BEFORE THE ENVIRONMENTAL QUALITY COUNCIL
STATE OF WYOMING

IN THE MATTER OF:	)	
BASIN ELECTRICAL POWER COOPERATIVE	)	
DRY FORK STATION,	)	Docket No. 07-2801
AIR PERMIT CT-4631	)	

RESPONDENT DEPARTMENT OF ENVIRONMENTAL QUALITY'S MEMORANDUM IN SUPPORT OF MOTION FOR PARTIAL SUMMARY JUDGMENT

Schlichtemeir Affidavit

EXHIBIT F

CH2MHILL

CH2M HILL
9193 South Jamaica Street
Englewood, CO 80112-5946
Tel 720.286.5919
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March 3, 2006

MAR 2006
RECEIVED
AIR QUALITY
DIVISION

Mr. Ken Rairigh
Air Quality Specialist
Wyoming Department of Environmental Quality
Air Quality Division
Herschler Building, 4-W
122 West 25th Street
Cheyenne, WY 82002

Subject: Basin Electric Power Cooperative
Dry Fork Station PSD Air Construction Permit Application No. AP-3546
Response to 12/21/05 DEQ Completeness Review Letter
Electronic Modeling Files

Dear Ken,

Basin Electric is planning on sending the response to the referenced completeness letter to DEQ on Friday March 3, 2005. Basin Electric asked that we send you the revised modeling files and other data that was requested in an electronic format. I have enclosed a data CD and a list of the files.

If you have any questions about this information, please let Josh Nall or myself know.

Sincerely,

Joseph J. Hammond, P.E.
Project Manager

Enclosure

cc: Jerry Menge, Basin Electric Power Cooperative
Josh Nall, CH2M HILL

List of Files on CD:

File Name	Description
\DEM	
MODEL.DEM	Digital Elevation Model (DEM) data used for ISCST3 modeling
\PlotPlans	
Fig7-4_Sources.MXD	ArcMap9.1 base file for Figure 7-4
Fig7-5-plot_plan_fenceline.MXD	ArcMap9.1 base file for Figure 7-5
\PlotPlans\GeoData	Background ArcMap files for Figures 7-4 and 7-5
\Isopleth	
SO2_24hINC.EMF	Isopleth plot of 24-hour increment consumption for SO_2 (Windows Picture - Enhanced [emf] format)
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\CalcSpreadsheets	
B-1_BEPC_Dry_Fork_Emission Calculations_for_WDEQ_11-07-05.XLS	Excel workbook containing emissions inventory for Dry Fork Station Project
Attachment_7_Auxiliary_Equipment_Emissions_Workbook_03-02-2006.XLS	Excel workbook containing revised emissions calculation sheets for auxiliary equipment for Dry Fork Station Project
\ISC	
DF_SO2_CUM_Incr_PR2.DTA (.LST, .GRF)	ISC-Prime input (.DTA), output (.LST), and graphics (.GRF) files for revised SO2 increment run
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CH2MHILL

BASIN ELECTRIC
POWER COOPERATIVE

CD Format
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Basin Electric Power Cooperative
Dry Fork Station Project
Files for Response to WDEQ
March 2006
CD 1 of 1

DEQ/AQD 000685

Basin Electric Power Cooperative

Dry Fork Station
Gillette, Wyoming

Permit Application Number AP-3546

Response To
Wyoming Department of Environmental Quality
Completeness Review
December 21, 2005

Submitted:
March 3, 2006

Basin Electric Power Cooperative
Dry Fork Unit 1 PSD Permit Application
Response to Wyoming Department of Environmental Quality, Air Quality Division
Permit Application No. AP-3546 Completeness Review Dated December 21, 2005

Provided below is a detailed response to questions included in the Wyoming Department of Environmental Quality's (WDEQ) Completeness Review dated December 21, 2005. WDEQ comments are provided below in italics.

WDEQ Comment 1: *SO_2 BACT for PC Boiler Basin Electric proposed a dry lime scrubber with emission limits of 0.1 lb/MMBtu (3-hour and 30-day averages) as BACT for SO_2. Basin Electric also considered a wet scrubber and an emission limit of 0.09 lb/MMBtu and determined that the average cost effectiveness was reasonable at $1,450/ton but excluded this option based on an incremental cost of $13,157/ton.*

An analysis of the technical feasibility and cost effectiveness is required for wet scrubbers at 0.07 and 0.08 lb/MMBtu, 30-day average, and for dry scrubbers at 0.07, 0.08, and 0.09 lb/MMBtu, 30-day average. This analysis needs to include an explanation of expected variability and how it affects a 3-hour versus 30-day average limit.

Response: A detailed analysis is included in Attachment 1. Based on information available from FGD vendors, emission rates achieved in practice by existing sources, economic impacts, and engineering judgment, BEPC is proposing dry scrubbing (SDA or CDS) with a controlled SO_2 emission rate of 0.10 lb/mmBtu (30-day rolling average) as BACT for Dry Fork Unit 1. An SO_2 emission limit of 0.10 lb/mmBtu (30-day rolling average) appears to be both technically and economically feasible, and will require the unit to achieve a control efficiency greater than 92% (based on the worst-case design coal), which is very close to the design limits of the equipment. To ensure compliance, the dry scrubbing system proposed by BEPC will have to be designed to achieve a target emission rate below 0.10 lb/mmBtu under all normal operating conditions. To account for short-term variability in the controlled SO_2 emission rate, BEPC is proposing an average 3-hour SO_2 emission rate of 380.1 lb/hr (versus the proposed 0.10 lb/mmBtu 3-hour limit in the permit application). This emission limit is based on a maximum heat input to the boiler of 3,801 mmBtu/hour and a controlled SO_2 emission rate of 0.10 lb/mmBtu, and is equivalent to the short-term SO_2 emission rate used in impact modeling. Establishing a mass-based short-term emission limit will allow BEPC to respond to short-term excursions associated with fuel sulfur content, boiler load changes, and routine equipment maintenance and repairs. The proposed BACT emission limits (0.10 lb/mmBtu 30-day average and 380.1 lb/hr 3-hour average) will ensure that the Dry Fork Unit 1 dry scrubbing system will be operated in such a way as to continuously achieve a high control efficiency, while providing a reasonable margin to allow the system to respond to routine operating and process changes. The proposed emission rates will require state-of-the-art SO_2 control and are consistent with other recently permitted PC units.

WDEQ Comment 2: *NO_x BACT for PC Boiler Basin Electric proposed low NO_x burners, overfire air, and SCR with an emission limit of 0.07 lb/MMBtu, 30-day average as BACT. An analysis of the technical feasibility and cost effectiveness is required for emission levels of 0.05 and 0.06 lb/MMBtu, 30-day average.*

Response: A detailed analysis is included in Attachment 2. Based on technical feasibility, physical limitations of the control system, emissions achieved in practice at existing sources, and economic impacts, BEPC is proposing an emission rate of 0.07 lb/mmBtu (30-day average) as BACT for NO_x control. Reducing the permitted NO_x emission rate below 0.07 lb/mmBtu would eliminate almost all margin between the design target of the control system and the permit limit. Furthermore, the incremental cost effectiveness associated with reducing NO_x emissions from 0.07 to 0.06 lb/mmBtu is calculated to be $7,210/ton, which is more then three times the average cost effectiveness of NO_x control at Dry Fork Unit 1.

WDEQ Comment 3: *<u>PM_{10} BACT for PC Boiler</u> Basin Electric proposed fabric filters with an emission limit of 0.012 lb/MMBtu, 3-hour average. An analysis of the technical feasibility and cost effectiveness is required for emission levels of 0.009, 0.01, and 0.011 lb/MMBtu, 3-hour average.*

Response: A detailed analysis is included in Attachment 3. All recently permitted PC boilers have been permitted with fabric filters as BACT for PM_{10} control. The lowest filterable PM_{10} emission rate designated as BACT is 0.012 lb/mmBtu at Comanche Unit 3 (Colorado) and Wygen Unit 2 (Wyoming). Neither unit has commenced operation or demonstrated the ability to achieve the proposed BACT emission limit on an on-going long-term basis. Several other facilities, including Roundup Units 1 and 2 (Montana) and Intermountain Unit 3 (Utah), have been permitted with a filterable PM_{10} emission rate of 0.015 lb/mmBtu. Because BPEC is proposing a control technology that results in the most stringent controlled emission rate, the use of fabric filters and a controlled PM_{10} emission rate of 0.012 lb/mmBtu should be considered BACT for the proposed boiler.

WDEQ Comment 4: *<u>BACT for 134 MMBtu/hr Auxiliary Boiler</u> Basin Electric estimated emissions of 0.05 lb/MMBtu NO_x and 0.11 lb/MMBtu CO and proposed an hours limit of 2000 hours per year but did not address BACT. A top down BACT analysis required for NO_x, CO, SO_2, PM_{10} and VOC including an evaluation of a 0.03 lb/MMBtu NO_x emission level.*

Response: A top down BACT analysis for the Auxiliary Boiler has been completed for NO_x, CO, SO_2, PM_{10}, and VOC and is included as Attachment 4. The analysis included an evaluation of control systems capable of achieving controlled NO_x emission rates below 0.054 lb/MMBtu, including flue gas recirculation (FGR) and selective catalytic reduction (SCR). A cost analysis of Low NO_x burners, FGR and SCR is shown in Attachment 5. A summary of RBLC database information is shown in Attachment 6. Revised emission workbook calculations for the auxiliary equipment are shown in Attachment 7. Based on a review of BACT controls required for auxiliary boilers, and a review of economic impacts, BEPC is proposing combustion controls, including low NO_x burners plus FGR as BACT for NO_x and CO control. BEPC is proposing a NO_x emission rate of 0.04 lb/mmBtu and a CO emission rate of 0.08 lb/mmBtu for the auxiliary boiler. Compliance with the proposed BACT emission limits will be demonstrated based on annual stack tests conducted on the auxiliary boiler using approved U.S. EPA test methods.

WDEQ Comment 5: *<u>BACT for 8.36 MMBtu/hr Inlet Gas Heater</u> Basin Electric estimated emissions of 0.1 lb/MMBtu NO_x and 0.08 lb/MMBtu CO and proposed an hours limit of 2000 hours per year but did not address BACT. A top down BACT analysis required for NO_x, CO, SO_2, PM_{10} and VOC including an evaluation of Low NO_x burners.*

Response: A top down BACT analysis for the Inlet Gas Heater has been completed for NO_x, CO, SO_2, PM_{10}, and VOC and is included as Attachment 4. The analysis includes an evaluation of low-NO_x burners. A summary of RBLC database information is shown in Attachment 8. Revised emission workbook calculations for the auxiliary equipment are shown in Attachment 7. BEPC is proposing a NO_x emission rate of 0.10 lb/mmBtu and a CO emission rate of 0.08 lb/mmBtu for the inlet gas heater.

WDEQ Comment 6: *Diesel Engines Basin Electric estimated emissions of 14.1 g/hp-hr NO_x and 3.0 g/hp-hr CO for the 360 hp Fire Pump. Basin Electric estimated emissions of 10.9 g/hp-hr NO_x and 2.5 g/hp-hr CO for the 2377 hp Emergency Generator. The Division currently considers EPA Tier 2 to represent BACT and needs confirmation that these engines will meet Tier 2 levels.*

Response: WDEQ indicated that EPA Tier II non-road emission rates are currently considered by the Division as BACT for diesel-fired engines. The federal regulation (40 CFR Parts 60 and 89) proposes a mandate that by 2007 and later, depending on the engine category, owners and operators of stationary diesel engines are responsible for emission compliance and must buy emission certified engines. Based on the Tier phase-in schedule and the anticipated date of construction for the emergency fire pump and emergency generator, these units must be certified to Tier II standards, with Tier II standards becoming effective around 2008-2011. The emergency fire pump engine and the emergency generator must be certified to standards that are generally based on non-road Tier II standards provided in the appropriate engine power category. The emission estimates (see Attachment 7) for the 360 hp emergency fire pump and 2,377 hp emergency generator were revised to be based on EPA Tier II non-road emission rates for NO_x (4.8 g/hp-hr) and CO (2.6 g/hp-hr).

WDEQ Comment 7: *Emergency Coal Truck Unloading Hopper A detailed description of this emissions unit, predicted hours of usage, and an analysis of the feasibility of control measures such as a stilling shed, water sprays, and choke loading is required. Also, it is the Division's understanding that this unit is subject to NSPS Subpart Y because the 200 ton per day threshold in Subpart Y refers to the coal preparation plant rather than an individual affected facility.*

Response:

Description of Emission Unit

The emergency truck hopper is designed for coal that would be delivered via truck into a below ground truck hopper. The coal from the truck hopper would then be conveyed to transfer house 2, at a rate of 900 tons per hour (tph) on a 42-inch-wide conveyor. From transfer house 2, the coal would then be conveyed to the three coal silos. From the coal silos, the coal would be transferred via enclosed conveyor to the coal crusher house.

The emergency truck hopper has been included in the facility design and would only be used in cases where the normal delivery system could not be utilized. This would include potential events such as major failures or downtime with the overland conveyor or issues with the Dry Fork Mine such as ~~equipment failures, fire or labor strike. Predicted hours of this emergency operation have not been~~ provided. It is not practical to anticipate the usage of the truck hopper for the emergency situations described. Basin Electric proposes notification to WDEQ when emergency operation is necessary, and that hours of usage will be tracked during these emergency situations and associated estimated emissions will be reported using WDEQ fugitive dust emission factors for coal truck dumping.

Feasibility of control measures

It is Basin Electric's intent that the proposed emergency truck hopper will be designed to control fugitive particulate emissions from the unloading of trucks by dust suppression methods so that emissions from such sources are minimized. Potential methods for minimizing fugitive dust emissions from the truck hopper include the following:

- Use of a partial or total enclosed building;
- Use of dry fogging or water sprays;
- Choke loading (method of transferring coal which precludes a free fall velocity of coal from a discharge spout into the receiving container);
- Use of bottom dump (belly dump) haul trucks.

Generally, the use of partial or total enclosure of the unloading area with a dust collection system is the most effective control option. The next most effective option would be the use of bottom dump trucks in combination with water sprays or dry fogging to minimize emissions. It is believed that choke loading would not be a practical or efficient method relative to coal unloading. The cost of a partial or totally enclosed building is estimated to be $500,000 to $1,000,000. BEPC considers this to be cost prohibitive based on the emergency nature of the unloading facility. BEPC proposes that the use of bottom dump haul trucks and the use of portable water sprays or fogging systems be considered BACT for this application.

NSPS Subpart Y

The emergency coal truck hopper is subject to NSPS performance standards for coal preparation plants in 40 CFR Part 60 Subpart Y. The affected facilities located at the Dry Fork Plant that are subject to the Subpart Y standards shall not discharge into the atmosphere, fugitive emissions which exhibit 20 percent opacity or greater. Fugitive dust control systems planned for the emergency truck unloading hopper, including portable water sprays and/or fogging systems, will be designed to meet the Subpart Y performance standards.

WDEQ Comment 8: *WAQSR Chapter 6, Section 5 The Auxiliary Boiler is subject to 40 CFR 63 Subpart DDDDD and Diesel Emergency Generator is subject to 40 CFR 63 Subpart ZZZZ. Therefore, the application requirements in Chapter 6, Section 5(a)(ii) are applicable.*

All of the information in Chapter 6, Section 5(a)(iii)(A)(II) is required for these units. Specifically, items 5 (expected commencement date of construction), and 8 (units and averaging times specified in the standard or percent reduction with justifying parameters).

Response: Section 4.2.2 of the permit application describes the applicability of the auxiliary boiler to 40 CFR Subpart DDDDD and the applicability of the emergency generator to 40 CFR Subpart ZZZZ. The provisions of Chapter 6 in WAQS&R, establish permitting requirements for all sources constructing and/or operating in the State of Wyoming; apply to this facility. The information below was provided to address the requirements of Chapter 6, Section 5(a)(ii) and Section 5(a)(iii) as requested by WDEQ.

- *Chapter 6, Section 5 (a)(iii)(A)(II)(5)* – The expected commencement date of construction of the facility including the above mentioned sources is May 2007.
- *Chapter 6, Section 5 (a)(iii)(A)(II)(6)* – The expected completion date of the construction for the facility including the above mentioned sources is June 2010.
- *Chapter 6, Section 5 (a)(iii)(A)(II)(7)* – The anticipated date of startup of the facility including the above mentioned sources is June 2010 (commercial operation January 2011).
- *Chapter 6, Section 5 (a)(iii)(A)(II)(8)* – This section requires the owner or operator to provide an estimate of the type and quantity of hazardous air pollutants expected to be emitted by the source reported in units and averaging times specified in the relevant standard. The estimated emission summary (criteria and HAP emission estimates) for the auxiliary boiler were provided in Appendix B, Table B-1 of the original submittal and has been included in this submittal (see Attachment 7). The Auxiliary boiler is considered a new large gaseous fuel boiler and is subject to the emission limitations, work practice standards, performance testing, monitoring, startup shutdown malfunction plan, and notification requirements of 40 CFR 60 Subpart DDDDD. 40 CFR Subpart DDDDD identifies the use CO as a surrogate to represent the variety of organic compounds emitted from the various fuels burned in boilers and process heaters. Because CO is a good indicator of incomplete combustion, there is a direct correlation between CO emissions and the formation of organic HAP emissions. CO emissions from the unit are limited to 400 ppm by volume dry basis @ 3% O_2 on a 30 day rolling average. The estimated emissions of CO are expected to be in the range of 150 ppm which is lower than the Subpart DDDDD limit. A performance test for CO emissions in accordance with Subpart DDDDD is required annually and CO CEMS will be installed as the unit is larger than 100 mmBtu/hr heat input. Compliance with the 30-day rolling average CO emissions standard will be demonstrated using the CO CEMS, as required by Subpart DDDDD.

  The diesel emergency generator located at the Dry Fork Station meets the definition of an emergency stationary RICE as its purpose is to produce power when electrical power from the local utility is interrupted therefore per 40 CFR 63.6590(b)(1)(i), the unit does not have to meet the required emission or operating limitations but will be required to submit an initial notification per 40 CFR 63.6645(d). In addition the estimate of the type and quantity of hazardous air pollutants expected to be emitted by the source was provided in the estimated emission summary for this unit in Appendix B, Table B-1 of the original submittal and has been included in this submittal.
- *Chapter 6, Section 5 (a)(iii)(A)(III)* – Worst case estimates and preliminary information were submitted in place of actual emissions data and analysis required by this subpart. BEPC intends to submit actual, measured emissions data where required for the auxiliary boiler as soon as available but no later than with the notification of compliance status required in Chapter 5, Section 3.

WDEQ Comment 9: <u>*PSD Class II Modeling Issues*</u> *CH2MHILL conducted the PM_{10} modeling analysis using a meteorological data set collected by Basin Electric at an anemometer height of 10* *meters for the 2002 calendar year. For the Class II modeling analyses, the Division will require the use of the meteorological data collected at the Eagle Butte mine for conducting PM_{10} ambient air quality assessments in the Gillette area; the Basin Electric meteorological (100-meter) data would be used to model all other criteria pollutants and HAPs from elevated releases, such as the coal-fired boiler stack.*

As a result, the Class II annual PM_{10} significant impact analysis must be rerun the using the Eagle Butte meteorological data set. If the results of the revised annual PM_{10} significant impact analysis indicates the proposed project will have a significant annual impact, the Eagle Butte meteorological data would be used in any cumulative PM_{10} modeling assessments. The Eagle Butte meteorological data set is more representative because it better approximates the wind flows at the proposed release heights of the sources that will most strongly influence the maximum PM_{10} impacts (material handling sources); the Eagle Butte meteorological data were collected using an anemometer height of 10 meters.

The Division will not require Basin Electric to rerun the 24-hour PM_{10} significant impact analyses, as the present Division policy does not endorse short-term (24-hour) modeling exercises as a viable tool in predicting short-term ambient impacts from fugitive dust particulate emissions, as the recommended EPA dispersion models have not shown to work well when evaluating short-term fugitive particulate emissions.

Six (6) PM_{10} sources were identified as horizontal releases; these sources are reported to have a release temperature of 68°F. If these sources are non-buoyant horizontal releases, the convention for modeling emissions from non-buoyant horizontal releases is to set the exit velocity to 0.001 meters per second, set the exit diameter to one meter, and model the release with a temperature of zero (0) Kelvin. Correcting the initial velocity and stack diameter parameters reduces the momentum flux to near zero. Setting the exit temperature to zero (0) causes the ISC model to use the hourly ambient temperature value in the meteorological data file to represent the stack exit temperature, which eliminates buoyancy-induced dispersion from the horizontal release.

CH2MHILL performed a Class II cumulative 24-hour SO_2 increment analysis for the Dry Fork project. The analysis identified the Wyodak coal-fired boiler as the only baseline source of SO_2. As a result, the emissions from this unit were not included in the 24-hour SO_2 increment analysis. The Division's records indicate that the Wyodak unit was not in operation and commercially producing electrical power until after the Minor Source baseline date for SO_2 (February 2, 1978), even though the commencement of construction was reported prior to 1978. Current allowable emissions from the Wyodak unit would therefore be included in the cumulative SO_2 increment analysis. Additionally, the Neil Simpson Unit I boiler was in operation prior to February 2, 1978, and therefore can-be removed from the SO_2 increment analysis.

Electronic copies of the 7.5 minute Digital Elevation Models (DEM), the facility plot plans, concentration isopleth plots, and calculation spreadsheets were not provided in the permit application. Please include these electronic data, along with hard copies of the isopleth plots for all the applicable WAAQS and increment modeling analyses that were conducted for this project.

Table 7-5 summarizes the modeled impacts from the coal-fired boiler stack and compares the ambient impacts to applicable standards. However, Wyoming's Fluoride standards are *incorrectly listed in this table. The 12-hour, 24-hour, 7-day, and 30-day Fluoride standards are 3.0, 1.8, 0.5, and 0.4 ug/m^3, respectively.*

Response: In response to WDEQ's request, CH2M HILL has conducted additional Class II modeling analyses for the Dry Fork Station Project. The following describes the results of these additional analyses, and provides additional information that WDEQ has requested.

The first of the Class II modeling issues was a request from WDEQ to repeat the annual preliminary modeling analysis for PM_{10} using meteorological data from the Eagle Butte mine. WDEQ also suggested that the six PM_{10} sources with horizontal releases should be modeled as non-buoyant point sources with 0.001 meter per second exit velocity, a one-meter stack diameter, and a release temperature of zero Kelvin. CH2M HILL revised the annual preliminary model runs using the Eagle Butte meteorological data and the revised characterization of the horizontal releases. The results of this analysis were below the Class II modeling significance level, as shown in Table 1. All maximum modeled impacts occurred at the facility fenceline in areas of 50-meter receptor spacing.

TABLE 1
Results of Preliminary Analysis for Annual PM_{10} (Eagle Butte Mine Meteorological Data)

Year of Meteorology	Maximum Project Predicted Impact (μg/m^3)
1995	0.81
1996	0.87
1997	0.76
1998	0.76
1999	0.80
2000	0.79
Class II Modeling Significance Level	1.0

WDEQ also indicated that the 24-hour PSD increment model run for SO_2 should be revised. After a review of their records, WDEQ determined that the Wyodak source was not a pre-baseline source and therefore should be added to the analysis. On the other hand, WDEQ determined that Neil Simpson Unit 1 was a pre-baseline source and could be removed from the analysis. CH2M HILL made those two changes, and the results remained below the allowable 24-hour PSD increment, as shown in Table 2. A surfer plot for this revised analysis is provided as Figure 1, with a similar plot for the 24-hour NAAQS analysis (also requested by WDEQ) provided as Figure 2.

