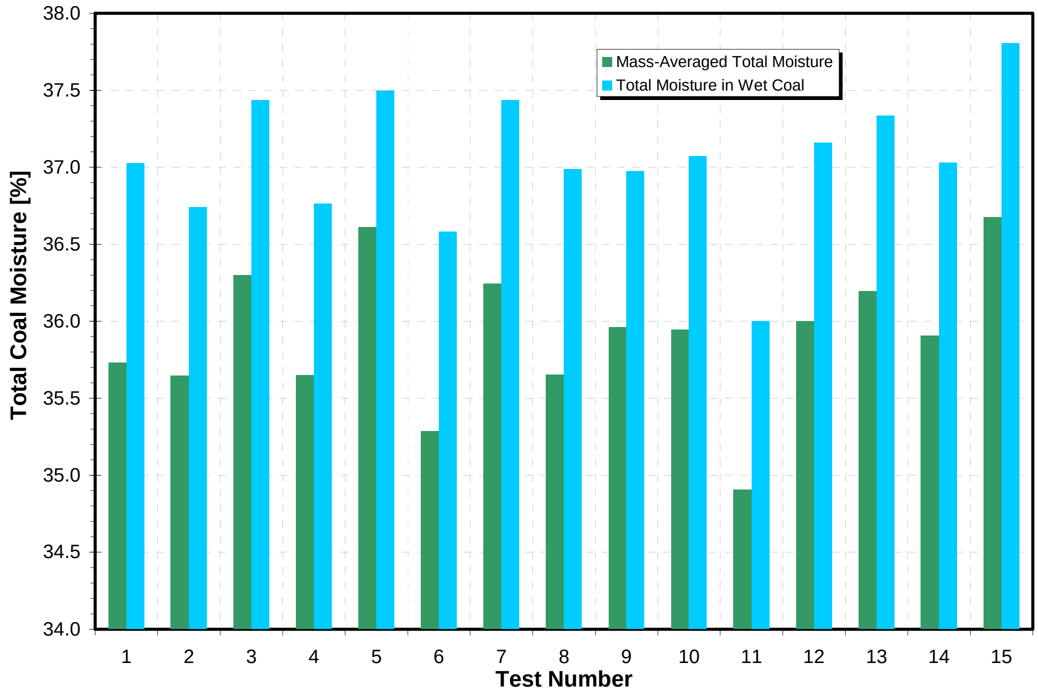

Figure 2-2: Total Coal Moisture in Wet and Partially Dried Coal

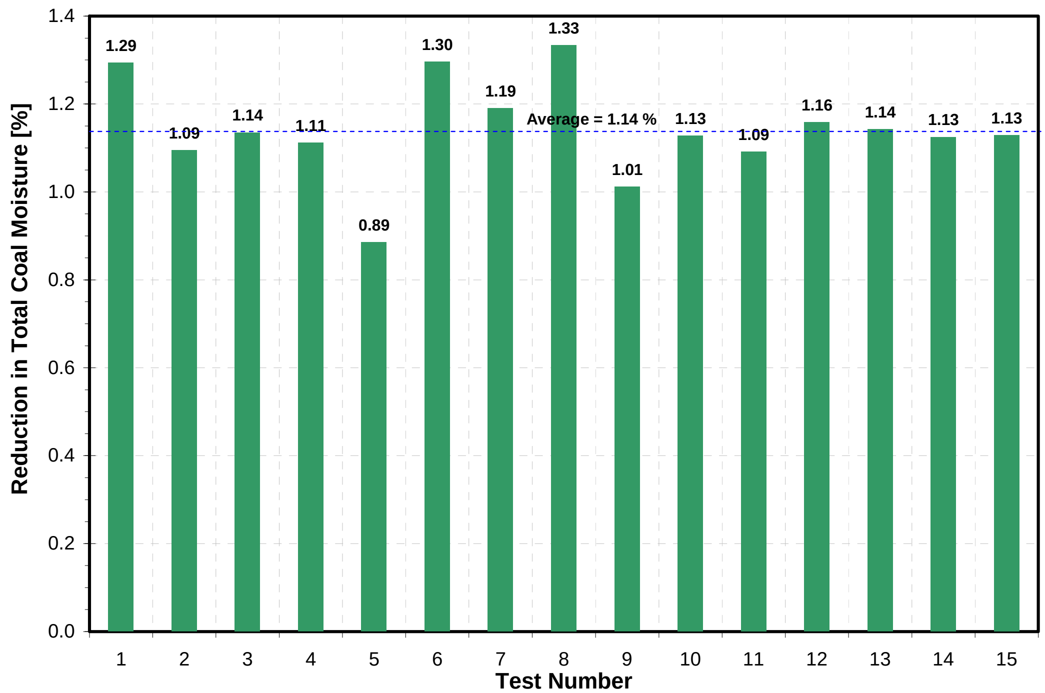

Figure 2-3: Reduction in Total Coal Moisture Content

954085v4

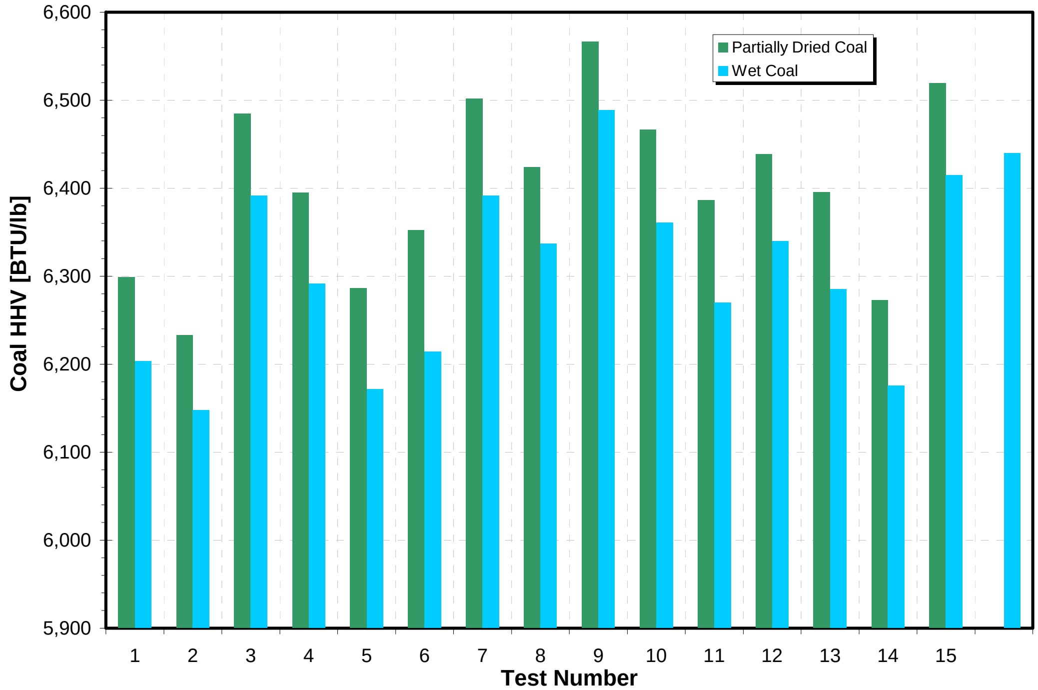

Figure 2-4: HHV of Wet and Partially Dried Coal

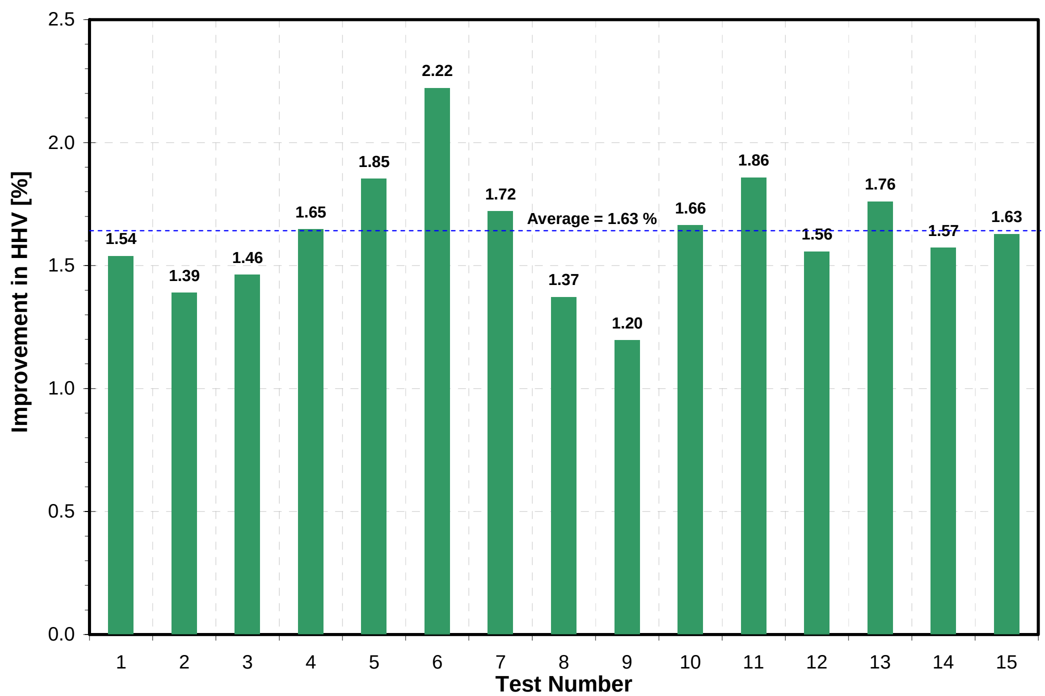

Figure 2-5: Improvement in Coal HHV

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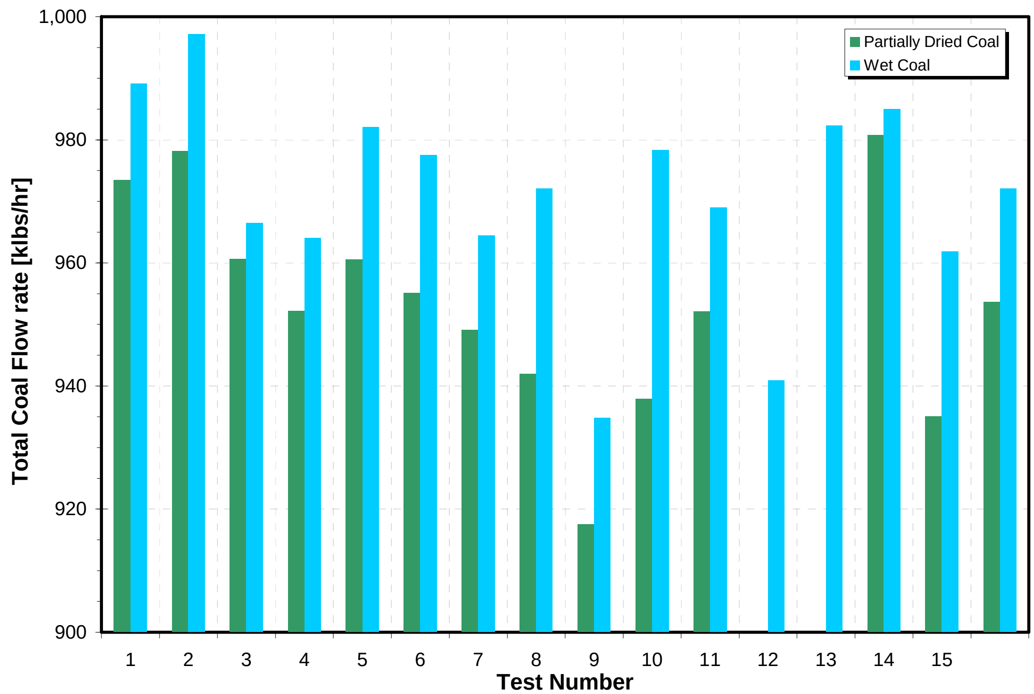

