Plant Washington

Prevention of Significant Deterioration Air Permit Application

Supplemental Data

Prepared for:

Power4Georgians, LLC

258 N. Harris Street
P.O Box 258
Sandersville, Georgia 31082

Prepared by:

MACTEC Engineering and Consulting, Inc.
3200 Town Point Drive NW, Suite 100
Kennesaw, Georgia 30144

January 17, 2008
(November 26, 2008 – Supplemental Data)

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LIST OF ACRONYMS AND ABBREVIATIONS

Acronym	**Definition**
ACFM	Actual Cubic Feet per Minute
ACGIH	American Conference of Governmental Industrial Hygienists
AEGI	Amine Enhanced Gas Injection
AERMAP	AERMOD Mapping Program
AERMOD	ARMS/EPA Regulatory Model
AGR	Advanced Gas Reburning
AHPC	Advanced Hybrid Particulate Collector
AOI	Area of Impact
ARMS	AERMOD Retrieval Modeling System
BACT	Best Achievable Control Technology
BART	Best Available Retrofit Technology
BMP	Best Management Practice
BPIP	Building Profile Input Program
Btu	British Thermal Unit(s)
Btu/hr	British Thermal Unit(s) per Hour
Btu/lb	British Thermal Unit per Pound
$Ca(OH)_2$	Slaked Lime or Hydrated Lime
CAIR	Clean Air Interstate Rule
CALPUFF	(Dispersion Model Name)
CAMR	Clean Air Mercury Rule
$CaSO_4 \cdot 2H2O$	Calcium Sulfate (Gypsum)
CDS	Circulating Dry Scrubber
CEM	Continuous Emission Monitor
CFB	Circulating Fluidized Bed
CFR	Code of Federal Regulations
CISWI	Commercial and Industrial Solid Waste Incineration
CO	Carbon Monoxide
COALQUAL	Coal Quality
D.C.	District of Columbia
DDF	Data Decryption Field

LIST OF ACRONYMS AND ABBREVIATIONS
(Continued)

Acronym	**Definition**
DEM	Digital Elevation Model
DSI	Dry Sorbent Injection
EMC	Electric Membership Cooperatives
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitators
F	Fahrenheit
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
FLAG	Federal Land Managers Air Quality Related Values Workgroup
FLGR	Fuel Lean Gas Reburning
FLM	Federal Land Management
g/s	Grams per Second
GA EPD	Georgia Environmental Protection Division
GCP	Good Combustion Practice
gr/dscf	Grain(s) per Dry Standard Cubic Foot
H_2SO_4	Sulfuric Acid
HAP	Hazardous Air Pollutant
HCl	Hydrochloric Acid
HEM	Human Exposure Model
HF	Hydrogen Fluoride
Hg	Mercury
Hg^{2+}	Oxidized Mercury
$HgCl_2$	Mercuric Chloride
HWC	Hazardous Waste Combustor
$\mu g/m^3$	Microgram(s) per Cubic Meter
hp	Horsepower
ID	Identification
IGCC	Integrated Gasification Combined Cycle
in/yr	Inch per Year

LIST OF ACRONYMS AND ABBREVIATIONS
(Continued)

Acronym	**Definition**
ISCST3	Industrial Source Complex Short Term
kPa	Kilopascals
kV	Kilovolts
kw	kilowatts
LAER	Lowest Achievable Emission Rate
lb/MMBtu	Pound(s) per Million British Thermal Unit
LCC	Lambert Conformal Coordinate
LNB	Low NO_X Burner
m^3	Cubic Meters
MACT	Maximum Achievable Control Technology
MACTEC	MACTEC Engineering and Consulting, Inc.
MEI	Maximally Exposed Individuals
MEL	Magnesium-Enhanced Lime
mg/L	Milligrams per Liter
MGLC	Maximum Ground-level Concentration
MMBtu/hr	Million British Thermal Unit(s) per Hour
MW	Megawatts
MWH	Megawatt hours
N_2	Molecular Nitrogen
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emissions Standards for Hazardous Air Pollutants
ng/J	Nanogram per Joule
NEI	Nuclear Energy Institute
NGR	Natural Gas Reburning
NH_3	Ammonia
NO_2	Nitrogen Dioxide
NO	Nitrogen Monoxide
NO_x	Nitrogen Oxide
NSCR	Non-selective Catalytic Reduction
NSPS	New Source Performance Standard

LIST OF ACRONYMS AND ABBREVIATIONS
(Continued)

Acronym	Definition
NSR	New Source Review
OFA	Over-fired Air
OSHA	Occupational Safety and Health Administration
PAC	Powdered Activated Carbon
Pb	Lead
PM	Particulate Matter
PM_{10}	Particulate Matter Less Than 10 Microns
$PM_{2.5}$	Particulate Matter Less Than 2.5 Microns
ppb	Part(s) per Billion
ppm	Part(s) per Million
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
psia	Pound(s) per Square Inch Absolute
psig	Pound(s) per Square Inch Gauge
PSM	Process Safety Management
RACT	Reasonably Achievable Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RfC	Reference Concentration
RMP	Risk Management Programs
ROFA	Rotating Opposed Fire Air
RTC	Report to Congress
SAM	Sulfuric Acid Mist
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SCRAM	Support Center for Regulatory Air Models
SDA	Spray Dryer Absorption
SIA	Significant Impact Area
SIL	Significant Impact Level
SIP	State Implementation Plan
SMHF	Solid Materials Handling Facility

LIST OF ACRONYMS AND ABBREVIATIONS
(Continued)

Acronym	Definition
SNCR	Selective Non-catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
T/hr	Tons per Hour
TDS	Total Dissolved Solids
TRI	Toxic Release Inventory
UBC	Unburned Carbon
USB	Ultra Supercritical Boilers
USEPA	U.S. Environmental Protection Agency
USGS	U.S. Geological Survey
USNPS	U.S. National Park Service
UTM	Universal Transverse Mercator
VISCREEN	Visibility Screening Model
VISTAS	Visibility Improvement – State and Tribal Association of the Southeast
VOC	Volatile Organic Compound
WESP	Wet Electrostatic Precipitator
WFGD	Wet Flue Gas Desulfurization

1.0 INTRODUCTION

Plant Washington is being developed by Power4Georgians, LLC, a consortium of ten electric membership cooperatives (EMCs) in Georgia, to provide reliable and affordable electricity. Review of the future power demands indicates a 5 percent per year increase in demand due to changes in population beyond the current nearly 700,000 commercial and residential members. The facility will have one unit with a total net generating capacity of 850 megawatts (MW). The proposed unit is intended to be operational in May 2014.

The proposed location for Plant Washington is a 1,641-acre site in Washington County, northeast of the City of Sandersville, Georgia. Figures 1-1 and 1-2 show the approximate location of the planned project site near Sandersville. The facility will employ 100 to 150 people and will consist of the power block, office areas, rail service approach and rail sidings, and looped 500-kilovolt (kV) power transmission lines. In addition, a solid materials handling facility (SMHF) will be maintained on-site for storage of limestone, gypsum, and bottom/fly ash. The plant will also have various water storage basins to hold raw water, wastewater effluent, and stormwater runoff.

The proposed project consists of one Supercritical Pulverized Coal (SCPC) fired steam generating unit and associated steam turbine generators along with other auxiliary equipment. The generating plant will be rated at approximately 850 MW net output capacity, and will be designed to burn sub-bituminous coal (Powder River Basin, or PRB coal) and as an alternate fuel up to a 50/50 blend of eastern bituminous coal (Illinois #6) and PRB. Although the facility will be designed for use of PRB and Illinois #6 coals, the facility will also have the capability of utilizing bituminous and subbituminous coals with equivalent characteristics of PRB and Illinois #6. Supercritical power plants use a boiler/turbine system that operates at a high enough pressure and temperature (greater than 3200 pounds per square inch gauge [psig] and 1075ºF) that water is no longer considered a gas or a liquid but is characterized as a supercritical fluid with thermodynamic properties that are in between the two phases. Operating in this mode allows a supercritical plant to be more energy efficient than a subcritical plant which generally operates at lower steam temperatures (usually 2,400 psig and 850 degrees Fahrenheit). Therefore, a supercritical power plant produces more power from less coal with lower emissions. Supercritical power plants were first pioneered in the United States as early as 1957 and many large power plants constructed after 1970 are of this design. Today, this design is considered state-of-the-art for power plants in the United States. The power industry is continuously improving technology and some recent units are being called “ultra

supercritical boilers" (USB). Unlike the term supercritical, which refers to a specific temperature and pressure where a phase change occurs, there is no generally accepted industrywide definition of what constitutes "ultra-supercritical". The term USB is often used loosely in vendor literature and news items since there is no clear definition for an ultra supercritical unit. The Electric Power Research Institute (EPRI) in their literature has defined ultra supercritical units as having final steam temperatures greater than 1,100 degrees Fahrenheit and pressures greater than 3,625 pounds per square inch acceptable/atmospheric (psia). The project design basis for Plant Washington calls for steam properties approaching these levels.

This project will be a major source of air emissions under the Prevention of Significant Deterioration (PSD) program of New Source Review (NSR) rules. This application contains the appropriate analyses required under that program. Proposed control equipment and emission limits at the facility have been selected based on a Best Available Control Technology (BACT) analysis. The facility will be equipped with Continuous Emission Monitors (CEMs) to record pollutant emissions as required under State and Federal regulations. The following equipment is proposed for use at the facility:

- One coal-fired electric utility steam generating unit with a rated heat input of 8,300 million British Thermal Units per hour (MMBtu/hr) using a supercritical cycle design, which will be equipped with low nitrogen oxide (NO_X) burners, overfire air, Selective Catalytic Reduction (SCR), a fabric filter baghouse, and a Wet Flue Gas Desulfurization (WFGD) System. In addition, emission controls will include sorbent injection systems for the control of sulfuric acid (H_2SO_4) mist (SAM) and mercury (Hg) emissions.
- A steam turbine and associated generator
- Facilities for receiving, handling, storing, blending, and processing two types of coal—Sub-bituminous and Bituminous. The preliminary design coal basis for Plant Washington is based on use of PRB and Illinois #6 coals, with a nominal consumption rate of approximately 417 tons per hour (ton/hr) of blended coal at a 50/50 blend or at a rate of approximately 488 ton/hr when burning only PRB coal, but the facility will be designed to handle any similar subbituminous and bituminous coals.
- Facilities for receiving, handling, and storing anhydrous ammonia, which is a raw material for the SCR system
- Facilities for receiving, handling, storing, and processing limestone, which is a raw material for the WFGD system
- Facilities for receiving, handling, storing, and delivering mercury removal adsorbent (sorbent) and sulfur trioxide (SO_3) removal sorbent (to control SAM emissions)
- A SMHF for handling and storing process byproducts for potential reuse
- An emergency diesel-fired generator

- A diesel engine driven fire pump
- A 240 MMBtu/hr No. 2 fuel oil fired auxiliary boiler

Figure 1-1 Plant Washington Site Vicinity Location

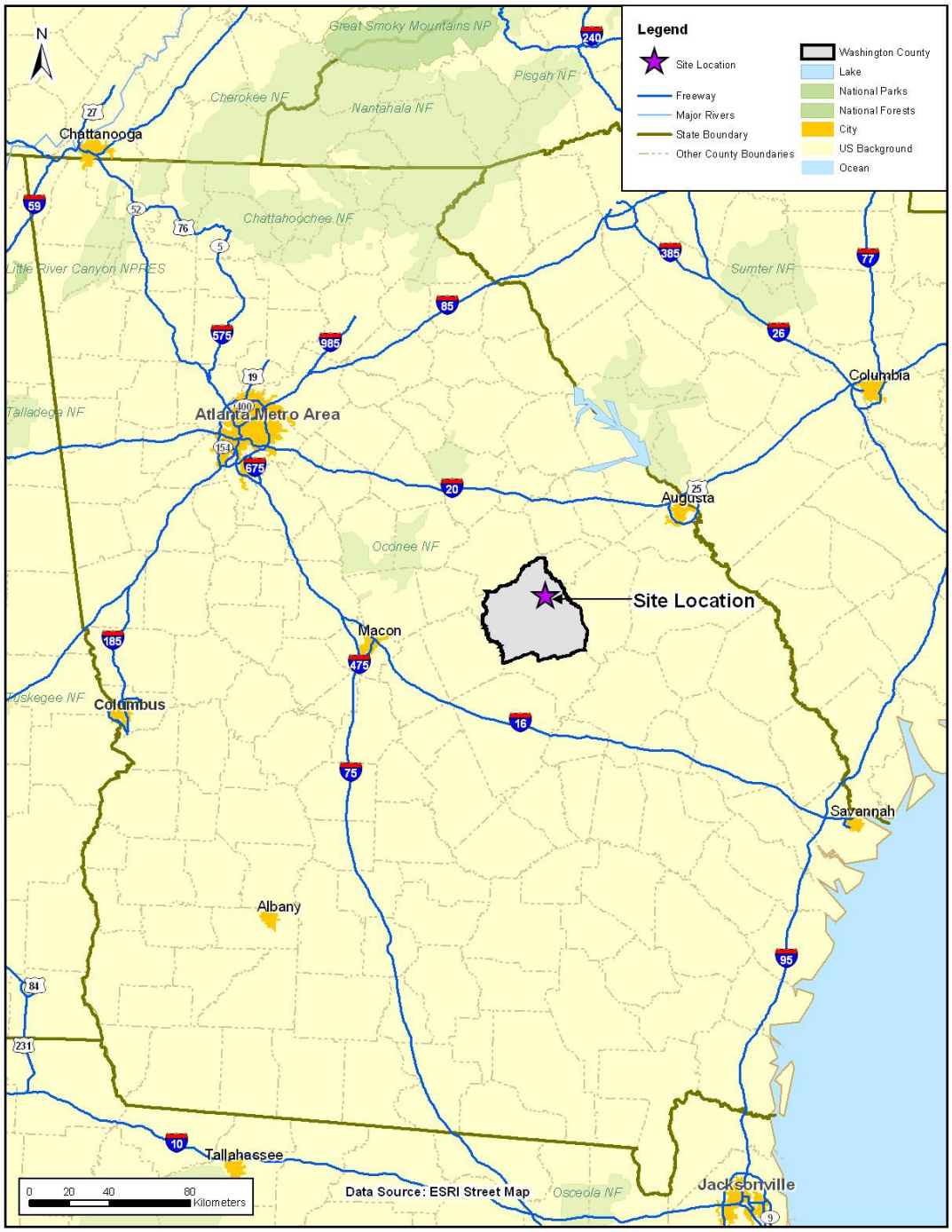

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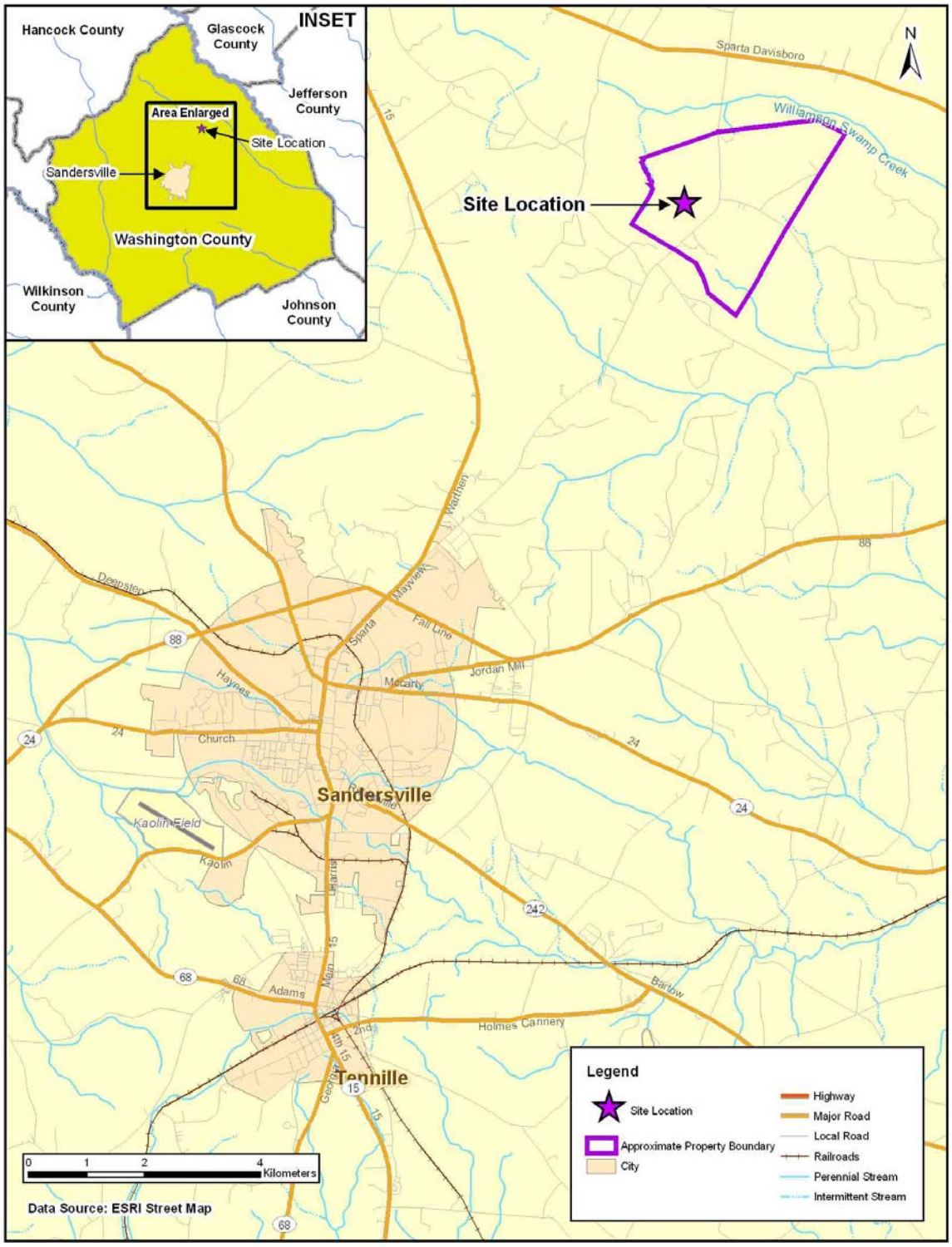
Figure 1-2 Plant Washington Approximate Site Location



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This air permit application includes a process and project description (Section 2), an emission calculation summary and regulatory analysis of the proposed project (Section 3), a BACT analysis (Section 4) for the affected equipment, the required National Ambient Air Quality Standard (NAAQS) and PSD air quality modeling analyses (Section 5), Georgia Air Toxics Modeling (Section 6), Class I Area modeling (Section 7), Class II visibility and an other impacts analysis (Section 8), the required Georgia Environmental Protection Division (GA EPD) permit application forms (Section 9), a Case-By-Case MACT analysis for the facility main boiler and auxiliary boiler (Section 10), and a list of references (Section 11).

The application also includes the following exhibits: emission calculations (Exhibit A) that form the basis of the permitting approach and modeling assessments, the site layout (Exhibit B), air quality modeling information (Exhibit C), an electronic copy of models (Exhibit D), and reference documentation discussed in the Case-by-Case MACT analysis (Exhibit E).

1.1 Power Demand for Georgia

Power4Georgians, LLC is a company formed to ensure that Georgians will continue to have reliable, affordable electric power in the coming years. The company consists of 10 Georgia EMCs that have pooled their resources to construct a baseload power generating facility in middle Georgia. Power4Georgians, LLC, will be the legal entity developing the power plant. The 10 EMCs and their locations are: Upson EMC, Thomaston; Central Georgia EMC, Jackson; Snapping Shoals EMC, Covington; Diverse Power, LaGrange; Excelsior EMC, Metter; GreyStone Power, Douglasville; Jackson EMC, Jefferson; Cobb EMC, Marietta; Pataula EMC, Cuthbert; and Washington EMC, Sandersville. All of these EMCs have independently concluded that, despite efforts in promoting energy conservation, power demand will substantially increase in the years ahead. Although power demand is increasing, the supply of power that the EMC have contracts for will be decreasing, and starting in the year 2009 the EMCs will begin to have a growing gap to fill between the demand for power and the loss of available resources. Figure 1-3 shows the historic annual energy sales to the EMC members of Power4Georgians, LLC from 1996 to 2006, showing a general trend of a 5% increase in power sales to the EMC members. Assuming this increase in demand continues in the future, Figure 1-4 shows the projected increase in peak power demand and the short fall of available power in the coming years. Plant Washington will be a significant step toward filling this energy gap.

Power4Georgians, LLC, is exploring all sources of energy including natural gas, wind, solar, and biomass (such as on-site storage of methane gas, wood chips, and poultry litter-to-energy) to ensure a reliable energy supply. An example of this is the EMCs' the biomass plant in Bleckley County. Many of the co-ops in this project participate in Georgia's Green Power EMC and make green energy available to members. Power generated by Green Power EMC helps meet peak demand but is not sufficient to meet baseload demand.

In reviewing options to meet baseload power requirements, the members of this coalition investigated several possible options for baseload generation. The two options that appear most appropriate for the coalition were nuclear and coal. The nuclear option, Plant Vogtle's expansion, has an anticipated startup of 2016 or later. Consortium members are currently taking power from the existing Vogtle units, and the current forecast assumes that the Consortium will participate in the expansion; however, the Consortium's baseload needs must be met by a date much earlier than 2016.

The first coal option, the proposed Longleaf power plant in southwest Georgia, has been put on hold until an appeal of a court ruling regarding the air permit is resolved. Depending on the outcome of the appeal and various other business issues, that plant could meet some of our needs for baseload, but even with proposed plant capacity, the ten members would be deficient in baseload capacity; therefore, it is necessary for this group (due to reliability and demand requirements) to construct a baseload coal plant. Additional options using renewable and solar energy sources have been investigated, contracted for, and partially implemented. Portions of the load will be served by these energy sources; however, there is not enough capacity to cover our member's energy needs within Georgia.

Figure 1-3 Historic Annual Energy Sales To EMC Members From 1996 to 2006

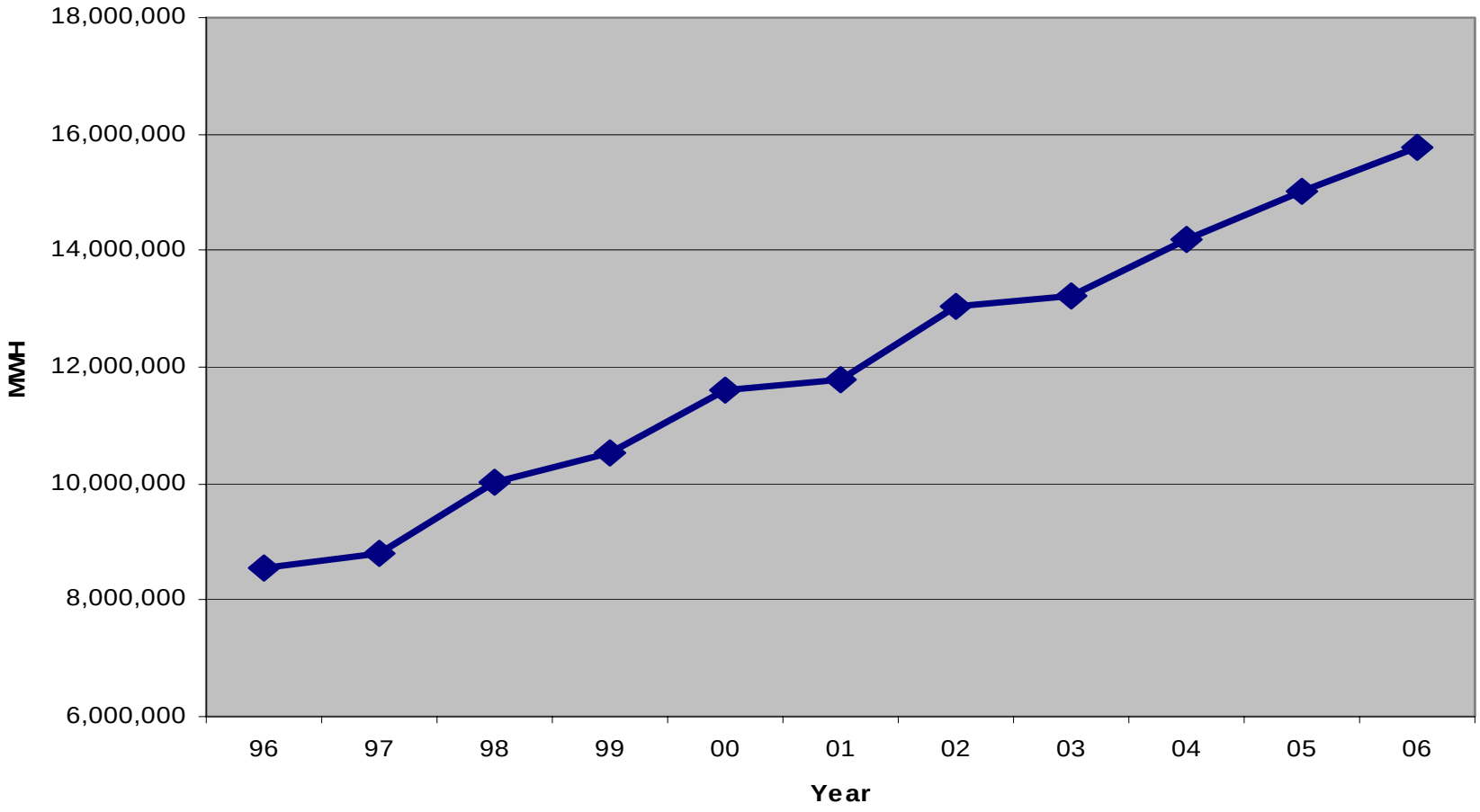

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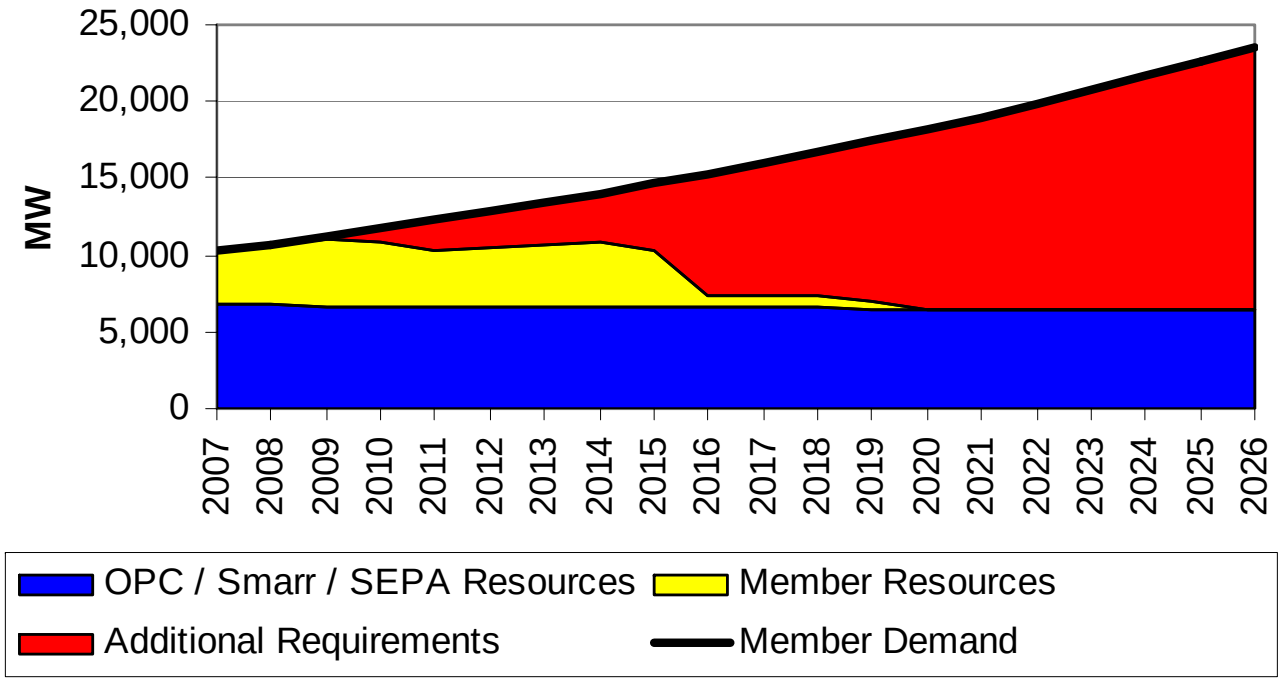
Figure 1-4 EMC Projections of Power Demand and Availability



Prepared by: PBS 11/26/08
Checked by: SAK 11/26/08

2.0 PROCESS DESCRIPTION

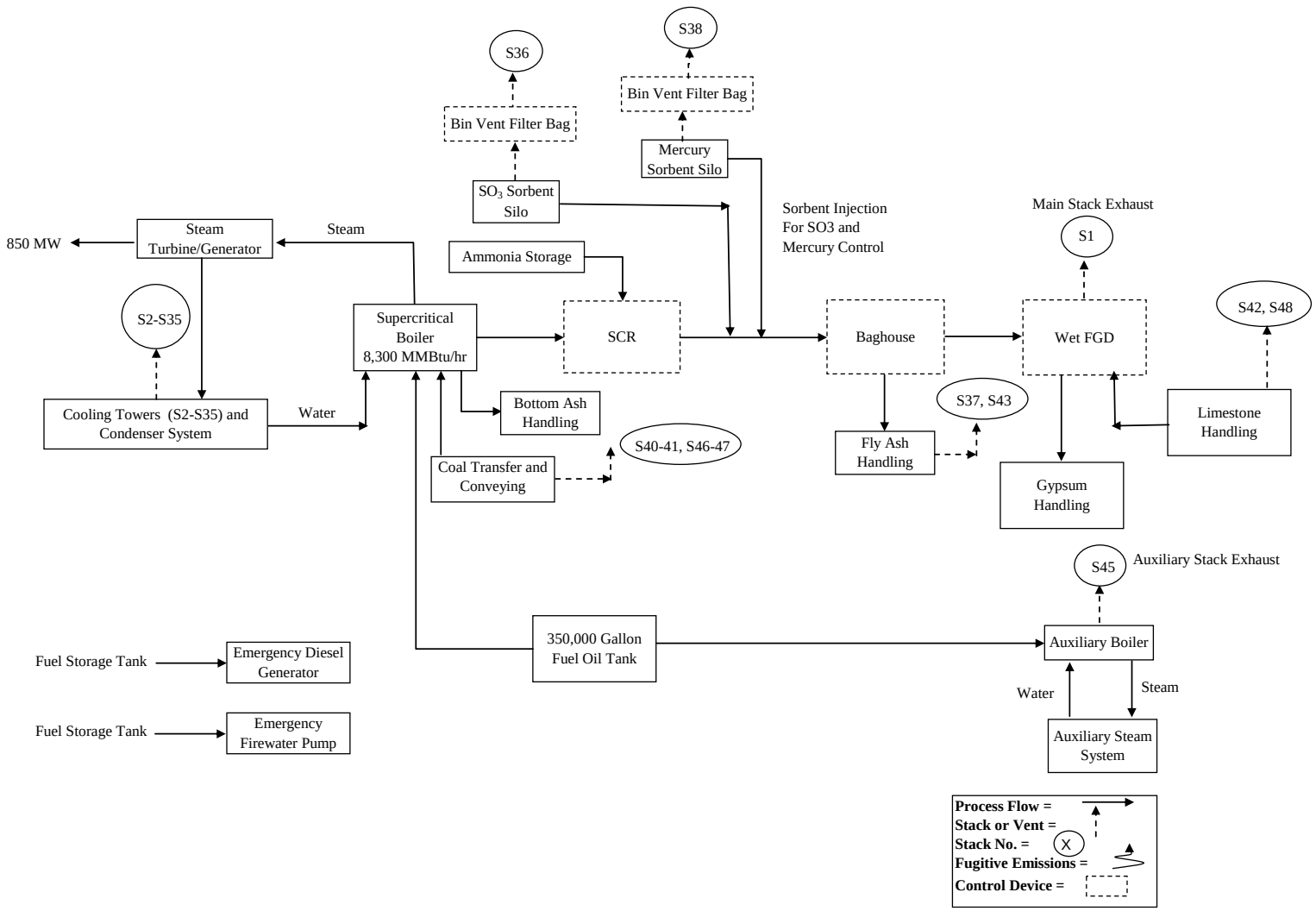
Power4Georgians, LLC proposes to construct and operate a new power generation facility in Washington County near Sandersville, Georgia. The proposed project consists of one SCPC fired steam generating unit and associated steam turbine generator along with other auxiliary equipment. The generating plant will be rated at approximately 850 MW net output capacity, and will be designed to burn sub-bituminous coal (Powder River Basin, or PRB coal), or up to a 50/50 blend of PRB and eastern bituminous coal (Illinois #6). Although the facility will be designed for use of PRB and Illinois #6 coals, the facility will also have the capability of utilizing coals with equivalent characteristics of PRB and Illinois #6. The unit will be normally used for "base load" electricity generating operations. The unit may also operate for extended periods at loads within the operating range of 40 to 100 percent load during the shoulder months (spring and fall). The steam produced by the main facility boiler will be sent to a steam turbine, which in turn will drive a generator making electricity.

The primary fuel will be the low sulfur PRB coal but the alternate fuel blend is needed to keep the plant operational considering the projected demands from other power plants for PRB coal and the potential future constraints on rail transportation from this western location (Wyoming). Both Powder River Basin (PRB) and Illinois #6 coals will be brought to the facility by bottom dump railcars. Coal will be unloaded from the railcars at the railcar unloading facility and sent to the PRB and Illinois #6 active coal piles, with a portion of the coals being sent to the PRB and Illinois #6 inactive coal piles in order to accommodate interruptions of the fuel supply. Coal will be pulled from the PRB and Illinois #6 coal piles, blended to a 50/50 coal blend, and sent to the crushers where the coal is crushed and pulverized. Crushed coal will be fed to conveyors and transferred to fuel storage silos.

Pulverized coal will then be combusted in the facility main boiler. Produced steam will be used to drive a steam turbine, which in turn will create electricity through the mechanical energy created by driving the generator shaft. The facility will be an 850 MW net output capacity electrical generating unit. Emissions from the main facility boiler will be controlled by air pollution control equipment prior to discharge from the main boiler stack. The air pollution control equipment in use to control emissions from the main boiler will include low NOx burners, OFA, and an SCR system for control of NO_X emissions, sorbent injection systems for the control of Sulfuric Acid Mist (SAM) and mercury emissions, a fabric filter for the control of Particulate Matter (PM) emissions, and a wet scrubber (WFGD) for control of sulfur dioxide (SO_2) emissions. Additional pollutants will be controlled through use of the above discussed air pollution control equipment, which is discussed further in the BACT analysis in Section 4.

Figure 2-1 provides an overall process flow diagram of the facility operations surrounding the main facility boiler.

Figure 2-1 Overall Process Flow Diagram



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2.1 PROCESS DESCRIPTION FOR THE POWER BOILER

The SCPC fired boiler will be a pulverized coal single reheat, wall-fired or tangentially-fired boiler with low NO_X burners and overfire air. The unit will be designed to produce very high pressure steam while minimizing the formation of NO_X in the combustion process. NO_X formation is minimized by the use of air staging. Overfire air is injected to the furnace in several different levels. This in effect divides the furnace volume in three different zones: 1) the primary firing zone, 2) the NO_X reduction zone and 3) the final burnout zone. The maximum heat input rate of the boiler will be approximately 8,300 MMBtu/hr (while firing coal). Actual heat input and generator production will depend on a variety of operating variables, including ambient temperature and pressure and the condition of equipment associated with boiler operation. No. 2 fuel oil will be used for unit startup and for flame stabilization. The maximum heat input rate of the boiler while burning No. 2 fuel oil will be 1,300 MMBtu/hr.

Flue gas from the boiler will be passed through a series of control devices. After leaving the furnace, the economized hot flue gases will be sent to two SCR system reactor chambers operating in parallel for the control of NO_X. Anhydrous ammonia, stored in pressurized tanks will be injected into the SCR reactor vessels as the chemical agent for driving the NO_X reduction reaction (ammonia combines with the NO_X in the exhaust gas to ultimately form nitrogen and water vapor). From the SCR chambers the exhaust gases will be directed through an air preheater to recover heat before being sent to a baghouse to control particulate emissions. Before entering the baghouse, the sorbents will be injected into the exhaust gas stream. One sorbent (activated carbon) is used to adsorb the small amount of elemental Hg vapor in the exhaust air while the second sorbent reacts with SO_3 in the exhaust air to prevent sulfuric acid mist formation further downstream. The baghouse removes both the fly ash in the exhaust gas and the sorbents that were added and the reaction products of the sorbents. The gas then passes through induced draft fans. Finally, the exhaust gas passes through a wet limestone scrubber to remove the SO_2 in the gas before being exhausted out the main stack (S1).

Boiler Start up Procedures

The unit cold startup procedure for the main facility boiler will include a 15-hour startup cycle, beginning with the main facility boiler using ultra low sulfur No. 2 distillate fuel oil. The combustion of oil is used to slowly warm the boiler systems to reduce thermal stresses on the boiler system during startup and to provide an ignition source for the coal burners. At the same time the auxiliary boiler produces steam to seal and warm up the steam turbine to assist in the startup process to full load. During the entire start up process, the fabric filter baghouse is used for control of PM emissions. The wet flue gas desulfurization

system (wet scrubber or WFGD) used for control of SO_2 emissions will be in service by approximately four hours into the startup procedure at a reduced emissions efficiency. However, the SCR system, used for control of NO_X emissions, will not be in operation during the startup procedure since the process is ineffective until the equipment reaches a sufficient minimum temperature and the flue gas must be heated to a minimum temperature to minimize the risk of deposition of ammonium sulfates/bisulfates (approximately 600 degrees Fahrenheit). Coal will be introduced to the main boiler after approximately four hours into the startup procedure. As the startup procedure continues, the coal input to the boiler will be increased while the distillate fuel oil input to the boiler will be decreased by progressively turning on pulverizers and coal burners. The SCR system will come online approximately thirteen hours into the startup procedure. The startup procedure will end at hour 15, with the boiler experiencing full coal-based operation.

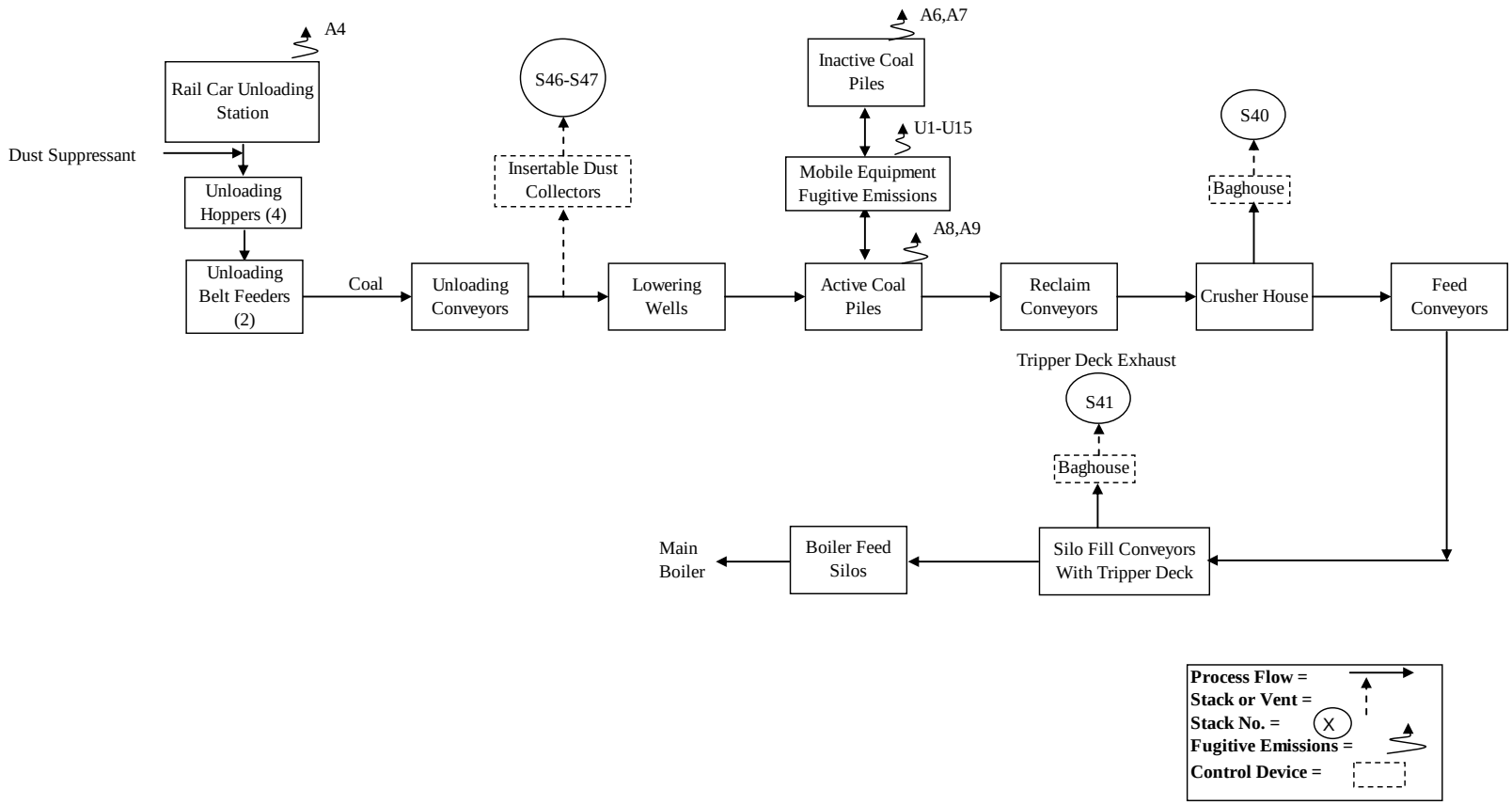
2.2 PROCESS DESCRIPTION FOR COAL HANDLING

Figure 2-2 provides a process flow diagram for the coal handling activities. At the railcar unloading facility, coal is dumped into four underground receiving hoppers which discharge onto underground dual unloading belt feeders. The unloading station will be enclosed (except for the railcar openings) and will use a dust suppression system with the capability to apply a chemical mixture dust suppressant. The dust suppression mixture used at the unloading station will have residual dust suppression characteristics, will remain on the coal for approximately two weeks, and will be applied as necessary to adequately control fugitive dust. During periods of precipitation and/or high humidity, application of the dust suppressant mixture may be discontinued, or a water spray application may be used instead of the chemical mixture as conditions warrant.

The unloading belt feeders will transfer onto the unloading conveyor that moves coal to the transfer point above the Lowering Well. From this point, PRB coal will be dumped into the PRB Lowering Well. When unloading Illinois #6 coal, the coal will be routed to the Illinois #6 Lowering Well via the Transfer/Storage Conveyor. At the lowering wells, the coal will be stacked out to the respective active coal storage piles. A lowering well is simply a large rigid tube with holes in the sides which allows the coal to flow out of the tube and “stack out” into a conical shape. Fugitive dust emissions from the end of the unloading conveyor are controlled by a dust collection system called an “insertable dust collector” (emission points S46 and S47 for PRB and Illinois coal, respectively). To accommodate interruptions of fuel supply, the coal handling system includes inactive coal storage piles for both PRB and Illinois #6 coals next to the respective active piles. Coal is transferred from the active piles to inactive storage using

mobile equipment such as bulldozers and scrapers. When needed, coal will be transferred from the inactive piles to the active piles using mobile equipment. Ninety days of storage (includes active and inactive) will be maintained on-site for all coal.

Figure 2-2 Coal Handling Process Flow Diagram



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Coal is pulled from the active storage piles via eight grizzly hoppers and feeders to two Reclaim Conveyors. Two hoppers from PRB active storage and two hoppers from Illinois #6 active storage feed Reclaim Conveyor 1. Two hoppers from PRB active storage and two hoppers from Illinois #6 active storage feed Reclaim Conveyor 2. Belt scales weighing Illinois #6 and the total coal flow on the reclaim conveyors will facilitate blending the coals to specific ratios. The conveying system includes a tramp metal cleaning system.

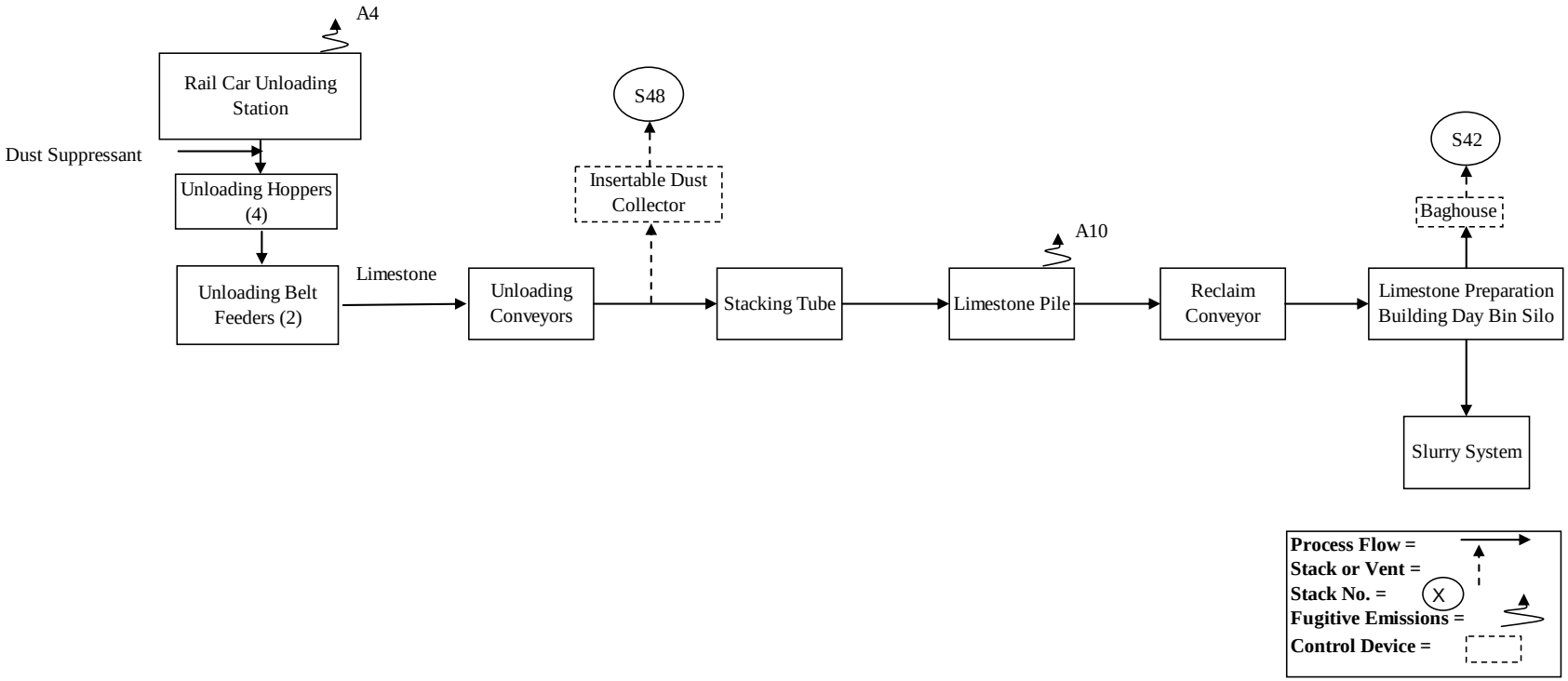
Coal will be conveyed to the Crusher Surge Bin on Reclaim Conveyors 1 and/or 2. In the Crusher House, the coal will be fed from the surge bin to two diverters with fixed grizzlys. From the diverters, the coal is routed to two crushers where the coal is crushed. Dust created from the crushers is controlled by a baghouse (emission point S40). Coal fines will be bypassed around the crushers. The crushed coal will be fed from the crushers to two conveyors, Feed Conveyors 1 and 2. The coal is then distributed to boiler Silo Fill Conveyors 1 and 2 in the Boiler Silo Bay. Silo Fill Conveyors 1 and 2 will be outfitted with traveling trippers used to fill each of the 6 boiler silos for feed to the pulverizers. All the emissions from the conveyors and tripper are controlled by a single baghouse (emission point S41).

2.3 PROCESS DESCRIPTION FOR LIMESTONE HANDLING

Figure 2-3 provides a process flow diagram for the limestone handling activities at the facility. Limestone will be delivered to the site by bottom-dump railcars for use in the WFGD system. At the limestone unloading station, limestone is dumped into four underground receiving hoppers that discharge onto underground dual Unloading Belt Feeders. The enclosed unloading station will use a dust suppression system similar to that in the coal unloading facility. Here, the Unloading Belt Feeders will dump onto the Limestone Unloading Conveyor where limestone is transported to the Limestone Stacking Tube. Here it is stacked out to the Limestone Storage Pile. The unloading conveyor will include a dust collection system called an “insertable dust collector” (emission point S48).

Limestone will be pulled from the storage pile via two grizzly hoppers with vibrating feeders to a single Limestone Reclaim Conveyor. The Reclaim Conveyor will deliver the limestone to the day bin silo located at the limestone reagent preparation area (air exhausted from the bin vent filter point S-42). The conveying system will include a belt scale and a tramp metal cleaning system.

Figure 2-3 Limestone Handling Process Flow Diagram



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2.4 PROCESS DESCRIPTION FOR FLY ASH HANDLING

Figure 2-4 provides a process flow diagram for handling fly ash at the facility. The fly ash system will pneumatically convey dry free flowing ash from the pulse jet fabric filter (baghouse) hoppers and air heater hoppers to the fly ash Storage Silo, which will have a storage capacity of 3,600 tons (5 to 6 days storage). Fly ash will be stored in the silo until load-out to trucks for transfer to the on-site storage facility. The fly ash handling system will be designed to include a vacuum system to transfer ash from the baghouse and air heater hoppers through a filter separator (exhaust point S-43) that deposits the ash into silo. Ash is removed from the silo into a truck load out station through ash pugmills which uses water for dust control. The fly ash handling system serving the baghouse and air heater systems will have a conveying capacity of approximately 50 tons per hour.

The fly ash storage silo will be equipped with a bin vent dust filter, and fly ash mixing/conditioning equipment. The silo and associated bin vent filter will be designed with sufficient bag filtering capacity to support operation of fly ash transport. Each bag filter will operate with an air-to-cloth ratio of approximately 2 to 1 during normal operation. The air-to-cloth ratio is well within the range of optimum performance of the pulse jet bag filter. The silo will vent from the bin vent filter with side exhausts (S-37)

The fly ash storage silo is equipped with a fluidizing air system including the porous fluidizing media, two blowers, and two electric air heaters to enhance gravity flow of ash from the bottom of the silo. Fly ash destined for storage will be conditioned by wetting with water as it is unloaded from the silo to minimize dust generation. The conditioned ash will be unloaded through a chute into trucks for transportation to an on-site storage facility. The system will employ redundant features to ensure dependable operation, including a spare vacuum mechanical exhauster and fluidizing blower. The silo and its associated equipment (fly ash conditioner and automatic bin vent filter) will be designed to accommodate the fly ash from the boiler.

2.5 PROCESS DESCRIPTION FOR BOTTOM ASH HANDLING

Figure 2-5 provides a process flow diagram for the bottom ash handling activities at the facility. The bottom ash handling system collects boiler bottom ash and pyrites from the coal pulverizers for

Figure 2-4 Fly Ash Handling Process Flow Diagram

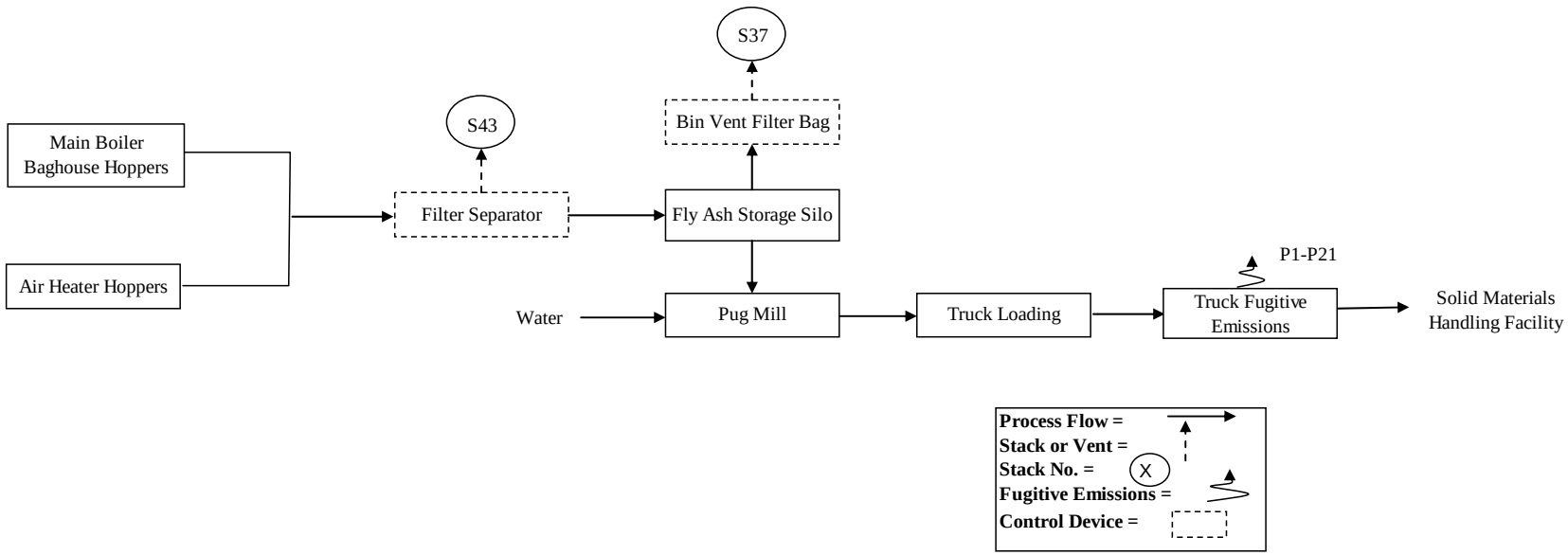

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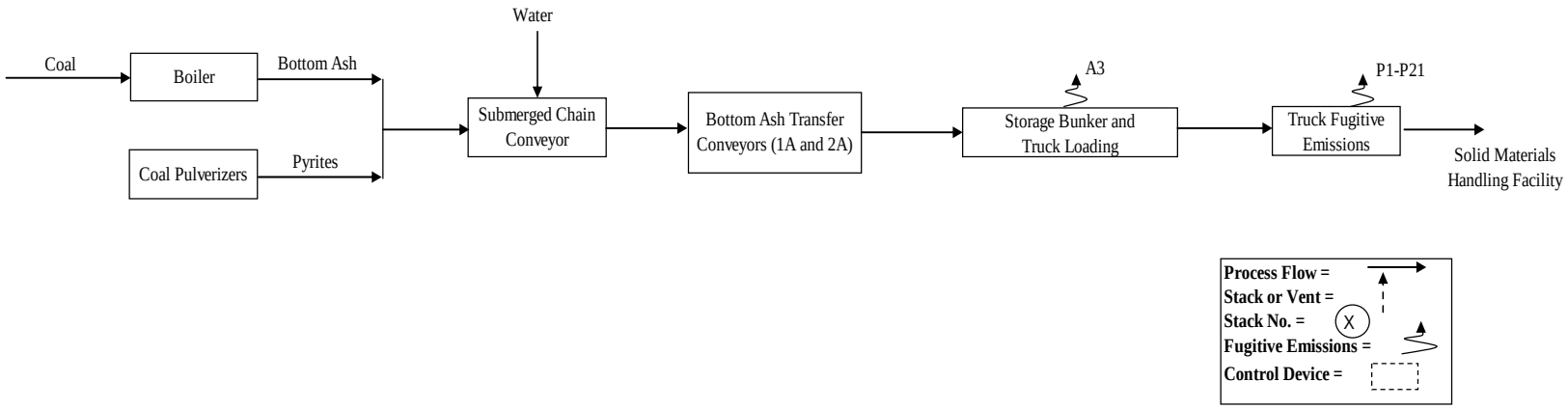
Figure 2-5 Bottom Ash Handling Process Flow Diagram



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disposal. The bottom ash from the boiler furnace is collected in the submerged chain conveyor. The pyrites are sluiced from the pulverizers and fed into the submerged chain conveyor. The drag chain conveyor discharges onto bottom ash transfer conveyor 1A. Bottom ash transfer conveyor 1A discharges onto bottom ash transfer conveyor 1B. Bottom ash transfer conveyor 1B discharges into a three sided ground level bunker for disposal. From the bunker, the bottom ash is loaded onto trucks using mobile equipment for transfer to on-site storage.