TABLE 2
Revised 24-Hour SO_2 Increment Modeling

Averaging Period/ Pollutant	High 2nd-High Modeled Increment Impact (μg/m^3)	Class II PSD Increment (μg/m^3)
24-hour SO_2	37.8	91

DEQ/AQD 000701

Figure 1: 24-Hour SO2 Increment Results (ug/m^3)

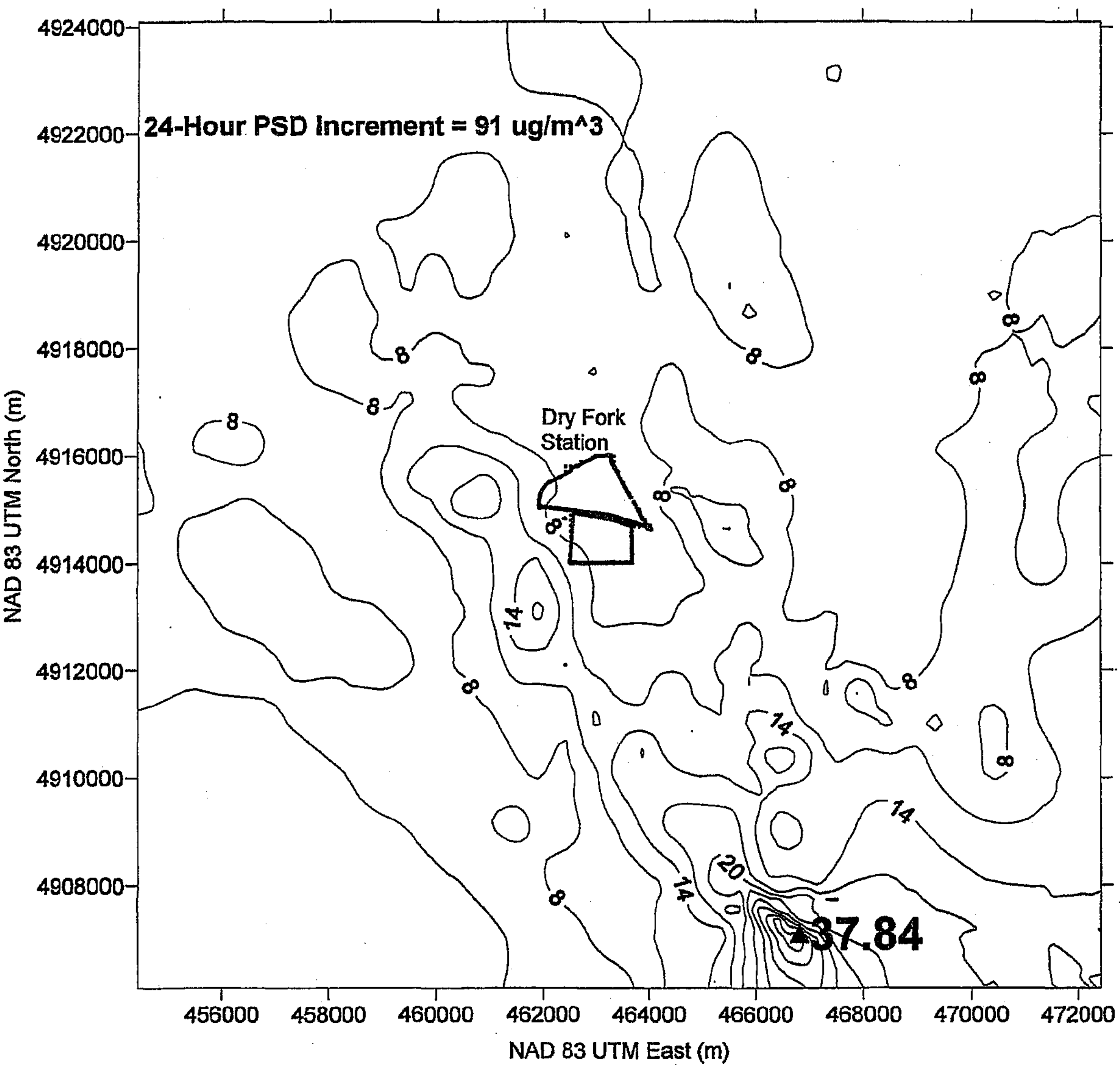
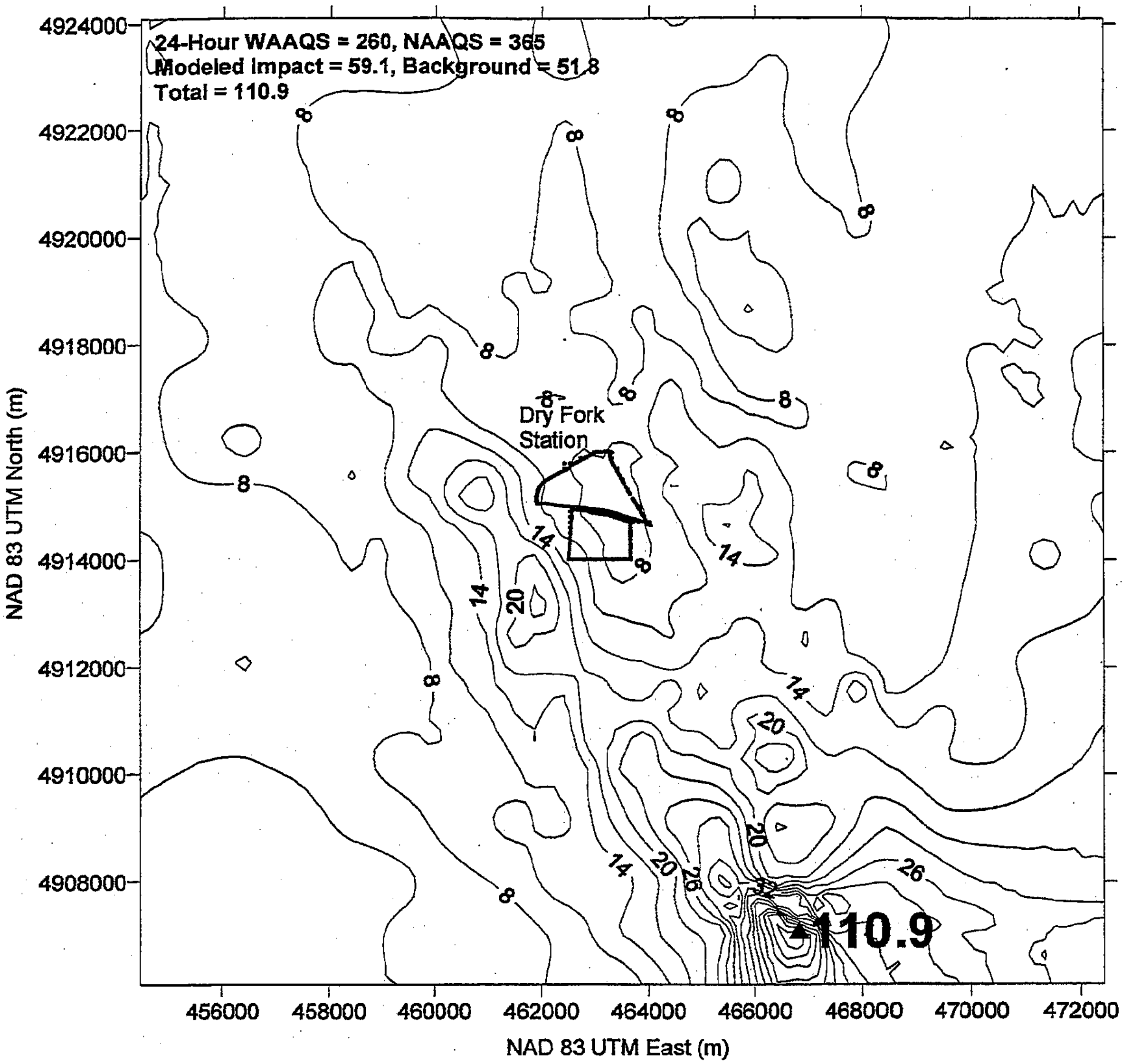


Figure 2: 24-Hour SO2 NAAQS Results (ug/m^3)



WDEQ noted that the Wyoming Fluoride standards were incorrectly listed in Table 7-5 in the permit application. The maximum predicted project impacts are well below the 3.0 ug/m^3 12-hour, 1.8 ug/m^3 24-hour, 0.5 ug/m^3 7-day and 0.4 ug/m^3 30-day Wyoming Fluoride standards.

WDEQ also requested that Basin Electric provide electronic copies of: 1) the DEM data that were used for the analysis, 2) the facility plot plan, and 3) calculation spreadsheets. These data, along with the input/output files for the revised modeling runs, are provided on CD with this response memo.

List of Attachments:

Attachment 1	SO_2 BACT Review PC Boiler
Attachment 2	NO_x BACT Review PC Boiler
Attachment 3	PM_{10} BACT Review PC Boiler
Attachment 4	Auxiliary Equipment BACT Analysis
Attachment 5	Auxiliary Equipment Cost Analysis
Attachment 6	RBLC Tables Auxiliary Boiler
Attachment 7	Auxiliary Equipment Emission Calculations
Attachment 8	RBLC Tables Inlet Gas Heater

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Attachment 1

ATTACHMENT NO. 1

Response to WDEQ's Completeness Review Dated December 21, 2005

WDEQ Comment 1: *Basin Electric proposed a dry lime scrubber with emission limits of 0.1 lb/MMBtu (3-hour and 30-day averages) as BACT for SO_2. Basin Electric also considered a wet scrubber and an emission limit of 0.09 lb/MMBtu and determined that the average cost effectiveness was reasonable at $1,450/ton but excluded this option based on an incremental cost of $13,157/ton.*

An analysis of the technical feasibility and cost effectiveness is required for wet scrubbers at 0.07 and 0.08 lb/MMBtu, 30-day average, and for dry scrubbers at 0.07, 0.08, and 0.09 lb/MMBtu, 30-day average. This analysis needs to include an explanation of expected variability and how it affects a 3-hour versus 30-day average limit.

Response: The response to WDEQ Comment 1 has been divided into the following subtopics:

(a) Proposed Dry Fork Fuel Characteristics.
(b) Wet FGD control efficiencies and the technical feasibility of achieving emission rates of 0.07 and 0.08 lb/MMBtu, 30-day average.
(c) Dry FGD control efficiencies and the technical feasibility of achieving emission rates of 0.07, 0.08, and 0.09 lb/MMBtu, 30-day average.
(d) Cost effectiveness of each technically feasible control scenario.
(e) Collateral environmental issues associated with FGD control systems.
(f) Proposed SO_2 emission limit and expected variability in the controlled emission rate.

(a) Proposed Dry Fork Fuel Characteristics

The generation of sulfur dioxide (SO_2) in a coal-fired boiler, and the feasibility of various control technologies and controlled emission rates, is related to the sulfur content and heating value of the fuel burned. As described in Basin Electric Power Cooperative's (BEPC's) Air Construction Permit Application submitted November 10, 2005 (the "Permit Application"), the proposed Dry Fork Station will be located adjacent to the Dry Fork Mine. Coal from the mine will be delivered to the power plant via a covered, overland conveyor. Based on available analyses, coal burned at the Dry Fork Station will have the following characteristics (see, Permit Application Table 2-1):

Parameter	Unit	Design	Minimum	Maximum
Gross (Higher) Heating Value	Btu/lb	8,045	7,800	8,300
Moisture	wt %	32.1	30.5	33.8
Volatile Matter	wt %	30.1	28.0	32.0
Sulfur Content	wt %	0.33	0.25	0.47
Ash Content	wt %	4.8	4.2	6.5
Uncontrolled SO_2 Emission Rate	lb/mmBtu	0.82	0.60	1.21

The proposed Dry Fork Unit 1 boiler will be a pulverized coal-fired boiler designed for base-load operation. Coal characteristics summarized above were used to establish the boiler's performance characteristics, and to evaluate the feasibility of various emission control technologies and controlled emission rates.

(b) Wet FGD Chemistry and Control Efficiency

As discussed in section 5.2.3 of the Permit Application, wet FGD technology is an established SO_2 control technology for coal-fired boilers. There are several commercially available wet scrubbing systems. All wet scrubbing system designs will vary in design, however, all wet scrubbing systems use an alkaline slurry that reacts with SO_2 in the flue gas to form insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts. Wet FGD systems may be generally categorized as lime (CaO) or limestone ($CaCO_3$) scrubbing systems. The scrubbing process and equipment for either lime- or limestone scrubbing is similar. Typically an alkaline slurry consisting of hydrated lime or limestone is sprayed countercurrent to the flue gas in a spray tower. Design variations may include modifications to increase slurry/SO_2 contact and minimize scaling in the reactor vessel. Equations 1-1 through 1-5 summarize the chemical reactions that take place within the wet scrubbing systems to remove SO_2 from flue gas.

$$SO_2 + CaO + \tfrac{1}{2}H_2O \rightarrow CaSO_3 \bullet \tfrac{1}{2}H_2O \qquad (1\text{-}1)$$
$$SO_2 + CaO + 2H_2O \rightarrow CaSO_4 \bullet 2H_2O \qquad (1\text{-}2)$$
$$SO_2 + CaCO_3 + H_2O \rightarrow CaSO_3 \bullet H_2O + CO_2 \qquad (1\text{-}3)$$
$$CaSO_3 + \tfrac{1}{2}O_2 + 2H_2O \rightarrow CaSO_4 \bullet 2H_2O \qquad (1\text{-}4)$$
$$SO_2 + 2H_2O + \tfrac{1}{2}\,O_2 + CaCO_3 \rightarrow CaSO_4 \bullet 2H_2O + CO_2 \qquad (1\text{-}5)$$

Forced oxidation of the scrubber slurry can be used with either the lime or limestone wet FGD system to produce gypsum solids instead of the calcium sulfite by-product. Air blown into the reaction tank provides oxygen to convert most of the $CaSO_3$ to a relatively pure calcium sulfate, or gypsum ($CaSO_4$) as shown in equation 4. Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the FGD. The gypsum by-product from this process must be dewatered, but may be salable if a viable local market exists.

Wet scrubbing systems using limestone as the reactant account for a large majority of the wet scrubbing systems on utility boilers firing high-sulfur coals. Wet lime and limestone scrubbing systems will achieve essentially the same SO_2 control efficiencies, however, the higher cost of lime typically makes wet limestone scrubbing the more attractive option. Wet limestone systems have demonstrated the ability to achieve control efficiencies as high as approximately 98% on boilers firing high-sulfur bituminous coals under optimal conditions. The actual control efficiency of a wet FGD system will depend on several factors, including the SO_2 concentration in the flue gas entering the system.

The chemistry of wet scrubbing consists of a complex series of kinetic and equilibrium-controlled reactions occurring in the gas, liquid, and solid phases. In general, the amount of SO_2 absorbed from the flue gas is governed by the vapor-liquid equilibrium between SO_2 in the flue gas and the absorbent liquid. If no soluble alkaline species are present in the liquid, the liquid quickly becomes saturated with SO_2 and absorption is limited.[1] Likewise, as the flue gas SO_2 concentration goes down, absorption will be limited by the SO_2 equilibrium vapor pressure. Therefore, higher control efficiencies can be achieved on flue gases with high concentrations of SO_2. High control efficiencies become increasingly difficult to achieve as the SO_2 concentration in the flue gas decreases.

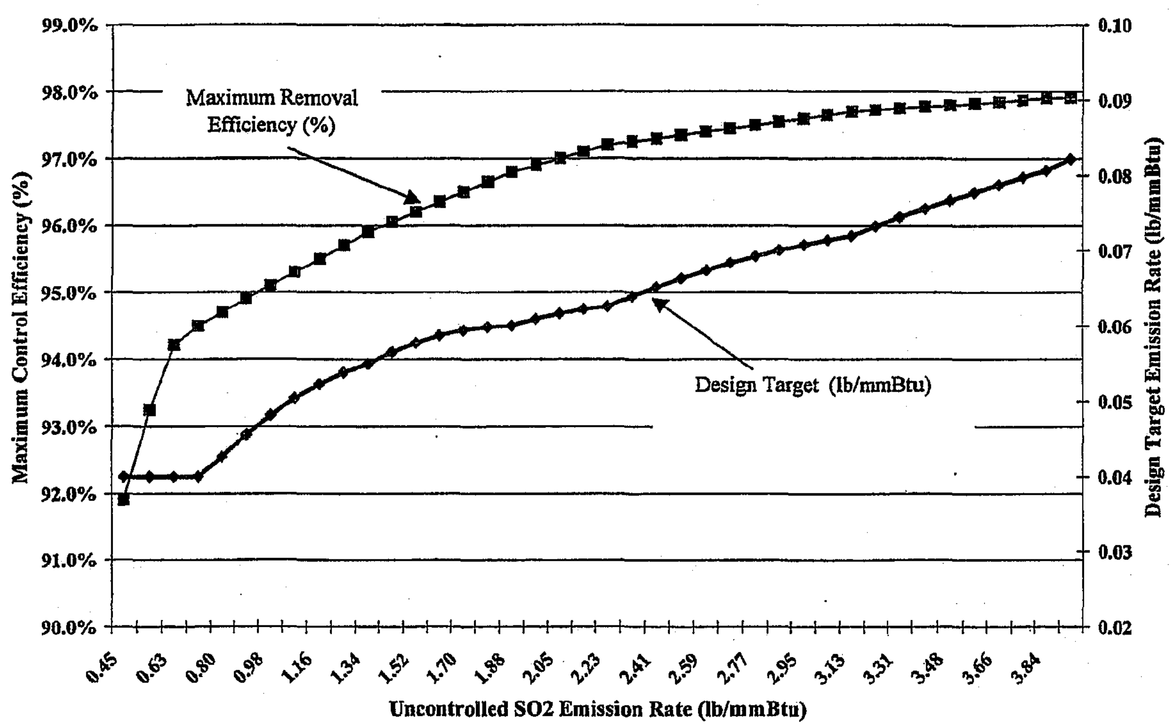
Based on information available from FGD vendors, the control efficiency of a wet FGD control system is limited to approximately 98% of the incoming SO_2 (in high sulfur applications) or a controlled SO_2 concentration of approximately 20 ppmvd @ 3% O2, whichever is achieved first. FGD vendors have not guaranteed controlled SO_2 rates below approximately 20 ppmvd @ 3% O2 because of the low SO_2 concentration in the flue gas, high flue gas flow rate, and physical limitations of the reactor vessels and control systems. A controlled SO_2 concentration of 20 ppmvd @ 3% O2 is equivalent to an emission rate of approximately 0.04 lb/mmBtu.

Figure 1 depicts the maximum control efficiencies and target controlled SO_2 emission rates of a wet FGD control system as a function of the inlet SO_2 rate.[2] Based on a maximum uncontrolled SO_2 emission rate of 1.21 lb/mmBtu, a wet FGD control system on Dry Fork Unit 1 would be expected to achieve a maximum control efficiency in the range of 95.5% and a minimum target emission rate in the range of 0.054 lb/mmBtu. These represent the most aggressive control efficiency and the lowest target emission rate that would be expected as guaranteed values from wet FGD vendors.

[1] Combustion Fossil Power – A Reference Book on Fuel Burning and Steam Generation, edited by Joseph P. Singer, Combustion Engineering, Inc., 4th ed., 1991 (pp. 15-41).

[2] Figure 1 is based on information from FGD vendors and emission rates achieved in practice at existing coal-fired boilers equipped with wet FGD control systems. Actual guaranteed control efficiencies and emission rates may vary from those shown in Figure 1.

Figure 1
WFGD Control Efficiency as a Function of Uncontrolled SO_2 Emission Rate



Although an emission rate as low as 0.054 lb/mmBtu may be an acceptable "design target" for Dry Fork Unit 1, this emission rate does not represent a "permit limit" or an emission rate that can be achieved on a long-term basis under all normal operating conditions. Some reasonable margin must be provided between the design target and the permit limit to allow for normal fluctuations in the controlled emission rate.

Bonanza Unit 1 is a 400 MW PC unit equipped with wet FGD. The unit fires low-sulfur western bituminous coal with a potential uncontrolled SO_2 emission rate of approximately 0.84 lb/mmBtu.[3] Based on data available from U.S.EPA's Acid Rain Database, Bonanza Unit 1 consistently achieves one of the lowest controlled SO_2 emission rates in the U.S. Figure 2 shows the actual hourly emission rates reported by Bonanza Unit 1 during a one-year period, and the calculated 30-day

[3] Coal data for Bonanza Unit 1 was based on information available from the Federal Energy Regulatory Commission (FERC). Based on the FERC data, Bonanza Unit 1 received western bituminous coal with an average heating value of approximately 10,000 Btu/lb and a sulfur content of approximately 0.42%.

rolling average. A summary of the variation in the controlled emission rate based on several averaging times is provided in Table 1. It can be seen that variability in the controlled emission rate increases with decreased averaging times.

Figure 2
SO2 Emission Rates Achieved In-Practice at Bonanza Unit 2
(Low-Sulfur Western Bituminous Coal and Wet FGD)

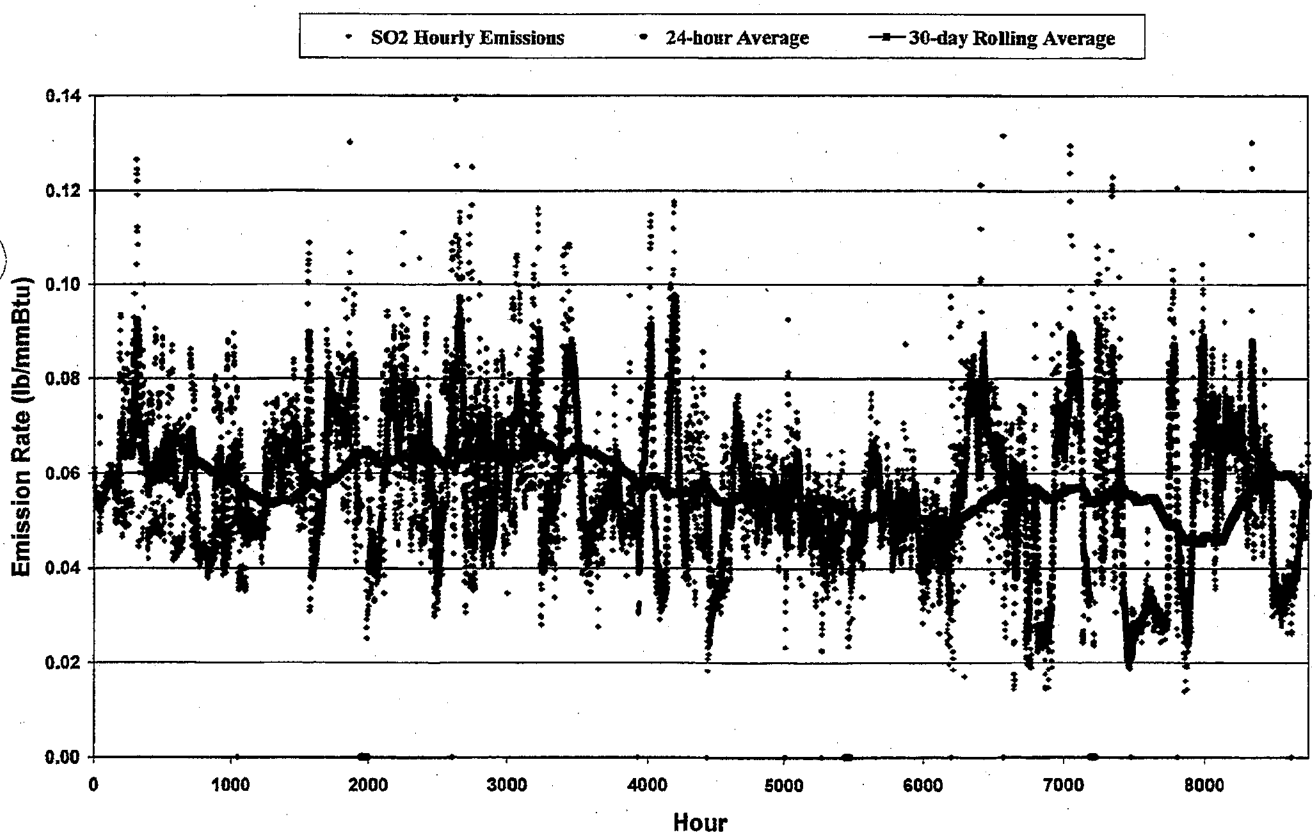


Table 1
Average SO_2 Controlled Emission Rates
Low-Sulfur Bituminous Coal / PC Boiler / Wet FGD

	Averaging Time		
	3-hour	24-hour	30-day
Average Emission Rate (lb/mmBtu)	0.057	0.057	0.057
Standard Deviation (lb/mmBtu)	0.018	0.014	0.005
Emission Rate at 95% Confidence Level (lb/mmBtu)	0.093	0.085	0.067
Percent Increase Above Average Emission Rate	63.2%	47.4%	17.5%

Based on information from FGD vendors, actual emission rates achieved in practice at existing sources, the Dry Fork coal characteristics summarized above, and a design target of 0.054 lb/mmBtu, controlled emission rates of 0.07 and 0.08 lb/mmBtu (30-day average) using wet FGD may be achievable at the Dry Fork Station. However, emission rates below approximately 0.09 lb/mmBtu would eliminate almost all the margin between the design limit and the permit limit, and would increase the risk of potential compliance issues at the plant. For this analysis it was concluded that emission rates of 0.07 and 0.08 lb/mmBtu (30-day average) could be achieved with a wet FGD system, assuming an increased reactor size, additional spray levels, and increased Ca/S stoichiometry.

(c) Dry FGD Chemistry and Control Efficiency

Another scrubbing system that has been designed to remove SO_2 from coal-fired combustion gases is dry scrubbing. As described in section 5.2.3 of the Permit Application, dry scrubbing involves the introduction of dry or hydrated lime slurry into a reaction vessel where it reacts with SO_2 in the flue gas to form calcium sulfite solids (see equations 1-1 and 1-2). Unlike wet FGD systems that produce a slurry by-product that is collected separately from the fly ash, dry FGD systems produce a dry by-product that must be removed with the fly ash in the particulate control equipment. Therefore, dry FGD systems must be located upstream of the particulate control device to remove the reaction products and excess reactant material.

Two potentially feasible dry FGD systems were described in the Permit Application, lime spray dryer absorber (SDA) and circulating dry scrubbers (CDS). A brief description of each dry scrubbing system is provided below.

Spray Dryer Absorber

SDA systems have been used in large coal-fired utility applications, and have demonstrated the ability to effectively reduce SO_2 emissions. The typical spray dryer absorber uses a slurry of lime and water injected into an absorption tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a dry by-product. The process equipment associated with a spray dryer typically includes an alkaline storage tank, mixing and feed tanks, one or more atomizers, spray chamber, particulate control device and a recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce alkaline sorbent use.

Various process parameters affect the efficiency of the SDA process including: the type and quality of the additive used for the reactant, reactant stoichiometric ratio, the inlet flue gas temperature, how close the SDA is operated to saturation conditions, and the amount of solids product recycled to the atomizer.[4] Chemical and physical limitations including flue gas temperature, Ca/S stoichiometry, approach to saturation, mixing and reaction time limit the control efficiency of the SDA to a maximum of approximately 94%. SDA systems have been permitted as BACT on pulverized coal-fired boilers firing low-sulfur PRB coals.[5]

Based on an uncontrolled SO_2 emission rate of 1.21 lb/mmBtu, the most aggressive design target for an SDA-FGD would be approximately 0.073 lb/mmBtu (i.e., 94% control based on worst-case design fuel). Although an emission rate as low as 0.073 lb/mmBtu may be an acceptable design target for Dry Fork Unit 1, this emission rate does not represent a permit limit or an emission rate that can be achieved on a long-term basis under all normal operating conditions. Some reasonable margin must be provided between the design target and the permit limit to allow for normal fluctuations in the controlled emission rate.

Figure 3 shows the actual hourly SO_2 emission rate reported by KCPL Hawthorne Unit 5 during the time period January 1, 2004 through March 31, 2005. Hawthorne Unit 5 is a nominal 570 MW pulverized coal-fired unit firing subbituminous coal and equipped with an SDA control system. A summary of the variation in the controlled emission rate based on several averaging times is provided in Table 2.

[4] ~~Combustion-Fossil Power, (pp. 15-58).~~

[5] See, for example, Comanche Unit 3, City Utilities of Springfield – Southwest Power Station, MidAmerican Council Bluffs Unit 4, and Kansas City Power & Light – Hawthorne Facility

Figure 3
Actual SO_2 Emission Rates
PRB-Fired PC Unit Equipped with SDA

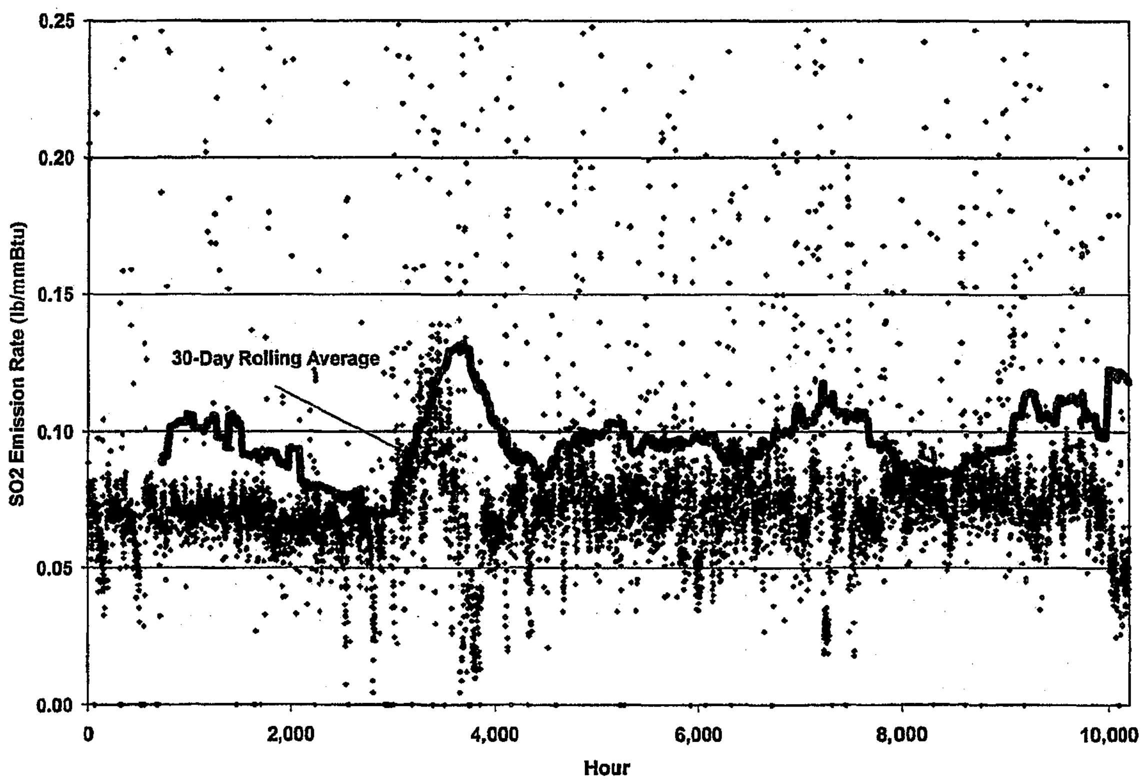


Table 2
Average SO_2 Controlled Emission Rates
Subbituminous Coal / PC Boiler / SDA

	Averaging Time		
	3-hour	24-hour	30-day
Average Emission Rate (lb/mmBtu)	0.099	0.099	0.099
Standard Deviation (lb/mmBtu)	0.083	0.052	0.012
Emission Rate at 95% Confidence Level (lb/mmBtu)	0.26	0.20	0.12
Percent Increase Above Average Emission Rate	163%	102%	21%

Based on the Dry Fork fuel characteristics, the physical/chemical limitations of an SDA control system, and the controlled emission rates achieved in practice, it is concluded that the most aggressive SO_2 design target would be 0.073 lb/mmBtu and that a minimum 20% margin would be needed between the design target and the permit limit (30-day average) to account for normal fluctuations. Based on these assumptions, the most aggressive permit limit associated with an SDA would be 0.09 lb/mmBtu (30-day average). Permit limits below 0.09 lb/mmBtu are not considered technically feasible with the SDA control system.