Figure 2-6: Total Coal Flow Rate Sent to the Mills of Partially Dried and Wet Coal

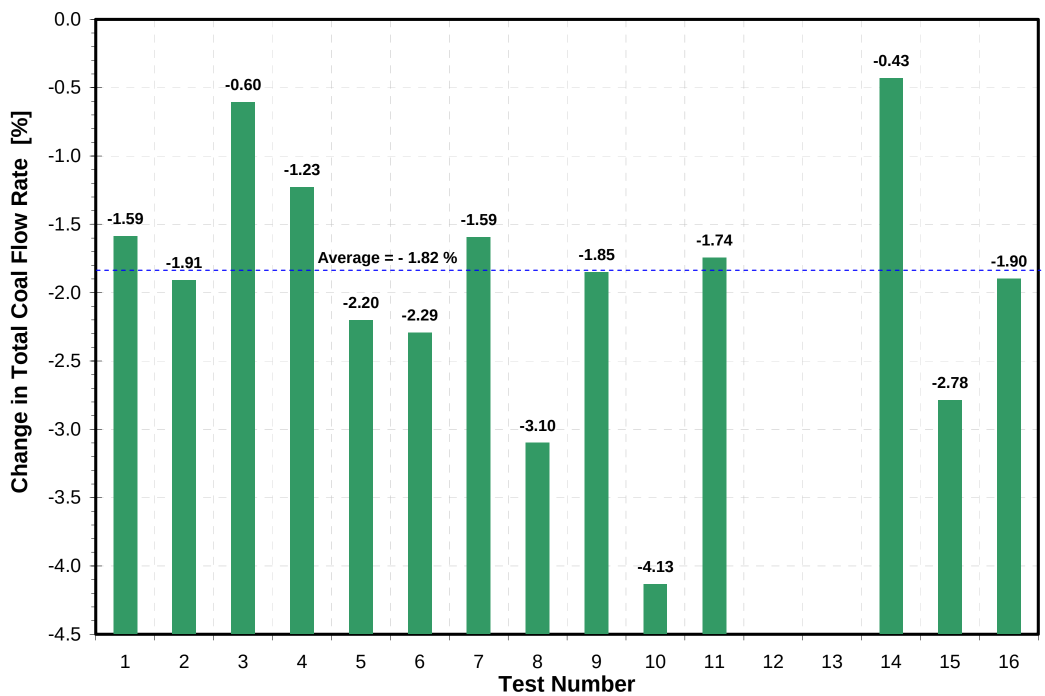

Figure 2-7: Reduction in Total Coal Flow Rate Sent to the Mills Due to Drying

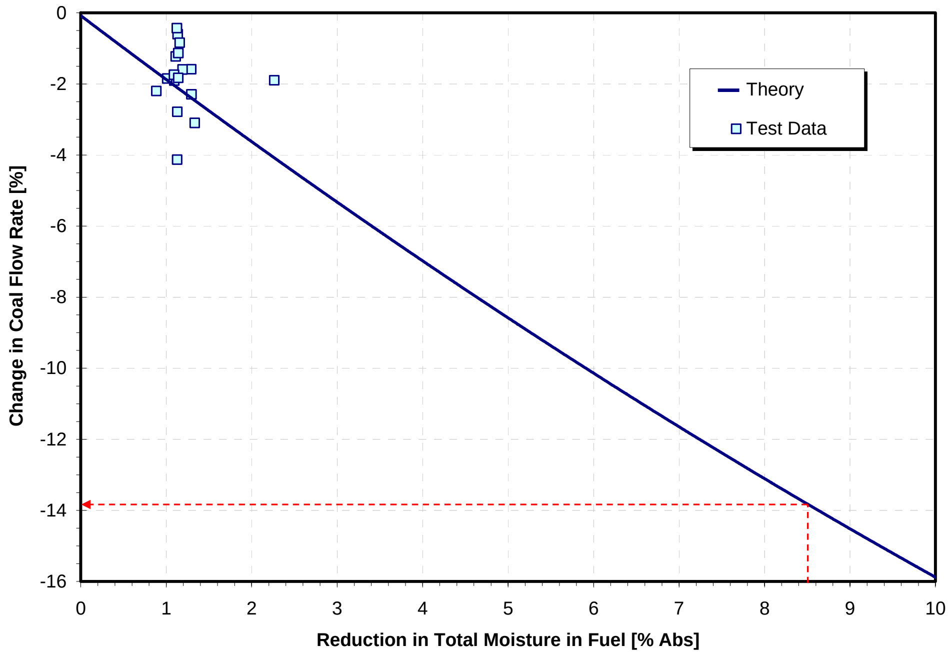

Figure 2-8: Comparison Between Measured and Predicted Reduction in Coal Flow Rate to the Mills vs. Reduction in Total Coal Moisture Content

7.1: <u>Boiler and Plant Operating Parameters</u>

The average process parameters, determined in a series of 16 paired tests with the prototype CD26 in and out of service, are summarized in Table 2-2.

The gross unit load, main (throttle) and reheat steam temperatures, and fanroom temperature (temperature of the PA and SA at the inlet to the PA and FD fans) were constant throughout the test. The boiler feedwater flow was 0.3 percent higher with partially dried coal, compared to the wet coal. The superheater ("SHT") desuperheating spray flow rate was approximately 10 percent lower compared to the operation with wet coal.

The average coal feed to the prototype dryer during the test was 73 t/hr. This corresponds to 14.12 percent of the total coal input to Unit 2 boiler, or 15.5 percent of fuel heat input to the boiler.

Table 2-2

Average Process Parameters Determined in a Series of 16 Paired Performance Tests

Description	Units	Mass-Average Dry	Average Wet	% Change WRT Wet	Absolute Change WRT Wet
Ambient Dry Bulb Temperature	Deg. F	47	51		**-4**
FAN ROOM TEMP	Deg. F	71	72		
CD26 CONVEYOR 263 SCALE RATE MI2924	**tons/hr**	**73**	**0**		
Gross Power Output	**MW**	**590**	**590**		**0**
Throttle Steam Temperature	Deg. F	988	989		**0**
Reheat Steam Temperature	Deg. F	1,002	1,002		**0**
Boiler Feewater Flow Rate	**klbs/hr**	**4,008**	**3,996**	**0.30**	
SHT Desuperheating Spray Flow Rate	klbs/hr	45	51		**-6**
Flue Gas Temperature at APH Inlet	Deg. F	828.5	828.7		**-0.2**
AVG AH 21 GAS OUT TEMP	Deg. F	353.4	361.6		**-8.3**
AVG AH 22 GAS OUT TEMP	Deg. F	368.4	377.2		**-8.8**
PULV 21 FEEDER FLOW RATE	klbs/hr	128	140		
PULV 22 FEEDER FLOW RATE	klbs/hr	137	140		
PULV 23 FEEDER FLOW RATE	klbs/hr	137	138		
PULV 24 FEEDER FLOW RATE	klbs/hr	127	139		
PULV 25 FEEDER FLOW RATE	klbs/hr	135	139		
PULV 26 FEEDER FLOW RATE	klbs/hr	135	**0**		
PULV 27 FEEDER FLOW RATE	klbs/hr	137	121		
PULV 28 FEEDER FLOW RATE	klbs/hr	137	138		
TOTAL FEEDER COAL FLOW RATE	**klbs/hr**	**953**	**971**	**-1.83**	
Dried Coal Flow Rate	klbs/hr	**135**	**0**		
Dried Coal as Percentage of Total	**%**	**14.12**	**0.00**		
Heat Input with Dry Coal	MBTU/hr	947	0		
Heat Input with Wet Coal	MBTU/hr	5,155	6,117		
Total heat input	**MBTU/hr**	**6,102**	**6,117**	**-0.24**	
Heat Iput with Dry Dry Coal as % of Total	**% of Total**	**15.50**	**0.0**		
PULV 21 FUEL-AIR TEMPERATURE	Deg. F	152	152		
PULV 22 FUEL-AIR TEMPERATURE	Deg. F	148	148		
PULV 23 FUEL-AIR TEMPERATURE	Deg. F	148	148		
PULV 24 FUEL-AIR TEMPERATURE	Deg. F	146	146		
PULV 25 FUEL-AIR TEMPERATURE	Deg. F	149	149		
PULV 26 FUEL-AIR TEMPERATURE	Deg. F	158	147		
PULV 27 FUEL-AIR TEMPERATURE	Deg. F	147	147		
PULV 28 FUEL-AIR TEMPERATURE	Deg. F	149	148		
AVG DRY COAL PULV TEMP (PULV 26)	Deg. F	158	147		**10**
AVG WET COAL PULV TEMPERATURE	Deg. F	149	148		**12**
PULV 21 KW	kW	593	605		
PULV 22 KW	kW	577	588		
PULV 23 KW	kW	530	543		
PULV 24 KW	kW	543	603		
PULV 25 KW	kW	586	603		
PULV 26 KW	kW	549	0		
PULV 27 KW	kW	612	625		
PULV 28 KW	kW	590	610		
TOTAL PULVERIZER POWER	**kW**	**4,037**	**4,176**	**-3.34**	**-140**
FD Fan Power	kW	2,056	2,049	**0.36**	**7**
PA Fan Power	kW	6,989	6,618	**5.61**	**371**
ID Fan Power	kW	11,613	11,782	**-1.43**	**-169**
Total mill and fan power	kW	24,694	24,624	**0.28**	**70**

7.2: Mill Operation and Performance

With drier coal, mill power is 3.34 percent (140 kW) lower compared to the operation with wet coal (Figure 2-9). This decrease in mill power is due to a decrease in coal flow rate, and also due to the mill power required to grind a given coal flow rate, which is reduced with drier coal. With drier coal, the specific mill work is reduced by approximately 4.2 percent (Figure 2-10). The comparison of the measured and theoretically predicted reductions in mill power, presented in Figure 2-11, shows an excellent agreement between the calculated and measured values.