2.6 PROCESS DESCRIPTION FOR GYPSUM HANDLING

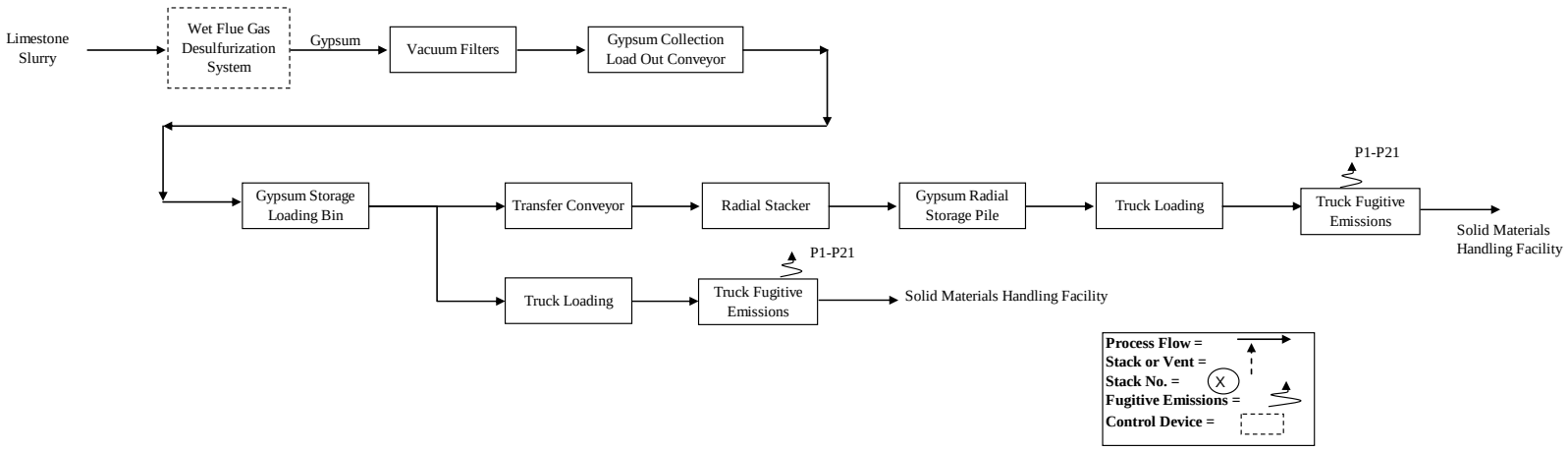
Figure 2-6 provides a process flow diagram for the gypsum handling operations. Operation of the WFGD scrubber will produce gypsum as a by-product, which will be transported to the on-site long-term storage facility. Vacuum belt or drum filters will dewater the gypsum to a free moisture content of approximately 15 to 20 percent. Two vacuum filters will transfer dewatered gypsum onto the Gypsum Collection/Load-out Conveyor. This conveyor will transfer gypsum to the Gypsum Storage/Loading Bin, which at a capacity of 800 tons will hold approximately ten days worth of gypsum production.

Trucks will be loaded out from the gypsum storage/loading bin during periods when trucks are operating and transporting gypsum to the on-site storage. Gypsum will be transferred from the storage bin to a radial stacker that will pile the gypsum on the ground near the bin when trucks are not operating (i.e. nights, weekends, and emergency situations). The piled gypsum will be loaded onto trucks when operations resume using mobile equipment and removed to the on-site storage. Due to the high moisture content of the gypsum being handled, fugitive dust emissions from these processes are assumed to be negligible.

2.7 PROCESS DESCRIPTION FOR ANHYDROUS AMMONIA

Anhydrous ammonia storage and handling facilities associated with the SCR system will be installed as part of the project as shown in Figure 2-1. The ammonia unloading facilities will be equipped with vapor recovery whereby vapors will vent back to the host tank when transferring ammonia. The ammonia will be stored in pressurized storage tanks each with an emergency relief valve. From the storage tanks the ammonia will be piped to the SCR system for injection and mixing in the flue gas upstream of the catalyst layers. A Risk Management Plan will be prepared to address on-site storage and handling of anhydrous ammonia pursuant to the requirements of 40 Code of Federal Regulations (CFR) 68 Subpart G.

Figure 2-6 Gypsum Handling Process Flow Diagram



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2.8 PROCESS DESCRIPTION FOR SO_3 AND MERCURY SORBENTS

The air quality control system of the plant will include sorbent injection systems for capture of mercury and SO_3 (for control of sulfuric acid mist emissions). Systems to handle these materials will incorporate self unloading of trucks and pneumatic conveying of the sorbents to their respective storage silos. The sorbent storage silos will be equipped with bin vent filters designed with sufficient bag filtering capacity to support sorbent unloading operations. Conveying air from the self unloading trucks is exhausted from the silo through the bin vent filters at the top of the silos to separate suspended particulates and return them to the silo. Emissions from these silos are expected to occur only during filling operation at a maximum of one hour per shift.

2.9 PROCESS DESCRIPTION FOR THE PRETREATMENT SODA ASH SILO AND THE PRETREATMENT LIME SILO

As part of the raw water treatment system at the facility, soda ash and lime will be used to reduce iron and phosphorous levels before use in industrial services (i.e., cooling tower) at the facility. The lime and soda ash will precipitate iron and phosphorous and be removed in a clarifier system. Systems to handle these materials will incorporate self unloading of trucks and pneumatic conveying of the soda ash and lime to their respective storage silos (emission points S-39 & S-44). The soda ash and lime storage silos will be equipped with bin vent filters designed with sufficient bag filtering capacity to support material unloading operations. Conveying air from the self unloading trucks is exhausted from the silo through the bin vent filters located at the top of the silos to separate suspended particulates and return them to the silo.

2.10 PROCESS DESCRIPTION FOR THE AUXILIARY BOILER

The plant will be served by an auxiliary boiler to provide steam for startup and other operations as required when steam from the boiler is unavailable or inadequate to supply auxiliary steam equipment needs as shown in Figure 2-1. The auxiliary boiler will be fired on ultra low sulfur No. 2 fuel oil and will have a maximum gross heat input of 240 MMBtu/hr. The auxiliary boiler will be equipped with low NO_X burners and Flue Gas Recirculation (FGR). The exhaust from the auxiliary boiler will be emitted through a stack. Operation of the auxiliary boiler will be limited to a 10 percent annual capacity factor based on heat input. During the initial plant commissioning activities, the auxiliary boiler may operate more than the 10 percent capacity factor over the first 12 months.

2.11 PROCESS DESCRIPTION FOR THE EMERGENCY EQUIPMENT

The plant configuration, as indicated in Figure 2-1, will include an emergency diesel generator, which will be used for shutdown or other operations when normal power supply to plant equipment is interrupted. The generator engine will be fired on diesel fuel and its output will be approximately 1,120 kilowatts (kw). It is anticipated that the generator will not be operated for more than 500 hours per year as it will be for emergency use and maintenance/testing operations only. The generator will be equipped with a small, approximately 750 gallon capacity diesel storage tank.

The plant will also include a diesel driven emergency fire water pump. The pump engine will be fired on diesel fuel and its output will be approximately 350 horsepower (hp). The emergency fire water pump is expected to operate no more than 500 hours per year as it is only for emergency use and maintenance/testing. The fire water pump will be equipped with a small, approximately 250 gallon capacity diesel storage tank.

2.12 PROCESS DESCRIPTION FOR THE COOLING TOWER

The cooling tower will be a multi-celled, back-to-back style tower. The purpose of the cooling tower is to cool the water that is circulated in the heat exchangers that condense the steam from the steam turbine. The cooling tower will be comprised of 34 cells using drift eliminators for the reduction of drift (the amount of water from the cooling tower carried into the ambient air in liquid form) (emission points S-2 through S-35). Mineral salts present in the water droplets released in the drift form PM as the water droplets evaporate in the air. In order to reduce the amount of particulate generated in this manner, the cooling tower will be equipped with drift eliminators designed to limit drift to 0.0005 percent of the cooling tower water flow. A water minimization plan will in place at the plant with a goal to reuse water as much as possible. Even with this plan in place the total dissolved solids (TDS) in the cooling tower water is expected to be maintained at less than 3,300 ppm.

2.13 PROCESS DESCRIPTION FOR THE SOLID MATERIALS HANDLING FACILITY FOR LONG TERM STORAGE

The facility will maintain a long-term storage facility on site for solid material produced by the plant, namely gypsum, fly ash, and bottom ash. The materials will be loaded into trucks from the appropriate storage silo or storage bunker in the main operational areas of the facility and transported to the on-site storage. The trucks will unload the solid materials into an active “cell” of the SMHF. There will be separate storage areas for the gypsum, fly ash, and bottom ash. It is planned that the fly ash can be sold to

concrete production facilities and the gypsum used to produce wall board. Trucks and other large equipment will be fueled with biodiesel fuel if available. Biodiesel fuel does not have a long shelf life so it can not be used to fuel the auxiliary boiler or emergency generators at the plant.

2.14 PLANT PRODUCTION CAPACITY

The nominal coal consumption of the main facility boiler is 417 ton/hr, or 3.65 x 10^6 ton/yr for use of a 50/50 blend of fuel (PRB and Illinois #6 coals) at the facility, and 488 ton/hr, or 4.27 x 10^6 ton/yr for use of PRB coal alone. The maximum anticipated power output of the facility is 850 MW net.

3.0 REGULATORY ANALYSIS

3.1 PSD Applicability Analysis

The Plant Washington facility will emit more than 100 tons per year of several PSD pollutants including PM, VOC, NO_x, CO, and SO_2; therefore, the facility will be considered a major source under the PSD program since it is one of the 27 industrial categories (fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input). The facility will be located in Washington County, which is currently designated as an attainment area for all criteria pollutants. Before the proposed project can be permitted, it must be evaluated according to a PSD applicability analysis, and, if the project exceeds significant impact levels, a PSD review must be completed for each significant pollutant.

In December 2002, the United States Environmental Protection Agency (USEPA) enacted rules that changed the NSR program. This permit application, therefore, has been prepared under the new PSD rules. The first step is to evaluate the potential emissions for all regulated pollutants. As shown in Table 3-1, the proposed project will result in a PSD significant increase for PM, NO_x, CO, VOC, SO_2, Fluorides, and Sulfuric Acid Mist Because this will be a new facility, there will be no contemporaneous reductions of emissions to offset these increases, so the project triggers a PSD review for PM, NO_x, CO, VOCs, SO_2, Fluorides, and Sulfuric Acid Mist. The facility has elected to propose a lead PSD avoidance limit for the main facility boiler of 1.60×10^{-5} lb/MMBtu. Compliance with this limit will maintain facility wide lead emissions to below the lead PSD significance threshold of 0.60 ton/yr.

Also, although mercury emissions are not subject to PSD review per *40 CFR 52.21 Prevention of Significant Deterioration of Air Quality*, the *Georgia Rules for Air Quality Control, Georgia Rules Chapter 391-3-1-.02(ttt)* require that any boiler installed later than January 1, 2007 operating to produce greater than 25 MW of electricity for sale apply Best Available Control Technology (BACT) for control of mercury emissions. Therefore, a BACT evaluation has been conducted for the main facility boiler for control of mercury emissions.

Exhibit A provides calculations of potential emissions for each PSD pollutant for all of the proposed emission units at Plant Washington. Table 3-1 below provides a facility wide emissions summary for the facility.

Table 3-1 Facilitywide Emissions Summary

	Stack/Source ID	PM	PM_{10}	$PM_{2.5}$	SO_2	NO_x	CO	VOC	Pb	HF	H_2SO_4
		Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)	Future Emissions (tpy)
Coal-fired Boiler	S1	654	654	449	1890	1818	3635	109	0.58	9.74	145
Auxiliary Boiler	S45	2.52	2.52	1.23	5.26	10.51	4.20	0.32	9.46E-04	3.35E-06	6.31E-03
Emergency Diesel Generator	-	0.26	0.26	7.55E-03	0.15	4.88	2.06	0.26	-	-	-
Emergency Firewater Pump	-	0.193	0.19	5.54E-03	0.18	2.71	0.58	0.22	-	-	-
Cooling Towers	S2-S35	16.28	7.51	3.29E-02	-	-	-	-	-	-	-
Crusher House Dust Collector	S40	4.51	4.51	0.72	-	-	-	-	-	-	-
Tripper Deck	S41	3.38	3.38	0.54	-	-	-	-	-	-	-
Limestone Preparation Building Silo	S42	0.94	0.94	0.25	-	-	-	-	-	-	-
Fly Ash Mechanical Exhausters (Fly Ash Filter Seperator)	S43	0.45	0.45	0.24	-	-	-	-	-	-	-
Fly Ash Silo	S37	0.28	0.28	0.15	-	-	-	-	-	-	-
Bottom Ash Transfer Point to Bottom Ash Bin	A3	2.69E-02	1.27E-02	1.93E-03	-	-	-	-	-	-	-
Bottom Ash Transfer Point from Bin to Truck	A3	2.69E-02	1.27E-02	1.93E-03	-	-	-	-	-	-	-
Mercury Sorbent Silo	S38	7.04E-02	7.04E-02	7.04E-02	-	-	-	-	-	-	-
SO_3 Sorbent Silo	S36	7.04E-02	7.04E-02	7.04E-02	-	-	-	-	-	-	-
Pre-Treatment Soda Ash Silo	S44	3.52E-02	3.52E-02	3.52E-02	-	-	-	-	-	-	-
Pre-Treatment Hydrated Lime Silo	S39	3.52E-02	3.52E-02	9.50E-03	-	-	-	-	-	-	-
PRB Stackout (Insertable Dust Collector)	S46	0.28	0.28	4.51E-02	-	-	-	-	-	-	-
Illinois No. 6 Stackout (Insertable Dust Collector)	S47	0.28	0.28	4.51E-02	-	-	-	-	-	-	-
Limestone Stackout (Insertable Dust Collector)	S48	0.28	0.28	7.60E-02	-	-	-	-	-	-	-
Solid Material Handling - Ash	A1	1.73	0.33	0.18	-	-	-	-	-	-	-
Solid Material Handling - Gypsum	A2	1.73	0.33	0.18							
Limestone Unloading	A5	1.89E-01	8.95E-02	1.35E-02	-	-	-	-	-	-	-
Limestone Transfer Point	A10	3.45E-02	1.63E-02	2.47E-03	-	-	-	-	-	-	-
Limestone Pile (Wind Erosion)	A10	0.36	9.88E-04	1.48E-04	-	-	-	-	-	-	-
Rail Unloading	A4	2.84E-01	1.34E-01	2.03E-02	-	-	-	-	-	-	-
Inactive PRB Coal Pile	A6	0.07	0.03	4.97E-03	-	-	-	-	-	-	-
Inactive Illinois No. 6 Coal Pile	A7	0.32	0.15	2.27E-02	-	-	-	-	-	-	-
Active PRB Coal Pile (Wind Erosion)	A8	1.95	8.79E-03	1.32E-03	-	-	-	-	-	-	-
Transfer Point for Active PRB Coal Pile	A8	0.07	3.28E-02	4.97E-03							
Active Illinois No. 6 Coal Pile (Wind Erosion)	A9	1.95	8.79E-03	1.32E-03	-	-	-	-	-	-	-
Transfer Point for Active Illinois Basin Coal Pile	A9	0.32	1.50E-01	2.27E-02							
Solid Material Handling Haul Road	P1-P21	0.55	0.55	8.19E-02	-	-	-	-	-	-	-
Fugitive Road Sources Between Coal Piles Unpaved Road	U1-U15	1.31	0.35	3.49E-02							
Storage Tank Emissions	-	-	-	-	-	-	-	0.06	-	-	-
Project Totals		695	678	453	1,896	1,836	3,642	110	0.58	10	145
PSD Significance Level		25	15	10	40	40	100	40	0.6	3	7
Significant Emissions Increase (Yes or No)		**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**	**Yes**

Prepared by: BSA 11/26/08
Checked by: SAK 11/26/08

3.2 New Source Performance Standard – Subpart Da Applicability

40 CFR 60.40, Subpart Da regulations apply to fossil fuel fired electric utility steam generating units for which construction, modification, or reconstruction commenced after September 18, 1978 and have a heat input capacity of greater than 250 MMBtu/hr. Also, an electric utility steam generating unit is defined in 40 CFR 60.41Da (Definitions) as "…*any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steamelectric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility*". Since the main facility boiler will have a maximum heat input capacity of greater than 8300 MMBtu/hr, and meets the definition of an electric utility steam generating unit, the main facility boiler will be subject to Subpart Da.

Subpart Da contains regulatory provisions involving emission limitations, monitoring, reporting, and recordkeeping requirements for the pollutants PM, SO_2, NO_X, and opacity. The following is a summary of the emission standards present in Subpart Da. Additional regulatory provisions in Subpart Da, regarding compliance, monitoring, performance testing, and reporting are not provided in this document. The PM emission standards, NO_X emission standards, and Hg emission standards apply at all times except during periods of startup, shutdown, or malfunction (40 CFR 60.48Da(c)). The emissions limitations applicable to the main boiler operations are given below.

<u>Opacity – 40 CFR 60.42Da</u>

(b) On and after the date the initial PM performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

Particulate Matter – 40 CFR 60.42Da

(c) Except as provided in paragraph (d) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility for which construction, construction, or modification commenced after February 28, 2005, any gases that contain PM in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel.

Compliance is determined through a Continuous Opacity Monitoring (COM) system or through PM CEMS on a 24-hr block average.

Sulfur Dioxide – 40 CFR 60.43Da

(i) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2 in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain SO_2 in excess of either: (i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or (ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

Nitrogen Oxides (NO_X) – 40 CFR 60.44Da

On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under § 60.48Da(k).

NSPS Subpart Da for mercury regulatory information is no longer included due to the vacature of those rules. When the D.C. Circuit Court of Appeals vacated the CAMR regulations in February 2008 the New Source Performance Standards (40 CFR Part 60 Subpart Da) for mercury were also effectively vacated.

3.3 New Source Performance Standard – Subpart Db Applicability

40 CFR 60.40 Subpart Db regulations apply to steam generating units that commence construction, modification, or reconstruction after June 19, 1984, and have a heat input capacity of 29 MW, or 100

MMBtu/hr. Since the facility auxiliary boiler will have a maximum heat input capacity of 240 MMBtu/hr, it will be subject to Subpart Db.

Subpart Db contains regulatory provisions involving emission limitations, monitoring, reporting, and recordkeeping requirements for the pollutants PM, SO_2, NO_X, and opacity. Regulatory provisions in Subpart Db, regarding compliance, monitoring, performance testing, and reporting are not provided in this document.

3.4 New Source Performance Standard – Subpart Y Applicability

40 CFR 60.250 Subpart Y regulations apply to any of the following affected facilities in a coal preparation plant that processes more than 200 tons per day of coal and were constructed or modified after October 24, 1974: thermal dryers, pneumatic coal cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems.

The facility will not have a thermal dryer or coal cleaning equipment, but will have coal conveying and crushing operations. For these operations the only standard is an opacity limit verified through use of EPA Method 9 and the procedures established in 40 CFR 60.254 Subpart Y. The opacity limit applicable to facility operations under Subpart Y is given below;

(c) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

3.5 New Source Performance Standard – Subpart OOO Applicability

The emission standards listed in 40 CFR 60 Subpart OOO, which provide standards of performance for non-metallic mineral processing plants for applicable sources constructed, modified, or reconstructed after August 31, 1983, apply to the limestone handling, gypsum handling, and possibly sorbent material handling and processing operations at Plant Washington. Stack emissions from conveying equipment cannot exceed 0.022 gr/dscf and opacity cannot exceed 7%. Plant Washington will comply with the monitoring, testing, reporting, and recordkeeping requirements of Subpart OOO.

3.6 New Source Performance Standard – Subpart IIII Applicability

40 CFR Part 60, Subpart IIII establishes standards of performance for stationary compression ignition internal combustion engines. Applicable sources to Subpart IIII at Plant Washington will include the emergency generator (engine) and the fire pump. Applicable emission standards under Subpart IIII are related to the hp rating of the engine and the year the engine was manufactured. The facility will comply with the applicable Subpart IIII emission limits by purchasing an emergency generator (engine) and fire pump certified to the emissions standards of Subpart IIII.

3.7 New Source Performance Standard – Subpart Kb

40 CFR Part 60, Subpart Kb establishes standards of performance for volatile organic liquid storage Vessels (including petroleum liquid storage vessels) for which construction, reconstruction, or modification commenced after July 23, 1984. Subpart Kb applies to storage vessels containing volatile organic liquids (VOLs) with a capacity greater than or equal to 75 cubic meters (m^3), or approximately 19,800 gallons. One on-site storage vessel, the 350,000 gallon distillate fuel oil tank used for operation of the auxiliary boiler and main boiler startup operations, will have a storage capacity greater than 75 m^3. However, Subpart Kb does not apply to storage vessels with a capacity greater than 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa). Since the vapor pressure of distillate fuel oil is below 3.5 kPa, the tank is exempt from Subpart Kb. No other VOL tanks are being planned at the facility.

3.8 National Emission Standards For Hazardous Air Pollutants – Subpart ZZZZ

40 CFR Part 63, Subpart ZZZZ establishes a Maximum Achievable Control Technology (MACT) standard for Stationary Reciprocating Internal Combustion Engines. Engines rated at less than 500 hp, such as the emergency fire water pump, are not subject to the Rule. Under Subpart ZZZZ, emergency internal combustion engines, such as the emergency diesel generator at the facility, are subject to the initial notification requirements of 40 CFR 63.6645(d).

3.9 National Emission Standards For Hazardous Air Pollutants – Subpart DDDDD

40 CFR Part 63, Subpart DDDDD, affected Industrial, Commercial, and Institutional Boilers and Process Heaters. However, Subpart DDDDD was rescinded. Therefore, a case-by-case MACT evaluation was conducted for the facility auxiliary boiler. The Case-By-Case MACT evaluation conducted for the auxiliary boiler is included in Section 10.

3.10 Clean Air Mercury Rule (CAMR)

On February 8, 2008, the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit issued a decision vacating and remanding USEPA's final Clean Air Mercury Rule (CAMR). As part of this decision it was found that USEPA's determination that HAP emissions from electric generation units should not be subject to standards under Section 112 of the Clean Air Act was invalid. This determination invalidated the earlier USEPA decision to delist the electric generating unit source category from applicability to Section 112.

This judgment has led to the implied requirement that since electric steam generating units may now be reinstated to the list of Section 112(c) source categories, such units are now required to submit a Section 112(g) Maximum Achievable Control Technology (MACT) analysis for applicable HAPs. A Section 112(g) Case-By-Case MACT analysis for the main facility boiler has been conducted and is included in Section 10.

3.11 Acid Rain Program

The Title IV Acid Rain provisions, adopted as part of the 1990 Clean Air Act (CAA) Amendments, are primarily designed to control SO_2 and NO_X emissions from fossil fuel-fired combustion devices in the electricity generating industry. Along with emission limitations, there are requirements for monitoring, testing, recordkeeping, and reporting. A new facility must apply for an acid rain program permit at least 24 months before operations of the proposed unit begin. All requirements of the Acid Rain Program will be met by Plant Washington. The proper Acid Rain Permit Application forms will be submitted following submittal of this permit application.

3.12 New Source Review

Plant Washington will be located in Washington County, which is currently classified as an attainment area for all criteria pollutants. PSD section (40 CFR 51.166) of the NSR Regulations (40 CFR 51 Subpart I) requires states to implement a program to prevent deterioration of air quality beyond National Ambient Air Quality Standards (NAAQS) levels. The Georgia EPD has implemented such a program by adopting past federal regulations (namely 40CFR 52.21). Because Plant Washington would be considered a new major PSD source of emissions, the project must be evaluated to determine whether emission increases will exceed major modification levels. This evaluation is discussed in Section 3.1, and the supporting analyses for PSD are presented in Sections 4, 5, 7, and 8.

3.13 Fine Particulate Review Requirements ($PM_{2.5}$)

In 1997 NAAQS were set for fine particulate. Fine particles or "$PM_{2.5}$" can aggravate heart and lung diseases and have been associated with premature death and a variety of serious health problems including heart attacks, chronic bronchitis and asthma attacks. This standard was set in addition to the PM_{10} NAAQS that was already existing. On September 8, 2005, the Environmental Protection Agency (EPA) issued a proposed rule implementing the 1997 fine particle ($PM_{2.5}$) national ambient air quality standards. On March 29, 2007, EPA issued a final rule defining requirements for state plans to clean the air in 39 areas where particle pollution levels do not meet national air quality standards. This rule addressed only those areas that which are not in attainment with the standard and listed no additional requirements for those areas which are currently in attainment with the standard. Therefore in this application we have reviewed and addressed control of emissions of PM_{10} which also includes the subcategory of $PM_{2.5}$. By doing this it is expected that controls specified for PM_{10} will also address required controls of $PM_{2.5}$.

On May 8, 2008 the USEPA issued final rules governing the implementation of the New Source Review (NSR) program for $PM_{2.5}$. The rule has established a direct $PM_{2.5}$ significant emission rate of 10 tpy. Emissions of direct $PM_{2.5}$, as well as precursor pollutants SO_2 and NOx, have been evaluated in the BACT evaluation in Section 4.3 of this application.

3.14 Georgia State Requirements

The Georgia Rules For Air Quality Control, Chapter 391-3-1, have promulgated rules for emission limitations regarding visible emissions, fuel burning equipment, fugitive dust, and mercury emissions from new electric generating units. Georgia Rule 391-3-1-.02(ttt) requires application of BACT to Hg emissions from new coal-fired electric generation units installed after January 1, 2007 and that generate greater than 25 MW of electricity for sale. Therefore, the main boiler at Plant Washington will be subject to the Georgia Rule 391-3-1-.02(ttt). Additional emission limitation requirements under the Georgia Rules for Air Quality Control are less stringent than the application of BACT, or other applicable requirements such as New Source Performance Standards (NSPS) to the emission units present at Plant Washington. Plant Washington, where applicable, shall maintain compliance with all Georgia State Requirements.

3.15 Compliance Assurance Monitoring (CAM) Plan

The Compliance Assurance Monitoring (CAM) Rule, established in 40 CFR Part 64, was established in order to provide reasonable assurance that facilities comply with emissions limitations by monitoring the operation and maintenance of their control devices. In order to be subject to CAM, the following criteria must be met:

1. An emission unit must be subject to an emission limit or standard for the pollutant of concern.

2. A control device is used to achieve compliance with the emission limit or standard.

3. The emission unit's potential pre control emissions are greater than the applicable Title V Major Source threshold for the pollutant of concern.

The CAM rule is not applicable to emission unit pollutant emissions that are subject to New Source Performance Standards (NSPS) or National Emission Standards For Hazardous Air Pollutants (NESHAP) regulations, Acid Rain Program, or other emissions trading programs. For example, Nitrogen Oxides (NO_X) and Sulfur Dioxide (SO_2) emissions from the main facility boiler are subject to monitoring requirements under the Acid Rain Program. Therefore, the facility will be exempt from CAM for NO_X and SO_2 for the main boiler. A continuous emissions monitor is proposed for NESHAP considerations for both PM and CO which leaves only VOC being emitted in quantities greater than 100 ton/yr unmonitored. CO serves as a good surrogate for VOC monitoring. Therefore emissions monitoring for all pollutants from the main boiler are covered by other regulatory requirements and exempt from CAM.

This leaves only a few baghouses used for particulate control in the materials handling area that require a CAM assessment. A CAM Plan will be developed for these applicable facility units and submitted with the facility Title V Application.

4.0 BACT ANALYSIS

4.1 Introduction

Sources undergoing a PSD review must apply BACT to any new or modified emission unit that emits a PSD-triggered pollutant in an amount above significant impact levels. Federal PSD regulations define BACT as:

> … an emission limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act, which would be emitted from any proposed major stationary source or major modification, which the administrator [GA EPD], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant.

The determination proceeds to state that no BACT determination may be less stringent than the applicable NSPS, NESHAP, or State Implementation Plan (SIP) limits. Also, the definition allows a design or work practice to be established as BACT.

On December 1, 1987, the USEPA Assistant Administrator for Air and Radiation issued a memorandum that implemented certain program initiatives designed to improve the effectiveness of the New Source Review (NSR) programs in the confines of existing regulations and SIPs. Among these was the "top-down" method for determining BACT. The top-down process provides that available control technologies be ranked in descending order of control effectiveness. The first step of this process is to evaluate the most stringent or "top" alternative. This represents BACT, unless it can be demonstrated, and the permitting authority agrees, that technical considerations, energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in a particular case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on, until the most appropriate control strategy is selected for each source.

BACT is required for any emission unit that emits a PSD triggering pollutant. Table 3-1 identifies all PSD triggering pollutants as PM/PM_{10}, $PM_{2.5}$, NO_x, CO, SO_2, VOCs, fluorides, and H_2SO_4. In addition, a BACT analysis should also address opacity. A BACT analysis is required for any emission unit that emits any one of these pollutants. Table 4-1 summarizes the facility operations requiring a BACT analysis.

Table 4-1 Facility Operations at the Facility Requiring a BACT Review

The Washington Plant
- Supercritical Pulverized Coal Boiler - Auxiliary Boiler - Diesel Engine Generator and Fire Water Pump - Cooling Towers - Material Handling and Storage Facilities - Storage Tanks

Prepared by: PMH 1/10/08
Checked by: JDF 11/26/08

4.2 Key Steps in a Top-down BACT Analysis

To develop the BACT analysis, the key steps outlined in the Draft New Source Review Workshop Manual (1990) were followed. These steps include:

Step 1 – Identify All Control Technologies

The primary objective of Step 1 is to identify all "available" control options for the emission unit in question (i.e., PC boiler). Available control options are defined in the 1990 Draft NSR Workshop Manual as:

> … those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives. The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies. Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative.

A lower-polluting process or practice is considered applicable if it has been demonstrated for a similar emission unit or application. An add-on control is considered applicable if it can

properly function given the physical characteristics of the pollutant stream being controlled (i.e., gas stream temperature, pollutant concentration, etc.).

Potentially applicable control options were surveyed. These included control technologies that have been used in other source categories and countries. Control technologies identified by LAER determinations were also included as available control technologies.

Based on the guidelines provided in the USEPA Draft New Source Review Workshop Manual document, a comprehensive list of available control technologies was developed for this permit application.

A December 13, 2005, letter from Stephen Page, Director of USEPA's Office of Air Quality, Planning and Standards to E3 Consulting, LLC, regarding BACT requirements for proposed coal-fired power plant projects, stated:

> As noted in prior EPA decisions and guidance, EPA does not consider the BACT requirement as a means to redefine the basic design of the source or change the fundamental scope of the project when considering available control alternatives. For example, we do not require applicants proposing to construct a coal-fired steam electric generator to consider building a natural gas-fired combustion turbine as part of a BACT analysis, even though the turbine may be inherently less polluting per unit product (in this case electricity).

An excerpt from USEPA's Draft New Source Review Workshop Manual, page B.13, states the following:

> Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator, have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity). However, this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire. Thus, a gas turbine normally would not be included in the list of control alternatives for a coal-fired boiler. However, there may be instances where, in the permit authority's judgment, the consideration of alternative production processes is warranted and appropriate for consideration in the BACT analysis.

Due to the above discussed documentation, alternative plant design strategies, such as Integrated Gasification Combined Cycle (IGCC) or Circulating Fluidized Bed (CFB) technologies, have not been evaluated as part of this BACT analysis.

Step 2 – Eliminate Technically Infeasible Options

The purpose of Step 2 is to evaluate the technical feasibility of the control technology options identified in Step 1. Control technologies that have been installed and operated successfully on the type of emission unit under review are considered demonstrated and technically feasible. Control technologies that are not applicable or not available are determined to be technically infeasible. For a technology that has not been demonstrated for a particular type of emission unit, the Draft New Source Review Workshop Manual provides the following guidance:

> Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.
>
> A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review. An exception would be if the technology were proposed and permitted under the qualifications of an innovative control device consistent with the provisions of 40 CFR 52.21(v) or, where appropriate, the applicable SIP.
>
> Commercial availability by itself, however, is not necessarily sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration.
>
> Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed

> (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary.

Step 3 – Rank Remaining Technically Feasible Control Options

The third step in the five step top-down BACT evaluation process involves ranking of the technically feasible control options determined in Step 2 from most effective to least effective in terms of emissions reduction potential. Step 3 also determines the energy, economic, and environmental impacts associated with the technically feasible control options, which are more fully evaluated in Step 4 of the process.

Ranking control options involves the selection of appropriate units of emissions for comparison between types of control technologies and emission units. For purposes of this BACT evaluation, the unit of measure for comparing emission rates for each pollutant from a combustion source was pounds per million British thermal units (lb/MMBtu) heat input. The resulting BACT determinations were then expressed as lb/MMBtu as well. Achievable emission limits were determined for each of the control technology options based on engineering estimates, published literature, and testing data from existing sources. After establishing performance levels for the technically feasible control technologies, control technology alternatives were ranked by their demonstrated emissions reduction performance. Also, as indicated in the Draft New Source Review Workshop Manual regarding selection of the defined "top" control technology alternative:

> … an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top, and review for collateral environmental impacts.

Step 4 – Evaluate Remaining Control Technologies

Step 4 of the five step top-down BACT evaluation process involves evaluating the suitability of the ranked control technology options under Step 3, based on energy, economic, and environmental impacts of use of the control technology. The following excerpt, taken from the

Draft New Source Review Workshop Manual, explains the general evaluation process of Step 4:

> If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT.

The energy impacts analysis determines whether the use of the control technology results in any significant or unusual energy penalties or benefits. The economic impacts analysis evaluates average and incremental cost effectiveness to determine if use of the control technology would result in a negative economic impact. The evaluation of environmental impacts considers the site-specific environmental impacts of use of the control technology option, involving issues such as waste generation, water use and discharge, visibility impacts, emissions of additional pollutants, etc.

Step 5 – Selection of BACT

The highest ranked and most effective control option not eliminated in Step 4 for energy, economic, or environmental impacts is selected and proposed as BACT for that pollutant and emission unit.

Table 4-2 summarizes the proposed BACT levels for all emission units subject to BACT. This table provides the overall conclusions of all the analyses that follow. In addition to proposing BACT emission limits for the emission units subject to BACT, Table 4-2 also includes a summary of the proposed compliance methods for demonstrating compliance with the applicable pollutants. To develop these analyses, MACTEC obtained information from the following databases and listings to identify emission limits and control technologies which apply to sources being proposed for the project:

- The USEPA RACT/BACT/LAER Clearinghouse (RBLC)

- USEPA's NSR Technology Transfer Network website
- Federal and State NSR permits, permit applications, and associated reports
- Discussions with control technology vendors and design engineers
- Discussions with Georgia EPD and other State Air Quality Branch personnel
- National Coal-fired Utility NSR Spreadsheet (November 2007)
- Literature Search of Recent Control Technology for Coal-fired Boilers
- USEPA Clean Air Markets Program Emissions Database Information
- Federal Energy Regulatory Commission (FERC) Coal Database Information

Table 4-2 BACT Analysis Summary Table

Source	Pollutant	Control Technology	Emission Limit (lb/MMBtu)	Proposed Compliance Test Method
Supercritical Pulverized Coal (SCPC) Boiler	Particulate Matter (PM/PM_{10})	Fabric Filter Baghouse	Total PM_{10} – 0.018 lb/MMBtu (3-hr. Avg.)	PM_{10} – USEPA Method 201A/202 or USEPA CTM-039/40
			Filterable PM – 0.012 lb/MMBtu (24-hr. Block Avg.)	CEMS
	Nitrogen Oxides (NO_x)	LNB/OFA/SCR	0.05 lb/MMBtu – 30-day Rolling Avg.	CEMS
	Carbon Monoxide (CO)	Combustion Controls	0.10 lb/MMBtu – 30-day Rolling Avg. 0.30 lb/MMBtu 1-hr. Avg.	CEMS
	Volatile Organic Compounds (VOC)	Combustion Controls	0.0030 lb/MMBtu – 3 hr. Avg.	USEPA Method 25A Minus USEPA Method 18 (Methane Removal)
	Sulfur Dioxide (SO_2)	Wet Flue Gas Desulfurization (WFGD)	0.052 lb/MMBtu 12-month rolling average 0.069 lb/MMBtu 30-day rolling average 959 lb/hr 3-hr. average Minimum 97.5% Removal	CEMS
	Fluorides (as HF)	Wet Flue Gas Desulfurization (WFGD)	2.68×10^{-4} lb/MMBtu	USEPA Method 13A or USEPA Method 26A
	Sulfuric Acid Mist (H_2SO_4)	Sorbent Injection and Wet Flue Gas Desulfurization (WFGD)	0.004 lb/MMBtu 3-hr. Avg.	USEPA CTM-013 (Controlled Condensate Method 8A)
	Mercury (Hg)	Multi-control: Sorbent Injection In Conjunction With SCR/FF/WFGD	1.68×10^{-6} lb/MMBtu 15×10^{-6} lb/MW-hr 12-month rolling average	CEMS

Table 4-2 BACT Analysis Summary Table (Continued)

Source	Pollutant	Control Technology	Emission Limit (lb/MMBtu)	Proposed Compliance Test Method
Auxiliary Boiler	Particulate Matter (PM/PM_{10})	Fuel Specification and Combustion Controls	0.024 lb/MMBtu (total) 0.014 lb/MMBtu (filterable)	Fuel Specification
	Nitrogen Oxides (NO_x)	Combustion Controls – LNB/FGR	0.1 lb/MMBtu	Engineering Controls
	Carbon Monoxide (CO)	Combustion Controls	0.04 lb/MMBtu	Engineering Controls
	Volatile Organic Compounds (VOC)	Combustion Controls	0.003 lb/MMBtu	Engineering Controls
	Sulfur Dioxide (SO_2)	Use of Ultra Low-Sulfur Fuel	0.05 lb/MMBtu	Fuel Specification
	Sulfuric Acid Mist (H_2SO_4)	Use of Ultra Low-Sulfur Fuel	6.0×10^{-5} lb/MMBtu	Fuel Specification
Diesel Engine Generator and Fire Water Pump	Particulate Matter (PM/PM_{10})	Use of Ultra Low-Sulfur Fuel	See BACT Discussion Section 4.5	
	Nitrogen Oxides (NO_x)	Good Combustion Practices		
	Carbon Monoxide (CO)	Good Combustion Practices		
	Volatile Organic Compounds (VOC)	Good Combustion Practices		
	Sulfur Dioxide (SO_2)	Use of Ultra Low-Sulfur Fuel		
	Sulfuric Acid Mist (H_2SO_4)	Use of Ultra Low-Sulfur Fuel		
Cooling Towers	Particulate Matter (PM/PM_{10})	Drift Eliminators	0.0005 percent Drift Total Dissolved Solids (TDS) Limit 3300 mg/L	Vendor Data Quarterly TDS Testing
Material Handling and Storage Facilities	Particulate Matter (PM/PM_{10})	See BACT Discussion Section 4.7		
Fuel Storage Tanks	VOC	See BACT Discussion Section 4.8		
Opacity	Multi – Pollutant	See BACT Discussion Section 4.9		

Prepared by: PBS 7/15/08
Checked by: JDF 11/26/08

4.3 Supercritical Pulverized Coal (SCPC) Boiler

This section contains the BACT analysis for the planned 850 MW net SCPC unit planned for use at the facility. A summary of the BACT results for the SCPC boiler is in Table 4-2.

4.3.1 BACT Demonstration for $PM/PM_{10}/PM_{2.5}$ Emissions from the Supercritical Pulverized Coal Boiler

The composition and amount of PM emissions from a coal-fired boiler is a function of the type of coal used, firing configuration of the boiler, and emission controls in place on the unit. The primary source of PM emissions from coal-fired boilers is a result of incombustible inert matter (ash) in the fuel and condensable organic substances and acid gases. The primary form of PM emissions from the main boiler will be in the form of PM_{10}, or particles less than 10 microns in diameter, a portion of which will consist of $PM_{2.5}$, or particles less than 2.5 microns in diameter. This BACT analysis addresses both filterable PM_{10} and filterable $PM_{2.5}$. Another form of PM is termed condensable particulate matter. This is material that is not captured on a filter at stack conditions but could condense in the atmosphere to form an aerosol. BACT for the condensable portion of the PM is more appropriately addressed as VOC BACT and SAM BACT, located in Sections 4.3.4 and 4.3.8.

Step 1 – Identify All Control Technologies

<u>Lower-emitting Process or Practice – Coal Selection</u>

A potential pre-combustion control method for reduction of Particulate Matter (PM) emissions is the use of coals that contain lower ash content. Combustion of a lower ash containing coal would lead to a lower content of incombustible matter in the coal fuel source, leading to less fly ash generation and thus lower PM emissions.

<u>Lower-emitting Process or Practice – Coal Cleaning</u>

Coal cleaning, also called "coal benefaction" or "coal washing," is a cleaning process in which mineral ash matter is removed from mined coal to produce a "cleaner" coal. Coal cleaning is generally performed to remove impurities in the coal to improve the heat content of the coal, thereby improving power plant capacity, reduce maintenance costs at power plants and extend plant life. Coal cleaning can reduce the ash content of coal.

The most common method of coal cleaning involves physical coal cleaning methods, while other methods such as chemical cleaning (i.e., microwave cleaning/magnetization) are also in development.

The most common method of physical coal cleaning involves coal washing, a term given to mechanical cleaning of coal by separating out non-coal material in a liquid medium. The process involves grinding the coal into small pieces and passing it through a process called "gravity separation." The technique involves feeding the coal into barrels containing a fluid that has a density that causes the coal to float, while unwanted material such as sulfur (within an iron compound called "pyrite") and ash containing rock materials sink and are removed from the fuel. The washing medium is an aqueous chemical solution prepared to enhance dissociation of the coal and non-coal materials, or to produce specific gravities calibrated higher than water alone. Other wet cleaning techniques can include particle agitation by aeration of the coal liquid feed, materials sorting by relative density in hydro-cyclonic chambers, and froth flotation to capture fine coal particles.

Fabric Filter Baghouse

Fabric filters are used for PM control in a variety of industries, including use as PM control on PC-fired boilers, and are capable of achieving control efficiencies of 99 percent or greater. According to USEPA's fabric filter fact sheet (2003):

> … flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to be collected on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are the most common type of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured in cylindrical bags. Bags may be 6 to 9 m (20 to 30 ft) long and 12.7 to 30.5 centimeters (cm) (5 to 12 inches) in diameter. Groups of bags are placed in isolatable compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter.

Advantages of fabric filters can include the following:

1. Can provide high collection efficiencies on both coarse and fine (submicron) particulates.

2. Fabric filters are available in a large number of configurations and system designs, allowing for high flexibility in design.

3. Collected material is collected dry for subsequent processing or disposal.

Some disadvantages of fabric filters include:

1. Fabric filters can have relatively high maintenance requirements (filter bag replacement).

2. Concentrations of dust in the collector can represent a fire or explosion hazard if a spark or flame is somehow introduced.

3. The units cannot be operated in high moisture gas streams; moisture can cause caking or plugging of the fabric filter.

Fabric filters are a viable technology as long as they are not downstream of a wet scrubber and far enough downstream of the combustion zone that they do not pose a fire hazard.

Dry Electrostatic Precipitator (ESP)

Dry electrostatic precipitators (ESPs) are used in a variety of source categories for control of PM emissions, and are capable of achieving control efficiencies of 99 percent or greater. The following is an excerpt from USEPA's dry ESP fact sheet (2003):

> An ESP is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. The entrained particles are given an electrical charge when they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the electrical field that forces the particles to the collector walls. In dry ESPs, the collectors are knocked, or "rapped", by various mechanical means to dislodge the particulate, which slides downward into a hopper where they are collected. The hopper is evacuated periodically, as it becomes full. Dust is removed through a valve into a dust handling system, such as a pneumatic conveyor, and is then disposed of in an appropriate manner.

Advantages of dry ESPs include the following:

1. Are capable of high removal efficiencies, even for small particulate sizes.

2. Can be designed for a range of gas temperatures, and can handle high temperatures (up to 1,300 degrees Fahrenheit).

3. Relatively large gas flow rates can be effectively handled.

Some disadvantages of dry ESPs include the following:

1. High capital costs and high maintenance items, such as the wire discharge electrodes.

2. Generally not suited for processes that are highly variable because they are sensitive to fluctuations in gas stream conditions (temperature, flow rate, particulate loading, etc.).

3. Fly ash from the combustion of low-sulfur coal (<1.5%) typically has a high resistivity, and thus is difficult to collect.

<u>Wet Electrostatic Precipitator (WESP)</u>

A Wet Electrostatic Precipitator (WESP) is commonly used in situations where a dry ESP is not viable, such as when the material to be collected is wet, flammable, or has a high resistivity. WESPs are commonly used by the wood products and metallurgical industries, and can achieve PM control efficiencies of greater than 99 percent. The following is an excerpt from USEPA's WESP fact sheet (2003):

> In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. The collection hoppers used by dry ESPs are replaced with a drainage system. The wet effluent is collected, and often treated on-site.

Advantages of WESPs include the following:

1. Are capable of high removal efficiencies, even for low particulate sizes.

2. Relatively large gas flow rates can be effectively handled.

3. WESPs can collect sticky particles, mists, and highly resistive or explosive dusts due to the humid atmosphere from washing in the ESP.

4. Continuous or intermittent washing with a liquid eliminates the re-entrainment of particles, which dry ESPs are subject to through the rapping process.

Some disadvantages of WESPs include the following:

1. High capital costs and high maintenance items, such as the wire discharge electrodes.

2. Generally not suited for processes that are highly variable because they are sensitive to fluctuations in gas stream conditions (temperature, flow rate, particulate loading, etc.).

3. WESPs add the complexity of a wash system, and the fact that the resulting slurry must be handled more carefully than a dry product, and can require treatment.

4. WESPs are typically operated at gas stream temperatures less than 190 degrees Fahrenheit, and usually must be constructed of noncorrosive materials.

Venturi Scrubber

A venturi scrubber is a type of wet scrubber using a venturi device to increase the gas velocity in the unit. The increased velocity in the throat of the venturi allows the fine droplets of water to mix and adsorb particles in the air stream. The water droplets are then removed in an adjoining cyclonic separator. The particulate is filtered out of the water stream and sent back to the venturi. There may be a mist eliminator at the outlet of the separator to reduce particulate laden mist from leaving the scrubber.

Centrifugal Separator (Cyclone)

A cyclone is a particulate control device which uses centrifugal forces to separate PM from the flue gas stream. The use of cyclones, and multiple cyclone type devices (multiclones) or series cyclone devices, are being replaced over time by more efficient control devices such as fabric filter baghouses and ESPs. Cyclones are not as efficient at collecting small particles, and are

most efficient at collecting larger coarse particles. This is because the smaller particles have a lower mass to generate the centrifugal forces needed for collection. Pulverized coal-fired boilers tend to produce a smaller fraction of coarse particles compared to other types of boilers.

Advanced Hybrid Particulate Collector

An Advanced Hybrid Particulate Collector (AHPC), now known as "Advanced Hybrid™," is a new type of control device under development that enhances normal fabric filter collections by placing ESP electrodes just before the bag collectors. By doing this it reduces the particulate loading on the bags allowing a smaller design and in addition when the bags are cleaned (by shaking or pulse jet) the ESP portion of the device prevents re-entrainment of the dust onto the bags. An AHPC is being tested by the Otter Tail Power Company at Big Stone City, South Dakota.

Agglomerator

There are varying types of particulate control devices termed "agglomerator." An agglomerator works on a similar principal as an ESP, but instead of particles attracted to a collection plate, they electrostatically adhere to each other to form larger particles that are easier to remove. The device is a pre-conditioner that could improve an ESP's downstream performance.

One type of agglomerator, the Indigo Agglomerator, was developed in Australia for reduction in visible emissions from coal-fired boilers. In the Indigo Agglomerator there are two sections, a bipolar charger followed by a mixing section. The bipolar charger has varying passages with positive or negative charging. Following the charging sections, the positive and negatively charged particles are brought together in a mixing chamber, where the particles are electrostatically attracted to each other. The agglomerated particles enter the downstream ESP, where they are more effectively removed due to their large size.

Step 2 – Eliminate Technically Infeasible Options

Lower-emitting Process or Practice – Coal Selection

The type of coal used in a boiler can greatly affect the design of the boiler and associated air pollution control equipment. The facility is planning to use both sub-bituminous and

bituminous coals, including PRB (sub-bituminous) and Illinois #6 (bituminous) coals. Of these two coal types, PRB coal has a lower ash content, thereby potentially resulting in lower filterable particulate matter emissions. Coal selection is considered technically feasible for this analysis favoring the selection of PRB coal.

Lower-emitting Process or Practice – Coal Cleaning

Coal cleaning is considered effective for coals with a significant overburden. However, sub-bituminous coals such as PRB coals are typically mined from thick coal seams with little overburden, and PRB coal mining techniques produce a coal product with little rock and non-combustible material. Also, PRB coals typically contain low ash levels. For these reasons, coal cleaning is typically not conducted for PRB coals. Illinois #6 coals contain higher ash content than PRB coals. Coal cleaning is considered technically feasible for bituminous/Illinois #6 coals.

Fabric Filter Baghouse

A fabric filter baghouse is a proven technology in the control of PM/PM_{10} emissions from PC-fired boiler units. This technology has been demonstrated in similar applications to the current project and is considered technically feasible.

Dry Electrostatic Precipitator (ESP)

A dry ESP is a proven technology in the control of PM/PM_{10} emissions from PC-fired boiler units. This technology has been demonstrated in similar applications to the current project and is considered technically feasible.

Wet Electrostatic Precipitator (WESP)

A WESP is a proven technology in the control of PM/PM_{10} emissions. This technology has been demonstrated in similar applications to the current project and is considered technically feasible, although this technology has not been applied on a large scale to large coal-fired utility units.

Venturi Scrubber

Venturi scrubbers have not been used on utility plants since the 1970s. The low PM/PM_{10} removal efficiency of venturi scrubbers makes them ineffective as a standalone control device for PM emissions from a coal-fired boiler, or in combination with other pollutant controls. As a standalone device, venturi scrubbers are effective at removing 94 percent [based on AP-42] particulate matter, but this efficiency is not adequate to achieve the emission levels required for BACT. If multiclones were used in combination with a venturi scrubber, however, the overall efficiency would increase. Venturi scrubbers are determined to be technically feasible for this analysis.

Centrifugal Separator (Cyclone)

The low efficiency of these units for control of PM/PM_{10} makes them ineffective as a standalone control device for PM emissions from a coal-fired boiler, or in combination with other pollutant controls. As a standalone device, cyclones are effective at removing 80 percent [based on AP-42] particulate matter, but this efficiency is not adequate to achieve the emission levels required for BACT. Cyclones are ineffective at removing particles less than 2 microns in size, and primarily collect larger sized coarse particulate matter. If multiclones were used in combination with a venturi scrubber, however, the overall efficiency would increase. Cyclones are considered to be technically feasible for this project.

Advanced Hybrid Particulate Collector (AHPC)

An AHPC demonstration unit is still being evaluated and AHPCs are not yet commercially available, and therefore not considered technically feasible for this project.

Agglomerator

Limited information is available regarding the effectiveness of agglomerator particulate control devices when compared to more standard devices such as ESPs and fabric filter baghouses.Agglomerators are primarily used in retrofit operations for improving collection efficiencies of older ESPs, and used in fluid bed applications to capture and return the bed materials. Agglomerators have not been demonstrated as effective with a combination of controls other than an ESP, although the potential does exist for their use with fabric filter baghouse technology. However, no data regarding the effectiveness of an agglomerator in conjunction with a fabric filter baghouse are available. On the whole, use of an agglomerator is considered technically feasible.

Step 3 – Rank Remaining Technically Feasible Control Options

Lower-emitting Process or Practice - Coal Selection

Coal selection was deemed technically feasible for this analysis. The current business plan for the facility is to predominantly use western sub-bituminous coals (i.e. PRB) alone or blended with bituminous coals (i.e. Illinois #6) at the facility. Providing for the use of bituminous coal is a necessity considering the uncertainty in future supply of western sub-bituminous coals.

Lower-emitting Process or Practice – Coal Cleaning

Coal cleaning was considered technically feasible for this analysis. As discussed previously, non-bituminous PRB coals are not typically washed due to the low ash content of PRB coals in comparison to other coals. Since coal washing is effective at removing ash and mineral content bound in rock and non-combustible material, and PRB coals are typically mined from thick coal seams with little overburden, rock, and non-combustible material, coal washing to improve the ash content of PRB coals would not be highly effective. Therefore, coal washing for PRB coals will no longer be considered in this analysis. However, coal washing will be conducted for the bituminous Illinois #6 coals used at Plant Washington, due to the higher ash and sulfur content of that coal.

Venturi Scrubber and Centrifugal Separator (Cyclone)

Venturi scrubbers and centrifugal separators (i.e. multiclones) were considered technically feasible for this analysis. However, based on data from AP-42 a venturi scrubber is effective at removing 94% of PM, and cyclones are effective at removing 80% particulate matter. Both of these types of control units primarily collect larger coarse particulate matter. If multiclones were used in combination with a venturi scrubber, the overall efficiency achieved would be approximately 95.8%, still inadequate to achieve the emission levels required for BACT. Therefore, the use of these pollution control technologies will no longer be considered in this analysis.

Agglomerator

An agglomerator was also considered technically feasible for this analysis. Documentation received from the manufacturer of the agglomerator technology, Indigo Technologies, indicates that installations to date have focused on retrofits to older ESP devices, with no installations in conjunction with a new ESP (or baghouse).

Data from Indigo Technologies have indicated that an agglomerator was installed on Georgia Power Plant Hammond, Unit 3, in October 2004. A review of PM testing data available at the Georgia EPD for Unit 3 prior to and following installation of the agglomerator did not indicate an improvement in the PM performance from the unit. Compliance testing was conducted from 2004 through 2008 on a single stack with combined emissions from Units 1 to 3 at Plant Hammond. Prior to installation of the agglomerator, the boilers tested at 0.043 lb/MMBtu, and following installation, they tested at a level of 0.07 lb/MMBtu.

Agglomerator units have also been installed at four other facilities in the United States, at the Havana Power Station Unit 6 in Illinois, the Widows Creek Unit 8 facility in Alabama, the Jack Watson Unit 4 in Mississippi, and the Asbury Station Unit 1 in Missouri. A technical report received from Indigo Technologies discussing the status of the performance of these agglomerator installations indicated improvement in facility opacity and particulate emissions following their installation. This report states the average PM emission rate for Jack Watson Unit 1 dropped from 0.0735 lb/MMBtu to 0.0475 lb/MMBtu after the installation of the

agglomerator. This "improved" level is still well above the emission level that a modern ESP or fabric filter baghouse would achieve.

As agglomerators have not been technically demonstrated on units other than retrofits on existing older ESP units, their ability to reduce filterable PM cannot be compared to the performance of a new fabric filter baghouse or ESP is unknown. Considering the mixed results from the trial units and the fact that agglomerators are really intended for retrofit of older ESP units, agglomerators will no longer be considered in this analysis.

Dry Electrostatic Precipitator (ESP) and Wet Electrostatic Precipitator (WESP) and Fabric Filter Baghouses

The remaining technically feasible control technologies identified from Step 2 include fabric filter baghouses, dry ESP, and WESP. According to the USEPA fact sheets, the typical new equipment design removal efficiencies for all three technologies are capable of achieving 99 percent or potentially more. Comparing data provided by USEPA in AP-42 Table 1.1-6 for coal-fired boilers, baghouses generally are slightly more effective at removal of particulate than ESPs, especially for the finer-particulate-size fractions.

In addition, research data indicate that activated carbon is not collected efficiently in an ESP. These particles do not hold an electrostatic charge, which is why they tend to not be collected in an ESP. This is important considering that activated carbon injection is part of the proposed mercury removal process. In selection of BACT, other pollutants (in particular, toxic compounds) must be considered.

Step 4 – Evaluate Remaining Control Technologies

The remaining two control technologies, fabric filter baghouses and ESPs (including WESPs), both provide the maximum degree of emissions reduction of PM emissions from coal-fired units. Both controls are cost effective and do not have any significant collateral environmental impacts. WESPs have a slight disadvantage when compared to fabric filter baghouses and dry ESPs, in that they produce a wet waste product, which can lead to additional treatment and disposal costs versus dry systems. While both a fabric filter baghouse and an ESP can achieve the maximum amount of PM reduction available, fabric filter baghouses have additional benefits when sorbent injection is used (as it will be at Plant Washington), and may be more

effective in the combined control of metallic (i.e., Pb, Hg) emissions. For these reasons, a fabric filter baghouse was chosen as the most effective and top control.

Energy Impacts

This subsection discusses the energy impacts of the PM control options. The main energy impact which affects the remaining control options is the electrical energy required to operate the system. A secondary energy impact is the energy impact associated with the pressure drop of the systems. An increase in pressure drop increases the power required to operate the system. Based on data in a USEPA Air Pollution Training Institute publication on Electrostatic Precipitator Operation, the power required to operate either a dry or wet ESP can be around 1,000 watts per 1,000 acfm, with limited collection efficiency degradation at 750 watts per 1,000 acfm. For the estimated air flow currently available for the site, this could lead to ESP power requirements from 2 to 3 MW. Fabric filters can experience higher pressure drops than those associated with ESPs. Although a fabric filter baghouse would require additional auxiliary power to overcome the pressure drop across the fabric filter bags, leading to a potential total power requirement of as much as 10 MW for a fabric filter baghouse, such energy requirements would not be enough to preclude use of a fabric filter baghouse.

Environmental Impacts

Fabric filter baghouses and dry ESPs both collect dry collected waste materials that would have to be disposed of in accordance with applicable State and Federal Regulations. With a fabric filter baghouse, an additional waste source would be the disposal of worn-out filter bags. Waste materials collected by the fabric filter baghouses will be disposed of in accordance with state and federal regulations. There are no other major environmental issues that would preclude the use of a baghouse.

As mentioned above, ESP control devices are not as effective as a fabric filter baghouse in control of particulate emissions when used in conjunction with activated carbon injection, due to the resistivity properties of activated carbon and the corresponding difficulty of collecting activated carbon in an ESP. The use of an ESP would reduce the effectiveness of activated carbon injection for control of mercury emissions over a fabric filter baghouse.

Economic Impacts

An obvious economic impact is the loss of saleable power due to the high internal power demands of an ESP or a fabric filter baghouse. Potential power requirements for ESP units at the site could exceed 2 to 3 MW, while potential power requirements for a fabric filter baghouse system could exceed 10 MW. Although use of a fabric filter baghouse could lead to the loss of more saleable power than the use of an ESP, these losses do not preclude use of a fabric filter baghouse.

Step 5 – Selection of BACT

A fabric filter baghouse was chosen as BACT for this analysis, since it has been demonstrated to be the most effective control for removal of PM emissions and does not preclude use of activated carbon for control of mercury. This selection is supported in review of the RBLC database. A summary of recent RBLC PM BACT evaluations conducted for similar projects is in Table 4-3. As Table 4-3 demonstrates, nearly all of the facilities with the lowest permitted PM limits have selected a fabric filter baghouse as the top PM control technology.

The proposed BACT emission limit for PM_{10} is 0.018 lb/MMBtu (total – filterable and condensable) on a 3-hour average basis using Method 201A and 202 excluding ammonium chloride. The filterable PM limit chosen would be 0.012 lb/MMBtu on a 24-hour block average basis, with compliance demonstrated through use of a PM continuous emissions monitor (CEM) device. This level of control and emission limit has been proposed as BACT on recent similar projects. The BACT level proposed for total PM_{10} matches the lowest values listed in Table 4-3 for total PM_{10}.