Circulating Dry Scrubber

A second type of dry scrubbing system is the CDS. A CDS system uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. Flue gas passes through a venturi at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime where SO_2 is removed. The desulfurized flue gas passes out of the scrubber, along with reaction products, including unreacted hydrated lime, calcium carbonate, and the fly ash to the particulate removal system (fabric filter baghouse).

Based on information available from equipment vendors, the CDS flue gas desulfurization system should be capable of achieving SO_2 removal efficiencies similar to those achieved with an SDA. In fact, vendors advise that the CDS system is capable of achieving even higher removal efficiencies with increased reactant injection rates and higher Ca/S stoichiometric ratios. To date the CDS has had limited application, and has not been used on large pulverized coal boilers. The largest CDS unit, in Austria, is on a 275 MW size oil-fired boiler burning oil with a sulfur content of 1.0 to 2.0%. Operating experience on smaller pulverized coal boilers in the U.S. has shown high lime consumption rates, and significant fluctuations in lime utilization based on inlet SO_2 loading.[6]

Neil Simpson Unit 2 is a nominal 80 MW pulverized coal-fired unit equipped with a CDS control system. The CDS system has been in operation since 1995, and is equipped with an ESP for particulate matter control. Summarized in Table 3 are the hourly SO_2 emission rates reported by Neil Simpson Unit 2 between 1/1/2002 through 12/31/2004 and the calculated 30-day rolling averages. Table 3 includes a summary of the average controlled emission rate and the variation in the controlled emission rate for several averaging times.

[6] See, Lavely, L.L., Schild, V.S., and Toher, J., "First North American Circulating Dry Scrubber and Precipitator Remove High Levels of SO2 and Particulate",

Figure 3
Actual SO_2 Emission Rates
PRB-Fired PC Unit Equipped with CDS

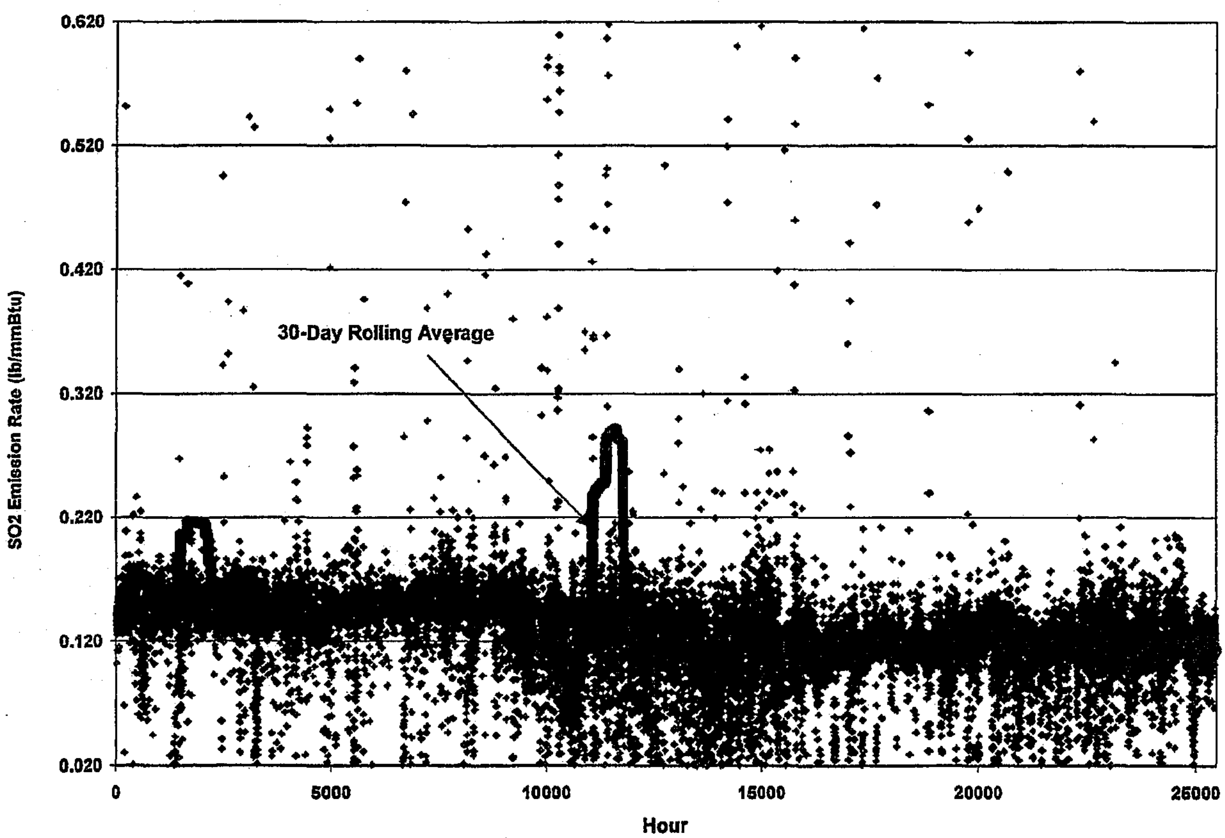


Table 3
Average SO_2 Controlled Emission Rates
Subbituminous Coal / PC Boiler / CDS

	Averaging Time		
	3-hour	24-hour	30-day
Average Emission Rate (lb/mmBtu)	0.137	0.137	0.137
Standard Deviation (lb/mmBtu)	0.125	0.095	0.029
Emission Rate at 95% Confidence Level (lb/mmBtu)	0.387	0.327	0.195
Percent Increase Above Average Emission Rate	182%	139%	42%

Based on engineering judgment it has been determined that a CDS-FGD control system would be technically feasible at Dry Fork Unit 1. However, there is limited operating experience with CDS scrubbers upon which to establish a control efficiency that could be achieved on an on-going long-term basis. Based on emission rates achieved in practice at an existing source, it appears that the CDS control system may offer the opportunity to achieve more stringent SO_2 emission rates, but the CDS system has shown more variability in the controlled SO_2 rate over an extended time period. For this assessment it was determined that the CDS-FGD system could achieve controlled SO_2 emission rates as low as 0.08 lb/mmBtu (30-day average) with a properly designed reactor vessel and relatively high Ca/S stoichiometric ratios.

(d) Cost Evaluation

An estimate of annual emission reductions, capital costs, and annual operating costs associated with each technically feasible control scenario was prepared. Table 4 includes the expected controlled SO_2 emission rates and maximum annual SO_2 mass emissions associated with each technology. Table 5 presents the capital costs and annual operating costs associated with building and operating each control system. Table 6 shows the average annual cost effectiveness of each control system.

Table 4
Annual SO_2 Emissions

Control Technology	SO_2 Emissions (lb/mmBtu)	Annual Emissions (tpy)*	Annual Reduction in Emissions (tpy from base case)*
Wet FGD @ 0.07	0.07	1,183	12,469
CDS @ 0.08	0.08	1,332	12,320
Wet FGD @ 0.08	0.08	1,352	12,300
SDA @ 0.09	0.09	1,498	12,154
Wet FGD @ 0.09	0.09	1,521	12,131
SDA @ 0.10	0.10	1,665	11,987
Low Sulfur Sub-bituminous Coal (Baseline)	0.82	13,652	--

* Annual emissions were calculated based on a maximum heat input of 3,801 mmBtu/hr for the dry FGD configurations, and a maximum heat input of 3,858 mmBtu/hr for the wet FGD to account for the additional auxiliary power required for the wet FGD system. Baseline annual emissions were calculated using the average sulfur content in the coal. All emissions were calculated assuming a 100% capacity factor.

Table 5
SO_2 Emission Control System
Cost Summary

Control Technology	Total Installed Capital Cost ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annualized Costs ($/year)
Wet FGD @ 0.07	$82,783,594	$7,814,200	$12,520,200	$20,334,400
CDS @ 0.08	$68,512,849	$6,467,100	$11,105,000	$17,512,100
Wet FGD @ 0.08	$79,723,340	$7,525,300	$11,456,000	$18,981,300
SDA @ 0.09	$67,741,165	$6,394,300	$9,100,700	$15,495,000
Wet FGD @ 0.09	$77,386,350	$7,304,700	$10,416,000	$17,720,700
SDA @ 0.10	$63,565,800	$6,000,200	$8,256,700	$14,256,900

Table 6
SO_2 Emission Control System
Cost Effectiveness

Control Technology	Total Annualized Costs ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)
Wet FGD @ 0.07	$20,334,400	12,469	$1,631
CDS @ 0.08	$17,512,100	12,320	$1,426
Wet FGD @ 0.08	$18,981,300	12,300	$1,543
SDA @ 0.09	$15,495,000	12,154	$1,275
Wet FGD @ 0.09	$17,720,700	12,131	$1,461
SDA @ 0.10	$14,256,900	11,987	$1,189

All of the technically feasible post-combustion desulfurization control systems (e.g., wet FGD, SDA, and CDS) appear to be economically feasible based on average annual cost effectiveness, with average cost effectiveness values ranging from approximately $1,189 to $1,631/ton. However, because of the large quantity of pollutant removed by the FGD systems, average cost effectiveness may not accurately represent economic impact on the project. For example, all of the FGD control systems will remove approximately 12,000 tons of potential SO_2 emissions per year. Therefore, total annualized costs of more than $60 million dollars per year would be needed to exceed an average cost effectiveness of $5,000/ton.

Because all the FGD systems effectively remove SO_2 emissions, it is appropriate to include an evaluation of the incremental cost effectiveness of the potentially feasible systems.[7] Summarized in Tables 7 and 8 are the incremental cost effectiveness calculations for various control combinations. Table 7 compares dry FGD systems at increasingly stringent SO_2 emission rates, and Table 8 compares wet FGD to dry FGD.

Table 7
SO_2 Emission Control System
Dry FGD Incremental Cost Effectiveness

Control Technology	Estimated Annual Emissions (tpy)	Incremental Emission Reduction (tpy)	Incremental Increase in Total Annual Cost ($/yr)	Incremental Cost Effectiveness ($/ton)
CDS @ 0.08	1,332	166	$2,098,000	$12,476
SDA @ 0.09	1,498	167	$1,238,100	$7,437
SDA @ 0.10	1,665	--	--	$1,189

Table 8
SO_2 Emission Control System
Wet FGD Incremental Cost Effectiveness

Control Technology	Estimated Annual Emissions (tpy)	Incremental Emission Reduction (tpy)	Incremental Increase in Total Annual Cost ($/yr)	Incremental Cost Effectiveness ($/ton)
Wet FGD @ 0.07 compared to CDS @ 0.08	1,183 1,332	149	$2,762,300	$18,538
Wet FGD @ 0.09 compared to SDA @ 0.10	1,521 1,665	144	$3,463,800	$24,052
Wet FGD @ 0.08 compared to SDA @ 0.10	1,352 1,665	313	$4,724,400	$15,094
Wet FGD @ 0.07 compared to SDA @ 0.10	1,183 1,665	482	$6,077,500	$12,610

The wet FGD control system offers the potential to achieve the most stringent SO_2 emission limits. However, the incremental costs associated with the wet FGD system on a subbituminous-fired boiler are excessive. The incremental cost effectiveness of wet FGD ranges from approximately $12,610 to more then $24,000/ton, depending on the dry scrubbing system and the controlled emission rate. The

[7] New Source Review Workshop Manual (NSR Manual), USEPA Office of Air Quality Planning and Standards, Research Triangle Park, NC, Draft October 1990 (pp. B.31).

incremental cost effectiveness of the wet FGD system is significantly greater than the average cost of SO_2 control at similar sources. Wet FGD systems have a higher initial capital requirement (compared to dry systems), require more energy to operate, and have slightly higher annual operating costs.

The average cost effectiveness of the dry systems (SDA and CDS) is similar. Based on information available from system vendors, it appears that capital requirements will be essentially equal, however the CDS system may have higher operating cost because of additional reactant consumption and auxiliary power requirements. In addition, it may be difficult to obtain stringent guaranteed emission limits with the CDS system because of the limited number of CDS systems currently in operation.

The average cost effectiveness of a dry scrubbing system (SDA or CDS) designed to achieve a controlled emission limit of 0.10 lb/mmBtu is estimated to be approximately $1,189/ton. An emission limit of 0.10 lb/mmBtu represents a control efficiency of approximately 92% from the worst-case design coal. The dry scrubbing system would have to be designed to achieve a target emission rate less than 0.10 lb/mmBtu to provide some margin between the design limit and the permit limit.

Reducing the permit limit below 0.10 lb/mmBtu would minimize any margin between the design target and the permit limit, and will likely result in increased O&M costs associated with more frequent atomizer changes, more frequent bag changes in the downstream fabric filter, and increased maintenance materials and the corresponding O&M labor costs. Based on an estimate of the total annualized cost for each control level, the incremental cost of reducing the permit limit from 0.10 to 0.09 lb/mmBtu is estimated to be $7,437/ton. To achieve a controlled SO_2 emission rate of 0.08 lb/mmBtu with a dry system, the system would have to be designed as a CDS-FGD, and the incremental cost effectiveness of the CDS-FGD systems is estimated to be approximately $12,610/ton. In addition to minimizing the margin between the permit limit and the design target, these incremental costs are significantly greater than the average cost effective of SO_2 control at Dry Fork Unit 1 and the average cost effectiveness of SO_2 control as similar sources.

(e) Collateral Environmental Impacts

In addition to the economic impact associated with various control scenarios, BACT requires an applicant to evaluate potential collateral environmental impacts. Potential collateral environmental impacts associated with each FGD system are discussed below.

Wet FGD Environmental Impacts

There are several collateral environmental impacts associated with wet FGD control systems. First, wet FGD systems generate a calcium sulfate waste by-product that must be properly managed. Historically, solid wastes generated from wet FGD systems have been dewatered and disposed of in landfills. Most new wet FGD systems utilize a forced oxidation system that results in a gypsum by-product that can sometimes be sold into the local gypsum market. If an adequate local gypsum market is not available, the gypsum by-product will require proper disposal.

Second, wet FGD systems will result in greater potential emissions from the following sources:

1. Wet FGD systems use more reactant (e.g., limestone) than do dry systems, therefore the limestone handling system and storage piles will generate more fugitive dust emissions.

2. Wet FGD systems must be located downstream of the unit's particulate control device therefore, dissolved solids from the wet FGD system will be emitted with the wet FGD plume. Wet FGD control systems also generate lower stack temperatures that can reduce plume rise and result in a visible plume.

3. SO_3 remaining in the flue gas will react with moisture in the wet FGD to generate sulfuric acid mist. Sulfuric acid mist is classified as a condensible particulate. Condensable particulates from the wet FGD system can be captured using additional emission controls (for example, wet electrostatic precipitation). However the effectiveness of a wet ESP system on a sub-bituminous fired unit has not been demonstrated and the additional cost of the wet ESP system would significantly increase the cost of SO_2 control.

Third, overall emissions of NO_x, CO, VOC and PM10 will increase with the wet FGD configuration. Auxiliary power requirements for the wet FGD system are greater then the auxiliary power requirements of the dry FGD systems, and will reduce the unit's net plant heat rate. Consequently, heat input to the boiler would need to increase by approximately 1.5% with the wet FGD to achieve the same net plant output. The calculated maximum heat input to the boiler with the dry FGD configuration is 3,801 mmBtu/hr. To achieve the same net output with a wet FGD the maximum heat input would need to increase to approximately 3,858 mmBtu/hr, increasing NOx, CO, PM10, and VOC emissions on a per MW-generated basis.

Alternatively, BEPC could design the proposed unit with wet FGD and reduce the net plant output from 385 MW to approximately 380 MW without an increase in collateral emissions. However, the lost output (approximately 43,800 MW annually) would need to be replaced with power from existing power stations. Most existing power stations emit significantly more pollutants per MW output than the proposed Dry Fork Station.

Finally, Wet FGD systems also require significantly more water than the dry systems. Based on preliminary engineering calculations, it is estimated that a wet FGD system would require at least 30% more water than a dry system, or approximately 200 million gallons per year. Water consumption is an important factor in the viability of the Dry Fork Station, in fact, the station is being designed with an air cooled condensing system to minimize water consumption. Wet FGD systems also generate a wastewater stream that must be treated and discharged.

Dry FGD – Environmental Impacts

Collateral environmental impacts are less significant with dry scrubbing systems (both the spray dryer absorber and circulating dry scrubber). First, dry scrubbing systems utilize lime as the reactant rather than limestone. Lime-based scrubbing systems use less reactant than limestone-based systems, reducing overall particulate matter emission from the facility's material handling system. Although the lime in a dry scrubbing system will be hydrated prior to use, it is estimated, based on preliminary engineering calculations, that a dry system will require approximately 30% less than the water requirements for a wet system. Furthermore, water used to hydrate the lime will be evaporated in the absorber vessel, and a dry FGD should not generate a wastewater stream.

Dry scrubbing systems are located upstream of the unit's particulate control device. FGD solids mixed with fly ash will be captured in the particulate control device. The mixture of dry FGD solids and fly ash is generally not salable, however the material does not require dewatering and is easily landfilled. Assuming the unit is equipped with a fabric filter baghouse for particulate control, the alkaline filter cake associated with the dry scrubber will augment the capture of acid gases (including sulfuric acid), and will minimize condensible particulate emissions.

(f) Expected Variability in the Controlled Emission Rate

Based on technical, economic, and collateral environmental impacts, BEPC is proposing dry FGD as BACT for the Dry Fork Station. Dry FGD has been permitted as BACT for several proposed pulverized coal-fired boilers firing low-sulfur subbituminous coal, including: (1) City of Springfield-Southwest Power Station, Missouri (0.095 lb/mmBtu 30-day average); (2) Comanche Unit 3, Colorado (0.10 lb/mmBtu 30-day average); (3) Wygen Unit 2, Wyoming (0.10 lb/mmBtu 30-day average; and (4) MidAmerican Council Bluffs Unit 4, Iowa (0.10 lb/mmBtu 30-day average). None of the units listed above have been built or commenced operation.

The most stringent 30-day average SO_2 limit recently permitted as BACT for a facility equipped with a dry scrubbing system that has begun operation is 0.12 lb/mmBtu at the Hawthorne Generating Station in Missouri. The Hawthorne permit requires the facility to burn only low-sulfur subbituminous coals with a maximum sulfur content of 0.65%, and SO_2 emissions are controlled with an SDA. Hourly SO_2 emissions from Hawthorne Unit 5 for the time period January 1, 2004 through March 31, 2005 were summarized in Figure 2. During that time period, Hawthorne Unit 5 achieved an average SO_2 emission rate of 0.099 lb/mmBtu with a standard deviation of 0.012 lb/mmBtu (30-day rolling average). The data also show that variability in the controlled SO_2 emission rate increased with shorter averaging times. For example, the standard deviation in the controlled emission rate on a 24-hour average was 0.052 lb/mmBtu.

(g) Conclusions

Based on information available from FGD vendors, emission rates achieved in practice by existing sources, economic impacts, and engineering judgment, BEPC is proposing dry scrubbing (SDA or CDS) with a controlled SO_2 emission rate of 0.10 lb/mmBtu as BACT for Dry Fork Unit 1. An SO_2 ~~emission limit of 0.10 lb/mmBtu (30-day rolling average) appears to be both technically and~~ economically feasible, and will require the unit to achieve a control efficiency of approximately 92% (based on the worst-case design coal), which is very close to the design limits of the equipment. To ensure compliance, the dry scrubbing system proposed by BEPC will have to be designed to achieve a target emission rate below 0.10 lb/mmBtu under all normal operating conditions.

Dry scrubbing systems have proven to be very reliable, however, like all emission control systems, dry scrubbing systems take time to respond to process changes and allowances must be made for routine maintenance and repairs. As discussed above, variability in the controlled SO_2 emission rate will increase with shortened averaging times. No information is available specifically describing causes of the short-term increases in the controlled SO_2 emission rate. However, based on information available from equipment vendors, short-term variations in the controlled emission rate are likely due (at least in part) to changes in sulfur content of the fuel, boiler load changes, atomizer change-outs, and short-term equipment failures (e.g., pumps, plugging, etc).

Dry Fork Unit 1 will be designed to proactively identify processes that may cause short-term increases in the controlled SO_2 emission rate. For example, Dry Fork Unit 1 will be designed with coal sampling/testing systems that will allow the facility to identify short-term increases in the fuel sulfur content, and the ability to blend incoming fuel to minimize short-term increases in SO_2 loading to the dry scrubbing system. The dry scrubbing system will also be specified to include advanced process control systems to minimize response time to process changes, and the facility will implement comprehensive inspection/maintenance programs to minimize the frequency of unplanned equipment failures. These systems and procedures should minimize the short-term variability in the controlled SO_2 emission rate, however, it is anticipated that the short-term SO_2 emission rate (e.g., 3-hour average) will continue to show more variability than the 30-day rolling average. To account for short-term variability in the controlled SO_2 emission rate, BEPC is proposing an average 3-hour SO_2 emission rate of 380.1 lb/hr. This emission limit is based on a maximum heat input to the boiler of 3,801 mmBtu/hour and a controlled SO_2 emission rate of 0.10 lb/mmBtu. Establishing a mass-based short-term emission limit will allow BEPC to respond to short-term excursions associated with fuel sulfur content, boiler load changes, and routine equipment maintenance and repairs.

The proposed BACT emission limits (0.10 lb/mmBtu 30-day average and 380.1 lb/hr 3-hour average) will ensure that the Dry Fork Unit 1 dry scrubbing system will be operated in such a way as to continuously achieve a high control efficiency, while providing a reasonable margin to allow the system to respond to routine operating and process changes. The proposed emission rates will require state-of-the-art SO_2 control and are consistent with other recently permitted PC units.

Attachment 2

ATTACHMENT NO. 2

Response to WDEQ's Completeness Review Dated December 21, 2005

WDEQ Comment 2: *Basin Electric proposed low NOx burners, overfire air, and SCR with an emission limit of 0.07 lb/MMBtu, 30-day average as BACT. An analysis of the technical feasibility and cost effectiveness is required for emission levels of 0.05 and 0.06 lb/MMBtu, 30-day average.*

Response: In the Permit Application, BEPC evaluated the potential feasibility of several NOx control systems and concluded that combustion controls (including low NOx burners and overfire air) coupled with selective catalytic reduction (SCR) represented the most effective technically feasible NOx control systems for Dry Forks Unit 1 (see, section 5.2.4 of the Permit Application). Based on BACT emission rates included in recently issued PSD permits for large subbituminous coal-fired boilers, BEPC proposed a controlled NOx emission rate of 0.07 lb/mmBtu (30-day average).

SCR involves injecting ammonia into boiler flue gas in the presence of a catalyst to reduce NO_x to N_2 and water. The overall SCR reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 4NO_2 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

The performance of an SCR system is influenced by several factors including flue gas temperature, SCR inlet NO_x level, the catalyst surface area, volume and age of the catalyst, and the amount of ammonia slip that is acceptable.

The optimal temperature range for NOx reduction depends on the type of catalyst used, but is typically between 560 °F and 800 °F. This temperature range typically occurs between the economizer and air heater in a large utility boiler. Below this range, ammonium sulfate is formed resulting in catalyst deactivation. Above the optimum temperature, the catalyst will sinter and thus deactivate rapidly. Another factor affecting SCR performance is the condition of the catalyst material. As the catalyst degrades over time or is damaged, NO_x removal decreases.

SCR is a relatively new control technology, and there are limited operating data available to evaluate the long-term effectiveness of SCR on subbituminous-fired PC units. KCPL's Hawthorne Unit 5 (Missouri) is a new subbituminous coal-fired boiler equipped with SCR for NO_x control. The unit was permitted in August 1999 and began actual operation around May 2001. SCR has also been installed on subbituminous-fired PC units at the W.A. Parish Generating Station in Houston, Texas. The Parish Station is located in the Houston/Galveston severe ozone non-attainment area. Parish Units 5 and 6 are tangentially fired boilers, and were retrofit with low-NOx burners and SCR to achieve stringent NOx emission limits imposed by the Houston/Galveston Area Ozone SIP. The SCR systems for Units 5 and 6 went into service in April 2003 and January 2003, respectively.

Table 1 summarizes the average NOx emission rates reported by Hawthorn Unit 5, Parish Unit 5, and Parish Unit 6 to the U.S.EPA pursuant to the federal Acid Rain Program. Table 1 includes an evaluation of the variability of the controlled NOx emission rate as a function of averaging time. Figures 1, 2, and 3 show the hourly NOx emission rates reported by each unit and the calculated 30-day rolling averages.

Table 1
NOx Emission Rates and Variability at Hawthorn Unit 5, Parish Unit 5, and Parish Unit 6

Unit / SCR Startup Date	NOx Emissions Data Evaluated Between the Dates:	Average Hourly NOx Emission Rate	Standard Deviation*	Hourly/30-Day Emission Rate Achieved at 95% Confidence Interval**
		(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)
Hawthorn Unit 5 May 2001	July 1, 2004 to March 31, 2005	0.072	0.009 (hourly) 0.0044 (24-hour) 0.0032 (30-day)	0.09 (hourly) 0.081 (24-hour) 0.078 (30-day)
Parish Unit 5 April 2003	June 1, 2003 to June 30, 2005	0.039	0.0136 (hourly) 0.0096 (24-hour) 0.0068 (30-day)	0.066 (hourly) 0.058 (24-hour) 0.053 (30-day)
Parish Unit 6 January 2003	June 1, 2003 to June 30, 2005	0.041	0.0162 (hourly) 0.0123 (24-hour) 0.0094 (30-day)	0.073 (hourly) 0.066 (24-hour) 0.060 (30-day)

* NOx emissions data for the hourly, 24-hour, and 30-day rolling average NOx emission rates were evaluated for normal distribution, and variation in the data was evaluated by calculating the standard deviation for each averaging period.

** The 95% confidence level for each averaging period was calculated based on the average emission rate plus two standard deviations.