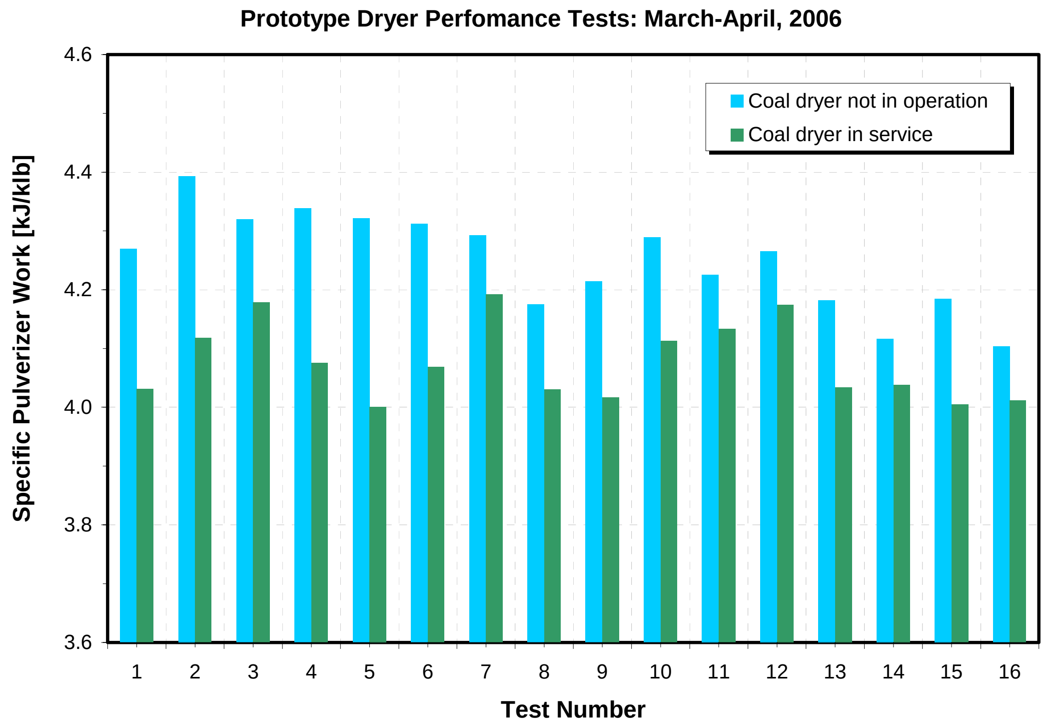

Figure 2-9: Total Mill (pulverizer) Power

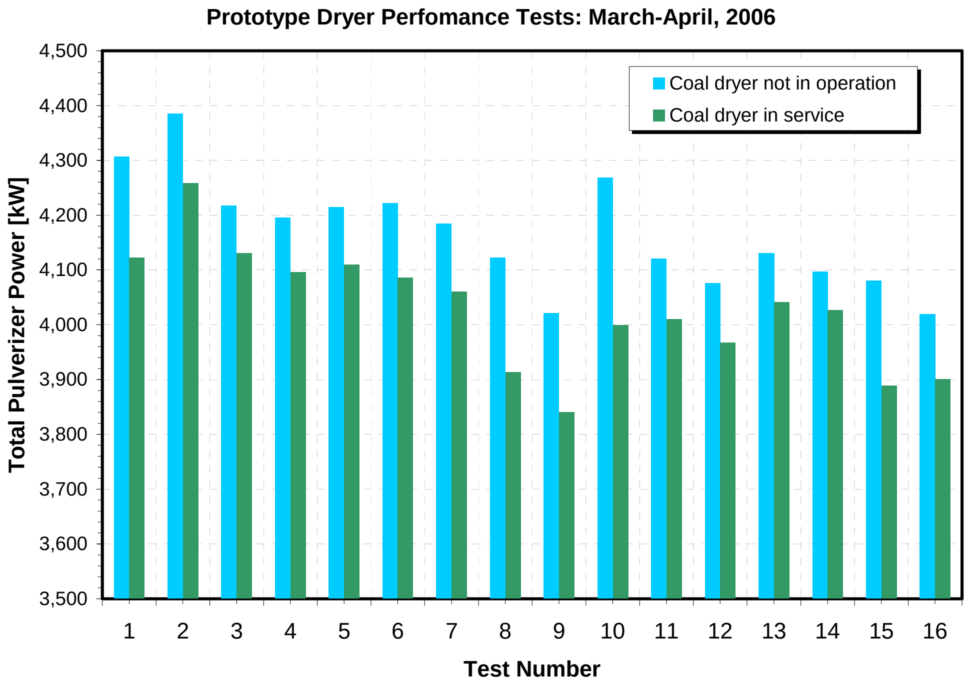

Figure 2-10: Specific Mill (pulverizer) Work

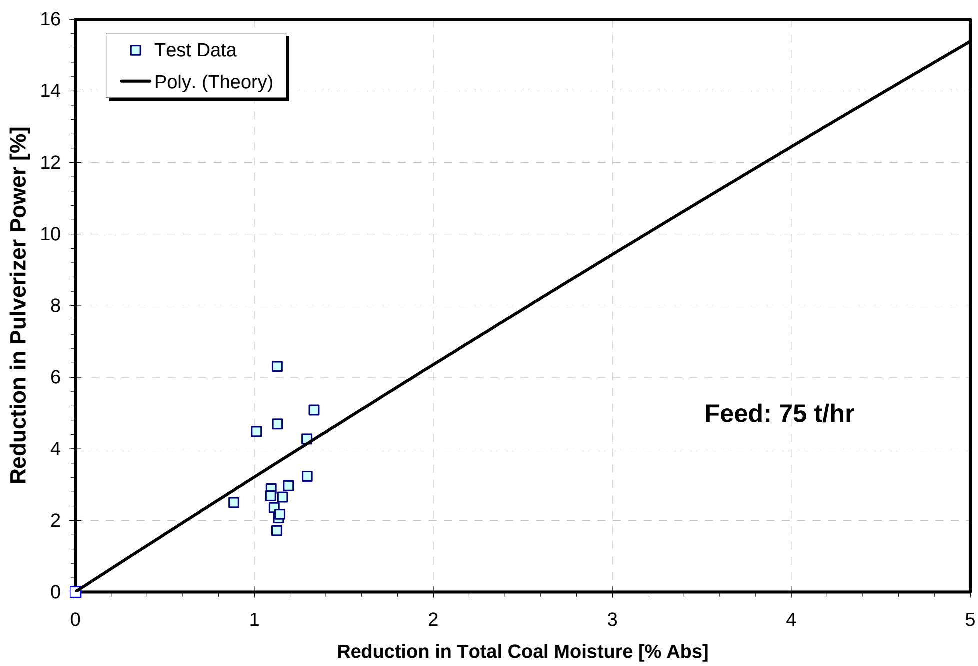

Figure 2-11: Comparison of Predicted and Measured Reduction in Mill Power

The temperature of the air-coal mixture leaving the No. 26 mill, processing partially dried coal, is 10°F higher compared to the mills processing wet coal (Figure 2-

12). This increase is due to the lower moisture content and higher temperature of partially dried coal entering the No. 26 mill.

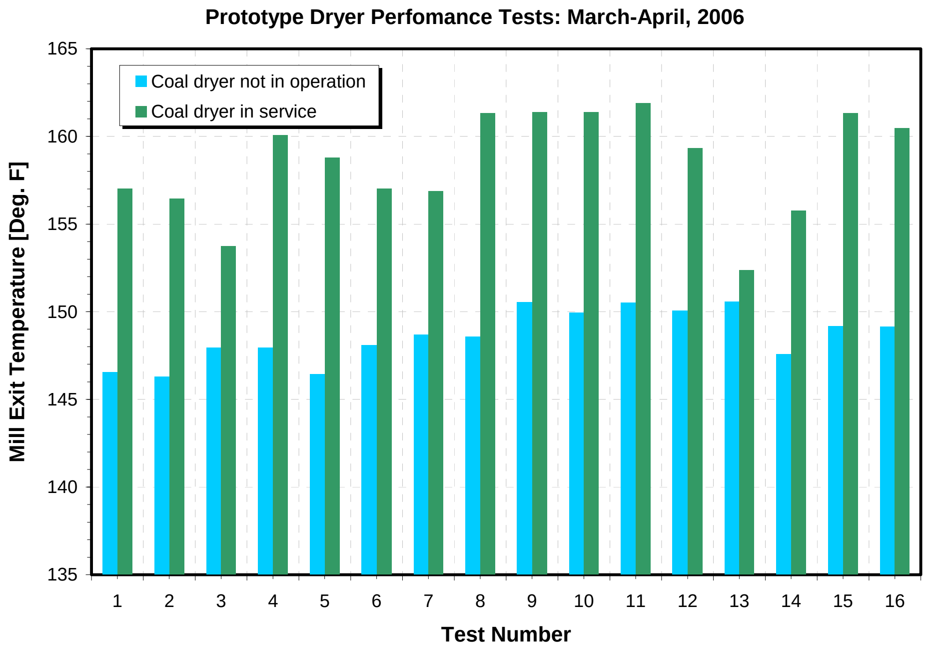

Figure 2-12: Mill Exit Temperature

Also, with CD26 in service, mill feeder No. 26 trips were eliminated. This is because the oversize material, typically responsible for feeder trips, was either screened out or discharged from the first dryer stage with the rest of the non-fluidizable material.

A coal crusher is used at Coal Creek to reduce coal top particle size to ¼-inch. The crusher power requirement for a baseline coal feed rate of 75 tons per hour is approximately 100 kW.

7.3: <u>Flue Gas Flow</u>

The flow rates of combustion air and flue gas decrease as coal moisture content is reduced. A decrease in combustion air flow rate is due to the improvement in boiler and unit performance, which result in a reduction in coal flow rate and heat input. The decrease in flue gas flow rate is due to the improvement in boiler and unit performance and decreased coal moisture content. A lower coal moisture results in lower water vapor content of flue gas. With blended coal fired during the paired tests, the flue gas moisture content was reduced from 15.5 to 15.1 percent on a volume basis. For a target value of total coal moisture removal of 8.5 percent, the flue gas moisture content will be reduced by more than 2.5 percentage points. As a result, the decrease in flue gas flow rate is larger than the decrease in combustion air flow rate.

The flue gas volumetric flow rates, measured by the plant CEM during the paired tests, are presented in Figure 2-13. A comparison between measured and predicted decrease in flue gas flow rate, presented in Figure 2-14, shows a very good agreement between the measured and predicted values.

For a target value of total moisture reduction of 8.5 percent, the predicted decrease in flue gas flow rate is approximately 3.9 percent. The average values of flue gas flow rate corresponding to the partially dried and wet coals are summarized in Table 2-3.