Although lower values for filterable PM have been proposed, this project will use a CEM device to continuously monitor filterable PM for compliance on a 24-hour block average basis, which justifies a higher emission limit when compared to a limit that has only a single stack test per year as a compliance requirement. For example, the Toquop Energy facility in Nevada was issued a draft permit with a filterable PM limit of 0.01 lb/MMBtu. However, compliance with this limit was to be determined on a 3-hr average from a stack test, and the permit did not indicate requirements for use of a PM CEMS device. Since Plant Washington will utilize a PM CEMS for determination of continuous compliance on a 24-hr block average, instead of an intermittent stack test, selection of a higher filterable limit of 0.012 lb/MMBtu is justified.

In addition this project includes a wet scrubber for SO_2 control, which is downstream of the PM control device. On occasion, the mist generated in the wet scrubber could introduce a small amount of filterable particulate into the flue gas stream. Since PM will be monitored on a continuous basis this is another reason why a higher filterable limit is justified. With a more stringent averaging period, the uncertainty of the performance of a PM CEMS device, and uncertainty in the continuous system performance for PM emissions, a higher filterable limit is selected to account for variability in system (and CEM) performance over a 24-hour averaging period.

The recently issued permit for the Desert Rock Energy Facility indicates a filterable PM limit of 0.01 lb/MMBtu on a 24-hr block period, with compliance demonstrated through use of a PM CEMS device. This facility has not yet been built, however, and thus it has not demonstrated its ability to comply with its PM filterable limit. Moreover, the permit for this facility contains a total PM limit of 0.02 lb/MMBtu, which is higher than the total PM_{10} limit of 0.018 lb/MMBtu determined for Plant Washington. Accordingly, Plant Washington's proposed PM limits together will be as stringent, if not more stringent, than the PM limits set forth in Desert Rock's permit.

Table 4-3 PM Emissions from Pulverized Coal Boilers Taken from the RBLC or Draft Permits

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Capacity (MW)	Control Description	Emission Limit		Demonstrated Compliance ?	Avg Period
DESERT ROCK	NM	AZP 04-01	7/31/2008	SCPC BOILER NO. 1 AND 2	6810 mmbtu	FABRIC FILTER (BAGHOUSE)	0.01 (Filterable) 0.02 (total)	lb/MMBtu	No	24-hr block average (filterable) 3-hr average total
TOQUOP	NV	ap4911-1146		SCPC BOILER	750	BAGHOUSE	0.01 (Filterable) 0.03 (total)	lb/MMBtu	No	3-hr averaging period
DRY FORK STATION	WY	CT-4631	10/15/2007	PC BOILER (ES1-01)	385	FABRIC FILTER (BAGHOUSE)	0.012	lb/MMBtu	No	Annual
TS POWER PLANT	NV	5/5/2005	5/5/2005	200 MW PC COAL BOILER	200	FABRIC FILTER DUST COLLECTION	0.012 (Filterable) 0.038 (Total)	lb/MMBtu	Yes	24-hour averaging period
WYGEN 2*	WY	CT-3030A	7/11/2005	BOILER, 100 MW PC	100	FABRIC FILTER	0.012 (Filterable)	lb/MMBtu	Yes	Unknown
WYGEN 3	WY	CT-4517	2/5/2007	PC BOILER	100	BAGHOUSE	0.012 (Filterable)	lb/MMBtu	No	Unknown
HARDIN GENERATOR PROJECT	MT	3185-00	6/11/2002	BOILER, PULVERIZED COAL-FIRED	113	MULTICLONE USED IN CONJUNCTION WITH WET SCRUBBER	0.012 (Filterable) 0.024 (Total)	lb/MMBtu	Yes	Unknown
LONGLEAF	GA	4911-099-0030-P-(	5/14/07	BOILER #1	600	BAGHOUSE	0.012 (Filterable) 0.030 (Total)	lb/MMBtu	No	3-hr averaging period
LONGLEAF	GA	4911-099-0030-P-(	5/14/07	BOILER #2	600	BAGHOUSE	0.012 (Filterable) 0.030 (Total)	lb/MMBtu	No	3-hr averaging period
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 1	390	FABRIC FILTERS	0.012 (Filterable)	lb/MMBtu	No	Not Specified
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 2	390	FABRIC FILTERS	0.012 (Filterable)	lb/MMBtu	No	Not Specified
INTERMOUNTAIN POWER STATION UNIT 3	UT	DAQE-AN0327010-04	10/15/04	PC BOILER	950	BAGHOUSE	0.013 (Filterable) 0.0244 (Total)	lb/MMBtu	No	3 test run average
AGP SOY PROCESSING	NE	CP05-0050	9/11/2006	STEAM GENERATION	382 mmbtu	FABRIC FILTER	0.015 (Filterable)	lb/MMBtu	Unknown	Unknown
HOLCOMB UNIT #2	KS	0550087/C-3855	10/8/2002	BOILER, PULVERIZED COAL	700	DRY FABRIC FILTER	0.015 (Filterable) 0.035 (Total)	lb/MMBtu	No	3 runs of at least 120 min in duration
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 2	7800 mmbtu	KCPL SHALL INSTALL A FABRIC FILTRATION SYSTEM (BAGHOUSE) FOR THE UNIT 2 BOILER TO REDUCE PM10 EMISSIONS.	0.015 (Filterable) 0.0236 (Total)	lb/MMBtu	No	3-hour averaging period
BIG CAJUN II POWER PLANT	LA	PSD-LA-677	8/22/2005	NEW 675 MW PULVERIZED COAL BOILER (UNIT 4)	675	ESP AND BAGHOUSE IN SERIES CONFIGURATION	0.015 (Filterable)	lb/MMBtu	No	Annual
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AN	7/24/2006	PULVERIZED COAL BOILER	800	BAGHOUSE	0.015 (Filterable) 0.040 (Total)	lb/MMBtu	No	Annual
SANTEE COOPER PEE DEE	SC	1040-0113-CA.1 DRAFT	12/1/07	BOILER NO. 1 AND NO. 2	660 each	BAGHOUSE	0.015 (Filterable) 0.018 (Total)	lb/MMBtu	No	3-hour averaging period
THOROUGHBRED GENERATING STATION	KY	TV-02-001	10/11/2002	BOILER, COAL, (2)	2-750	ESP, AND WET ELECTROSTATIC PRECIPATATOR (WESP)	0.018 (Filterable)	lb/MMBtu	No	3-hr averaging period
VIRGINIA TECH	VA	20124	9/15/2005	OPERATION OF BOILER 11	146.7 mmbtu	BAG HOUSE EQUIPED WITH CEM	0.018	lb/MMBtu	Unknown	Unknown
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	MO	122004-007	12/15/2004	PULVERIZED COAL FIRED BOILER	275	BAGHOUSE	0.018	lb/MMBtu	No	Unknown
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATION	MO	888	8/17/1999	ELECTRIC GENERATION, BOILER, COAL	565	FABRIC FILTER SYSTEM	0.018	lb/MMBtu	Yes	Unknown

Note: Hardin Generator Project Facility originally permitted as a multiclone used in conjunction with a venturi wet scrubber. In 2004, a permit amendment modified the facility control strategy to a fabric filter baghouse with a spray dryer absorber (dry scrubber). Compliance was demonstrated with use of a fabric filter baghouse.

Table 4-3 PM Emissions from Pulverized Coal Boilers Taken from the RBLC or Draft Permits (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Capacity (MW)	Control Description	Emission Limit		Demonstrated Compliance ?	Avg Period
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	500	FABRIC FILTER BAGHOUSE (WHEN FIRING COAL) NATURAL GAS USE (W/O BAGHOUSE) LIMITED TO 500 MMBTU/HR	PM_{10} 0.018 (Total)	lb/MMBtu	No	3-hr averaging period
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	600	DRY SOLID INJECTION W/ FABRIC FILTER AND WET SCRUBBER	0.018 (Total)	lb/MMBtu	No	6-hr averaging period
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	600	DRY SOLID INJECTION W/ FABRIC FILTER AND WET SCRUBBER	0.018 (Total)	lb/MMBtu	No	6-hr averaging period
OPPD - NEBRASKA CITY STATION	NE	58343C01	3/9/2005	UNIT 2 BOILER	660	FABRIC FILTER BAGHOUSES	0.018 (Total)	lb/MMBtu	No	3 test runs
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER , UNIT 1 - SN-01	665	BAGHOUSE	0.018 (Filterable)	lb/MMBtu	No	Unknown
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER - SN-01	665	BAGHOUSE	0.018 (Filterable)	lb/MMBtu	No	Unknown
SANTEE COOPER CROSS	SC	0420-0030-CI	2/5/04	BOILER #3	660	BAGHOUSE	0.018 (Total)	lb/MMBtu	Yes	Unknown
SANTEE COOPER CROSS	SC	0420-0030-CI	2/5/04	BOILER #4	660	BAGHOUSE	0.018 (Total)	lb/MMBtu	No	Unknown
ELY ENERGY STATION	NV		2007	SUPERCRITICAL BOILER	2-750	FABRIC FILTER	0.02 (Total)	lb/MMBtu	No	3-hour averaging period
AES BEAVER VALLEY, LLC	PA	PA-04-446C	11/21/2001	COAL FIRED BOILER	2155 mmbtu	BAGHOUSE	0.02	lb/MMBtu	Unknown	Unknown
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	500	FABRIC FILTER BAGHOUSE (WHEN FIRING COAL). NATURAL GAS USE (W/O BAGHOUSE) IS LIMITED TO 500 MMBTU/HR.	PM 0.02 (Total)	lb/MMBtu	No	3-hr averaging period
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	BOILER, STEAM ELECTRIC POWER GENERATING	250	BAGHOUSE	0.02	lb/MMBtu	No	Unknown
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	BOILER, COAL FIRED, MAIN STACK	240	BAGHOUSE	0.02	lb/MMBtu	No	Unknown
JK SPRUCE ELECTRIC GENERATING STATION	TX	PSD-TX 1037 & 70492	12/28/05	UNIT 2 BOILER	750	FABRIC FILTER	0.022	lb/MMBtu	No	Unknown
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 1	850	BAGHOUSE	0.0244 (Total)	lb/MMBtu		30-day rolling average
AMERICAN MUNICIPAL POWER GENERATING STATION	OH	06-08138	2/7/2008	BOILER (2), PULVERIZED COAL FIRED	5191 mmbtu	BAGHOUSE IN COMBINATION WITH A WET ELECTROSTATIC PRECIPITATOR (WESP)	0.0250	lb/MMBtu		3-hr averaging period
ARCHER DANIELS MIDLAND COMPANY	IL	97070097	12/24/1998	BOILER (9&10), FLUIDIZED BED	1500 mmbtu	FABRIC FILTER. IF UNIT DEMONSTRATES 0.015 LB/MMBTU OR LESS, TESTING INTERVAL IS DOUBLED.	0.025	lb/MMBtu		Unknown
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	750	BAGHOUSE	PM_{10} 0.025 (Total) PM 0.027 (Total)	lb/MMBtu		Unknown
CRYSTAL RIVER POWER PLANT	FL	PSD-FL-383	5/18/2007	FFFSG UNITS 4 AND 5	760	MODIFIED ESP (IMPROVEMENTS)	0.03	lb/MMBtu		Unknown
AGP SOY PROCESSING	NE	CP05-0050	9/11/2006	STEAM GENERATION	382 mmbtu	GOOD COMBUSTION PRACTICES	0.041	lb/MMBtu		Unknown
INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	GA	2631-115-0021-V-	10/13/2004	BOILER, COAL FIRED	565 mmbtu	ESP	0.05	lb/MMBtu		Unknown

Table 4-3 PM Emissions from Pulverized Coal Boilers Taken from the RBLC or Draft Permits (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Capacity (MW)	Control Description	Emission Limit		Demonstrated Compliance ?	Avg Period
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD	10/15/2003	BOILER UNIT 7, COAL, WAP7	6700 mmbtu	COMBUSTION CONTROL	0.085	lb/MMBtu		Unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	6700 mmbtu	COMBUSTION CONTROL	0.086	lb/MMBtu		Unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	6700 mmbtu	COMBUSTION CONTROL	0.086	lb/MMBtu		Unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	6700 mmbtu	FIRING NAT GAS	0.087	lb/MMBtu		Unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	7400 mmbtu	COMBUSTION CONTROL	0.088	lb/MMBtu		Unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	7400 mmbtu	COMBUSTION CONTROL	0.089	lb/MMBtu		Unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	7400 mmbtu	FIRING NAT GAS	0.089	lb/MMBtu		Unknown
SOUTHWESTERN PUBLIC SERVICE COMPANY-HARRINGTON STATION	TX	P017M1	10/17/2006	UNIT 3 BOILER	3870 mmbtu	COAL CRUSHERS OPERATE AT BELOW ATMOSPHERIC PRESSURE WITH COAL DUST CONTROLLED	0.09	lb/MMBtu		Unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	7400 mmbtu	NONE INDICATED	0.097	lb/MMBtu		Unknown
MANSFIELD MILL	LA	PSD-LA-93 (M-6)	8/14/2001	POWER BOILER #1 & #2, COAL	645 mmbtu	SINGLE STAGE DUST COLLECTOR/ESP	0.1	lb/MMBtu		Unknown
THERMAL VENTURES	VA	30529	2/15/2002	BOILER, STEAM	120 mmbtu	GOOD COMBUSTION PRACTICES, CLEAN BURNING FUEL, AND CONTINUOUS EMISSION MONITORING DEVICE.	0.14	lb/MMBtu		Unknown
THERMAL VENTURES	VA	30529	2/15/2002	BOILER, STEAM	120 mmbtu	GOOD COMBUSTION PRACTICES, CLEAN BURNING FUEL, AND CONTINUOUS EMISSION MONITORING DEVICE.	0.15	lb/MMBtu		Unknown

* Wygen submitted revised application to reduce capacity of the plant from 500 MW to 100 MW.

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

4.3.2 BACT Demonstration for NO_x Emissions from the Supercritical Pulverized Coal Boiler

NO_x emissions are a byproduct of coal combustion, and originate from both the coal-bound nitrogen and the nitrogen from the air, used in the combustion process. There are three main formation mechanisms for NO_x: thermal NO_x, fuel NO_x, and prompt NO_x. Thermal NO_x results from the reaction between oxygen and nitrogen in the combustion air at the high temperatures of combustion. Fuel NO_x results from oxidation of coal-bound nitrogen compounds, and depends on the nitrogen content of the coal, the amount of nitrogen evolved at high temperatures during devolatilization, and burner design. Prompt NO_x is formed in the early stages of combustion, which cannot be explained by either thermal NO_x or fuel NO_x. It is presumed to result from the fixation of atmospheric (molecular) nitrogen by carbon fragments that produce OH radical in the flame zone, rather than the fixation of nitrogen in the post-flame gases, as is the case with thermal NO_x.

A review of available research concerning NO_x emissions from coal-fired boilers has identified numerous parameters (fuel, boiler design, control device parameters, etc.) that impact NO_x emissions. These include the including:

- Coal nitrogen and oxygen content
- Fuel ratio (fixed carbon/volatile matter)
- Carbon-to-hydrogen ratio
- Boiler load
- Air flow and distribution
- Fuel and flue gas flow through the boiler
- Boiler performance
- Furnace slagging
- Fouling of tube surfaces
- Ambient conditions
- Operator and control system actions
- Point of time in catalyst life
- Catalyst fouling from other pollutants
- Ammonia (NH_3) injection rates
- Mixing of the injected NH_3 and flue gases

To a degree, these factors can be accounted for in design and operation of the plant, but some of these parameters cannot be controlled. The proposed BACT limit and its averaging period must therefore allow for variations in all of these factors to ensure that the limit is the best level that can be achieved based on discussions with the boiler designer, control device manufacturer, and operator, while also an emission

level that will be achievable on a continuous basis under all normal and reasonably expected operating conditions over the life of the unit.

Step 1 – Identify All Control Technologies

Lower-emitting Processes or Practices – LNB

Low NO_x burners (LNBs) incorporate mechanisms for reducing the peak flame temperature in the combustion zone of a combustion unit. This reduction in peak flame temperature results in lower NO_x emissions. Peak flame temperature is controlled by carefully regulating the distribution and mixing of the fuel and air in the combustion zone, and is most commonly reduced by separating combustion into multiple zones, or stages. The unique design of features of an LNB may create: (1) a reduced oxygen level in the combustion zone to limit fuel NO_x formation; (2) a reduced flame temperature that limits thermal NO_x formation; and/or (3) a reduced residence time at peak temperature, which also limits thermal NO_x formation. LNBs are used for the reduction of NO_x emissions and can be combined with overfired air systems to achieve even greater NO_x reduction.

Lower-emitting Processes or Practices – OFA

In the Overfire Air (OFA) process, combustion air is diverted from the burners to create a fuel-rich zone in the lower portion of the combustion zone, or furnace. OFA limits NO_x by: (1) suppressing thermal NO_x by partially delaying and extending the combustion process, resulting in less intense combustion and cooler flame temperatures, and (2) suppressing fuel NO_x formation by reducing the concentration of air in the combustion zone where volatile fuel nitrogen is evolved. This process inhibits fuel bound nitrogen conversion to NO_x emissions on fossil fuel-fired boilers. Peak flame temperatures are also reduced to limit thermal NO_x formation. The concept of OFA has also been adapted for other applications such as the Rotating Opposed Fire Air (ROFA) system. ROFA uses a booster fan to supply high-velocity air to improve mixing and lower the maximum temperature, thereby reducing the formation of thermal NO_x. ROFA has been installed only as a retrofit technology.

Lower-emitting Processes or Practices – Flue Gas Recirculation (FGR)

In FGR, emissions of NO_x can be reduced by recirculating a portion of the boiler flue gas into the main combustion chamber. This process reduces the peak combustion temperature and lowers the percentage of oxygen in the combustion air/flue gas mixture, thus reducing the formation of thermal NO_x caused by high flame and combustion zone temperatures.

Selective Catalytic Reduction (SCR)

SCR is a post-combustion control process, which chemically reduces NO_x into molecular nitrogen and water vapor. SCR is capable of NO_x reduction efficiencies in the range of 70 percent to 90 percent. The following is a description of the SCR process from USEPA's Selective Catalytic Reduction Fact Sheet (2003):

> A nitrogen based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and reagent diffuse through the catalyst. The reagent reacts selectively with the NO_x within a specific temperature range and in the presence of the catalyst and oxygen. The catalyst is composed of active metals or ceramics with a highly porous structure. Catalysts configurations are generally ceramic honeycomb and pleated metal plate (monolith) designs.

The SCR reactor can be located at various positions in the process, including before an air heater and particulate control device, or downstream of the air heater, particulate control device, and flue gas desulfurization systems. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, NH_3-to-NO_x ratio, inlet NO_x concentration, space velocity, and catalyst condition. As indicated in USEPA's Selective Catalytic Reduction Fact Sheet (2003), NO_x reduction by the SCR is only effective within a certain temperature range, depending on the type of catalyst used and the composition of the flue gas. Optimum SCR temperatures can vary from 480 ^oF to 800 ^oF.

Selective Non-catalytic Reduction (SNCR)

Selective Non-catalytic Reduction (SNCR) is a post-combustion control process. It controls NO_x emissions through the injection of NH_3 or urea into specific temperature zones in the upper furnace or convective pass section of a boiler. The NH_3 or urea reacts with NO_x in the flue gas to

produce nitrogen and water. The effectiveness of SNCR depends on the temperature of the combustion gas where reagents are injected, mixing of the reagent in the combustion gas, residence time of the reagent within the required temperature window, ratio of reagent to NO_x, and the sulfur content of the fuel that may create sulfur compounds that deposit in downstream equipment. Standalone NO_x reduction levels for an SNCR can range from 30 percent to 50 percent, and when used in conjunction with LNB or other combustion controls can achieve NO_x emissions reductions of 65 percent to 75 percent. The following is a description of the SNCR process from USEPA's SNCR Fact Sheet (2003):

> SNCR is based on the chemical reduction of the NO_x molecule into molecular nitrogen (N_2) and water vapor (H_2O). In the SNCR process, the combustion unit acts as the reactor chamber. The reagent is generally injected within the boiler superheater and reheater radiant and convective regions, where the combustion gas temperature is at the required temperature range. The injection system is designed to promote mixing of the reagent with the flue gas. The number and location of injection points is determined by the temperature profiles and flow patterns within the combustion unit. Both ammonia and urea are used as reagents.

<u>$SCONO_x$</u>

The $SCONO_x$ system is a relatively new catalytic reduction technology that is based on integration of catalytic oxidation and absorption technology. The system uses a coated catalyst to oxidize and reduce both CO and NO_x emissions. NO_x emissions are oxidized to NO_2 and then absorbed onto the catalyst. In the second step, natural gas is passed through a catalyst periodically. The natural gas desorbs the NO_2 from the catalyst and reduces it to N_2. The system does not use NH_3 as a reagent, but instead uses natural gas as the basis for a proprietary catalyst regeneration process.

<u>Gas Reburning</u>

Various forms of gas reburn technologies exist, including Advanced Gas Reburning (AGR), Fuel Lean Gas Reburning (FLGR), Natural Gas Reburning (NGR), and Amine Enhanced Gas Injection (AEGI). Gas reburning systems typically use a second combustion zone following the primary combustion zone in the main boiler. The second combustion zone has a secondary fuel source, such as natural gas or coal. In a reburn system, NO_x produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main combustion zone and introducing that heat

input above the top row of burners to create a reburn zone. Reburn fuel (natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone that reduces the NO_x created in the main combustion zone to nitrogen and water vapor. The fuel-rich combustion gases from the reburn zone are completely combusted by injecting overfire air above the reburn zone. The application and effectiveness of reburn are site-specific because each boiler is originally designed to achieve specific steam conditions and capacity that may be altered due to reburn. Commercial experience is limited; however, NO_x reduction of 50 to 60 percent from uncontrolled levels may be achieved with reburn.

Electrocatalytic Oxidation

Electrocatalytic oxidation is a multipollutant technology developed by the Powerspan Corporation. Electrocatalytic oxidation is reportedly capable of simultaneously controlling NO_x, SO_2, PM, mercury, and other trace elements in a three step process involving ash removal in a conventional dry ESP, passing the gas stream through a barrier discharge reactor to oxidize gaseous pollutants, and finally passing the gas stream through a WESP.

Hybrid SNCR/Catalyst Systems

An emerging technology involves the use of an SNCR and SCR system in series. The hybrid technology uses an SNCR to reduce NO_x levels with a controlled amount of ammonia slip. The ammonia slip then functions as an ammonia source for the secondary SCR step that achieves additional NO_x reduction and minimizes total ammonia slip.

Pahlman Process

The Pahlman process is a multipollutant control technology that simultaneously controls SO_2, NO_x, and mercury (Hg) emissions. EnviroScrub Technologies Corporation is the developer of the Pahlman process, and limited information on the process is available. The process uses a patented sorbent material that is injected via a spray dryer into a reaction zone where pollutant removal occurs. The reaction zone is located downstream of the main particulate matter control device.

THERMALONO$_x$

THERMALONO$_x$ is a technology developed by Thermal Energy International, Inc., that uses the reaction of elemental phosphorous, oxygen, and nitrogen monoxide to form NO_2. The NO_2 further reacts to form a nitrogen oxide (nitric pentoxide [N_2O_5]) that can be removed by a wet scrubber.

Oxygen Enhanced Combustion

Oxygen enhanced combustion is a technology that replaces a small fraction of the combustion air at the burner with oxygen. By generating higher flame temperatures, nitrogen compounds from the coal are released in a manner allowing air staging to be more effective in reducing NO_x emissions. While demonstration data from use of this technology appear promising, this technology is still in the pilot stages of development.

Step 2 – Eliminate Technically Infeasible Options

Lower-emitting Process or Practice –LNB

LNBs are a proven and demonstrated technology for the reduction of NO_x emissions from combustion processes. LNBs are considered standard equipment for modern boilers, and are therefore considered technically feasible for this project.

Lower-emitting Process or Practice – OFA

OFA is a demonstrated technology for the reduction of NO_x emissions from combustion processes, commonly used in conjunction with LNB. OFA is a common design incorporation into new boilers. For these reasons, use of OFA is considered technically feasible for this project.

Lower-emitting Process or Practice – Flue Gas Recirculation (FGR)

FGR is a demonstrated technology in the reduction of NO_x emissions on gas and oil-fired boilers, and is generally only commercially applied to these types of boiler systems. The primary NO_x reduction mechanism in FGR is through production of thermal NO_x, and has a relatively small effect on fuel-bound NO_x production; therefore, FGR is not often applied for NO_x control on coal-fired boilers. Also, to recirculate the flue gas, it must be cleaned of particulate matter. In

most large systems, this is downstream of an air heater and large particulate control device (baghouse or ESP). The gas at this point has cooled, and recirculation of the flue gas to the boiler could cause flame instability. Pulverized coal boilers retrofitted with FGR have shown only marginal benefits in NO_x emissions, since the thermal NO_x portion of total NO_x is generally small from these units when low NO_x burners and OFA have minimized thermal NO_x formation. Therefore, FGR technology is not considered technically feasible for this project.

Selective Catalytic Reduction (SCR)

SCR is a proven and demonstrated technology for the reduction of NO_x emissions on PC-fired boiler units. For this reason, the use of SCR is considered technically feasible for this project.

Selective Non-catalytic Reduction (SNCR)

SNCR is a proven and demonstrated technology for the reduction of NO_x emissions on PC-fired boiler units. For this reason, the use of SNCR is considered technically feasible for this project.

$SCONO_x$

$SCONO_x$ technologies have been developed and are currently commercially available for natural gas-fired turbines and units. It is not a demonstrated technology for use with coal-fired boilers. Since this technology is not commercially available or applicable for a coal-fired boiler, use of this technology is considered technically infeasible for this project.

Gas Reburning

Various forms of gas reburn technologies exist, including advanced gas reburning, fuel lean gas reburning, natural gas reburning, and amine enhanced gas injection. Gas reburning systems typically use a second combustion zone following the primary combustion zone in the main boiler. The second combustion zone has a secondary fuel source, such as natural gas or coal. The use of gas reburning is considered technically feasible for this project.

Electrocatalytic Oxidation

Electrocatalytic oxidation has been commercially demonstrated at the R.E. Burger Plant in Shadyside, Ohio. A review of information regarding the commercial demonstration indicates that the project was treating a 50-MW "equivalent" slipstream of flue gas from the unit at a duct tie in point downstream of the existing facility electrostatic precipitator. Therefore, this demonstration project was not a "full-scale" project and was not run on the scale of a 850 MW PC boiler. A final report of the project study, prepared in 2005, indicated NO_x outlet levels of 0.05 lb/MMBtu. Earlier pilot studies at the R.E. Burger facility conducted in 1999 indicated NO_x removal efficiencies of only 74.5 percent. Even if electrocatalytic oxidation was considered technically feasible for a facility the size of Plant Washington, the reported removal efficiencies (74.5%) are well below the removal efficiencies achievable through use of SCR technology. Accordingly, electrocatalytic oxidation will no longer be considered in this analysis.

Hybrid SNCR/Catalyst Systems

An emerging technology involves the use of an SNCR and SCR system in series. The hybrid technology uses an SNCR to reduce NO_x levels with a controlled amount of ammonia slip. The NH_3 slip then functions as an ammonia source for the secondary SCR step that achieves additional NO_x reduction and minimizes total ammonia slip. This technology is in the demonstration phase and is primarily aimed at reduction in operating costs for NO_x control systems. It is not aimed at achieving improved NO_x reductions. Even if this hybrid technology was considered technically feasible, it is not commercially available and does not contribute significantly to improved NO_x reductions. For this reason, use of hybrid SNCR/catalyst systems will no longer be considered in this analysis.

Pahlman Process

The Pahlman process is a multipollutant control technology that simultaneously controls SO_2, NO_x, and mercury (Hg) emissions. EnviroScrub Technologies Corporation is the developer of the Pahlman process, and limited information on the process is available. The process is located downstream of the particulate matter collection device and uses a spray dryer absorber where a proprietary scrubber material is used. The technology is still in the pilot study state of development. The USEPA Draft New Source Review Workshop Manual states that "technologies

in the pilot scale testing stages of development would not be considered available for BACT review." Since the Pahlman process is still in the pilot stage, and not commercially available, it is not considered technically feasible for this project.

THERMALONO$_x$

THERMALONO$_x$ was tested on a full-scale unit (335 MW), which was funded by American Electric Power Industry in 2001. This test showed that the technology failed to reduce NO$_x$ emissions from the unit. Since the only demonstration of THERMALONO$_x$ indicated that the technology does not reduce NO$_x$ emissions, it is not considered technically feasible for this project.

Oxygen Enhanced Combustion

While demonstration data from oxygen enhanced combustion appear promising, this technology is still in the pilot stages of development and is not commercially available; therefore, it is not considered technically feasible for this project.

Step 3 – Rank Remaining Technically Feasible Control Options

Table 4-4 provides a ranking of the NO$_x$ control technologies considered technically feasible for the proposed project.

Table 4-4 NOx Control Technology Ranking

Control Technique	Description	Control Efficiency (Percent Reduction)
Overfire Air	Injection of air above main combustion zone	10-20%
Low NO_x Burners	Burner design controls mixing of air and fuel to lower combustion temperature	35-55%
Gas Reburn	Injection of reburn fuel and combustion air above the main combustion zone	50-60%
Hybrid SNCR/Catalyst Systems	Hydrid technology that uses SNCR followed by a catalysts that uses NH_3 slip from the SNCR for the SCR process	50-60%
SNCR	Injection of NH_3 or urea in the convective pass zone of the boiler	30-60%
SCR	Injection of NH_3 followed by catalyst bed	70-90%

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The above control efficiencies for various NO_x control techniques are taken from AP-42, Chapter 1.1, Table 1.1-2 (Fifth Edition, Volume I). The NO_x reduction potentials indicated were derived from uncontrolled NO_x data as determined in the development of Chapter 1.1 of AP-42.

OFA and low NO_x burners can be incorporated into the boiler design and can be used in combination with SCR. This is considered the most effective combination of all the combustion controls identified above, followed by the use of SCR for post-combustion control. For the design capacity of the main boiler for Plant Washington and the available fuels, gas reburning was not determined to be as effective as low NO_x burners and OFA in pre-add-on control of NO_x emissions. As standalone technologies, gas reburning and SNCR are not able to achieve the levels reached by these combustion controls in combination with the use of SCR. It would be reasonable to expect a new boiler to "typically" emit NO_x emissions up to 0.22 lb/MMBtu before add-on controls, following low NO_x burners and overfire air. However, this estimate would vary depending on the range of operation variables possible in a pulverized coal-fired boiler. Presuming a maximum 75 percent control efficiency through use of OFA and low NO_x burners from uncontrolled levels, this would indicate an estimated total uncontrolled NO_x emission rate from a coal-fired boiler of 0.88 lb/MMBtu.

Several proprietary technologies identified in Step 1 (Pahlman process, oxygen enhanced combustion, THERMALONO$_x$, and SCONO$_x$) are proprietary technologies that have a limited number of applications and are not considered capable of achieving the NO$_x$ reduction levels achievable through the combination of low NO$_x$ burners, OFA and SCR.

Step 4 – Evaluate Remaining Control Technologies

Combustion controls and SCR are considered the only feasible control technologies to achieve the lowest levels of NO$_x$ emissions from a coal-fired boiler.

Control Effectiveness

Following elimination of the technically infeasible control options in Step 2, SCR is the only effective add-on control technology. For added control of NO$_x$ emissions, SCR can be used in conjunction with LNB and OFA. Recent control effectiveness values, based on the RBLC database, range from 0.05 lb/MMBtu to 0.09 lb/MMBtu.

Energy Impacts

LNB and OFA are incorporated into the standard design of combustion units and do not create any significant energy impacts. Use of the SCR will require additional power to overcome the pressure drop loss across the system catalyst, and operation of the SCR equipment (i.e., NH_3 distribution equipment).

Environmental Impacts

Properly designed combustion controls, such as LNB and OFA, do not create adverse environmental impacts, since such controls are designed to minimize the generation of pollutant emissions. However, furnace design for low NOx combustion does run counter to minimization of CO and VOC emissions due to lower furnace temperatures and minimization of excess air. Use of SCR technology will require the storage and use of ammonia, which can have significant environmental consequences if not handled properly. Storage and use of ammonia at the facility could trigger requirements of multiple different USEPA- and OSHA-related programs, including Risk Management Programs (RMP), Process Safety Management (PSM), and specialized safety

and training programs. Modern SCRs provide effective mixing of the ammonia and flue gas and thereby are able to minimize ammonia slip; therefore, it is not considered to be an environmental hazard. The SCR catalyst can also lead to higher sulfuric acid mist emissions due to the conversion of SO_2 to SO_3 in the catalyst bed.

SCR systems have added collateral benefits in the conversion of elemental mercury to an oxidized form, typically mercuric chloride ($HgCl_2$). Elemental mercury is difficult to collect and remove in pollution control equipment, but the oxidized form can be collected in a wet flue gas desulfurization (wet scrubber) system.

Economic Impacts

While the capital costs and annualized operating costs of SCR technology at the site are significant, SCR technology represents the top tier of controls available for NO_x emissions reduction. The economic impacts are not significant enough to preclude the use of SCR in combination with LNB and OFA.

Step 5 – Selection of BACT

Based on the ranking of technologies, it was determined that the NO_x emissions control technologies that have consistently demonstrated the lowest NO_x levels are NO_x combustion controls (OFA and low NO_x burners) in combination with SCR. The RBLC Clearinghouse was reviewed to determine an appropriate emission limit for this technology application. Table 4-8 provides the results from the RBLC Clearinghouse search. This search confirms that all of the best performing units that are operating or have been permitted achieve their levels through these identified technologies (combustion controls and SCR). Use of an SCR system in conjunction with LNB and OFA has been demonstrated to achieve the lowest NO_x emission rates, and is both technically feasible and demonstrated in PC-fired boilers**. Therefore, BACT for NO_x emissions is proposed as the use of an SCR system in conjunction with LNB and OFA, with an emission limit of 0.05 lb/MMBtu on a monthly average basis (30-day rolling).** This level matches the lowest levels, which have been proposed for BACT on similar projects. In developing this proposed NO_x level, consideration was given to the numerous operational variables that impact NO_x emissions from a PC-fired boiler.

Variables Impacting NO_x Emissions

When considering both the NO_x BACT limit as well as the averaging period for the NO_x limit, the variables impacting NO_x emissions must be considered. A review of available research concerning NO_x emissions from coal-fired boilers has identified numerous parameters that impact NO_x emissions. These include fuel properties such as:

- Coal nitrogen and oxygen content
- Fuel ratio (fixed carbon/volatile matter)
- Carbon-to-hydrogen ratio

In addition to fuel parameters, numerous process parameters impact NO_x emissions. These include:

- Boiler load
- Air flow and distribution
- Fuel and flue gas flow through the boiler
- Boiler performance
- Furnace slagging
- Fouling of tube surfaces
- Ambient conditions
- Operator and control system actions

All these factors will vary over the life of a coal-fired boiler, between maintenance overhauls, and throughout the year. As an example, the nitrogen content of the burned coal can significantly impact NO_x emissions. One of the coals expected to be burned in the unit is PRB coal. There is a significant amount of variability of fuel characteristics within PRB coals. For example, the USGS Coal Quality Database found that the nitrogen content of Wyoming coal (the source of PRB coals) can vary from 0.38 percent to 2.05 percent. USEPA has indicated that fuel-bound NO_x contributes approximately 75 percent to 80 percent of the NO_x formed from coal combustion. This means that one of the most significant variables impacting NO_x (fuel nitrogen content) could vary by more than a factor of 5 within the PRB coal being burned at the plant. This variation, which is outside the control of the plant operator, should be considered when establishing NO_x limits and their associated averaging periods.

Based on these data, a plant burning Wyoming coal could conceivably see a five-fold swing in nitrogen content. Assuming a 15 percent nitrogen-to-NO_x conversion rate (conservative estimate based on typically reported values), an SCR control efficiency of 90 percent (upper bound of expected efficiency range for SCRs), and a coal heat content of 8,300 Btu/lb, a swing of nitrogen content in coal being fed to

the boiler from the low end of the above range (0.38 percent) to the high end (2.05 percent) would result in an increase in nitrogen content by 1.67 percent, which would correspond to an increase in NO_x emissions of 0.065 lb/MMBtu as calculated below:

Estimate of NOx variation due to variations in coal nitrogen content:

$$\frac{1.67 \text{ lb N}}{100 \text{ lb coal}} * \frac{\text{lb coal}}{8{,}300 \text{ Btu}} * \frac{1.00\text{E+06 Btu}}{\text{MMBtu}} * \frac{0.15 \text{ lb NOx}}{\text{lb N}} * \frac{30 \text{ lb NO/lb mole}}{14 \text{ lb N/lb mole}} * \frac{0.1}{1} = \frac{0.065 \text{ lb NOx}}{\text{MMBtu}}$$

The calculation above demonstrates how significantly NO_x could be impacted by a single fuel characteristic (fuel nitrogen content).

Lastly, the conditions of the NO_x control device (SCR) will impact NO_x emissions. SCR catalysts have a typical life of three years. NO_x emissions could therefore be contingent upon specific SCR operating parameters, including:

- Point of time in catalyst life
- Catalyst fouling from other pollutants
- Ammonia injection rates
- Mixing of the injected ammonia and flue gases
- Contact between the mixed gases and the catalyst

In addition to variability in the fuels, process, and control device, there is also variability associated with the monitoring of NO_x emissions. Under the USEPA NO_x continuous emissions monitoring method (40 CFR Part 60 Appendix B), the allowed relative accuracy of CEMs as compared to the reference method is 20 percent (10 percent when the applicable emission limit is used to calculate relative accuracy). This variability must therefore be considered when comparing NO_x emissions among units with different CEMs, as well as when considering short-term emission limits.

Many parameters identified (fuel characteristics, ambient conditions, catalyst life, monitoring methodology, etc.) cannot be controlled by the plant on a daily basis. Any permit limit must therefore allow variations in all of these factors.

Basis for Proposed NO_x BACT Level

The proposed BACT level was derived from a detailed review of proposed PC projects that are in the permitting process (draft permits may or may not have been issued for some of these projects), projects

that have been permitted but have not yet begun construction, and plants that are currently operating with SCRs. In this analysis, emphasis was given to NO_x levels, which are actually being achieved in practice, but the review also considered the levels that other projects have determined to be achievable by engineering and design teams as part of the permitting process. This approach is consistent with the USEPA Draft New Source Review Workshop Manual (page B-24), which states that "Manufacturer's data, engineering estimates, and the experience of other sources provide the basis for determining achievable limits."

To assess actual NO_x emissions from currently operating units, a review of continuous emissions monitoring (CEM) data available through the USEPA Clean Air Markets website was completed. This database includes actual reported NO_x emission rates on all coal boilers reporting emissions for the USEPA acid rain program and includes NO_x emissions data for various averaging periods (hourly, daily, monthly, etc.). This evaluation examined long-term (annual and ozone seasons) and short-term (monthly and daily) levels being achieved in practice.

Long-term NO_x Evaluation of Operating Units

Because NO_x emissions limits commonly apply only during ozone season (May 1 to September 30 in most areas), many boilers in the Clean Air Markets database do not operate their SCRs outside the season. For this reason, the initial evaluation concentrated on only the ozone season to find the best performing boilers currently operating in the United States. Table 4-5 shows all units from the database with average ozone season NO_x emission rates at or below the proposed BACT level of 0.05 lb/MMBtu for the most recent year of complete data (2007). This search found a total of 25 operating boilers that are achieving levels equal to or below the proposed BACT level (0.05 lb/MMBtu) for the entire 2007 ozone season as defined by the Clean Air Markets database. Generally, all these boilers use NO_x controls systems that are similar to those proposed for the Plant Washington site. These include process controls (low NO_x burners and overfire air) and pollution control equipment (SCRs).

Next, an evaluation was completed to determine how these units performed during all other ozone periods during which the units have been operating SCRs. These units had SCRs that became operable from 2002 to 2007. Though NO_x data were available for all these units for all six years, only a few units operate their SCR year round, so for consistency in comparison, Table 4-5 reports only those ozone season averages during which their SCRs were in operation. Table 4-5 also includes the installation dates for the SCRs on these units.

Table 4-5 NO_x Data for Units Averaging Less than 0.05 lb/MMBtu during the 2007 ozone season

			NOx Emission Rate (lb/MMbtu) - Ozone Season - After SCR Installation									
STATE	FACILITY_NAME	UNITID	2002	2003	2004	2005	2006	2007	Average	Maximum	SCR Installation Date	SCR Status (Year Round Operation or Ozone Season Only)
KY	Ghent	4			0.043	0.027	0.031	0.039	0.035	0.043	Began Mar 11, 2004	Ozone Season
VA	Chesterfield Power Station	6			0.048 *	0.033	0.033	0.033	0.037	0.0475	Began May 26, 2004	Ozone Season
TX	W A Parish	WAP7			0.03	0.045	0.039	0.036	0.038	0.045	Began Mar 29, 2004	Year round
TX	W A Parish	WAP8			0.03	0.042	0.036	0.044	0.038	0.044	Began Mar 29, 2004	Year round
WV	John E Amos	1				0.037	0.032	0.049	0.039	0.049	Began Apr 10, 2005	Ozone Season
IA	Walter Scott Jr. Energy Center	4						0.04	0.040	0.04	New unit	Year round
MA	Brayton Point	1						0.04	0.040	0.04	Began Oct 25, 2006	Ozone Season
MA	Brayton Point	3						0.04	0.040	0.04	Began Jun 16, 2006	Ozone Season
TX	W A Parish	WAP6		0.046	0.03	0.042	0.047	0.039	0.041	0.047	Began Jan 28, 2003	Year round
AL	Colbert	5			0.043	0.043	0.041	0.039	0.042	0.043	Assumed 2004	Ozone Season
KY	Mill Creek	4			0.044	0.044	0.044	0.037	0.042	0.044	Began Aug 06, 2003	Ozone Season
TX	W A Parish	WAP5		0.055	0.03	0.042	0.056	0.038	0.044	0.056	Began Apr 14, 2003	Year round
IL	Havana	9			0.084	0.032	0.036	0.03	0.046	0.084	Began Aug 04, 2003	Year round
TN	Kingston	5					0.053	0.049	0.051	0.053	Began May 23, 2005	Ozone Season
WV	Mountaineer (1301)	1	0.062	0.058	0.055	0.043	0.05	0.039	0.051	0.062	Began May 01, 2002	Ozone Season
VA	Chesapeake Energy Center	3			0.122	0.039	0.031	0.028	0.055	0.122	Began Jun 02, 2003	Ozone Season
OH	Cardinal	3		0.135	0.046	0.037	0.041	0.023	0.056	0.135	Began May 01, 2003	Ozone Season
PA	Keystone	2		0.048	0.06	0.06	0.082	0.045	0.059	0.082	Began Feb 09, 2003	Ozone Season
VA	Chesterfield Power Station	5		0.074	0.102	0.038	0.043	0.046	0.061	0.102	Began Jun 17, 2002	Ozone Season
OH	Muskingum River	5				0.063	0.071	0.048	0.061	0.071	Began Apr 03, 2005	Ozone Season
VA	Chesapeake Energy Center	4			0.138	0.061	0.042	0.036	0.069	0.138	Began Jun 25, 2003	Ozone Season
AL	Widows Creek	8			0.13	0.049	0.053	0.047	0.070	0.13	Began May 01, 2004	Ozone Season
NC	Belews Creek	1			0.105	0.076	0.081	0.028	0.073	0.105	Began Jun 12, 2003	Year round
IN	Gibson	1	0.263	0.317	0.283	0.083	0.067	0.034	0.175	0.317	2002	Ozone Season
IA	Ames	7		0.358	0.391	0.393	0.358	0.033	0.307	0.393	Doesn't operate a SCR	NA

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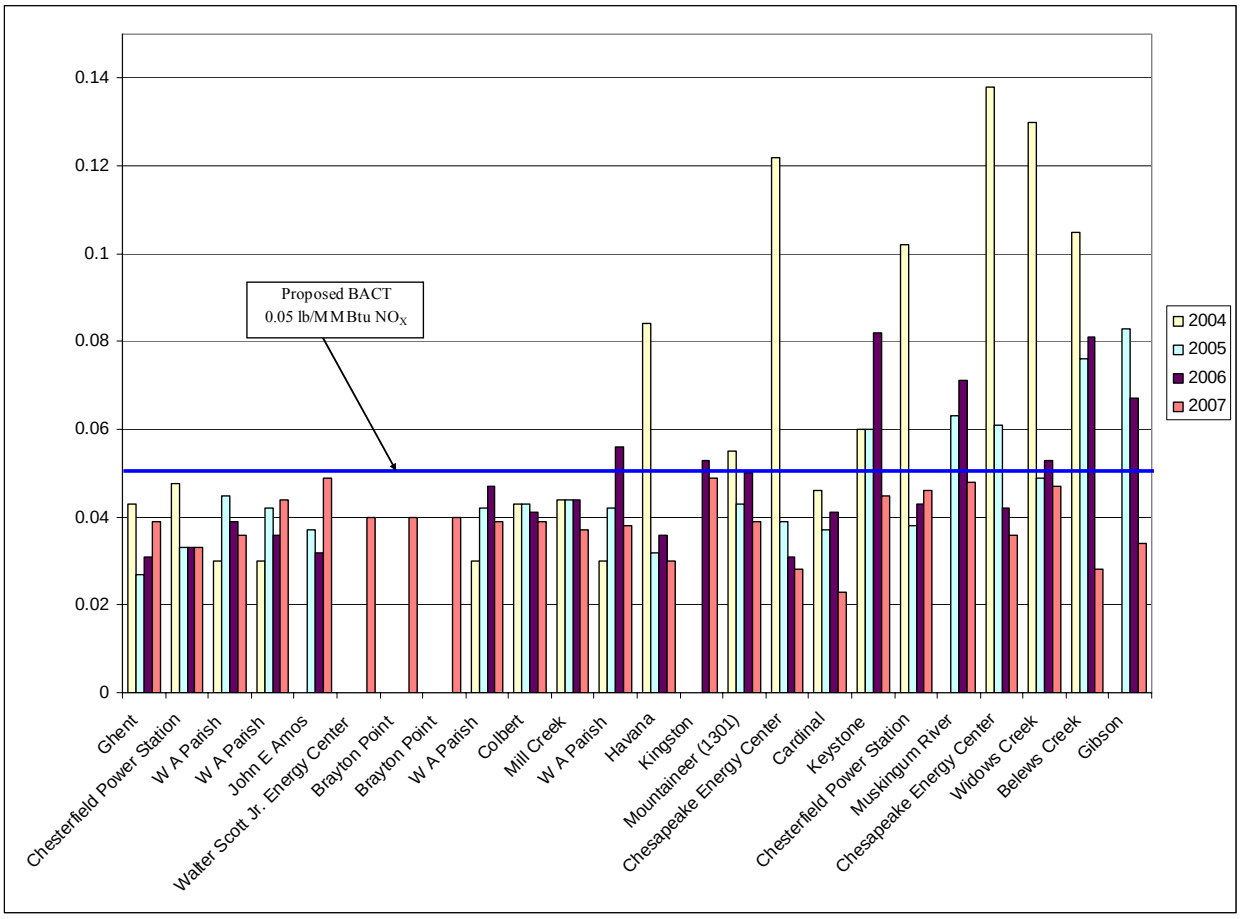
Checked by: SAK 11/26/08

The primary concern with the comparison of actual sampling data to a proposed permit limit is that the proposed limit must provide a reasonable assurance of compliance on a consistent basis. These data were therefore evaluated to determine the lowest emission rate that could reasonably be assured of being achieved on a consistent basis. Of the 25 units identified in Table 4-5, only 11 units (indicated in red) have maintained an NO_x emission level of 0.05 lb/MMBtu for all the ozone seasons for which the units have been operating with SCRs (3 of these units have only been operating for one complete ozone season). This indicates that a small subset of boilers has been able to achieve the proposed NO_x BACT level for sustained periods. Figure 4-1 is a graphical illustration of the average lb/MMBtu NO_x emissions data for each of the ozone seasons for the 2004-07 operating period.

Figure 4-1 NOx Data for Units Averaging Less than 0.05 lb/MMBtu During the 2007 Ozone Season For Calendar Years 2004 Through 2007



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This initial evaluation has been limited to the ozone season. Of the 25 units identified in Table 4-5 (the best performers of 2007), only 7 units achieved levels below 0.05 lb/MMBtu level on a year-round basis. While Table 4-5 focused on just the ozone season, Table 4-6 provides the annual NO_x performance data for these boilers.

Table 4-6 Annual NO_x Data for Lowest Emitting Units in 2007

			NOx Emission Rate (lb/MMBtu) - Annual				
STATE	**FACILITY_NAME**	**UNITID**	**2003**	**2004**	**2005**	**2006**	**2007**
OH	Cardinal	3					0.255
NC	Belews Creek	1		0.411	0.307	0.322	**0.047**
VA	Chesapeake Energy Center	3					0.39
IL	Havana	9		0.198	0.039	0.051	**0.047**
IA	Ames	7					0.333
VA	Chesterfield Power Station	6					0.231
IN	Gibson	1					0.23
TX	W A Parish	WAP7		0.053	0.044	0.042	**0.038**
VA	Chesapeake Energy Center	4					0.25
KY	Mill Creek	4					0.215
TX	W A Parish	WAP5		0.031	0.043	0.052	**0.046**
AL	Colbert	5					0.114
KY	Ghent	4					0.223
TX	W A Parish	WAP6	0.059	0.033	0.043	0.047	**0.043**
WV	Mountaineer (1301)	1					0.253
IA	Walter Scott Jr. Energy Center	4					**0.039**
MA	Brayton Point	1					0.099
MA	Brayton Point	3					0.105
TX	W A Parish	WAP8		0.041	0.041	0.038	**0.044**
PA	Keystone	2					0.185
VA	Chesterfield Power Station	5					0.228
AL	Widows Creek	8					0.232
OH	Muskingum River	5					0.359
TN	Kingston	5					0.251
WV	John E Amos	1					0.305

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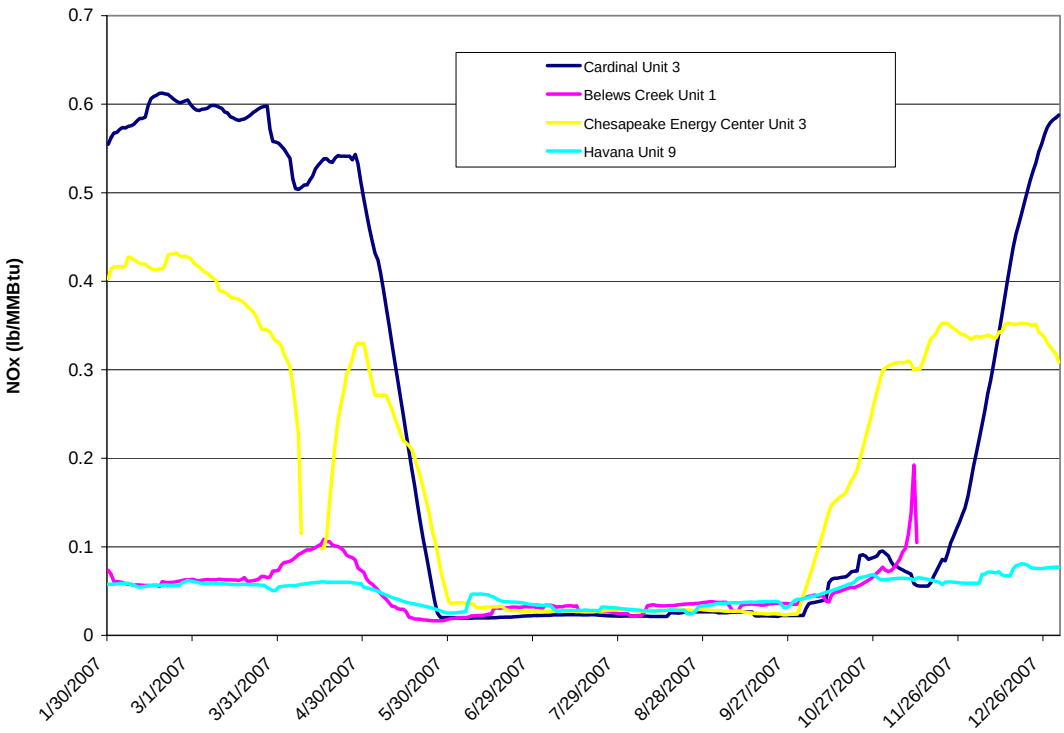
* Units with 2007 averages below 0.05 lb/MMBtu shown in red.

Of the seven units achieving NO_x levels of 0.05 lb/MMBtu annually, only two units (Unit 4 at the Walter Scott Jr. Energy Center in Iowa and unit WAP8 at WA Parish in Texas) have had annual averages consistently below the proposed BACT level of 0.05 lb/MMBtu. These two units represent only five operating years of data with SCRs on coal-fired boilers. Four of the operating years apply to the WA Parish WAP8 unit; therefore, only one of the best performing units in 2007 has achieved NO_x levels below the proposed BACT level annually for more than one year. The conclusion from this evaluation is that the experience of the year-round use of SCRs on coal-fired boilers operating below the 0.05 lb/MMBtu NO_x level is extremely limited. This data review also validates the proposed BACT level as a stringent and difficult-to-achieve standard in real world practice.

This review should, however, consider that some of the boilers identified operate their SCRs only during the ozone season, because the regulatory emphasis is on the formation of ground-level ozone, which is a problem only during the ozone season. These units could therefore likely achieve lower NO_x limits annually than are demonstrated in practice. To evaluate this further, the NO_x emissions were plotted for 11 units consistently achieving 0.05 lb/MMBtu during the ozone season (shown in red in Table 4-5). Figure 4-2 provides a plot of the 30-day rolling average NO_x emissions for 2007 for four of the units identified in Table 4-5. As shown in the figure, two of the units (Cardinal Unit 3 and Chesapeake Energy Center Unit 3) show drops in NO_x of approximately 90 percent during the ozone season, while the Belews Creek Unit 1 and Havana Unit 9 show a consistent low NO_x level year round, suggesting that these two units operate their SCRs year round. They do show a slight reduction during the ozone season; however, the low levels being achieved outside the ozone period could not be practically achieved without operating their SCRs. This evaluation was repeated for all units identified in Table 4-5 and it was determined that seven of the boilers operate their SCRs year round. The status of the SCR (year round or ozone season only) is identified in Table 4-5.

Generally, this evaluation confirms that there is limited experience with operating SCRs year round, which could affect operation in several ways. First, by operating for only five months per year, the life of the SCR could be extended, and secondly, longer downtime will allow a significant period to perform extended maintenance on the SCR, which may not otherwise be available to a unit operating continuously year round.

Figure 4-2 Units Achieving Ozone Season Averages Below 0.05 lb/MMBtu(30-day Rolling Averages)



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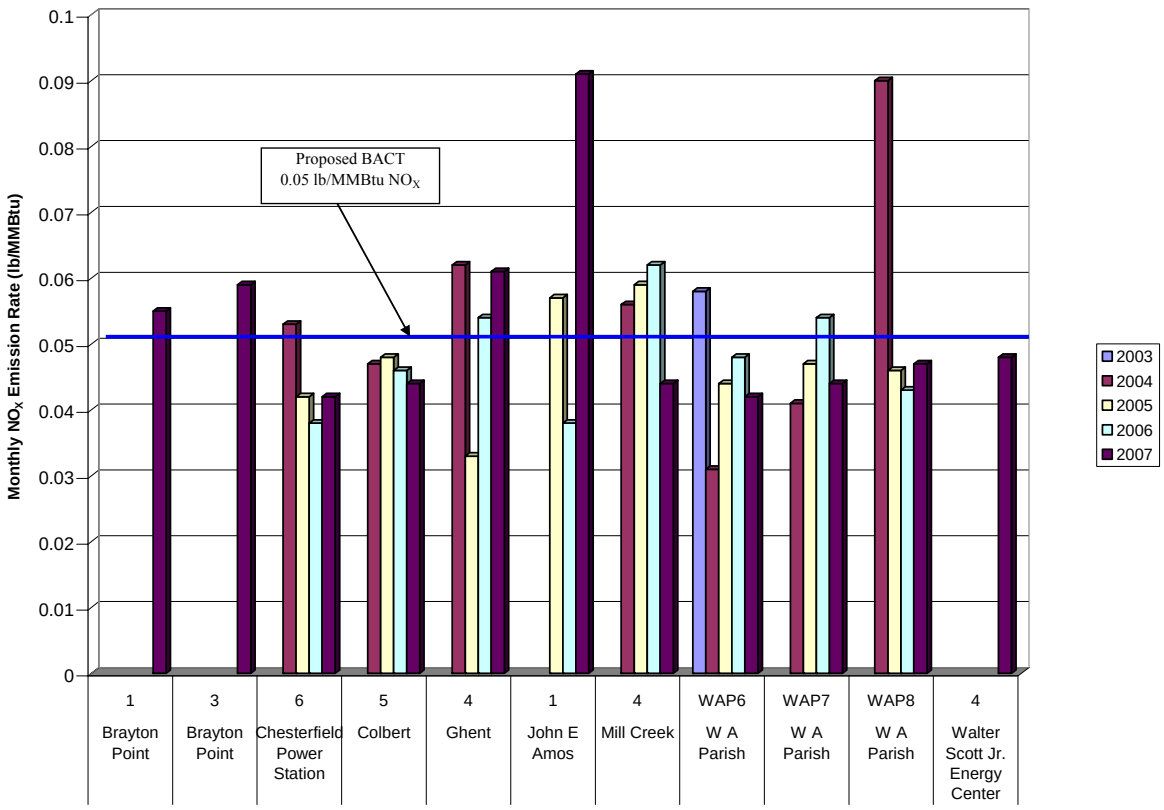
Monthly Average Evaluation

The above analysis considered first ozone season estimates and then annual NO_x emission rates. The proposed BACT level is, however, on a monthly average basis and would therefore be more difficult to achieve than an average based on only the ozone season or an annual average basis. Therefore, the monthly averages for all units identified in Table 4-5 were evaluated separately. This evaluation was limited to only those monthly averages during which plants were operating their SCRs as determined by the evaluation discussed previously.