DEQ/AQD 000727

Figure 1
KCPL Hawthorn Unit 5
Hourly NOx Emission Rates 6/1/2004 – 3/31/2005

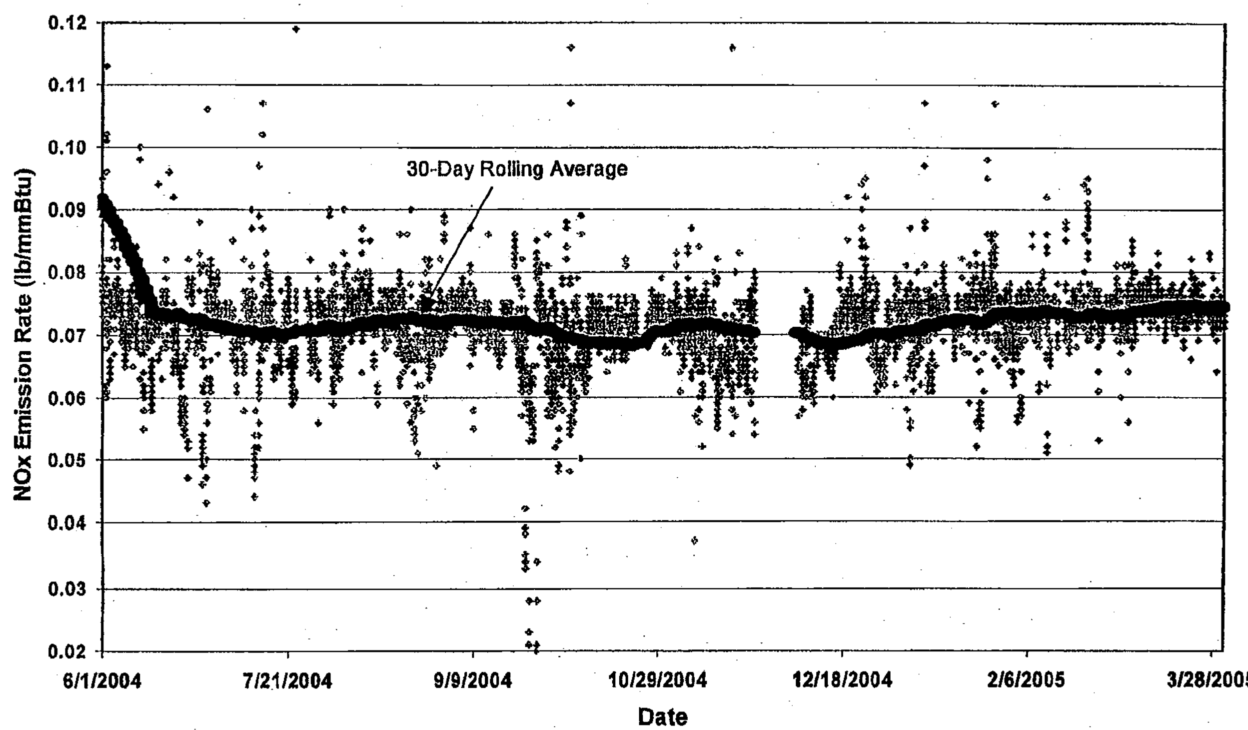
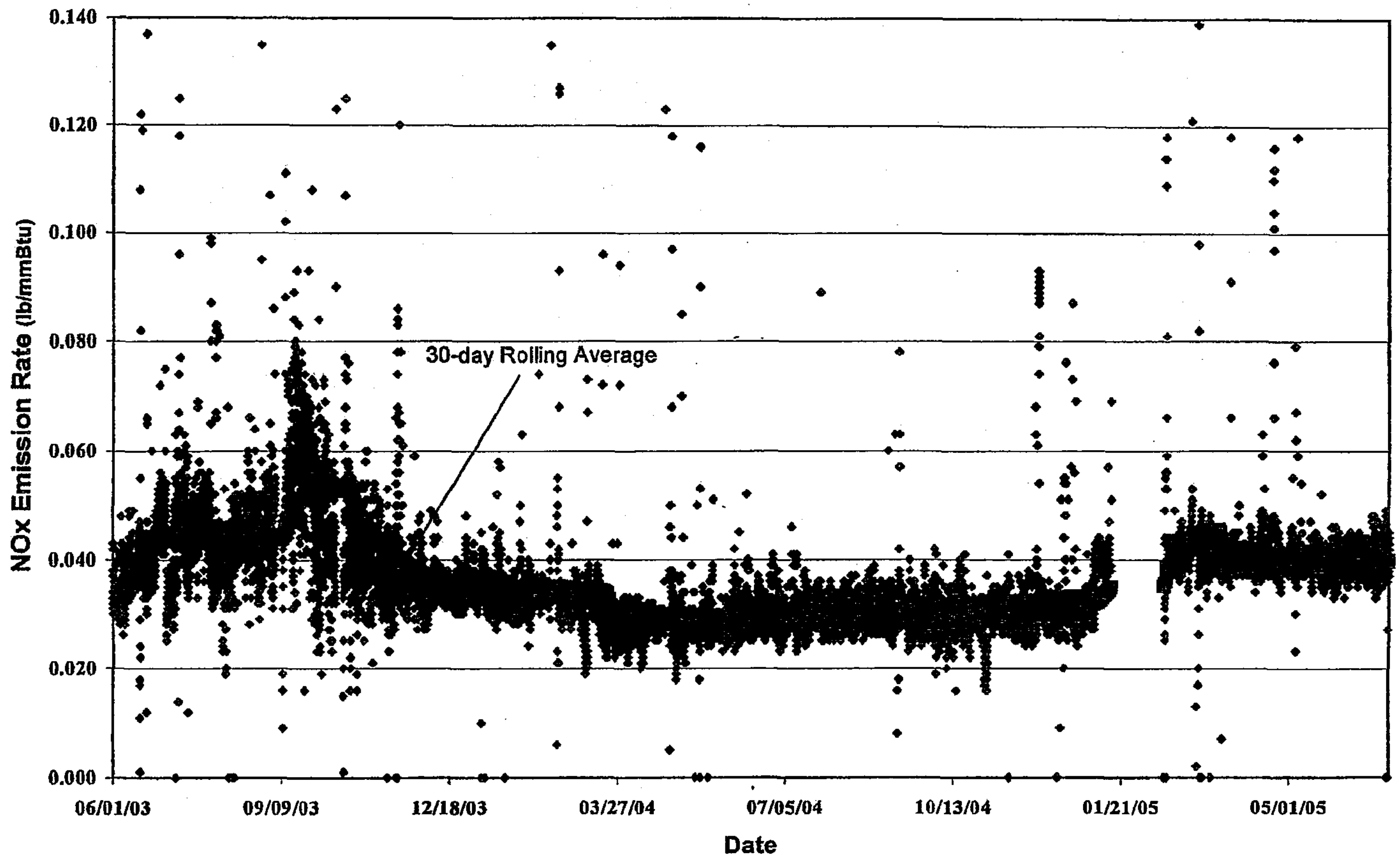
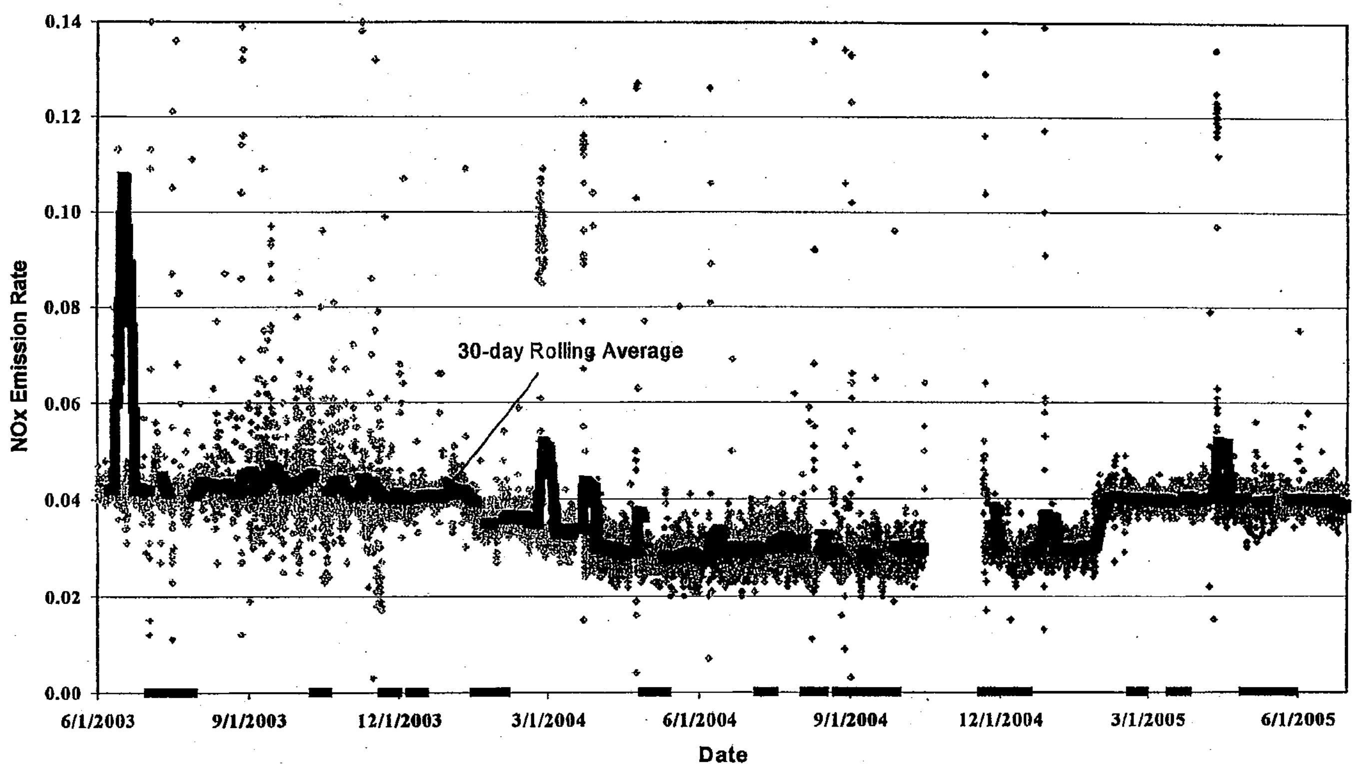


Figure 2
Parish Unit 5
Hourly NOx Emission Rates 6/1/2003 – 6/30/2005



DEQ/AQD 000729

Figure 3
Parish Unit 6
Hourly NOx Emission Rates 6/1/2003 – 6/30/2005



The Parish units have demonstrated the ability to achieve very stringent NOx emission rates. Between June 1, 2004 and June 30, 2005, Parish Units 5 and 6 achieved average NOx emission rates of 0.039 and 0.041 lb/mmBtu, respectively. Both Parish units have shown variability in the controlled NOx emission limit, as would be expected with any emissions control system. Based on standard deviation calculations, Parish Unit 5 has consistently achieved an average controlled NOx emission rate below 0.058 lb/mmBtu (24-hour average) about 95% of the time, and below 0.053 lb/mmBtu (30-day rolling average). Parish Unit 6 has achieved average NOx emission rates of 0.066 lb/mmBtu (24-hour average) and 0.060 lb/mmBtu (30-day average) about 95% of the time. The SCR systems for Parish Units 5 and 6 were designed to use four layers of catalyst, with three installed initially and the fourth installed after two years of operation. The systems were designed to operate year-round in two-year cycles.[1]

Since July 1, 2004, Hawthorn Unit 5 has also demonstrated the ability to achieve stringent NOx emission rates, and variability in the controlled NOx emission rate at Hawthorn Unit 5 is similar to the variability seen at Parish Units 5 and 6. Between July 1, 2004 and March 31, 2005, Hawthorn Unit 5 achieved an average NOx emission rate of 0.072 lb/mmBtu, and achieved controlled NOx emission rates below 0.081 lb/mmBtu (24-hour average) and 0.078 lb/mmBtu (30-day average) about 95% of the time.

Several design variables will influence the performance of the SCR system, including the volume, age and surface area of the catalyst (e.g., catalyst layers), uncontrolled NO_x emission rate, flue gas characteristics, and catalyst activity.[2] Catalyst that has been in service for a period of time will have decreased performance because of normal deactivation and deterioration. Catalyst that is no longer effective due to plugging, blinding or deactivation must be replaced. Catalyst deterioration and deactivation is a function of the flue gas characteristics. As stated above, there is limited operating history describing exactly how flue gas generated from burning subbituminous coals will affect catalyst life and overall SCR performance.

Based on NO_x emission rates reported to EPA from existing subbituminous-fired units, it can be concluded that the lowest achievable emission rate (LAER) for NOx is approximately 0.056 lb/mmBtu (30-day average). The LAER emission rate is based on the average 30-day NOx emission rate achieved using a 95% confidence level at Parish Units 5 and 6, which are both located in the Houston/Galveston severe ozone non-attainment area. The site-specific NOx emission rate for a subbituminous-fired PC unit equipped with SCR may be greater than 0.056 lb/mmBtu depending on site-specific boiler design, flue gas characteristics, operating practices, and the incremental costs

[1] See, Power Magazine, "W.A. Parish Electric Generation Station, Thompson, Texas," August 15, 2004.

[2] See, e.g., Sanyal, A., Pircon, J.J., "What and How Should You Know About U.S. Coal to Predict and Improve SCR Performance", proceedings of the USEPA, DOE, EPRI, Combined Power Plant Air Pollution Control Mega Symposium, Chicago, IL, August 2001. See also, Gutberlet, H., Schluter, A., Licata, A., "Deactivation of SCR Catalyst", proceedings of the DOE's 2000 Conference on Selective Catalytic and Selective Non-Catalytic Reduction for NOx Control, Pittsburgh, PA, 2000.

associated with achieving LAER.[3] Costs associated with achieving LAER may include a larger SCR control system, additional layers of catalyst, larger ammonia delivery system, increased ammonia use, and more frequent catalyst changes.

Cost estimates were developed for SCR control systems designed to achieve controlled NOx emission rates between 0.056 lb/mmBtu (LAER) and 0.09 lb/mmBtu. Capital costs were based on U.S.EPA's Coal Utility Environmental Cost (CueCost) cost estimating worksheets.[4] O&M costs were calculated using guidelines in U.S.EPA's OAQPS Control Cost Manual[5] and fixed and variable O&M calculations. Table 2 summarizes the inputs used to develop the capital and O&M cost estimates for the SCR control systems.

Table 2
SCR Capital Cost and O&M Cost Variables

Variable	**Units**	**Case 1 0.09 lb/mmBtu**	**Case 2 0.08 lb/mmBtu**	**Case 3 0.07 lb/mmBtu**	**Case 4 0.06 lb/mmBtu**	**Case 5 0.056 lb/mmBtu**
Space Velocity Used to Estimate Catalyst Volume	$1/ft^3$	6700	6533	6365	6097	5695
NH_3/NOx Stoichiometric Ratio	ratio	1.0	1.1	1.2	1.4	1.5
NOx Emission Rate to SCR	lb/mmBtu	0.3	0.3	0.3	0.3	0.3
Controlled NOx Emission Rate	lb/mmBtu	0.090	0.080	0.070	0.060	0.056
Overall Catalyst Life	years	4.0	3.5	3.0	2.5	2.0
Ammonia Cost	$/ton	$400	$400	$400	$400	$400
Catalyst Cost	$\$/ft^3$	$195	$195	$195	$195	$195

[3] See, Cichanowicz, J.E., Smith, L.L., "SCR Performance Analysis Hints at Difficulty in Achieving High NOx Removal Targets", Power Engineering, November 2002.

[4] Coal Utility Environmental Cost (CUECost) Workbook User's Manual, Version 1.0, Prepared for the U.S. ~~Environmental Protection Agency, EPA Contract No. 68-D7-0001.~~

[5] OAQPS Control Cost Manual, U.S.EPA, EPA-450/3-90-006, January 1990.

The maximum annual NOx emission rates associated with each level of NOx control are summarized in Table 3. Table 4 presents the capital costs and annual operating costs associated with building and operating each SCR system, based on the cost variables summarized in Table 2. Table 5 shows the average annual and incremental cost effectiveness for each controlled emission rate. The average cost effectiveness calculations and incremental cost effectiveness calculations are depicted graphically in Figures 4 and 5, respectively.

Table 3
Annual NOx Emissions

Control Technology	NOx Emissions (lb/mmBtu)	Maximum Annual Emissions (tpy)*	Annual Emission Reductions (tpy from base case)*
Case 5 - 0.056 lb/mmBtu LAER	0.056	932	4,062
Case 4 – 0.06 lb/mmBtu	0.06	999	3,663
Case 3 – 0.07 lb/mmBtu	0.07	1,165	3,849
Case 2 – 0.08 lb/mmBtu	0.08	1,332	3,663
Case 1 – 0.09 lb/mmBtu	0.09	1,498	3,496
Baseline – Combustion Controls (LNB + OFA)	0.30	4.995	na

* Maximum annual emissions, and annual emission reductions for this analysis are based on a maximum heat input of 3,801 mmBtu/hr and 8,760 hours per year.

Table 4
NOx Emission Control System
Cost Summary

Control Technology	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)
Case 5 - 0.056 lb/mmBtu LAER	$30,047,700	$2,836,300	$5,839,600	$8,675,900
Case 4 – 0.06 lb/mmBtu	$28,176,900	$2,659,700	$4,830,300	$7,490,000
Case 3 – 0.07 lb/mmBtu	$25,086,000	$2,367,900	$3,921,400	$6,289,300
Case 2 – 0.08 lb/mmBtu	$24,398,500	$2,303,000	$3,577,000	$5,880,000
Case 1 – 0.09 lb/mmBtu	$23,881,900	$2,254,300	$3,340,700	$5,595,000

Table 5
NOx Emission Control System
Average and Incremental Cost Effectiveness

Control Technology	Total Annual Cost ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)	Incremental Emission Reductions (tpy)	Incremental Annual Cost Effectiveness ($/ton)
Case 5 - 0.056 lb/mmBtu LAER	$8,675,900	4,062	$2,140	67	$17,810
Case 4 – 0.06 lb/mmBtu	$7,490,000	3,663	$1,870	166	$7,210
Case 3 – 0.07 lb/mmBtu	$6,289,300	3,849	$1,640	166	$2,460
Case 2 – 0.08 lb/mmBtu	$5,880,000	3,663	$1,610	166	$1,710
Case 1 – 0.09 lb/mmBtu	$5,595,000	3,496	$1,600	–	na

Figure 4
Average Cost Effectiveness of SCR at Various Controlled Emission Rates

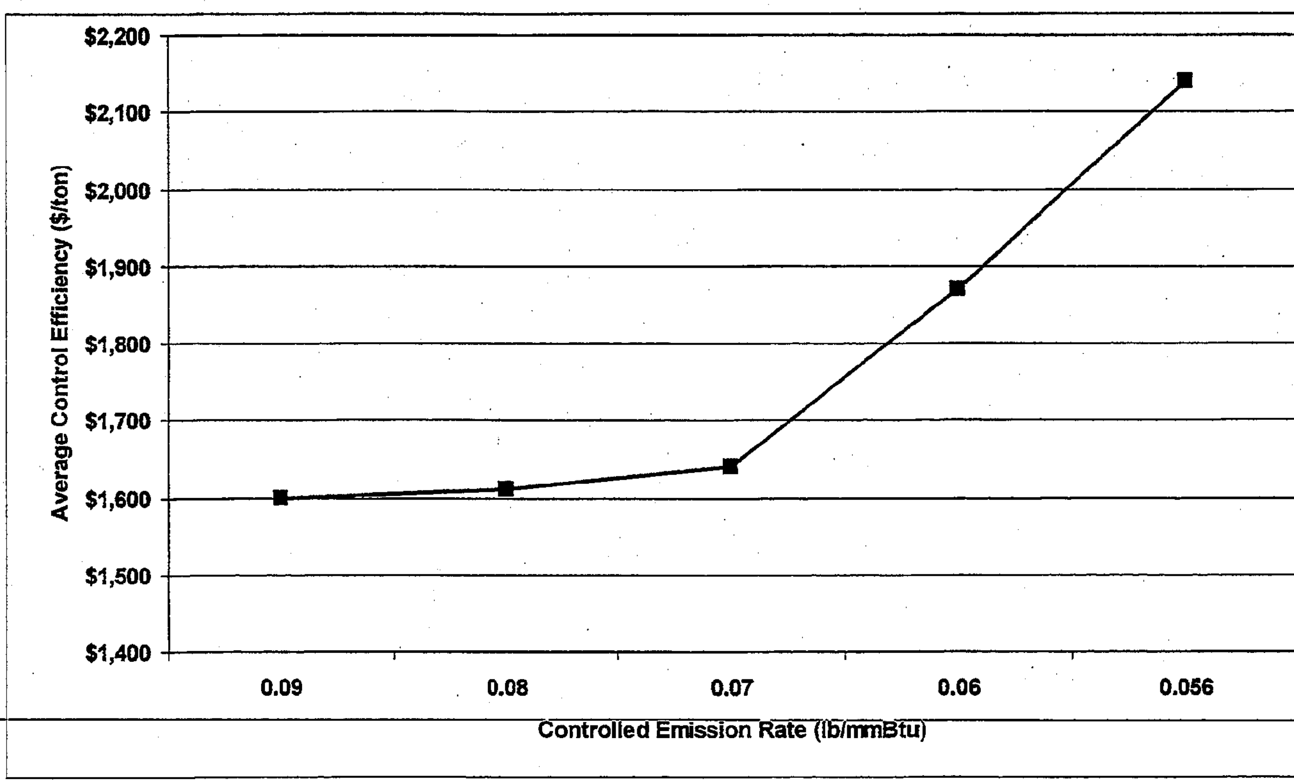
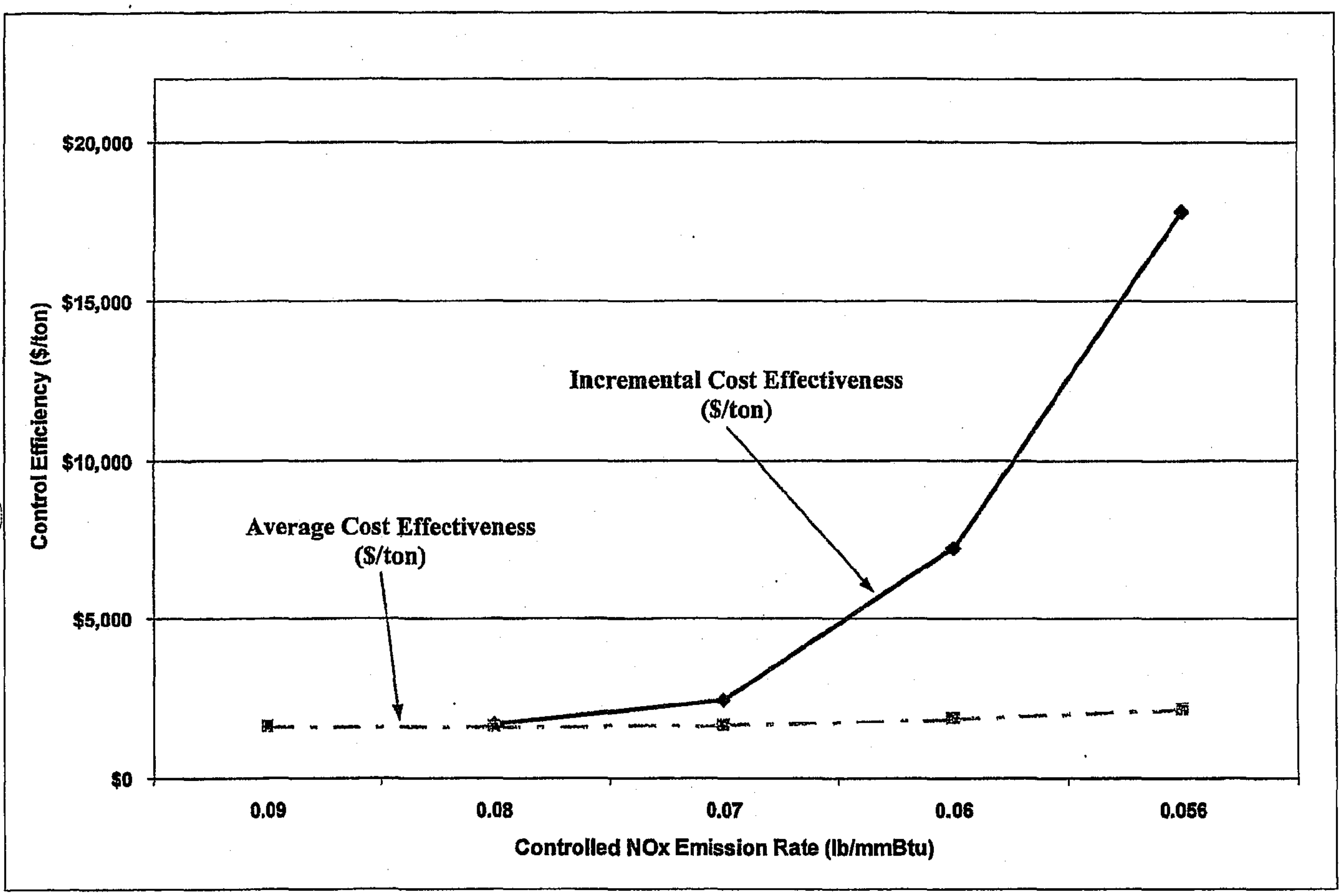


Figure 5
Incremental Cost Effectiveness of SCR at Various Controlled Emission Rates



SCR control systems become increasingly less cost effective as the controlled NOx emission rate becomes more stringent (see, Figure 4). Factors affecting the cost effectiveness of an SCR system include both capital requirements and O&M. Figure 4 also shows that the rate of change in the average cost effectiveness continues to increase as the controlled NOx emission rate becomes more stringent, especially below a controlled NOx emission rate of approximately 0.07 lb/mmBtu.

The average cost effectiveness of SCR varies between approximately $1,600/ton at 0.09 lb/mmBtu and $2,140/ton at 0.056 lb/mmBtu. Although LAER emission rates appear to be economically feasible based on the average cost effectiveness calculation, average cost effectiveness may not accurately describe economic impacts on the project because of the large quantity of NOx removed under each SCR scenario. The SCR control system will reduce annual NOx emissions by approximately 3,800 tons/year. Because of the large quantity of NOx removed under any SCR scenario, it is appropriate to evaluate the incremental cost effectiveness associated with achieving more stringent NOx emission rates.[6]

The incremental costs associated with achieving more stringent NOx emission rates significantly increase below a controlled NOx rate of approximately 0.07 lb/mmBtu. Between 0.08 and 0.07 lb/mmBtu the incremental cost is estimated to be approximately $2,460/ton, or approximately 50% greater than the average cost effectiveness. Between 0.07 and 0.06 lb/mmBtu the incremental cost effectiveness increases to approximately 3.4 times the average cost effectiveness, or $7,210/ton. The incremental cost associated with achieving a controlled NOx emission rate equivalent to LAER (0.056 lb/mmBtu) is estimated to be approximately $17,810/ton. Both capital costs and annual operating costs have a significant impact on the cost effectiveness of an SCR control system. The most significant annual operating costs associated with the SCR include increased ammonia costs associated with the lower NOx emission rates, and increased catalyst replacement costs associated with more frequent catalyst changes.

A permit limit below 0.07 lb/mmBtu would eliminate almost all the margin between recently proposed design targets for an SCR system and the permit limit. The BACT emission limit established during the initial permitting process will be enforceable over the life of the unit. As a result, the BACT analysis must take into account the full range of possible fuels, operating conditions, operating system fluctuations, and normal wear-and-tear on the units and control systems. The U.S.EPA Environmental Appeals Board has recognized that "permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather will allow permittees to achieve compliance on a consistent basis." See, Three Mountain Power, PSD Appeal No. 01-05 at 21 (May 30, 2001), citing: In re Masonite Corp., 5 E.A.D. 560-61 (EAB 1994) ("There is nothing inherently wrong with setting an emission limitation that takes into account a reasonable safety factor."); and In re Knauf Fiber Glass, GmbH, PSD Appeal Nos. 99-8 to –72, slip op. at 21 (EAB, Mar. 14, 2000) ("The inclusion of a reasonable safety factor in the emission limitation is a legitimate method of deriving a specific emission limitation that may not be exceeded.").

All recently permitted PC boilers have been permitted with combustion controls and SCR as BACT. Of the PC boilers that have recently been constructed and begun operation, the most stringent NO_x emission rate is 0.08 lb/mmBtu at the Hawthorne facility in Missouri.[7] Since July 1, 2004,

[6] See, NSR Review Manual: "In addition to the average cost effectiveness of a control option, incremental cost effectiveness between dominant control options should also be calculated. The incremental cost effectiveness should be examined in combination with the average cost effectiveness in order to justify elimination of a control system." page B.41. "A comparison of incremental costs can be useful in evaluating a specific control option over a range of efficiencies. For example, depending on the capital and operational costs of a control device, total and incremental cost may vary significantly (either increasing or decreasing) over the operation range of a control device." page B.43.