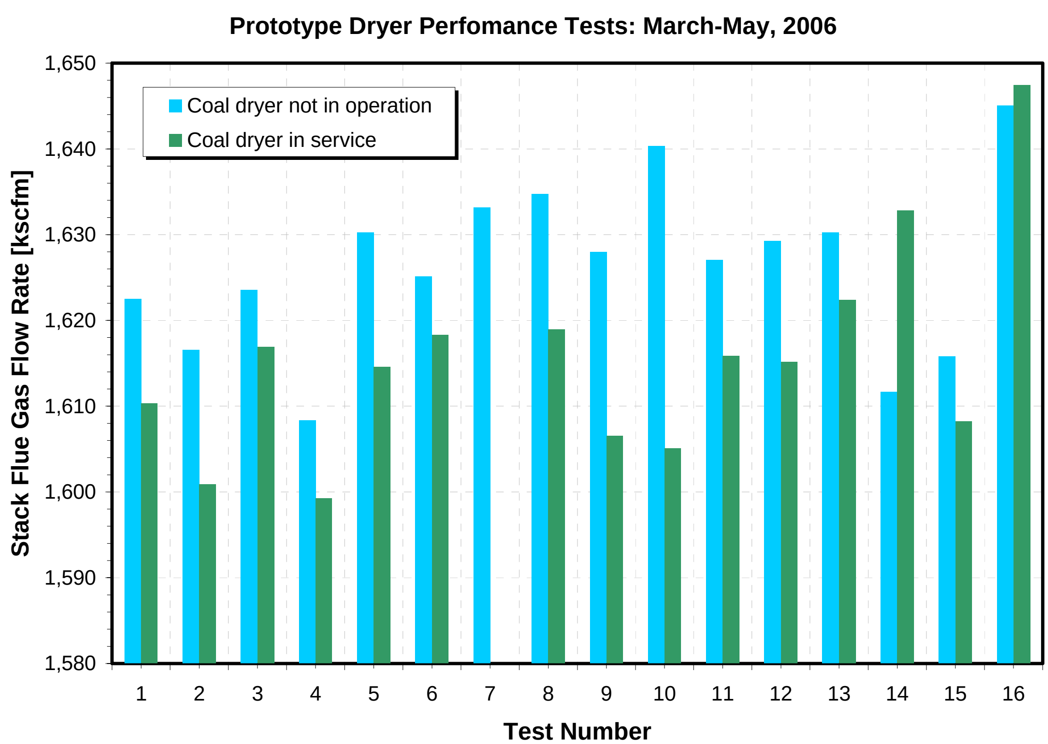

Figure 2-13: Flue Gas Flow Rate in Standard Volumetric Units

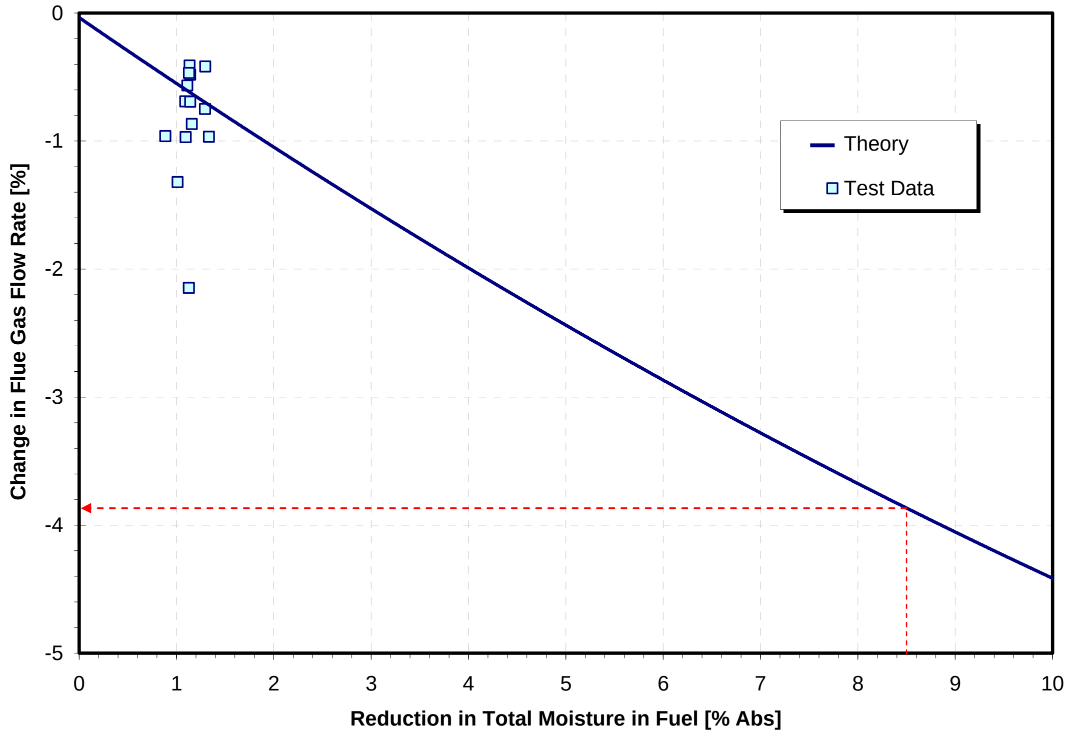

Figure 2-14: Comparison of Measured and Predicted Reduction in Flue Gas Flow Rate

Table 2-3

Flue Gas Flow Rate and Temperature, and Scrubber ΔP

Description	Units	Average Dry	Average Wet	% Change WRT Wet	Change WRT Wet
FLUE GAS FLOW RATE	kscfm	1,613	1,625	**-0.73**	
FLUE GAS TEMP	^oF	180	184		**-4.1**
Flue gas flow rate	kacfm	1,922	1,949	**-1.36**	
Flue gas flow rate	klbs/hr	7,101	7,140	**-0.55**	
U2 SCRUBBER DIFF PRESS	" wg	5.46	5.50	**-0.83**	**-0.05**

Table 2-3 also summarizes the values of the flue gas temperature at the stack inlet and the differential pressure, ΔP, across the wet scrubber. The flue gas flow rate, reported in standard volumetric units (kscfm), was converted to actual volumetric units (kacfm) and to mass units (klbs/hr) using the flue gas density values from Table 2-4. With a partially dried coal, the density of the flue gas is approximately 0.8 percent higher compared to the flue gas density corresponding to the wet coal.

Table 2-4

Flue Gas Density Calculation

Description	Units	Mass-Average Dry	Average Wet	% Change WRT Wet	Absolute Change WRT Wet
Flue gas molecular weight	kg/mole	28.754	28.702	**0.18**	
Actual flue gas temperature	Deg. C	82.16	84.41		**-2.25**
Actual flue gas temperature	K	355.31	357.56		**-2.25**
Gas constant	J/mole-K	289.14	289.67	**-0.18**	
Ambient pressure	N/m^2	101,300	101,300		
Flue gas density	kg/m^3	0.9860	0.9781		
Flue gas density	**lb/ft^3**	**0.06156**	**0.06106**	**0.82**	
Standard temperature	Deg.C	25	25		
Standard temperature	K	298.15	298.15		

The results from Table 2-3 show that with the partially dried coal, the volumetric flue gas flow rate, at actual conditions, decreased 1.36 percent compared to that with wet coal. The reduction in mass flow rate of flue gas is lower, 0.55 percent, due to the increase in flue gas density with partially dried coal. The measured reduction in flue gas flow rate is close to the theoretically calculated value of 0.65 percent.

With partially dried coal, the flue gas temperature at the stack inlet is lower compared to that with wet coal by approximately 4.3°F (2.25°C). This lower temperature decrease can be explained by the fact that with reduced flue gas flow rate with partially dried coal, a larger fraction of flue gas passes through the wet scrubber (where its temperature is decreased to a value close to the saturation temperature) while a smaller flue gas fraction bypasses the scrubber, compared to that with wet coal operation. The bypass and scrubbed streams mix downstream of the scrubber before entering the stack, resulting in inlet stack temperature being higher than saturation temperature. Measured values of flue gas temperature at the stack inlet are presented in Figure 2-15. The red bar indicates an erroneous temperature reading.

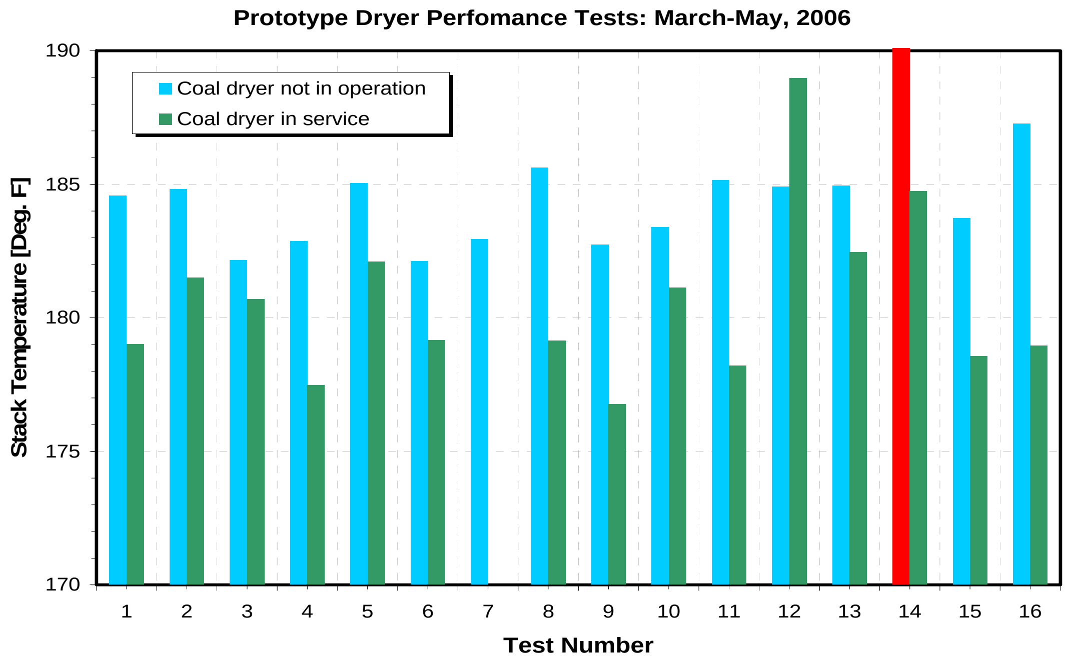

Figure 2-15: Flue Gas Temperature at Stack Inlet

The air flow through the forced draft (FD) and primary air (PA) fans at CCS is, at present, controlled with inlet guide vanes (IGV). Flow control through the induced draft (ID) fans at Coal Creek is accomplished by the inlet damper (ID). With the IGV and ID methods of flow control, a full reduction in fan power due to the reduced air and flue gas flow rates with partially dried coal is not possible. Variable speed fan drives (VSD) are needed to achieve the maximum reduction in fan power with partially dried coal.

With the presently used fan flow control methods at CCS, the FD fan power remained virtually constant (2,056 vs. 2,049 kW) for both the partially dried and wet coals. For the case of partially dried coal, the ID fan power was reduced 1.43 percent (169 kW).

7.4: Calculation of the Average Boiler Efficiency Improvement From Plant Data

By using the definition of boiler efficiency, η_B, shown below, the improvement in this parameter due to firing of partially dried coal can be determined directly from the measured plant data, using the input/output method without performing boiler efficiency calculations. Since the input/output approach suffers from large errors due to uncertainties (random errors) in coal flow rate and HHV measurement, this approach is not suitable for determining boiler efficiency improvement for individual performance tests. Instead, the input/output approach was used to calculate average efficiency improvement for all 16 performance tests, where individual test uncertainties averaged out reducing, therefore, the overall test uncertainty.

By definition:

$$\eta_B = Q_T/Q_{Fuel} \qquad \text{Eqn. 2-4}$$

where:

Q_T Boiler thermal duty (heat transferred to the steam turbine cycle)

Q_{Fuel} Heat input with fuel, in this case coal:

$$Q_{Fuel} = M_{Fuel}\ HHV \qquad \text{Eqn. 2-5}$$

where:

M_{Fuel} Fuel (coal) flow rate

HHV Fuel (coal) higher heating value

The relative improvement in boiler efficiency, $\Delta\eta_{/}\eta_{B,Wet}$, can then be determined as:

$$\Delta\eta_{/}\eta_{B,Wet} = Q_{T,Dry}/Q_{T,Wet} \times Q_{Fuel,Wet}/Q_{Fuel,Dry} - 1 \qquad \text{Eqn. 2-6}$$

Using results from Table 2-5 show, the improvement in boiler efficiency due to firing of partially dried coal, calculated by the input/output method is:

$$\Delta\eta_{/}\eta_{B,Wet} = 0.00535 \pm 0.000315$$

Expressed on a relative basis, the improvement in boiler efficiency $\Delta\eta_{/}\eta_{B,Wet}$ is equal to 0.535 ± 0.0315 percent.

Table 2-5

Boiler Efficiency Improvement Calculated From the Plant Data

Description	Units	Mass-Average Dry	Average Wet	% Change WRT Wet	Absolute Change WRT Wet
$Q_{T,dry}/Q_{T,wet}$	ratio			1.002962	
$Q_{fuel,wet}/Q_{fuel,dry}$	ratio			1.002388	
$\eta_{B,dry}/\eta_{B,wet}$	ratio			**1.005357**	

The uncertainty in $\Delta\eta/\eta_{B,Wet}$ was determined by assuming typical uncertainty value of ± 3 percent for coal flow rate measurement, ± 1 percent for laboratory determination of coal HHV, and baseline boiler efficiency of 80 percent.

The calculated values of boiler efficiency for the partially dried and wet coals are presented in Table 2-6 and Figure 2-16.