Figure 4-3 is a graphical presentation of the maximum monthly average by year for all 11 units that consistently achieve 0.05 lb/MMBtu NO_x during the 2007 ozone season. This figure includes only those months during which the units were operating SCRs. As shown in Figure 4-3, this analysis found that Unit 4 at the Walter Scott Jr. Energy Center and the Colbert Unit 5 are the only boilers that have been able to consistently maintain NO_x emissions below 0.05 lb/MMBtu for all months of operation reviewed. Of the 32 months of available data for the 2 boilers (12 months for Walter Scott Jr. Energy Center and 20 months for Colbert), the highest monthly reported NO_x is 0.048 lb/MMBtu for both units. The month-to-month variation at these plants may be due to the variation of the nitrogen in the coal, which as noted previously is unpredictable, or to any one of the other operational variables discussed previously. The conclusion from this analysis is that the proposed BACT level of 0.05 lb/MMBtu is representative of the lowest level currently being achieved in industry. It should also be noted that the proposed NO_x BACT level of 0.05 lb/MMBtu is 29 percent below the monthly average NO_x limit (0.07 lb/MMBtu) that the Georgia EPD issued as BACT for the Longleaf boiler in 2007.

Figure 4-3 Maximum Monthly NO_x Emissions By Year for Units Operating SCRs – Top 11



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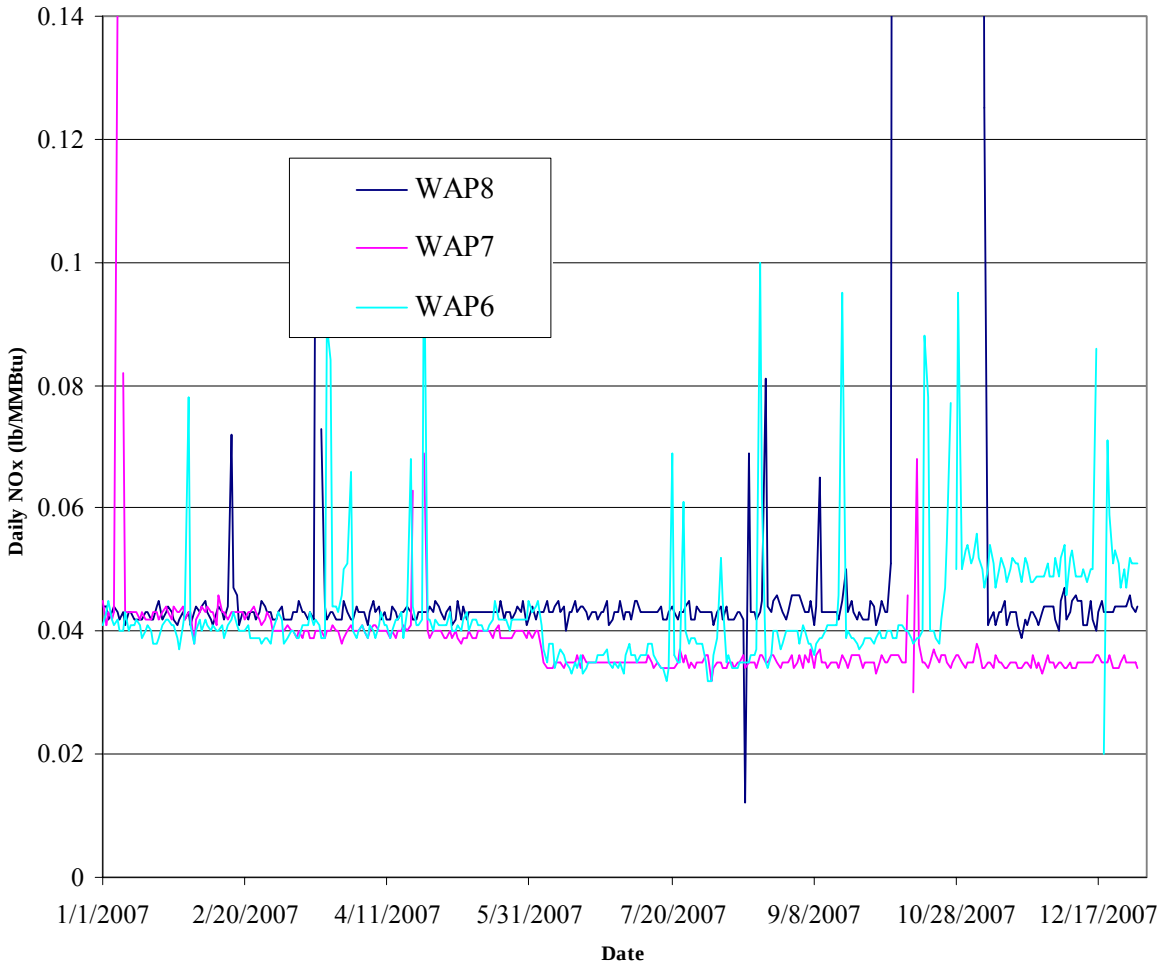
NO_x BACT Averaging Periods – 24 hour

The proposed 30-day average BACT level matches the lowest of any proposed or existing permitted level currently in place in industry for similar boilers. Some permits have recently been issued with higher permitted NO_x emission levels and shorter averaging periods.. These include the Toquop and Ely Energy plants (both in Nevada), which have permit levels of 0.06 lb/MMBtu for 24-hour periods. The Trimble County boiler is permitted at a NO_x limit of 4.17 ton/day, which at the unit's maximum firing rate is equivalent to the proposed NO_x limit of 0.05 lb//MMBtu. However, this limit would not match 0.05 lb/MMBtu when the boiler fired at reduced loads. These emission levels have not yet been demonstrated in practice since the units have not yet been constructed. These units are proposing the same source control technology, SCR, as Plant Washington.

To determine whether a 24-hour averaging time (and limit) can be reasonably achieved and complied with in practice, short term NO_x emissions data from the USEPA Clean Air Markets database were reviewed. A review of actual operating data demonstrates that meeting NO_x emissions on such a short-term basis is impractical. The data from the Clean Air Markets database were evaluated to determine how much NO_x emissions vary on a daily basis. This evaluation was completed for the three units (WAP6, WAP7, and WAP8) at the WA Parish site in Texas, which were identified as top performers in Table 4-5 and have shown annual averages below the 0.05 lb/MMBtu NO_x level. Figure 4-4 provides the daily NO_x emission levels for these three units for 2007.

Figure 4-4 2007 Daily NO_x Values at WA Parish Boilers (WAP6, WAP7, WAP8)



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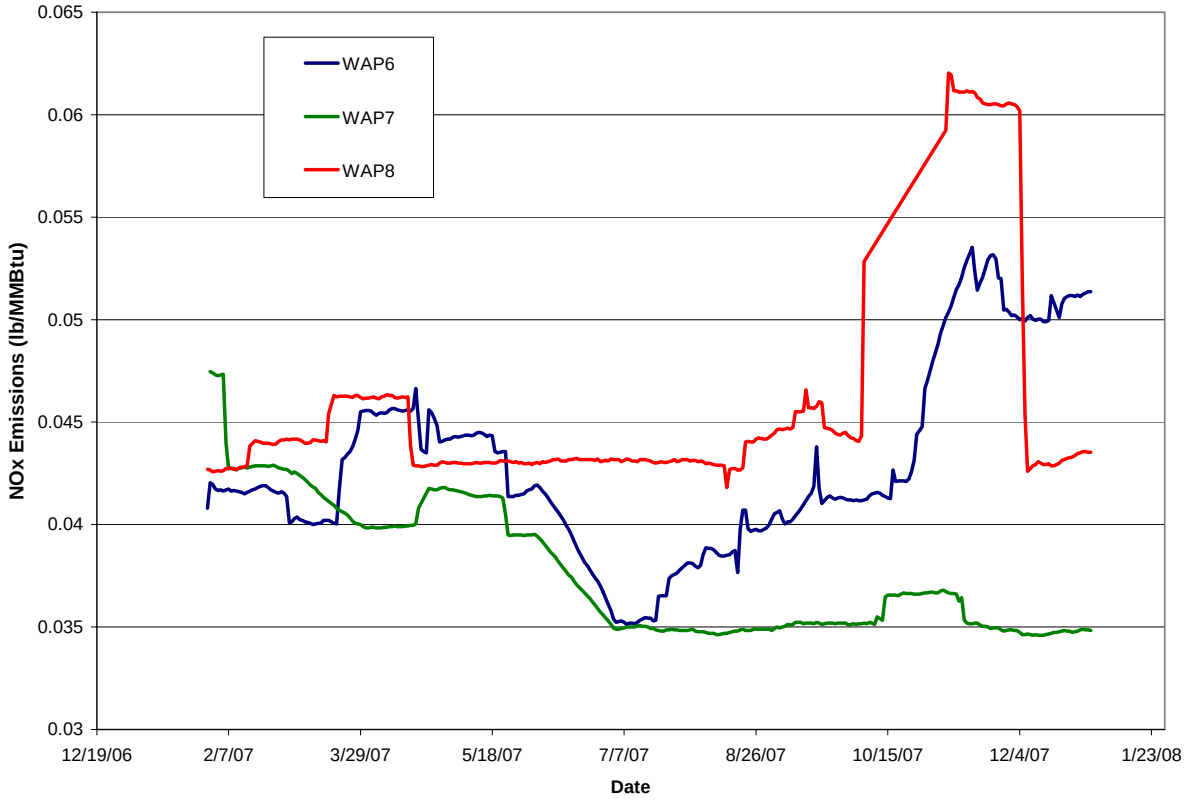
As shown in Figure 4-4, there are numerous incidents of daily averages exceeding 0.06 lb/MMBtu at these units. On average, these units exceed 0.06 lb/MMBtu on a 24-hour basis more than 2.2 percent of the time. This would not be considered an acceptable operating condition for the proposed Plant Washington boiler. Because operating units have not been able to demonstrate consistent compliance with a 0.06 lb/MMBtu limit on a 24-hour basis, such short-term limits are not being proposed as BACT for Plant Washington. An additional plot has been prepared in Figure 4-5, illustrating the 30-day rolling average values for WAP6, WAP7, and WAP8.

Figure 4-5 30-day Rolling Average NO_x Values at WA Parish Boilers (WAP6, WAP7, WAP8)



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Figures 4-6 and 4-7 are graphical illustrations of data available for calendar year 2007 for daily reported NO_x emissions, and 30-day rolling average NO_x emissions, for the Walter Scott Jr. Energy Center (also known as the "Council Bluffs Energy Center") Unit 4 in Iowa. This unit is a new supercritical boiler unit with state-of-the-art combustion controls and an SCR that came online in 2007. As shown in Figures 4-6 and 4-7, there is a great deal of variation in NO_x emissions on a daily basis. Figure 4-6 demonstrates that 0.06 lb/MMBtu could not be met on this unit on a consistent basis for a 24-hr averaging period. The 30-day rolling average for the unit for 2007 is, however, consistent with the emissions limit and averaging period chosen for Plant Washington, 0.05 lb/MMBtu on a 30-day rolling average.

Figure 4-6 Daily NO_x Values at the Walter Scott Jr. Energy Center Unit 4

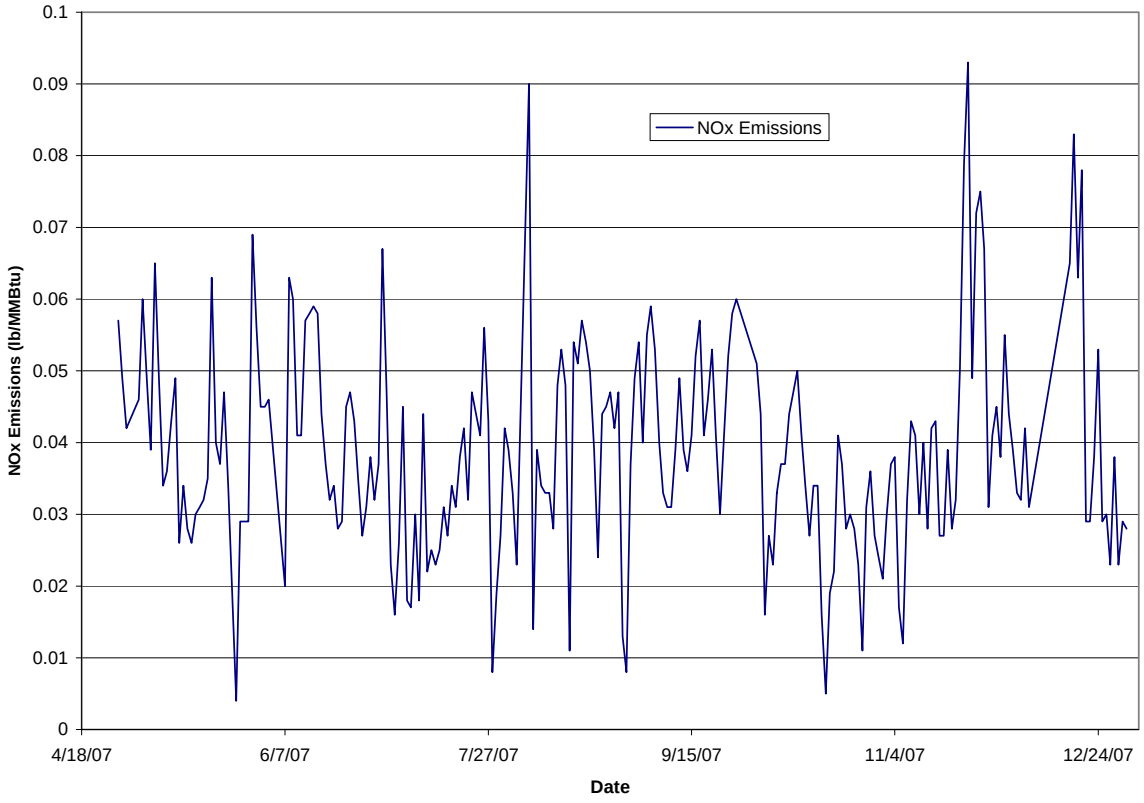

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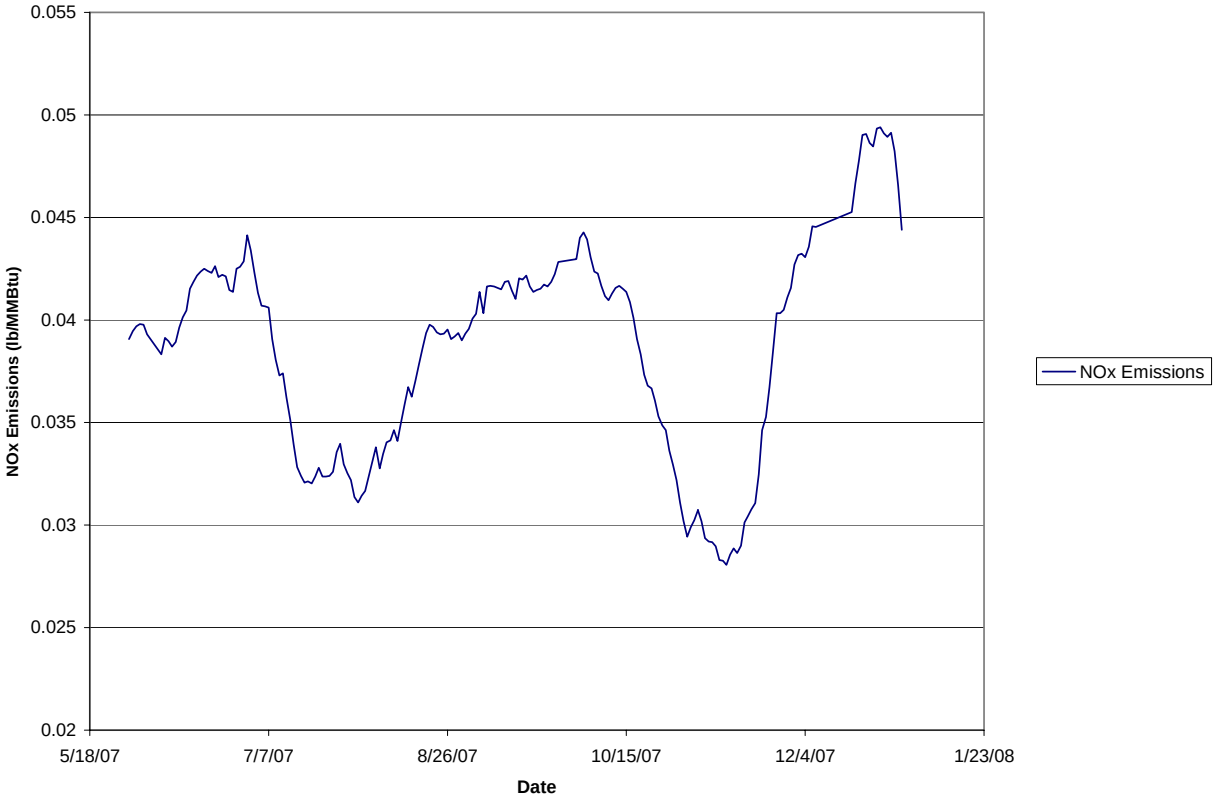
Figure 4-7 30-day Rolling NOx Values at the Walter Scott Jr. Energy Center Unit 4



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Expected SCR Control Efficiency with Effective Combustion Controls

The proposed NO_x BACT levels are based on an evaluation of the entire boiler system that must consider its operational controls (low NO_x burners and overfire air), fuel variations, and possible variations that occur in the operation of the SCR, which were identified previously. As indicated, the effectiveness of SCRs will typically range from 70 percent to 90 percent. The actual efficiency will vary depending on the actual design of the system, the unit's actual operating conditions, and the loading of NO_x to the system. There would be a concern with assuming that a new modern boiler will be able to simultaneously achieve the lowest uncontrolled NO_x emissions from the boiler while simultaneously achieving the highest level of NO_x emissions control from an SCR. It would be reasonable to expect a new boiler to "typically" emit NO_x up to 0.22 lb/MMBtu NO_x before controls; however, this estimate would vary depending on the range of operational variables previously discussed (fuels, boiler loads, CO/VOC emission levels, etc.). It would not, however, be reasonable to expect such a boiler to achieve the highest

SCR NO_x control efficiencies (90 percent) on top of these already low uncontrolled emission rates. If this were the case, units would be permitted at and be achieving levels as low as 0.02 lb/MMBtu. As indicated by the review of the Clean Air Markets database discussed above, these low levels have not been demonstrated on units comparable to Plant Washington.

Operating SCRs were evaluated for the top performing units in 2007 (those identified in Table 4-5) to determine what NO_x removal efficiencies SCRs are currently achieving in practice. The only way to definitively determine an individual SCR's NO_x control efficiency would be to complete continuous NO_x sampling on the inlet and outlet of the SCR. Such data are not available. In lieu of that, an evaluation was conducted to compare the average ozone season emission rate for the boilers identified in Table 4-5 two years prior to the installation of their SCRs to the average ozone season results for the units after the installation of their SCRs (a before-and-after comparison). This would not consider variations that occur over the years of operation of the SCRs at these units; however, this is thought to be a reasonable approach at estimating long-term SCR efficiency. Table 4-7 shows the results of this evaluation. The calculated SCR efficiency was then plotted against the NO_x loading to the SCR and is shown in Figure 4-8.

This plot demonstrates a clear trend of decreasing SCR efficiency with a decrease in NO_x loading to the SCR. Because of this, it is reasonable to expect that a new unit with an optimum design to minimize the formation of NO_x at the burners would reduce the effectiveness of an SCR, when compared to older, higher-emitting combustion units. This is a reasonable result considering that reaction rates are often proportional to the concentration of the reactants. The lower NO_x concentrations in the inlet gas, therefore, result in a lower conversion reaction.

Examples of this are the four WA Parish units, which show some of the lowest uncontrolled NO_x emission rates on a consistent basis (NO_x emissions from these units averaged 0.16 to 0.18 lb/MMBtu before installation of the their respective SCRs), but they also achieve some of the lowest SCR control efficiencies of 72 percent to 77 percent for the four units.

Table 4-7 SCR Control Efficiency Estimates for Lowest Emitting Units of 2007

			NOx Emission Rate (lb/MMbtu) - Ozone Season Before SCR					NOx Emission Rate (lb/MMbtu) - Ozone Season - After SCR Installation							
STATE	**FACILITY_NAME**	**UNITID**	**2000**	**2001**	**2002**	**2003**	**Average**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**Average**	**SCR Efficeincy**
KY	Ghent	4			0.292	0.28	0.286			0.043	0.027	0.031	0.039	0.035	88%
VA	Chesterfield Power Station	6			0.377	0.371	0.374			0.048 *	0.033	0.033	0.033	0.037	90%
TX	W A Parish	WAP7			0.137	0.129	0.133			0.03	0.045	0.039	0.036	0.038	72%
TX	W A Parish	WAP8			0.16	0.151	0.156			0.03	0.042	0.036	0.044	0.038	76%
WV	John E Amos	1			0.556	0.536	0.546				0.037	0.032	0.049	0.039	93%
IA	Walter Scott Jr. Energy Center	4											0.04	0.040	
MA	Brayton Point	1			0.285	0.235	0.260						0.04	0.040	85%
MA	Brayton Point	3			0.396	0.336	0.366						0.04	0.040	89%
TX	W A Parish	WAP6		0.171	0.178		0.175		0.046	0.03	0.042	0.047	0.039	0.041	77%
AL	Colbert	5			0.393	0.400	0.397			0.043	0.043	0.041	0.039	0.042	90%
KY	Mill Creek	4		0.38	0.292		0.336			0.044	0.044	0.044	0.037	0.042	87%
TX	W A Parish	WAP5		0.177	0.168		0.173		0.055	0.03	0.042	0.056	0.038	0.044	74%
IL	Havana	9		0.419	0.28		0.350			0.084	0.032	0.036	0.03	0.046	87%
TN	Kingston	5			0.585	0.564	0.575					0.053	0.049	0.051	91%
WV	Mountaineer (1301)	1	0.47	0.418			0.444	0.062	0.058	0.055	0.043	0.05	0.039	0.051	88%
VA	Chesapeake Energy Center	3		0.419	0.411		0.415			0.122	0.039	0.031	0.028	0.055	87%
OH	Cardinal	3		0.502	0.481		0.492		0.135	0.046	0.037	0.041	0.023	0.056	89%
PA	Keystone	2		0.304	0.301		0.303		0.048	0.06	0.06	0.082	0.045	0.059	80%
VA	Chesterfield Power Station	5	0.346	0.375			0.361		0.074	0.102	0.038	0.043	0.046	0.061	83%
OH	Muskingum River	5			0.658	0.747	0.703				0.063	0.071	0.048	0.061	91%
VA	Chesapeake Energy Center	4		0.438	0.419		0.429			0.138	0.061	0.042	0.036	0.069	84%
AL	Widows Creek	8			0.384	0.387	0.386			0.13	0.049	0.053	0.047	0.070	82%
NC	Belews Creek	1		0.458	0.502		0.480			0.105	0.076	0.081	0.028	0.073	85%
IN	Gibson	1	0.445	0.443			0.444	0.263	0.317	0.283	0.083	0.067	0.034	0.175	
IA	Ames	7							0.358	0.391	0.393	0.358	0.033	0.307	

* Reported ozone season value excludes May 2004

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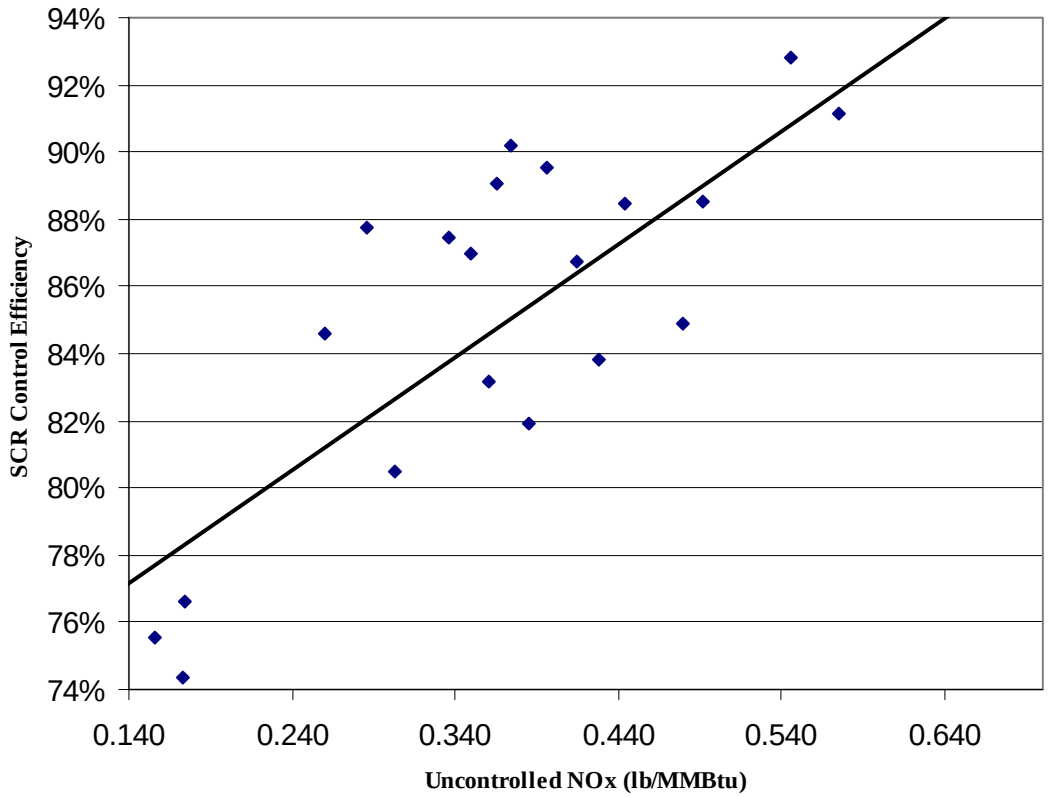
Figure 4-8 Uncontrolled NO_x vs. SCR Control Efficiency



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Compliance Demonstration

Plant Washington would propose to use a NO_x CEM to demonstrate compliance with the 0.05 lb/MMBtu 30-day rolling average limit.

Table 4-8 Listing of NO_x Emissions from Pulverized Coal Boilers Taken From the RBLC and Draft Permits

Facility Name	Facility State	Permit Number	Capacity (MW)	Permit Date	Process Name	Control Description	Emission Limit		Avg Period
WYGEN 3	WY	CT-4517	100	2/5/2007	PC BOILER	SCR/LNB/OVERFIRE AIR	0.05	lb/MMBtu	12-month rolling average
HUGO GENERATING STA	OK	97-058-C M 2 PSD	750	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	LOW NOX BURNERS (LNB) W/ OVERFIRE AIR (OFA) AND SELECTIVE CATALYTIC REDUCTION (SCR)	0.05	lb/MMBtu	12-month rolling average
JK SPRUCE ELECTRIC GENERATING STATION	TX	PSD-TX 1037 & 70492	750	12/28/05	UNIT 2 BOILER	SCR/LNB/OVERFIRE AIR	0.05	lb/MMBtu	Annual average
DRY FORK STATION	WY	CT-4631	385	10/15/2007	PC BOILER (ES1-01)	LOW NOX BURNERS AND SCR	0.05	lb/MMBtu	12-month rolling average
TRIMBLE COUNTY GENERATING STATION	KY	DRAFT	7/6/2005	7/6/2005	PULVERIZED COAL BOILER	SCR	0.05	lb/MMBtu	24-hour rolling average
DESERT ROCK	NM	DRAFT	7/1/2006	7/1/2006	(2) 750 MW PC BOILERS	SCR/LNB	0.06	lb/MMBtu	24-hour rolling average
WPS - WESTON PLANT	WI	04-RV-248	500	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	LOW NOX BURNERS, GOOD COMBUSTION PRACTICES SELECTIVE CATALYTIC REDUCTION (SCR)	0.06	lb/MMBtu	12-month rolling average
TOQUOP	NV	ap4911-1146	750		SCPC BOILER	SCR/LNB/OVERFIRE AIR	0.06	lb/MMBtu	24-hour rolling average
ELY ENERGY STATION	NV	Ap4911-2241	2-750	2007	SUPERCRITICAL BOILER	SCR/LNB/OVERFIRE AIR	0.06	lb/MMBtu	24-hour rolling average
TS POWER PLANT	NV	AP4911-1349	200	5/5/2005	200 MW PC COAL BOILER	SCR & LOW NOX BURNERS	0.067	lb/MMBtu	unknown
HUGO GENERATING STATION	OK	97-058-C M 2 PSD	750	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	LOW NOX BURNERS (LNB) W/ OVERFIRE AIR (OFA) AND SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	lb/MMBtu	30-day rolling average
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJEC	MT	3182-00	390	7/21/2003	BOILER, PC NO. 1	LOW NOX BURNER, OVERFIRE AIR, AND SCR.	0.07	lb/MMBtu	unknown
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJEC	MT	3182-00	390	7/21/2003	BOILER, PC NO. 2	LOW NOX BURNER, OVERFIRE AIR, SCR	0.07	lb/MMBtu	unknown
WPS - WESTON PLANT	WI	04-RV-248	500	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	LOW NOX BURNERS, GOOD COMBUSTION PRACTICES SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	lb/MMBtu	30-day rolling average
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	750	6/17/2003	CBEC 4 BOILER	LOW NOX BURNERS, OVERFIRE AIR, AND SELECTIVE CATALYTIC REDUCTION	0.07	lb/MMBtu	30-day rolling average
BIG CAJUN II POWER PLANT	LA	PSD-LA-677	705	8/22/2005	NEW 705 MW PULVERIZED COAL BOILER (UNIT 4)	LOW NOX BURNERS AND SELECTIVE CATALYTIC REDUCTION	0.07	lb/MMBtu	30-day rolling average
OPPD - NEBRASKA CITY STATION	NE	58343C01	660	3/9/2005	UNIT 2 BOILER	SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	lb/MMBtu	30-day rolling average
WYGEN 2	WY	CT-3030	100	9/25/2002	BOILER, 500 MW PC	LOW NOX BURNERS/SCR	0.07	lb/MMBtu	30-day rolling average

Table 4-8 Listing of NO_x Emissions from Pulverized Coal Boilers Taken From the RBLC and Draft Permits (Continued)

Facility Name	Facility State	Permit Number	Capacity (MW)	Permit Date	Process Name	Control Description	Emission Limit		Avg Period
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	800		PULVERIZED CAOL BOILER	AT THIS POINT, THE FLUE GAS HAS BEEN COOLED TO THE APPROPRIATE TEMPERATURE FOR SCR, SO IT NEXT PASSES THROUGH THE SCR REACTOR, WHERE NOX IS REDUCED TO FORM NITROGEN.	0.07	lb/MMBtu	30-day rolling average
LONGLEAF	GA	4911-099-0030-P-01-0	600	5/14/07	BOILER #1	SCR/LNB/OVERFIRE AIR	0.07	lb/MMBtu	30-day rolling average
LONGLEAF	GA	4911-099-0030-P-01-0	600	5/14/07	BOILER #2	SCR/LNB/OVERFIRE AIR	0.07	lb/MMBtu	30-day rolling average
INTERMOUNTAIN POWER STATION UNIT 3	UT	DAQE-AN0327010 04	950	10/15/04	PC BOILER	SCR/LNB/OVERFIRE AIR	0.07	lb/MMBtu	30-day rolling average
AMERICAN MUNICIPAL POWER GENERATING STATION	OH	06-08138	5191 mmbtu	2/7/2008	BOILER (2), PULVERIZED COAL FIRED	SELECTIVE CATALYTIC REDUCTION	0.07	lb/MMBtu	30-day rolling average
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER S	MO	122004-007	275	12/15/2004	PULVERIZED COAL FIRED BOILER	IT WAS DETERMINED THAT THE BACT FOR NOX FROM THE PULVERIZED COAL FIRED BOILER IS GOOD COMBUSTION PRACTICES ALONG WITH SCR HAVING A NOX EMISSION LIMIT OF 0.08 LB/MMBTU ON A 30-DAY ROOLING AVERAGE.	0.08	lb/MMBtu	30-day rolling average
THOROUGHBRED GENERATING STATION	KY	V-02-001	2-750	10/11/2002	BOILER, COAL, (2)	PROPER BOILER DESIGN, LOW NOX BURNERS, AND SCR	0.08	lb/MMBtu	30-day rolling average
HOLCOMB UNIT #2	KS	0550087/C-3855	660	10/8/2002	BOILER, PULVERIZED COAL	SCR, LOW NOX BURNERS, SEPARATED OVERFIRE AIR (SOFA)	0.08	lb/MMBtu	30-day rolling average
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATIC	MO	888	384 T/H	8/17/1999	ELECTRIC GENERATION, BOILER, COAL	SELCTIVE CATALYTIC REDUCTION (SCR) & GOOD COMBUSTION PRACTICE. BASIS OF STANDARD EMISSION LIMIT - 30-DAY AVG. ALT LIMIT 24 H AVG.	0.08	lb/MMBtu	30-day rolling average
KANSAS CITY POWER & LIGHT COMPANY - IATAN STAT	MO	012006-019	850	1/27/2006	PULVERIZED COAL BOILER - UNIT 2	KCPL SHALL INSTALL SCR UNIT FOR THE UNIT 2 BOILER TO REDUCE NOX EMISSIONS AND ALSO SHALL INSTALL WET SCRUBBER TO REDUCE SOX EMISSIONS. BOTH CONTROLS ARE NOT BACT FOR NOX AND SOX	0.08	lb/MMBtu	30-day rolling average
MAIDSVILLE	WV	R14-0024	600	3/2/2004	BOILER, PC	LOW-NOX BURNERS IN SERIES WITH SCR	0.08	lb/MMBtu	24-hour rolling average
WHELAN ENERGY CENTER	NE	58048	220	3/30/2004	BOILER, UNIT 2 UTILITY	SELECTIVE CATALYTIC REDUCTION	0.08	lb/MMBtu	30-day rolling average

Table 4-8 Listing of NO_x Emissions from Pulverized Coal Boilers Taken From the RBLC and Draft Permits (Continued)

Facility Name	Facility State	Permit Number	Capacity (MW)	Permit Date	Process Name	Control Description	Emission Limit		Avg Period
SANTEE COOPER CROSS	SC	0420-0030-CI	660	2/5/04	BOILER #3	SCR/LNB/OVERFIRE AIR	0.08	lb/MMBtu	365-day rolling average
SANTEE COOPER CROSS	SC	0420-0030-CI	660	2/5/04	BOILER #4	SCR/LNB/OVERFIRE AIR	0.08	lb/MMBtu	365-day rolling average
HARDIN GENERATOR PROJECT	MT	3185-00	116	6/11/2002	BOILER, PULVERIZED COAL-FIRED	SELECTIVE CATALYTIC REDUCTION	0.09	lb/MMBtu	30-day rolling average
JEA NORTHSIDE GENERATING STATION	FL	PSD-FL-265	2764 mmbtu	7/14/1999	BOILER, COAL	SELECTIVE NON-CATALYTIC REDUCTION (SNCR) EMISSION	0.09	lb/MMBtu	30-day rolling average
PLUM POINT ENERGY	AR	1995-AOP-R0	665	8/20/2003	BOILER , UNIT 1 - SN-01	LOW NOX BURNERS	0.09	lb/MMBtu	24-hour rolling average
PLUM POINT ENERGY	AR	1995-AOP-R0	665	8/20/2003	BOILER - SN-01	LOW NOX BURNERS	0.09	lb/MMBtu	24-hour rolling average
GASCOYNE GENERATING STATION	ND	PTC 05005	2116 mmbtu	6/3/2005	BOILER, COAL-FIRED	FLUIDIZED BED COMBUSTION AND SELECTIVE NON-CATALYTIC REDUCTION (SNCR).	0.09	lb/MMBtu	30-day rolling average
AMERICAN MUNICIPAL POWER GENERATING STATION	OH	06-08138	5191 mmbtu	2/7/2008	BOILER (2), PULVERIZED COAL FIRED	SELECTIVE CATALYTIC REDUCTION	0.10	lb/MMBtu	24-hour rolling average
KANSAS CITY POWER & LIGHT COMPANY - IATAN STAT	MO	012006-019	695	1/27/2006	PULVERIZED COAL BOILER - UNIT 1		0.10	lb/MMBtu	30-day rolling average
SEVIER POWER COMPANY	UT	DAQE-AN252900104	270	10/12/2004	LOW-NOX BURNERS WITH SNCR (SELECTIVE NON-CATALYTIC REDUCTION)	LOW NOX BURNERS WITH SNCR WITH AMMONIA INJECTION	0.10	lb/MMBtu	24-hour rolling average
AES BEAVER VALLEY, LLC	PA	PA-04-446C	2155 mmbtu	11/21/2001	COAL FIRED BOILER	SNCR	0.101	lb/MMBtu	unknown
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATIC	MO	888	384 t/h	8/17/1999	ELECTRIC GENERATION, BOILER, COAL	SELCTIVE CATALYTIC REDUCTION (SCR) & GOOD COMBUSTION PRACTICE. BASIS OF STANDARD EMISSION LIMIT - 30-DAY AVG. ALT LIMIT 24 H AVG.	0.12	lb/MMBtu	24-hour rolling average
EDISON MISSION ENERGY	PA	32-0055C	5700 mmbtu	5/25/1999	BOILER, COAL, PULVERIZED BITUMINOUS, UNITS 1, 2 &3	SCR. SEE COMMENT ABOUT NOX EMISSION LIMITS IN FACILITY NOTES. REGULATORY BASIS IS STATE IMPLEMENTATION PLAN.	0.15	lb/MMBtu	unknown
TWO ELK GENERATION PARTNERS, LIMITED PARTNERS	WY	CT-1352	250	2/27/1998	BOILER, STEAM ELECTRIC POWER GENERATING	LOW NOX BURNERS WITH OVER FIRE AIR AND SELECTIVE CATALYTIC REDUCTION	0.15	lb/MMBtu	30-day rolling average
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FA	WY	CT-1324	240	10/10/1997	BOILER, PULVERIZED COAL FIRED POWER GENERATION UNI	LOW NOX BURNERS ITH OVERFIRE AIR AND SELECTIVE CATALYTIC REDUCTION	0.15	lb/MMBtu	unknown
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FA	WY	CT-1324	3960 mmbtu	10/10/1997	BOILER, COAL FIRED, MAIN STACK	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION.	0.16	lb/MMBtu	unknown

Table 4-8 Listing of NO_x Emissions from Pulverized Coal Boilers Taken From the RBLC and Draft Permits (Continued)

Facility Name	Facility State	Permit Number	Capacity (MW)	Permit Date	Process Name	Control Description	Emission Limit		Avg Period
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FA(	WY	CT-1324	352	10/10/1997	LIQUIDS FROM COAL PLANT (3 MODULES PER PLANT)	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION	0.17	lb/MMBtu	unknown
SANTEE COOPER CROSS	SC	0420-0030-CI	660	2/5/04	BOILER #3	SCR/LNB/OVERFIRE AIR	0.185	lb/MMBtu	30-day rolling average
SANTEE COOPER CROSS	SC	0420-0030-CI	660	2/5/04	BOILER #4	SCR/LNB/OVERFIRE AIR	0.185	lb/MMBtu	30-day rolling average
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	800	7/24/2006	PULVERIZED COAL BOILER	AT THIS POINT, THE FLUE GAS HAS BEEN COOLED TO THE APPROPRIATE TEMPERATURE FOR SCR, SO IT NEXT PASSES THROUGH THE SCR REACTOR, WHERE NOX IS REDUCED TO FORM NITROGEN.	0.20	lb/MMBtu	1-hour average
VIRGINIA TECH	VA	20124	146.7 mmbtu	9/15/2005	OPERATION OF BOILER 11	EMISSIONS CONTROLLED BY A MASS-FEED STOKER CONFIGURATION WITH LOW EXCESS AIR/STAGED COMBUSTION	0.246	lb/MMBtu	30-day rolling average
SOUTHWESTERN PUBLIC SERVICE COMPANY-HARRING	TX	P017M1	389	10/17/2006	UNIT 3 BOILER	LOW NOX BURNERS, SEPARATED OVERFIRE AIR WINDBOX, WITH ADDITIONAL YAW CONTROL OF THE BURNERS FOR ADDITIONAL NOX CONTROL	0.3	lb/MMBtu	30-day rolling average
CAMBRIA COKE CO.	PA	11-00332		8/25/2006	PYROPOWER UNIT A	COMBUSTION STAGING	0.3	lb/MMBtu	30-day rolling average
CAMBRIA COKE CO.	PA	11-00332		8/25/2006	PYROPOWER UNIT B	COMBUSTION STAGING	0.3	lb/MMBtu	30-day rolling average
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	6700 mmbtu	10/15/2003	BOILER UNIT 7, COAL, WAP7	NONE INDICATED	0.324	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	6700 mmbtu	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	NONE INDICATED	0.325	lb/MMBtu	unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	6700 mmbtu	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	EMISSIONS SHALL COMPLY WITH 30 TAC CHAPTER 17.	0.352	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	6700 mmbtu	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	NONE INDICATED	0.353	lb/MMBtu	unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	7400 mmbtu	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	NONE INDICATED	0.38	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	7400 mmbtu	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	NONE INDICATED	0.38	lb/MMBtu	unknown

Table 4-8 Listing of NO_x Emissions from Pulverized Coal Boilers Taken From the RBLC and Draft Permits (Continued)

Facility Name	Facility State	Permit Number	Capacity (MW)	Permit Date	Process Name	Control Description	Emission Limit		Avg Period
THERMAL VENTURES	VA	30529	120 mmbtu	2/15/2002	BOILER, STEAM	GOOD COMBUSTION PRACTICES, CLEAN BURNING FUEL, AND CONTINUOUS EMISSION MONITORING DEVICE.	0.4	lb/MMBtu	unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	7400 mmbtu	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	NONE INDICATED	0.40	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	7400 mmbtu	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	NONE INDICATED	0.40	lb/MMBtu	unknown
ORION POWER MIDWEST LP	PA	37-00023	1029 mmbtu	4/8/1999	BOILERS, COAL (3)	OVERFIRE AIR, LOW NOX BURNERS	0.5	lb/MMBtu	
LIMESTONE ELECTRIC GENERATING STATION	TX	PSD-TX-371 (M3)	7863 mmbtu	5/23/2001	(2) BOILER UNIT 1 & 2 SCRUBBER STACKS, LMS1 & 2	WATER INJECTION	0.5	lb/MMBtu	
MANSFIELD MILL	LA	PSD-LA-93 (M-6)	645 mmbtu	8/14/2001	POWER BOILER #1 & #2, COAL	LOW NOX STAGED BURNERS, CMS FOR O2 NOX EMISSIONS	0.7	lb/MMBtu	unknown
AES BEAVER VALLEY PARTNERS, INC.	PA	040446B	550 mmbtu	6/1/1999	BOILER, PULVERIZED COAL FIRED	LNB/SOFA MODEL DRB-XCL, LOW NOX BURNER	0.7	lb/MMBtu	unknown

Prepared by: PBS 6/18/08
Checked by: JDF11/26/08

4.3.3 BACT Demonstration for CO Emissions from the Supercritical Pulverized Coal Boiler

Carbon monoxide (CO) is a byproduct of the incomplete combustion of carbon in the fuel source, in this case coal. Control of CO is usually accomplished by providing proper fuel residence time and proper combustion conditions (excess air). However, factors to reduce CO emissions, such as addition of excess air to improve combustion, can lead to an increase in NO_x emissions. Therefore, an evaluation of the reduction of CO emissions must consider the potential secondary impacts on NO_x emissions. CO can be accurately measured in stack gases and be continuously monitored and recorded. Complete combustion of carbon results in carbon dioxide, so the presence of CO indicates incomplete combustion. As such, it would be an effective indicator of incomplete combustion of any type.

Step 1 – Identify All Control Technologies

Combustion Controls

The use of combustion controls for CO emissions would be a lower pollutant emitting process, through managing the combustion process and reducing the generation of CO emissions. Important factors in proper combustion include proper fuel residence time, proper air-to-fuel ratios in the combustion chamber, and consistent proper temperatures in the combustion chamber. CO formation will be limited through the use of a properly designed combustion chamber with adequate controls to regulate the combustion process. Proper maintenance is also necessary for proper combustion control. Proper operation of fuel feed systems, fans, system dampers, and other equipment will assist in minimization of CO emissions. However, as stated above, careful consideration is necessary in the process of combustion controls, since increasing the combustion temperature or oxygen concentration in the combustion chamber would decrease CO emissions but potentially increase the formation of thermal NO_x, and increase overall NO_x emissions.

Add-on Controls

No effective add-on controls currently exist for CO emissions from a boiler. Use of control technologies such as afterburners would use large quantities of natural gas and simply convert CO to carbon dioxide. Use of afterburners, and other control devices such as catalytic oxidation or flares, has not been demonstrated in practice in PC boiler units. Any such control devices

would lead to negative secondary environmental impacts, such as increased fuel usage and associated air emissions. CO catalysts, which involve sending the waste gases across a catalyst bed to complete the combustion process, have also been applied to some combustion systems (turbines). These units, however, require operation within a certain temperature window.

Step 2 – Eliminate Technically Infeasible Options

Combustion Controls

Combustion controls, such as the proper combustion chamber and system design, and proper operation and maintenance, are demonstrated and proven techniques for the reduction of CO emissions. Combustion controls are considered a demonstrated technology for PC-fired boiler CO emissions controls, and therefore considered technically feasible under the BACT evaluation process.

Add-on Controls

As discussed above, the use of add-on controls to reduce CO emissions for the PC boiler units is not technically feasible. The use of add-on controls such as flares, afterburners, catalytic oxidation, and external thermal oxidation has not been demonstrated in practice for control of CO emissions from PC-fired boilers. These systems would be energy-intensive and impractical. Straight catalytic systems without additional energy would not be technically feasible because the proposed boiler achieves such a high level of heat recovery such that the outlet temperatures of the boiler where a catalyst system could be effectively installed are well below those levels at which a catalyst could effectively operate. Therefore, the only way that a catalyst system could be used would be to derate the heat effectiveness of the boiler to elevate its exhaust temperature. This would, however, be counterproductive in that it would result in a proportional increase in CO emissions as well as all other pollutants to achieve the same amount of power production.

A catalyst system or thermal oxidizer would have to be installed downstream of a particulate matter control device to avoid plugging and blinding of the catalyst. Oxidation catalysts are susceptible to poisoning from high sulfur compounds and can experience fouling in gas streams with high particulate loading. This would also make installation of the oxidation catalyst as an integral part of the SCR system impractical for a coal fired boiler system.

The minimum temperature for use of an oxidation catalyst would be 350 degrees Fahrenheit, based on technical information on BASF and EmeraChem catalysts, and a thermal oxidizer could

not effectively function at temperatures less than 1000 degrees Fahrenheit. The exhaust gas temperature from the boiler downstream of the filter is estimated to be less than 350 degrees Fahrenheit. Therefore, use of such systems is deemed technically infeasible for this analysis.

Step 3 – Rank Remaining Technically Feasible Control Options

Good combustion controls are determined to be the only feasible technology for control of CO emissions. Combustion controls are designed to minimize the emissions of CO (and consequently NO_x) from a PC-fired boiler. Therefore, no energy or environmental impacts are associated with the implementation of combustion controls. There are no economic impacts associated with the implementation of combustion controls.

Step 4 – Evaluate Remaining Control Technologies

No energy, environmental, or economic impacts are associated with the use of combustion controls that would preclude their use as BACT for CO emissions for a PC-fired boiler.

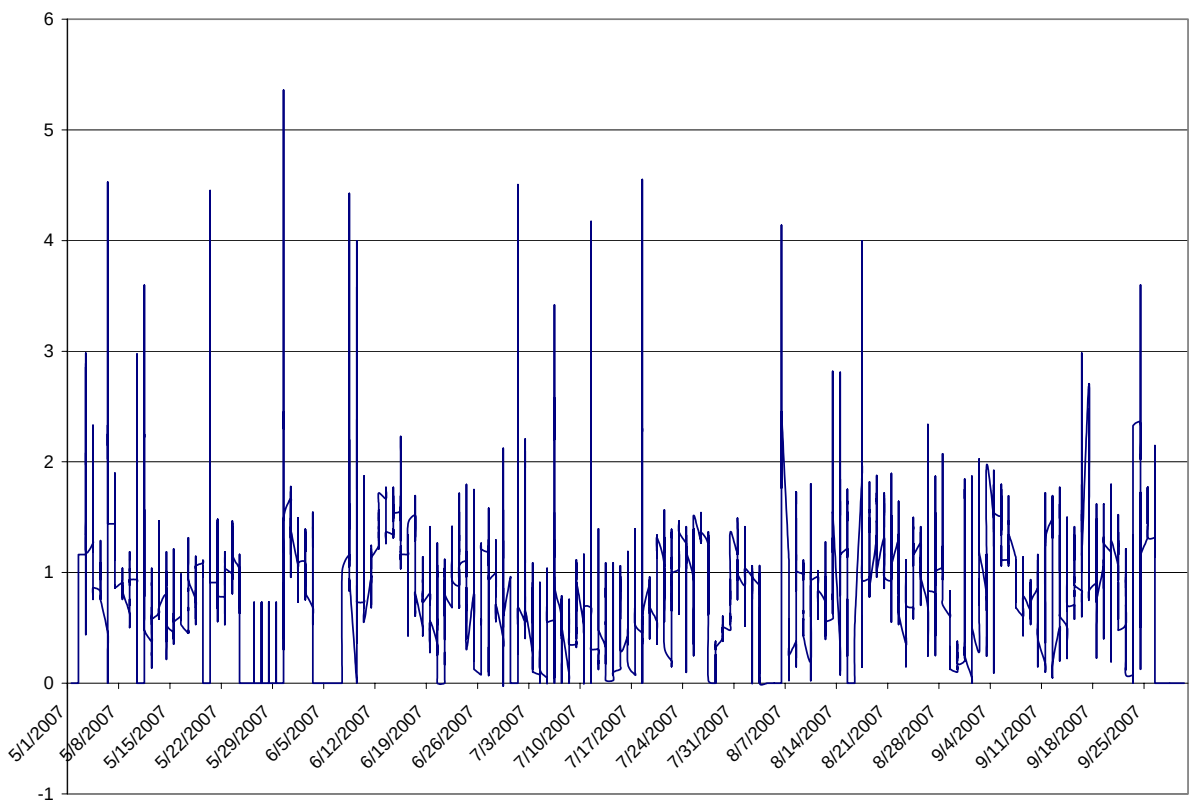
Step 5 – Selection of BACT

The selected control technology for the proposed PC boiler is the application of good combustion controls along with continuous monitoring of CO. A review of the RBLC listings was completed along with a review of vendor literature to determine the BACT limit associated with this technology. Table 4-9 shows the RBLC listings for CO emissions from PC boilers. The lowest emission rate listed in this table is 0.1 lb/MMBtu. Based on the review of technology supplier literature, discussions with experienced power plant design engineers, and multiple equipment suppliers, this emission rate is confirmed to be the lowest CO emissions level achievable based on steady state operation and could only be achieved on a 30-day rolling average basis. Transients in the boiler due to air and fuel fluctuations that primarily occur during load changes cause a higher level of CO to occur during short periods. Additionally, CO emissions may not trend slowly up or down, and can spike dramatically causing difficulties for plant operators and plant control systems to react over short periods of time to meet a stringent emissions limit. Therefore, BACT for Plant Washington for CO emissions is chosen as use of good combustion controls and an emission limit of 0.10 lb/MMBtu on a 30-day rolling average. The selection of a 30-day rolling average period for CO emissions makes it consistent with the NO_x BACT emissions limit determination of a 30-day rolling average limit.

In addition to the 30-day rolling average limit of 0.10 lb/MMBtu, a limit of 0.3 lb/MMBtu is proposed as a 1-hour permit limit for the boiler. This value was derived from an evaluation of the expected variation of CO emissions on an hourly basis.

Continuous CO emissions data for a similar boiler are not available; however, a review of continuous NO_x data (which would be expected to correlate with CO concentrations) indicates a large variability in CO emissions should be expected. Figure 4-9 provides the hourly NO_x emission rate for the Walter Scott Jr. Energy Center Unit 4 boiler that has been normalized to the unit's average NO_x emissions. This unit is a new supercritical pulverized coal fired boiler which came on-line in 2007. This shows that NO_x can vary by up to 6 times the average NO_x value, but that the bulk of the values are less than 3 times the average. The chosen "peak" hourly estimate for CO from the boiler was therefore chosen as 3 times the proposed monthly average value of 0.10 lb/MMBtu, or 0.3 lb/MMBtu.

Figure 4-9 Ratio of Actual to Average NO_x at the Walter Scott Jr. Energy Center Unit 42007 Ozone Season



Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

Compliance Demonstration

Plant Washington will operate a continuous emissions monitor (CEM) for CO emissions. This monitor will be used to demonstrate continuous compliance with the proposed BACT limit on a daily basis.