[7] The Hawthorne facility was permitted to operate with a NOx emission rate of 0.12 lb/mmBtu for the first three years of operation. During that time, the facility was required to determine the feasibility of achieving a lower

Hawthorne Unit 5 has maintained a controlled NOx emission rate of 0.078 lb/mmBtu on a 30-day rolling average (see, Figure 1). The lowest NO_x emission limit identified for any proposed, but not yet constructed, pulverized coal unit is 0.069 lb/mmBtu (30-day rolling average) for the City Public Service Spruce Unit 2 (Texas). Roundup Units 1 and 2 (Montana), Council Bluffs Unit 4 (Iowa), Intermountain Power Unit 3 (Utah), and Wygen Unit 2 (Wyoming) have recently been permitted at 0.07 lb/mmBtu. Xcel Comanche Unit 3 (Colorado) and City Utilities of Springfield (Missouri) were recently permitted with a NO_x emission limit of 0.08 lb/mmBtu (30-day rolling average).

Based on technical feasibility, physical limitations of the control system, emissions achieved in practice at existing sources, and economic impacts, BEPC is proposing an emission rate of 0.07 lb/mmBtu (30-day average) as BACT for NOx control. Reducing the permitted NOx emission rate below 0.07 lb/mmBtu would eliminate almost all margin between the design target of the control system and the permit limit. Furthermore, the incremental cost effectiveness associated with reducing NOx emissions from 0.07 to 0.06 lb/mmBtu is calculated to be $7,210/ton, which is more then three times the average cost effectiveness of NOx control at Dry Fork Unit 1.

Finally, there are collateral environmental issues associated with using an SCR system, including ammonia slip emissions, the potential formation of ammonia salts, catalyst disposal and increased SO_2 to SO_3 conversion in the flue gas. These environmental impacts tend to increase as the controlled NOx emission rate is pushed lower. For example, lower NOx emission rates are typically associated with increased ammonia slip, increased SO_2 to SO_3 conversion, and increased condensible particulate matter emissions. More stringent NOx emission rates will also require more frequent catalyst changes, increasing the quantity of spent catalyst requiring storage, treatment and disposal.

NOx emission rate (0.08 lb/mmBtu) on a consistent basis while remaining in compliance with all other permitted emission limits (e.g., CO and VOC).

Attachment 3

ATTACHMENT NO. 3

Response to WDEQ's Completeness Review Dated December 21, 2005

WDEQ Comment 3: *Basin Electric proposed fabric filters with an emission limit of 0.012 lb/MMBtu, 3-hour average. An analysis of the technical feasibility and cost effectiveness is required for emission levels of 0.009, 0.01, and 0.011 lb/MMBtu, 3-hour average.*

Response: In the Permit Application, BEPC evaluated the potential feasibility of both electrostatic precipitation (ESP) control systems and fabric filter baghouse systems. Based on a technical review of each particulate matter (PM) control system, and BACT emission limits included in recently issued PSD permits for coal-fired power plants, BEPC concluded that the fabric filter baghouse represented the most effective PM_{10} control device, and proposed a controlled PM_{10} (filterable) emission rate of 0.012 lb/mmBtu (3-hour average).

Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Fabric filters use fabric bags as filters to collect particulate matter. The particulate-laden gas enters a fabric filter compartment and passes through a layer of filter bags. The collected particulate forms a cake on the bag that enhances the bag's filtering efficiency. Excessive caking will increase the pressure drop across the fabric filter at which point the filters must be cleaned.

The particulate removal efficiency of fabric filters is dependent upon a variety of particle and operational characteristics. Particle characteristics that affect the collection efficiency include particle size distribution, particle cohesion characteristics, and particle electrical resistivity. Operational parameters that may affect fabric filter collection efficiency include bag material, air-to-cloth ratio, and operating pressure loss.

Fabric-filters have relatively constant outlet emissions while exhibiting varying pressure drops dependent upon the degree of cake thickness. As the flue gas passes through the fabric, the captured particulate forms a cake on the surface of the fabric. This deposit increases both the filtration efficiency and its resistance to gas flow. Therefore, for continuous operation, a fabric-filter must have some mechanism for periodic cleaning of the deposited cake. Cleaning mechanisms include reverse-air systems and pulse-jet systems. The cleaning mechanism is frequently used to describe the type of fabric filter. BEPC proposed a pulse jet baghouse following the dry flue gas desulfurization system for Dry Fork Unit 1.

Fabric specifications include such properties as tensile strength, abrasion resistance, chemical attack resistance and limitations of operating temperature. Synthetic fibers are typically used because they can operate at higher temperatures and more effectively resist chemical attack. The synthetic fiber most used for high temperature applications (i.e., 400 °F to 500 °F) is fiberglass. For low temperature applications below approximately 200 °F, such as dry FGD systems and coal crushers, polypropylene is often used. For power plant applications, with typical air heater outlet temperatures around 300 °F, other registered trademark fibers such as Teflon, Fiberglas, Ryton, and P84 have also been used. Most of the baghouses currently operating on coal fired utility boilers use bags made with Fiberglas or Ryton. Ryton is a felted filter made of polyphenylene sulfide fibers generally attached to a polyfluorocarbon scrim. Ryton can operate at continuous temperatures of 370 °F or less, and shows good resistance to acids and alkalis. Fiberglas, Teflon, Nomex and Ryton have been used to remove particulate emissions generated from industrial and utility coal-fired boilers. Another material used to make bags is Gore-tex membrane. The Gore-tex membrane is an expanded polytetrafluoroethylene (PTFE) membrane that is laminated with a variety of fibers such as Fiberglas to produce felt and woven filters. Pulse-jet baghouse vendors typically specify either PPS or P84 bag material. Other fabric materials may not be suitable because of the more aggressive cleaning system associated with a pulse-jet baghouse.

Overall fabric filter system designs involve the selection of the cleaning mechanism and type of fabric to be used for a particular service. When assessing emission control limits of fabric filters, the issue of mechanical integrity of the filter housing (e.g., welds, seams, bag hangers, and connections) may become just as important as the filter fabric. As specialty fabrics reduce the flow or particulates through the fabric, the relative importance of particulate emissions due to compromises in the integrity of the filter housing (e.g., failed welds, cracks, loose bag hangers, etc) becomes more pronounced.

Based on engineering experience, it is expected that a properly sized and operated fabric filter should consistently achieve a filterable PM_{10} emission rate below 0.015 lb/mmBtu, and may achieve actual emission rates in the range of 0.010 lb/mmBtu. However, because of the potential for increased particulate emissions immediately following a cleaning cycle (i.e., before the filter cake is re-established), and because of the potential for particulate emissions associated with filter housing integrity, fabric filter vendors have not provided guarantees below 0.012 lb/mmBtu. Based on recent coal-fired boiler projects, the most stringent guaranteed PM_{10} emission rate available is in the range of 0.012 lb/mmBtu. Furthermore, to guarantee an emission rate below approximately 0.012 lb/mmBtu, it is likely that the fabric filter vendors will specify the use of specialty filter bags such as PTFE membrane bags. These specialty bags are more expensive but should provide slightly higher control efficiencies. Between controlled emission rates of 0.015 and 0.012 lb/mmBtu it appears that several commercially available fabrics could be used successfully to ensure compliance.

This evaluation is based on the following assumptions: (1) guarantees for a controlled emission rate below 0.010 lb/mmBtu are not currently available; (2) controlled emission rates of 0.010 and 0.011 lb/mmBtu would be technically feasible, however, to ensure compliance with these emission rates the baghouse vendor would specify specialty membrane filter bags; and (3) controlled emission rates between 0.012 and 0.015 lb/mmBtu are technically feasible, and compliance with these emission rates could be achieved using a variety of commercially available fabrics.

Summarized in Table 1 are the maximum annual PM_{10} mass emissions associated with each technically feasible PM_{10} emission rate. Table 2 presents the capital costs and annual operating costs associated with building and operating each fabric filter control system. Table 3 shows the average annual cost effectiveness and incremental cost effectiveness of the fabric filter control systems.

Table 1
Annual PM_{10} Emissions

Control Technology	PM_{10} Emissions (lb/mmBtu)	Maximum Annual Emissions (tpy)*	Annual Emission Reductions (tpy from base case)*
Fabric Filter @ 0.009 lb/mmBtu	0.009	NA (emission rate not commercially available)	NA (emission rate not commercially available)
Fabric Filter @ 0.010 lb/mmBtu (Specialty membrane bags)	0.010	166	31,743
Fabric Filter @ 0.011 lb/mmBtu (Specialty membrane bags)	0.011	183	31,726
Fabric Filter @ 0.012 lb/mmBtu (Ryton or equivalent bags)	0.012	200	31,709
Fabric Filter @ 0.013 lb/mmBtu (Ryton or equivalent bags)	0.013	216	31,693
Fabric Filter @ 0.014 lb/mmBtu (Ryton or equivalent bags)	0.014	233	31,676
Baseline Emissions** (No Control)	1.92	31,909	-

* Maximum annual emissions, and annual emission reductions were calculated based on a maximum heat input to the boiler of 3,801 mmBtu/hr and 100% capacity factor.

** Baseline PM_{10} emissions were calculated based on the following assumptions: (1) maximum heat input to the boiler of 3,801 mmBtu/hr; (2) fuel heating value of 7,800 Btu/lb; (3) maximum ash content of 6.5%; (4) 80:20 split between fly ash and bottom ash; and (5) 23% of the potential PM emissions were PM_{10} (AP-42 Table 1.1-6).

Table 2
PM_{10} Emission Control System
Cost Summary

Control Technology	Total Capital Investment ($)	Total Capital Investment ($/kW-net)	Annual Capital Recovery Cost ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)
Fabric Filter @ 0.010 lb/mmBtu (Specialty membrane bags)	$40,811,390	$106.0	$3,852,300	$3,410,500	$7,262,800
Fabric Filter @ 0.011 lb/mmBtu (Specialty membrane bags)	$40,719,990	$105.8	$3,843,700	$3,247,400	$7,091,100
Fabric Filter @ 0.012 lb/mmBtu (Ryton or equivalent bags)	$38,372,990	$99.7	$3,622,100	$2,594,500	$6,216,600
Fabric Filter @ 0.013 lb/mmBtu (Ryton or equivalent bags)	$38,281,490	$99.4	$3,613,500	$2,536,400	$6,149,900
Fabric Filter @ 0.014 lb/mmBtu (Ryton or equivalent bags)	$38,194,590	$99.2	$3,605,300	$2,476,100	$6,081,400
Baseline Emissions** (No Control)					

Table 3
PM_{10} Emission Control System
Cost Effectiveness

Control Technology	Total Annual Cost ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)	Incremental Annual Cost Effectiveness* ($/ton)
Fabric Filter @ 0.010 lb/mmBtu (Specialty membrane bags)	$7,262,800	31,743	$229	$10,100
Fabric Filter @ 0.011 lb/mmBtu (Specialty membrane bags)	$7,091,100	31,726	$224	$51,441
Fabric Filter @ 0.012 lb/mmBtu (Ryton or equivalent bags)	$6,216,600	31,709	$196	$4,169
Fabric Filter @ 0.013 lb/mmBtu (Ryton or equivalent bags)	$6,149,900	31,693	$194	$4,029
Fabric Filter @ 0.014 lb/mmBtu (Ryton or equivalent bags)	$6,081,400	31,676	$192	--

* Incremental cost effectiveness was calculated by comparing each control technology with the next most stringent control technology, and dividing the incremental increase in the Total Annual Cost by the incremental decrease in annual PM10 emissions.

The average cost effectiveness of the fabric filter system varies between approximately \$192/ton and \$229/ton. The average cost effectiveness is low because of the large quantity of particulate matter removed by the system (greater than 31,500 tons per year).. Because all of the potentially feasible fabric filter control systems remove large quantities of particulate matter, it is appropriate to evaluate the incremental cost effectiveness of the fabric filter systems designed to achieve more stringent emission limits.[1]

The incremental cost associated with reducing controlled PM_{10} emissions from 0.014 to 0.013 lb/mmBtu and from 0.013 to 0.012 lb/mmBtu is estimated to be approximately \$4,029 and \$4,169/ton, respectively. These costs are significantly higher than the average cost of PM_{10} control at Dry Fork Unit 1, but would not create a significant economic impact because of the relatively small reduction in annual PM_{10} emissions (approximately 17 tons/year). Costs associated with the more stringent PM_{10} emission rates would include a small increase in initial capital cost and a small increase in annual O&M costs.

Below a permit limit of approximately 0.012 lb/mmBtu, it is anticipated that fabric filter vendors would specify the use of specialty bags. Specialty bags represent a significant increase in the initial capital investment and a significant increase in the cost of replacement bags. Assuming specialty bags would be specified, the incremental cost effectiveness associated with reducing PM_{10} emissions from 0.012 to 0.011 lb/mmBtu is estimated to be approximately \$51,441/ton. This incremental cost effectiveness is disproportionately high because of the relatively small increase in emission reductions (approximately 17 tpy) and the relatively large increase in initial capital and O&M costs associated with the specialty bags. The incremental cost effectiveness associated with the more stringent PM_{10} emission limits should preclude specialty bags from consideration as BACT.

Based on technical feasibility, physical limitations of the control system, guaranteed emission rates available from control system vendors, and economic impacts, BEPC is proposing an emission rate of 0.012 lb/mmBtu (3-hour average) as BACT for filterable PM_{10} control.

In addition to potential economic impacts, there may be collateral environmental impacts associated with the membrane filters. The effectiveness of a bag filter increases as the particulate cake builds on the fabric and within the interstitial space of the filtering material. In addition to increasing the filtering effectiveness, the alkaline filter cake captures SO_2, acid gases, and trace constituents including mercury. Once the pressure drop across the filter cake reaches a certain level, the bag is cleaned and the filtering/cake building process starts over. Membrane fabrics will release virtually all of the filter cake during the cleaning cycle, and may not retain a particulate cake within the

[1] See, NSR Review Manual: "In addition to the average cost effectiveness of a control option, incremental cost effectiveness between dominant control options should also be calculated. The incremental cost effectiveness should be examined in combination with the average cost effectiveness in order to justify elimination of a control system." page B.41. "A comparison of incremental costs can be useful in evaluating a specific control option over a range of efficiencies. For example, depending on the capital and operational costs of a control device, total and incremental cost may vary significantly (either increasing or decreasing) over the operation range of a control device." page B.43.

fabric's interstitial space after cleaning. This characteristic of a membrane filter may inadvertently reduce the unit's overall control efficiency of acid gases and mercury.

All recently permitted PC boilers have been permitted with fabric filters as BACT for PM_{10} control. The lowest filterable PM_{10} emission rate designated as BACT is 0.012 lb/mmBtu at Comanche Unit 3 (Colorado) and Wygen Unit 2 (Wyoming). Neither unit has commenced operation or demonstrated the ability to achieve the proposed BACT emission limit on an on-going long-term basis. Several other facilities, including Roundup Units 1 and 2 (Montana) and Intermountain Unit 3 (Utah), have been permitted with a filterable PM_{10} emission rate of 0.015 lb/mmBtu. Because BPEC is proposing a control technology that results in the most stringent controlled emission rate, the use of fabric filters and a controlled PM_{10} emission rate of 0.012 lb/mmBtu should be considered BACT for the proposed boiler.

Attachment 4

Attachment 4
Best Available Control Technology Analysis Auxiliary Boiler and Inlet Gas Heater

A Best Available Control Technology (BACT) analysis review has been conducted for the auxiliary boiler and the inlet gas heater for carbon monoxide (CO), particulate matter (PM), particulate matter less than 10 microns (PM_{10}), volatile organic compounds (VOC), sulfur dioxide (SO_2), and nitrogen oxides (NO_x) in response to the issues requested to be addressed by Wyoming Department of Environmental Quality.

1.1 Pollution Controls

1.1.1 Sulfur Dioxide and Related Compounds

Exclusive use of clean burning natural gas constitutes BACT for this project for the auxiliary boiler and inlet gas heater.

1.1.2 Nitrogen Oxides

NO_x is formed in the boiler in the combustion process. The emissions of NO_x from the auxiliary boiler at Dry Fork will be controlled to BACT levels through the use of Low NO_x Burners (LNB) and flue gas recirculation (FGR). Low NO_x burners control the formation of NO_x by staging the combustion of the natural gas to keep the peak flame temperature below the threshold needed for NO_x formation. LNB control of NOx was also evaluated for the inlet gas heater.

1.1.3 Particulate Matter and PM_{10}

The use of natural gas as the fuel source for the auxiliary boiler and inlet gas heater are BACT for particulate matter and PM_{10}.

1.1.4 Carbon Monoxide and Volatile Organic Compounds

Carbon monoxide (CO) and non-methane volatile organic compounds (VOCs) are formed from the incomplete combustion of the natural gas in the auxiliary boiler and inlet gas heater. The formation of CO and VOCs is limited by controlling the combustion of the fuel and providing adequate oxygen for complete combustion. Thus, good combustion practice is the technique to be used to limit CO and VOC emissions.

1.2 BACT Determination

This section presents the required BACT analyses.

1.2.1 Applicability

The requirement to conduct a BACT analysis and determination is set forth in section 165(a)(4) of the Clean Air Act and in federal regulations 40 CFR 52.21(j).

1.2.2 Top-Down BACT Process

EPA has developed a process for conducting BACT analyses. This method is referred to as the "top-down" method. The steps to conducting a "top-down" analysis are listed in EPA's "New Source Review Workshop Manual," Draft, October 1990. The steps are the following:

- Step 1 – Identify All Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
- Step 3 – Rank Remaining Control Technologies by Control Effectiveness
- Step 4 – Evaluate Most Effective Controls and Document Results
- Step 5 – Select BACT

Each of these steps has been conducted for SO_2, NOx, CO, VOC, PM, and PM_{10} and are described below.

1.2.3 Auxiliary Boiler

1.2.3.1 SO_2 Analysis

Step 1 – Identify All Control Technologies

The first step is to evaluate SO_2 controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RACT/BACT/LAER Clearinghouse (RBLC) database accessible on the Internet. The printout from the database for SO_2 is shown in Attachment 6 Table 5-A. A broad range of other information sources were also reviewed in an effort to identify all potentially applicable emission control technologies.

Potential SO_2 emission reduction options found in the RBLC and other sources that could be applied to the Dry Fork Station auxiliary boiler include:

- Use of clean burning low sulfur fuel (natural gas)
- Good Combustion Practice

Step 2 – Eliminate Technically Infeasible Options

Both of these options are technically feasible for use in reducing SO_2 emissions from the auxiliary boiler at the Dry Fork Station. Based on a maximum total sulfur content in the natural gas of 2,000 grains/10^6 scf, and assuming 100% conversion of the sulfur to SO_2, the maximum SO2 emission rate would be 0.6 lb/mmscf or 0.0006 lb/mmBtu. See, AP-42 Table 1.4-2.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Based on the Step 2 analysis, good combustion practice and use of clean burning fuel are the only technologies for this application.

Step 4 – Evaluate Most Effective Controls and Document Results

No environmental or energy costs are associated with the use of low sulfur fuel or good combustion practices in an auxiliary boiler.

Step 5 – Select BACT

The final step in the top-down BACT analysis process is to select BACT. EPA's RACT/BACT/LAER Clearinghouse (RBLC), a database of past technology decisions, and recently approved PSD permits were again consulted to assist in selecting BACT for this project.

Based on the technology and clearinghouse database discussion above, good combustion practice and use of clean burning fuel in an auxiliary boiler are chosen as the technology to control emissions of SO_2 with BACT emission limits of 0.0006 lb/mmBtu for the auxiliary boiler.

1.2.3.2 NO_x Analysis

Step 1 – Identify All Control Technologies

The first step is to evaluate NO_x controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RACT/BACT/LAER Clearinghouse (RBLC) database assessable on the Internet. The printout from the database for NO_x is shown in Attachment 6, Table 6-A. A broad range of other information sources were also reviewed in an effort to identify all potentially applicable emission control technologies.

Potential NO_x control technology options are:

- Selective catalytic reduction (SCR)
- Low NOx Burner (LNB) Technology with Flue Gas Recirculation (FGR)
- Low NO_x Burners (LNB)
- Good combustion practice

Step 2 – Eliminate Technically Infeasible Options

All of these technologies have been used to reduce NO_x emissions from natural gas fired boilers, and all of these technologies are listed in the RBLC for natural gas fired auxiliary boilers. Based on engineering judgement, all of the technologies listed above are technically feasible.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Emission rates for each of the technology combinations are required to rank them in order of effectiveness. Estimated controlled emission rates and projected permit limits are provided in Table 1. The controlled emission rates summarized in Table 1 are based on information included in the RBLC database (Attachment 6, Table 6-A).

The PSD NSR regulations require that BACT, at a minimum, meet the applicable NSPS limit. Because there is an NSPS that applies to the boiler (40 CFR Part 60 Subpart Db), the NSPS emission limit is also included in the ranking.

TABLE 1
NO_x Control Technology Emission Rate Ranking

Control Technology	Controlled NO_x Emission Rate [a]	Projected NO_x Permit Limit [b]
SCR and Low NO_x Burners	0.010 – 0.050	0.012
Low NO_x Burners plus FGR	0.036 – 0.090	0.040
Low NO_x Burners	0.036 – 0.200	0.054
Good Combustion Practice with Base Burner System	0.095 – 0.280	0.116
NSPS Limit	0.200	0.200

[a] Pounds per million Btu as found in the RBLC database.

[b] Pounds per million Btu based on the NOx emission rates found in the RBLC database, and including a reasonable margin between the design target and the permit limit.

Nomenclature:
SCR = Selective catalytic reduction
FGR = Flue Gas Recirculation
NSPS = New Source Performance Standards

Step 4 – Evaluate Most Effective Controls and Document Results

Low NOx Burners and Flue Gas Recirculation

Combustion controls, including Low NO_x burners and flue gas recirculation, are being considered for this project, thus environmental, energy, and economic impacts associated with the combustion control systems must be examined.

Low NO_x burners[1] limit NO_x formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced flame temperature and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NO_x emissions during the combustion process.

Flue gas recirculation controls NO_x by recycling a portion of the flue gas back into the primary combustion zone. The recycled air lowers NO_x emissions by two mechanisms: (1) the recycled gas is made up of combustion products which are inert during combustion,

[1] The term "LNB" is used generically in this BACT analysis, and refers to advanced low-NOx burners available from leading boiler/burner manufacturers. The term does not represent any vendor-specific trade name

thereby lowering combustion temperatures, and (2) by lowering the oxygen content in the primary flame zone. The amount of recirculation is based on flame stability.

Combustion modifications designed to decrease NO_x formation (lower temperature and less oxygen availability) also tend to increase the formation and emission of CO and VOCs. Therefore, the combustion controls must be designed to reduce the formation of NO_x while maintaining CO and VOC formation at an acceptable level. Other than the NO_x/CO-VOC trade-off, there are no environmental issues associated with using combustion controls to reduce NO_x emissions.

SCR

SCR is a control technique that uses ammonia to react with the NO_x in the flue gas at the appropriate temperature in the presence of a catalyst to form water and nitrogen. SCR has two well-documented environmental impacts associated with it, ammonia emissions (sometimes called ammonia slip) and disposal of spent catalyst. Some ammonia emissions from an SCR system are unavoidable because of imperfect distribution of the reacting gases, and ammonia injection control limitations as well as a partially degraded catalyst that results in an incomplete reaction of the available ammonia with NO_x. The NO_x removal efficiency of an SCR system depends on the ratio of ammonia to NO_x. Therefore, increasing the amount of ammonia injected increases the control efficiency but also increases the amount of unreacted ammonia that is emitted to the atmosphere. Ammonia emissions from a well-controlled SCR system can likely be limited to 10 ppmv or less. Ammonia emissions are of concern, because ammonia is a significant contributor to regional secondary particulate formation and visibility degradation. In this case reduced NO_x emissions as an environmental benefit would be traded for increased ammonia emissions as an environmental cost.

The other environmental impact associated with SCR is disposal of the spent catalyst. Some of the catalyst used in SCR systems must be replaced every three to five years. These catalysts contain heavy metals including vanadium pentoxide. Vanadium pentoxide is an acute hazardous waste under the Resource Conservation and Recovery Act (RCRA), Part 261, Subpart D – Lists of Hazardous Materials. This must be addressed when handling and disposing of the spent catalyst.

Good combustion practice

The next control technology in the hierarchy is good combustion practice. No environmental or energy costs are associated with good combustion practice for an auxiliary boiler.

Economic Evaluation

SCR represents the control system that will result in the lowest controlled NO_x emission rate. Based on a maximum heat input to the auxiliary boiler of 134.1 mmBtu/hr and 2,000 hours/year maximum operation, an SCR system would reduce potential NO_x emissions from the auxiliary boiler from approximately 7.24 tpy (based on LNB only) to approximately 1.61 tpy. The second most effective control system would be LNB combustion with FGR. This configuration would reduce potential annual emissions to approximately 5.36 tpy.

The installation of Low NO_x burners, Low NO_x Burners with FGR or Low NO_x Burners with SCR will increase the capital cost of the auxiliary boiler. Capital costs associated with FGR include additional ductwork, fans, and instrumentation and controls. Capital costs associated with SCR include the SCR grid, initial catalyst, ammonia injection system, and system instrumentation. The SCR system will also increase the annual operating costs of the auxiliary boiler. Operating costs associated with the SCR include ammonia usage and catalyst replacement costs.

A summary of the capital costs and annual O&M costs associated with Low NO_x Burner, FGR and SCR control systems is provided in Table 2. Detailed cost estimates are provided in Attachment 5.

TABLE 2
NO_x Control Technology Cost Effectiveness Evaluation

Control Technology	Total Installed Capital Costs	Total Annualized Costs	Annual Emission Reduction	Incremental Cost Effectiveness
SCR	$688,500	$263,409	3.75	$70,242
FGR	$93,500	$15,006	1.88	$7,982
Low NO_x Burners	$197,290	$29,553	8.32	$3,552
Combustion Control with Base Burner System	Base	Base		

Tons/Year emissions based on 134.1 mmBtu/hr boiler heat input x 2,000 hours of operation per year x NO_x emission rate for each control technology.

Based on information available from boiler vendors, an SCR system will increase the cost of the auxiliary boiler by approximately $688,500. Total annualized costs associated with the SCR system, including ammonia, catalyst replacement, auxiliary power, capital recovery, and indirect operating costs are estimated to be approximately $263,409/year. Based on an annual reduction in NO_x emissions of 3.75 tpy (5.36 tpy – 1.61 tpy) compared to the Low NO_x Burner with FGR alternative, the incremental cost effectiveness of the SCR system would be approximately $70,242/ton. This cost is disproportionately high compared to the average cost effectiveness for NO_x control from a natural gas fired boiler, and should preclude SCR as BACT for NO_x control.

The FGR control system will increase the cost of the auxiliary boiler by approximately $93,500, and will result in a slight increase in annual O&M costs associated with additional auxiliary power and increased maintenance costs. Total annualized costs associated with the FGR system are estimated to be approximately $15,006/year. Based on an annual reduction in NO_x emissions of 1.88 tpy (7.24 tpy - 5.36 tpy), the incremental cost effectiveness of the FGR system would be approximately $7,982/ton. Based on the ~~relatively small increase in annualized cost, BEPC feels that is appropriate to construct the~~ auxiliary boiler with low NO_x burners and a FGR control system.

Step 5 – Select BACT

The final step in the top-down BACT analysis process is to select BACT. EPA's RACT/BACT/LAER Clearinghouse (RBLC), a database of past technology decisions, was again consulted to assist in selecting BACT for this project.