Table 2-6

Boiler Efficiency for Partially Dried and Wet Coal Calculated by Using the Mass and Energy Balance Approach and Paired Performance Test Data

Test	Total Fuel Moisture, TM [%]		DTM	Boiler Efficiency [%]		Difference
	Dry Mix	Wet	% Abs	Dry Mix	Wet	% Abs
1	35.73	37.03	**1.29**	78.54	78.06	**0.48**
2	35.69	36.74	**1.06**	78.37	78.00	**0.37**
3	36.29	37.44	**1.14**	78.41	78.01	**0.40**
4	35.70	36.76	**1.07**	78.51	78.41	**0.10**
5	36.58	37.50	**0.92**	77.93	77.41	**0.52**
6	35.25	36.58	**1.34**	78.88	78.46	**0.42**
7	36.25	37.44	**1.19**	78.66	78.23	**0.43**
8	35.65	36.99	**1.33**	78.91	78.74	**0.17**
9	35.97	36.98	**1.00**	78.43	78.14	**0.29**
10	35.93	37.07	**1.14**	77.87	77.07	**0.80**
11	34.92	36.00	**1.08**	78.36	77.93	**0.43**
12	35.99	37.16	**1.16**	78.79	78.60	**0.19**
13	36.19	37.34	**1.14**	78.05	77.59	**0.46**
14	35.91	37.03	**1.12**	78.64	78.56	**0.08**
15	36.71	37.81	**1.10**	78.25	77.90	**0.35**
16	**35.17**	**37.47**	**2.30**	**78.91**	**78.39**	**0.52**
Average	**35.92**	**37.06**	**1.14**	**78.44**	**78.07**	**0.37**
Std. Dev	0.49	0.43	0.31	0.33	0.45	0.18
Std. Error	0.14	0.13	0.09	0.10	0.13	0.05
Random Error	**0.30**	**0.27**	**0.19**	**0.20**	**0.28**	**0.11**

The results show that boiler efficiency achieved by firing partially dried coal is consistently higher compared to the boiler efficiency corresponding to firing wet coal. The average absolute boiler efficiency improvement, $\Delta\eta_B$, calculated from the boiler efficiency values from Table 2-5, excluding test point 16, is:

$$\Delta\eta_B = 0.37 \pm 0.11 \text{ percentage points}$$

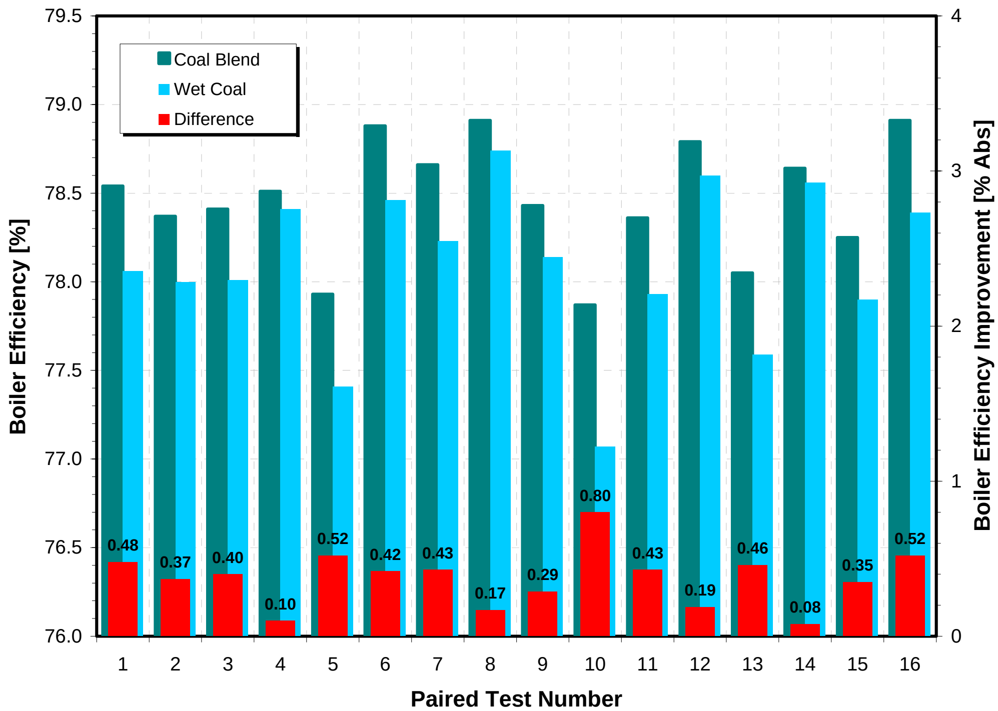

Figure 2-16: Boiler Efficiency for Partially Dried and Wet Coal

This corresponds to $\Delta\eta/\eta_{B,Wet}$ = 1.0047, or a **0.470** percent improvement on a relative basis. Considering the uncertainties in coal composition, HHV, and flow rate measurement, this value is close (within 14 percent) to the relative boiler efficiency improvement of **0.5357** percent calculated by the input/output approach.

Since the uncertainty interval of ± 0.11 percentage points is significantly smaller than the calculated boiler efficiency difference of 0.37 percentage points, the calculated improvement in boiler efficiency is statistically significant.

The comparison of theoretically predicted boiler efficiency improvement and boiler efficiency improvement determined from a series of 16 paired performance tests is presented in Figure 2-17. Theoretical predictions were obtained by applying the mass and energy balance and above-described calculation approach.

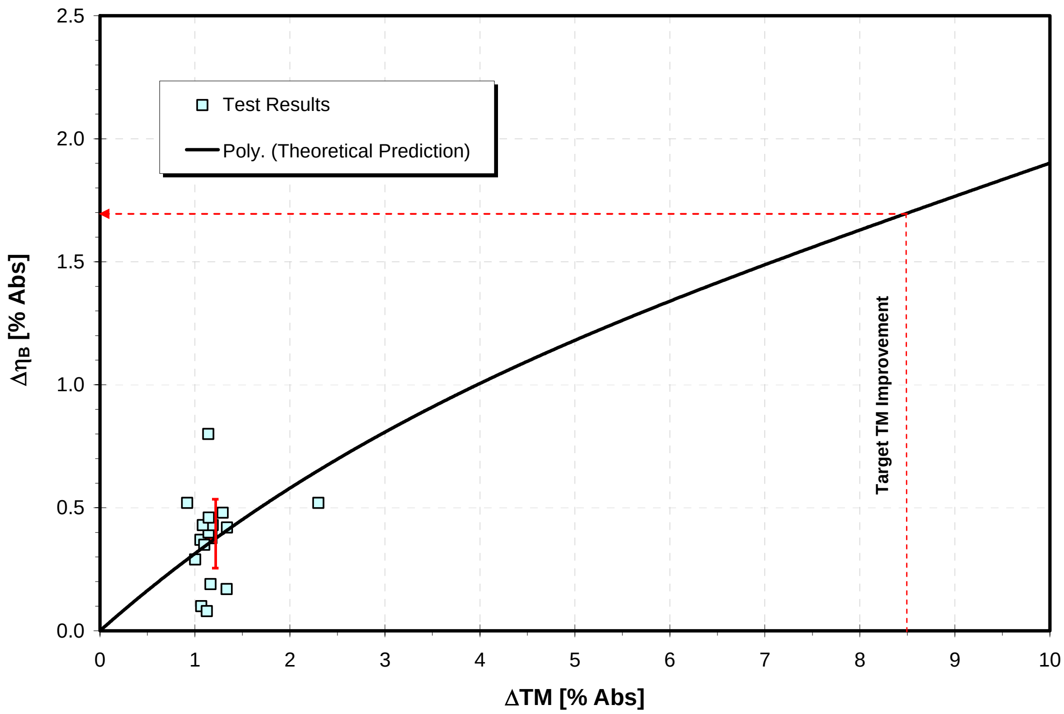

Figure 2-17: Comparison of Predicted and Test Values of Absolute Boiler Efficiency Improvement

The difference between the theoretical calculations and performance test results is that in the theoretical calculations, analytical models for APH thermal performance and fan and mill power were used to determine temperatures of flue gas, PA and SA leaving the APH, and FD, PA, ID and mill power. The coal flow rate was calculated by assuming constant boiler thermal duty, Q_T. When calculating boiler efficiency from the boiler performance test data, measured values of these parameters, obtained in a series of 16 paired performance tests were used.

With the exception of one outlier test point, the results in Figure 2-17 show excellent agreement between theoretical predictions and performance test results. For a target reduction in total coal moisture of 8.5 percent, the predicted improvement in boiler efficiency is 1.7 percent.

7.5: <u>Net Unit Heat Rate</u>

The net unit heat rate is calculated according to the following expression:

$$HR_{net} = HR_{cycle}/[\eta_B(1 - P_{ss}/P_g)] \qquad \text{Eqn. 2-16}$$

where:

HR_{cycle}	Turbine cycle heat rate (8,000 Btu/kWh for CCS)
η_B	Boiler efficiency
P_{ss}	Total measured station service power (mills, fans, crusher, etc.)
P_g	Gross unit power output

The values of net unit heat rate calculated from the paired performance test data for the partially dried and wet coal are presented in Table 2-7 and Figure 2-18.

Table 2-7

Net Unit Heat Rate for Partially Dried and
Wet Coal Calculated by Using the Mass and
Energy Balance Approach and Paired Performance Test Data

Test	**TM [%]**		**DTM**	**$HR_{net,mix}$**	**$HR_{net,wet\ coal}$**	**ΔHR_{net}**	**ΔHR_{net}**
	Dry Mix	Wet	**% Abs**	BTU/kWh	BTU/kWh	BTU/kWh	%
1	35.73	37.03	**1.29**	10,634	10,688	54	0.51
2	35.69	36.74	**1.06**	10,661	10,702	41	0.38
3	36.29	37.44	**1.14**	10,664	10,693	29	0.27
4	35.70	36.76	**1.07**	10,638	10,643	5	0.05
5	36.58	37.50	**0.92**	10,725	10,789	64	0.59
6	35.25	36.58	**1.34**	10,589	10,634	45	0.42
7	36.25	37.44	**1.19**	10,611	10,661	50	0.47
8	35.65	36.99	**1.33**	10,585	10,588	3	0.03
9	35.97	36.98	**1.00**	10,647	10,677	30	0.28
10	35.93	37.07	**1.14**	10,732	10,827	95	0.88
11	34.92	36.00	**1.08**	10,660	10,709	49	0.46
12	35.99	37.16	**1.16**	10,602	10,621	19	0.18
13	36.19	37.34	**1.14**	10,695	10,754	59	0.55
14	35.91	37.03	**1.12**	10,620	10,629	9	0.08
15	36.71	37.81	**1.10**	10,657	10,705	48	0.45
16	**35.17**	**37.47**	**2.30**	**10,578**	**10,634**	**56**	**0.53**
Average	**35.92**	**37.06**	**1.14**	**10,648**	**10,688**	**40**	**0.37**
Std. Dev	0.49	0.43	0.31	47	64	24	0.23
Std. Error	0.14	0.13	0.09	13	18	7	0.07
Random Error	**0.30**	**0.27**	**0.19**	**29**	**39**	**15**	**0.14**