Table 4-9 RBLC and Draft Permit Listings for CO Emissions from Pulverized Coal-fired Boilers

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit		Avg Period	Operational Facility
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	BOILER, COAL, (2)	COAL	750	PROPER BOILER DESIGN AND OPERATION	0.10	lb/MMBtu	**30-day rolling average**	NO
TOQUOP ENERGY, LLC	NV	AP4911-1146	DRAFT	750 MW PC BOILER	COAL	750	COMBUSTION CONTROLS	0.10	lb/MMbtu	**24-hour averaging period**	NO
ELY ENERGY CENTER	NV	AP4911-2241	DRAFT	(2) 750 MW PC BOILERS	COAL	750	COMBUSTION CONTROLS	0.10	lb/MMbtu	**24-hour averaging period**	NO
DESERT ROCK	NM	DRAFT	7/1/2006	(2) 750 MW PC BOILERS	COAL	750	NONE INDICATED	0.10	lb/MMbtu	**24-hour averaging period**	NO
TRIMBLE COUNTY GENERATING STATION	KY	DRAFT	7/6/2005	PULVERIZED COAL BOILER	COAL	750	GOOD COMBUSTION PRACTICES	0.10	lb/MMbtu	**30-day rolling average**	NO
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	PULVERIZED COAL	600	GOOD COMBUSTION PRACTICES	0.11	lb/MMBtu	**3- hour rolling**	NO
COMANCHE STATION	CO	04UNITPB1015	7/5/2005	PC BOILER - UNIT 3	SUB-BITUMINOUS COAL	750	GOOD COMBUSTION PRACTICES	0.13	lb/MMBtu	**8-hr average**	NO
BIG CAJUN II POWER PLANT	LA	PSD-LA-677 (M-1)	8/22/2005	NEW 705 MW PULVERIZED COAL BOILER (UNIT 4)	SUBBITUMINOUS COAL	705	OPTIMUM BURNER DESIGN AND GOOD COMBUSTION TECHNIQUES	0.135	lb/MMBtu	**Annual average**	NO
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019B	8/3/2007	PULVERIZED COAL BOILER - UNIT 2	PULVERIZED COAL	8100 MMBtu/hr	NONE INDICATED	0.14	lb/MMBtu	**30-day rolling average**	NO
AGP SOY PROCESSING	NE	CP05-0050	9/11/2006	STEAM GENERATION	COAL	382 MMBtu/hr	COMBUSTION CONTROL	0.15	lb/MMBtu	-	NO-CFB
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 1	COAL	390	NONE INDICATED	0.15	lb/MMBtu	-	NO
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 2	COAL	390	NONE INDICATED	0.15	lb/MMBtu	-	NO
HOLCOMB UNIT #2	KS	0550087/C-3855	10/8/2002	BOILER, PULVERIZED COAL	COAL	660	GOOD COMBUSTION PRACTICES	0.15	lb/MMBtu	-	NO
HARDIN GENERATOR PROJECT	MT	3185-00	6/11/2002	BOILER, PULVERIZED COAL-FIRED	COAL	116	NONE INDICATED	0.15	lb/MMBtu	-	YES
TS POWER PLANT	NV	AP4911-1349	5/5/2005	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	200	GOOD COMBUSTION PRACTICES	0.15	lb/MMBtu	**24-hour rolling**	EXPECTED TO START IN 2008
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	500	GOOD COMBUSTION PRACTICES; LOW NOX BURNERS	0.15	lb/MMBtu	**Calender day average**	NO
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	BOILER, STEAM ELECTRIC POWER GENERATING	PULVERIZED COAL	250	NONE INDICATED	0.15	lb/MMBtu	-	NO
WYGEN 3	WY	CT-4517	2/5/2007	PC BOILER	SUBBITUMINOUS COAL	100	GOOD COMBUSTION	0.15	lb/MMBtu	**3 X 1-Hour tests**	NO
WHELAN ENERGY CENTER	NE	58048	3/30/2004	BOILER, UNIT 2 UTILITY	SUBBITUMINOUS COAL	220	GOOD COMBUSTION CONTROLS	0.15	lb/MMBtu		NO
WYGEN 2	WY	CT-3030	9/25/2002	BOILER, 500 MW PC	SUBBITUMINOUS COAL	5145 MMBtu/hr	GOOD COMBUSTION CONTROL	0.15	lb/MMBtu	-	YES
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	LIQUIDS FROM COAL PLANT (3 MODULES PER PLANT)	SUBBITUMINOUS COAL	240	NONE INDICATED	0.15	lb/MMBtu	-	YES
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	BOILER, COAL FIRED, MAIN STACK	SUBBITUMINOUS COAL	240	NONE INDICATED	0.15	lb/MMBtu	-	YES
SANTEE COOPER PEE DEE GENERATING STATION	SC	1040-0113-CA.1 DRAFT	12/1/2007	Boiler No. 1 and No. 2	BITUMINOUS COAL	660	GOOD COMBUSTION CONTROL	0.15	lb/MMBtu	**30-day rolling average**	NO

Table 4-9 RBLC and Draft Permit Listings for CO Emissions from Pulverized Coal-fired Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit		Avg Period	Operational Facility
HUGO GENERATING STATION	OK	97-058-C M-2 PSD	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	COAL	750	GOOD COMBUSTION CONTROL	0.15	lb/MMBtu	30-day rolling average	NO
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	BOILER, PULVERIZED COAL FIRED POWER GENERATION UNI	COAL	240	DUE TO THE LNB/OFA STRATEGY TO CONTROL NOX IT WOULD BE COUNTER PRODUCTIVE TO LIMIT CO.	0.15	lb/MMBtu	-	YES
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01 0	5/14/2007	(2) 600 MW UNITS	COAL	600	COMBUSTION CONTROLS - 30 DAY ROLLING AVG	0.15	lb/MMbtu	30-day rolling average	NO
JK SPRUCE ELECTRIC GENERATING UNIT 2	TX	70492	1/19/2006	PULVERIZED COAL FIRED ELECTRIC STEAM BOILER	COAL	750	GOOD COMBUSTION PRACTICES	0.15	lb/MMbtu		NO
INTERMOUNTAIN POWER GENERATING STATION UNIT #3	UT	DAQE-AN0327010-04	10/15/2004	PULVERIZED COAL FIRED ELECTRIC	COAL	950	COMBUSTION CONTROLS	0.15	lb/MMbtu	30-day rolling average	NO
DRY FORK STATION	WY	CT-4631	10/15/2007	PC BOILER (ES1-01)	COAL	385	GOOD COMBUSTION PRACTICES	0.15	lb/MMbtu	Annual average	NO
DOLET HILLS POWER STATION	LA	PSD-LA-117(M-5)	11/21/2006	UNIT 1 BOILER	LIGNITE	7600.2 MMBtu/hr	GOOD COMBUSTION PRACTICES	0.15	lb/MMbtu	Annual average	YES
AMERICAN MUNICIPAL POWER GENERATING STATION	OH	06-08138	2/7/2008	BOILER (2), PULVERIZED COAL	PULVERIZED COAL	5191 MMBtu/hr	GOOD COMBUSTION PRACTICES	0.154	lb/MMbtu	3- hour rolling	NO
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	PRB COAL	750	COMBUSTION CONTROLS	0.154	lb/MMBtu	1 Calender day average	YES
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 1	COAL	7800 MMBtu/hr	GOOD COMBUSTION CONTROL PRATICE	0.16	lb/MMBtu	30-day rolling average	NO
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	MO	122004-007	12/15/2004	PULVERIZED COAL FIRED BOILER	COAL	275	THE UTILIZATION OF GOOD COMBUSTION PRACTICES	0.16	lb/MMBtu	30-day rolling average	NO
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATION	MO	888	8/17/1999	ELECTRIC GENERATION, BOILER, COAL	COAL	384 T/HR	GOOD COMBUSTION PRACTICES	0.16	lb/MMBtu	-	YES
OPPD - NEBRASKA CITY STATION	NE	58343C01	3/9/2005	UNIT 2 BOILER	SUBBITUMINOUS COAL	660	COMBUSTION CONTROLS	0.16	lb/MMBtu	3-hr rolling average	NO
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER , UNIT 1 - SN-01	SUB-BITUMINOUS COAL	665	COMBUSTION CONTROLS	0.16	lb/MMBtu	-	NO
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER - SN-01	SUB-BITUMINOUS COAL	665	COMBUSTION CONTROLS	0.16	lb/MMBtu	-	NO
SANDY CREEK ENERGY STATION	TX	DRAFT	3/1/2005	BOILER	COAL	800	COMBUSTION CONTROLS	0.16	lb/MMbtu		NO
SANTEE COOPER CROSS GENERATING STATION	SC	0420-0030-CI	2/5/2004	BOILER NO. 3 AND 4	COAL	660	GOOD COMBUSTION PRACTICES	0.16	lb/MMbtu	-	YES
OTTUMWA GENERATING STATION	IA	78-A-019P-S8	2/27/2007	BOILER #1	COAL	6370 MMBtu/hr	GOOD COMBUSTION PRACTICES	0.163	lb/MMbtu	30-day rolling average	YES
CRYSTAL RIVER POWER PLANT	FL	PSD-FL-383	5/18/2007	FFFSG UNITS 4 AND 5	COAL	760	COMBUSTION CONTROL AND OPERATION	0.17	lb/MMbtu	30-day rolling CEM average	NO
DOLET HILLS POWER STATION	LA	PSD-LA-117(M-5)	11/21/2006	UNIT 1 BOILER	LIGNITE	7600.2 MMBtu/hr	GOOD COMBUSTION PRACTICES	0.20	lb/MMbtu	30-day rolling average	YES

Table 4-9 RBLC and Draft Permit Listings for CO Emissions from Pulverized Coal-fired Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Thruput (MW)	Control Description	Emission Limit		Avg Period	Operational Facility
AES BEAVER VALLEY, LLC	PA	PA-04-446C	11/21/2001	COAL FIRED BOILER	2155 MMBtu/hr	GOOD COMBUSTION PRACTICES	0.20	lb/MMBtu	-	YES
MANSFIELD MILL	LA	PSD-LA-93 (M-6)	8/14/2001	POWER BOILER #1 & #2, COAL	645 MMBtu/hr	LESS THAN 0.041 LB/MMBTU FROM COAL	0.20	lb/MMBtu	-	YES
MANSFIELD MILL	LA	PSD-LA-93 (M-6)	8/14/2001	POWER BOILER #1 & #2, COMBINED FUEL	645 MMBtu/hr	RESTRICTION ON INPUTS	0.20	lb/MMBtu	-	YES
BRANDON SHORES GENERATING STATION	MD	CPCN CASE NO. 9075	6/2/2007	BRANDON SHORES UNIT 1 & UNIT 2	710	GOOD COMBUSTION PRACTICES	0.20	lb/MMBtu	**3-Hour Average**	YES
VIRGINIA TECH	VA	20124	9/15/2005	OPERATION OF BOILER 11	146.7 MMBtu/hr	CEM	0.226	lb/MMBtu	-	NO
ORION POWER MIDWEST LP	PA	37-00023	4/8/1999	BOILERS, COAL (3)	1029 MMBtu/hr		0.233	lb/MMBtu	-	YES
INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	GA	2631-115-0021-V-01-4	10/13/2004	BOILER, COAL FIRED	565 MMBtu/hr	STAGED COMBUSTION AND GOOD COMBUSTION PRACTICES	0.25	lb/MMBtu	-	YES
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL, WAP7	6700 MMBtu/hr	COMBUSTION CONTROL	0.282	lb/MMBtu	-	YES
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	7400 MMBtu/hr	COMBUSTION CONTROL	0.292	lb/MMBtu	-	YES
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	6700 MMBtu/hr	COMBUSTION CONTROL	0.294	lb/MMBtu	-	YES
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600 MW UNITS	600	COMBUSTION CONTROLS - 1 HR AVG	0.30	lb/MMbtu	**1-Hour Average**	NO
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED CAOL BOILER	800	NONE INDICATED	0.30	lb/MMBtu	**1-Hour Average**	NO
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	7400 MMBtu/hr	COMBUSTION CONTROL	0.302	lb/MMBtu	-	YES
SEVIER POWER COMPANY	UT	DAQE-AN2529001-04	10/12/2004	COMBUSTION CONTROLS	270	NONE INDICATED	0.32	lb/MMBtu	**1-Hour Average**	NO
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	6750 MMBtu/hr	COMBUSTION CONTROL	0.321	lb/MMBtu	-	NO
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	6700 MMBtu/hr	COMBUSTION CONTROL	0.33	lb/MMBtu	-	NO
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	7400 MMBtu/hr	COMBUSTION CONTROL	0.33	lb/MMBtu	-	NO
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	6700 MMBtu/hr	COMBUSTION CONTROL	0.33	lb/MMBtu	-	NO
INDEPENDENCE	AR	449-AOP-R0	3/10/1998	BOILER (2 EACH), COAL FIRED	8700 MMBtu/hr	GOOD COMBUSTION PRACTICE	0.37	lb/MMBtu	**24-Hour Average**	YES
NEAL ENERGY CENTER SOUTH	IA	05-A-655-P	9/28/2005	UNIT 4 BOILER	399	GOOD COMBUSTION	0.42	lb/MMBtu	**1 Calender day average**	NO
THERMAL VENTURES	VA	30529	2/15/2002	BOILER, STEAM	120 MMBtu/hr	GOOD COMBUSTION PRACTICES, CLEAN BURNING FUEL, AND CONTINUOUS EMISSION MONITORING DEVICE.	0.44	lb/MMBtu	-	NO
GEORGE NEAL NORTH	IA	05-A-878-P	12/9/2005	NEAL 1 BOILER	1363 MMBtu/hr	GOOD COMBUSTION PRACTICES	1.26	lb/MMBtu	**3-hour Average**	YES
GEORGE NEAL NORTH	IA	07-A-951-P	9/5/2007	NEAL 2 BOILER	3081 MMBtu/hr	GOOD COMBUSTION PRACTICES	1.63	lb/MMBtu	**3- hour rolling**	YES

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

4.3.4 BACT Demonstration for VOC Emissions from the Supercritical Pulverized Coal Boiler

VOC emissions are generated during the combustion process from incomplete combustion of the fuel, similar to CO emissions. The control of VOC emissions, therefore, is achieved through use of the same good combustion controls that minimize CO emissions, including providing adequate fuel residence time in the combustion chamber, maintaining a high temperature and sufficient oxygen in the combustion zone to ensure complete combustion, and providing adequate turbulence. Excessive VOC emissions could result from below optimal combustion zone conditions. Low levels of VOC emissions are expected from properly operated PC-fired boilers.

Step 1 – Identify All Control Technologies

Combustion Controls

As noted in the CO emissions evaluation, the most effective means of reducing VOC emissions is managing the combustion process to achieve complete combustion. Important factors in proper combustion include proper fuel residence time, proper air to fuel ratios in the combustion chamber, and consistent proper temperatures in the combustion chamber. VOC formation will be limited through use of a properly designed combustion chamber with adequate controls to regulate the combustion process. Proper maintenance is also necessary for proper combustion control. Proper operation of fuel feed systems, fans, system dampers, and other equipment will assist in minimization of VOC emissions. However, as stated above, careful consideration is necessary in the process of combustion controls. Since increasing the combustion temperature or oxygen concentration in the combustion chamber would decrease VOC emissions, it would likely increase the formation of thermal NO_x, and increase overall NO_x emissions.

Add-on Controls

No effective add-on controls currently exist for VOC emissions from a boiler. Use of afterburners and other control devices, such as catalytic oxidation or flares, has not been demonstrated in practice in PC boiler units. Any such control devices would lead to negative secondary environmental impacts, such as higher NO_x emissions.

Step 2 – Eliminate Technically Infeasible Options

Combustion Controls

Combustion controls, such as the proper combustion chamber and system design, and proper operation and maintenance, are demonstrated and proven techniques for the reduction of VOC emissions. Combustion controls are considered a demonstrated technology for PC-fired boiler VOC emissions controls, and therefore considered technically feasible under the BACT evaluation process.

Add-on Controls

As discussed above, the use of add-on controls for control of VOC emissions for the PC boiler units is not technically feasible. Use of add-on controls such as flares, afterburners, catalytic oxidation, and thermal oxidation has not been demonstrated in practice for control of VOC emissions from PC-fired boilers. These systems would be energy-intensive and impractical. Straight catalytic systems without additional energy would not be technically feasible because the proposed boiler achieves such a high level of heat recovery such that the outlet temperatures of the boiler where a catalyst system could be effectively installed are well below those levels at which a catalyst could effectively operate. Therefore, the only way that a catalyst system could be used would be to derate the heat effectiveness of the boiler to elevate its exhaust temperature. This would, however, be counterproductive in that it would result in a proportional increase in VOC emissions as well as all other pollutants to achieve the same amount of power production.

A catalyst system or thermal oxidizer would have to be installed downstream of a particulate matter control device to avoid plugging and blinding of the catalyst. Oxidation catalysts are susceptible to poisoning from high sulfur compounds and can experience fouling in gas streams with high particulate loading. This would also make installation of the oxidation catalyst as an integral part of the SCR system impractical for a coal fired boiler system.

The minimum temperature for use of an oxidation catalyst would be 350 degrees Fahrenheit, based on technical information on BASF and EmeraChem catalysts, and a thermal oxidizer could not effectively function at temperatures less than 1000 degrees Fahrenheit. The exhaust gas temperature from the boiler downstream of the filter is estimated to be less than 350 degrees Fahrenheit. Therefore, use of such systems is deemed technically infeasible for this analysis.

Step 3 – Rank Remaining Technically Feasible Control Options

Combustion controls are the only feasible technology for control of VOC emissions. Combustion controls are designed to optimize the emissions of VOC (and consequently NO_x) from a PC-fired boiler. Therefore, no energy or environmental impacts are associated with the implementation of combustion controls. There are no economic impacts associated with the implementation of combustion controls.

Step 4 – Evaluate Remaining Control Technologies

No energy, environmental, or economic impacts are associated with the use of combustion controls, which would preclude the use of combustion controls as BACT for VOC emissions for a PC-fired boiler.

Step 5 – Selection of BACT

The use of combustion controls is recognized as BACT for VOC emissions for PC-fired boilers. The selected control technology for the proposed PC boiler is the application of good combustion controls along with continuous monitoring of CO. Because CO and VOC are both generated from the incomplete combustion of the fuel and are both controlled with good combustion controls, CO will serve as an effective surrogate for monitoring VOC emissions. The RBLC listings and vendor literature were reviewed to determine the BACT limit associated with this technology. Table 4-11 provides RBLC listings for VOC emissions from PC-fired boilers. VOC emission limits indicated in Table 4-11 are based on a 3-hr. average (stack test). **BACT for VOC emissions was chosen as the implementation of good combustion controls and an emission limit of 0.003 lb/MMBtu on a 3-hour average basis.**

In the development of this proposed BACT level, consideration was given to the proposed boiler, which will be designed to minimize NO_x emissions. PC coal-fired boilers emit significantly more NO_x than VOCs on a mass basis, and NO_x is considered a higher-priority pollutant because NO_x is the controlling variable in the formation of ground-level ozone. VOCs, like NO_x, participate in the formation of ground-level ozone; however, naturally occurring VOCs are sufficiently prevalent such that NO_x is the controlling factor in the formation of ground-level ozone.

There are five boilers that are currently permitted at VOC levels below the proposed level of 0.003 lb/MMBtu. Table 4-10 provides a list of these units with their corresponding VOC and NO_x emission limits. All VOC limits listed in Table 4-10 are based on a 3-hr. average. The boiler design parameters that tend to result in lower VOC emissions (high combustion temperatures, excess air, and effective air/fuel mixing) result in higher NO_x emissions. In fact, the boiler design is largely aimed at reducing peak temperatures that result in NO_x formation. Therefore, when establishing BACT for VOCs, consideration must also be given to the impact that a low level could have on NO_x emissions and the fact that the unit will have to achieve compliance with both limits simultaneously. The proposed NO_x limit for the boiler (0.05 lb/MMBtu on a 30-day rolling average) is an aggressive NO_x limit and therefore would not be an optimum design for minimizing VOC emissions.

Only one of the boilers with a lower VOC limit (Santee Cooper Cross) is in operation, and this unit has a significantly higher NO_x limit compared to the proposed value for Plant Washington (0.08 lb/MMBtu as compared to 0.05 lb/MMBtu for Plant Washington). This would mean that the Santee Cooper boiler would have more flexibility in meeting the slightly lower VOC limit, while also meeting the higher NO_x limit. The JK Spruce boiler has an equivalent NO_x limit; however, its NO_x limit is on an annual averaging period. Therefore, the unit will have significantly more flexibility with the NO_x/VOC balance on a short-term basis. Furthermore, because this unit is not in operation, whether these two emission levels can be achieved simultaneously at the unit is unclear.

Table 4-10 NO_x and VOC Emission Limits for Units Permitted Below 0.003 lb/MMBtu VOC

Facility Name	NOx Emission Limit (lb/MMBtu)	Averaging Period	VOC Emissions (lb/MMBtu)
Virginia Tech	0.246	30-day	0.002
Santee Cooper Pee Dee Generating Station	0.07	30-day	0.0024
Santee Cooper Cross Generating Station	0.08	Annual	0.0024
JK Spruce Electric Generating Unit 2	0.05	Annual	0.0025
Intermountain Power Generating Station - Unit #3	0.07	30-day	0.0027

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

Compliance Demonstration

Plant Washington would propose to use USEPA Method 25A VOC minus USEPA Method 18 (methane) stack sampling to demonstrate compliance with the proposed limit. The plant will operate a continuous emission monitor (CEM) for CO emissions. Both VOCs and CO are indicators of complete combustion; therefore, it is expected that if the unit demonstrates compliance with the proposed CO limit during the

VOC stack test, its CO emissions could be used as a surrogate for VOC emissions. Plant Washington would therefore propose to use the CO CEM as a means of continuous demonstration of compliance with the VOC BACT limit.

Table 4-11 RBLC and Draft Permit Listings for VOC Emissions from Pulverized Coal-fired Boilers

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit	Emission Limit Unit	Operational Facility
VIRGINIA TECH	VA	20124	9/15/2005	OPERATION OF BOILER 11	COAL	146.7 MMBtu/hr	GOOD COMBUSTION PRACTICE	0.002	lb/MMBtu	NO
SANTEE COOPER PEE DEE GENERATING STATION	SC	1040-0113-CA.1 DRAFT	12/1/2007	Boiler No. 1 and 2	BITUMINOUS COAL	660	GOOD COMBUSTION PRACTICE	0.0024	lb/MMBtu	NO
SANTEE COOPER CROSS GENERATING STATION	SC	0420-0030-CI	2/5/2004	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	1320	GOOD COMBUSTION PRACTICE	0.0024	lb/MMBtu	YES
JK SPRUCE ELECTRIC GENERATING UNIT 2	TX	70492	1/19/2006	PULVERIZED COAL FIRED ELECTRIC STEAM BOILER	COAL	750	GOOD COMBUSTION PRACTICES	0.0025	lb/MMbtu	NO
INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	UT	DAQE-AN0327010-04	10/15/2004	PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	BITUMINOUS OR BLEND	950	COMBUSTION CONTROL	0.0027	lb/MMBtu	NO
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 1	COAL	390	NONE INDICATED	0.003	lb/MMBtu	NO
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 2	COAL	390	NONE INDICATED	0.003	lb/MMBtu	NO
TOQUOP ENERGY, LLC	NV	AP4911-1146	DRAFT	750 MW PC BOILER	COAL	750	COMBUSTION CONTROLS	0.003	lb/MMbtu	NO
DESERT ROCK ENERGY FACILITY	NM	DRAFT	7/1/2006	(2) 750 MW SCPC BOILERS	COAL	750	GOOD COMBUSTION PRACTICES	0.003	lb/MMbtu	NO
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL, WAP7	COAL	6700 MMBtu/hr	COMBUSTION CONTROL	0.0030	lb/MMBtu	YES
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	COAL	6700 MMBtu/hr	COMBUSTION CONTROL	0.0030	lb/MMBtu	NO
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-234	12/21/2000	UTILITY BOILER UNIT 8		6700 MMBtu/hr	NONE INDICATED	0.0030	lb/MMBtu	YES
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	COAL	7400 MMBtu/hr	COMBUSTION CONTROL	0.0031	lb/MMBtu	YES
TRIMBLE COUNTY GENERATING STATION	KY	DRAFT	7/6/2005	PULVERIZED COAL FIRED BOILER	COAL	750	GOOD COMBUSTION PRACTICES	0.0032	lb/MMbtu	NO
HARDIN GENERATOR PROJECT	MT	3185-00	1/25/2008	BOILER, PULVERIZED COAL-FIRED	COAL	116	GOOD COMBUSTION PRACTICES, SOME CONTROL OFFERED BY WET SCRUBBER (REQUIRED FOR SO2 CONTROL)	0.0034	lb/MMBtu	YES
OPPD - NEBRASKA CITY STATION	NE	58343C01	3/9/2005	UNIT 2 BOILER	SUBBITUMINOUS COAL	660	COMBUSTION CONTROLS	0.0034	lb/MMBtu	NO
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	COAL	6750 MMBtu/hr	COMBUSTION CONTROL	0.0035	lb/MMBtu	NO
HOLCOMB UNIT #2	KS	0550087/C-3855	10/8/2002	BOILER, PULVERIZED COAL	COAL	660	GOOD COMBUSTION PRACTICES	0.0035	lb/MMBtu	NO
COMANCHE STATION	CO	04UNITPB1015	7/5/2005	PC BOILER - UNIT 3	SUB-BITUMINOUS COAL	750	GOOD COMBUSTION PRACTICES	0.0035	lb/MMBtu	NO
ELY ENERGY CENTER	NV	AP4911-2241	DRAFT	(2) 750 MW PC BOILERS	COAL	750	COMBUSTION CONTROLS	0.0035	lb/MMbtu	NO
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	COAL	7400 MMBtu/hr	COMBUSTION CONTROL	0.0035	lb/MMBtu	YES
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	COAL & NAT GAS	6750 MMBtu/hr	COMBUSTION CONTROL	0.0035	lb/MMBtu	NO
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED CAOL BOILER	COAL	800	NONE INDICATED	0.0036	lb/MMBtu	NO

Table 4-11 RBLC and Draft Permit Listings for VOC Emissions from Pulverized Coal-fired Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Thruput (MW)	Control Description	Emission Limit	Emission Limit Unit	Operational Facility
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	6700 MMBtu/hr	COMBUSTION CONTROL	0.0036	lb/MMBtu	YES
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	6700 MMBtu/hr	COMBUSTION CONTROL	0.0036	lb/MMBtu	NO
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 1	7800 MMBtu/hr	GOOD COMBUSTION CONTROL PRACTICE	0.0036	lb/MMBtu	NO
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	MO	122004-007	12/15/2004	PULVERIZED COAL FIRED BOILER	275	UTILIZATION OF GOOD COMBUSTION PRACTICES .	0.0036	lb/MMBtu	NO
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATION	MO	888	8/17/1999	ELECTRIC GENERATION, BOILER, COAL	384 T/HR	GOOD COMBUSTION PRACTICES	0.0036	lb/MMBtu	YES
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	500	GOOD COMBUSTION PRACTICES, LOW NOX BURNERS	0.0036	lb/MMBtu	NO
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	7675 MMBtu/hr	COMBUSTION CONTROLS	0.0036	lb/MMBtu	YES
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 2	7800 MMBtu/hr	NONE INDICATED	0.0036	lb/MMBtu	NO
HUGO GENERATING STATION	OK	97-058-C M-2 PSD	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	750	GOOD COMBUSTION CONTROLS	0.0036	lb/MMBtu	NO
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600 MW UNITS	600	COMBUSTION CONTROLS	3.60E-03	lb/MMbtu	NO
AMERICAN MUNICIPAL POWER GENERATING STATION	OH	06-08138	2/7/2008	BOILER (2), PULVERIZED COAL	5191 MMBtu/hr	GOOD COMBUSTION PRACTICES	3.70E-03	lb/MMbtu	NO
DRY FORK STATION	WY	CT-4631	10/15/2007	PC BOILER (ES1-01)	385	GOOD COMBUSTION PRACTICES	3.70E-03	lb/MMbtu	NO
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	600	GOOD COMBUSTION PRACTICES	0.004	lb/MMBtu	NO
LONGVIEW POWER MAIDSVILLE	WV	R14-0024	3/2/2004	PULVERIZED COAL FIRED BOILER	600	GOOD COMBUSTION PRACTICES	0.004	lb/MMbtu	NO
LIMESTONE ELECTRIC GENERATING STATION	TX	PSD-TX-371 (M3)	5/23/2001	(2) BOILER UNIT 1 & 2 SCRUBBER STACKS, LMS1 & 2	7863 MMBtu/hr	NONE INDICATED	0.006702276	lb/MMBtu	YES
AES BEAVER VALLEY, LLC	PA	PA-04-446C	11/21/2001	COAL FIRED BOILER	2115 MMBtu/hr	NONE INDICATED	0.0068	lb/MMBtu	YES

Table 4-11 RBLC and Draft Permit Listings for VOC Emissions from Pulverized Coal-fired Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Thruput (MW)	Control Description	Emission Limit	Emission Limit Unit	Operational Facility
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	BOILER, COAL, (2)	750	PROPER BOILER DESIGN AND OPERATION	0.0072	lb/MMBtu	NO
INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	GA	2631-115-0021-V-01-4	10/13/2004	BOILER, COAL FIRED	565 MMBtu/hr	STAGED COMBUSTION AND GOOD COMBUSTION PRACTICES.	0.01	lb/MMBtu	YES
WYGEN 2	WY	CT-3030A	7/11/2005	BOILER, 500 MW PC	100	GOOD COMBUSTION CONTROL	0.01	lb/MMBtu	YES
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	BOILER, STEAM ELECTRIC POWER GENERATING	250	NONE INDICATED	0.015	lb/MMBtu	NO
BIG CAJUN II POWER PLANT	LA	PSD-LA-677 (M-1)		NEW 705 MW PULVERIZED COAL BOILER (UNIT 4)	705	OPTIMUM BURNER DESIGN AND GOOD COMBUSTION TECHNIQUES	0.0034	lb/MMBtu	NO
PLUM POINT ENERGY	AR	1995-AOP-R1	8/20/2003	BOILER , UNIT 1 - SN-01	665	COMBUSTION CONTROLS	0.02	lb/MMBtu	NO
PLUM POINT ENERGY	AR	1995-AOP-R1	8/20/2003	BOILER - SN-01	665	COMBUSTION CONTROLS	0.02	lb/MMBtu	NO
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	LIQUIDS FROM COAL PLANT (3 MODULES PER PLANT)		NONE INDICATED	0.05	lb/MMBtu	YES
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	BOILER, COAL FIRED, MAIN STACK	3960 MMBtu/hr	NONE INDICATED	0.05	lb/MMBtu	YES
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	BOILER, PULVERIZED COAL FIRED POWER GENERATION UNI	240	DUE TO LNB/OFA STRATEGY TO CONTROL NOX IT WOULD BECOUNTER PRODUCTIVE TO LIMIT VOC.	0.05	lb/MMBtu	YES
MANSFIELD MILL	LA	PSD-LA-93 (M-6)	8/14/2001	POWER BOILER #1 & #2, COAL	645 MMBtu/hr	GOOD PROCESS CONTROLS	0.1550	lb/MMBtu	YES
THERMAL VENTURES	VA	30529	2/15/2002	BOILER, STEAM	120 MMBtu/hr	GOOD COMBUSTION PRACTICES, CLEAN BURNING FUEL, AND CONTINUOUS EMISSION MONITORING DEVICE.	0.18	lb/MMBtu	NO

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

4.3.5 BACT Demonstration for SO_2 Emissions from the Supercritical Pulverized Coal Boiler

Emissions of sulfur dioxide (SO_2) are generated in fossil fuel fired units from oxidation of sulfur in the fuel source. Uncontrolled emissions of SO_2 are therefore significantly affected by the sulfur content of the fuel, as well as the heating value (Btu/lb) of the fuel. This BACT analysis examines add-on controls and reduction of the fuel's sulfur content to reduce the SO_2 that is generated in the combustion process.

Step 1 – Identify All Control Technologies

Lower-emitting Process or Practice – Coal Selection

Emissions of SO_2 result from the oxidation of sulfur in the coal during the combustion process. Therefore, coal source selection can have an impact on SO_2 emissions from a coal-fired boiler. Western sub-bituminous coals, such as Powder River Basin (PRB) coals, typically have lower sulfur content than bituminous coals. An additional variable in coal selection is the availability of certain coals for use. With increasing demand for the use of lower-sulfur coals, including PRB coal, the prospects for current and future availability of these coals must be evaluated and included in any coal selection analysis.

Emissions of SO_2can be impacted by not only the sulfur content of the coal selected, but also the heating value (Btu/lb) of the fuel source. The uncontrolled SO_2 emissions generated from coal combustion can be estimated by the following equation, where S is the sulfur content (percent) of the coal and HHV is the higher heating value in Btu/lb.

$$S / (100 * HHV) * 1E6 / MMBtu * 2 \text{ lb } SO_2 / \text{lb } S = \underline{X} \text{ lb } SO_2/MMBtu$$

For example, from the above equation, a low-sulfur coal of approximately 0.5 percent S with a heating value of 8,500 Btu/lb would have an uncontrolled SO_2 emission rate of 1.18 lb/MMBtu, while a low-sulfur coal of approximately 0.5 percent S with a heating value of 9,000 Btu/lb would have an uncontrolled SO_2 emission rate of 1.11 lb/MMBtu. This difference of 0.07 lb/MMBtu may seem insignificant, but when using a boiler with a firing rate of 8,300 MMBtu/hr, the difference in uncontrolled SO_2 emissions from the two scenarios given above is more than 2,500 tons/yr of uncontrolled SO_2 emissions. Therefore, two coals with identical sulfur contents, but different heating values, could have significantly different uncontrolled and controlled SO_2

emissions. Therefore based on the above equation, SO_2 emissions are impacted not just from the sulfur content of the coal but its heating value as well.

Refined coal could also be selected for use at the facility. Coal refining is a mechanical and thermal process to remove moisture, sulfur, nitrogen, and heavy metals from coal. Also, as a result of the refining process, the ash content and moisture of the coal can be lowered, as well as increasing the heat content of the coal. Coal refining processes include those still in the research and development stage, such as patented technologies for conversion of coal to char, a "clean" boiler fuel, and processes already in limited operation, such as the Evergreen Energy, Inc., K-Fuel patented pre-combustion coal refining process.

Lower-emitting Process or Practice – Coal Cleaning

Coal cleaning is generally performed to remove impurities and improve the coal's heat content, thereby improving power plant capacity, reducing maintenance costs at power plants, and extending plant life. Coal cleaning is also performed to reduce the coal's sulfur content, which reduces the SO_2 emissions that result from oxidation of the sulfur in the coal during combustion. The current common method of coal cleaning involves physical coal cleaning methods, while other advanced methods such as microwave cleaning or the use of magnetization are in development.

The most common method of physical coal cleaning involves coal washing, a term given to mechanical cleaning of coal by separating out non-coal material in a liquid medium. Coal washing involves removing the sulfur from the fuel before it is combusted in the boiler. The process involves grinding the coal into small pieces and passing it through a process called "gravity separation." The technique involves feeding the coal into barrels containing a fluid that has a density that causes the coal to float, while unwanted material such as sulfur (within an iron compound called "pyrite") sinks and is removed from the fuel. The washing medium is an aqueous chemical solution prepared to enhance dissociation of the coal and non-coal materials, or to produce specific gravities calibrated higher than water alone. Other wet cleaning techniques can include particle agitation by aeration of the coal liquid feed, materials sorting by relative density in hydro-cyclonic chambers, and froth flotation to capture fine coal particles. Advanced washing techniques can remove as much as 40 percent of the inorganic sulfur in coal.

Wet Scrubber

Wet scrubbers systems are often used as FGD systems, where they are used to control emissions of SO_2 from oil and coal-fired combustion sources. A wet scrubber brings the exhaust gas stream into contact with a sorbent material designed to absorb and react with the SO_2 in the gas stream. Reagents commonly used in the process include lime and limestone. Additives, such as magnesium, are sometimes added to the reagent materials to further improve the reaction of the reagent with the SO_2 in the gas stream. The byproducts of the wet scrubber are in a wet slurry form and must be dewatered prior to handling and further disposal. Wastewaters generated through the wet scrubbing process may also require some level of treatment.

Spray Dryer Absorber (Dry Scrubber)

In a spray dryer absorber (SDA), or spray dryer, a fine spray of reagent slurry (mixed with water) is atomized and comes into contact with the hot exhaust gas, or flue gas. Lime is the typical reagent used in an SDA unit. A significant part of the acidic components of the flue gas is rapidly absorbed into the alkaline droplets, with the water/moisture content evaporated simultaneously. Control of exhaust gas distribution, slurry flow rate, and spray droplet size ensures that the droplets introduced into the gas stream are effectively dried to a fine powder before touching the chamber walls of the spray dryer unit or exiting the SDA system. A portion of the reacted product is collected and discharged from the SDA, and sometimes recycled to the feed of the SDA to reduce alkaline sorbent use. The treated flue gas is then discharged to a fabric filter baghouse, or other PM control device, where reacted product is collected from the exhaust gas stream.

Circulating Dry Scrubber

A CDS is similar in concept and reaction chemistry to a SDA. In a CDS system, a circulating fluidized bed arrangement is used for contacting the sorbent reagent, lime, with the SO_2-laden flue exhaust gas. As with a SDA, the reaction products exit the system in a dry form and are collected down stream in a fabric filter baghouse or other PM control device. The advantage of a CDS over SDA is the more efficient use of the alkaline slurry injected into the stream because it improves the use of the reagent, making it more economical.

Dry Sorbent Injection (DSI)

Dry sorbent injection (DSI) is a process used to control SO_2 emissions by injecting a sorbent into the flue gas stream. The sorbent can be injected into the furnace, economizer, or downstream ductwork. The injection point can depend on the type of sorbent used and required reaction time, as some sorbents must be injected at high temperatures to properly decompose the sorbent into porous solids with a high surface area. An expansion or reaction chamber may be included to increase the residence time of the flue gas to react with the sorbent. Dry sorbent systems typically use calcium and sodium based alkaline reagents. The waste product is removed using particulate matter control equipment, such as a baghouse or electrostatic precipitator. Sorbent injection will be used by Plant Washington for the control of sulfuric acid mist (SAM) emissions.

Activated carbon can also be used as the sorbent for removal of SO_2 emissions. Activated carbon is injected into the flue gas exhaust stream through a series of header nozzles upstream of a fabric filter baghouse or other PM control device. A portion of the reacted carbon and fly ash collected by the PM control device is recycled and injected back into the flue gas exhaust stream to minimize the need for fresh activated carbon, making the process a partially "regenerable" process. Other activated carbon contact methods with the flue gas have been postulated. Activated carbon injection is planned for this unit for control of mercury. Activated carbon desulfurization could not be expected to reach the required SO_2 emissions reduction necessary to achieve BACT as a standalone technology. In fact, reinjecting carbon risks liberating any adsorbed mercury. Therefore, activated carbon desulfurization will no longer be considered in this analysis.

Step 2 – Eliminate Technically Infeasible Options

Lower-emitting Process or Practice – Coal Selection

Coal selection is a demonstrated method for minimizing the amount of sulfur available for SO_2 formation. Therefore, coal selection is determined to be technically feasible for this project, and the facility will predominantly use PRB coal, a low-sulfur sub-bituminous coal. However, due to concern of the availability of this coal in the future provisions must be made to be able to burn a 50/50 blend of sub-bituminous and bituminous coal as an alternative fuel.

Another form of coal selection includes selection of a source of "refined" coal. A company called "Evergreen Energy, Inc.," is the only vendor currently found to offer refined PRB coal. The refined fuel product is called "K-Fuel," and claims made regarding the use of the fuel indicate that the use of K-Fuel can lead to lower emissions of SO_2, NO_x, and CO than standard PRB coal. However, the company is only operating one facility in Wyoming, which has thus far seen limited production. The company hopes to produce over 50 million tpy of K-Fuel in 5 years, through full operation at the existing facility and expansion of new facilities. However, wide-scale production and use, and demonstration of the improved performance of the K-Fuel, have yet to be conducted. If it becomes available, such a coal will be considered for purchase.

Based on the current lack of sufficient supply of coal refining facilities, coal refining is not considered an available technology for SO_2 emissions reduction. Therefore, coal refining is determined to be technically infeasible as a coal selection option for this project.

Lower-emitting Process or Practice – Coal Cleaning

Physical coal cleaning, most often conducted by coal washing, involves removing a portion of the sulfur from the fuel before combusting it in a boiler. Generally, the majority of the sulfur in the coal is organic and is chemically bonded in the molecular structure of the coal itself. This sulfur cannot be removed by physical coal cleaning methods, but a small fraction of the sulfur in the coal is within an iron compound called "pyrite" that can be removed through washing of the coal. Plant Washington will have the capability of utilizing either sub-bituminous coals, bituminous coals, or a blend of bituminous and sub-bituminous coals. Specifically for the design coals for Plant Washington, the pyritic sulfur content of PRB coal is low, with a pyritic sulfur content of approximately 0.03 percent for PRB coals, compared to the total sulfur content of the PRB of 0.32 percent sulfur. This level is so low that further attempts at reduction by coal washing would not be effective.

On the other hand, Illinois #6 coals typically contain a higher pyritic content than PRB coals. The potential pyritic content of unwashed Illinois #6 coals at the facility based on reviewed coal analysis data of unwashed coal would be 2.15 percent, from a total sulfur content of approximately 4.6 percent. Assuming the removal efficiency of coal washing is 40 percent of the pyritic sulfur content of the coal, this would reduce the sulfur content of the coal to approximately 3.7 percent, with a total reduction of 0.9 percent of the sulfur content of the coal.

Therefore, coal washing for PRB coals would be ineffective because there would be little sulfur content removed by the process. However, Illinois #6 coals are routinely washed to reduce the pyritic sulfur content, as well as other impurities in the coal. Therefore, coal washing for Illinois #6 coals is considered technically feasible for this analysis. Illinois #6 coals purchased by the facility will be washed prior to shipment to Plant Washington. If any additional bituminous coals are purchased for use at the facility, those coals will fall within the specifications of washed Illinois #6 coal.

Wet Scrubber

Wet scrubbers have been demonstrated in wide-scale use on coal-fired boilers and are available from a number of vendors. Wet scrubbers are therefore considered to be technically feasible.

Spray Dryer Absorber (Dry Scrubber)

Dry scrubbers have been demonstrated in wide-scale use on coal-fired boilers and are available from a number of vendors. Dry scrubbers are therefore considered to be technically feasible.

Circulating Dry Scrubber

Circulating dry scrubbers have not yet been demonstrated on a coal-fired boiler of greater than 400 MW. The size and scale differences between the proposed utility boiler and the boilers on which this technology have been demonstrated would likely lead to the requirement for further design, research, and testing for assessing viability on such a large-scale unit. Circulating fluidized bed systems, as with a circulating fluidized bed boiler, are not in use at the size and scale of the proposed utility boiler. Therefore, circulating dry scrubber systems are not considered available for this project and are considered technically infeasible for this analysis.

Dry Sorbent Injection (DSI)

Although some level of SO_2 removal would be expected from use of injection of dry sorbent materials into the flue gas exhaust stream, removal efficiencies when using this technology as a standalone control methodology are not as effective as those of other standalone control devices, such as wet or dry scrubbers.

Research data have shown that concentrations of NO_x in the flue gas exhaust stream, specifically nitrogen monoxide (NO), can lead to inhibition of the catalytic effect of any porous activated carbon material used as a sorbent, leading to deteriorated desulfurization performance. This deteriorated desulfurization performance can lead to the requirement for an increasing amount of activated carbon use, thereby increasing the treatment costs. Activated carbon desulfurization would not be expected to reach the required SO_2 emissions reduction necessary to achieve BACT as a standalone technology, and would inhibit the effectiveness of other control technologies.

Therefore, for the above-listed reasons, the use of dry sorbent injection for removal of SO_2 emissions will no longer be evaluated for this project. Sorbent injection will be used by Plant Washington for control of sulfuric acid mist (SAM) emissions. Also, the facility will implement a sorbent injection system, using activated carbon, for control of mercury emissions. Therefore, some co-benefit in reduction of SO_2 emissions through use of the SAM and mercury sorbent injection system could result.

Step 3 – Rank Remaining Technically Feasible Control Options

Control Effectiveness

Coal Selection

Plant Washington will have the capability of utilizing either sub-bituminous coals, bituminous coals, or a blend of bituminous and sub-bituminous coals. The current business plan for the facility is to burn predominantly PRB coal either alone or up to a 50/50 blend of sub-bituminous and bituminous coal (typically Illinois #6 and PRB coals).

Coal Cleaning

Coal cleaning was considered technically feasible for this analysis. As discussed previously, PRB coals are not washed due to their low sulfur content. However, Illinois #6 coals at Plant Washington will be washed prior to purchase.

Scrubber Technology

The feasible add-on control technologies found during Step 2 of this analysis include wet scrubbers and spray dryer absorbers (dry scrubbers). Technical publications, the USEPA RBLC, and vendor information were reviewed to determine the control efficiencies of each of these identified technically feasible SO_2 reduction technologies. Based on data provided in the 2000 USEPA report *Controlling SO_2 Emissions: A Review of Technologies*, dry scrubbers can have design efficiencies up to 96 percent, while wet scrubbers can have a design efficiency of up to 98 percent. In addition, wet scrubbers have an added collateral control benefit for secondary pollutants due to more effective capture of secondary acid gases in the flue gas exhaust stream than a dry scrubber, including reactive mercury, hydrogen chloride, and fluorides.

To further evaluate the control effectiveness of wet scrubbers versus dry scrubbers, data from available resources were reviewed. These resources included the USEPA Clean Air Markets program and the Federal Energy Regulatory Commission (FERC). Data collected from the USEPA Clean Air Markets website included continuous emissions monitoring (CEM) data for emissions of SO_2 for sources required to report emissions under the Acid Rain Program. Data collected from this source can be used to determine the lb/MMBtu emission rate of SO_2 emissions on an hourly, daily, monthly, or annual average basis. Data collected from the FERC website included coal quality data for selected sites, including the coal source, sulfur content (percent), higher heating value (Btu/lb), and quantity of coal obtained in thousands of tons. Use of these data, in conjunction with emissions data from the USEPA Clean Air Markets website, can produce an evaluation of the SO_2 collection efficiency of facility unit SO_2 control devices.

Data collected from the USEPA Clean Air Markets website and the FERC website were used to estimate the SO_2 collection efficiencies for selected coal-fired boiler units using wet scrubbers and dry scrubbers for control of SO_2 emissions. To accomplish this, it was necessary to derive an uncontrolled SO_2 emission rate for the boiler. An estimate of uncontrolled emissions was made using the sulfur content (percent) and higher heating value (Btu/lb) data obtained from the FERC website. The following equation was used to estimate the uncontrolled SO_2 emission rate using the FERC data.

$$S / (100 * HHV) * 1E6 / MMBtu * 2 \text{ lb } SO_2 / \text{lb } S = \underline{X} \text{ lb } SO_2/MMBtu$$

The above calculation was performed for each data entry into the FERC database for the facility in question. The annual average lb/MMBtu uncontrolled SO_2 emission rate was then used in calculation of the SO_2 removal efficiency using the following method.

Removal Efficiency = [1 – (controlled SO_2 lb/MMBtu / uncontrolled SO_2 lb/MMBtu)] * 100% = % Removal

It is important to note that estimating the removal efficiency in this way provides an overall removal efficiency for the facility as a whole, not just the final control device. For instance, in a process known as "alkaline ash scrubbing," alkaline content in the ash of the coal combusted in a boiler can remove a portion of the SO_2 emissions created in the boiler. The reacted SO_2 adsorbed in the bottom ash or fly ash, usually in the form of SO_3, reduces the inlet SO_2 concentration to the SO_2 control device. Alkaline ash scrubbing is a "natural" process related to the alkaline ash content of the fuel being combusted.

Published literature regarding alkaline ash scrubbing and data reviewed for the sulfur content in ash collected from coal-fired boilers, indicate that approximately 20 percent of the potential SO_2 emissions can be removed in this manner. Taking this pre-scrubbing into account, overall removals can be obtained by reducing the estimated efficiency by 1 percent. However, since the effectiveness of alkaline ash scrubbing depends on the chemical composition of the coals being combusted, as well as overall system design of a facility, the effectiveness of alkaline ash scrubbing at one facility could be different from another, and difficult to estimate without detailed site-specific facility information. Therefore, no direct adjustments were made to the SO_2 removal efficiencies estimated by the methodologies discussed above, and removal efficiencies indicated are "system wide" efficiencies for the units listed.

Data for the top 10 performing facilities using wet scrubbers and the top 10 facilities using dry scrubbers were reviewed for calendar years 2006 and 2007 to determine the operational SO_2 removal efficiencies of the coal-fired boiler units at those facilities. These facilities were ranked to determine the top 10 wet scrubbing and dry scrubbing units in calendar years 2006 and 2007 based on calendar year average SO_2 emissions (lb/MMBtu), so it is believed that a comparison is being made between the best performing units. Data were used to generate the information

presented in Tables 4-12, 4-13, 4-14, and 4-15. The average removal for the top 10 dry scrubbers for calendar years 2006 and 2007 is 91.7 percent, while the average for the top 10 wet scrubbers for calendar years 2006 and 2007 is 96.6 percent. This indicates that wet scrubbing is a superior technology for SO_2 removal over dry scrubbing. The 24-hour average values indicated in the table are the maximum and minimum daily SO_2 emission rate values (midnight to midnight) reported to the USEPA Clean Air Markets program.

Table 4-12 SO_2 Emissions Evaluation for Top 10 Dry Scrubbers in 2006

Facility Name	State	2006 Average Coal Sulfur Content (%)	Coal Type / Source State	Heating Value (Btu/lb)	Unit	Maximum Heat Capacity (MMBtu/hr)	Maximum 24-hr Average Value (lb/MMBtu)	Minimum 24-hr Average Value (lb/MMBtu)	Maximum 30 Day Rolling Average Value (lb/MMBtu)	Minimum 30 Day Rolling Average Value (lb/MMBtu)	Annual Average (lb/MMBtu)	Annual Average SO_2 Removal (%)
Stanton	ND	0.33	SUB-MT	9,347	10	642	0.301	0.0005	0.109	0.007	0.0303	95.55
Altavista Power Station	VA	1.15	BIT - KY	12,695	1	383	0.124	0.0047	0.067	0.029	0.0531	96.14
					2	383	0.428	0.0047	0.071	0.030	0.0531	96.14
Southampton Power Station	VA	0.84	BIT - KY/WV	12,559	2	400	0.499	0.0070	0.093	0.033	0.0670	95.00
					1	400	0.445	0.0027	0.093	0.048	0.0695	94.81
Rawhide Energy Station	CO	0.24	SUB-WY	8,856	101	3500	0.112	0.0390	0.084	0.071	0.0776	85.77
Shiras	MI	0.33	SUB-MT	9,321	3	517	0.431	0.0064	0.144	0.039	0.0901	87.27
Hawthorn	MO	0.35	SUB-WY	8,520	5A	6300	0.762	0.0071	0.152	0.070	0.0906	88.66
Holcomb	KS	0.29	SUB-WY	8,520	SGU1	4320	0.596	0.0301	0.189	0.071	0.0933	85.79
Craig	CO	0.40	SUB-CO	10,116	C3	6000	0.403	0.0582	0.139	0.077	0.0992	87.15

Average Efficiency 92.2%

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

Table 4-13 SO_2 Emissions Evaluation for Top 10 Dry Scrubbers in 2007

Facility Name	State	2007 Average Coal Sulfur Content (%)	Coal Type / Source State	Heating Value (Btu/lb)	Unit	Maximum Heat Capacity (MMBtu/hr)	Maximum 24-hr Average Value (lb/MMBtu)	Minimum 24-hr Average Value (lb/MMBtu)	Maximum 30 Day Rolling Average Value (lb/MMBtu)	Minimum 30 Day Rolling Average Value (lb/MMBtu)	Annual Average (lb/MMBtu)	Annual Average SO_2 Removal (%)
Altavista Power Station	VA	0.772	BIT - VA/KY	12830	1	383	0.455	0.004	0.065	0.025	0.037	97.0
					2	383	0.450	0.008	0.056	0.025	0.037	97.0
Shiras	MI	0.311	SUB-MT	9316	3	517	0.328	0.002	0.093	0.021	0.046	93.2
Stanton	ND	0.326	SUB-MT	9353	10	642	0.214	0.006	0.065	0.039	0.050	92.8
Southampton Power Station	VA	0.849	BIT - KY/WV	12365	1	400	0.486	0.014	0.098	0.046	0.059	95.7
					2	400	0.879	0.019	0.109	0.049	0.060	95.6
Holcomb	KS	0.282	SUB-WY	8601	SGU1	4320	0.458	0.029	0.097	0.055	0.072	89.0
Rawhide Energy Station	CO	0.246	SUB-WY	8844	101	3500	0.131	0.023	0.088	0.074	0.080	85.5
Walter Scott Jr. Energy Center	IA	0.292	SUB-WY	8512	4	7675	0.377	0.004	0.113	0.072	0.081	88.8
Hawthorn	MO	0.322	SUB-WY	8560	5A	6300	0.523	0.008	0.148	0.068	0.093	87.6

Average Efficiency 91.2%

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

Table 4-14 SO_2 Emissions Evaluation for Top 10 Wet Scrubbers in 2006

Facility Name	State	2006 Average Coal Sulfur Content (%)	Coal Type / Source State	Heating Value (Btu/lb)	Unit	Maximum Heat Capacity (MMBtu/hr)	Maximum 24-hr Average Value (lb/MMBtu)	Minimum 24-hr Average Value (lb/MMBtu)	Maximum 30 Day Rolling Average Value (lb/MMBtu)	Minimum 30 Day Rolling Average Value (lb/MMBtu)	Annual Average (lb/MMBtu)	Annual Average SO_2 Removal (%)
Navajo Generating Station	AZ	0.52	BIT - AZ	10,915	1	16700	0.431	0.0124	0.055	0.026	0.0344	96.40
Bonanza	UT	0.36	BIT - CO	9,616	1-Jan	5500	0.403	0.0232	0.062	0.028	0.0397	94.85
Asheville	NC	0.968	BIT-KY/VA/WV	12,470	1	2596	0.208	0.0106	0.085	0.018	0.0375	97.38
Navajo Generating Station	AZ	0.52	BIT - AZ	10,915	2	16700	0.540	0.0074	0.063	0.028	0.0417	95.63
					3	16700	0.116	0.0002	0.052	0.031	0.0425	95.55
Mount Storm Power Station	WV	1.82	BIT-MD/WV/PA	11,568	3	6005	0.579	0.0068	0.073	0.023	0.0427	98.67
Reid Gardner	NV	0.67	BIT - CO/UT	12,149	3	1237	0.389	0.0004	0.077	0.019	0.0435	95.48
Trimble County	KY	3.41	BIT-KY/WV/OH	11,916	1	5333	0.171	0.0132	0.082	0.026	0.0435	99.22
Clover Power Station	VA	1.13	BIT - KY/VA	12,518	1	5127	0.091	0.0149	0.063	0.036	0.0480	97.18
Reid Gardner	NV	0.67	BIT - CO/UT	12,149	2	1215	0.225	0.0007	0.069	0.034	0.0483	94.98

Average Efficiency 96.5%

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

Table 4-15 SO_2 Emissions Evaluation for Top 10 Wet Scrubbers in 2007

Facility Name	State	2007 Average Coal Sulfur Content (%)	Coal Type / Source State	Heating Value (Btu/lb)	Unit	Maximum Heat Capacity (MMBtu/hr)	Maximum 24-hr Average Value (lb/MMBtu)	Minimum 24-hr Average Value (lb/MMBtu)	Maximum 30 Day Rolling Average Value (lb/MMBtu)	Minimum 30 Day Rolling Average Value (lb/MMBtu)	Annual Average (lb/MMBtu)	Annual Average SO_2 Removal (%)
Pleasant Prairie	WI	0.32	SUB-WY	8470	1	8250	0.050	0.0086	0.030	0.014	0.0202	97.3
Reid Gardner	NV	0.53	BIT - CO/UT	11773	3	1237	0.194	0.0003	0.051	0.022	0.0349	96.0
					1	1215	0.160	0.0003	0.062	0.023	0.0361	95.8
					2	1215	0.272	0.0032	0.069	0.022	0.0387	95.5
Mitchell (WV)	WV	1.65	BIT-WV	12334	2	7020	1.375	0.0017	0.066	0.013	0.0414	98.7
Navajo Generating Station	AZ	0.55	BIT - AZ	10894	2	16700	3.358	0.0049	0.179	0.032	0.0426	95.8
Craig	CO	0.42	SUB-CO	10092	C2	6000	0.161	0.0015	0.053	0.032	0.0433	94.8
Asheville	NC	1.028	BIT-KY/VA/WV	12504	1	2596	0.277	0.0034	0.071	0.019	0.0441	97.5
					2	2326	0.201	0.0116	0.060	0.032	0.0442	97.5
Clover Power Station	VA	1.04	BIT - KY/VA	12660	2	5173	0.087	0.0076	0.056	0.031	0.0444	97.4

Average Efficiency 96.6%

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

In addition to an evaluation of specific facilities using dry scrubbers and wet scrubbers for calendar years 2006 and 2007, an evaluation was conducted of the top performing facility emission units for those years. The USEPA Clean Air Markets Program was sorted to find boilers burning coal as their primary fuel, and further sorted by the reported annual average SO_2 lb/MMBtu emission rate. This evaluation produced Tables 4-16 and 4-17. As shown in Table 4-16, the lowest achieved lb/MMBtu emission rate in calendar year 2006 was 0.03 lb/MMBtu for the Stanton Station Unit 10 in North Dakota, a facility using a dry scrubber in conjunction with low-sulfur PRB coal (annual average 0.33 percent S). A review of calendar monthly average SO_2 emissions for 2006 for this unit indicated that emissions varied from approximately 0.01 to 0.16 lb/MMBtu on a monthly average basis. Table 4-19 indicates the referenced monthly values.

As shown in Table 4-17, the lowest achieved lb/MMBtu emission rate in calendar year 2007 was an annual average rate of 0.02 lb/MMBtu for Pleasant Prairie Unit 1, a facility using a wet scrubber in conjunction with use of low-sulfur PRB coal (annual average 0.32 percent S). A review of calendar monthly average SO_2 emissions for 2007 for this unit indicated that emissions varied from 0.016 to 0.030 lb/MMBtu on a monthly average basis. Table 4-18 indicates the referenced monthly values.

Table 4-16 Top Performing Emission Units in Calendar Year 2006 Based on lb/MMBtu Emission Rates

State	Facility Name	Unit ID	Year	Operating Time	SO_2 (Tons)	Heat Input (MMBtu)	Fuel Type (Pimary)	SO_2 Control	Annual Average SO_2 (lb/MMBtu)	2006 Average Coal Sulfur Content (%)	Coal Type / Source State	Annual Inlet SO_2 Average (lb/MMBtu)	Annual Average SO_2 Removal (%)
ND	Stanton	10	2006	7273.24	73.179	4826505	Coal	Dry Lime FGD	0.030	0.33	SUB-MT	0.68	95.55
AZ	Navajo Generating Station	1	2006	8580.48	1216.02	70729515	Coal	Wet Limestone	0.034	0.52	BIT - AZ	0.954	96.40
UT	Bonanza	1-Jan	2006	8681	864.159	43570506	Coal	Wet Limestone	0.040	0.36	BIT - CO	0.771	94.85
NC	Asheville	1	2006	8085	267.901	13318066	Coal	Wet Lime FGD	0.040	0.968	BIT-KY/VA/WV	1.538	97.38
AZ	Navajo Generating Station	2	2006	7820.08	1300.85	62437748	Coal	Wet Limestone	0.042	0.52	BIT - AZ	0.954	95.63
AZ	Navajo Generating Station	3	2006	7982.91	1326.12	62462256	Coal	Wet Limestone	0.042	0.52	BIT - AZ	0.954	95.55
WV	Mount Storm Power Station	3	2006	8212.75	880.73	41288342	Coal	Wet Limestone	0.043	1.82	BIT-MD/WV/PA	3.204	98.67
WA	Centralia	BW21	2006	6241.01	867.46	40024108	Coal	Wet Limestone	0.043				
NV	Reid Gardner	3	2006	6948.25	195.758	9009871	Coal	Sodium Based	0.043	0.67	BIT - CO/UT	0.961	95.48
KY	Trimble County	1	2006	8452.14	828.745	38139279	Coal	Wet Limestone	0.043	3.41	BIT-KY/WV/OH	5.607	99.22
WA	Centralia	BW22	2006	5498.62	796.199	34480303	Coal	Wet Limestone	0.046				
VA	Clover Power Station	1	2006	8604.25	890.135	37107725	Coal	Wet Limestone	0.048	1.13	BIT - KY/VA	1.701	97.18
NV	Reid Gardner	2	2006	7590.75	249.144	10323703	Coal	Sodium Based	0.048	0.67	BIT - CO/UT	0.961	94.98
CO	Craig	C2	2006	8672.31	999.61	41101830	Coal	Wet Limestone	0.049	0.40	SUB-CO	0.772	93.70
CO	Craig	C1	2006	7512.12	865.066	34560386	Coal	Wet Limestone	0.050	0.40	SUB-CO	0.772	93.52
VA	Clover Power Station	2	2006	8618.75	964.276	37638268	Coal	Wet Limestone	0.051	1.13	BIT - KY/VA	1.701	96.99
VA	Altavista Power Station	1	2006	7104	57.214	2156624	Coal	Dry Lime FGD	0.053	1.15	BIT - KY	1.376	96.14
VA	Altavista Power Station	2	2006	6989	54.949	2068876	Coal	Dry Lime FGD	0.053	1.15	BIT - KY	1.376	96.14
UT	Intermountain	1SGA	2006	8747.75	2229.48	83006107	Coal	Wet Limestone	0.054	0.61	BIT/SUB - WY/UT	1.196	95.51
NV	Reid Gardner	1	2006	7911.25	247.374	9088376	Coal	Sodium Based	0.054	0.67	BIT - CO/UT	0.961	94.33
UT	Intermountain	2SGA	2006	8014.25	2009.55	73285622	Coal	Wet Limestone	0.055	0.61	BIT/SUB - WY/UT	1.196	95.41
WV	Mount Storm Power Station	2	2006	8269	1190.99	42299329	Coal	Wet Limestone	0.056	1.82	BIT-MD/WV/PA	3.204	98.24
WV	Mount Storm Power Station	1	2006	7820.25	1067.33	37900743	Coal	Wet Limestone	0.056	1.82	BIT-MD/WV/PA	3.204	98.24
IN	Petersburg	1	2006	8019	518.75	17708186	Coal	Wet Limestone	0.059	3.08	BIT-IN	5.096	98.85
KS	Lawrence Energy Center	4	2006	7679.2	295.5	8974308	Coal	Wet Limestone	0.066	0.26	SUB-WY	0.580	88.65
WV	Harrison Power Station	2	2006	8165.38	1594.58	47950889	Coal	Wet Lime FGD	0.067	3.47	BIT - KY/WV/OH/PA	5.793	98.85
VA	Southampton Power Station	2	2006	6887.75	66.435	1982354	Coal	Dry Lime FGD	0.067	0.84	BIT - KY/WV	1.34	95.00
VA	Southampton Power Station	1	2006	6903.75	69.288	1994216	Coal	Dry Lime FGD	0.069	0.84	BIT - KY/WV	1.34	94.81
WV	Harrison Power Station	3	2006	6983.92	1519.14	40279866	Coal	Wet Lime FGD	0.075	3.47	BIT - KY/WV/OH/PA	5.793	98.70
CO	Rawhide Energy Station	101	2006	8383.52	942.744	24285618	Coal	Dry Lime FGD	0.078	0.24	SUB-WY	0.55	85.77

Note: SO_2 removal for Centralia units BW21 and BW22 not determined due to unavailable coal quality data for that facility.