Proposed BACT for the auxiliary boiler is good combustion control, combined with low-NO_x burner technology and flue gas recirculation that will achieve a controlled NO_x emission rate of 0.04 lb/mmBtu. The economic factors for installation of SCR as the next most stringent level of control on the auxiliary boiler indicate that there is relatively little control benefit obtained for the significant investment in addition to the increase in potential environmental impacts. The cost of SCR to control emissions to 0.012 lb/mmBtu is estimated at $70,242 per ton of NO_x removed (compared to LNB and FGR at 0.04 lb/mmBtu). The Low NO_x Burner, FGR and SCR cost estimates are shown in Attachment 5.

Therefore, based on the discussion above, low-NO_x burner technology with flue gas recirculation, a NOx emission rate of 0.04 lb/mmBtu, and 2,000 hour per year operation are selected as BACT for the auxiliary boiler.

1.2.3.3 CO and VOC Analysis

Step 1 – Identify All Control Technologies

Two control technologies were identified to control CO and VOC emissions from the Dry Fork Auxiliary Boiler:

- Catalytic oxidation
- Low NOx Burners with Flue Gas Recirculation
- Good combustion Practice

Catalytic oxidation is a post-combustion control device that would be applied to the combustion system exhaust, while good combustion practices are part of the combustion system design.

Step 2 – Eliminate Technically Infeasible Options

Implementation of good combustion controls is technically feasible. Implementation of add-on controls such as catalytic oxidation to the proposed auxiliary boiler is also technically feasible.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Emission rates for each of the technically feasible CO/VOC control technologies are summarized in Table 3. The controlled emission rates summarized in Table 3 are based on information included in the RBLC database (Attachment 6, Tables 1-A and 2-A), information from equipment vendors, and AP-42 emission factors.

TABLE 3
CO / VOC Control Technology Emission Rate Ranking

Control Technology	Projected Controlled CO Permit Limit[a]	Projected Controlled VOC Permit Limit[b]
Low NO_x Burners	0.11	0.0054
Low NO_x Burners plus FGR	0.08	0.0054
CO Catalyst	0.011	0.0027

[a] Pounds per million Btu based on information available from boiler vendors, and assuming 90% overall control with the CO oxidation catalyst control system.

[b] Pounds per million Btu based on AP-42 emission factors for natural gas combustion (Table 1.4-2), and assuming 50% overall VOC control with the CO oxidation catalyst control system.

Note: Compliance with the projected permit limits would be demonstrated based on annual stack tests using U.S.EPA Test Methods 10, 10A, or 10B (CO) and Method 25 (VOC), as applicable

Nomenclature:
FGR = Flue Gas Recirculation

Step 4 – Evaluate Most Effective Controls and Document Results

Implementation of proper burner design to achieve good combustion efficiency in heaters and boilers will minimize the generation of CO. Good combustion efficiency relies on both hardware design and operating procedures. Satisfactory burner design provides proper residence time, temperature and combustion zone turbulence, with in combination with proper control of air-to fuel ratio, are essential elements of a low-CO technology. Combustion modifications designed to control CO/VOC emissions could result in higher NO_x emissions. However, proper burner design and operation should limit CO and VOC emissions while controlling the average NO_x emission rate. Other than the CO/VOC - NO_x trade-off, there are no other environmental issues related to combustion controls.

A catalytic oxidation system typically consists of a passive reactor fitted with a honeycomb grid of metal panels and coated with a precious metal catalyst (usually platinum, palladium or rhodium). The catalyst promotes the oxidation of CO and VOCs to CO_2 and water at temperatures lower than would be necessary for oxidation without a catalyst. Pressure drop across the grid system will reduce the efficiency of the boiler system, requiring additional fuel to be burned to achieve the same energy output. CO catalysts may also plug or become deactivated with use. Therefore, it will be necessary to change-out the catalyst on a routine basis. Changing the catalyst will generate a solid waste material that must be properly handled.

Based on a maximum heat input of 134.1 mmBtu/hr, a controlled CO emission rate of 0.08 lb/mmBtu (based on low-NO_x burners and FGR), and a maximum of 2,000 hour/year operation, the total annual CO emissions are estimated at 10.73 tons per year for the auxiliary boiler. A CO catalyst system could reduce CO emissions from approximately 0.08 lb/mmBtu to approximately 0.011 lb/mmBtu (86% reduction). However, based on the planned hours of operation and low estimated emissions with combustion control only, the estimated cost of CO catalyst add-on control is estimated to be $21,618 per ton. This cost is disproportionately high compared to the average cost effectiveness for CO control from a natural gas fired boiler, and should preclude an Oxidation Catalyst as BACT for CO control. A summary of the capital costs and annual O&M costs associated with CO control systems is provided in Table 4. The capital cost estimate for an Oxidation Catalyst control system is shown in Attachment 5.

TABLE 4
CO Control Technology Cost Effectiveness Evaluation

Control Technology	Total Installed Capital Costs	Total Annualized Costs	Annual Emission Reduction	Cost Effectiveness
CO Oxidation Catalyst	$365,107	$199,967	9.25	$21,618
Low NO_x Burners with FGR (Base Case)	Base	Base		

Tons/Year emissions based on 134.1 mmBtu/hr boiler heat input x 2,000 hours of operation per year x CO emission rate for each control technology.

Step 5 – Select BACT

The EPA NSR RBLC database for comparable sources related to CO and VOCs is shown in Attachment 6, Tables 1-A and 2-A. The final step in the top-down BACT analysis process is to select BACT. Based on the above analysis, good combustion practice (Low NO_x Burners with FGR) is chosen as the technology to control emissions of CO and VOCs with BACT emission limits of 0.08 lb/mmBtu for CO and 0.0054 lb/mmBtu for VOCs for the auxiliary boiler.

1.2.3.4 PM/PM_{10} Analysis

Step 1 –Identify All Control Technologies

Two control technologies for the auxiliary boiler have been identified for PM/PM_{10} control:

- Use of clean burning low sulfur fuel (natural gas)
- Good Combustion Practice

Step 2 –Eliminate Technically Infeasible Options

Both of these options are technically feasible for use in limiting PM/PM_{10} emissions from the auxiliary boiler at the Dry Fork Station.

Step 3 –Rank Remaining Control Technologies by Control Effectiveness

Based on the Step 2 analysis, good combustion practice and use of clean burning fuel are the only technologies for this application.

Step 4 –Evaluate Most Effective Controls and Document Results

No environmental or energy costs are associated with good combustion practice in an auxiliary boiler.

Step 5 –Select BACT

Based on the above analysis and review of the EPA NSR RBLC database (refer to Attachment 6, Table 3-A), good combustion practice and use of clean burning fuel in an auxiliary boiler are chosen as the technology to achieve a PM/ PM_{10} emission rate of 0.0075 lb/mmBtu, is selected as BACT for this project. Good combustion control and use of natural gas fuel are proposed as BACT represent accepted practice for such sources.

1.2.4 Inlet Gas Heater

1.2.4.1 SO_2 Analysis

Step 1 – Identify All Control Technologies

The first step is to evaluate SO_2 controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RACT/BACT/LAER Clearinghouse (RBLC) database accessible on the Internet. The printout from the database for SO_2 is shown in, Attachment 8 Table 5-B. A broad range of other information sources were also reviewed in an effort to identify all potentially applicable emission control technologies.

The potential SO_2 emission reduction options found in the RBLC and other sources that could be applied to the Dry Fork Station inlet gas heater are:

- Use of clean burning low sulfur fuel (natural gas)
- Good Combustion Practice

Step 2 – Eliminate Technically Infeasible Options

Both of these options are technically feasible for use in reducing SO_2 emissions from the inlet gas heater at the Dry Fork Station.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Based on the Step 2 analysis, good combustion practice and use of clean burning fuel are the only technologies for this application.

Step 4 – Evaluate Most Effective Controls and Document Results

No environmental or energy costs are associated with good combustion practice in an inlet gas heater.

Step 5 – Select BACT

The final step in the top-down BACT analysis process is to select BACT. EPA's RACT/BACT/LAER Clearinghouse (RBLC), a database of past technology decisions, and recently approved PSD permits were again consulted to assist in selecting BACT for this project.

Based on the technology and clearinghouse database discussion above, good combustion practice and use of clean burning fuel in an inlet gas heater are chosen as the technology to control emissions of SO_2 with BACT emission limits of 0.0006 lb/mmBtu.

1.2.4.2 NO_x Analysis

Step 1 – Identify All Control Technologies

The first step is to evaluate NO_x controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RACT/BACT/LAER Clearinghouse (RBLC) database assessable on the Internet. The printout from the database for NO_x is shown in Attachment 8, Table 6-B. A broad range of other information sources were also reviewed in an effort to identify all potentially applicable emission control technologies.

Potential NO_x control technology options are:

- Low NO_x Burners (LNB)
- Good combustion practice

Step 2 – Eliminate Technically Infeasible Options

LNB and good combustion practice are listed in the RBLC for natural gas fired heaters, and both are technically feasible control options.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Emission rates for each of the technology combinations are required to rank them in order of effectiveness. These emission rates are provided in Table 5. The control efficiencies are those shown in the RBLC database (Attachment 8 Table 6-B).

TABLE 5
NO_x Control Technology Emission Rate Ranking

Control Technology	NO_x Emission Rate [a]
LNB	0.04
Good Combustion Practice	0.10

[a] Pounds per million BTU as found in the RBLC database.
Estimated emission rates based on vendor data.

Step 4 – Evaluate Most Effective Controls and Document Results

LNB technology is being considered for this project, so its environmental, energy, and economic impacts must be examined. No environmental costs and minimal energy costs are associated with LNB.

The next control technology in the hierarchy is good combustion practice. No environmental or energy costs are associated with good combustion practice for an inlet gas heater.

Economic Evaluation

Low NO_x burners offer the potential for the lowest controlled NO_x emission rate from the inlet gas heater. Based on a maximum heat input to the heater of 8.36 mmBtu/hour and 2,500 hours/year maximum operation, low NO_x burners will reduce potential NO_x emissions from approximately 1.05 tpy (based on 0.1 lb/mmBtu) to approximately 0.42 tpy (based on 0.04 lb/mmBtu). However, low NO_x burners will also increase the capital cost of the gas heater by approximately $265,000. Based on information provided by heater vendors, the cost of the gas heater will increase from approximately $210,000 to approximately $475,000 with low NO_x burners. Assuming no increase in annual O&M, the total annual cost of the low NO_x burner system will be approximately $29,150/year (capital recovery), which results in an incremental cost effectiveness of approximately $46,000/ton. This cost is disproportionately high when compared to the average cost of NO_x control in a process heater and should preclude low NO_x burners from consideration as BACT.

Step 5 – Select BACT

The final step in the top-down BACT analysis process is to select BACT. EPA's RACT/BACT/LAER Clearinghouse (RBLC), a database of past technology decisions, was again consulted to assist in selecting BACT for this project. BEPC is proposing good combustion practices, a controlled NO_x emission rate of 0.10 lb/mmBtu, and 2,500 hours per year maximum operation as BACT for inlet gas heater. Low NO_x burners will significantly increase the cost of the gas heater and reduce potential NO_x emissions by less than approximately 0.5 tpy, therefore, the incremental cost effectiveness of the LNB system should preclude it from consideration as BACT.

1.2.4.3 CO and VOC Analysis

Step 1 – Identify All Control Technologies

Two potentially feasible control technologies have been identified for control of CO and VOC:

- Catalytic oxidation
- Good combustion practice

Catalytic oxidation is a post-combustion control device that would be applied to the combustion system exhaust, while good combustion practices are part of the combustion system design.

Step 2 – Eliminate Technically Infeasible Options

Implementation of good combustion controls is a technically feasible control strategy. Implementation of add-on controls, such as catalytic oxidation, have been used to reduce CO/VOC emissions from natural-gas fired boilers and combustion turbines, however, post-combustion controls have not been identified as BACT for small natural gas-fired process heaters.

A catalytic oxidation system typically consists of a passive reactor fitted with a honeycomb grid of metal panels and coated with a precious metal catalyst (usually platinum, palladium or rhodium). The catalyst promotes the oxidation of CO and VOCs to CO_2 and water at temperatures lower than would be necessary for oxidation without a catalyst.

The inlet gas heater is an indirect natural-gas fired process heater, therefore, combustion gases do not mix with or exhaust to the atmosphere with any gases emanating from the process. The fire tube within the heater transfers heat released by the natural-gas burners to a media, typically oil, which in turn transfers heat to the process gas (fuel gas) through the process coils submerged in the media. Based on information from heater vendors, indirect process heater exhaust temperatures do not fall within the temperature window needed to support a CO catalyst control system. Based on a review of the RBLC database, and inquiries of heater vendors, it is concluded that a catalytic oxidation system is not commercially available for the inlet gas heater.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Emission rates for the technically feasible CO/VOC control technologies are summarized in Table 6. The controlled emission rates summarized in Table 5 are based on information included in the RBLC database (Attachment 8, Tables 1-B and 2-B), information from equipment vendors, and AP-42 emission factors.

TABLE 6
CO / VOC Control Technology Emission Rate Ranking

Control Technology	Projected Controlled CO Permit Limit[a]	Projected Controlled VOC Permit Limit[b]
Combustion Control	0.08	0.0054

[a] Pounds per million Btu based on AP-42 emission factors for natural gas combustion (Table 1.4-1) and information available from boiler vendors
[b] Pounds per million Btu based on AP-42 emission factors for natural gas combustion (Table 1.4-2)

Step 4 – Evaluate Most Effective Controls and Document Results

Implementation of proper burner design to achieve good combustion efficiency in heaters and boilers will minimize the generation of CO. Good combustion efficiency relies on both hardware design and operating procedures. Satisfactory burner design provides proper residence time, temperature and combustion zone turbulence, with in combination with proper control of air-to fuel ratio, are essential elements of a low-CO technology.

Combustion modifications designed to control CO/VOC emissions could result in higher NO_x emissions. However, proper burner design and operation should limit CO and VOC emissions while controlling the average NO_x emission rate. Other than the CO/VOC - NO_x trade-off, there are no other environmental issues related to combustion controls.

Step 5 – Select BACT

The EPA NSR RBLC database for comparable sources related to CO and VOCs is shown in Attachment 8 Tables 1-B and 2-B. The final step in the top-down BACT analysis process is to select BACT. Based on the above analysis, good combustion practice for an inlet heater is chosen as the technology to control emissions of CO and VOCs with BACT emission limits of 0.08 lb/mmBtu for CO and 0.0054 lb/mmBtu for VOCs.

1.2.4.4 PM/PM_{10} Analysis

Step 1 –Identify All Control Technologies

Two control technologies for the auxiliary boiler and inlet gas heater have been identified for PM/PM_{10} control:

- Use of clean burning low sulfur fuel (natural gas)
- Good Combustion Practice

Step 2 –Eliminate Technically Infeasible Options

Both of these options are technically feasible for use in limiting PM/PM_{10} emissions from the inlet gas heater at the Dry Fork Station.

Step 3 –Rank Remaining Control Technologies by Control Effectiveness

Based on the Step 2 analysis, good combustion practice and use of clean burning fuel are the only technologies for this application.

Step 4 –Evaluate Most Effective Controls and Document Results

No environmental or energy costs are associated with good combustion practice in an inlet gas heater.

Step 5 –Select BACT

Based on the above analysis and review of the EPA NSR RBLC database (refer to Attachment 8 Table 3-B), good combustion practice and use of clean burning fuel in an inlet gas heater are chosen as the technology to achieve a PM/ PM_{10} emission rate of 0.0075 lb/mmBtu, is selected as BACT for this project. Good combustion control and use of natural gas fuel are proposed as BACT represent accepted practice for such sources.

Attachment 5

Attachment 5
Basin Electric Power Cooperative
Dry Fork Station
Auxiliary Equipment BACT Cost Analysis
Revision 03/07/2006

Analysis Workbook sheets include:

Equipment	Pollutant	Control System
Unit 1 Auxiliary Boiler	NOx	Low NOx Burner and Combustion Control System
Unit 1 Auxiliary Boiler	NOx	Flue Gas Recirculation System
Unit 1 Auxiliary Boiler	NOx	Selective Catalytic Reduction
Unit 1 Auxiliary Boiler	CO	Oxidation Catalyst

Dry Fork Unit 1 Auxiliary Boiler
Low NOx Burner and Combustion Control System
Cost Estimate

Capital Cost Factors

DIRECT COSTS	Cost Factors					
(1) Purchased Equipment						
(a) Basic Equipment and auxiliaries						
Capital Cost of Low NOx Burner & Combustion Control System				=	$	147,000
Capital Cost of Spare Catalyst	(Spare Catalyst not included)				na	
Total Capital Cost				=	$	147,000
(b) Instruments and controls [0.1 * (a)]	(Included in Purchased Equipment Costs)					
(c) Taxes [0.07(a)]	0.07	*	(a)	=	$	10,290
Total Equipment Cost (TEC)				=	$	157,290
(2) Construction Costs						
(a) Foundations and supports	(Included in Total Construction Costs)					
(b) Handling and Erection	(Included in Total Construction Costs)					
(c) Electrical	(Included in Total Construction Costs)					
(d) Piping	(Included in Total Construction Costs)					
(e) Insulation	(Included in Total Construction Costs)					
(f) Painting	(Included in Total Construction Costs)					
Total Construction Costs (TCC)				=	$	20,000
TOTAL DIRECT COSTS (TDC)	(TEC)	+	(TCC)	=	$	177,290
INDIRECT COSTS						
(3) Engineering and supervision	(Included in Total Indirect Costs)					
(4) Construction and field expenses	(Included in Total Indirect Costs)					
(5) Construction fee	(Included in Total Indirect Costs)					
(6) Start-up	(Included in Total Indirect Costs)					
(7) Performance test	(Included in Total Indirect Costs)					
TOTAL INDIRECT COSTS (TIC)				=	$	20,000
TOTAL DIRECT AND INDIRECT COSTS (TDIC)	(TDC)	+	(TIC)	=	$	197,290
(8) Contingency	(Included in Total Indirect Costs)					
TOTAL INSTALLED CAPITAL COSTS (TICC)				=	$	197,290

Dry Fork Unit 1 Auxiliary Boiler
Low NOx Burner and Combustion Control System
Cost Estimate (continued)

Annualized Cost Factors

DIRECT COSTS	**Cost Factors**					
Fixed O&M Costs						
(1) Operating Labor	(Included in Total Fixed O&M Costs)					
(2) Supervisory Labor	(Included in Total Fixed O&M Costs)					
(3) Maintenance Labor	(Included in Total Fixed O&M Costs)					
(4) Parts and Materials	(Included in Total Fixed O&M Costs)					
Total Fixed O&M Costs				=	$	-
Variable O&M Costs						
(5) Ammonia Reagent Cost:				=	na	
(6) Catalyst Replacement Cost:				=	na	
(7) Auxiliary Power Cost:				=	$	-
Total Variable O&M Costs					$	-
TOTAL DIRECT COSTS (TDAC)				=	$	-
INDIRECT COSTS						
(8) Overhead	60%	of	Fixed O&M Costs	=	$	-
(9) Property Tax	1%	of	(TICC)	=	$	1,973
(10) Insurance	1%	of	(TICC)	=	$	1,973
(11) G&A Charges	2%	of	(TICC)	=	$	3,946
(12) Capital Recovery	0.110	*	(TICC)	=	$	21,661
TOTAL INDIRECT COSTS (TIAC)				=	$	29,553
TOTAL ANNUALIZED COSTS	TDAC + TIAC			=	$	29,553
TOTAL TONS REMOVED PER YEAR (NO_x)	15.56 tons with Base Case Burner System - 7.24 tons with Low NOx			=		8.32
COST EFFECTIVENESS ($ per ton of pollutant removed)				=	$	3,552

Notes:

1) Cost factors - from OAQPS Control Cost Manual, Chapter 3

2) Capital Recovery Factor for System - Based on a 15-year equipment life and 7% interest rate.

3) Rentech and Nebraska Boiler provided Low NOx Burner and Combustion Control System purchased equipment cost.

4) Cost effectiveness, $ per ton of NOx removed, based on Low NOx Burner only. Does not include removal by Base Case Burner System

Dry Fork Unit 1 Auxiliary Boiler
Flue Gas Recirculation (FGR) System
Cost Estimate

Capital Cost Factors

	Cost Factors					
DIRECT COSTS						
(1) Purchased Equipment						
(a) Basic Equipment and auxiliaries						
Capital Cost of FGR System				=	$	50,000
Capital Cost of Spare Catalyst	(Spare Catalyst not included)				na	
Total Capital Cost				=	$	50,000
(b) Instruments and controls [0.1 * (a)]	(Included in Purchased Equipment Costs)					
(c) Taxes [0.07(a)]	0.07	*	(a)	=	$	3,500
Total Equipment Cost (TEC)				=	$	53,500
(2) Construction Costs						
(a) Foundations and supports	(Included in Total Construction Costs)					
(b) Handling and Erection	(Included in Total Construction Costs)					
(c) Electrical	(Included in Total Construction Costs)					
(d) Piping	(Included in Total Construction Costs)					
(e) Insulation	(Included in Total Construction Costs)					
(f) Painting	(Included in Total Construction Costs)					
Total Construction Costs (TCC)				=	$	20,000
TOTAL DIRECT COSTS (TDC)	(TEC)	+	(TCC)	=	$	73,500
INDIRECT COSTS						
(3) Engineering and supervision	(Included in Total Indirect Costs)					
(4) Construction and field expenses	(Included in Total Indirect Costs)					
(5) Construction fee	(Included in Total Indirect Costs)					
(6) Start-up	(Included in Total Indirect Costs)					
(7) Performance test	(Included in Total Indirect Costs)					
TOTAL INDIRECT COSTS (TIC)				=	$	20,000
TOTAL DIRECT AND INDIRECT COSTS (TDIC)	(TDC)	+	(TIC)	=	$	93,500
(8) Contingency	(Included in Total Indirect Costs)					
TOTAL INSTALLED CAPITAL COSTS (TICC)				=	$	93,500

Dry Fork Unit 1 Auxiliary Boiler
Flue Gas Recirculation (FGR) System
Cost Estimate (continued)

Annualized Cost Factors

DIRECT COSTS		**Cost Factors**				
Fixed O&M Costs						
(1) Operating Labor		(Included in Total Fixed O&M Costs)				
(2) Supervisory Labor		(Included in Total Fixed O&M Costs)				
(3) Maintenance Labor		(Included in Total Fixed O&M Costs)				
(4) Parts and Materials		(Included in Total Fixed O&M Costs)				
Total Fixed O&M Costs				=	$	-
Variable O&M Costs						
(5) Ammonia Reagent Cost:				=	na	
(6) Catalyst Replacement Cost:				=	na	
(7) Auxiliary Power Cost:				=	$	1,000
Total Variable O&M Costs					$	1,000
TOTAL DIRECT COSTS (TDAC)				=	$	1,000
INDIRECT COSTS						
(8) Overhead	60%	of	Fixed O&M Costs	=	$	-
(9) Property Tax	1%	of	(TICC)	=	$	935
(10) Insurance	1%	of	(TICC)	=	$	935
(11) G&A Charges	2%	of	(TICC)	=	$	1,870
(12) Capital Recovery	0.110	*	(TICC)	=	$	10,266
TOTAL INDIRECT COSTS (TIAC)				=	$	14,006
TOTAL ANNUALIZED COSTS		TDAC + TIAC		=	$	15,006
TOTAL TONS REMOVED PER YEAR (NO_x)	7.24 tons with Low Nox Burners - 5.36 tons with FGR			=		1.88
COST EFFECTIVENESS ($ per ton of pollutant removed)				=	$	7,982

Notes:

1) Cost factors - from OAQPS Control Cost Manual, Chapter 3

2) Capital Recovery Factor for System - Based on a 15-year equipment life and 7% interest rate.

3) Rentech and Nebraska Boiler provided Flue Gas Recirculation (FGR) purchased equipment cost.

4) Cost effectiveness, $ per ton of NOx removed, based on FGR System only. Does not include removal by Low-NOx Burner System.

Dry Fork Unit 1 Auxiliary Boiler
Selective Catalytic Reduction
Cost Estimate

Capital Cost Factors

DIRECT COSTS	Cost Factors					
(1) Purchased Equipment						
(a) Basic Equipment and auxiliaries						
Capital Cost of SCR System				=	$	550,000
Capital Cost of Spare Catalyst	(Spare Catalyst not included)					
Total Capital Cost				=	$	550,000
(b) Instruments and controls [0.1 * (a)]	(Included in Purchased Equipment Costs)					
(c) Taxes [0.07(a)]	0.07	*	(a)	=	$	38,500
Total Equipment Cost (TEC)				=	$	588,500
(2) Construction Costs						
(a) Foundations and supports	(Included in Total Construction Costs)					
(b) Handling and Erection	(Included in Total Construction Costs)					
(c) Electrical	(Included in Total Construction Costs)					
(d) Piping	(Included in Total Construction Costs)					
(e) Insulation	(Included in Total Construction Costs)					
(f) Painting	(Included in Total Construction Costs)					
Total Construction Costs (TCC)				=	$	50,000
TOTAL DIRECT COSTS (TDC)	(TEC)	+	(TCC)	=	$	638,500
INDIRECT COSTS						
(3) Engineering and supervision	(Included in Total Indirect Costs)					
(4) Construction and field expenses	(Included in Total Indirect Costs)					
(5) Construction fee	(Included in Total Indirect Costs)					
(6) Start-up	(Included in Total Indirect Costs)					
(7) Performance test	(Included in Total Indirect Costs)					
TOTAL INDIRECT COSTS (TIC)				=	$	50,000
TOTAL DIRECT AND INDIRECT COSTS (TDIC)	(TDC)	+	(TIC)	=	$	688,500
(8) Contingency	(Included in Total Indirect Costs)					
TOTAL INSTALLED CAPITAL COSTS (TICC)				=	$	688,500

Dry Fork Unit 1 Auxiliary Boiler
Selective Catalytic Reduction
Cost Estimate (continued)

Annualized Cost Factors

DIRECT COSTS	**Cost Factors**					
Fixed O&M Costs						
(1) Operating Labor	(Included in Total Fixed O&M Costs)					
(2) Supervisory Labor	(Included in Total Fixed O&M Costs)					
(3) Maintenance Labor	(Included in Total Fixed O&M Costs)					
(4) Parts and Materials	(Included in Total Fixed O&M Costs)					
Total Fixed O&M Costs				=	$	20,000
Variable O&M Costs						
(5) Ammonia Reagent Cost:				=	$	15,000
(6) Catalyst Replacement Cost:				=	$	125,000
(7) Auxiliary Power Cost:				=	$	2,000
Total Variable O&M Costs					$	142,000
TOTAL DIRECT COSTS (TDAC)				=	$	162,000
INDIRECT COSTS						
(8) Overhead	60%	of	Fixed O&M Costs	=	$	12,000
(9) Property Tax	1%	of	(TICC)	=	$	6,885
(10) Insurance	1%	of	(TICC)	=	$	6,885
(11) G&A Charges	2%	of	(TICC)	=	$	13,770
(12) Capital Recovery	0.110	*	(TICC - Catalyst Cost)	=	$	61,869
TOTAL INDIRECT COSTS (TIAC)				=	$	101,409
TOTAL ANNUALIZED COSTS	TDAC + TIAC			=	$	263,409
TOTAL TONS REMOVED PER YEAR (NO_x)	5.36 tons with FGR - 1.61 tons with SCR			=		3.75
COST EFFECTIVENESS ($ per ton of pollutant removed)				=	$	70,242

Notes:

1) Cost factors - from OAQPS Control Cost Manual, Chapter 3

2) Capital Recovery Factor for System - Based on a 15-year equipment life and 7% interest rate, base cost excludes cost of catalyst because equipment life will be less than 15 years. Catalyst replacement included as an operating and maintenance cost.