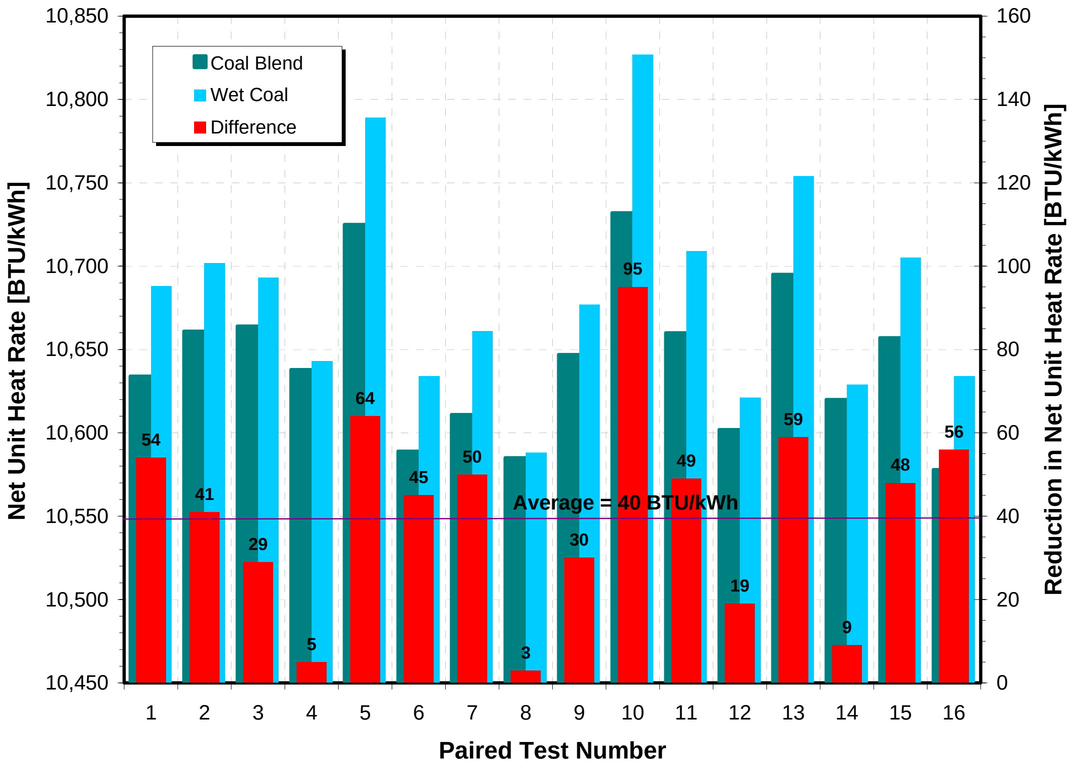

Figure 2-18: Net Unit Heat Rate for Partially Dried and Wet Coal

The results show that the net unit heat rate, HR_{net}, corresponding to the unit operation with partially dried coal is consistently lower compared to HR_{net} obtained with the wet coal. The average improvement in net unit heat rate due to lower fuel moisture, excluding Test 16, is:

$$\Delta HR_{net} = 40 \pm 15 \text{ Btu/kWh}$$

On a relative scale this corresponds to a HR_{net} improvement of 0.37 percent. Since the uncertainty interval of ± 15 Btu/kWh is significantly smaller than the calculated heat rate difference of 40 Btu/kWh, the calculated improvement in HR_{net} is statistically significant.

If VSD were used for fan flow control, fan power requirement would be lower than with the presently used fan flow control methods (Table 2-7). With a partially dried coal and VSD drives, the FD fan power would be reduced 0.58 percent, while the ID fan power would be 2.98 percent (350 kW) lower compared to the wet coal and IGV/ID flow control. With VSD drive the PA fan power would be 66 kW lower than with the IGV flow control.

The final result would be a 0.80 percent (197 kW) reduction in total fan power and a 0.50 percent (54 Btu/kWh) total improvement in net unit heat rate (Table 2-8).

Table 2-8

Effect of VSD Fan Flow Control on Fan Power Requirements and Net Unit Heat Rate

Description	Units	Mass-Average Dry	Average Wet	% Change WRT Wet	Absolute Change WRT Wet	Comments
Pulverizer Power	kW	4,037	4,176	**-3.34**	**-140**	
FD Fan Power	kW	2,056	2,049	**0.36**	**7**	IGV
PA Fan Power	kW	6,989	6,618	**5.61**	**371**	IGV
ID Fan Power	kW	11,613	11,782	**-1.43**	**-169**	Inlet Damper
Total Mill and Fan Power	kW	**24,694**	**24,624**	**0.28**	**70**	
Boiler Efficiency	%	**78.44**	**78**	**0.47**	**0.37**	
Net Unit Heat Rate	BTU/kWh	**10,648**	**10,688**	**-0.37**	**-40**	
FD Fan Power	kW	2,037	2,049	**-0.58**	**-12**	VSD for dry coal
ID Fan Power	kW	11,430	11,782	**-2.98**	**-351**	VSD for dry coal
PA Fan Power	kW	6,923	6,618	**4.62**	**305**	VSD for dry coal
Total Mill and Fan Power	kW	**24,427**	**24,624**	**-0.80**	**-197**	VSD for dry coal
Net Unit Heat Rate	BTU/kWh	**10,639**	**10,693**	**-0.50**	**-54**	VSD for dry coal

8. EMISSIONS

The NO_x and SO_x emissions, flue gas flow rate, and flue gas CO_2 composition, measured by the plant CEM for 16 paired performance tests, are summarized in Table 2-9. As discussed earlier, firing partially dried coal results in lower flue gas flow rate. For the coal moisture reduction of 1.14 percent, achieved in the dryer performance tests, the reduction in flue gas mass flow rate is 0.55 percent.

Table 2-9

NO_x and SO_x Emissions, Stack Flow Rate,
and Flue Gas CO_2 Concentration Measured by the Plant CEM

Description	Units	Mass-Average Dry	Average Wet	% Change WRT Wet	Absolute Change WRT Wet
NOx Emissions	lbs/hr	1,359	1,469	**-7.52**	**-111**
SOx Emissions	lbs/hr	3,641	3,670	**-0.81**	**-30**
Flue Gas Flow Rate	kscfm	1,613	1,625	**-0.73**	**-12**
Flue Gas Flow Rate	klbs/hr	7,101	7,140	**-0.55**	**-39**
Flue Gas CO2	%	11.90	11.87	**0.27**	**0**

8.1: <u>NO_x Emissions</u>

The 7.5 percent average reduction in NO_x mass emissions, measured during the paired performance tests (Figure 2-19), is significantly higher than the percentage reduction in flue gas flow rate. This reduction in NO_x emissions cannot be explained by a lower flue gas flow rate. Instead it is attributed to a lower primary air flow rate to Mill No. 26, which was handling partially dried coal. From combustion optimization tests, performed by the ERC and GRE engineers at Coal Creek in 1997 [10], it is known that NO_x emissions at this plant are quite sensitive to the primary air flow. NO_x decreases as primary air flow is reduced.

The primary air flow rates to Mill 26 and to other mills handling wet coal are presented in Figure 2-20. With partially dried coal, the primary air flow rate to the No. 26 mill was, on average, reduced from 355 to 310 klbs/hr, a 12 percent reduction. Modifications to the coal mills will allow the primary air flow to be decreased even more to 255 klbs/hr. This is expected to result in a further decrease in NO_x emissions.

With the commercial coal drying system in service, i.e., with 100 percent dried coal delivered to the coal mills, and the reduced PA flows to the mills, the reduction in NO_x emissions is expected to exceed 10 percent.

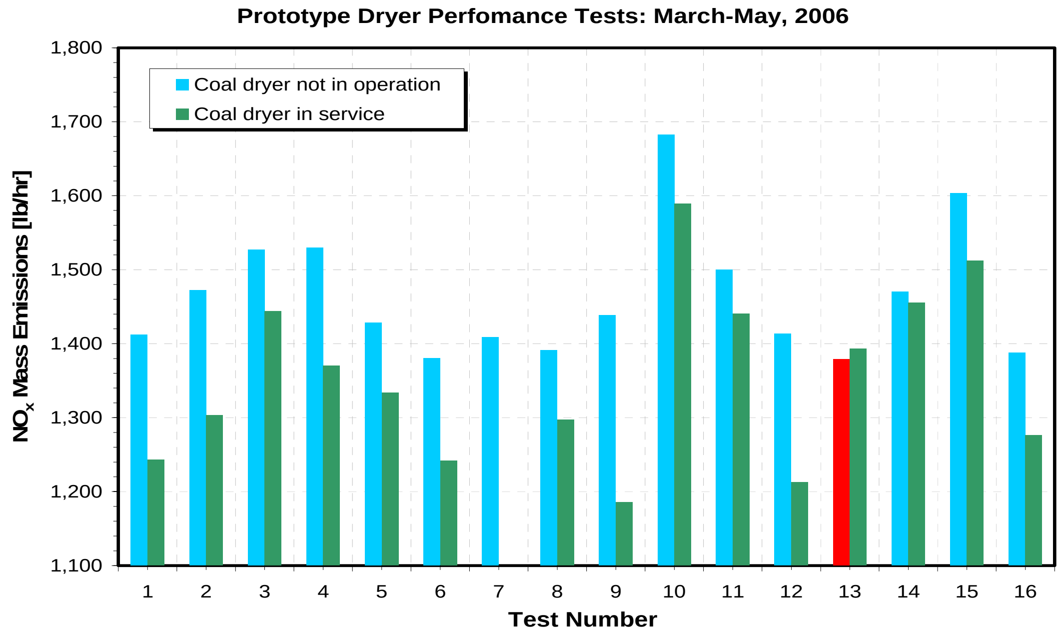

Figure 2-19: NO_x Emissions with Wet and Partially Dried Coal

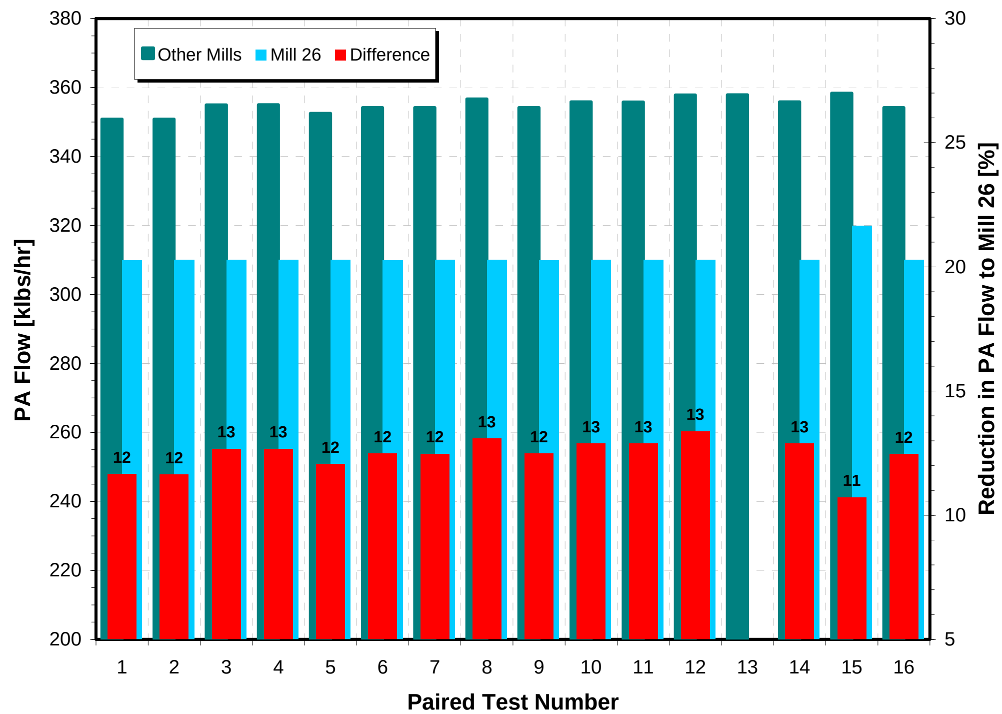

Figure 2-20: Primary Air Flow Rates to the Mills with Wet and Partially Dried Coal

8.2: SO_x Emissions

The measured reduction in SO_x emissions with partially dried coal, measured during the series of 16 paired parametric tests, is approximately 0.8 percent (Table 2-9 and Figure 2-21). The red bar represents a bad reading.