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

Table 4-17 Top Performing Emission Units in Calendar Year 2007 Based on lb/MMBtu Emission Rates

State	Facility Name	Unit ID	Year	Operating Time	SO_2 (Tons)	Heat Input (MMBtu)	Fuel Type (Pimary)	SO_2 Control	Annual Average SO_2 (lb/MMBtu)	2007 Average Coal Sulfur Content (%)	Coal Type / Source State	Annual Inlet SO_2 Average (lb/MMBtu)	Annual Average SO_2 Removal (%)
WI	Pleasant Prairie	1	2007	7912	510.436	50518063	Coal	Wet Limestone	0.020	0.32	SUB-WY	0.751	97.3
NV	Reid Gardner	3	2007	6833.33	141.604	8126408	Coal	Sodium Based	0.035	0.53	BIT - CO/UT	0.865	96.0
NV	Reid Gardner	1	2007	6583.68	132.603	7345334	Coal	Sodium Based	0.036	0.53	BIT - CO/UT	0.865	95.8
VA	Altavista Power Station	1	2007	7558.25	40.638	2225231	Coal	Dry Lime FGD	0.037	0.772	BIT - VA/KY	1.207	97.0
VA	Altavista Power Station	2	2007	7414.25	39.308	2148592	Coal	Dry Lime FGD	0.037	0.772	BIT - VA/KY	1.207	97.0
WA	Centralia	BW21	2007	7884.69	934.265	50806435	Coal	Wet Limestone	0.037				
NV	Reid Gardner	2	2007	8157.26	188.967	9771674	Coal	Sodium Based	0.039	0.53	BIT - CO/UT	0.865	95.5
WV	Mitchell (WV)	2	2007	7106.79	1017.26	49157016	Coal	Wet Limestone (1/ 15/ 2007)	0.041	1.65	BIT-WV	3.284	98.7
AZ	Navajo Generating Station	2	2007	7800.68	1333.33	62605067	Coal	Wet Limestone	0.043	0.55	BIT - AZ	1.012	95.8
CO	Craig	C2	2007	7931.84	797.059	36782886	Coal	Wet Limestone	0.043	0.42	SUB-CO	0.827	94.8
NC	Asheville	1	2007	7170	240.604	10910350	Coal	Wet Lime FGD	0.044	1.028	BIT-KY/VA/WV	1.751	97.5
NC	Asheville	2	2007	7961	278.353	12585831	Coal	Wet Lime FGD	0.044	1.028	BIT-KY/VA/WV	1.751	97.5
VA	Clover Power Station	2	2007	8375.75	814.624	36710057	Coal	Wet Limestone	0.044	1.04	BIT - KY/VA	1.719	97.4
IA	Muscatine	9	2007	8120.61	300.266	13167281	Coal	Wet Limestone	0.046	0.572	SUB-WY	1.292	96.5
MI	Shiras	3	2007	7978.5	94.281	4133774	Coal	Dry Lime FGD	0.046	0.311	SUB-MT	0.667	93.2
AZ	Navajo Generating Station	1	2007	8353.93	1605.57	69467378	Coal	Wet Limestone	0.046	0.55	BIT - AZ	1.012	95.4
AZ	Navajo Generating Station	3	2007	8238.22	1497.91	64603853	Coal	Wet Limestone	0.046	0.55	BIT - AZ	1.012	95.4
VA	Clover Power Station	1	2007	8322.75	814.71	35026241	Coal	Wet Limestone	0.047	1.04	BIT - KY/VA	1.719	97.3
WV	Mountaineer (1301)	1	2007	7501.81	2301.85	95972918	Coal	Wet Limestone	0.048	3.24	BIT-KY/OH/WV	2.709	98.2
WA	Centralia	BW22	2007	7746.14	1193.09	49288934	Coal	Wet Limestone	0.048				
WV	Mount Storm Power Station	2	2007	7290.53	866.413	35006151	Coal	Wet Limestone	0.050	1.87	BIT-MD/WV/PA	3.088	98.4
WV	Mount Storm Power Station	1	2007	7149.82	836.066	33373503	Coal	Wet Limestone	0.050	1.87	BIT-MD/WV/PA	3.088	98.4
ND	Stanton	10	2007	8108.49	131.582	5238500	Coal	Dry Lime FGD	0.050	0.967	BIT/SUB-KY/PA/MT/	1.687	97.0
KS	Lawrence Energy Center	4	2007	8610.8	275.131	10561984	Coal	Wet Limestone	0.052	0.25	SUB-WY	0.571	90.9
CO	Craig	C1	2007	8604.01	1053.07	40119561	Coal	Wet Limestone	0.052	0.42	SUB-CO	0.827	93.7
SC	Cross	3	2007	8046.21	1069.58	39617006	Coal	Wet Limestone (1/8/2007)	0.054	1.64	BIT - KY/PA	2.406	97.8
WV	Harrison Power Station	2	2007	6827.83	1164.14	39368535	Coal	Wet Lime FGD	0.059	3.37	BIT-OH/PA/WV	5.182	98.9
VA	Southampton Power Station	1	2007	7768.27	75.023	2526561	Coal	Dry Lime FGD	0.059	0.849	BIT - KY/WV	1.376	95.7
WV	Mount Storm Power Station	3	2007	7000.04	1070.92	35915776	Coal	Wet Limestone	0.060	1.87	BIT-MD/WV/PA	3.088	98.1
VA	Southampton Power Station	2	2007	7392.95	70.81	2355970	Coal	Dry Lime FGD	0.060	0.849	BIT - KY/WV	1.376	95.6

Note: SO_2 removal for Centralia units BW21 and BW22 not determined due to unavailable coal quality data for that facility.

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Table 4-18 Monthly Average SO2 Emissions Values for Stanton Unit 10 and Pleasant Prairie Unit 1

Facility	Month	Average SO_2 Emissions (lb/MMBtu)
Stanton Unit 10 CY 2006 (Dry Scrubber)	January	0.026
	February	0.020
	March	0.008
	April	0.010
	May	0.024
	June	0.012
	July	0.010
	August	0.021
	September	0.010
	October	0.157
	November	0.081
	December	0.103
Pleasant Prairie Unit 1 CY 2007 (Wet Scrubber)	January	0.030
	February	0.023
	March	0.019
	April	0.021
	May	0.019
	June	0.016
	July	0.016
	August	0.025
	September	0.018
	October	0.021
	November	0.017
	December	0.017

Note: Values above rounded to three decimal places. The average of monthly averages indicated for Stanton Unit 10 are not equivalent to the annual average of 0.03 lb/MMBtu, due to the limited operation of the unit in September and October of 2006.

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Step 4 – Evaluate Remaining Control Technologies

Because of their demonstrated effectiveness for controlling SO_2 emissions at plants across the nation, wet scrubbing and dry scrubbing are evaluated as the top control options.

Energy Impacts

Energy penalties are much more significant for a wet scrubber than for a dry scrubber. With wet scrubbers, greater energy requirements exist due to greater system pressure drops and larger energy requirements for ancillary equipment, such as water recycling pumps and slurry dewatering pumps. Use of a wet scrubber can demand greater than 2 percent of the gross power generation of the facility, while dry scrubbers can demand typically around 1 percent of the gross

power generation of the facility. This approximately 1 percent difference in gross power demand does not preclude the use of a wet scrubber system at the facility.

Environmental Impacts

Wet scrubbers have an added collateral environmental benefit over dry scrubbers in that they are more effective in the capture of secondary acid gases in the flue gas exhaust stream than a dry scrubber, including reactive mercury, hydrogen chloride, and fluorides. Water consumption is an important environmental impact when evaluating wet scrubbers and dry scrubbers, since wet scrubbers have more significant water usage than dry scrubbers. However, dry scrubbers are not truly "dry," because water is used in preparation of the reagent slurry, which is atomized and injected into the exhaust gas stream.

Another significant environmental impact involves the generation of solid waste and wastewaters from wet scrubbers and dry scrubbers. Wastewater from a wet scrubber would require more specialized handling and treatment than a dry scrubber, since dry scrubber systems do not produce blowdown or a wastewater stream. Wet scrubbers can produce a solid waste stream (gypsum), which can be marketable depending on the quality of the gypsum produced and the status of the current market. Dry scrubbers produce a solid waste stream with little to no commercial value that is traditionally disposed of in a solid waste facility. Waste streams generated by a wet scrubber are inherently more saleable or recyclable than those waste streams generated by a dry scrubber. Dry scrubbers are not as efficient in use of adsorbent. A larger portion of the sorbent material can remain un-reacted, therefore generating more waste from the dry scrubber.

Economic Impacts

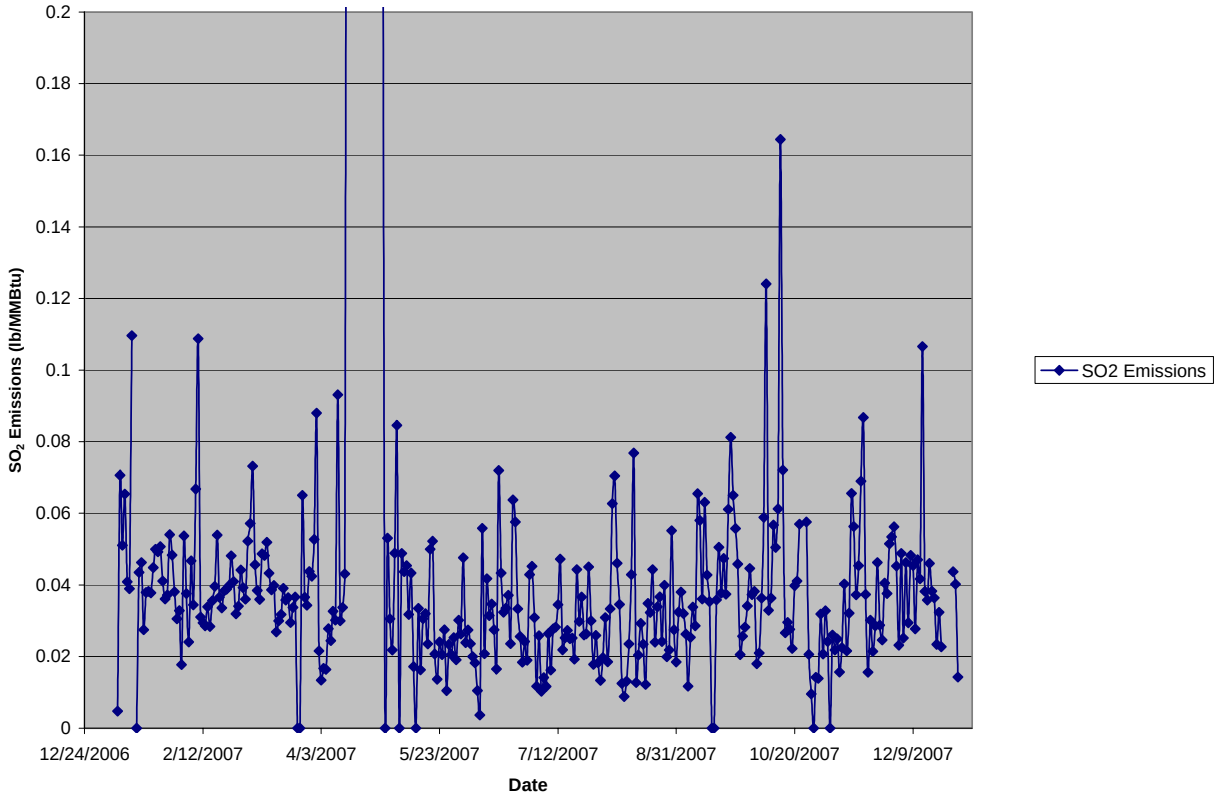
Based on data provided by USEPA in air emissions control cost guidance, and USEPA's Coal Utility Environmental Cost Model (CUECost), the installation and operation of a dry scrubber would cost less than the installation and operation of a wet scrubber. However, use of a wet scrubber would not be economically prohibitive for the facility.

Step 5 – Selection of BACT

Averaging Time Evaluation

Use of a wet scrubber was selected as the BACT in this analysis, in conjunction with coal selection and coal washing of bituminous (Illinois #6) coals. Having selected a wet scrubber as the control technology, vendor information, data from recently issued draft permits, and data for recently installed wet scrubbers were reviewed to determine the appropriate BACT emissions limit. The lowest proposed BACT emission limit to date for SO_2 emissions is 0.06 lb/MMBtu on a 24-hour basis, recently proposed by both the Toquop Energy Station and the Ely Energy Station in Nevada and the Desert Rock Energy facility in New Mexico. A review of 24-hour average emissions for some of the top performing units in calendar year 2007 indicated that emission limits this stringent on a 24-hour average basis may be difficult to achieve. Figure 4-10 is an illustration of the 24-hour average (daily) values for calendar year 2007 for the Altavista Power Station Unit 1 in Virginia, which had an annual average SO_2 emissions rate of 0.037 lb/MMBtu. Daily emissions indicated in the figure are the daily SO_2 emission rates reported to the USEPA Clean Air Markets Program.

Figure 4-10 Daily (24-hour Average) SO_2 Emission Rate Values for Altavista Power Station Unit 1 in Calendar Year 2007



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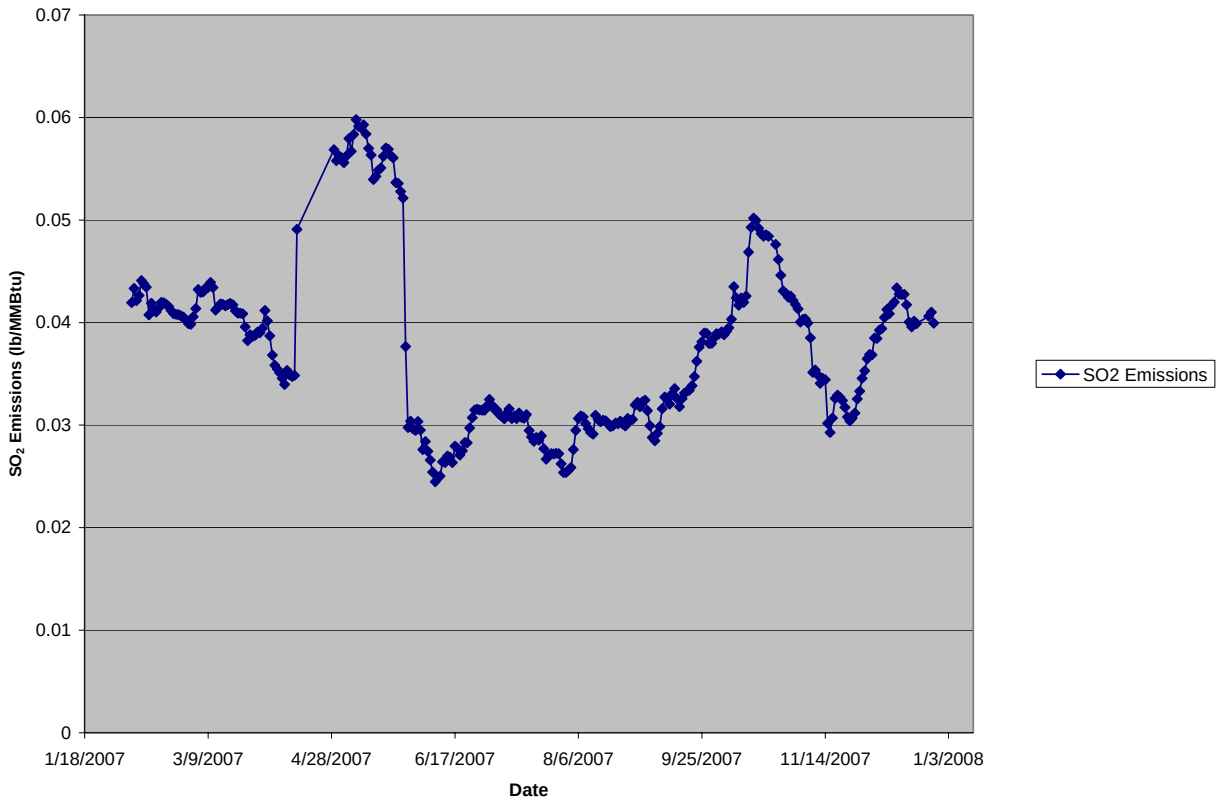
Although the Altavista Power Station achieved annual average SO_2 emissions of 0.037 lb/MMBtu, the facility would have experienced over 20 violations of a limitation of 0.06 lb/MMBtu on a 24-hour average (daily) basis. Therefore, emission limits on a 24-hour average basis would be extremely stringent and potentially difficult to achieve. This same unit, excluding a single 24-hour period with a reported average emission rate of 0.45 lb/MMBtu (likely due to an upset condition), would have had no violations with a limit of 0.06 lb/MMBtu on a 30-day rolling average basis. Figure 4-11 is an illustration of the 30-day rolling SO_2 emissions average for the Altavista Power Station Unit 1 in calendar year 2007. This figure includes a data point (0.45 lb/MMBtu) that is possibly due to an upset condition, which significantly affects the 30-day rolling average, producing values of approximately 0.06 lb/MMBtu.

Figure 4-11 30-Day Rolling Average SO2 Emission Rate Values for Altavista Power Station Unit 1 in Calendar Year 2007



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The 24-hour average (daily) and 30-day rolling average SO_2 emissions were also evaluated for the Mitchell Unit 2 facility in West Virginia. This facility had annual average SO_2 emissions of 0.041 lb/MMBtu. Although Mitchell Unit 2 achieved annual average SO_2 emissions of 0.041 lb/MMBtu, the facility would have experienced over 20 violations of a limitation of 0.06 lb/MMBtu on a 24-hour average (daily) basis. Therefore, this provides further support that an emission limit this stringent on a 24-hour average basis would be potentially difficult to achieve. This same unit would have had over 10 violations with a limit of 0.06 lb/MMBtu on a 30-day rolling average basis but the violations would be centered around true upset conditions, not just standard daily variations. Figures 4-12 and 4-13 are illustrations of the 24-hour and 30-day rolling average SO_2 emissions for calendar year 2007 for the Mitchell Unit 2 facility. Therefore, we conclude that appropriate averaging periods for an emission limit for this analysis is a 30-day rolling average or a 12-month rolling average. A more stringent emissions limit by making it based on a shorter averaging period (e.g. 24-hr) is unwarranted because the daily data contains too much

noise due to daily fluctuations resultant from system variation (both coal quality and scrubber effectiveness) to be able to consistently achieve compliance.

Figure 4-12 Daily (24-hour Average) SO_2 Emission Rate Values for Mitchell Unit 2 in Calendar Year 2007

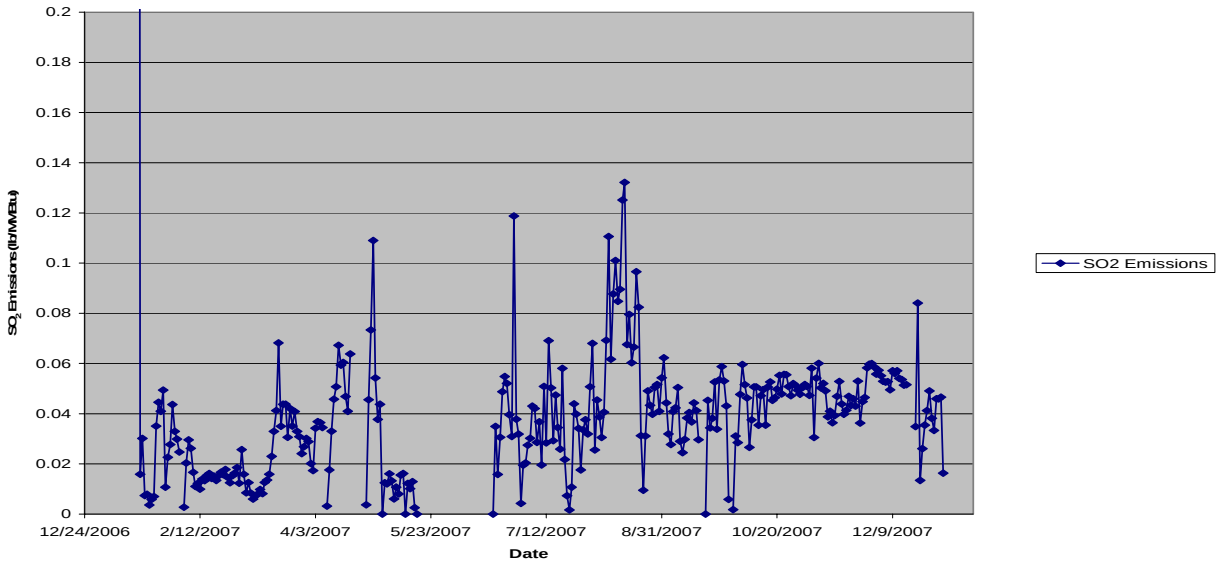

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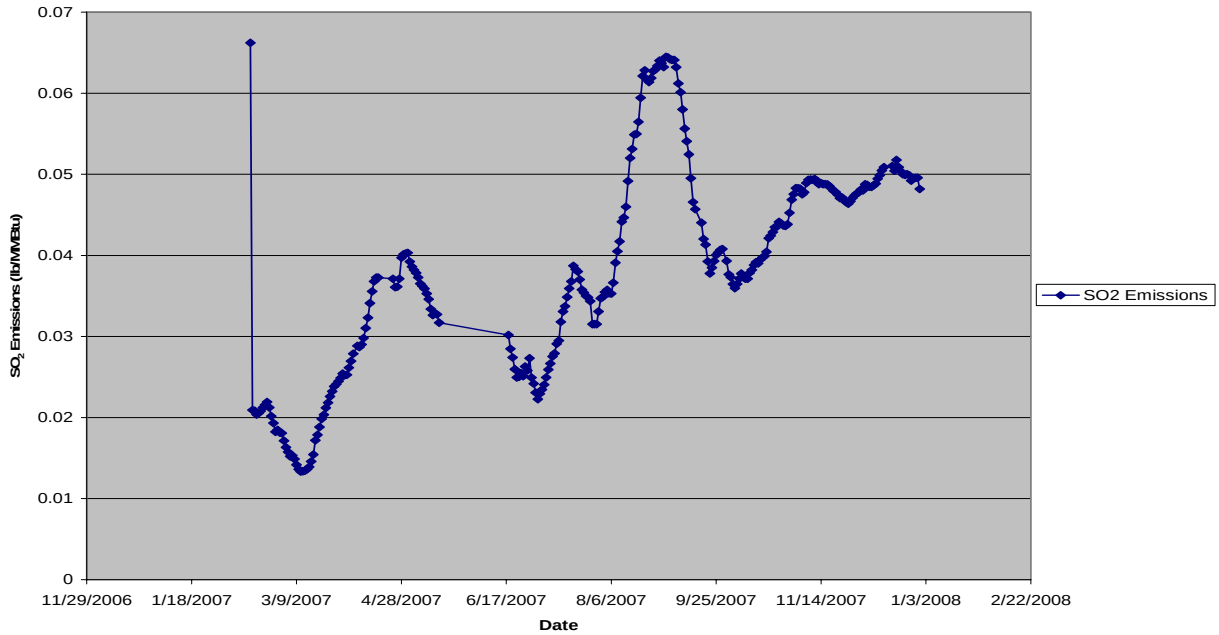
Figure 4-13 30-day Rolling Average SO_2 Emission Rate Values for Mitchell Unit 2 in Calendar Year 2007



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Establishment of BACT Level

A direct basis of comparison to Plant Washington is the Pleasant Prairie Unit 1 facility. This facility is using PRB coals with a sulfur content of approximately 0.32 percent, the same as the design PRB coals for the Plant Washington facility. Based on calendar year 2007 information in the USEPA Clean Air Markets Program database, this facility is achieving annual average emissions of 0.02 lb/MMBtu.

Pleasant Prairie Unit 1 is the only unit currently achieving emission limits this low based on calendar year 2007 emissions data. As indicated in Table 4-18, the next best performing unit in calendar year 2007 is Unit 3 at the Reid Gardner facility, with an annual average of 0.035 lb/MMBtu SO_2 emissions.

A concern in developing the BACT emission limit is the effective percent removal of a wet scrubber operating system on a consistent basis. To evaluate the proper removal efficiency to select for Plant Washington, emissions data from the USEPA Clean Air Markets website, as well as data from the Federal Energy Regulatory Commission (FERC) website, were reviewed to prepare an estimate of removal efficiencies from 154 utility boiler units using wet scrubbers and firing coal as their primary fuel source in calendar year 2007. Although the USEPA Clean Air Markets website contains a listing of 187 coal-fired utility units using a wet scrubber (either wet lime or wet limestone), only 154 of those units had available coal data from the FERC database to estimate uncontrolled SO_2 emissions, or had controlled SO_2 emissions expectant from use of a wet scrubber.

The units evaluated included reportedly high-performance units such as the Chiyoda CT121 scrubber unit installed at the Ohio Killen Station Unit 2, as well as the DCFS wet scrubber unit recently online at the Paradise Power (Fossil Plant) in Kentucky. System wide removal efficiencies for SO_2 emissions were estimated for 154 coal-fired boiler units operating in calendar year 2007. Selected units' long-term performance was then evaluated from calendar year 2003 to calendar year 2007. The units selected for evaluation in Table 4-19 were those wet scrubber units (of the 154 evaluated) that were determined to have an SO_2 removal efficiency of 95 percent or greater in calendar year 2007.

Table 4-20 indicates the estimated SO_2 removal efficiency for selected wet scrubber units for calendar years 2003 through 2007. The table illustrates that a facility's SO_2 removal efficiency performance can vary from year to year. Those units highlighted in Table 4-20 are those units that have an average SO_2 removal efficiency of 97.5 percent or greater for the annual data evaluated for that unit. Of 47 wet scrubber units identified in Table 4-19, only 11 of those units had an average SO_2 removal efficiency (for

those years data evaluated) of greater than 97.5 percent. Eight of the 11 units had an average SO_2 removal efficiency from 97.5 percent to 98 percent. The remaining three units—Mitchell Unit 2, Mountaineer Unit 1, and Petersburg Unit 1—had SO_2 removal efficiencies greater than 98 percent. However, the wet scrubbers on Mitchell Unit 2 and Mountaineer Unit 1 have only been online since 2007, so the long-term performance of these units is not yet known. This historic removal efficiency data evaluated indicate that 97.5 percent removal efficiency on an annual average should be considered minimum BACT performance.

Please note that several units, including data for facilities such as the Pleasant Prairie Unit 2 wet scrubber, and the Marshall Unit 3 wet scrubber, were not included in Table 4-19. This is due to the fact that those wet scrubbers did not come online at the facility until April 2007 or later, so inclusion of those wet scrubbers into the evaluation would not be an accurate basis of comparison to those units which operated for the entire calendar year in 2007.

Table 4-19 Wet Scrubber SO_2 Removal Efficiency Data from 2003 Through 2007

		FGD Efficiency (%)							
STATE	FACILITY_NAME	UNITID	2003	2004	2005	2006	2007	Average	Mimimum
AZ	Navajo Generating Station	1	96.17	95.88	96.0	96.44	95.45	95.98	95.45
AZ	Navajo Generating Station	2	96.28	96.57	96.6	95.60	95.75	96.17	95.60
AZ	Navajo Generating Station	3	95.84	94.99	94.9	95.60	95.45	95.36	94.93
UT	Intermountain	1SGA	96.11	95.52	95.79	95.5	94.87	95.56	94.87
UT	Intermountain	2SGA	95.99	95.29	96.05	95.4	94.87	95.52	94.87
NV	Reid Gardner	1		95.61	95.78	94.48	95.84	95.43	94.48
NV	Reid Gardner	2		95.61	94.92	94.69	95.49	95.18	94.69
NV	Reid Gardner	3		95.72	93.90	95.32	95.95	95.22	93.90
VA	Clover Power Station	1	96.09	95.67	96.77	97.18	97.27	96.60	95.67
VA	Clover Power Station	2	96.06	95.72	97.05	97.00	97.44	96.65	95.72
UT	Deseret Power Plant	1				94.71	95.16	94.94	94.71
NC	Asheville	1				97.56	97.49	97.52	97.49
NC	Asheville	2				97.57	97.49	97.53	97.49
WV	Mount Storm Power Station	1	94.92	96.83	98.12	98.25	98.38	97.30	94.92
WV	Mount Storm Power Station	2	94.73	96.81	98.07	98.25	98.40	97.25	94.73
WV	Mount Storm Power Station	3	95.95	97.95	98.15	98.66	98.07	97.76	95.95
KY	Trimble County	1	93.20	95.56	94.56	99.23	98.82	96.28	93.20
IN	Petersburg	1	96.36	98.00	98.70	98.84	98.55	98.09	96.36
IN	Petersburg	2	97.83	97.64	98.04	97.84	98.29	97.93	97.64
IN	Petersburg	3				92.01	96.38	94.20	92.01
SC	Cross	1	89.91	91.38	92.87	95.19	95.89	93.05	89.91
SC	Cross	3					97.76	97.76	97.76
TX	H W Pirkey Power Plant	1				95.05	96.86	95.95	95.05
TN	Cumberland	1	95.58	96.26	95.88	96.09	96.07	95.98	95.58
TN	Cumberland	2	95.37	95.48	95.25	95.74	95.72	95.51	95.25
IN	Merom	2SG1	92.63	90.45	90.00	92.59	94.96	92.13	90.00
IN	F B Culley Generating Station	2	90.16	93.23	92.18	92.28	95.01	92.57	90.16
IN	F B Culley Generating Station	3	93.95	96.63	96.45	95.92	96.12	95.81	93.95
WI	Pleasant Prairie	1				96.99	97.34	97.16	96.99
KY	Paradise	3				97.01	97.01	97.01	97.01
IN	Gibson	3				96.96	97.47	97.22	96.96
OH	Killen Station	2				95.99	95.89	95.94	95.89
IL	Duck Creek	1			90.09	92.79	95.47	92.78	90.09
KY	East Bend	2				96.37	97.38	96.87	96.37
NM	Four Corners Steam Elec Station	1			93.00	93.72	95.15	93.96	93.00
WV	Harrison Power Station	1	96.13	97.47	98.69	98.43	98.26	97.80	96.13
WV	Harrison Power Station	2	96.02	97.28	98.66	98.85	98.84	97.93	96.02
WV	Harrison Power Station	3	96.13	97.47	98.69	98.43	98.65	97.87	96.13
IL	Dallman	31	95.74	95.62	96.94	96.77	95.33	96.08	95.33
IL	Dallman	32	94.69	95.46	96.98	96.88	97.10	96.22	94.69
KY	Elmer Smith	1			90.90	96.32	95.85	94.36	90.90
KY	Elmer Smith	2			89.39	95.72	95.67	93.59	89.39
WV	Mitchell (WV)	2					98.78	98.78	98.78
WV	Mountaineer (1301)	1					98.15	98.15	98.15
IA	Muscatine	9	92.90	93.10	94.20	93.20	96.50	93.98	92.90
NC	Marshall	4					95.80	95.80	95.80
MI	Endicott	1	90.30	91.00	89.40	94.50	95.40	92.12	89.40

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Data for the 47 wet scrubber units listed in Table 4-19 were also evaluated to determine the SO_2 removal efficiency performance of those units combusting low-sulfur fuel, which for this evaluation was considered to be an uncontrolled SO_2 emission rate of 2.4 lb/MMBtu. The value selected of 2.4 lb/MMBtu was found to be the approximate "breakpoint" uncontrolled SO_2 emission rate at which pulverized coal fired units experienced approximately up to 97.5% removal efficiency (less than 2.4 lb/MMBtu) and greater than 97.5% removal (greater than 2.4 lb/MMBtu).

The SO_2 removal efficiency performance of those units with an uncontrolled SO_2 emissions rate of less than 2.4 lb/MMBtu (as determined from the FERC database) is shown in Figure 4-14. This figure demonstrates that 97.5 percent removal efficiency is BACT performance for combustion of low-sulfur coals (i.e., PRB and other low-sulfur coals with an uncontrolled SO_2 emission rate of 2.4 lb/MMBtu). Only two units with an identified uncontrolled SO_2 emission rate of less than 2.4 lb/MMBtu evaluated had an estimated SO_2 removal efficiency of greater than 97.5 percent. Those units, Asheville Unit 1 and Unit 2, had an estimated SO_2 removal efficiency in 2006 of just over 97.5 percent (97.56 percent Unit 1, 97.57 percent Unit 2).

Data for the wet scrubber units evaluated in Table 4-19 were also evaluated to determine the SO_2 removal efficiency of those units combusting fuel with an uncontrolled emission rate greater than 2.4 lb/MMBtu (as determined from the FERC database). Figure 4-15 is a graph of all facility emission units evaluated meeting this criteria, while Figure 4-16 is a graph of those emission units shown in Figure 4-15 with at least one year of data evaluated which indicated an SO_2 removal efficiency of greater than 98 percent. These figures demonstrate that 98.5 percent removal efficiency is BACT performance for combustion of high sulfur coals (i.e. Illinois #6 or other bituminous coals). Seven units identified had at least one year of data with an estimated SO_2 removal efficiency of greater than 98 percent. However, six of those seven units had at least one year of evaluated data with an estimated SO_2 removal efficiency of less than 98.5 percent. The seventh unit evaluated, Mitchell (WV) Unit 2, had an estimated SO_2 removal efficiency of approximately 98.8 percent for calendar year 2007. No further historic data for this unit was available as the unit came online in 2007. Therefore, the long term performance of this unit is still unknown. Although the Trimble County Unit 1 facility had an estimated SO_2 removal efficiency of greater than 99 percent for calendar year 2006, the estimated SO_2 removal efficiency of the unit decreased by approximately 0.4 percent in 2007 to 98.8 percent.

Figure 4-14 Wet Scrubber SO_2 Removal Efficiency Data for Calendar Years 2003 Through 2007 with Uncontrolled SO2 Emissions Rate Less Than 2.4 lb/MMBtu

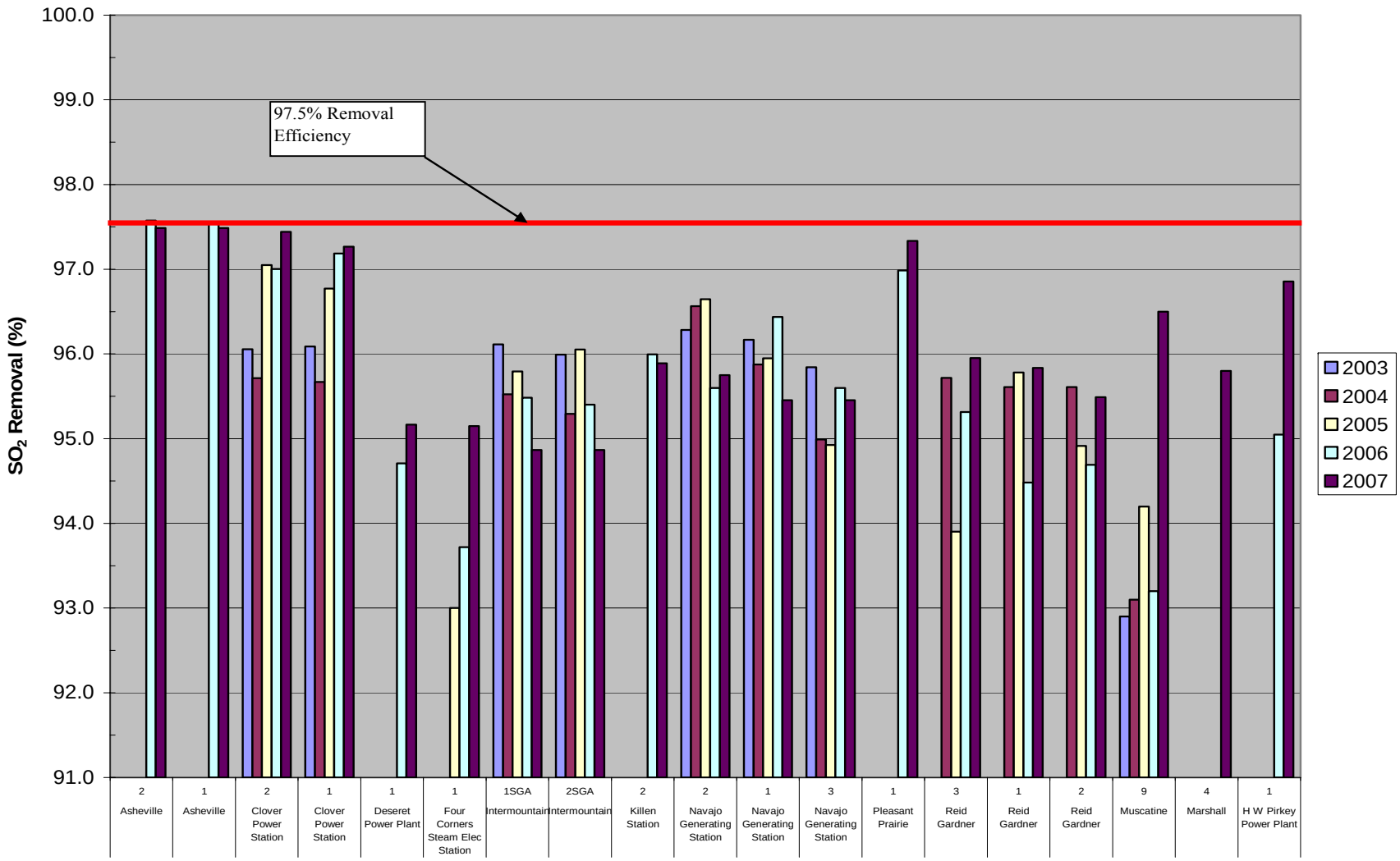

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Figure 4-15 Wet Scrubber SO_2 Removal Efficiency Data for Calendar Years 2003 Through 2007 with Uncontrolled SO2 Emissions Rate Greater Than 2.4 lb/MMBtu

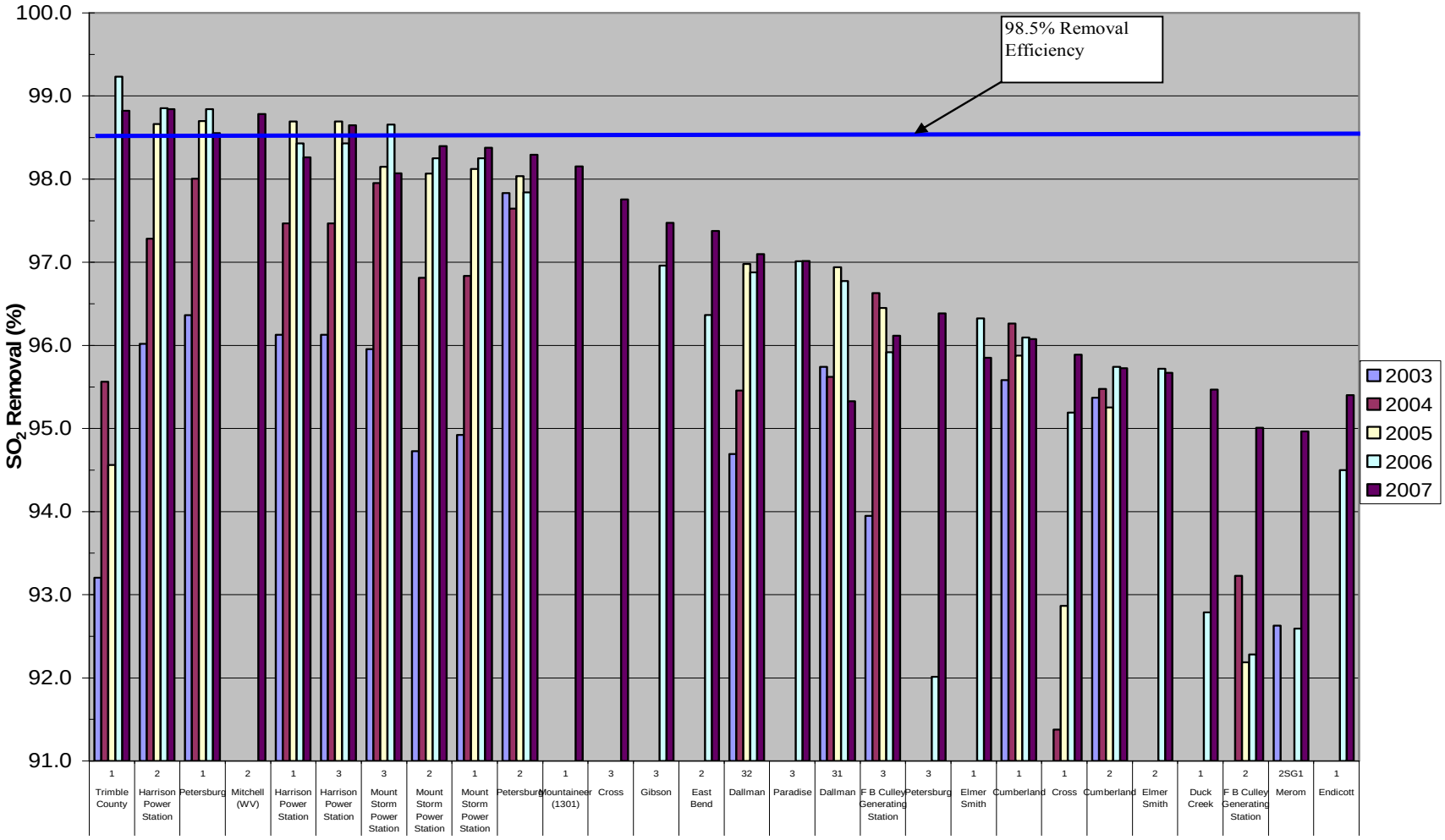

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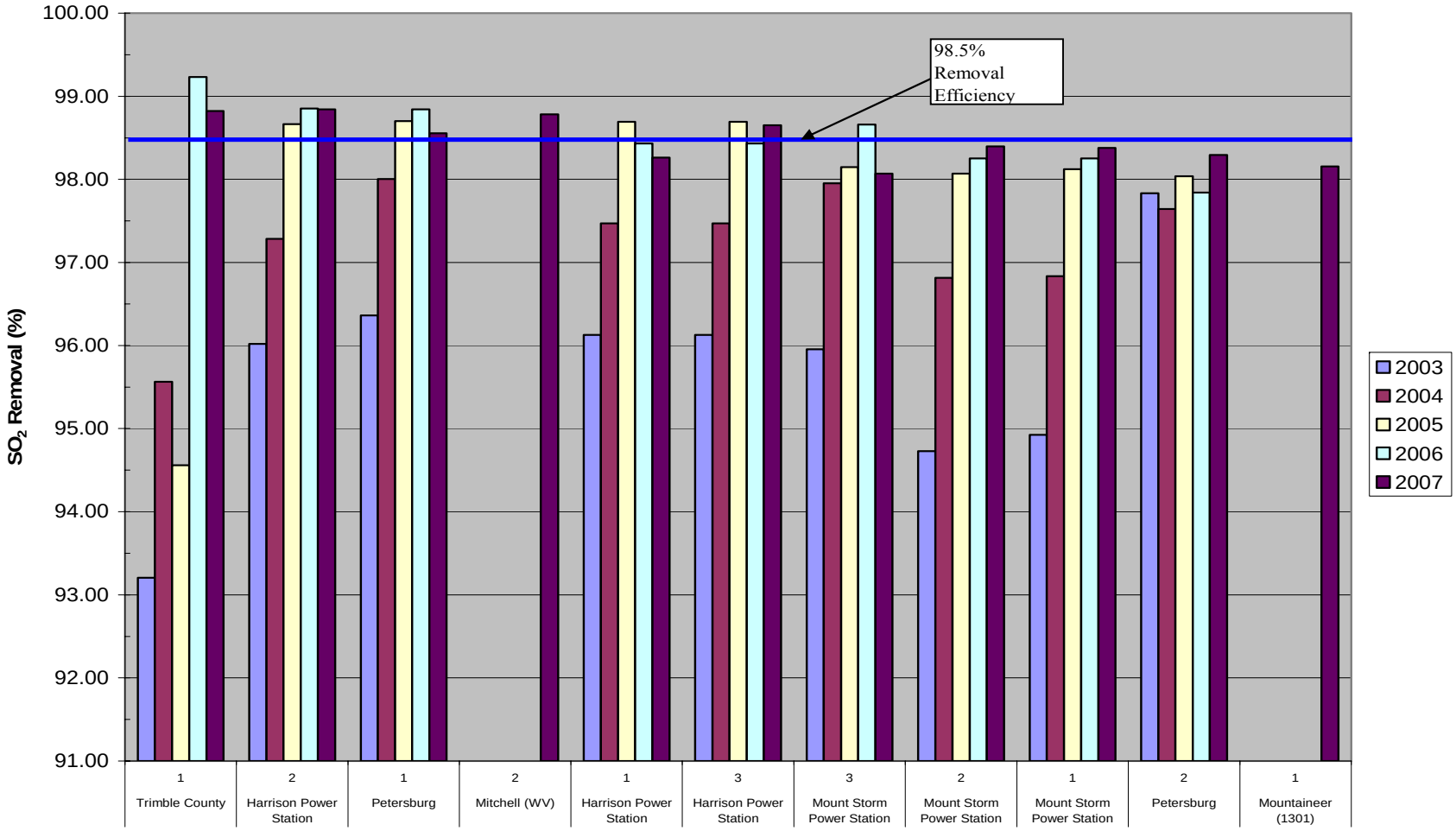
Figure 4-16 Wet Scrubber SO_2 Removal Efficiency Data for Calendar Years 2003 Through 2007 with Uncontrolled SO_2 Emissions Rate Greater Than 2.4 lb/MMBtu – High Performing Units (> 98% Removal For At Least One Year Evaluated)



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The minimum SO_2 collection efficiency of 98.5 percent determined to be BACT for the higher sulfur coals was used to calculate the proposed emissions from use of the 50/50 coal blend. Using an estimated removal efficiency of 98.5%, and a design coal basis for Plant Washington of 3.46 lb/MMBtu uncontrolled SO_2 emissions for an average blend sulfur content and 4.62 lb/MMBtu uncontrolled SO_2 emissions for an above average (high month) blend, long term and short term emission limits can be derived.

3.46 lb/MMBtu uncontrolled SO_2 * (1-.985) = 0.052 lb/MMBtu Annual Average

4.62 lb/MMBtu uncontrolled SO_2 * (1-.985) = 0.069 lb/MMBtu 30-Day Rolling Average

In comparison use of lower sulfur sub-bituminous coals (i.e. PRB) alone with a minimum removal efficiency of 97.5% and an average sulfur content of 1.0 lb/MMBtu and an above average (high month) level of 2.4 lb/MMBtu will have estimated emissions of the following;

2.4 lb/MMBtu uncontrolled SO_2 * (1-.975) = 0.06 lb/MMBtu

1.0 lb/MMBtu uncontrolled SO_2 (PRB) * (1-.975) = 0.025 lb/MMBtu

Emission limits derived for the Plant Washington facility need to account for the range of fuels that can be utilized in the boiler design for Plant Washington. Therefore, BACT for SO_2 emissions for Plant Washington is determined as use of a wet scrubber, with a **proposed BACT emission limit for SO_2 emissions of 0.052 lb/MMBtu on a 12-month rolling average, and with a proposed BACT emission limit of 0.069 lb/MMBtu on a 30-day rolling average basis. BACT is also proposed as a limit of 959 lb/hr on a 3-hour average, and a minimum scrubber removal efficiency of 97.5%.** The proposed 12-month rolling average BACT limit corresponds to an average coal blend and optimal scrubber conditions. The proposed 30-day rolling average BACT limit corresponds to an above average coal blend and optimal scrubber conditions. The proposed 3-hour average BACT limit corresponds to an above average coal blend and sub-optimal scrubber conditions with the scrubber operating at a minimum efficiency of 97.5% on a short term 3-hr average basis. The minimum removal efficiency of 97.5% will ensure that emissions of SO_2 during use of low sulfur coals will be effectively controlled.

The facility proposes to comply with the proposed BACT emission limits through use of inlet and outlet continuous emissions monitoring systems (CEMS) for SO_2. .

Three facilities—the Desert Rock, Toquop, and Ely Energy Station facilities—have proposed SO_2 emissions limits of 0.06 lb/MMBtu on a 24-hour average basis. However, as discussed above, operational data from high-performance SO_2 control units indicate that there can be significant variability in monitored concentrations on a 24-hour average basis. Therefore, an emissions limit averaging period of a 30-day rolling average has been chosen.

Table 4-20 provides a listing of SO_2 emissions limit determined through BACT analysis gathered from the USEPA RBLC database and a review of recently issued draft permits. Both the Longleaf Energy Station and the Hugo Generating Station have proposed lower SO_2 emission limits on a 30-day rolling average basis. However, the Longleaf permit was based on a tiered approach, with a limit of 0.065 lb/MMBtu on a 30-day rolling average under certain conditions, but a limit of 0.08 or 0.105 lb/MMBtu on a 30-day rolling average under other conditions. Therefore, a direct comparison to only the lower tier of the Longleaf permit is not a valid basis of comparison.

Also, according to permit information for the Hugo Generating Station, this facility will only utilize sub-bituminous PRB coals of lower sulfur content and will not utilize bituminous coals. Therefore, a direct comparison to a singular emission limit chosen for Plant Washington is not valid since Plant Washington will utilize both sub-bituminous and bituminous coals at the facility. This is also true for the Toquop and Ely Energy Station which have indicated use of PRB coals only. The Desert Rock facility will utilize coal from a nearby mining facility, the BHP Billiton New Mexico coal mine, which is a low sulfur blended coal that will be delivered to the facility by conveyor. Therefore, the emission limits derived for these facilities are not a direct basis of comparison to Plant Washington as they will only utilize sub-bituminous coals.

Table 4-20 RBLC And Draft Permit Listings for SO2 Emissions from Pulverized Coal-fired Boilers

Facility Name	Facility State	Permit Number	Permit Date	PROCESS NAME	Thruput (MW)	Control Description	Emission Limit		Avg Period
ELY ENERGY STATION	NV		2007	SUPERCRITICAL BOILER	2-750	WET LIMESTONE SCRUBBER	0.06	lb/MMBtu	24-hour avg
TOQUOP	NV	ap4911-1146		SCPC BOILER	750	WET LIMESTONE SCRUBBER	0.06	lb/MMBtu	24-hour avg
DESERT ROCK	NM	DRAFT	7/1/2006	(2) 750 MW PC BOILERS	750	HYDRATED LIME INJECTION AND WET LIMESTONE DESULFURISATION	0.06	lb/MMBtu	24-hour avg
HUGO GENERATING STATION	OK	97-058-C M-2 PSD	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	750	WET LIMESTONE FLUE GAS DESULFURIZATION	0.065	lb/MMBtu	30-day rolling average
LONGLEAF	GA	4911-099-0030-P 01-0	5/14/07	BOILER #1	600	DRY SCRUBBER	0.065	lb/MMBtu	30-day rolling average
DRY FORK STATION	WY	CT-4631	10/15/07	PC BOILER (ES1-01)	385	CIRCULATING DRY SCRUBBER	0.07	lb/MMBtu	12 month rolling
LONGLEAF	GA	4911-099-0030-P 01-0	5/14/07	BOILER #2	600	DRY SCRUBBER	0.12	lb/MMBtu	24-hr average
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 2	850	KCPL SHALL INSTALL SCR UNIT FOR THE UNIT 2 BOILER TO REDUCE NOX EMISSIONS AND ALSO SHALL INSTALL WET SCRUBBER TO REDUCE SOX EMISSIONS. BOTH CONTROLS ARE NOT BACT FOR NOX AND SOX	0.09	lb/MMBtu	30-day rolling average
TS POWER PLANT	NV	AP4911-1349	5/5/2005	200 MW PC COAL BOILER	200	LIME SPRAY SPRAY DRY SCRUBBER	0.09	lb/MMBtu	24-hour rolling
WYGEN 3	WY	CT-4517	2/5/2007	PC BOILER	100	DRY FGD	0.09	lb/MMBtu	12 month rolling
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	MO	122004-007	12/15/2004	PULVERIZED COAL FIRED BOILER	275	DRY FLUE GAS DESULFURIZATION > 90%	0.095	lb/MMBtu	30-day rolling average
OPPD - NEBRASKA CITY STATION	NE	58343C01	3/9/2005	UNIT 2 BOILER	660	DRY FLUE GAS DESULFURIZATION & FABRIC FILTER	0.095	lb/MMBtu	30-day rolling average
INTERMOUNTAIN POWER STATION UNIT 3	UT	DAQE-AN0327010-04	10/15/04	PC BOILER	950	WET LIMESTONE SCRUBBER	0.1	lb/MMBtu	30-day rolling average
BIG CAJUN II POWER PLANT	LA	PSD-LA-677	8/22/2005	NEW 705 MW PULVERIZED COAL BOILER (UNIT 4)	705	OPTION 1: SEMI-DRY LIME SCRUBBER OPTION 2: WET FLUE GAS DESULFURIZATION SYSTEM	0.100	lb/MMBtu	30-day rolling average
JK SPRUCE ELECTRIC GENERATING STATION	TX	PSD-TX 1037 & 70492	12/28/05	UNIT 2 BOILER	750	WET LIMESTONE SCRUBBER	0.1	lb/MMBtu	Annual average
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 1	850		0.070	lb/MMBtu	30-day rolling average
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	750	LIME SPRAY DRYER FLUE GAS DESULFURIZATION	0.100	lb/MMBtu	30-day rolling average
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	500	DRY FGD, LIMIT ON EMISSIONS ENTERING CONTROL SYSTEM: 1.23 LBS/MMBTU 30 DAY AVG.	0.100	lb/MMBtu	30-day rolling average
WYGEN 2	WY	CT-3030	9/25/2002	BOILER, 100 MW PC	100	SEMI-DRY LIME SPRAY DRYER ABSORBER	0.100	lb/MMBtu	30-day rolling average
AGP SOY PROCESSING	NE	CP05-0050	9/11/2006	STEAM GENERATION	382 mmbtu	LIMESTONE INJECTION	0.11	lb/MMBtu	

Table 4-20 RBLC and Draft Permit Listings for SO_2 Emissions from Pulverized Coal-fired Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	PROCESS NAME	Thruput (MW)	Control Description	Emission Limit		Avg Period
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 1	390	DRY FLUE GAS DESULFURIZATION (FGD)	0.12	lb/MMBtu	30-day rolling average
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 2	390	DRY FLUE GAS DESULFURIZATION (FGD)	0.12	lb/MMBtu	30-day rolling average
HOLCOMB UNIT #2	KS	0550087/C-3855	10/8/2002	BOILER, PULVERIZED COAL	700	DRY FLUE GAS DESULFURIZATION	0.12	lb/MMBtu	30-day rolling average
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATION	MO	888	8/17/1999	ELECTRIC GENERATION, BOILER, COAL	384 T/H	DRY FLUE GAS DESULFURIZATION & LOW SULFUR COAL. EMISSION LIMIT BASIS - 30-DAY AVG.	0.12	lb/MMBtu	30-day rolling average
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	600	WET LIMESTONE FORCED OXIDATION	0.12	lb/MMBtu	24-hr rolling average
SCHILLER STATION	NH	TP-B-0501	10/25/2004	BOILER, COAL FIRED, UNIT #5	635 mmbtu	LIME INJECTION, FUEL SULFUR LIMITS	0.12	lb/MMBtu	24-hour average
WHELAN ENERGY CENTER	NE	58048	3/30/2004	BOILER, UNIT 2 UTILITY	220	SPRAY DRYER ABSORBER (SDA)	0.12	lb/MMBtu	30-day rolling average
SANTEE COOPER CROSS	SC	0420-0030-CI	2/5/04	BOILER #3	660	WET LIMESTONE SCRUBBER	0.13	lb/MMBtu	Annual average
SANTEE COOPER CROSS	SC	0420-0030-CI	2/5/04	BOILER #4	660	WET LIMESTONE SCRUBBER	0.13	lb/MMBtu	Annual average
AES BEAVER VALLEY, LLC	PA	PA-04-446C	11/21/2001	COAL FIRED BOILER	2155 mmbtu	HYDRATED ASH RE-INJECTION SYSTEM	0.14	lb/MMBtu	12-month rolling average
HARDIN GENERATOR PROJECT	MT	3185-00	6/11/2002	BOILER, PULVERIZED COAL-FIRED	116	WET VENTURI SCRUBBER	0.11	lb/MMBtu	30-day rolling average
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	600	WET LIMESTONE FORCED OXIDATION	0.15	lb/MMBtu	3-hour average
AMERICAN MUNICIPAL POWER GENERATING STATION			2/7/2008	BOILER (2), PULVERIZED COAL FIRED	5191 mmbtu	FLUE GAS DESULFURIZATION (FGS) EITHER LIME OR AMMONIA-BASED	0.15	lb/MMBtu	30-day rolling average
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER , UNIT 1 - SN-01	665	DRY FLUE GAS DESULFURIZATION	0.16	lb/MMBtu	3-hour rolling average
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	BOILER - SN-01	665	DRY FLUE GAS DESULFURIZATION	0.16	lb/MMBtu	3-hour rolling average
VIRGINIA TECH	VA	20124	9/15/2005	OPERATION OF BOILER 11	146.7 mmbtu	DRY SCRUBBER FLUE GAS DESULFURIZATION SYSTEM AND CEMS	0.161	lb/MMBtu	30-day rolling average
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	BOILER, COAL, (2)	2-750	WET FLUE GAS DESULFURIZATION (FGD), WESP, AND PROPER BOILER DESIGN	0.167	lb/MMBtu	30-day rolling average
AMERICAN MUNICIPAL POWER GENERATING STATION		06-08138	2/7/2008	BOILER (2), PULVERIZED COAL FIRED	5191 mmbtu	FLUE GAS DESULFURIZATION (FGS) EITHER LIME OR AMMONIA-BASED	0.184	lb/MMBtu	24-hr rolling average
ENCOAL CORPORATION-ENCOAL NORTH ROCHELLE FACILITY	WY	CT-1324	10/10/1997	BOILER, COAL FIRED, MAIN STACK	240	LIME SPRAY DRYER	0.200	lb/MMBtu	2-hour fixed
JEA NORTHSIDE GENERATING STATION	FL	PSD-FL-265	7/14/1999	BOILER, COAL	2764 mmbtu	PROPOSED CONTROLS: CIRC. FLUIDIZED BED SCRUBBER/ELECTROSTATIC PREC. OR SPRAY DRYER ABSORBER/FABRIC FILTER OR CIRC. FLUIDIZED BED SCRUBBER/FABRIC FILTER.	0.200	lb/MMBtu	24-hour average

Table 4-20 RBLC and Draft Permit Listings for SO_2 Emissions from Pulverized Coal-fired Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	PROCESS NAME	Thruput (MW)	Control Description	Emission Limit		Avg Period
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	BOILER, STEAM ELECTRIC POWER GENERATING	250	LIME SPRAY DRY SCRUBBER	0.200	lb/MMBtu	2-hour fixed
ORION POWER MIDWEST LP	PA	37-00023	4/8/1999	BOILERS, COAL (3)	1029 mmbtu		0.230	lb/MMBtu	
AMERICAN MUNICIPAL POWER GENERATING STATION	OH	06-08138	2/7/2008	BOILER (2), PULVERIZED COAL FIRED	5191 mmbtu	FLUE GAS DESULFURIZATION (FGS) EITHER LIME OR AMMONIA-BASED	0.240	lb/MMBtu	3-hour average
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED COAL BOILER	800		0.30	lb/MMBtu	1-hour average
EDISON MISSION ENERGY	PA	32-0055C	5/25/1999	BOILER, COAL, PULVERIZED BITUMINOUS, UNIT 3	6600 mmbtu	WET LIMESTONE SCRUBBER	0.40	lb/MMBtu	
THERMAL VENTURES	VA	30529	2/15/2002	BOILER, STEAM	120 mmbtu	GOOD COMBUSTION PRACTICES, CLEAN BURNING FUEL, AND CONTINUOUS EMISSION MONITORING DEVICE.	0.47	lb/MMBtu	unknown
SANTEE COOPER CROSS	SC	0420-0030-CI	2/5/04	BOILER #3	660	WET LIMESTONE SCRUBBER	0.6	lb/MMBtu	30-day rolling average
SANTEE COOPER CROSS	SC	0420-0030-CI	2/5/04	BOILER #4	660	WET LIMESTONE SCRUBBER	0.6	lb/MMBtu	30-day rolling average
ARCHER DANIELS MIDLAND COMPANY	IL	97070097	12/24/1998	BOILER (9&10), FLUIDIZED BED	1500 mmbtu	LIMESTONE INJECTION INTO FLUIDIZED BED, FOLLOWED BY FABRIC FILTER PM CONTROL.	0.70	lb/MMBtu	
LIMESTONE ELECTRIC GENERATING STATION			5/23/2001	(2) BOILER UNIT 1 & 2 SCRUBBER STACKS, LMS1 & 2	7863 mmbtu	WET LIMESTONE FLUE GAS DESULFURIZATION	0.82	lb/MMBtu	24-hr rolling average
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	7400 mmbtu	FUEL S CONTENT LIMITED	1.06	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	7400 mmbtu	BURN LOW-S SUBBITUMINOUS COAL	1.07	lb/MMBtu	unknown
LIMESTONE ELECTRIC GENERATING STATION	TX	PSD-TX-371 (M3)	5/23/2001	(2) BOILER UNIT 1 & 2 SCRUBBER STACKS, LMS1 & 2	7863 mmbtu	WET LIMESTONE FLUE GAS DESULFURIZATION	1.14	lb/MMBtu	3-hr rolling average
OTTUMWA GENERATING STATION	IA	78-A-019P-S8	2/27/2007	BOILER #1	6370 mmbtu	LOW SULFUR COAL	1.20	lb/MMBtu	3-hr rolling average
MANSFIELD MILL	LA	PSD-LA-93 (M-6)	8/14/2001	POWER BOILER #1 & #2, COAL	645 mmbtu	SULFUR IN COAL NOT TO EXCEED 1.2% BY WEIGHT	1.20	lb/MMBtu	unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL, WAP7	6700 mmbtu	LIMITED FUEL S CONTENT	1.20	lb/MMBtu	unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	6700 mmbtu	FUEL S CONTENT LIMITED	1.20	lb/MMBtu	unknown
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	7400 mmbtu	FUEL S CONTENT LIMITED	1.20	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	6700 mmbtu	BURN LOW-S SUBBITUMINOUS COAL	1.20	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	6700 mmbtu	BURN LOW-S SUBBITUMINOUS COAL	1.20	lb/MMBtu	unknown
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	6750 mmbtu	NONE INDICATED	1.20	lb/MMBtu	unknown

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

4.3.6 BACT Demonstration for Fluoride Emissions from the Supercritical Pulverized Coal Boiler

Emissions of fluoride are generated in fossil fuel-fired sources from oxidation of fluorine in the fuel source. Fluoride is emitted predominantly in the gaseous form of hydrogen fluoride (HF). Hydrogen fluoride can be controlled by the same technologies available for SO_2 emissions.