3) EPIC provided SCR purchased equipment cost.

4) Cost effectiveness, $ per ton of NOx removed, based on SCR only. Does not include removal by Low NOx burners and FGR.

Dry Fork Unit 1 Auxiliary Boiler
CO Oxidation Catalyst
Cost Estimate

Capital Cost Factors

DIRECT COSTS	**Cost Factors**					
(1) Purchased Equipment						
(a) Basic Equipment and auxiliaries						
Capital Cost of Oxidation Catalyst = 1541.8 x (exhaust flow in lb/sec) + 102370				=	$	159,077
Capital Cost of Catalyst Housing = 0.3 x Capital Cost of Catalyst				=	$	47,723
Total Capital Cost				=	$	206,801
(b) Instruments and controls [0.1 * (a)]	(Included in Purchased Equipment Costs)					
(c) Taxes [0.07(a)]	0.07	*	(a)	=	$	14,476
Total Equipment Cost (TEC)				=	$	221,277
(2) Construction Costs						
(a) Foundations and supports	(Included in Total Construction Costs)					
(b) Handling and Erection	(Included in Total Construction Costs)					
(c) Electrical	(Included in Total Construction Costs)					
(d) Piping	(Included in Total Construction Costs)					
(e) Insulation	(Included in Total Construction Costs)					
(f) Painting	(Included in Total Construction Costs)					
Total Construction Costs (TCC)	0.25 x TEC			=	$	55,319
TOTAL DIRECT COSTS (TDC)	(TEC)	+	(TCC)	=	$	276,596
INDIRECT COSTS						
(3) Engineering and supervision	(Included in Total Indirect Costs)					
(4) Construction and field expenses	(Included in Total Indirect Costs)					
(5) Construction fee	(Included in Total Indirect Costs)					
(6) Start-up	(Included in Total Indirect Costs)					
(7) Performance test	(Included in Total Indirect Costs)					
TOTAL INDIRECT COSTS (TIC)	0.25 x TEC			=	$	55,319
TOTAL DIRECT AND INDIRECT COSTS (TDIC)	(TDC)	+	(TIC)	=	$	331,915
(8) Contingency	0.1 x TDIC			=	$	33,192
TOTAL INSTALLED CAPITAL COSTS (TICC)				=	$	365,107

Dry Fork Unit 1 Auxiliary Boiler
CO Oxidation Catalyst
Cost Estimate (continued)

Annualized Cost Factors

DIRECT COSTS		Cost Factors				
Fixed O&M Costs						
(1) Operating Labor		(Included in Total Fixed O&M Costs)				
(2) Supervisory Labor		(Included in Total Fixed O&M Costs)				
(3) Maintenance Labor		(Included in Total Fixed O&M Costs)				
(4) Parts and Materials		(Included in Total Fixed O&M Costs)				
Total Fixed O&M Costs				=	$	20,000
Variable O&M Costs						
(5) Catalyst Replacement Cost:				=	$	125,000
(6) Auxiliary Power Cost:				=	$	2,000
Total Variable O&M Costs					$	127,000
TOTAL DIRECT COSTS (TDAC)				=	$	147,000
INDIRECT COSTS						
(8) Overhead	60%	of	Fixed O&M Costs	=	$	12,000
(9) Property Tax	1%	of	(TICC)	=	$	3,651
(10) Insurance	1%	of	(TICC)	=	$	3,651
(11) G&A Charges	2%	of	(TICC)	=	$	7,302
(12) Capital Recovery	0.110	*	(TICC - Catalyst Cost)	=	$	26,362
TOTAL INDIRECT COSTS (TIAC)				=	$	52,967
TOTAL ANNUALIZED COSTS		TDAC + TIAC		=	$	199,967
TOTAL TONS REMOVED PER YEAR (CO)	10.73 tons with LNB & FGR - 1.48 tons Oxidation Catalyst			=		9.25
COST EFFECTIVENESS ($ per ton of pollutant removed)				=	$	21,618

Notes:

1) Cost factors - from OAQPS Control Cost Manual, Chapter 3

2) Capital Recovery Factor for System - Based on a 15-year equipment life and 7% interest rate, base cost excludes cost of catalyst because equipment life will be less than 15 years. Catalyst replacement included as an operating and maintenance cost.

3) Purchased Equipment Cost based on ICCR Combustion Work Group Oxidation Catalyst Cost Effectiveness documents.

4) Cost effectiveness, $ per ton of CO removed, based on Oxidation Catalyst only. Does not include removal by Low NOx burners and FGR.

Attachment 6

TABLE 1-A
NSR RACT/B... ..AER Clearinghouse Database
BACT-PSD Sources for CO
Natural Gas Fired Boilers (>100 MMBtu, <250MMBtu)

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
MN-0062	Heartland Corn Products Minnesota	2	Boiler 198.00 MMBtu/hr for both	None	N/A	0.04	lb/MMBtu		12/22/05 14300014-005
NC-0101	FORSYTH ENERGY PROJECTS, LLC FORSYTH ENERGY PLANT North Carolina	1	AUXILLIARY BOILER 110.20 MMBtu/hr	LOW-NOX BURNERS GOOD COMBUSTION CONTROL AND CLEAN BURNING LOWSULFUR FUEL (NATURAL GAS).		9.0800 0.0824	lb/hr lb/MMBtu	3-hour	09/29/2005 00986R1
OH-0241	MILLER BREWING COMPANY MILLER BREWING COMPANY - TRENTON	2	BOILER (2), NATURAL GAS 238.00 MMBtu/hr			20.0000 87.6000 0.0840	lb/hr each boiler tpy each boiler lb/MMBtu	12-Month Rolling	05/27/2004 14-05515
WV-0023	LONGVIEW POWER, LLC MAIDSVILLE West Virginia	1	AUXILIARY BOILER 225.00 MMBTu/hr	GOOD COMBUSTION PRACTICES, USE OF NATURAL GAS		0.04	lb/MMBtu	3-Hour Rolling	03/02/2004 R14-0024
WI-0204	UNITED WISCONSIN GRAIN PRODUCERS UWGP - FUEL GRADE ETHANOL PLANT Wisconson	1	BOILER /OXIDIZER (DRYER / DISTILLATION) 140.00 MMBtu	PROCESS IS THE CONTROL FOR OTHER SOURCES LISTED IN PROCESS ENTRY.		18.4000 0.1300	lb/hr lb/MMBtu		08/14/2003 03-DCF-048
VA-0270	VIRGINIA COMMONWEALTH UNIVERSITY VCU EAST PLANT	3	BOILER NATUAL GAS 150.60 MMBtu Each	GOOD COMBUSTION PRACTICES.		0.1000 14.9000	lb/MMBtu each lb/hr each		03/31/2003 VA-50126
CO-0052	ROCKY MOUNTAIN ENERGY CENTER, LLC. ROCKY MOUNTAIN ENERGY CENTER, LLC. Colorado	1	NATURAL GAS FIRED BOILER (AUXILIARY BOILER) 129.00 MMBtu/hr	GOOD COMBUSTION CONTROL PRACTICES.		0.039	lb/MMBtu		08/11/2002 02WE0228
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING, L.L.C.	1	BOILER, NO. 10 180.00 MMBtu/hr			0.18	lb/MMBtu		04/03/2002 0101-08PC AND 1010-05PCR
NJ-0043	LIBERTY GENERATING STATION LIBERTY GENERATING STATION New Jersey	1	AUXILIARY BOILER 200.00 MMBtu/hr	CO CATALYST	80%	100.0000 17.4000 0.0870	PPMVD @7% O2 lb/hr lb/MMBtu		03/28/2002 BOP990001
TX-0386	CALPINE CONSTRUCTION FINANCE CO. LP AMELLA ENERGY CENTER Texas	1	AUXILIARY BOILER 155 MMBtu/hr			13.9 0.08	lb/hr lb/MMBtu		3/26/2002 N-037
*NJ-0036	AES RED OAK LLC AES RED OAK LLC New Jersey	1	AUXILIARY BOILER 120.00 MMBtu/hr	GOOD COMBUSTION PRACTICE		0.05 6.00 10.8	lb/MMBtu lb/hr tpy		10/24/2001 10001
AR-0055	NUCOR YAMATO STEEL NUCOR YAMATO STEEL (ARMOREL) Arkansas	1	REHEAT FURNACE 225.00 MMBtu/hr	CLEAN FUEL		0.0824	lb/MMBtu		10/10/2001 883-AOP-R1(47-0202)
AR-0057	TENASKA ARKANSAS PARTNERS, LP TENASKA ARKANSAS PARTNERS, LP Arkansas	2	BOILER, NATURAL GAS, (2) 122 MMBtu/hr	GOOD COMBUSTION PRACTICES.		0.11	lb/MMBtu		10/9/2001 1959-AOP-R0 (43-00202)
IN-0085	PSEG LAWRENCEBURG ENERGY FACILITY PSEG LAWRENCEBURG ENERGY FACILITY Indiana	1	AUXILIARY BOILER, NATURAL GAS 124.6 MMBtu/hr	GOOD COMBUSTION. NATURAL GAS ONLY		0.082 10.28	lb/MMBtu lb/hr		6/7/2001 029-12517-00033

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
- Permit date on or after January 1, 2001
- Process Type Code: 12.310 - Natural Gas Industrial-Size Boiler/Furnaces

DEQ/AQD 000770

TABLE 2-A

NSR RACT/BACT/LAER Clearinghouse Database

BACT-PSD Sources for VOC

Natural Gas Fired Boilers (>100 MMBtu, <250MMBtu)

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
NC-0101	FORSYTH ENERGY PROJECTS, LLC FORSYTH ENERGY PLANT North Carolina	1	AUXILLIARY BOILER 110.20 MMBtu/hr	LOW-NOX BURNERS GOOD COMBUSTION CONTROL AND CLEAN BURNING LOWSULFUR FUEL (NATURAL GAS).		0.59	lb/hr	3-hour	09/29/2005 00986R1
OH-0241	MILLER BREWING COMPANY MILLER BREWING COMPANY - TRENTON Ohio	2	BOILER (2), NATURAL GAS 238.00 MMBtu/hr			2.6000 11.5000	lb/hr tpy	12-Month Rolling	05/27/2004 14-05515
WV-0023	LONGVIEW POWER, LLC MAIDSVILLE West Virginia	1	AUXILIARY BOILER 225.00 MMBTu/hr	GOOD COMBUSTION PRACTICES AND USE OF NATURAL GAS		0.0054	lb/MMBtu	3-Hour Rolling	03/02/2004 R14-0024
WI-0204	UNITED WISCONSIN GRAIN PRODUCERS UWGP - FUEL GRADE ETHANOL PLANT	1	BOILER /OXIDIZER (DRYER / DISTILLATION) 140.00 MMBtu	PROCESS IS THE CONTROL FOR OTHER SOURCES LISTED IN PROCESS ENTRY.		6.7000 0.3650	lb/hr LB /T DDGS AT 11% MOISTURE		08/14/2003 03-DCF-048
VA-0270	VIRGINIA COMMONWEALTH UNIVERSITY VCU EAST PLANT Virginia	3	BOILER NATUAL GAS 150.60 MMBtu Each	GOOD COMBUSTION PRACTICES.		2.1	lb/hr		03/31/2003 VA-50126
NJ-0043	LIBERTY GENERATING STATION LIBERTY GENERATING STATION New Jersey	1	AUXILIARY BOILER 200.00 MMBtu/hr	CO CATALYST	80%	50.0000 1.6000	PPMVD @ 7% O2 lb/hr		03/28/2002 BOP990001
TX-0386	CALPINE CONSTRUCTION FINANCE CO, LP AMELIA ENERGY CENTER Texas	1	AUXILIARY BOILER 155 MMBtu/hr			3.1	lb/hr		3/26/2002 N-037
*NJ-0036	AES RED OAK LLC AES RED OAK LLC New Jersey	1	AUXILIARY BOILER 120.00 MMBtu/hr	GOOD COMBUSTION PRACTICES		0.48 0.864	lb/hr tpy		10/24/2001 10001
AR-0055	NUCOR YAMATO STEEL NUCOR YAMATO STEEL (ARMOREL) Arkansas	1	REHEAT FURNACE 225.00 MMBtu/hr	CLEAN FUEL		0.0054	lb/MMBtu		10/10/2001 883-AOP-R1(47-0202)
AR-0057	TENASKA ARKANSAS PARTNERS, LP TENASKA ARKANSAS PARTNERS, LP Arkansas	2	BOILER, NATURAL GAS, (2) 122 MMBtu/hr	GOOD COMBUSTION PRACTICES.		0.004	lb/MMBtu		10/9/2001 1959-AOP-R0 (43-00202)
IN-0085	PSEG LAWRENCEBURG ENERGY FACILITY PSEG LAWRENCEBURG ENERGY FACILITY Indiana	1	AUXILIARY BOILER, NATURAL GAS 124.6 MMBtu/hr	GOOD COMBUSTION. NATURAL GAS ONLY		0.0054 0.672	lb/MMBtu lb/hr		6/7/2001 029-12517-00033
TN-0089	PROCTOR & GAMBLE MANUFACTURING COMPANY PROCTOR & GAMBLE MANUFACTURING COMPANY Tennesse	1	UTILITY BOILER #2 (NAT GAS) 183 MMBtu/hr			4.4 17.0	lb/hr tpy		3/5/2001 9252983P
TN-0089	PROCTOR & GAMBLE MANUFACTURING COMPANY PROCTOR & GAMBLE MANUFACTURING COMPANY Tennesse	1	UTILITY BOILER #50-1 (NAT GAS) 225 MMBtu/hr			5.4 21.0	lb/hr tpy		3/5/2001 9252983P

Notes:

DEQ/AQD 000771

TABLE 3-A
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM
Natural Gas Fired Boilers (>100 MMBtu, <250MMBtu)

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
WV-0023	LONGVIEW POWER, LLC MAIDSVILLE West Virginia	1	AUXILIARY BOILER 225.00 MMBTu/hr	GOOD COMBUSTION PRACTICES AND THE USE OF CLEAN FUELS		0.0022	lb/MMBtu	6-Hour Rolling	03/02/2004 R14-0024
WI-0204	UNITED WISCONSIN GRAIN PRODUCERS UWGP - FUEL GRADE ETHANOL PLANT Wisconsin	1	BOILER /OXIDIZER (DRYER / DISTILLATION) 140.00 MMBtu	PROCESS IS THE CONTROL FOR OTHER SOURCES LISTED IN PROCESS ENTRY.		5.5000 0.3000 0.0400	lb/hr LB /T DDGS AT 11% MOISTURE lb/MMBtu		08/14/2003 03-DCF-048
VA-0270	VIRGINIA COMMONWEALTH UNIVERSITY VCU EAST PLANT Virginia	3	BOILER NATUAL GAS 150.60 MMBtu Each			0.0080 1.2000	lb/MMBtu each lb/hr each		03/31/2003 VA-50126
NJ-0043	LIBERTY GENERATING STATION LIBERTY GENERATING STATION New Jersey	1	AUXILIARY BOILER 200.00 MMBtu/hr			0.0080 1.6000	lb/MMBtu lb/hr		03/28/2002 BOP990001
*NJ-0036	AES RED OAK LLC AES RED OAK LLC New Jersey	1	AUXILIARY BOILER 120.00 MMBtu/hr	GOOD COMBUSTION PRACTICES	-	0.0066 0.792 1.426	lb/MMBtu lb/hr tpy		10/24/2001 10001
NC-0073	BRIDGESTONE FIRESTONE BRIDGESTONE FIRESTONE North Carolina	2	BOILERS, (2) 121 MMBtu/hr			0.24	lb/MMBtu		6/28/2001 1660R39
IN-0085	PSEG LAWRENCEBURG ENERGY FACILITY PSEG LAWRENCEBURG ENERGY FACILITY Indiana	1	AUXILIARY BOILER, NATURAL GAS 124.6 MMBtu/hr	GOOD COMBUSTION		0.007 0.928	lb/MMBtu lb/hr		6/7/2001 029-12517-00033

Notes:

DEQ/AQD 000772

TABLE 4-A
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM_{10}
Natural Gas Fired Boilers (>100 MMBtu, <250MMBtu)

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
NC-0101	FORSYTH ENERGY PROJECTS, LLC FORSYTH ENERGY PLANT North Carolina	1	AUXILLIARY BOILER 110.20 MMBtu/hr	LOW-NOX BURNERS GOOD COMBUSTION CONTROL AND CLEAN BURNING LOWSULFUR FUEL (NATURAL GAS)		0.8200 0.0070	lb/hr lb/MMBtu	3-hour	09/29/2005 00986R1
MS-0069	E. I. DUPONT DE NEMOURS DUPONT DELISLE FACILITY Mississippi	1	BOILER #3 231.00 MMBtu/hr	USE OF NATURAL GAS CONSIDERED BACT.		1.7600 7.6900 0.0076	lb/hr tpy lb/MMBtu		06/08/2004 1020-00115
MS-0069	E. I. DUPONT DE NEMOURS DUPONT DELISLE FACILITY Mississippi	1	BOILER #4 231.00 MMBtu/hr	USE OF NATURAL GAS CONSIDERED BACT.		1.7600 7.6900 0.0076	lb/hr tpy lb/MMBtu		06/08/2004 1020-00115
MS-0069	E. I. DUPONT DE NEMOURS DUPONT DELISLE FACILITY Mississippi	1	BOILER (RENTAL/TEMPORARY) 231.00 MMBtu/hr	USE OF NATURAL GAS CONSIDERED BACT.		1.7600 1.8300 0.0076	lb/hr tpy lb/MMBtu		06/08/2004 1020-00115
OH-0241	MILLER BREWING COMPANY MILLER BREWING COMPANY - TRENTON Ohio	2	BOILER (2), NATURAL GAS 238.00 MMBtu/hr	BAGHOUSE		0.0200 122.9000 0.0100	lb/MMBtu tpy gr/acf	12-Month Rolling	05/27/2004 14-05515
WV-0023	LONGVIEW POWER, LLC MAIDSVILLE West Virginia	1	AUXILIARY BOILER 225.00 MMBTu/hr	GOOD COMBUSTION PRACTICES AND THE USE OF CLEAN FUELS		0.0022	lb/MMBtu	6-Hour Rolling	03/02/2004 R14-0024
VA-0270	VIRGINIA COMMONWEALTH UNIVERSITY VCU EAST PLANT Virginia	3	BOILER NATUAL GAS 150.60 MMBtu Each	GOOD COMBUSTION PRACTICES.		0.0100 1.2000	lb/MMBtu each lb/hr each		03/31/2003 VA-50126
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING, L.L.C. Tennesse	1	BOILER, NO. 10 180.00 MMBtu/hr			0.0075	lb/MMBtu		04/03/2002 0101-08PC AND 1010-05PCR
NJ-0043	LIBERTY GENERATING STATION LIBERTY GENERATING STATION New Jersey	1	AUXILIARY BOILER 200.00 MMBtu/hr			0.0080 1.6000	lb/MMBtu lb/hr		03/28/2002 BOP990001
TX-0386	CALPINE CONSTRUCTION FINANCE CO. LP AMELLA ENERGY CENTER Texas	1	AUXILIARY BOILER 155 MMBtu/hr			3.23 0.02	lb/hr lb/MMBtu		3/28/2002 N-O37
AR-0055	NUCOR YAMATO STEEL NUCOR YAMATO STEEL (ARMOREL) Arkansas	1	REHEAT FURNACE 225.00 MMBtu/hr	CLEAN FUEL		0.0168	lb/MMBtu		10/10/2001 883-AOP-R1(47-0202)
AR-0057	TENASKA ARKANSAS PARTNERS, LP TENASKA ARKANSAS PARTNERS, LP Arkansas	2	BOILER, NATURAL GAS, (2) 122 MMBtu/hr	GOOD COMBUSTION PRACTICES.		0.005	lb/MMBtu		10/9/2001 1959-AOP-R0 (43-00202)

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
- Permit date on or after January 1, 2001
- Process Type Code: 12.310 - Natural Gas Industrial-Size Boiler/Furnaces

DEQ/AQD 000773

TABLE 5-A
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for SO_2
Natural Gas Fired Boilers (>100 MMBtu, <250MMBtu)

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
NC-0101	FORSYTH ENERGY PROJECTS, LLC FORSYTH ENERGY PLANT North Carolina	1	AUXILLIARY BOILER 110.20 MMBtu/hr	LOW-NOX BURNERS GOOD COMBUSTION CONTROL AND CLEAN BURNING LOWSULFUR FUEL (NATURAL GAS).		0.6100 0.0055	lb/hr lb/MMBtu	3-hour	09/29/2005 00986R1
MI-0368	MICHIGAN PAPERBOARD COMPANY MICHIGAN PAPERBOARD COMPANY Michigan	1	BOILER 185.00 MMBtu/hr	None		280.0000 470.0000 1.5100	lb/hr tpy lb/MMBtu		09/08/2004 288-03
OH-0241	MILLER BREWING COMPANY MILLER BREWING COMPANY - TRENTON	2	BOILER (2), NATURAL GAS 238.00 MMBtu/hr			2758.0000 1.6000	tpy both boilers lb/MMBtu	12-Month Rolling	05/27/2004 14-05515
WV-0023	LONGVIEW POWER, LLC MAIDSVILLE West Virginia	1	AUXILIARY BOILER 225.00 MMBTu/hr	LOW SULFUR NATURAL GAS FUEL		1.8000 E-5 0.0040	lb/MMBtu lb/hr	3-Hour Rolling 3-Hour Rolling	03/02/2004 R14-0024
VA-0270	VIRGINIA COMMONWEALTH UNIVERSITY VCU EAST PLANT	3	BOILER NATUAL GAS 150.60 MMBtu Each	LOW SULFUR FUEL		0.0007 0.1000	lb/MMBtu each lb/hr each		03/31/2003 VA-50126
NJ-0043	LIBERTY GENERATING STATION LIBERTY GENERATING STATION New Jersey	1	AUXILIARY BOILER 200.00 MMBtu/hr			0.8000 0.0040	lb/hr lb/MMBtu		03/28/2002 BOP990001
TX-0386	CALPINE CONSTRUCTION FINANCE CO. LP AMELLA ENERGY CENTER Texas	1	AUXILIARY BOILER 155 MMBtu/hr			0.843 0.005	lb/hr MMBtu/hr		3/26/2002 N-037
*NJ-0036	AES RED OAK LLC AES RED OAK LLC New Jersey	1	AUXILIARY BOILER 120.00 MMBtu/hr	NATURAL GAS FUEL		0.0043 0.514 0.926	lb/MMBtu lb/hr tpy		10/24/2001 10001
AR-0055	NUCOR YAMATO STEEL NUCOR YAMATO STEEL (ARMOREL) Arkansas	1	REHEAT FURNACE 225.00 MMBtu/hr	CLEAN FUEL		0.0006	lb/MMBtu		10/10/2001 883-AOP-R1(47-0202)
AR-0057	TENASKA ARKANSAS PARTNERS, LP TENASKA ARKANSAS PARTNERS, LP Arkansas	2	BOILER, NATURAL GAS, (2) 122 MMBtu/hr	FUEL SPECIFICATION: NATURAL GAS.		0.006	lb/MMBtu		10/9/2001 1959-AOP-R0 (43-00202)
IN-0085	PSEG LAWRENCEBURG ENERGY FACILITY PSEG LAWRENCEBURG ENERGY FACILITY Indiana	1	AUXILIARY BOILER, NATURAL GAS 124.6 MMBtu/hr	LOW SULFUR NATURAL GAS (LESS THAN %0.8 BY WEIGHT)		0.006 0.7	lb/MMBtu lb/hr		6/7/2001 029-12517-00033
TN-0089	PROCTOR & GAMBLE MANUFACTURING COMPANY PROCTOR & GAMBLE MANUFACTURING COMPANY Tennesse	1	UTILITY BOILER #2 (NAT GAS) 183 MMBtu/hr	FUEL SPEC: SULFUR CONTENT OF FUEL SHALL NOT EXCEED 0.2% BY WEIGHT.					3/5/2001 9252983P
TN-0089	PROCTOR & GAMBLE MANUFACTURING COMPANY PROCTOR & GAMBLE MANUFACTURING COMPANY Tennesse	1	UTILITY BOILER #50-1 (NAT GAS) 225 MMBtu/hr	FUEL SPEC: SULFUR CONTENT OF FUEL SHALL NOT EXCEED 0.2% BY WEIGHT.					3/5/2001 9252983P

Notes:

DEQ/AQD 000774

TABLE 6-A
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for NO_x
Natural Gas Fired Boilers (>100 MMBtu, <250MMBtu)