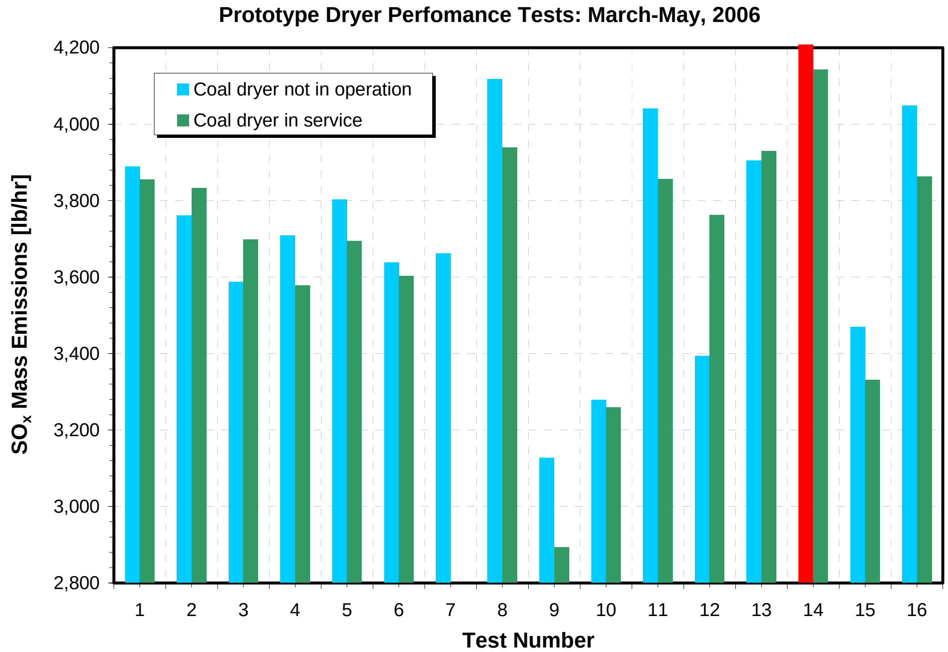

Figure 2-21: SO_x Emissions with Wet and Partially Dried Coal

A closer inspection of the recorded plant data and the results presented in Figure 2-21 points to problems with SO_x measurement that occurred during Tests 12 to 14, where measured SO_x emissions are higher with a partially dried coal compared to the wet coal. These inconsistencies are explained by a malfunctioning SO_x monitor that was providing unreliable SO_x readings for Tests 12 to 14. A comparison of the results for the first 11 paired tests and for all 16 paired tests shows a significant difference in SO_x reduction (1.9 percent for the first 11 tests vs. 0.8 percent for all 16 tests). It is, therefore, reasonable to assume that the actual reduction in SO_x emissions, achieved with partially dried coal, is in the 1.9 percent range.

The percentage reduction in SO_x emissions is larger than the percentage the reduction in flue gas mass flow rate. This is because with a lower flue gas flow rate, the flue gas bypass around the scrubber decreases (CCS is a partially scrubbed unit), resulting in a higher SO_x removal. With 100 percent partially dried coal fired in the boiler, the flue gas flow rate to the wet scrubber will be reduced by an estimated four percent. Combined with lower APH leakage, that would be achieved by using double-edge APH seals, the percentage of the scrubbed flue gas flow will further increase, approaching a zero scrubber bypass configuration. This will result in an additional reduction in SO_x emissions.

Due to a gravitational separation that is taking place in the first dryer stage, the sulfur concentration in the segregated stream is three times higher compared to the product and feed streams. This increase in sulfur content in the segregated stream can be explained by the fact that pyrites, having higher density than coal, are segregated out in the first dryer stage. For the present configuration of the prototype coal drying system at CCS, the segregated stream is returned to and mixed with the product stream from the coal dryer. Therefore, the benefit of sulfur removal in the first dryer stage, is not being realized, and the measured reduction in SO_x emissions is solely due to the lower flue gas and scrubber bypass flows.

The commercial coal drying system is designed to further process the segregated stream. After processing, the segregated stream will not be mixed with the product stream from the commercial dryers. With the segregated stream representing 5 to 10 percent of the dryer feed, the reduction in mass flow rate of sulfur to the boiler would be in the 7 to 12 percent range. By combining reductions due to the lower scrubber bypass and lower sulfur input to the boiler, the potential reduction in SO_x emissions that could be achieved with the commercial coal drying system at CCS operating at 100 percent capacity is expected to be in the 12 to 17 percent range.

Since the calculated reduction in SO_x emissions is very much affected by the accuracy of the measured S concentration levels in the feed, segregated, and product streams, and the segregated stream flow rate, the actual reduction in SO_x emissions will be determined from the plant CEM measurements with the commercial coal drying system at CCS operating at 100 percent capacity.

8.3: CO_2 Emissions

The reduction in CO_2 mass emissions is proportional to the improvement in unit performance (net unit heat rate). For the target moisture reduction of 8.5 percent, the expected reduction in CO_2 emissions is approximately 2.4 percent.

8.4: Mercury (Hg) Emissions

The reduction in Hg emissions, achieved during paired performance tests at CCS, is proportional to the improvement in unit performance, and is estimated to be in the 0.4 percent range.

The segregated stream from the first dryer stage contains approximately 3.5 to 4 times more Hg compared to the product and feed streams, (Figures 2-22 and 2-23). This increase in Hg content in the segregated stream can be explained by the fact that for the Falkirk lignite, a significant portion of mercury is bound to pyrites that are segregated out in the first dryer stage.

With the present configuration of the prototype coal drying system at CCS, the segregated stream is returned to the product stream from the coal dryer. Therefore, the benefit of Hg removal in the first dryer stage on Hg emissions is not realized.

As discussed in Section 8.2, the commercial coal drying system is designed to further process the segregated stream. After processing, the segregated stream will not be mixed with the product stream from the commercial dryers and will not be burned in the CCS boiler. With the segregated stream representing 5 to 10 percent of the dryer feed, the estimated reduction in mass flow rate of mercury to the boiler is in the 13 to 25 percent range (Figures 2-22 and 2-23).