Step 1 – Identify All Control Technologies

Lower-emitting Process or Practice – Coal Cleaning

Coal cleaning, also called "coal beneficiation" or "coal washing," is a cleaning process in which mineral ash matter is removed from mined coal to produce a "cleaner" coal. Coal cleaning is generally performed to remove impurities and improve the coal's heat content, thereby improving power plant capacity, reducing maintenance costs at power plants, and extending plant life. Coal cleaning could potentially reduce the levels of fluorine in the coal, thereby reducing the amount of fluorine available to form HF during the combustion process.

Wet Scrubber

Wet scrubber systems are often used as flue gas desulfurization (FGD) systems, where the wet scrubbers are used to control emissions of SO_2 from oil and coal combustion sources from industrial sources and electrical utilities. Wet scrubbers can also be used in the control of HF emissions. The HF is removed from the flue gas by sorption and reaction with the reagent slurry used in the wet scrubber. The reagents commonly used include lime and limestone. Additives, such as magnesium, can be added to the reagent materials to further improve the reaction of the reagent with the HF in the gas stream. The byproducts of the wet scrubber are in a wet slurry form and must be dewatered prior to handling and further disposal. Wastewaters generated through the wet scrubbing process may also require some level of treatment.

Spray Dryer Absorber (SDA)

In an SDA, or spray dryer, a fine spray of reagent slurry is atomized and comes into contact with the hot exhaust gas, or flue gas. Lime is the typical reagent used in an SDA unit. A significant part of the acidic components of the flue gas, including HF, is rapidly absorbed into the alkaline droplets, with the water/moisture content evaporated simultaneously. Control of exhaust gas distribution, slurry flow rate, and spray droplet size ensures that the droplets introduced into the gas stream are effectively dried to a fine powder before touching the chamber walls of the spray dryer unit or exiting the spray dryer system. A portion of the reacted product is collected and discharged from the spray dryer absorber. The treated flue gas is then discharged to a fabric filter baghouse, or other PM control device, where additional reacted product is collected from the exhaust gas stream.

Circulating Dry Scrubber (CDS)

A CDS is similar in concept and reaction chemistry to an SDA. In a CDS system, a circulating fluidized bed arrangement is used for contacting the sorbent reagent, lime, with the HF in the flue exhaust gas. As with a spray dryer absorber, the reaction products exit the system in a dry form and are collected downstream in a fabric filter baghouse or other PM control device. The advantage of a CDS over SDA is the more efficient use of the alkaline slurry injected into the stream because it improves the use of the reagent, making it more economical.

Sorbent Injection

One potential control technology is the use of sorbent injection, in which a reagent, such as limestone, is injected into the ductwork between the air heater and particulate collection device. Sorbent injection is discussed in more detail in Section 4.3.7.

Step 2 – Eliminate Technically Infeasible Options

Lower-emitting Process or Practice – Coal Cleaning

No evidence was found that coal cleaning would reduce the fluorine content present in coal. Generally fluorine is thought to be associated with clay minerals in the coal and its content does not correlate with ash yield, total sulfur, pyritic sulfur, or other trace elements. Therefore, it is not

expected that fluorine would be removed through standard coal cleaning methods such as coal washing. Therefore, coal cleaning will no longer be considered for this analysis. However, Illinois #6 coals purchased by the facility will be washed prior to shipment to Plant Washington.

Wet Scrubber

Wet scrubbers have been installed and operated on PC-fired boiler units. Therefore, wet scrubbers are considered technically feasible for this project.

Spray Dryer Absorber (Dry Scrubber)

Dry scrubbers have been installed and operated successfully on PC-fired boiler units. Therefore, dry scrubbers are considered technically feasible for this project.

Circulating Dry Scrubber

Circulating dry scrubbers have not yet been demonstrated on a coal-fired boiler greater than 400 MW. The size and scale differences between the proposed utility boiler and the boilers on which this technology has been demonstrated would likely lead to the requirement for further design, research, and testing for assessing viability on such a large-scale unit. Circulating fluidized bed systems, as with a circulating fluidized bed boiler, are not in use at the size and scale of this proposed utility boiler. Therefore, circulating dry scrubber systems are not considered available for this project and are considered technically infeasible for this analysis.

Sorbent Injection

Although there is limited evidence that sorbent injection would be effective at the removal of hydrogen fluoride (HF) emissions from the exhaust gas stream, sorbent injection is considered technically feasible for this analysis.

Step 3 – Rank Remaining Technically Feasible Control Options

Control Effectiveness

The feasible control technologies found during Step 2 of this analysis include wet scrubbers, sorbent injection, and spray dryer absorbers (dry scrubbers). Technical publications, the USEPA RBLC, and vendor information were reviewed to determine the control efficiencies of each of these identified technically feasible HF reduction technologies. There are not many instances where the performance of control technologies for HF emissions control has been evaluated, and data regarding the effectiveness of differing control technologies are limited. A review of data from the RBLC database includes a variety of controls deemed applicable historically for BACT for HF emissions from coal-fired boilers, including use of dry scrubbers, wet scrubbers, and sorbent injection with a fabric filter baghouse. Based on information from experienced power plant design engineers the estimated removal efficiency for HF from the wet scrubber design for Plant Washington is 98.5%.

Step 4 – Evaluate Remaining Control Technologies

As stated above in Step 3, there are not many instances where the performance of control technologies for HF emissions control has been evaluated, and data regarding the effectiveness of differing control technologies are limited. A review of data from the RBLC database includes a variety of controls deemed applicable historically for BACT for coal-fired boilers.

Therefore, for the above-listed reasons, use of a wet scrubber was chosen as the top option for control of HF emissions. Use of a baghouse system (for PM control) should provide some additional control of HF emissions. Since the use of sorbent injection has been determined as BACT for control of H_2SO_4 emissions, there will be co-benefit control of HF emissions through use of the sorbent injection system.

A wet scrubber was already selected as BACT for control of SO_2 in Section 4.3.5. As discussed in that section no energy, environmental, or economic impacts would preclude the use of a wet scrubber at Plant Washington.

Step 5 – Selection of BACT

BACT for emissions of HF is determined to be use of a wet scrubber. Coal analysis data obtained for PRB and Illinois coals from the USGS COALQUAL database were reviewed to determine the 90 percent confidence level values for fluorine. The 90 percent confidence level value for PRB coal was approximately 181 ppm, and for the 50/50 coal blend the 90 percent confidence level concentration was approximately 152 ppm. The COALQUAL database provided a limited data set for Illinois basin coals.

Based on data provided by experienced power plant design engineers, and an evaluation of available research data regarding control of the acid gas HF, the removal efficiency for acid gases with use of a wet scrubber was determined to be 98.5 percent.

Based on this removal efficiency, the proposed maximum emissions for fluorides (as HF) are estimated as 2.68×10^{-4} lb/MMBtu for use of 100 percent PRB, and estimated as 2.13×10^{-4} lb/MMBtu for use of the 50/50 coal blend. Due to the similarity in these numbers, and the similarity in the expected fluorine concentration in bituminous and sub-bituminous coals used at the facility, a singular limit of 2.68×10^{-4} lb/MMBtu is chosen to encompass use of the potential fuels used at Plant Washington.

Therefore, BACT for Plant Washington for fluorides (as HF) is proposed as use of a wet scrubber with an emissions limit of 2.68×10^{-4} lb/MMBtu on a 3-hr average (stack test). The proposed 3-hour average emission limit is based on the 90 percent confidence level ppm concentration value derived for PRB coals. The 90 percent confidence level was chosen for establishment of a short-term limit because on a given day when a stack test will be conducted, the fluorine concentration in the coal would be unknown. Also, no contracts have been established for coal acquisition, so the mines from which the facility will purchase coal are unknown, thereby requiring an additional margin of safety when evaluating a short-term interval test. The proposed emission limits are based on ppm concentration values as derived from the USGS COALQUAL database for PRB coals.

These emission limits are believed to be the maximum achievable levels for emissions of HF from Plant Washington when factoring in the ppm concentration data for coals planned for use at the Plant Washington facility, as well as the maximum degree of reduction (98.5 percent) believed achievable for emissions of HF. Compliance with the proposed 3-hour average limits

will be demonstrated through stack testing using USEPA Method 26, with ongoing compliance determined through use of surrogate monitoring of the operating pH of the wet scrubber.

A summary of recent HF BACT evaluations conducted for similar projects is in Table 4-21. Several facilities, including the Thoroughbred Generating Station, the Maidsville Station, and the WPS Weston Plant indicated BACT emission limits less than those proposed for Plant Washington. The design coal data for these facilities were not able to be obtained for review. The achievable emissions of HF are directly related to the concentration of fluorine in the coals to be combusted at a facility. Those facilities may have planned to use coals with lower estimated fluorine content than those coals proposed for Plant Washington. Also, the heating value of the coal planned for use at the facility (Btu/lb) can also influence the emission factor chosen. For a coal of equal ppm concentration, higher emissions on a lb/MMBtu basis would be expected from a coal with a lower heating value when being used in a boiler firing at a consistent heat rate. Therefore, facilities with lower BACT limits for fluorides (as HF) indicated in Table 4-21 may also be firing coal with a higher heating value (Btu/lb) than the coals (PRB and 50/50 coal blend) planned for use at Plant Washington.

The facilities in question may have also derived the facility emission limits based on AP-42, Table 1-1-15. Table 1.1-15 provides an emission rate for HF of 0.15 lb/ton coal combusted. A footnote for the table indicates that the factor applies to both uncontrolled and controlled sources, was developed from use of bituminous coals, sub-bituminous coals, and lignite. The same emission factor of 0.15 lb/ton is indicated for all types of boilers indicated in the Table (wet bottom, cyclone, etc.). Using PRB coal as an example, the higher heating value of PRB design coal for Plant Washington is 8,500 Btu/lb. Using this value, and the maximum heat rate of the main boiler of 8,300 MMBtu/hr for Plant Washington, the maximum coal firing rate would be approximately 488 ton/hr.

Using the value of 488 ton/hr, with an emission rate for HF of 0.15 lb/ton of coal, would give an emission rate of 73.2 lb/hr. Assuming this rate is an uncontrolled emission rate, and applying a control efficiency of 98.5%, would give a controlled emission rate for HF of 1.1 lb/hr. This emission rate, on a lb/MMBtu basis (based on 8,300 MMBtu/hr), would be approximately 1.3 x 10^{-4} lb/MMBtu. Therefore, those emission limits lower than Plant Washington identified in Table 4-21 may have been derived in this fashion. However, the methodology used for development of

emission factors used in this analysis is believed to be more accurate than utilizing AP-42 for derivation of emission factors.

Table 4-21 RBLC and Draft Permit Listings for Hydrogen Fluoride Emissions from Pulverized Coal-fired Boilers

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit		Operational Facility
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	PULVERIZED COAL	600	DRY SORBENT INJECTION W/ FABRIC FILTER BAGHOUSE	0.0001	lb/MMBtu	NO
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	BOILER, COAL, (2)	COAL	750	PROPER BOILER DESIGN AND CONTROL TECHNOLOGY, WFGD, AND WESP	0.000159	lb/MMBtu	NO
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	PC BOILERS (2)	COAL	750	PROPER BOILER DESIGN AND CONTROL TECHNOLOGY, WFGD, AND WESP	0.000159	lb/MMBtu	NO
WPS WESTON PLANT	WI	04-RV-248	10/19/2004	SUPERCRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER	COAL	500	DRY FGD AND BAGHOUSE	0.000217	lb/MMbtu	NO
TOQUOP ENERGY, LLC	NV	AP4911-1146	DRAFT	750 MW PC BOILER	COAL	750	WET SCRUBBER	0.00024	lb/MMbtu	NO
DESERT ROCK ENERGY FACILITY	NM	DRAFT	7/1/2006	(2) 750 MW SCPC BOILERS	COAL	750	LIMESTONE WET FGD, HYDRATED LIME INJECTION	0.00024	lb/MMbtu	NO
SANTEE COOPER CROSS GENERATING STATION	SC	0420-0030-CI	2/5/2004	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	660	FLUE GAS DESULFURIZATION (WET SCRUBBING)	0.0003	lb/MMBtu	YES - BOILER #3
SANTEE COOPER PEE DEE GENERATING STATION	SC	1040-0113-CA.1 DRAFT	12/1/2007	BOILER NO. 1 AND NO. 2	BITUMINOUS COAL	660	FLUE GAS DESULFURIZATION (WET SCRUBBING)	0.000341	lb/MMBtu	NO
WHELAN ENERGY CENTER	NE	58048	3/30/2004	BOILER, UNIT 2 UTILITY	SUBBITUMINOUS COAL	220	SPRAY DRYER ABSORBER & PM CONTROL EQUIPMENT	0.0004	lb/MMBtu	NO
ELY ENERGY CENTER	NV	AP4911-2241	DRAFT	(2) 750 MW PC BOILERS	COAL	750	WET SCRUBBER	0.0004	lb/MMbtu	NO
OPPD NEBRASKA CITY STATION	NE	58343C01	3/9/2005	BOILER	COAL	660	FLUE GAS DESULFURIZATION AND FABRIC FILTER	0.0004	lb/MMbtu	NO
PLUM POINT ENERGY	AR	1995-AOP-R1	8/20/2003	PC BOILERS (2)	COAL	665	DRY FGD AND BAGHOUSE	0.00044	lb/MMbtu	NO
COMANCHE STATION	CO	04UNITPB1015	7/5/2005	PC BOILER - UNIT 3	SUB-BITUMINOUS COAL	750	LIME SPRAY DRYER FOLLOWED BY A BAGHOUSE	0.0005	lb/MMBtu	NO
GASCOYNE GENERATING STATION	ND	PTC 05005	6/3/2005	BOILER, COAL-FIRED	LIGNITE	220	LIMESTONE INJECTION AND SPRAY DRYER.	0.0005	lb/MMBtu	NO
INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	UT	DAQE-AN0327010-04	10/15/2004	PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	BITUMINOUS OR BLEND	950		0.0005	lb/MMBtu	NO
TS POWER PLANT	NV	AP4911-1349	5/5/2005	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	200	DRY SPRAY SCRUBBER & FABRIC FILTER DUST COLLECTION	0.000576	lb/MMBtu	EXPECTED TO START IN 2008
JK SPRUCE ELECTRIC GENERATING UNIT 2	TX	70492	1/19/2006	PULVERIZED COAL FIRED ELECTRIC STEAM BOILER	COAL	750	WET FGD	0.0008	lb/MMbtu	NO
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	PRB COAL	750	LIME SPRAY DRYER FLUE GAS DESULFURIZATION	0.0009	lb/MMBtu	YES

Table 4-21 RBLC and Draft Permit Listings for Hydrogen Fluoride Emissions from Pulverized Coal-fired Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit		Operational Facility
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600 MW UNITS	PRB COAL	600	DRY SCRUBBER AND FABRIC FILTER BAGHOUSE	0.00095	lb/MMbtu	NO
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600 MW UNITS	CAPP COAL	600	DRY SCRUBBER AND FABRIC FILTER BAGHOUSE	0.0014	lb/MMbtu	NO
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED CAOL BOILER	COAL	800		0.00281	lb/MMBtu	NO
KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	MO	012006-019	1/27/2006	PULVERIZED COAL BOILER	COAL	7800 MMBtu/hr	NONE INDICATED	0.00425	lb/MMbtu	NO
LIMESTONE ELECTRIC GENERATING STATION	TX	PSD-TX-371 (M3)	5/23/2001	(2) BOILER UNIT 1 & 2 SCRUBBER STACKS, LMS1 & 2	LIGNITE	800	NONE INDICATED	0.0103523	lb/MMBtu	YES
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL, WAP7	COAL	6700 MMBtu/hr	NONE INDICATED	0.0165672	lb/MMBtu	YES
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	COAL	6700 MMBtu/hr	NONE INDICATED	0.0165672	lb/MMBtu	YES
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL ONLY	COAL	6700 MMBtu/hr	NONE INDICATED	0.0165672	lb/MMBtu	NO
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	BOILER STACK, WAP 7, COAL & NAT GAS	COAL & NAT GAS	6700 MMBtu/hr	NONE INDICATED	0.0165672	lb/MMBtu	NO
AGP SOY PROCESSING	NE	CP05-0050	9/11/2006	STEAM GENERATION	COAL	382 MMBtu/hr	LIMESTONE INJECTION	0.0017	lb/MMBtu	NO
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	COAL	7400 MMBtu/hr	NONE INDICATED	0.0172973	lb/MMBtu	YES
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	COAL	7400 MMBtu/hr	NONE INDICATED	0.0172973	lb/MMBtu	YES
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL & NAT GAS	COAL & NAT GAS	6750 MMBtu/hr	NONE INDICATED	0.0172973	lb/MMBtu	NO
WASHINGTON PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-33 M1	10/15/2002	(2) BOILER STACKS, WAP 5 & 6 , COAL ONLY	COAL	6750 MMBtu/hr	NONE INDICATED	0.018963	lb/MMBtu	NO
DRY FORK STATION	WY	CT-4631	10/15/2007	PC BOILER (ES1-01)	COAL	385	CIRCULATING DRY SCRUBBER	2.62	lb/hr	NO

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

4.3.7 BACT Demonstration for Sulfuric Acid Mist (H_2SO_4) Emissions from the Supercritical Pulverized Coal Boiler

Sulfuric Acid Mist (SAM) is formed in coal-fired boilers due to oxidation of SO_2 to SO_3, and subsequent reaction with water vapor to form H_2SO_4. The formation of SAM therefore depends on coal sulfur content and the presence of oxidizing catalysts. Some of the technologies and strategies for control of SAM emissions are similar to those technologies and strategies for control of SO_2 emissions. Factors affecting the generation of SAM include the sulfur content of the fuel used, the alkaline ash content of the fuel used, the SCR catalyst used, the rate of ammonia slip from an SCR control device, and the types of control equipment used for control of other pollutants (i.e., fabric filter baghouse, ESP, etc.).

Step 1 – Identify All Control Technologies

Lower-emitting Process or Practice – Coal Selection

Emissions of sulfur dioxide (SO_2) result from the oxidation of sulfur in the coal during the combustion process. Therefore, coal source selection can have an impact on SO_2 emissions, and corresponding SO_3 formation (leading to emissions of SAM) from a coal-fired boiler. Coal selection, as well as coal refining, is discussed further in the SO_2 BACT analysis in Section 4.3.5.

Lower-emitting Process or Practice – Coal Cleaning

Coal cleaning is discussed in the SO_2 BACT analysis in Section 4.3.5. A reduction in sulfur content in the coal reduces the amount of sulfur available to form SAM in the system exhaust gas.

Lower-emitting Process or Practice – Coal Refining

Coal refining is discussed further in the SO_2 BACT analysis in Section 4.3.5.

Lower-emitting Process or Practice – Low Oxidation Catalyst

Low oxidation catalysts can be used to reduce the conversion of SO_2 to SO_3 in the exhaust flue gas stream, thereby reducing the amount of formation of SAM emissions.

Wet Scrubber

Wet scrubber systems are often used as flue gas desulfurization (FGD) systems to control emissions of SO_2 from oil and coal-fired combustion sources. The control technology chosen for SO_2 control is the use of a wet scrubber. A small amount of the SAM can be removed from the flue gas by absorption and reaction with the reagent slurry created by the wet scrubber, but wet scrubbers are not highly effective at controlling SAM. Reagents commonly used in the process include lime and limestone. Additives, such as magnesium, can be added to the reagent materials to further improve the reaction of the reagent with the SAM in the gas stream. One detriment to the use of a wet scrubber is SO_3 entering the scrubber can also be converted to SAM. Proper design and operation are important to effective SAM capture in a wet scrubber system.

Spray Dryer Absorber (Dry Scrubber)

In a spray dryer absorber (SDA), or spray dryer, a fine spray of reagent slurry is atomized and comes into contact with the hot exhaust gas, or flue gas. Lime is the typical reagent used in an SDA unit. A significant part of the acidic components of the flue gas, including SAM, is rapidly absorbed into the alkaline droplets, with the water/moisture content evaporated simultaneously. Control of exhaust gas distribution, slurry flow rate, and spray droplet size ensures that the droplets introduced into the gas stream are effectively dried into a fine powder before touching the chamber walls of the spray dryer unit or exiting the SDA system. A portion of the reacted product is collected and discharged from the SDA. The treated flue gas is then discharged to a fabric filter baghouse, or other PM control device, where additional reacted product is collected from the exhaust gas stream.

Circulating Dry Scrubber

A Circulating Dry Scrubber (CDS) is similar in concept and reaction chemistry to a SDA. In a CDS system, a circulating fluidized bed arrangement is used for contacting the sorbent reagent (i.e., lime) with the SAM in the flue exhaust gas. In a CDS, the reaction products exit the system in a dry form and are collected downstream in a fabric filter baghouse or other PM control device.

Dry Sorbent Injection (DSI)

Dry sorbent injection (DSI) is a process used to control SAM emissions by injecting a sorbent into the flue gas stream. The sorbent can be injected into the furnace, the economizer, or downstream ductwork. The injection point can depend on the type of sorbent used and required reaction time, as some sorbents must be injected at high temperatures to properly decompose the sorbent into porous solids with a high surface area. An expansion or reaction chamber may be included to increase the residence time of the flue gas to react with the sorbent. Dry sorbent systems typically use calcium and sodium based alkaline reagents. Examples of sorbents used include hydrated lime, magnesium hydroxide, and soda ash (Trona). The waste product is removed using PM control equipment such as a baghouse or ESP.

Activated carbon can also be used as the sorbent for removal of SAM emissions. Activated carbon is injected into the flue gas exhaust stream through a series of header nozzles upstream of a fabric filter baghouse or other PM control device. A portion of the reacted carbon and fly ash collected by the PM control device is recycled and injected back into the flue gas exhaust stream to minimize the need for fresh activated carbon, making the process a partially "regenerable" process. Other activated carbon contact methods with the flue gas have been postulated. Activated carbon injection is planned for this unit for control of mercury.

Sorbent Injection and Wet Scrubber

One potential control technology is the combination of dry sorbent injection with a wet scrubber. A reagent, such as lime or limestone, is injected into the exhaust gas stream between the air heater and the PM control device. Sorbent injection technology could be used in conjunction with a wet scrubber device.

Sorbent Injection and Dry Scrubber

One potential control technology is the combination of sorbent injection with a dry scrubber. A reagent, such as lime or limestone, is injected into the exhaust gas stream between the air heater and the PM control device. Sorbent injection technology could be used in conjunction with a dry scrubber device.

Wet Electrostatic Precipitator (WESP)

A WESP is a particulate removal device discussed in detail in Section 4.3.1. A WESP removes PM from the exhaust gas stream, including SAM. In a WESP unit, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. This wet effluent is collected and often treated on-site. WESP systems have been demonstrated to be effective control devices for removal of SAM in the metallurgical industry as well as other industrial applications, with limited experience in electric utility applications. The AES Deepwater petroleum coke-fired cogeneration plant in Texas generates approximately 155 MW of electricity, and is one of few facilities where WESP technologies have been used on a full scale in a utility application. Applications at this site have shown greater than 90% reduction in SAM emissions.

The Xcel Energy Sherboune County Station utilizes WESP technology through a retrofit installation, by installing a WESP unit inside an existing particulate scrubber device. This was done for two 750 MW units. The New Brunswick Power Coleson Cove facility installed WESP units integrated with new limestone based wet scrubbers at the 1050 MW station. A smaller WESP system was also installed at another New Brunswick Power facility (Dalhousie) following installation of a wet scrubber.

The historic application of WESP technology provides a basis for design of high efficiency control of SAM for electric utility applications.

Step 2 – Eliminate Technically Infeasible Options

Lower-emitting Process or Practice – Coal Selection

Coal selection is a demonstrated method for minimizing the amount of sulfur available for SO_2 formation, and therefore SO_3 and H_2SO_4 formation. Coal selection is determined to be technically feasible for this project. The facility will utilize sub-bituminous coals, bituminous coals, or a blend of sub-bituminous and bituminous coals. The facility boiler has been designed for use of both 100% PRB coal and up to a 50/50 blend of PRB and Illinois #6 coals. The preference for the facility will be use of western low sulfur sub-bituminous coal (i.e. PRB coal), but will also retain the capability of use of bituminous coals (i.e. Illinois #6) due to coal availability concerns. Some flexibility in the fuel supply for the main boiler is needed to ensure a

reliable supply of fuel. A coal delivery interruption could adversely affect the power generating capabilities of Plant Washington if only one type of coal were permitted for use.

Lower-emitting Process or Practice – Coal Cleaning

Coal cleaning is discussed in the BACT analysis in Section 4.3.5. Coal washing for western sub-bituminous coals such as PRB coals would be ineffective because there would be little sulfur content removed by the process. However, bituminous coals such as Illinois #6 coals are routinely washed to reduce the pyritic sulfur content, as well as other impurities in the coal. Therefore, coal washing for Illinois #6 coals is considered technically feasible for this analysis. Illinois #6 coals purchased by the facility will be washed prior to shipment to Plant Washington. Other bituminous coals purchased for the facility will be assessed to determine if the coal parameters (i.e. pyritic sulfur content) are comparable to that of Illinois #6 coals. If any additional bituminous coals are purchased for use at the facility those coals will fall within the specifications of washed Illinois #6 coal.

Lower-emitting Process or Practice – Coal Refining

Coal refining is discussed in detail in the SO_2 BACT analysis in Section 4.3.5. Coal refining is determined to be technically infeasible for this project.

Lower-emitting Process or Practice – Low Oxidation Catalyst

Low oxidation catalysts have been used in practice, and are considered technically feasible for this project.

Wet Scrubber

Wet scrubbers have been demonstrated in wide-scale use on coal-fired boilers and are available from a number of vendors. Wet scrubbers are therefore considered to be technically feasible.

Spray Dryer Absorber (Dry Scrubber)

Dry scrubbers have been demonstrated in wide-scale use on coal-fired boilers and are available from a number of vendors. Dry scrubbers are therefore considered to be technically feasible.

Circulating Dry Scrubber

The advantage of a circulating dry scrubber system is the increased contact time between the sorbent material and the flue gas stream. Circulating dry scrubbers have not yet been demonstrated on a coal fired boiler of greater than 400 MW. The size and scale differences between the proposed utility boiler for Plant Washington and the boilers on which this technology have been demonstrated would likely lead to the requirement for further design, research, and testing for assessing viability on such a large scale unit. Circulating fluidized bed systems, as with a circulating fluidized bed boiler, are not in use at the size and scale of the proposed main boiler for Plant Washington. Therefore, circulating dry scrubber systems are not considered technically feasible for this project.

Dry Sorbent Injection (DSI)

Dry sorbent injection (DSI) is a process used to control sulfuric acid mist emissions by injecting a sorbent into the flue gas stream or into the combustion zone of the boiler. Dry sorbent injection is considered technically feasible for this project.

Sorbent Injection and Wet Scrubber

Some data indicate that the use of sorbent injection in conjunction with a wet scrubber would reduce SAM emissions. For these reasons, use of duct sorbent injection in conjunction with a wet scrubber is considered technically feasible for this project.

Sorbent Injection and Dry Scrubber

There are limited operating data available to indicate that there would be a substantial reduction in SAM emissions from use of sorbent injection along with a dry scrubber. Inclusion of duct sorbent injection with a dry scrubber would lead to increased capital and annualized operating

costs, with no assurance of improved system performance from use of a dry scrubber alone. Also, a secondary concern for use of sorbent injection with a dry scrubber is the potential for interference of the duct sorbent material with the operation of the dry scrubber. A sorbent material in the flue gas exhaust stream could interfere with the ability of the dry scrubber to evaporate the moisture in the reagent slurry, thus impacting the effectiveness of the unit. For these reasons, use of sorbent injection in conjunction with a dry scrubber is considered technically infeasible.

Wet Electrostatic Precipitator (WESP)

WESP units have been shown to remove SAM from exhaust streams and are considered technically feasible. As mentioned previously, WESP technology is a cross-over technology from the metallurgical industry with limited performance data available in full scale utility applications. Facilities such as AES Deepwater, Xcel Energy Sherbourne County Station, and New Brunswick Power Coleson Cove utilize WESP units.

Step 3 – Rank Remaining Technically Feasible Control Options

Control Effectiveness

The feasible control technologies found during Step 2 of this analysis include coal selection, coal cleaning, low oxidation catalysts, wet scrubbers, sorbent injection, wet scrubbers, spray dryer absorbers (dry scrubbers), and WESP.

The facility will primarily burn a low sulfur western sub-bituminous coal (PRB) but will also be capable of burning bituminous coal (i.e. Illinois #6) due to availability concerns. An interruption in coal delivery to Plant Washington would lead to a severe impact on the operational status of Plant Washington. Historic interruptions in PRB supply have impacted power plants in the United States. Therefore, the facility will retain the option of using alternate fuels in the instance of PRB fuel supply interruption.

Coal cleaning was considered technically feasible for this analysis. Coal cleaning normally occurs at the mine, not the facility. Therefore, this is more of a purchasing concern and not a matter of construction. As discussed previously, western sub-bituminous coals such as PRB coals are not typically washed due to the low ash content and low variability of PRB coals in

comparison to other coals. However, coal washing will be conducted for the Illinois #6 coals used at Plant Washington, due to the high ash and sulfur content of that coal. Other bituminous coals purchased for the facility will be assessed to determine if the coal parameters (i.e. pyritic sulfur content) are comparable to that of Illinois #6 coals. If any additional bituminous coals are purchased for use at the facility those coals will fall within the specifications of washed Illinois #6 coal.

Technical publications, the USEPA RBLC, and vendor information were reviewed to determine the control efficiencies of each of these identified technically feasible SAM control technologies. The comparative performance of control technologies for SAM emissions often has not been evaluated, and data regarding the effectiveness of various control technologies are limited and conflicting. A review of data on the RBLC database includes a variety of controls deemed applicable for BACT for coal-fired boilers, including wet scrubbers; dry scrubbers; dry scrubber and baghouse; baghouse and wet scrubber ; limiting of fuel sulfur content; and combination of an ESP, dry scrubber, and WESP unit.

A document prepared by the Electric Power Research Institute (EPRI) in 2007, titled *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants*, discusses the effects of the various control technologies used at a power plant on generation and control of SAM emissions, including the effects of SCR catalyst selection, NH_3 (ammonia) slip, and alkaline ash scrubbing. Data in this document indicates that the alkalinity of the ash enhances removal of SAM. PRB coals generally produce ash with substantially higher alkalinity than bituminous coals, which results in lower SAM emissions. One method of enhancing ash alkalinity is injection of sorbents into the flue gas stream.

SAM is formed by conversion of SO_2 to SO_3, where the SO_3 reacts with water to form H_2SO_4 (SAM). SO_3 is formed in the combustion zone of the boiler, with additional SO_3 formation from oxidation of SO_2 across the SCR catalyst. The following Table 4-22 is a graphical illustration of the control efficiency of the different SAM control methods evaluated.

Table 4-22 SAM Control Efficiency For Indicated Control Methods

Formation Mechanism/Zone	Control Method	Control Efficiency[1]
Combustion Zone Generated SO_3	Add Alkaline Adsorbent Into Combustion Zone	66%
Combustion Zone Generated SO_3 and SO_2 Conversion To SO_3 Across SCR Catalyst	Add Alkaline Adsorbent Into Duct	90%
Combustion Zone Generated SO_3 and SO2 Conversion To SO_3 Across SCR Catalyst	WESP Downstream of Wet Scrubber	98%

[1] Efficiency indicated for use of that control method only.

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

Step 4 – Evaluate Remaining Control Technologies

As stated above in Step 3, the removal efficiency performance of technologies for SAM emissions control has not often been evaluated, and data that is available regarding the effectiveness of various control technologies are limited and conflicting. A review of data on the RBLC database includes a variety of controls deemed applicable historically for BACT for coal-fired boilers, including wet scrubbers; dry scrubbers; dry scrubber and baghouse in coordination; baghouse and wet scrubber in coordination; limiting of fuel sulfur content; and coordination of an ESP, dry scrubber, and WESP unit.

Data available for combustion zone sorbent injection indicates that a control efficiency for SAM of 66% is achievable in combustion zone injection. Data provided by the design engineering company for Plant Washington indicates that duct sorbent injection technology can achieve a maximum of 90% effective control of SAM emissions, while a WESP can achieve a removal efficiency of 98% for SAM emissions. Therefore, this would make use of a WESP the top control option for direct control of SAM emissions, with duct sorbent injection being the next most effective direct control option.

Co-benefit from other pollution control equipment, such as use of a fabric filter baghouse, the type of oxidation catalyst selected for the SCR, coal type, etc. will impact the SAM emissions. However, in previous BACT analyses for PM and SO_2, use of a fabric filter baghouse and wet scrubber were selected as BACT. The following comparative analysis between use of a WESP and sorbent injection system presumes the use of a fabric filter baghouse, wet scrubber, use of

sub-bituminous (i.e. PRB) coal or a blend of sub-bituminous and bituminous coals (i.e. PRB and Illinois #6), and use of a low oxidation catalyst in the SCR.

Energy Impacts

Energy penalties are much more significant for a WESP than for a sorbent injection system. Use of sorbent injection along with a wet scrubber at the facility would be expected to add minimal power demand to the system. Any power demand for the sorbent injection system would come from power required to handle or process the sorbent powder or slurry.

Based on data in a USEPA Air Pollution Training Institute publication regarding electrostatic precipitator operation, the power required to operate a wet electrostatic precipitator can be around 1,000 watts per 1,000 acfm, with limited collection efficiency degradation at 750 watts per 1,000 acfm. For the estimated air flow currently available for the site, this could lead to ESP power requirements from 2 to 3 MW based on the USEPA guidance document. Estimates provided by the design engineering company for Plant Washington have indicated that a WESP unit for a facility the size of Plant Washington could require an auxiliary load of approximately 4.7 MW based on similar project OEM auxiliary load guarantees for high efficiency WESPs. Therefore, power generation requirements for a WESP unit would be more significant than the power generation requirements for a sorbent injection system.

If a wet scrubber were used in tandem with a WESP unit at the facility, significant demands of the facility's gross power generation would be required to operate the facility air pollution control equipment. Use of sorbent injection along with a wet scrubber would be expected to add minimal power demand to the system, and would not preclude use of a sorbent injection system at the facility. Therefore, use of a sorbent injection system would create less of an energy impact than use of a WESP system at Plant Washington.

Environmental Impacts

The two methods of sorbent injection control (duct and combustion zone injection) would not be expected to produce a wastewater stream. However, there would be additional solid materials for handling generated from use of the sorbent injection materials. Use of a WESP unit would generate a liquid waste stream (wastewater), which would have to be treated and discharged with

the plant effluent. If additional particulate matter is captured by the WESP, this material would need to be removed, dried, and sent to the ash handling system. A WESP unit would have a more significant environmental impact than use of a sorbent injection system.

Economic Impacts

The following are the assumptions used in the economic impacts analysis comparison between use of sorbent injection and use of a WESP at the Plant Washington facility, as provided by the engineering design company for Plant Washington. The WESP system capital cost estimate assumes a WESP unit designed with suitable alloy materials such as C276 for the high sulfur atmosphere with no chemical additive injection required for removal of SAM.

Sorbent Injection System Capital Cost Estimate = $12,500,000

Duct Sorbent Injection System Soda Ash (Trona) Use Annual Cost Estimate = $7,130,345

Magnesium Hydroxide (Combustion Zone SI) Use Annual Cost Estimate = $5,605,590

Sorbent Injection System Annual Ash Handling Cost (Estimate) = $600,000

Sorbent Injection System Estimated Removal Efficiency = 90%

Combustion Zone Sorbent Injection System Efficiency = 66%

WESP System Capital Cost Estimate = $290,000,000

WESP Unit Auxiliary Power Load = 4700 kW

Auxiliary Power Charge Rate = $0.04/kWhr

Capital Recovery Factor (CRF) = 0.1061

WESP Unit Estimated Removal Efficiency = 98%

The following Table 4-23 is an economics analysis evaluation of the remaining technically feasible control options for control of SAM emissions. The following table assumes an uncontrolled SAM emissions baseline of 0.04 lb/MMBtu, or 1,454 ton/yr. The value of 0.04 lb/MMBtu is an engineering estimate based on approximately 1% conversion of SO_2 to SO_3 across the emissions control system.

Table 4-23 SAM Emissions Economic Impacts Analysis

Control Alternative	Estimated Removal Efficiency	Emissions (lb/hr)	Emissions Reduction (ton/yr)	Total Annualized Cost ($/yr)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Toxics Impact (Yes/No)	Environmental Impact[1]	Energy Impacts
Sorbent Injection and WESP	99.8%	0.66	1,451	$41.5 million	$28,601	$350,000	No	Yes	4.7 MW
WESP	98%	6.6	1,425	$32.4 million	$22,737	$804,545	No	Yes	4.7 MW
Combustion Zone and Duct Sorbent Injection	96.5%[2]	11.6	1,403	$14.7 million	$10,478	$59,574	No	Yes	Limited
Duct Sorbent Injection	90%	33.2	1,309	$9.1 million	$6,952	$10,029	No	Yes	Limited
Combustion Zone Sorbent Injection	66%	112.9	969	$5.6 million	$5,833	---	No	Yes	Limited
Baseline	---	332	1,454	---	---	---	---	---	---

[1] Environmental impact for sorbent injection systems associated with additional ash handling. Environmental impacts from WESP unit from wastewater treatment and additional solid materials handling.
[2] Combustion zone and duct sorbent injection removal efficiency estimated is theoretical based on an assumption of an additive removal effect of use of two systems in conjunction. Limited information is available on the effectiveness of these two systems used in conjunction.

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

As indicated in Table 4-24, the most effective control technologies for control of SAM emissions, a WESP unit alone and use of a WESP unit in conjunction with sorbent injection, are rejected due to significant incremental cost effectiveness and average cost effectiveness. Use of a WESP unit would also have a significant energy impact to Plant Washington. Also, a combination of combustion zone and duct sorbent injection is also rejected due to a significant incremental cost effectiveness of $59,574/ton.

The average cost effectiveness of duct sorbent injection is $6,952/ton and the incremental cost effectiveness is $10,029/ton. This level of cost is determined acceptable for control of SAM emissions. Therefore, BACT for Plant Washington is determined as use of duct sorbent injection for control of SAM emissions.

Step 5 – Selection of BACT

Based on the significant energy, environmental, and economic impacts posed by use of a WESP as compared to duct sorbent injection, Plant Washington proposes the use of duct sorbent injection (along with the co-benefits achievable through use of a fabric filter baghouse and wet scrubber) as BACT for SAM. This same control technology combination has been proposed as BACT in recent PSD permit applications. This decision is further supported by the recent comments made by USEPA in support of the issued final permit for the Desert Rock facility in New Mexico, which proposed SAM emissions control through use of sorbent injection and a wet scrubber.

BACT is also proposed as an emission limit of 0.004 lb/MMBtu on a 3-hr average basis. Compliance with the proposed BACT emission limit will be demonstrated through stack testing using USEPA CTM013 (Controlled Condensate Method 8A). A summary of recent SAM BACT evaluations conducted for similar projects is in Table 4-24. The averaging period of the SAM limits listed in Table 4-24 is a 3-hr. average (stack test). Although multiple facilities have proposed or achieved emission levels lower than that proposed for Plant Washington, this level of control was determined to be the maximum amount of control achievable for Plant Washington based on the emissions controls and types of coal determined for use at Plant Washington.

Two additional sites were permitted with low SAM emissions but are not included in Table 4-24. These sites are the City Utilities of Springfield Southwest Power Station and the Whelan Energy

Center. The City Utilities of Springfield Southwest Power Station has a permit limit of 0.000184 lb/MMBtu. Mr. David Farley, with City Utilities of Springfield, was contacted, and indicated that the limit of 0.000184 lb/MMBtu was miscalculated. He indicated that the agency was concerned regarding how the plant would comply with such a limit, and that he was aware that the limit was significantly lower than others proposed for similar units. The control strategy for the facility was use of a dry scrubber. Mr. Kendall Hale, permit engineer with the Missouri Department of Environmental Quality, was also contacted. Mr. Hale indicated that the limit of 0.000184 lb/MMBtu was proposed by the facility to avoid BACT analysis. Therefore, no BACT analysis was conducted for SAM emissions from the facility. Mr. Hale indicated that the limit was much lower than limits proposed for other facilities in Missouri, and the facility will be required to conduct a test to demonstrate compliance once construction of the facility is completed. If the facility cannot meet the proposed limit, potential enforcement action and a requirement for the facility to conduct a BACT analysis for SAM emissions could result. Therefore, due to the uncertainty of both the facility and the regulatory authority to meet the emission limit chosen, and the potential actions that would be required of the facility if it cannot meet the proposed limit, this limit was not selected as BACT for this analysis.

The Whelan Energy Center had an indicated permit limit for H_2SO_4 of 0.82 lb/hr, which equates to approximately 0.000362 lb/MMBtu. This facility will also use a dry scrubber. Discussions with the permit engineer for this facility at the Nebraska Department of Natural Resources, Division of Environmental Quality, Mr. Brad Reid, indicated that the emission limit chosen was a PSD avoidance limit, and he thought the value was aggressive and that a value in the range of 0.0042 lb/MMBtu, as recently proposed by another facility, was more realistic. Since the limit taken was an avoidance limit, no BACT analysis was conducted for SAM emissions. The facility will be required to conduct compliance testing once the facility is constructed. It is questionable whether the facility will be able to demonstrate compliance with this low limit. Therefore, due to the uncertainty of both the facility and the regulatory authority to meet the emission limit chosen, and the potential actions that would be required of the facility if it cannot meet the proposed limit, this limit was not selected as BACT for this analysis.

Table 4-24 RBLC and Draft Permit Listings for Sulfuric Acid Mist (H2SO4) Emissions from Pulverized Coal-fired Boilers

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit		Operational Facility
TS POWER PLANT	NV	AP4911-1349	5/5/2005	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	200	DRY SPRAY SCRUBBER & FABRIC FILTER DUST COLLECTION	0.0010	lb/MMBtu	EXPECTED TO START IN 2008
SANTEE COOPER CROSS GENERATING STATION	SC	0420-0030-CI	2/5/2004	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	660 Each	FLUE GAS DESULFURIZATION (WET SCRUBBING)	0.0014	lb/MMBtu	YES
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-234	12/21/2000	UTILITY BOILER UNIT 8		6700 MMBtu/hr	FABRIC FILTER, FLUE GAS DESULFURIZATION	0.0015	lb/MMBtu	YES
DRY FORK STATION	WY	CT-4631	10/15/2007	PC BOILER (ES1-01)	COAL	385	CIRCULATING DRY SCRUBBER	0.0025	lb/MMBtu	NO
HUGO GENERATING STATION	OK	97-058-C M-2 PSD	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	UNKNOWN	750	WET FLUE GAS DESULFURIZATION	0.0037	lb/MMBtu	NO
JK SPRUCE ELECTRIC GENERATING UNIT 2	TX	N/A	1/19/2006	PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	COAL	750	WET FGD AND BAGHOUSE	0.0037	lb/MMbtu	NO
TRIMBLE COUNTY GENERATING STATION	KY	DRAFT	7/6/2005	PULVERIZED COAL BOILER	COAL	750	WESP	0.0038	lb/MMbtu	NO
AGP SOY PROCESSING	NE	CP05-0050	9/11/2006	STEAM GENERATION	COAL	382 MMBtu/hr	LIMESTONE INJECTION	0.0039	lb/MMBtu	NO
DESERT ROCK ENERGY FACILITY	NM	N/A	7/1/2006	(2) 750 MW SCPC BOILERS	COAL	750	LIMESTONE WET FGD, HYDRATED LIME INJECTION BEFORE FF	0.004	lb/MMBtu	NO
ELY ENERGY CENTER	NV	AP4911-2241	DRAFT	(2) 750 MW PC BOILERS	COAL	750	FF AND WET SCRUBBER	0.004	lb/MMbtu	NO
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	CBEC 4 BOILER	PRB COAL	750	LIME SPRAY DRYER FLUE GAS DESULFURIZATION	0.0042	lb/MMBtu	YES
OPPD - NEBRASKA CITY STATION	NE	58343C01	3/9/2005	UNIT 2 BOILER	SUBBITUMINOUS COAL	660	DRY FLUE GAS DESULFURIZATION & FABRIC FILTER	0.0042	lb/MMBtu	NO
COMANCHE STATION	CO	04UNITPB1015	7/5/2005	PC BOILER - UNIT 3	SUB-BITUMINOUS COAL	750	LIME SPRAY DRYER FOLLOWED BY A BAGHOUSE	0.0042	lb/MMBtu	NO
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL, WAP7	COAL	6700 MMBtu/hr	NONE INDICATED	0.0043	lb/MMBtu	YES
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	COAL	6700 MMBtu/hr	FUEL S CONTENT LIMITED	0.0043	lb/MMBtu	YES
INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	UT	DAQE-AN0327010-04	10/15/2004	PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	BITUMINOUS OR BLEND	950	BAGHOUSE/FABRIC FILTER AND WET FLUE GAS DESULPHURIZATION	0.0044	lb/MMBtu	NO

Table 4-24 RBLC and Draft Permit Listings for Sulfuric Acid Mist (H_2SO_4) Emissions from Pulverized Coal-fired Boilers (Continued)

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit		Operational Facility
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	COAL	7400 MMBtu/hr	FUEL S CONTENT LIMITED	0.0045	lb/MMBtu	YES
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	COAL	7400 MMBtu/hr	FUEL S CONTENT LIMITED	0.0045	lb/MMBtu	YES
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	(2) 750 MW PC BOILERS	COAL	750	PROPER BOILER DESIGN AND CONTROL TECHNOLOGY, ESP, FGD, AND WESP	0.00497	lb/MMbtu	NO
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	500	FGD SYSTEM	0.005	lb/MMBtu	NO
OTTER TAIL POWER COMPANY	SD	N/A	4/1/2006	600 MW SCPC BOILER	COAL	600	WET SCRUBBER AND BAGHOUSE	0.005	lb/MMBtu	NO
TRIMBLE COUNTY GENERATING STATION	KY	V-02-043 Rivision 3	7/6/2005	SUPER CRITICAL PULVERIZED COAL	COAL	750	WET FGD AND WET ESP	0.0038	lb/MMbtu	NO
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600 MW UNITS	COAL	600	DRY FGD AND BAGHOUSE	0.005	lb/MMbtu	NO
TOQUOP ENERGY, LLC	NV	AP4911-1146	DRAFT	750 MW PC BOILER	COAL	750	WET SCRUBBER AND SORBENT INJECTION	0.005	lb/MMbtu	NO
PLUM POINT ENERGY	AR	1995-AOP-R1	8/20/2003	BOILER , UNIT 1 - SN-01	SUB-BITUMINOUS COAL	665	DRY FGD/FABRIC FILTER	0.0061	lb/MMBtu	NO
PLUM POINT ENERGY	AR	1995-AOP-R1	8/20/2003	BOILER - SN-01	SUB-BITUMINOUS COAL	665	DRY FGD/FABRIC FILTER	0.0061	lb/MMBtu	NO
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 1	COAL	390	DRY FLUE GAS DESULFURIZATION (FGD) - SPRAY DRY ABSORBER	0.0064	lb/MMBtu	NO
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, PC NO. 2	COAL	390	DRY FLUE GAS DESULFURIZATION (FGD) SPRAY DRY ABSORBER	0.0064	lb/MMBtu	NO
AMERICAN MUNICIPAL POWER GENERATING STATION	OH	06-08138	2/7/2008	BOILER (2), PULVERIZED COAL FIRED	PULVERIZED COAL	5191 mmbtu	WET FLUE GAS DESULFURIZATION	0.0075	lb/MMBtu	NO
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	PULVERIZED COAL	600	DRY SOLID INJECTION W/ FABRIC FILTER	0.0075	lb/MMBtu	NO
CRYSTAL RIVER POWER PLANT	FL	PSD-FL-383	5/18/2007	FFFSG UNITS 4 AND 5	COAL	760	ALKALI INJECTION SYSTEM	0.009	lb/MMBtu	NO
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED COAL BOILER	COAL	800	NONE INDICATED	0.0155	lb/MMBtu	NO
LIMESTONE ELECTRIC GENERATING STATION	TX	PSD-TX-371 (M3)	5/23/2001	(2) BOILER UNIT 1 & 2 SCRUBBER STACKS, LMS1 & 2	LIGNITE	7863 MMBtu/hr	LIMESTONE WET SCRUBBING	0.0312	lb/MMBtu	YES

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

4.3.8 BACT Demonstration for Mercury (Hg) Emissions from the Supercritical Pulverized Coal Boiler

Although Hg emissions are not subject to PSD review per *40 CFR 52.21, Prevention of Significant Deterioration of Air Quality*, the *Georgia Rules for Air Quality Control, Chapter 391-3-1-.02(ttt)*, requires that any boiler installed later than January 1, 2007, capable of producing greater than 25 MW of electricity for sale must apply Best Available Control Technology (BACT) for control of mercury emissions. Therefore, a BACT evaluation has been conducted for the main facility boiler for control of mercury emissions.

Mercury is in coal in trace amounts, and is released into the main boiler exhaust flue gas during combustion. According to the USEPA document *Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update* (2005), the mercury content in typical coals is approximately 0.1 parts per million (ppm) on average. A specific evaluation of coal analysis data for PRB and Illinois coals from the USGS COALQUAL database indicates that the average mercury content for both PRB and Illinois coals is approximately 0.10 ppm. Therefore, it is expected that most bituminous and sub-bituminous coals planned for use at Plant Washington would have approximately this same level of mercury on average.

Mercury is present in the flue gas stream in one of three different forms, as (1) an elemental mercury vapor, (2) particle-bound mercury, or (3) vapor of an oxidized mercury species (Hg^{2+}), and is typically present in all three forms. The chemical form of the mercury in the flue gas stream can have a significant impact on the effectiveness of the control strategies employed for control of mercury emissions. Elemental mercury is regarded as the most difficult form of mercury to control since it cannot be scrubbed or filtered out. Particulate bound mercury is effectively controlled by particulate matter (PM) control strategies, such as a fabric filter baghouse or ESP. Oxidized mercury is more effectively controlled by gas scrubbing techniques (i.e. wet scrubber). Studies have been found that sorbent injection systems can be designed for effective capture of elemental mercury.

Step 1 – Identify All Control Technologies

<u>Coal Refining</u>

Coal refining is a mechanical and thermal process to remove moisture, sulfur, nitrogen, and heavy metals from coal. Also, as a result of the refining process, the ash content and moisture of the coal can be lowered, as well as increasing the heat content of the coal. Coal refining processes

include those still in the research and development stage, such as patented technologies for conversion of coal to char, a "clean" boiler fuel, and processes already in limited operation, such as the Evergreen Energy, Inc., K-Fuel patented pre-combustion coal refining process. The Alaska Cowboy Coal Power Consortium has conducted small-scale demonstration tests to remove a portion of the mercury content of the coal. The process removes mercury from the coal using a low-temperature ambient pressure method. However, the process has yet to be demonstrated on a full scale. A reduction in the mercury content in the coal would reduce the amount of mercury available and thereby released in the system exhaust gas.

Coal Cleaning

Coal cleaning methods, such as physical coal cleaning by coal washing, would involve pre-processing the coal and removing a portion of the mercury content present in the coal itself. Coal washing would involve gravity separation techniques to remove the mercury in the coal.

Fuel Blending

One of the primary reactions of Hg in the flue gas stream is with gas-phase chlorine. Reactions with gas-phase chlorine (or bromine) lead to formation of oxidized mercury in the form of mercuric chloride ($HgCl_2$), which can be more effectively removed from the flue gas stream than elemental mercury. Gas-phase Hg oxidation is a slow process and depends on the amount of chlorine in the flue gas. The amount of chlorine in the flue gas is proportional to the amount of chlorine in the coal being combusted.

Western sub-bituminous coals, such as PRB coals, typically have much lower chlorine content than eastern bituminous coals, such as Illinois #6 coal. Therefore, blending of sub-bituminous and bituminous coals for combustion in the main facility boiler may possibly lead to increased gas-phase reactions in the flue gas with chlorine, thereby increasing the effective capture of Hg and reducing mercury emissions. However, there is limited data available correlating fuel blending as a means to enhance mercury oxidation based on the proposed blend of fuels planned to be utilized at Plant Washington.

The effectiveness of fuel blending may also be due to the lower pyritic, or rock content, of PRB and other sub-bituminous coals. Bituminous coals, such as Illinois #6, typically have higher ash

levels and pyritic content than PRB coals, thus potentially containing more mercury in the particle bound phase, which is more effectively captured than elemental mercury. By blending of fuels, the total amount of particle bound mercury in the coal blend could increase in relation to the amount of elemental mercury, thus increasing the effective capture of the blended fuel.

Oxidizing Chemicals

Introduction of chlorine or other halogens into the flue gas stream or onto the coal could lead to increased gas-phase reactions in the flue gas, thereby increasing the effective capture of mercury and reducing mercury emissions. However, data regarding the effectiveness of such systems on a full scale power facility are limited, and the effectiveness of oxidizing chemicals would likely be influenced by the type and quality of coal being combusted, and the type and design of additional pollution control equipment in use at the facility. The use of oxidizing chemicals has found some success in DOE/NETL studies being conducted at the Monticello Unit 3 facility involving injection of calcium bromide. However, use of oxidizing chemicals would only be the first step in control of mercury, as the process would only oxidize the mercury present and not remove it. Operation of a scrubbing device such as a wet scrubber would be necessary to remove the oxidized mercury.