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
MN-0062	Heartland Corn Products Minnesota	2	Boiler 198.00 MMBtu/hr for both	None		0.04	lb/MMBtu		12/22/05 14300014-005
NC-0101	FORSYTH ENERGY PROJECTS, LLC FORSYTH ENERGY PLANT North Carolina	1	AUXILLIARY BOILER 110.20 MMBtu/hr	LOW-NOX BURNERS GOOD COMBUSTION CONTROL AND CLEAN BURNING LOWSULFUR FUEL (NATURAL GAS).		15.1300 0.1370	lb/hr lb/MMBtu	3-hour	09/29/2005 00986R1
NE-0024	CARGILL, INC. CARGILL - BLAIR PLANT Nebraska	3	BOILERS A, B & C 198.00 MMBtu/hr	LOW NOX BURNERS, INDUCED DRAFT FLUE GAS RECIRCULATION		0.07	lb/MMBtu		08/22/2004 57902CS6
MS-0069	E. I. DUPONT DE NEMOURS DUPONT DELISLE FACILITY Mississippi	1	BOILER #3 231.00 MMBtu/hr	LOW-NOX BURNER WITH FGR.		0.0900 20.7900	lb/MMBtu lb/hr		06/08/2004 1020-00115
MS-0069	E. I. DUPONT DE NEMOURS DUPONT DELISLE FACILITY Mississippi	1	BOILER #4 231.00 MMBtu/hr	LOW-NOX BURNER WITH FGR.		0.0580 13.4000	lb/MMBtu lb/hr		06/08/2004 1020-00115
MS-0069	E. I. DUPONT DE NEMOURS DUPONT DELISLE FACILITY Mississippi	1	BOILER (RENTAL/TEMPORARY) 231.00 MMBtu/hr	LOW-NOX BURNER WITH FGR.		0.0900 20.7900	lb/MMBtu lb/hr		06/08/2004 1020-00115
OH-0241	MILLER BREWING COMPANY MILLER BREWING COMPANY - TRENTON Ohio	2	BOILER (2), NATURAL GAS 238.00 MMBtu/hr	OVERFIRE AND SIDE FIRE AIR TO REDUCE FLAME TEMERATURE		0.7000 1375.9000	lb/MMBtu tpy	12-Month Rolling	05/27/2004 14-05515
ID-0015	J R SIMPLOT COMPANY J R SIMPLOT COMPANY - DON SIDING PLANT Indiana	1	BOILER 175.00 MMBtu/hr	LOW-NOX BURNER		0.0400 7.0000 30.7000	lb/MMBtu lb/hr tpy	30-Day Rolling	04/05/2004 T1-9507-114-1
WV-0023	LONGVIEW POWER, LLC MAIDSVILLE West Virginia	1	AUXILIARY BOILER 225.00 MMBTu/hr	LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES		0.098	lb/MMBtu	3-Hour Rolling	03/02/2004 R14-0024
NC-0106	UNIVERSITY OF NORTH CAROLINA - CHAPEL HILL UNIVERSITY OF NORTH CAROLINA - CHAPEL HILL North Carolina	2	MANNING STEAM PLANT (TWO BOILERS) 249.00 MMBtu Each	THE BOILERS ARE EQUIPPED WITH LOW NOX BURNERS AND FGR		BACT DOES NOT APPLY TO NONPROFIT EDUCATIONAL INSTALLATIONS.			02/10/2004 03069T16
WI-0204	UNITED WISCONSIN GRAIN PRODUCERS UWGP - FUEL GRADE ETHANOL PLANT Wisconson	1	BOILER /OXIDIZER (DRYER / DISTILLATION) 140.00 MMBtu	BOILER / BURNER DESIGN		0.095	lb/MMBtu		08/14/2003 03-DCF-048
VA-0278	VIRGINIA COMMONWEALTH UNIVERSITY VCU EAST PLANT Virginia	3	BOILER NATUAL GAS 150.60 MMBtu Each	LOW NOX BURNERS FLUE GAS RECIRCULATION, AND GOOD OPERATING PROCEDURES		0.1000 0.0800 15.6000	lb/MMBtu lb/MMBtu lb/hr	30-Day Rolling Annual Avg.	03/31/2003 VA-50126
CO-0052	ROCKY MOUNTAIN ENERGY CENTER, LLC. ROCKY MOUNTAIN ENERGY CENTER, LLC. Colorado	1	NATURAL GAS FIRED BOILER (AUXILIARY BOILER) 129.00 MMBtu/hr	OPERATION IS LIMITED TO 1900 H/YR. LOW NOX COMBUSTION SYSTEM.		0.038	lb/MMBtu		08/11/2002 02WE0228
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING, L.L.C. Tennesse	1	BOILER, NO. 10 180.00 MMBtu/hr			0.06	lb/MMBtu		04/03/2002 0101-08PC AND 1010 05PCR
NJ-0043	LIBERTY GENERATING STATION LIBERTY GENERATING STATION New Jersey	1	AUXILIARY BOILER 200.00 MMBtu/hr	SCR		0.2 7.2000 0.0360	lb/MMBtu lb/hr lb/MMBtu (standard)		03/28/2002 BOP990001
TX-0386	CALPINE CONSTRUCTION FINANCE CO. LP AMELLA ENERGY CENTER Texas	1	AUXILIARY BOILER 155 MMBtu/hr			6.2 0.04	lb/hr lb/MMBtu		3/26/2002 N-O37
WV-0015	E. I. DUPONT DE NEMOURS AND COMPANY E.I. DUPONT - WASHINGTON WORKS West Virginia	1	BOILER, NATURAL GAS 181.00 MMBtu/hr	BOILER USES LOW-NOX BURNERS, FLUE GAS RECIRCULATION AND COMBUSTION CONTROLS TO CONTROL NOX.	46.24%	18.1 79.28 0.1	lb/hr tpy lb/MMBtu		1/2/2002 R14-0014
FL-0251	NEW HOPE POWER PARTNERSHIP OKEELANTA CORPORATION SUGAR MILL Florida	1	BOILER, NATURAL GAS 211.00 MMBtu/hr	LOW NOX BURNERS W/FLUE GAS RECIRCULATION AND GOOD COMBUSTION.		0.06	lb/MMBtu		10/29/2001 PSD-FL-169A
DE-0017	SPI POLYOLS, INC. SPI POLYOLS, INC. Delaware	1	BOILER #4, NATURAL GAS 115.00 MMBtu/hr	MAINTAIN EXCESS OXYGEN LEVELS BELOW 5.5% AT LEAST 75% OF OPERATING TIME. ALSO ANNUAL BURNER TUNE-UPS REQUIRED.		0.28	lb/MMBtu		10/26/2001 AQM-003/00426

DEQ/AQD 000775

TABLE 6-A

NSR RACT/BACT/LAER Clearinghouse Database

BACT-PSD Sources for NO_x

Natural Gas Fired Boilers (>100 MMBtu, <250MMBtu)

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
*NJ-0036	AES RED OAK LLC AES RED OAK LLC New Jersey	1	AUXILIARY BOILER 120.00 MMBtu/hr	LIMITED OPERATION OF 3600 H/YR		0.036 4.32	lb/MMBtu lb/hr		10/24/2001 10001
AR-0057	TENASKA ARKANSAS PARTNERS, LP TENASKA ARKANSAS PARTNERS, LP Arkansas	2	BOILER, NATURAL GAS, (2) 122 MMBtu/hr	FLUE GAS RECIRCULATION (FGR).		0.04	lb/MMBtu		10/9/2001 1959-AOP-R0 (43-00202)
IN-0085	PSEG LAWRENCEBURG ENERGY FACILITY PSEG LAWRENCEBURG ENERGY FACILITY Indiana	1	AUXILIARY BOILER, NATURAL GAS 124.6 MMBtu/hr	LOW NOX BURNERS. NATURAL GAS ONLY		0.036 4.49	lb/MMBtu lb/hr		6/7/2001 029-12517-00033

Notes:

Attachment 7

Attachment 7
Basin Electric Power Cooperative
Dry Fork Station
Auxiliary Equipment Emission Calculations
Revision 03/02/2006

Emission Workbook sheets include:

Source Number	Source Name
Dry Fork Station	
ES1-02	**Unit 1 Auxiliary Boiler**
ES1-03	**Diesel Fire Pump**
ES1-05	**Diesel Generator**
ES1-06	**Inlet Gas Heater**

Basin Electric Power Cooperative
Dry Fork Station
Unit 1 Auxiliary Boiler (ES1-02)
Criteria Pollutant Potential To Emit

Heat Input Rating (MMBTU/hr)	134.1
Fuel Type	Natural Gas
Maximum NG Consumption (scf/hr)	131,471
Annual Hours of Operation (hr/yr)	2,000
Annual NG Consumption (MMscf/yr))	263
Natural Gas Heating Value (Btu/scf)	1,020

	Emission Factor (lb/MMBTU)	Emission Factor (lb/MMscf)	Maximum Hourly Emissions (lb/hr)	Maximum Hourly Emissions (g/s)	Annual Emissions (tpy)
NO_X	0.04		5.36	6.76E-01	5.36
CO	0.08		10.73	1.35E+00	10.73
SO_2	0.0006	0.6	7.89E-02	9.94E-03	7.89E-02
PM_{10}	0.0075	7.6	1.00	1.26E-01	1.00
VOC	0.0054	5.5	7.23E-01	9.11E-02	0.72
Lead	4.90E-07	5.00E-04	6.57E-05	8.28E-06	6.57E-05

Notes:
(1) Emission factors for NO_X and CO obtained from vendor design data - Rentech Boiler Systems, January 2005, Page 7 - Predicted Performance at 100% MCR, Natural Gas.
(2) Emission factors for NO_X and CO were provided with performance guarantees and includes the addition of a low NOx burner and Flue Gas Recirculation.
(3) Emission factors for other criteria pollutants from AP-42 Fifth Edition, Table 1.4-2, Revision 7/98.
(4) Assume Total PM Emission Factor in AP-42, Table 1.4-2 as PM_{10} Emission Factor.

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Basin Electric Power Cooperative
Dry Fork Station
Unit 1 Auxiliary Boiler (ES1-02)
HAP Emissions

Max Heat Input	134	MMBTU/hr	Natural Gas Burned	0.13	MMscf/hr
Annual Heat Input	1,174,716	MMBTU/yr	Natural Gas Burned	263	MMscf/yr

Pollutant	Emission Factor (lb/MMscf)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Source
Arsenic	2.00E-04	2.63E-05	2.63E-05	AP-42, Table 1.4-4
Beryllium	1.20E-05	1.58E-06	1.58E-06	AP-42, Table 1.4-4
Cadmium	1.10E-03	1.45E-04	1.45E-04	AP-42, Table 1.4-4
Chromium	1.40E-03	1.84E-04	1.84E-04	AP-42, Table 1.4-4
Cobalt	8.40E-05	1.10E-05	1.10E-05	AP-42, Table 1.4-4
Manganese	3.80E-04	5.00E-05	5.00E-05	AP-42, Table 1.4-4
Mercury	2.60E-04	3.42E-05	3.42E-05	AP-42, Table 1.4-4
Nickel	2.10E-03	2.76E-04	2.76E-04	AP-42, Table 1.4-4
Selenium	2.40E-05	3.16E-06	3.16E-06	AP-42, Table 1.4-4
Total Metal HAPs		**7.31E-04**	**7.31E-04**	
2-Methylnaphthalene	2.40E-05	3.16E-06	3.16E-06	AP-42, Table 1.4-3
3-Methylchloranthrene	1.80E-06	2.37E-07	2.37E-07	AP-42, Table 1.4-3
7,12-Dimethylbenz(a)anthracene	1.60E-05	2.10E-06	2.10E-06	AP-42, Table 1.4-3
Acenaphthene	1.80E-06	2.37E-07	2.37E-07	AP-42, Table 1.4-3
Acenaphthylene	1.80E-06	2.37E-07	2.37E-07	AP-42, Table 1.4-3
Anthracene	2.40E-06	3.16E-07	3.16E-07	AP-42, Table 1.4-3
Benz(a)anthracene	1.80E-06	2.37E-07	2.37E-07	AP-42, Table 1.4-3
Benzene	2.10E-03	2.76E-04	2.76E-04	AP-42, Table 1.4-3
Benzo(a)pyrene	1.20E-06	1.58E-07	1.58E-07	AP-42, Table 1.4-3
Benzo(b)fluoranthene	1.80E-06	2.37E-07	2.37E-07	AP-42, Table 1.4-3
Benzo(g,h,i)perylene	1.20E-06	1.58E-07	1.58E-07	AP-42, Table 1.4-3
Benzo(k)fluoranthene	1.80E-06	2.37E-07	2.37E-07	AP-42, Table 1.4-3
Chrysene	1.80E-06	2.37E-07	2.37E-07	AP-42, Table 1.4-3
Dibenzo(a,h)anthracene	1.20E-06	1.58E-07	1.58E-07	AP-42, Table 1.4-3
Dichlorobenzene	1.20E-03	1.58E-04	1.58E-04	AP-42, Table 1.4-3
Fluoranthene	3.00E-06	3.94E-07	3.94E-07	AP-42, Table 1.4-3
Fluorene	2.80E-06	3.68E-07	3.68E-07	AP-42, Table 1.4-3
Formaldehyde	7.50E-02	9.86E-03	9.86E-03	AP-42, Table 1.4-3
Hexane	1.80E+00	2.37E-01	2.37E-01	AP-42, Table 1.4-3
Indeno(1,2,3-cd)pyrene	1.80E-06	2.37E-07	2.37E-07	AP-42, Table 1.4-3
Naphthalene	6.10E-04	8.02E-05	8.02E-05	AP-42, Table 1.4-3
Phenanathrene	1.70E-05	2.24E-06	2.24E-06	AP-42, Table 1.4-3
Pyrene	5.00E-06	6.57E-07	6.57E-07	AP-42, Table 1.4-3
Toluene	3.40E-03	4.47E-04	4.47E-04	AP-42, Table 1.4-3
Total Organic HAPs		**2.47E-01**	**2.47E-01**	

Basin Electric Power Cooperative
Dry Fork Station
Fire Pump (ES1-03)

Engine Power (BHP)	360	S&L - 9/26/05
Diesel Fuel Heating Value (Btu/gal)	141,000	
Maximum Fuel Firing Rate (MMBtu/hr)	2.78	Estimated based on BHP
Maximum Hours of Operation (hrs/yr)	500	

Updated Emissions using Tier II emissions from 40 CFR Part 89 for Nonroad Diesel Engines.

	Emission Factor (lbs/hp-hr)	Emissions (lb/hr)	Emissions (tpy)
NO_x	1.06E-02	3.81	0.95
CO	5.73E-03	2.06	0.52
SO_2	2.05E-03	0.74	0.18
PM_{10}	3.30E-04	0.12	0.03
VOC	2.51E-03	0.91	0.23

Notes:
1) Engine power and hours of operation based on Engineering Estimates from S&L received on September 26, 2005.
2) Emission Factors for SO_2 and VOC are from AP-42 Table 3.3-1 for Diesel Fuel.
3) Emission Factors for NOx, PM10, and CO are from 40 CFR Part 89 emission standards for Nonroad Diesel Engines.

EPA Tier 1-4 Nonroad Diesel Engine Emission Standards (Engine Power Category 300 <= hp => 600)

Pollutant	Tier phase in	Emission Factor g/hp-hr	Emission Factor lb/hp-hr	Total HP HP	Emissions (lb/hr)	Emissions (tpy)
NOx AP-42		4.80	0.011	360	3.81	0.95
NOx Tier I	1996-2000	6.9	0.015	360	5.47	1.37
NOx Tier II	2000-2006	4.8	0.011	360	3.81	0.95
NOx Tier III	2006-2008	3	0.007	360	2.38	0.59
NOx Tier IV	2008-2015	0.3	0.001	360	0.24	0.06
CO AP-42		3.03	6.68E-03	360	2.40	0.60
CO Tier I	1996-2000	8.5	1.87E-02	360	6.74	1.69
CO Tier II	2000-2006	2.6	5.73E-03	360	2.06	0.52
CO Tier III	2006-2008	2.6	5.73E-03	360	2.06	0.52
CO Tier IV	2008-2015	2.6	5.73E-03	360	2.06	0.52

PM AP-42			1.00	2.20E-03	360	0.79	0.20
PM Tier I		1996-2000	0.40	8.81E-04	360	0.32	0.08
PM Tier II		2000-2006	0.15	3.30E-04	360	0.12	0.03
PM Tier III		2006-2008	0.15	3.30E-04	360	0.12	0.03
PM Tier IV		2008-2015	0.015	3.30E-05	360	0.01	0.00

Note:

The EPA mandate on sulfur content of fuel effective by 2007 is 500 PPM (0.05%). The EPA mandate by June 2010 is 15 PPM (0.0015%).
Tier III standards only applies to engines from 50 - 750 hp.
Emission standards from Engine Power category 300<= hp =>600

Revision: 03/02/2006

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Basin Electric Power Cooperative
Dry Fork Station
Diesel Generator (ES1-05)

Engine Power (BHP)	2377	S&L - 9/26/05
Diesel Fuel Heating Value (Btu/gal)	141,000	
Maximum Fuel Firing Rate (MMBtu/hr)	16.82	S&L - 9/26/05
Maximum Hours of Operation (hrs/yr)	500	

Updated Emissions using Tier II emissions from 40 CFR Part 89 for Nonroad Diesel Engines.

	Emission Factor (lbs/hp-hr)	Emissions (lb/hr)	Emissions (tpy)
NO_x	1.06E-02	25.13	6.28
CO	5.73E-03	13.61	3.40
SO_2	4.05E-04	0.96	0.24
PM	3.30E-04	0.79	0.20
VOC	7.05E-04	1.68	0.42

Note:
1) Engine power and hours of operation based on engineering estimates from S&L received on September 26, 2005.
2) Emission Factors for SO_2 and VOC are from AP-42 Table 3.4-1 for Diesel Fuel.
3) TOC emissions are essentially equal to VOC emissions.
4) Sulfur content was assumed to be 0.05% of diesel fuel.
The EPA mandate on sulfur content of fuel effective by 2007 is 500 PPM (0.05%). The EPA mandate by June 2010 is 15 PPM (0.0015%).
5) Emission Factors for NOx, PM_{10}, and CO are from 40 CFR Part 89 emission standards for Nonroad Diesel Engines.

EPA Tier 1-4 Nonroad Diesel Engine Emission Standards (Engine Power Category => 750 hp)

Pollutant	Tier phase in	Emission Factor g/hp-hr	Emission Factor lb/hp-hr	Total HP HP	Emissions (lb/hr)	Emissions (tpy)
NOx AP-42		4.80	0.011	2377	25.13	6.28
NOx Tier I	1996-2000	6.9	0.015	2377	36.13	9.03
NOx Tier II	2000-2006	4.8	0.011	2377	25.13	6.28
NOx Tier IV	2011-2014	0.5	0.001	2377	2.62	0.65
NOx Tier IV	2015	0.5	0.001	2377	2.62	0.65

CO AP-42		2.60	5.73E-03	2377	13.61	3.40
CO Tier I	1996-2000	8.5	1.87E-02	2377	44.50	11.13
CO Tier II	2000-2006	2.6	5.73E-03	2377	13.61	3.40
CO Tier IV	2011-2014	2.6	5.73E-03	2377	13.61	3.40
CO Tier IV	2015	2.6	5.73E-03	2377	13.61	3.40
PM AP-42		0.15	3.30E-04	2377	0.79	0.20
PM Tier I	1996-2000	0.40	8.81E-04	2377	2.09	0.52
PM Tier II	2000-2006	0.15	3.30E-04	2377	0.79	0.20
PM Tier IV	2011-2014	0.07	1.54E-04	2377	0.37	0.09
PM Tier IV	2015	0.022	4.85E-05	2377	0.12	0.03

Note:

The EPA mandate on sulfur content of fuel effective by 2007 is 500 PPM (0.05%). The EPA mandate by June 2010 is 15 PPM (0.0015%).
Tier III standards only applies to engines from 50 - 750 hp.
Emission standards from Engine Power category =>750 hp

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Basin Electric Power Cooperative
Dry Fork Station
Emergency Diesel Generator (ES1-05)
HAP Emissions

Engine Power (BHP)	2,377
Maximum Fuel Firing Rate (MMBtu/hr)	16.82
Maximum Hours of Operation (hrs/yr)	500

Pollutant	Emission Factor (lb/MMBtu)	Annual Emissions (lb/yr)	Source
Benzene	7.76E-04	6.53E+00	AP-42, Table 3.4-3
Toulene	2.81E-04	2.36E+00	AP-42, Table 3.4-3
Xylenes	1.93E-04	1.62E+00	AP-42, Table 3.4-3
Formaldehyde	7.89E-05	6.64E-01	AP-42, Table 3.4-3
Acetaldehyde	2.52E-05	2.12E-01	AP-42, Table 3.4-3
Acrolein	7.88E-06	6.63E-02	AP-42, Table 3.4-3
Naphthalene	1.30E-04	1.09E+00	AP-42, Table 3.4-4
Total HAPs		**1.25E+01**	

Notes:
1) Emission Factors are from AP-42 Table 3.4-3 and Table 3.4-4.

Basin Electric Power Cooperative
Dry Fork Station
Unit 1 Inlet Gas Heater (ES1-06)
Criteria Pollutant Potential To Emit

Heat Input Rating (MMBTU/hr)	8.36
Fuel Type	Natural Gas
Maximum NG Consumption (scf/hr)	8,196
Annual Hours of Operation (hr/yr)	2,000
Annual NG Consumption (MMscf/yr))	16.4
Natural Gas Heating Value (Btu/scf)	1,020

	Emission Factor (lb/MMscf)	Maximum Hourly Emissions (lb/hr)	Maximum Hourly Emissions (g/s)	Annual Emissions (tpy)	Emission Factor (lb/MMBtu)
NO_X	100	8.20E-01	1.03E-01	0.82	0.10
CO	84	6.88E-01	8.67E-02	0.69	0.08
SO_2	0.6	4.92E-03	6.20E-04	4.92E-03	0.0006
PM_{10}	7.6	6.23E-02	7.85E-03	0.06	0.0075
VOC	5.5	4.51E-02	5.68E-03	0.05	0.0054
Lead	5.00E-04	4.10E-06	5.16E-07	4.10E-06	4.90E-07

Notes:
1) Information for the Inlet Gas Heater based on the engineering estimates.
2) Emission factors for criteria pollutants from AP-42 Fifth Edition, Table 1.4-1 and Table 1.4-2.
(3) Assume Total PM Emission Factor in AP-42, Table 1.4-2 as PM_{10} Emission Factor.

Attachment 8

TABLE 1-B
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for CO
Gas Inlet Heater

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
IA-0060	ENTERGY HAWKEYE GENERATING, LLC Iowa	1	AUXILIARY BOILER 48.5 MMBtu/hr	Good Combustion Practice		0.073	lb/MMBtu		7/23/2002 01-687
IA-0060	ENTERGY HAWKEYE GENERATING, LLC Iowa	1	FUEL PREHEATER 6.5 MMBtu/hr	Good Combustion Practice		0.033	lb/MMBtu		7/23/2002 01-687
IA-0058	MIDAMERICAN ENERGY GREATER DES MOINES ENERGY CENTER Iowa	1	AUXILIARY BOILER 68 MMBtu/hr			0.084 25.1	lb/MMBtu tpy		4/10/2002 77-13-002
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING,	5	HEATERS, (5) 50 MMBtu/hr			0.07	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING,	1	HEATER, ISOM ADSORBER 9.1 MMBtu/hr			0.035	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING,	1	NHDS NO. 1 CHARGE HEATER 42.2 MMBtu/hr			0.01	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING,	1	BOILER, NO. 9 95 MMBtu/hr			0.09	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING,	1	CCR STABILIZATION REBOILER 54 MMBtu/hr			0.1	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TX-0378	ATOFINA PETROCHEMICALS INC LA PORTE POLYPROPYLENE PLANT	1	PACKAGE BOILER BO-4 60 MMBtu/hr			4.84 21.19 0.08	lb/hr tpy lb/MMBtu		11/5/2001 PSD-TX-989
WY-0060	WILLIAMS FIELD SERVICES CO. WILLIAMS FIELD SERVICES CO./ECHO SPRINGS GAS PLANT Wyoming	1	PROCESS HEATER, REGENERATION HEATER 11.1 MMBtu/hr	GOOD COMBUSTION		0.7 3.2 0.07	lb/hr tpy lb/MMBtu		3/21/2001 MD-606

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
- Permits issued from 01/01/2001 to Present
- Process Type Code: 19.600 - Misc. Boilers, Furnaces, and Heaters
- Process Type Code: 13.310 - Commercial Sized (<100 MMBtu/hr) Boilers

DEQ/AQD 000788

TABLE 2-B
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for VOC
Gas Inlet Heater

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
OH-0271	SUNOCO SUNOCO INC. Ohio	1	WASTEWATER TREATMENT PROCESS HEATER 8 MMBtu/hr			43.42	tpy		7/27/2004 07-00451
IA-0060	ENTERGY HAWKEYE GENERATING, LLC Iowa	1	AUXILIARY BOILER 48.5 MMBtu/hr	Good Combustion Practice		0.005	lb/MMBtu		7/23/2002 01-687
IA-0060	ENTERGY HAWKEYE GENERATING, LLC Iowa	1	FUEL PREHEATER 6.5 MMBtu/hr	Good Combustion Practice		0.033	lb/MMBtu		7/23/2002 01-687
TX-0378	ATOFINA PETROCHEMICALS INC LA PORTE POLYPROPYLENE PLANT	1	PACKAGE BOILER BO-4 60 MMBtu/hr			0.35 1.53	lb/hr tpy		11/5/2001 PSD-TX-989

Notes:

DEQ/AQD 000789

TABLE 3-B
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM
Gas Inlet Heater

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
IA-0060	ENTERGY HAWKEYE GENERATING, LLC Iowa	1	AUXILIARY BOILER 48.5 MMBtu/hr	Good Combustion Practice		0.007	lb/MMBtu		7/23/2002 01-687
IA-0060	ENTERGY HAWKEYE GENERATING, LLC Iowa	1	FUEL PREHEATER 6.5 MMBtu/hr	Good Combustion Practice		0.01	lb/MMBtu		7/23/2002 01-687

Notes:

TABLE 4-B
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM_{10}
Gas Inlet Heater

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
OH-0271	SUNOCO SUNOCO INC. Ohio	1	WASTEWATER TREATMENT PROCESS HEATER 8 MMBtu/hr			0.02	lb/MMBtu		7/27/2004 07-00451
IA-0060	ENTERGY HAWKEYE GENERATING, LLC Iowa	1	AUXILIARY BOILER 48.5 MMBtu/hr	Good Combustion Practice		0.007	lb/MMBtu		7/23/2002 01-687
IA-0060	ENTERGY HAWKEYE GENERATING, LLC Iowa	1	FUEL PREHEATER 6.5 MMBtu/hr	Good Combustion Practice		0.01	lb/MMBtu		7/23/2002 01-687
IA-0058	MIDAMERICAN ENERGY GREATER DES MOINES ENERGY CENTER Iowa	1	AUXILIARY BOILER 68 MMBtu/hr			0.0076 2.27	lb/MMBtu tpy		4/10/2002 77-13-002
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING, L.L.C. Tennesse	5	HEATERS, (5) 50 MMBtu/hr			0.005	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING, L.L.C. Tennesse	1	HEATER, ISOM ADSORBER 9.1 MMBtu/hr			0.014	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING, L.L.C. Tennesse	1	NHDS NO. 1 CHARGE HEATER 42.2 MMBtu/hr			0.014	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING, L.L.C. Tennesse	1	BOILER, NO. 9 95 MMBtu/hr			0.0075	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING, L.L.C. Tennesse	1	CCR STABILIZATION REBOILER 54 MMBtu/hr			0.005	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TX-0378	ATOFINA PETROCHEMICALS INC LA PORTE POLYPROPYLENE PLANT	1	PACKAGE BOILER BO-4 60 MMBtu/hr			0.48 4.11 0.008	lb/hr tpy lb/MMBtu		11/5/2001 PSD-TX-989

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
- Permits issued from 01/01/2001 to Present
- Process Type Code: 19.600 - Misc. Boilers, Furnaces, and Heaters
- Process Type Code: 13.310 - Commercial Sized (<100 MMBtu/hr) Boilers

DEQ/AQD 000791

TABLE 5-B
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for SO_2
Gas Inlet Heater

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
TX-0378	ATOFINA PETROCHEMICALS INC LA PORTE POLYPROPYLENE PLANT	1	PACKAGE BOILER BO-4 60 MMBtu/hr			0.95 4.17 0.02	lb/hr tpy lb/MMBtu		11/5/2001 PSD-TX-989

Notes:

TABLE 6-B
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for NO_x
Gas Inlet Heater

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
IA-0060	ENTERGY HAWKEYE GENERATING, LLC Iowa	1	AUXILIARY BOILER 48.5 MMBtu/hr	Good Combustion Practice		0.034	lb/MMBtu		7/23/2002 01-687
IA-0060	ENTERGY HAWKEYE GENERATING, LLC Iowa	1	FUEL PREHEATER 6.5 MMBtu/hr	Good Combustion Practice		0.054	lb/MMBtu		7/23/2002 01-687
IA-0058	MIDAMERICAN ENERGY GREATER DES MOINES ENERGY CENTER Iowa	1	AUXILIARY BOILER 68 MMBtu/hr			0.05 16.4	lb/MMBtu tpy		4/10/2002 77-13-002
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING, L.L.C. Tennessee	5	HEATERS, (5) 50 MMBtu/hr			0.03	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING,	1	HEATER, ISOM ADSORBER 9.1 MMBtu/hr			0.14	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING,	1	NHDS NO. 1 CHARGE HEATER 42.2 MMBtu/hr			0.073	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING,	1	BOILER, NO. 9 95 MMBtu/hr			0.084	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C. WILLIAMS REFINING & MARKETING,	1	CCR STABILIZATION REBOILER 54 MMBtu/hr			0.06	lb/MMBtu		4/3/2002 0101-08PC AND 1010 05PCR
TX-0378	ATOFINA PETROCHEMICALS INC LA PORTE POLYPROPYLENE PLANT	1	PACKAGE BOILER BO-4 60 MMBtu/hr	ULTRA LOW-NOX BURNERS		0.9 3.94 0.015	lb/hr tpy lb/MMBtu		11/5/2001 PSD-TX-969
WY-0060	WILLIAMS FIELD SERVICES CO. WILLIAMS FIELD SERVICES CO./ECHO SPRINGS GAS PLANT Wyoming	1	PROCESS HEATER, REGENERATION HEATER 11.1 MMBtu/hr	LOW NOX BURNERS		0.4 1.9 0.04	lb/hr tpy lb/MMBtu		3/21/2001 MD-606

Notes:

DEQ/AQD 000793