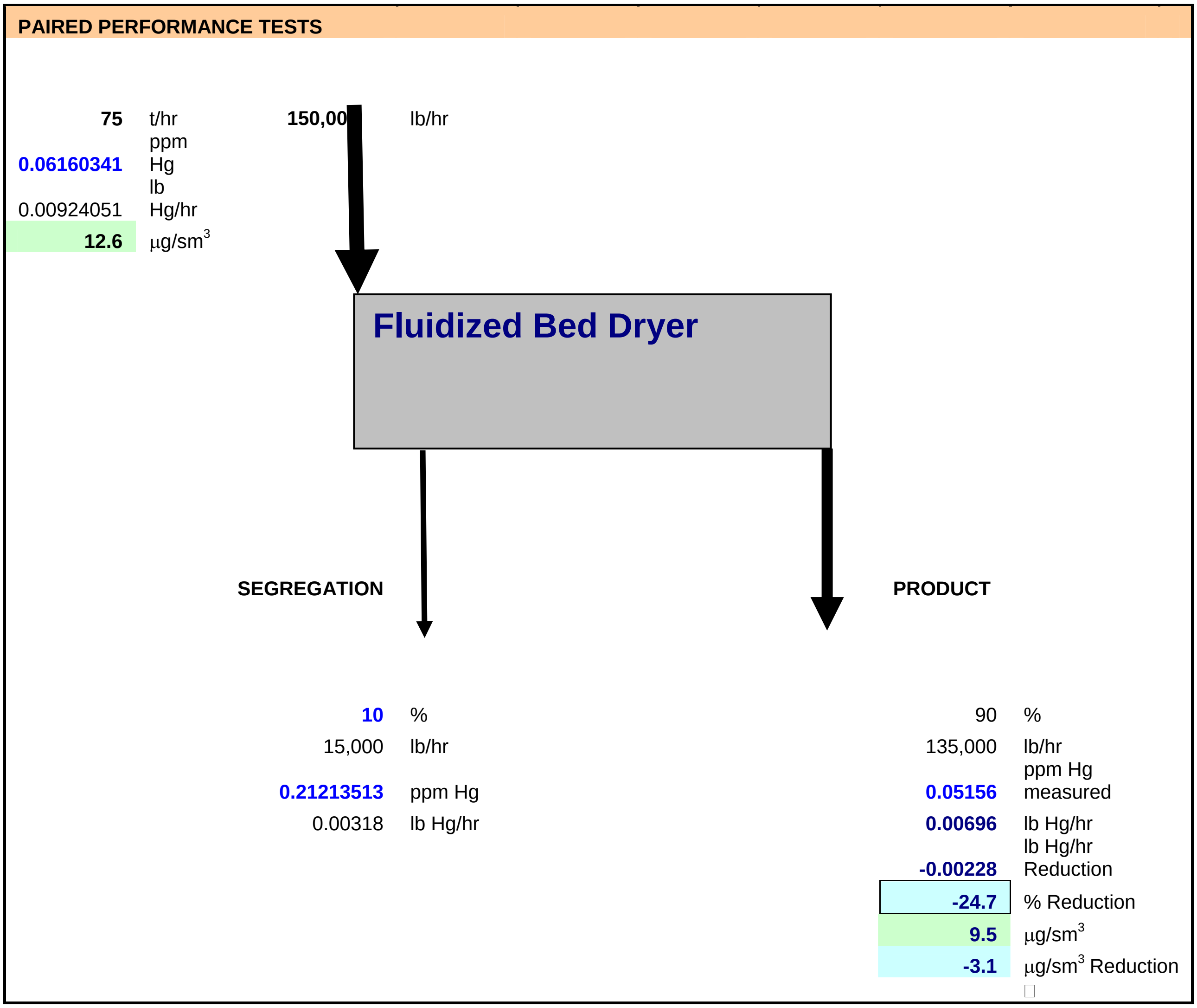

Figure 2-22: Mercury Mass Balance Around FBD – Paired Performance Tests

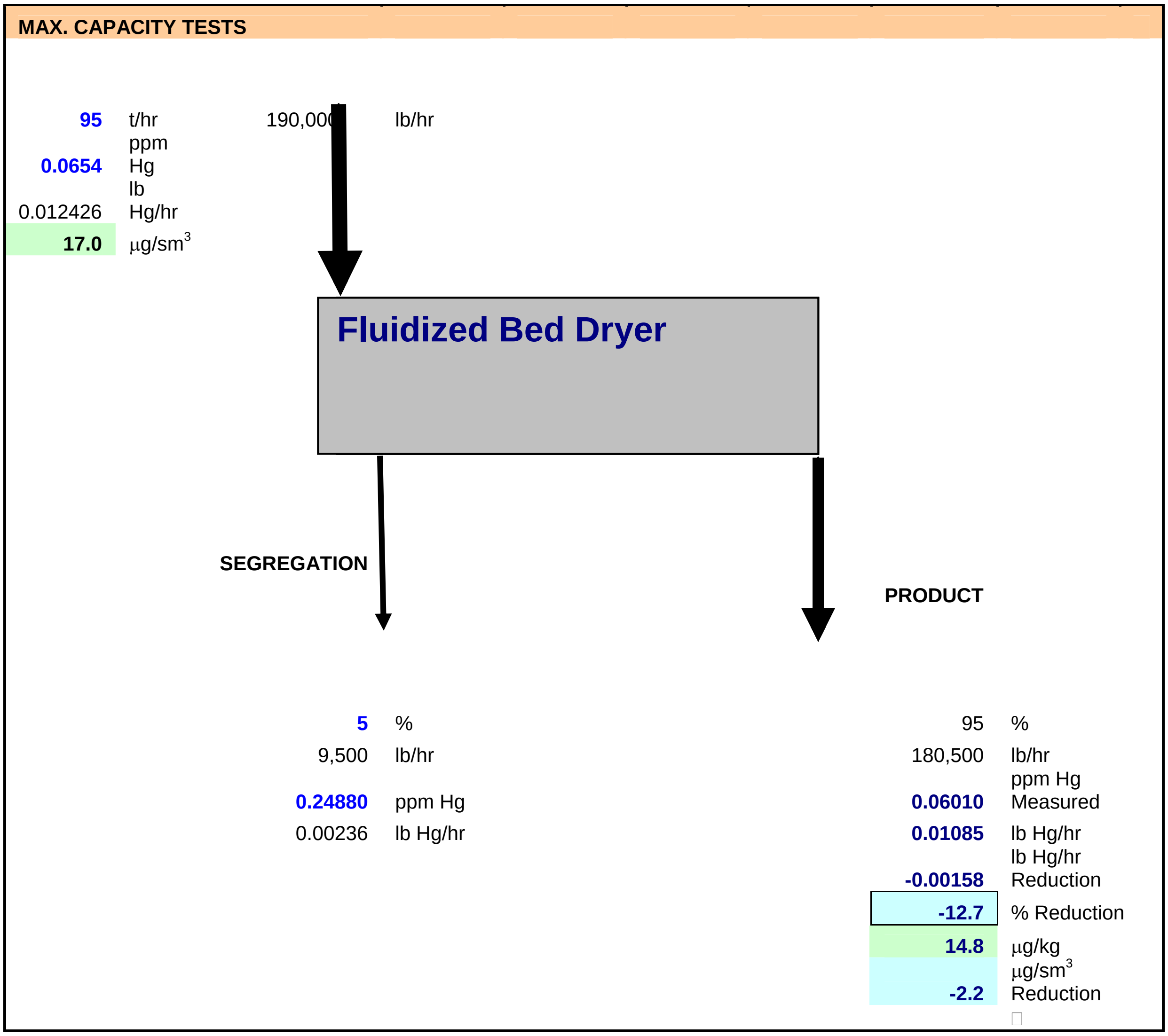

Figure 2-23: Mercury Mass Balance Around FBD – Maximum Capacity Tests

8.4.1: Effect of Flue Gas Moisture on Mercury Speciation

Mercury speciation is, among many other factors, affected by flue gas moisture content and residence time. With the target moisture removal of 8.5 percent, the flue gas moisture content is 2.5 percentage points lower compared to that with wet coal. According to the theoretical gas-phase results in Figure 2-24, this would result in approximately a 20 percent reduction in elemental mercury, Hg^o, in the flue gas [11].

Expressed differently, with a partially dried coal, approximately 20 percent more elemental mercury will be oxidized compared to the wet coal. The oxidized mercury, Hg^{+2}, is water soluble and can be removed in the wet scrubber.

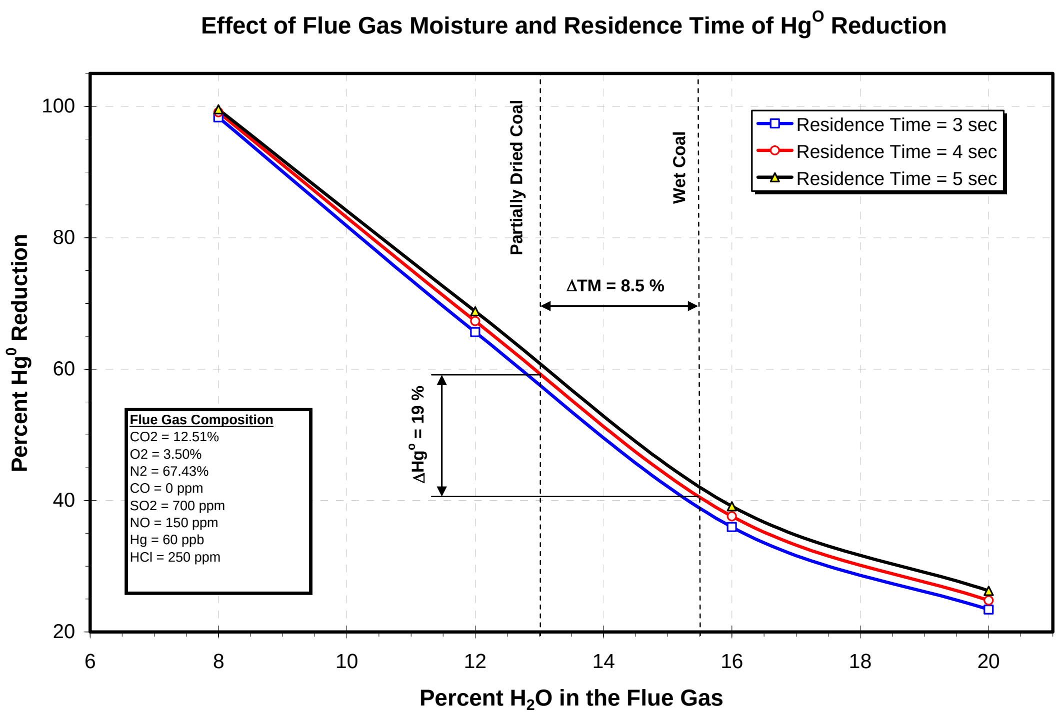

Figure 2-24: Effect of Flue Gas Moisture Content and Residence Time on Mercury Speciation (Theoretical results provided by Dr. Carlos Romero, ERC.)

Also, an increase in residence time has a positive effect on mercury oxidation. This effect is, however, small, of the order of one percent per one second increase in residence time. With a partially dried coal, the residence time will increase due to lower flow rates.

According to [12], the total vapor phase mercury concentration at CCS is in the 15 to 18 $\mu g/Nm^3$ range. This compares favorably to flue gas Hg concentrations calculated from the mercury content in coal and flue gas flow rate, Figures 2-22 and 2-23. Also, according to [12], approximately 65 percent (12 $\mu g/Nm^3$) of the vapor phase mercury at CCS is elemental mercury, Hg^o. Assuming a 20 percent relative reduction in elemental mercury due to lower flue gas moisture content and increased residence time, the reduction in Hg^o in flue gas stream would be 13 percent, or approximately 2.3 $\mu g/Nm^3$, assuming 98 percent Hg removal in the wet scrubber.

By combining a reduction in coal mercury content due to gravitational separation in a fluidized bed coal dryer (13 to 25 percent), and reduction in Hg^o due to the lower flue gas moisture content (13 percent), the total reduction in Hg emissions that could be achieved at CCS with the commercial coal drying system operating at 100 percent capacity, is predicted to be in the 25 to 35 percent range.

Similar to SO_x, reduction in Hg emissions that is achieved by gravitational separation in the coal dryer is very much affected by the accuracy of the measured Hg concentration levels in the feed, segregated, and product streams, and the segregated stream flow rate. The actual reduction in Hg emissions would be determined when the commercial coal drying system at CCS is operating at 100 percent capacity.

9. CONCLUSIONS

A prototype fluidized coal dryer, coal handling, particulate control, and dryer systems were designed, constructed and integrated into Unit 2 at Coal Creek as a Part of Phase 1 of the Lignite Fuel Enhancement project. The project objective was to demonstrate a 5 to 15 percentage point reduction in lignite moisture content by incremental drying using heat rejected from the power plant. Dryer performance was tested at the baseline (75 t/hr) and maximum (100 t/hr) coal feed rates.

The prototype coal drying system at CCS has been in almost continuous fully automatic operation since February 2006. A few minor problems that were easily corrected were encountered. The results obtained in a series of paired performance tests and from regular dryer operation confirm the theoretically predicted dryer performance and unit performance improvement. The achieved reduction in NO_x emissions is larger than expected.

The two-stage design of the dryer, with the first stage acting as a gravitational separator, worked as designed. The segregated stream, discharged from the first stage contained 3 to 3.5 times more sulfur and mercury compared to the product and feed streams. This first stage separation offers a potential for significant reduction in emissions. The segregated stream needs to be further processed to minimize the heat loss, which is proportional to the segregated stream flow rate, and remove additional amounts of sulfur, mercury, and other mineral matter from the dried coal. This will be accomplished in a commercial coal drying system.

In summary, the prototype coal drying system has met and exceeded expectations in terms of performance improvement, emissions reduction, operability, and positive effect on plant operation. It is, therefore, recommended to proceed with the commercial system design, construction, and implementation at CCS.

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LIST OF ACRONYMS AND ABBREVIATIONS

avg	Average
APH	Air preheater
CCPI	Clean Coal Power Initiative
CCS	Coal Creek Station
CD	Coal dryer
CD26	Coal dryer supplying dried coal to Mill Number 26
CO	Carbon monoxide
CO_2	Carbon dioxide
CT	Capacity test
CV	Control volume
DC	Dry coal, or dust control
DOE	Department of Energy
EPRI	Electric Power Research Institute
ERC	Energy Research Center
fg	Flue gas
FBD	Fluidized Bed Dryer
GRE	Great River Energy
h_{fg}	Latent heat of evaporation
Hg	Mercury
Hg^o	Elemental mercury
Hg^{+2}	Oxidized mercury
HHV	Higher heating value of fuel (coal)
HR_{cycle}	Turbine cycle heat rate (inverse of cycle efficiency)
HR_{net}	Net unit heat rate (inverse of unit efficiency)
HT	Heat transfer
HXE	Heat exchanger
ID	Inlet damper
IGV	Inlet guide vanes
M_{air}	Flow rate of air

M_{coal}	Coal flow rate
M_{Dry}	Flow rate of dried coal out of CD26
M_{Fuel}	Fuel flow rate
M_{Total}	Total coal flow rate (wet and dried) to the boiler
M_{Wet}	Flow rate of wet coal to the boiler
MAF	Moisture-and-ash-free
N	Number of independent tests (observations)
NDIC	North Dakota Industrial Commission
Nm^3	Normal cubic meter
NO_x	Nitrous oxide
P	Pressure or power
PA	Primary air
P_G, P_g	Gross unit power output
P_{PA}	PA fan power
P_{ss}	Station service power
Q_1	Heat input to the coal dryer
Q_2	Required heat input to the coal dryer
$Q_{Circulating\ water}$	Heat supplied to the in-bed heat exchanger
$Q_{Coal\ sensitive}$	Sensitive heat input with coal
Q_{air}	Heat input with air stream
Q_{evap}	Fuel moisture evaporation loss
Q_{fuel}, Q_{Fuel}	Heat input with fuel
Q_{loss}	Boiler heat loss
Q_{stack}	Dry gas stack loss
Q_T	Thermal energy transferred to the working fluid in the boiler
$Q_{T,Wet}$	Thermal energy transferred to the working fluid in the boiler – wet coal
$Q_{T,Dry}$	Thermal energy transferred to the working fluid in the boiler – dry coal
RE	Random error (test uncertainty)
S	Best estimate of standard deviation
SA	Secondary air
SO_2	Sulfur dioxide

SO_3	Sulfur trioxide
SO_x	SO_2 and SO_3
t	Student (W. Gosset) variable
T_{coil}	Surface temperature of the in-bed heat exchanger
$T_{coil,avg}$	Average surface temperature of the in-bed heat exchanger
$T_{FA,in}$	Temperature of fluidization air into the coal dryer
TM	Total coal moisture (moisture in coal and coal ash)
VSD	Variable speed drive
WC	Wet coal
X_{Blend}	Composition or HHV of blended coal
X_{Dry}	Composition or HHV of dried coal out of CD26
X_{Wet}	Composition or HHV of wet coal to the boiler
σ	Standard deviation
η_B	Boiler efficiency
Δ	Difference or change
ΔHR_{net}	Change in net unit heat rate
ΔP	Differential pressure or pressure loss
$\Delta\eta_B$	Change in boiler efficiency
$\Delta\eta_{B,TOT}$	Total change in boiler efficiency