Unburned Carbon (UBC) Enhancement

Increasing the unburned carbon in the coal ash could reduce mercury emissions through decreasing the amount of mercury released into the flue gas stream and by providing carbon for reaction with mercury. However, adjusting combustion conditions in the main boiler to increase the unburned carbon content in the ash could have detrimental effects on the efficiency and operation of the main boiler, and could negatively affect emissions of other pollutants, such as PM and SO_2, since more coal would have to be burned.

Fabric Filter Baghouse and Wet Scrubber

Fabric filter baghouses have been shown to be relatively more effective at control of mercury emissions than ESP control devices. The amount of control achieved by ESP devices is through capture of particle-bound mercury. Therefore, the effectiveness of an ESP system at control of mercury emissions would depend highly on the amount of particle-bound mercury in the flue gas

stream. Fabric filter baghouses are likely more effective at control of mercury emissions than ESPs due to the filter cake collecting on the outside of the baghouse filter bags. The filter cake will enhance gas-phase particle reactions, increasing adsorption of oxidized mercury and potentially oxidation of elemental mercury.

Wet scrubber systems are often used as FGD systems, where the wet scrubbers are used to control emissions of SO_2 from oil and coal combustion sources from industrial sources and electrical utilities. Wet scrubbers can also be used in the control of mercury emissions. Oxidized mercury, present in such forms as $HgCl_2$, is water-soluble, therefore potentially removed by a wet scrubber device. However, effectiveness of the wet scrubber in removal of mercury emissions could be reduced by the chemical reduction of oxidized mercury to elemental mercury in the wet scrubber, leading to re-emission of mercury. As stated in the USEPA document *Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update* (2005), "Experience has shown that Hg^{2+} reduction and reemission may be more difficult to avoid in magnesium-enhanced lime (MEL) scrubbers due to the much higher sulfite concentration in those systems."

Spray Dryer Absorber (Dry Scrubber) and Fabric Filter Baghouse

Spray dryer absorbers, or dry scrubbers, used in conjunction with fabric filter baghouses have been found to provide greater than 90 percent control efficiency for mercury with bituminous coal combustion. However, control efficiencies when burning sub-bituminous coals are approximately 25 percent, which is much less than the effectiveness of fabric filter baghouses alone. One possibility is that the spray dryer absorber is effectively removing the chlorine (as HCl), and that bituminous coals contain enough excess chlorine such that chlorine (as HCl) scrubbing by the spray dryer absorber is not an issue for bituminous coals.

Selective Catalytic Reduction (SCR)

Use of SCR units potentially enhances oxidation of elemental mercury, thus enabling more effective control of mercury in downstream air pollution control devices. Modified catalysts added to the SCR control device could increase the oxidation of elemental mercury and increase the capture of mercury in a wet FGD system. However, only limited information regarding the effectiveness of such practices is available. DOE/NETL studies conducted at Monticello Unit 3

have shown the effective oxidation of mercury through use of catalyst systems. However, the performance of these modified catalysts is still being studied.

Sorbent Injection

Unlike the pollution control devices listed above, sorbent injection would be conducted primarily for removal of mercury emissions, as opposed to achieving mercury removal as a co-benefit (i.e., fabric filter baghouse). Injection of dry sorbents such as Powdered Activated Carbon (PAC) into flue gas streams has been used for control of mercury emissions from waste combustors, and has been tested at electric utility units in the United States.

Dry sorbent is typically injected into the ductwork upstream of a PM control device, either an ESP or fabric filter baghouse. The sorbent is typically pneumatically injected as a powder. The sorbent provides an active surface for adsorption of mercury in the flue gas stream, thus promoting formation of particle-bound mercury that can be removed by a particulate matter control device, such as a fabric filter baghouse. As discussed above, due to the potential secondary reaction effects of dry sorbents on the filter cake of a fabric filter baghouse, a fabric filter baghouse would be a more effective PM control device when used in conjunction with a sorbent injection system for control of mercury emissions. Use of enhanced powdered activated carbon, such as brominated activated carbon, has also been evaluated in this analysis to evaluate the potential increases in adsorption through use of the enhanced sorbents.

Step 2 – Eliminate Technically Infeasible Options

Coal Refining

Coal refining is a mechanical and thermal process to remove moisture, sulfur, nitrogen, and heavy metals from coal. Based on the current lack of sufficient supply of coal refining facilities, and the lack of full-scale testing of certain methods such as the Cowboy Coal method, coal refining is not considered an available technology for Hg emissions reduction. Therefore, coal refining is determined to be technically infeasible for this project.

Coal Cleaning

Coal cleaning methods, such as physical coal cleaning by coal washing, would involve pre-processing the coal and removing a portion of the mercury content present in the coal itself. Coal washing would involve gravity separation techniques to remove the mercury in the coal. Mercury removal by physical separation methods is dependent upon the speciation of the mercury present in the coal. The mercury that can be removed by coal washing is dependent upon the amount of "rock bound" mercury present in the coal. Any mercury that is bound within the coal itself (i.e. organic) may not be affected by coal washing. The effectiveness of coal washing for removal of mercury can be highly dependent on the speciation of mercury present in the coal.

Sub-bituminous coals planned for use at the facility, such as PRB coals, are not typically washed. This is due to the fact that PRB coals typically have little overburden, or rock impurities present in the coal since it is as surface mined coal. As stated above, any reduction in mercury content through coal washing would be resultant from the removal of mercury in a form (i.e. rock bound mercury) that would be removed through gravity separation. With the low ash and pyritic content of PRB coals, minimal removal of mercury would be expected. Also, any mercury removal through these methods would likely remove only the particle bound mercury form from the PRB coal, which is a form of mercury effectively controlled through particulate matter control methods.

However, bituminous coals such as Illinois #6 coals are routinely washed prior to shipment and use in utility boilers. Illinois #6 coals purchased by the facility will be washed prior to shipment to Plant Washington. With respect to bituminous coals, coal cleaning is considered technically feasible for this analysis.

Fuel Blending

Western sub-bituminous coals, such as PRB coals, typically have much lower chlorine content than eastern bituminous coals, such as Illinois #6 coal. Therefore, blending of sub-bituminous and bituminous coals for combustion in the main facility boiler could lead to increased gas-phase reactions in the flue gas with chlorine, thereby increasing the effective capture of mercury and reducing mercury emissions. The design criterion for the facility is to burn a 50/50-by-weight

blend of western sub-bituminous PRB coal and eastern bituminous Illinois #6 coal. Therefore, fuel blending is considered technically feasible for this project.

Oxidizing Chemicals

Introduction of chlorine or other halogens into the flue gas stream or on the coal directly could lead to increased gas-phase reactions in the flue gas, thereby increasing the effective capture of mercury and reducing mercury emissions. However, data regarding the effectiveness of such systems, and the use of oxidizing chemicals, would likely be influenced by the type and quality of coal being combusted, and the type and design of additional pollution control equipment in use at the facility. Use of such oxidizing chemicals could potentially lead to corrosion problems within facility boiler and air pollution control devices if excessive amounts are required for mercury control, and potentially lead to emissions of unreacted chlorine. Limited data is available regarding the implementation of such control strategies on a full scale power facility with the planned air pollution control devices and the fuel mix anticipated for Plant Washington. As discussed in Step 1, oxidizing of the mercury present in the gas stream would only be the first step, as effective operation of a wet scrubber or other scrubbing device would be necessary to remove the oxidized mercury from the flue gas stream.

Use of oxidizing chemicals has been evaluated in several DOE/NETL studies with some success indicated at selected sites. Therefore, use of oxidizing chemicals is considered technically for this project. DOE/NETL studies on the use of oxidizing chemicals are further discussed in Step 3 of this BACT analysis.

Unburned Carbon (UBC) Enhancement

Adjusting combustion conditions in the main boiler to increase the unburned carbon content in the ash could have detrimental effects on the efficiency and operation of the main boiler, and could negatively affect emissions of other pollutants, such as PM. Therefore, unburned carbon enhancement is considered technically infeasible for this project.

Fabric Filter Baghouse and Wet Scrubber

BACT evaluations described above for the main facility boiler for PM and SO_2 emissions determined that a fabric filter baghouse and wet scrubber were BACT controls to be used at the facility. Fabric filter baghouses and wet scrubbers are in extensive use as pollution control devices for electric utility boilers. Therefore, use of a fabric filter baghouse in conjunction with a wet scrubber is considered technically feasible for control of Hg emissions.

Spray Dryer Absorber (Dry Scrubber) and Fabric Filter Baghouse

BACT evaluations described above for the main facility boiler for PM and SO_2 emissions determined that a fabric filter baghouse and wet scrubber were more effective controls to be used at the facility, since they are more effective in removing those pollutants. Mercury present in the exhaust gas stream would be associated with PM (particle bound), or treated similar to SO_2 with mercury in the oxidized form. Therefore, use of a fabric filter baghouse in conjunction with a spray dryer absorber is considered technically infeasible for control of mercury emissions for this project.

Selective Catalytic Reduction (SCR)

Use of SCR units potentially enhances oxidation of elemental mercury, thus enabling more effective control of mercury in downstream air pollution control devices. Use of an SCR unit has been proposed as BACT for control of NO_x emissions from the facility. Therefore, use of an SCR system for control of Hg emissions is technically feasible for this project.

Modified catalysts added to the SCR control device could increase the oxidation of elemental Hg and increase the capture of mercury in a wet FGD system. However, only limited information regarding the effectiveness of such practices is available. In addition, if the catalyst used is not a selective catalyst, use of the modified catalyst could lead to more SO_2 to SO_3 conversion, potentially increasing sulfuric acid mist emissions. DOE/NETL studies conducted at Monticello Unit 3 have shown the effective oxidation of mercury through use of catalyst systems. However, the performance of these modified catalysts is still being studied. Use of SCR and modified oxidation catalysts for control of mercury is considered technically feasible and is evaluated further in Step 3 of this analysis.

Sorbent Injection

Sorbent injection would be conducted primarily for removal of mercury emissions, and not achieving mercury removal as a co-benefit (i.e., fabric filter baghouse). Injection of dry sorbents such as PAC into flue gas streams has been used for control of mercury emissions from waste combustors, and has been tested at electric utility units in the United States. Therefore, use of sorbent injection for control of mercury emissions is considered technically feasible for this process.

Step 3 – Rank Remaining Technically Feasible Control Options

Control Effectiveness and Review of EPA's CAMR Assessment

The only feasible control technology found during Step 2 not already being employed as treatment for other pollutants is use of sorbent injection for control of mercury through use of PAC. Research data and evaluations conducted to date indicate that up to a 90 percent reduction in mercury emissions could be achieved. However, the removal efficiency achieved can vary greatly depending on the type of coal being burned and emission controls in use at the facility.

Reference data reviewed indicates that washing of coals can reduced mercury content anywhere from 5% to 39%, correlating with the pyritic sulfur content removal achievable through coal washing. Illinois #6 coals purchased by the facility will be washed prior to shipment to Plant Washington. However, as discussed earlier PRB coals have so little pyritic sulfur or "rock content" that washing of PRB coals is ineffective. Therefore, coal washing for removal of mercury from PRB coals will not be evaluated further in this analysis.

Information regarding the efficiency that can be expected for the combination of controls and coals planned for use at the Plant Washington facility is limited. Table 4-25 provides a summary of resource information reviewed which indicated the level of mercury control achieved for various facilities using comparable emission controls and coals planned for use at Plant Washington. The following Table 4-25 is taken from the *Control of Mercury Emissions from Coal-fired Electric Utility Boilers (2004),* prepared by the USEPA Office of Research and Development, Table 1. This table illustrates the variability present in mercury control depending on the type of coal and emissions control strategy utilized.

Table 4-25 Mercury Capture for Post Combustion Controls for Pulverized Coal Fired Boilers

Post-combustion Control Strategy	Post-combustion Emission Control Device Configuration	Average Mercury Capture by Control Configuration		
		Coal Burned in Pulverized-coal-fired Boiler Unit		
		Bituminous Coal	Subbituminous Coal	Lignite
PM Control Only	CS-ESP	36 %	3%	0 %
	HS-ESP	9 %	6 %	not tested
	FF	90 %	72 %	not tested
	PS	not tested	9 %	not tested
PM Control and Spray Dryer Adsorber	SDA+CS-ESP	not tested	35 %	not tested
	SDA+FF	98 %	24 %	0 %
	SDA+FF+SCR	98 %	not tested	not tested
PM Control and Wet FGD System[a]	PS+FGD	12 %	0 %	33%
	CS-ESP+FGD	75 %	29 %	44 %
	HS-ESP+FGD	49 %	29 %	not tested
	FF+FGD	98 %	not tested	not tested

CS-ESP = cold-side electrostatic precipitator (a) Estimated capture across both control devices
HS-ESP = hot-side electrostatic precipitator
FF = fabric filter
PS = particle scrubber
SDA = spray dryer absorber system

The control of mercury emissions from electric utility steam generating units has been thoroughly evaluated by the USEPA. For example, the USEPA's *Mercury Study Report To Congress (1997)* indicated that a WFGD system would remove approximately 90 percent of the Hg^{2+}, and a WFGD system working with a fabric filter baghouse could remove approximately 88 to 92 percent of the total mercury from bituminous coals. Also, the *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report To Congress – USEPA (1998)* indicated that both WFGD and dry FGD systems could remove over 90 percent of Hg^{2+}, and up to 70 percent of elemental mercury. These studies were used in the development of several subsequent regulatory actions by the USEPA, including development of the Proposed National Emission Standards For Hazardous Air Pollutants for Electric Utility Steam Generating Units, the New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units, and the development of the Clean Air Mercury Rule (CAMR).

The Proposed National Emission Standards For Hazardous Air Pollutants (NESHAP) for Electric Utility Units (2004) proposed mercury emission limits for coal fired utility boilers (new affected sources) of 20 x 10^{-6} lb/MW-hr for use of sub-bituminous coals 6 x 10^{-6} lb/MW-hr for use of bituminous coals, and 1.1 x 10^{-6} lb/MW-hr for use of coal refuse (coal waste). The NSPS and CAMR regulations specified mercury emission limits for new units of either 66 x 10^{-6} lb/MW-hr

or 97 x 10^{-6} lb/MW-hr for units utilizing sub-bituminous coals 20 x 10^{-6} lb/MW-hr for units utilizing bituminous coals, and 16 x 10^{-6} lb/MW-hr for units utilizing coal refuse (coal waste). These emission limits were based on the coal type, or coal rank being combusted as opposed to the type of combustion unit (with the exception of IGCC units).

USEPA determined through the above listed regulatory actions that the Best Demonstrated Technology (BDT) for control of mercury emissions included those controls generally installed for control of SO_2 and PM emissions, including use of fabric filter baghouse, ESP, SCR, and dry and wet scrubber systems. The EPA addressed the option of determining mercury removal across the system (mercury removal efficiency) and using such requirements as a demonstration of compliance, which would promote and give credit for mercury reduction from coal preparation practices such as coal washing. However, EPA found that such a requirement would lead to tracking the mercury concentration in coal from receipt to stack, not just before and after the control device, and could be difficult to implement. EPA determined that evaluation of emission rates would be the most effective for regulatory compliance.

Since the facility will not be utilizing waste coal (coal refuse) as a fuel, achieving the mercury emission limits determined achievable for use of waste coal is not practical. In the January 2004 proposed MACT standard for utility boilers, EPA noted that "[a]vailable data indicate that emissions from the combustion of coal refuse tends to result almost entirely in particulate bound Hg (greater than 99 percent for both units tested in the 1999 EPA ICR)" (FR 4692, Vol. 69, No. 20, 1/30/04). Therefore, with such a high percentage of mercury present in the particulate phase in coal refuse, significant removal efficiencies (i.e. 98%+) are possible for total mercury when combusting waste coal. Waste coal was evaluated as a separate coal rank in the development of the NSPS standards for mercury (Subpart Da), the Clean Air Mercury Rule (CAMR), and the draft MACT standards for utility boilers. The January 2004 proposed MACT standard indicated an emission limitation for a new unit utilizing waste coal as having a mercury emissions limit of 1.1 x 10^{-6} lb/MW-hr, while the emissions limit for a new unit utilizing sub-bituminous coal was 20 x 10^{-6} lb/MW-hr. The emissions limits for waste coal were based on testing data from CFB units utilizing waste coal.

These characteristics of coal refuse allow for much lower mercury limits for units combusting coal refuse. A recent MACT analysis for a Dominion Electric Circulating Fluidized Bed (CFB) boiler indicated a mercury limit of 49 lb/yr, based on a removal efficiency of 98% for total

mercury. This limit was based on the use of waste coal at the facility. CFB units are capable of burning waste coal, while standard pulverized coal fired boilers are not due to the high level of impurities present in the waste coal. Combustion of waste coal leads to increased emissions of other pollutants such as SO_2. Therefore, for the above discussed reasons, the mercury emissions performance of CFB units combusting waste coal will no longer be considered in this BACT analysis.

Recent Studies

The U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL), in conjunction with the EPA, Electric Power Research Institute (EPRI), state and local agencies, power plant facilities, and others manages a significant research and development program for control of mercury emissions from coal-fired power generation facilities. DOE/NETL initiated a research and development program in the 1990s evaluating mercury-specific control technologies such as sorbent injection and mercury oxidation concepts. The research and development program has been implemented in separate phases, with Phase II of the research and development program completed in 2007. Phase III projects were initiated in 2006 and have not yet been completed.

The following Table 4-26 is a summary of the information available to date on the DOE/NETL Phase II and Phase III studies, indicating the average total mercury removal (from co-benefit controls and new technology), the technology under investigation, the coal type utilized during the testing, and the standard emission controls (i.e. ESP, fabric filter baghouse, etc.) in use at the facility. Data indicated in Table 4-26 was taken from the document *An Update on DOE/NETL's Mercury Control Technology Field Testing Program (July 2008)*, and background DOE/NETL test reports and presentations prepared during field testing and evaluations of the units in question. Units indicated in Table 4-26 are those units studied in Phase II and Phase III for which data is available and which utilized either sub-bituminous (i.e. PRB), and a blend of sub-bituminous and bituminous coals during testing evaluations.

Table 4-26 DOE/NETL Testing Program Results

Facility	Technology Under Review	Coal Type In Use	Control Technology In Use	Average Total Mercury Removal[1]
Holcomb Unit 1	Blending Coal Coal Additives Enhanced Activated Carbon	PRB PRB and Bituminous During Blending Evaluations	Spray Dryer Absorber and Fabric Filter	93%
Meramec Unit 2	Coal Additives Enhanced Activated Carbon	PRB	Cold Side ESP	92.6%
Laramie River Unit 3	Blending Coal Coal Additives Enhanced Activated Carbon	PRB PRB and Bituminous During Blending Evaluations	Spray Dryer Absorber and Cold Side ESP	> 90%
Monroe Unit 4	Blending Coal SCR System Enhanced Activated Carbon	PRB/Bituminous Blend	SCR and Cold Side ESP	81%
Labadie Unit 2	Enhanced Activated Carbon – Impacts of SO_3	PRB	Cold Side ESP	50% - > 90%
Stanton Unit 1	Enhanced Activated Carbon	PRB	Cold Side ESP	85%
St. Clair Unit 1	Enhanced Activated Carbon	PRB/Bituminous Blend	Cold Side ESP	94%
Monticello Unit 3	Oxidation Catalysts Injection of Halogen Salts Wet Scrubber Additives	Texas Lignite/PRB Blend	Cold Side ESP and Wet Scrubber	65% - 92%
Big Brown Unit 2	Enhanced Powdered Activated Carbon and TOXECON	Texas Lignite/PRB Blend	Cold Side ESP and COHPAC Fabric Filter	74%
Dave Johnston Unit 3	Enhanced Powdered Activated Carbon and Mer-Cure	PRB	Cold Side ESP	92%
Independence Unit 1	Enhanced Powdered Activated Carbon and TOXECON II	PRB	Cold Side ESP	60% - 90%
Louisa Unit 1	Coal Additives	PRB	Hot Side ESP	No Increase In Mercury Removal Due to Use of Additive
Crawford Unit 7	Enhanced Powdered Activated Carbon	PRB	Cold Side ESP	81%
Will County Unit 3	Enhanced Powdered Activated Carbon	PRB	Cold Side ESP	60% - 73%

[1] Note: Average total mercury removal indicated is the maximum mercury removal determined during field studies at the site. Please see the summaries given below for details on the testing evaluations conducted at the indicated sites.

Table 4-26 DOE/NETL Testing Program Results (Continued)

Facility	Technology Under Review	Coal Type In Use	Control Technology In Use	Average Total Mercury Removal[1]
Fayette Unit 3	Enhanced Powdered Activated Carbon	PRB	Cold Side ESP and Wet Scrubber	80% - 90%
Hawthorne Unit 5	Enhanced Powdered Activated Carbon	PRB	SCR, Spray Dryer Absorber and Fabric Filter Baghouse	> 90%
Hardin Station	Long Term Evaluation Activated Carbon Injection	PRB	Spray Dryer Absorber and Fabric Filter	90%
Limestone Station Unit 1	Enhanced Powdered Activated Carbon and TOXECON II	Texas Lignite/PRB Blend	Cold Side ESP and Wet Scrubber	60% - 90%

[1] Note: Average total mercury removal indicated is the maximum mercury removal determined during field studies at the site. Please see the summaries given below for details on the testing evaluations conducted at the indicated sites.

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

While Table 4-26 provides the results of the Phase II and Phase III study results, the following summaries provide additional details on the results summarized in Table 4-26.

Sunflower Electric Holcomb Unit 1

Holcomb Unit 1 conducted a 30-day, long term field test of DARCO Hg-LH while utilizing PRB coal. DARCO Hg-LH is a proprietary product of Norit Americas, Inc., which is an impregnated lignite coal based activated carbon (bromine enhanced) manufactured specifically for the removal of mercury from coal fired utility units. Total mercury capture across the spray dryer absorber and fabric filter configuration at Holcomb Unit 1 averaged 93% with injection of DARCO Hg-LH at 1.2 lb/MMacf. For the first 6 days of testing, the injection concentration was increased until 90% removal was achieved. The average total mercury removal for the entire 30 day test was 91%, with the average removal from day 6 to 30, following increasing the sorbent injection rate to 1.2 lb/MMacf, was 93%. The average mercury outlet concentration from day 6 to day 30 was 0.83×10^{-6} lb/MMBtu, with a standard deviation of 0.30×10^{-6} lb/MMBtu.

Additional short term evaluations were also conducted at Holcomb Unit 1. These evaluations included an evaluation of the effects of mercury removal by blending western bituminous coal with PRB coal, and chemical addition to the coal to enhance the performance of standard activated carbon. Mercury removal increased to almost 80% by coal blending alone (without sorbent injection), and mercury removal of 86% was achieved at a carbon feed rate of 1.0 lb/MMacf when adding a proprietary chemical (KNX - a halogen based additive), to the coal.

However, the topical report prepared for the Holcomb Station Unit 1 study, *titled Evaluation of Sorbent Injection For Mercury Control, Topical Report For: Sunflower Electric's Holcomb Station (June 2005)*, stressed that these test studies were conducted for very brief periods, and additional longer-term tests were needed to fully evaluate the mercury removal capabilities of the fuel blending and coal additive strategies. Also, during portions of the study the mercury CEM was not properly operating and some of the results from the study are suspect.

AmerenUE's Meramec Unit 2

Meramec Unit 2 also conducted a 30-day long term field test of DARCO Hg-LH while utilizing PRB coal. The total mercury capture achieved across the cold side ESP in use on unit 2 was an average of 93% with sorbent injection at 3.3 lb/MMacf. The average inlet and outlet mercury concentrations were 5.98 x 10^{-6} lb/MMBtu, and 0.44 x 10^{-6} lb/MMBtu, respectively, over the 30-day testing period, with an approximate removal efficiency based on these values of 92.6%. Fly-ash samples collected from the ESP during the testing period, subjected to two different leaching protocols, did not indicate mercury above detection limits in any of the samples evaluated.

An additional short term evaluation was conducted at Meramec Unit 2 involving the use of a coal additive for mercury control (KNX). Greater than 80% total mercury removal was observed (without carbon injection) through use of KNX. However, the topical report for the Meramec Unit 2 study, titled *Evaluation of Sorbent Injection For Mercury Control, Topical Report For: AmerenUE's Meramec Station Unit 2 (September 2005)*, cautioned that the coal additive testing was conducted over a short period, and conditions during testing may not be able to be replicated by other units burning PRB coals. The report indicated that total mercury removal through use of coal additives at another site (Laramie Unit 3) was less than 20%, and additional long term testing needs to be conducted before the limits of the coal additive technology are fully understood.

Missouri Basin Power Project's Laramie River Unit 3

Evaluations at the Laramie River Unit 3 involved evaluation of field testing of sorbent injection utilizing DARCO Hg-LH while utilizing PRB coal, chemical addition to the coal (KNX), and fuel blending of PRB and western bituminous coals. The Laramie River Unit 3 utilized a cold side ESP and a spray dryer absorber during the field tests. As discussed in the Laramie River Unit 3 topical report, titled *Evaluation of Sorbent Injection For Mercury Control, Topical Report For:*

Basin Electric Power Cooperative's Laramie River Station (January 2006), during testing fuel blending was not found to significantly improve mercury removal to above baseline (non-sorbent injection) controls. Coal additive evaluations indicated that, although the speciated fraction of oxidized mercury in the gas stream increased, total mercury removal across the system due to use of coal additives was less than 20%. Sorbent injection through use of DARCO Hg-LH resulted in mercury removal in excess of 90% at injection concentrations of 4.5 lb/MMacf during short term parametric testing. No long-term tests were conducted at Laramie River.

DTE Energy's Monroe Unit 4

Testing at Monroe Power Plant Unit 4, utilizing a cold side ESP and SCR, was conducted to evaluate the effects of injecting a sorbent material for control of mercury when using a small to moderate size ESP, the effects of use of an SCR system on mercury speciation and sorbent effectiveness, and mercury speciation and removal effects when blending PRB and eastern bituminous coals. Based on summary information from the topical report *Evaluation of Sorbent Injection For Mercury Control, Topical Report For DTE Energy's Monroe Station (December 2006)*, no significant changes in mercury speciation or removal were noted when blending of PRB and bituminous coals (60% PRB, 40% bituminous). Also, the SCR was effective at increasing the fraction of oxidized mercury from 20 to 40% to greater than 85% when the SCR was online. Also, similar performance in mercury removal through use of DARCO Hg-LH was observed when the SCR was both online and offline, and an average vapor phase mercury capture of 87% (84% due to sorbent injection) was achieved at an average sorbent injection concentration of 5.9 lb/MMacf during long term testing. Long term testing was conducted at full boiler load conditions, using a blend of PRB and eastern bituminous coal (typically 60% PRB 40% bituminous). The observed change in total mercury emissions from baseline to long term testing was 81%.

AmerenUE's Labadie Unit 2

Testing at Labadie Unit 2 was conducted to evaluate the impacts of sulfur trioxide (SO_3) injection on use of sorbent injection on a unit utilizing SO_3 injection for flue gas conditioning with use of a cold side ESP. The coal type utilized during testing was PRB coal. Turning off the SO_3 flue gas conditioning increased total mercury removal from 50% to 80% when using DARCO Hg-LH sorbent injection at an injection rate of 8 lb/MMacf. Greater than 90% control was observed with

no SO_3 injection and injection of 5 lb/MMacf sorbent upstream of the air preheater. This testing demonstrated that activated carbon injection could be impacted by injection of SO_3, or high concentrations of SO_3, in the exhaust gas stream.

Great River Energy's Stanton Unit 1

Stanton Unit 1 utilizes a cold side ESP with use of PRB coal. Phase II field testing activities at the site investigated use of Sorbent Technologies Corporation (STC) brominated mercury sorbent B-PAC on the control of mercury. Over a 30-day long term test at Stanton Unit 1, 85% average total mercury removal was observed with use of B-PAC at an injection rate of 1.7 lb/MMacf.

DTE Energy's St. Clair Unit 1

DTE Energy's St. Clair Unit 1 utilizes a cold side ESP while combusting a blend of PRB and bituminous coal. During long term testing the unit burned a blend of 85% PRB and 15% bituminous coals, while evaluating use of Sorbent Technologies Corporation B-PAC sorbent. At St. Clair Unit 1 94% average total mercury removal was determined across the system at a sorbent injection rate of 3 lb/MMacf.

Luminant Power's Monticello Unit 3

Monticello Unit 3 utilizes a cold side ESP and wet scrubber (wet FGD) system, while burning a blend of Texas lignite and PRB coals. The facility has been involved in evaluations involving mercury oxidation catalysts, furnace injection of halogen salts ton increase mercury oxidation and improve wet scrubber mercury removal, and field testing of wet scrubber additives for mercury control enhancement. Four oxidation catalysts were installed downstream of the ESP, including gold, SCR catalyst, regenerated Pd#1, and fresh Pd#1. Tests completed in April 2005 indicated total mercury capture across a pilot scale wet scrubber varied from 76% to 87%. This represented an approximate 70% increase in mercury capture above baseline conditions due to use of the catalysts. Evaluation of a wet scrubber additive, Degussa Corporation's TMT-15, to determine if the additive could precipitate absorbed mercury as a stable salt, minimizing mercury re-emissions across the wet scrubber and reducing wet scrubber wastewater mercury concentrations, was inconclusive at a pilot scale. Also, evaluation of furnace injection of halogen salts determined that total mercury removals varied from 65 to 92% (from a baseline of 10 to 40% mercury

control) with increasing concentrations of calcium chloride and calcium bromide injected into the furnace.

Luminant Power's Big Brown Unit 2

Big Brown Unit 2 fires a blend of Texas lignite and PRB coal, and utilizes a cold side ESP and COHPAC fabric filter system. During the Phase II program the TOXECON configuration was evaluated at Big Brown Unit 2. During testing, the united fired a blend of 70% lignite and 30% PRB coal. The 30-day long term evaluation, conducted with enhanced Powdered Activated Carbon (PAC), demonstrated a total mercury capture average of 74% with a sorbent injection rate of 1.5 lb/MMacf.

PacifiCorp's Dave Johnston Unit 3

The Dave Johnston Unit 3 facility utilizes a cold side ESP while combusting PRB coal. The facility completed a 30-day long term study of mercury removal by utilizing the Mer-Cure process, a unique process where sorbent injection takes place in the high temperature region upstream of the air preheater and the process utilizes a proprietary processor to create uniform sorbent dispersion. Chemically treated Mer-Clean injection rates of 0.63 lb/MMacf achieved a total mercury removal of 92% across the system.

Entergy's Independence Unit 1

Long term field testing in 2005 at Independence Unit 1, a unit utilizing PRB coal and a cold side ESP, evaluated use of TOXECON II technology on control of mercury. TOXECON II technology injects sorbents directly into the downstream fields of an ESP, thereby reducing the amount of spent sorbent in collected ash. During field testing in 2005 about 60% average total mercury removal was observed with DARCO Hg-LH injection at 4 to 5 lb/MMacf. Subsequent field testing in 2007, with use of a new sorbent injection lance design, improved the average mercury removal efficiency to 90% while injecting 5.5 lb/MMacf of sorbent.

Midamerican's Louisa Unit 1

Louisa Unit 1 utilizes a hot side ESP while utilizing PRB coal. At this facility the impact on mercury removal of adding high temperature liquid sorbents (KNX) to the precombusted coal was evaluated. While the coal additive promoted mercury oxidation, the lack of SO_2/scrubber control lead to no increase in total mercury removal.

Midwestern Generation's Crawford Unit 7

Crawford Unit 7 utilizes a cold side ESP and PRB coal. Sorbent Technologies conducted a 30-day long term test at the site using a brominated concrete friendly sorbent (C-PAC). Total mercury removal at a sorbent injection rate of 4.6 lb/MMacf was found to be 81%. Fly ash samples collected during the evaluation indicated that the fly ash would be suitable for reuse in concrete production.

Midwestern Generation's Will County Unit 3

Will County Unit 3 utilizes a cold side ESP and PRB coal. Sorbent Technologies conducted filed testing at the facility using a brominated concrete friendly sorbent (C-PAC). Using a recently developed injection lance design, 73% mercury removal was achieved during parametric testing with C-PAC injection at 5 lb/MMacf. Mercury removal ranged from 60% to 73% over a six day continuous test.

Lower Colorado River Authority's Fayette Unit 3

Fayette Unit 3 utilizes a cold side ESP and wet scrubber, and utilizes PRB coal. The facility began a full scale field test in May 2008 of a gold based mercury oxidation catalyst. Results of this testing are not yet available. A Phase III evaluation of Mer-Cure was completed at Unit 3 in 2007. Activated carbon injection mercury capture was 80% with injection of 0.4 to 0.5 lb/MMacf sorbent, and increased to 90% mercury capture with use of 0.8 lb/MMacf Mer-Clean sorbent and eSorb, designed to preserve fly ash quality.

Kansas City Power & Light's Hawthorne Unit 5

Hawthorne Unit 5 utilizes an SCR, spray dryer absorber and fabric filter baghouse with use of PRB coal. During parametric testing on the unit greater than 90% total mercury capture was achieved with a sorbent enhancement additive added to the coal and injection of DARCO Hg-LH sorbent. Testing is still ongoing at the facility.

Rocky Mountain Power's Hardin Station

Hardin Station utilizes PRB coal and a spray dryer absorber and fabric filter emission controls. The facility is undergoing Phase III evaluations to evaluate the mercury removal performance, long term emissions variability, and operation and maintenance of a PAC injection system for greater than 90% mercury control for a 10 to 12 month demonstration. Preliminary results indicate that lower PAC injection rates are required to maintain 90% removal at lower load conditions, possibly due to a higher fraction of oxidized mercury believed produced at the lower load.

NRG Texas Power LLC's Limestone Station Unit 1

Limestone Station Unit 1 utilizes a 70/30 blend of Texas lignite and PRB coal, while utilizing a cold side ESP and wet scrubber. Phase III testing at the site evaluated use of low ash impact sorbent injection and TOXECON II. B-PAC and DARCO Hg-LH sorbents performed similarly with around 90% total mercury removal at a sorbent injection rate of 2 to 3 lb/MMacf. Parametric trials with the unit utilizing 100% PRB coal and the TOXECON II system only achieved 60% total mercury removal. The study is still ongoing.

DOE/NETL Phase II and Phase III Results Evaluation

Although many of the DOE/NETL Phase II and Phase III studies have observed removal efficiencies of 90% or greater for total mercury when utilizing PRB coals, the emission controls in use at the majority of these facilities did not include the full range of control technologies that will be in use at Plant Washington. Also, the document An Update on *DOE/NETL's Mercury Control Technology Field Testing Program (July 2008)* states as follows:

"Although 30-day long term tests were conducted in Phase II, the test period was not sufficient to answer many fundamental questions about long term consistency of mercury removal and reliability of the system with plant processes."

The closing statements of the same technical paper provide as follows:

"while the results achieved during NETL's field tests met or exceeded program goals, only through experience gained during long-term continuous operation of these advanced technologies in a range of full-scale commercial applications will their actual costs and performance be determined."

Assessment of Control Technology

Therefore, although the Phase II and Phase III studies to date have promising results, the long term effective performance of these units is still unknown. While not ranking these technologies for effectiveness, the Plant Washington emissions control scheme − SCR, fabric filter baghouse, and a wet scrubber − has been determined to effectively control mercury emissions. These controls were determined to be the Best Demonstrated Technology (BDT) for control of mercury emissions by the USEPA in development of the NSPS and CAMR mercury regulations. Use of these control strategies, in conjunction with sorbent injection techniques, will allow Plant Washington to implement all of the previously discussed emission control techniques in the DOE/NETL studies and the control strategies discussed in Step 1 and Step 2 of this analysis.

While one study indicated that blending of coals does improve mercury removal efficiency, other Phase II studies conducted at the Monroe and Laramie River facilities indicated that blending of PRB and bituminous coals, as would be done at Plant Washington, showed no marked improvement in total mercury capture with use over PRB coal alone. This is an important finding and supports the possibility that blending of PRB and Illinois #6 coals may not improve the mercury capture efficiency over use of PRB coal alone.

Studies at Labadie Unit 2 tend to indicate that sorbent injection effectiveness can be affected by the concentration of SO_3 present in the flue gas stream. Therefore, with a higher SO_3 duct concentration during consumption of a blend of PRB and bituminous coals (due to the higher sulfur bituminous coals), the additional SO_3 could affect the mercury capture efficiency with use

of activated carbon. Additional concerns for Plant Washington include use of the wet scrubber for SO_2 control, and the possible re-emission of mercury through conversion of oxidized mercury back to elemental mercury across the wet scrubber.

It is important to note that the mercury control strategies evaluated by the DOE/NETL testing programs are capable of implementation at Plant Washington. The majority of the programs involve evaluation of different types of materials (i.e. calcium chloride), different forms of powdered activated carbon (i.e. DARCO Hg-LH), use of coal additives (i.e. KNX), or use of mercury specific oxidation catalysts, all of which could be implemented at Plant Washington. Therefore, if in the future a sorbent material currently under evaluation, or a new sorbent not yet being evaluated, demonstrates superior performance compared to the powdered activated carbon planned for use at Plant Washington, use of those new sorbents or mercury control techniques will be evaluated for use at Plant Washington.

Step 4 – Evaluate Remaining Control Technologies

All of the previously established emission controls technologies and methods, including fabric filter baghouse, wet scrubber, SCR (oxidation), coal blending, and use of sorbent injection with PAC, is chosen as the top level of control for control of mercury emissions. Even though none of these technologies can be eliminated, the use of some of the various control strategies can be prioritized based on the assessments of energy, environmental and economic costs.

Energy Impacts

The only add-on technology not already discussed in previous BACT discussions is a PAC sorbent injection system, and it would be expected to add minimal power demand to the system compared to other facility pollution control devices. Any significant power demand for the sorbent injection system would come from power required to handle or process the sorbent powder. No energy impacts would preclude the use of activated carbon sorbent injection.

Environmental Impacts

The main environmental impact associated with use of the activated carbon or other sorbent injection system is generation of solid waste materials now containing small amounts of mercury. A study by Consol Energy, *The Evolution of Mercury From Coal Combustion Materials and By-*

products (2003), evaluated the fate of mercury collected on fly ash, which is material collected by the particulate matter control devices, on flue gas desulfurization solids, and on bottom ash materials. The objective of the study was to address the concern of mercury evolution into the ecosystem following disposal of waste materials from a coal-fired power plant potentially containing mercury. Samples were collected from fly ash, FGD sludge, and bottom ash waste streams and analyzed for leachable mercury, or mercury that could be released into the surrounding soils following disposal. The mercury content in the filtrates of all fly ash, FGD sludge, and bottom ash samples analyzes fell below the analytical detection limit of 1 part per billion (ppb) of mercury. For a waste stream to be considered a hazardous waste due to the concentration of Hg, it must contain greater than 200 ppb leachable Hg.

Groundwater samples were also collected in areas of active FGD sludge disposal and ash impoundments. Groundwater samples contained less than the Hg analytical detection limit of 1 ppb. Therefore, environmental impacts from use of activated carbon sorbent injection do not pose a concern.

Economic Impacts

Using the USEPA Air Pollution Control Cost Manual and data provided in the USEPA document *Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update* and the DOE report *Preliminary Cost Estimate of Activated Carbon Injection for Controlling Mercury Emissions from an Un-scrubbed 500 MW Coal-fired Power Plant*, the total annual cost of a PAC sorbent injection system would be a minimum of approximately $1.6 million. At this cost, the dollar-per-ton cost effectiveness of the system would be much greater than $10,000/ton, at a cost of greater than $60,000/ton. The dollar-per-ton cost effectiveness of the system is high due to the low concentration of mercury (approximately 0.10 ppm) in the coal planned for use at the facility. However, due to the underlying environmental concerns regarding emissions of Hg, use of an activated carbon sorbent injection system is being considered regardless of its economic feasibility.

Step 5 – Selection of BACT

The pollutant control strategy for Plant Washington, including use of SCR, a fabric filter baghouse, a wet scrubber, and sorbent injection for control of mercury emissions were determined to be the Best Available Control Technology (BACT) for control of mercury

emissions. The current plan for the facility is use of powdered activated carbon (PAC) for sorbent injection. Plant Washington will continue to monitor the development of alternative control strategies and their control effectiveness for control of mercury. Flexibility in the selection of the particular sorbent is important since studies regarding the relative effectiveness of particular sorbents is still in progress.

The next step is to determine the appropriate BACT emission limit. Separate limits could be developed for the operating mode of burning just PRB and the 50-50 blend. However, several case studies indicate that blending bituminous coals with PRB does not improve expected mercury removal efficiencies. And even if they did, the overall efficiency is not linear with the blend proportions. For this reason, Plant Washington proposes a single BACT limit for the case of burning PRB.

The first step in developing a BACT limit is to determine an appropriate concentration of mercury in the coal. Coal analysis data obtained for PRB coal from the USGS COALQUAL database were reviewed to determine the <u>average</u> ppm concentration values for mercury. The <u>average</u> concentration is sought on the basis that the emission limit will be an <u>annual average limit</u> to be monitored on a continuous basis. Use of a maximum mercury concentration, or use of a confidence level (i.e. 90% confidence level) [estimated by taking the average and adding the t statistic (1.282) times the standard deviation] is not appropriate for an evaluation of mercury since the BACT emissions limit proposed for mercury will be on an annual average, with the limit being more effectively evaluated based on an average, or mean value. What is appropriate is to allow for the upper range of the confidence level of the average. This is calculated by adding the quantity of the t statistic times the standard deviation divided by the square root of the number of samples. This COALQUAL data was evaluated in this manner to determine the 95% Upper Confidence Level (UCL) for the mercury concentration of PRB coals. The 95% UCL value, the value which equals or exceeds the true mean of the data set being evaluated 95% of the time, was calculated to be 0.11 ppm. It should be noted that this concentration is on a semi-dry basis.

The proposed BACT emission limit for mercury is 1.68 x 10^{-6} lb/MMBtu on a 12-month rolling average, which is approximately equivalent to 15 x 10^{-6} lb/MW-hr on a 12-month rolling average for this project. This corresponds to a removal efficiency of approximately 84% based on project coal specification mercury content, higher heating value (Btu/lb), and moisture content. Based on data reviewed from all the available resources that is presented in this

report, the estimated control efficiency for mercury when burning sub-bituminous coals (i.e. PRB) ranges from 19% to 93% depending on the reference being cited. The most recent studies indicate that with the control scheme proposed for Plant Washington, control efficiencies of 80% to 90% could be expected. Considering that no data currently exists on any one of these newer control schemes for any long length of time (maximum of one month), the proposed BACT limit does fall within the expected removal efficiency range.

A summary of recent mercury BACT evaluations conducted for similar projects is in Table 4-27. A review of BACT determination information from the RBLC database and draft permits reviewed indicates that the mercury emission limit proposed for Plant Washington is the lowest emission limit value yet proposed for a unit utilizing sub-bituminous (i.e. PRB) coals. While some facilities have indicated higher removal efficiencies for mercury with use of PRB coal, it is important to evaluate the inlet mercury concentration indicated in those evaluations which could be more representative of short term maximums.

One facility, the WE Energies Elm Creek facility, was issued a construction permit in 2004 with a permitted limit of 1.12×10^{-6} lb/MMBtu. However, the facility was given the option of modifying this limit to more accurate levels for the facility operating permit based on initial compliance testing. The facility is not yet operating, so the permit limit has not yet been demonstrated to be achievable. Therefore, this limit is not evaluated as a valid basis of comparison at this time.

Plant Washington is proposing a singular limit for mercury equivalent to the use of 100% sub-bituminous coals (i.e. PRB coal). Compliance with the proposed annual average emission limit will be confirmed through use of a mercury CEMS device.

Table 4-27 RBLC and Draft Permit Listings for Mercury (Hg) Emissions from Pulverized Coal-fired Boilers

Facility Name	Facility State	Permit Number	Permit Date	Process Name	Fuel	Thruput (MW)	Control Description	Emission Limit	Emission Limit Unit	Operational Facility
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	500	FABRIC FILTER BAGHOUSE, SORBENT INJECTION OPTIMIZATION STUDY	1.70E-06	lb/MMBtu	NO
MAIDSVILLE	WV	R14-0024	3/2/2004	BOILER, PC	PULVERIZED COAL	600	SCR, DRY SOLID INJECTION W/ FABRIC FILTER, AND WET LIMESTONE FORCED OXIDATION	2.39E-06	lb/MMBtu	NO
THOROUGHBRED GENERATING STATION	KY	V-02-001	10/11/2002	BOILER, COAL, (2)	COAL	750	ESP, WESP, WFGD	3.21E-06	lb/MMBtu	NO
SANTEE COOPER CROSS GENERATING STATION	SC	0420-0030-CI	2/5/2004	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	660	ESP/FLUE DESULFURIZATION/LOW NOX BURNERS, AND SCR COMBINED	3.60E-06	lb/MMBtu	YES
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	MO	122004-007	12/15/2004	PULVERIZED COAL FIRED BOILER	COAL	275	NONE INDICATED	7.50E-06	lb/MMBtu	NO
TRIMBLE COUNTY	KY	V-02-043 R3	2/29/2008	UNIT 2 750 MW SUPERCRITICAL BOILER	COAL	750	SCR, DRY ESP, ACTIVATED CARBON INJECTION, FABRIC FILTER BAGHOUSE, WET FGD, WET ESP	1.30E-05	lb/MW-hr	NO
LONGLEAF ENERGY ASSOCIATES, LLC	GA	4911-099-0030-P-01-0	5/14/2007	(2) 600MW UNITS	COAL	600	NONE INDICATED	1.50E-05	lb/MW-hr	NO
LIMESTONE ELECTRIC GENERATING STATION	TX	PSD-TX-371 (M3)	5/23/2001	(2) BOILER UNIT 1 & 2 SCRUBBER STACKS, LMS1 & 2	LIGNITE	7863 MMBtu/hr	NONE INDICATED	5.09E-05	lb/MMBtu	YES
SANDY CREEK ENERGY STATION	TX	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED COAL BOILER	COAL	800	NONE INDICATED	1.15E-04	lb/MMBtu	NO
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL, WAP7	COAL	6700 MMBtu/hr	NONE INDICATED	2.78E-04	lb/MMBtu	YES
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	BOILER UNIT 7, COAL & GAS, WAP7	COAL	6700 MMBtu/hr	NONE INDICATED	2.78E-04	lb/MMBtu	YES
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, WAP5&6, COAL	COAL	7400 MMBtu/hr	NONE INDICATED	2.88E-04	lb/MMBtu	YES
WA PARISH ELECTRIC GENERATING STATION	TX	PSD-TX-901, PSD-TX-902 & -33M1	10/15/2003	(2) BOILERS, UNITS 5 & 6, COAL & GAS, WAP5&6	COAL	7400 MMBtu/hr	NONE INDICATED	2.88E-04	lb/MMBtu	YES

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

4.4 Auxiliary Boiler

This section contains the BACT analysis for the 240-MMBtu/hr auxiliary boiler unit planned for use at the facility. A summary of the BACT results for the auxiliary boiler is in Table 4-2. Pollutants in *de minimis* quantities in the boiler fuel (No. 2 fuel oil), including lead, mercury, and fluorides (as HF), were not evaluated due to their low level of estimated annual emissions (<2 lb/yr). If required, BACT emission levels for these pollutants will be established as the pollutant emission factors in AP-42, Fifth Edition, Volume 1, Chapter 1.3.

4.4.1 BACT Demonstration for Particulate Matter (PM) Emissions from the Auxiliary Boiler

PM emissions can be affected by the grade of fuel oil fired in a boiler. PM emissions from oil-fired boilers primarily consist of particles resulting from the incomplete combustion of the oil, and are not correlated to the ash or sulfur content of the oil. Combustion of lighter distillate oil results in lower PM formation than combustion of heavier residual oils.

Step 1 – Identify All Control Technologies

Lower-emitting Process or Practice – Fuel Selection

The only applicable lower-emitting process or practice would be the selection of ultra low-sulfur distillate fuel oil (0.0015 percent) for fuel for the auxiliary boiler. The use of light distillate fuel oil for combustion would lead to lower PM emissions than use of heavier residual oils.

Fabric Filter Baghouse

Fabric filters are used for PM control in a variety of industries, including use as PM control on PC-fired boilers, and are capable of achieving control efficiencies of 99 percent or greater. According to USEPA's fabric filter fact sheet (2003):

> … flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to be collected on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are the most common type of fabric filter. The dust cake that forms on the filter from

> the collected PM can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured in cylindrical bags. Bags may be 6 to 9 m (20 to 30 ft) long and 12.7 to 30.5 centimeters (cm) (5 to 12 inches) in diameter. Groups of bags are placed in isolable compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter.

Advantages of fabric filters can include the following:

1. Can provide high collection efficiencies on both coarse and fine (submicron) particulates.

2. Fabric filters are available in a large number of configurations and system designs, allowing for high flexibility in design.

3. Material is collected dry for subsequent processing or disposal.

Some disadvantages of fabric filters include:

1. Fabric filters can have relatively high maintenance requirements (filter bag replacement).

2. Concentrations of dusts in the collector can represent a fire or explosion hazard if a spark or flame is somehow introduced.

3. The units cannot be operated in high-moisture gas streams; moisture can cause caking or plugging of the fabric filter.

<u>Dry Electrostatic Precipitator (ESP)</u>

Dry ESPs are used in a variety of source categories for control of PM emissions, and are capable of achieving control efficiencies of 99 percent or greater. The following is an excerpt from USEPA's dry ESP fact sheet (2003):

> An ESP is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. The entrained particles are given an electrical charge when they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the electrical field that forces the particles to the collector walls. In dry ESPs, the collectors are knocked, or "rapped", by various mechanical means to dislodge the particulate, which

> slides downward into a hopper where they are collected. The hopper is evacuated periodically, as it becomes full. Dust is removed through a valve into a dust handling system, such as a pneumatic conveyor, and is then disposed of in an appropriate manner.

Advantages of dry ESPs include the following:

1. Are capable of high efficiencies, even for small particulate sizes.

2. Can be designed for a range of gas temperatures, and can handle high temperatures (up to 1,300 degrees Fahrenheit).

3. Relatively large gas flow rates can be effectively handled.

Some disadvantages of dry ESPs include the following:

1. High capital costs and high maintenance items, such as the wire discharge electrodes.

2. Generally not suited for processes that are highly variable because they are sensitive to fluctuations in gas stream conditions (temperature, flow rate, particulate loading, etc.).

3. Fly ash from the combustion of low-sulfur coal typically has high resistivity, and thus is difficult to collect.

<u>Wet Electrostatic Precipitator (WESP)</u>

A WESP is commonly used in situations where a dry ESP is not viable, such as when the material to be collected is wet or flammable, or has high resistivity. WESPs are commonly used by the wood product and metallurgical industries, and can achieve PM control efficiencies greater than 99 percent. The following is an excerpt from USEPA's WESP fact sheet (2003):

> An ESP is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. The entrained particles are given an electrical charge when they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the electrical field that forces the particles to the collector walls. In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. The

collection hoppers used by dry ESPs are replaced with a drainage system. The wet effluent is collected, and often treated on-site.

Advantages of WESPs include the following:

1. Are capable of high efficiencies, even for low particulate sizes.

2. Relatively large gas flow rates can be effectively handled.

3. WESPs can collect sticky particles, mists, and highly resistive or explosive dusts due to the humid atmosphere from washing in the ESP.

4. Continuous or intermittent washing with a liquid eliminates the re-entrainment of particles, to which dry ESPs are subject through the rapping process.

Some disadvantages of WESPs include the following:

1. High capital costs and high maintenance items, such as the wire discharge electrodes.

2. Generally not suited for processes that are highly variable because they are sensitive to fluctuations in gas stream conditions (temperature, flow rate, particulate loading, etc.).

3. WESPs add the complexity of a wash system, and the fact that the resulting slurry must be handled more carefully than a dry product, and can require treatment.

4. WESPs are typically operated at gas stream temperatures less than 190 degrees Fahrenheit, and usually must be constructed of non-corrosive materials.

Step 2 – Eliminate Technically Infeasible Options

Lower-emitting Process or Practice – Fuel Selection

The combustion of light distillate fuel oils results in lower levels of PM emissions than combustion of heavier residual fuel oils. Fuel selection is considered technically feasible for this analysis.

Fabric Filter Baghouse

A fabric filter baghouse is a proven technology in the control of PM/PM_{10} emissions. Data indicate that oily mist from the combustion of fuel oil can clog the filter bags, thus affecting the performance and efficiency of the fabric filter baghouse. However, this technology has been demonstrated on solid fuel boilers and is considered technically feasible.

Dry Electrostatic Precipitator (ESP)

A dry ESP is a proven technology in the control of PM/PM_{10} emissions. This technology is considered technically feasible.

Wet Electrostatic Precipitator (ESP)

A WESP is a proven technology in the control of PM/PM_{10} emissions. This technology is considered technically feasible.

Step 3 – Rank Remaining Technically Feasible Control Options

The combination of the low duty cycle (10 percent), in conjunction with the placement and configuration of the auxiliary boiler at a power plant, has generally eliminated consideration of add-on emission control devices. Since the primary purpose of the auxiliary boiler is for startup and shutdowns of the PC boiler, its operational schedule generally precludes the use of on-site control systems.

Step 4 – Evaluate Remaining Control Technologies

Fabric filter baghouses and ESPs both provide the maximum degree of reduction of PM emissions from an auxiliary boiler unit. Both controls do not have any significant collateral environmental impacts. WESPs have a slight disadvantage compared to fabric filter baghouses and dry ESPs in that WESPs produce a wet waste product, which can lead to additional treatment and disposal costs than with dry systems.

Energy Impacts

Although a fabric filter baghouse would require additional auxiliary power to overcome the pressure drop across the fabric filter bags, such energy requirements would not be enough to preclude use of a fabric filter baghouse. The energy requirements needed for operation of an electrostatic precipitator would be significant and represent an adverse energy impact.

Environmental Impacts

There are no major environmental issues that would preclude the use of a fabric filter baghouse or dry ESP. Solid waste materials collected by the fabric filter baghouses and dry ESPs would be disposed of in accordance with state and federal regulations. WESPs would also create a liquid waste stream.

Economic Impacts

Due to the inherently low amount of PM emissions generated from light distillate fuel oil combustion, compared to the significant annualized costs of PM control technologies, costs for a fabric filter baghouse or an ESP for an auxiliary boiler would be significantly higher than $10,000/ton, which is not cost effective. Therefore, the use of PM control technologies on a light distillate fuel oil-fired boiler would lead to a significant negative economic impact.

Step 5 – Selection of BACT

A summary of recent PM BACT evaluations conducted for similar projects is in Table 4-28. BACT for PM emissions is proposed as use of ultra low-sulfur distillate fuel oil (if commercially available) with an emission limit of 0.024 lb/MMBtu total PM/PM_{10}, and a filterable PM_{10} limit of 0.014 lb/MMBtu. If ultra low sulfur fuel is not available the facility will utilize low sulfur fuel. This level of control and emission limit has been proposed as BACT on recent similar projects.

Table 4-28 RBLC Listings for PM Emissions from Distillate Oil Boilers Up to 250 MMBtu/hr

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit unit
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILLARY BOILER	175	MMBTU/H	LOW ASH FUEL	0.0071	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU	LOW ASH FUEL	0.0071	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #2 FUEL OIL, (3)	150.6	MMBTU/H	NONE INDICATED	0.01	LB/MMBTU
LONGLEAF	GA	4911-099-0030-P-01-0	5/14/07	AUXILLARY BOILER	175	MMBTU/H		0.01 (Filterable) 0.05 (Total)	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - DISTILLATE	150	MMBTU	GOOD COMBUSTION PRACTICES.	0.011	LB/MMBTU
ARCHER DANIELS MIDLAND CO. - NORTHERN SUN VEG. OIL	ND	PTC98002	7/9/1998	BOILER, KEWAUNEE	13	MMBTU/H		0.015	LB/MMBTU
TOQUOP	NV	AP4911-1146	Draft	AUXILARY BOILER	86.4	MMBTU/H		0.018 (Filterable) 0.024 (Total)	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 2 FUEL OIL	238	MMBTU/H	BAGHOUSE	0.02	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #2 FUEL OIL, (3)	150.6	MMBTU/H	NONE INDICATED	0.02	LB/MMBTU
ALABAMA POWER COMPANY	AL	-X002	12/17/1997	BOILER, FUEL OIL (NEW/USED)	190	MMBTU/H	NONE INDICATED	0.02	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - DISTILLATE	150	MMBTU	GOOD COMBUSTION PRACTICES.	0.022	LB/MMBTU
RAYONIER, INC	FL	PSD-FL-256	12/17/1998	INDUSTRIAL BOILER, NO. 6 OIL	212	MMBTU/H		0.0226	LB/MMBTU
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	1822-AOP-R0	5/5/1999	BOILER, FUEL OIL	346	MMBTU/H	CLEAN FUELS AND GOOD COMBUSTION PRACTICES	0.03	LB/MMBTU
OKEELANTA CORPORATION SUGAR MILL	FL	PSD-FL-169A	3/31/2003	BOILER, FUEL OIL	211	MMBTU/H	FUEL SPECIFICATIONS - LOW SULFUR (0.05% S BY WT) DISTILLATE OIL	0.03	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 2 (NO. 2 OIL)	230.8	MMBTU/H	NONE LISTED	0.0498	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 1 (NO. 2 OIL)	84.4	MMBTU/H	NOT LISTED	0.05	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - NO 6 FUEL OIL	150	MMBTU/H	GOOD COMBUSTION PRACTICES.	0.05	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #6 FUEL OIL, (3)	150.6	MMBTU/H	NONE INDICATED	0.05	LB/MMBTU
INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	GA	4	10/13/2004	BOILER, OIL-FIRED	192	MMBTU/H	NONE INDICATED	0.05	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 3 (NO. 2 OIL)	241.6	MMBTU/H	NONE LISTED	0.0513	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 4 (NO. 2 OIL)	204.2	MMBTU/H	NONE LISTED	0.0514	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #6 FUEL OIL, (3)	150.6	MMBTU/H	NONE INDICATED	0.06	LB/MMBTU
LSP - COTTAGE GROVE, L.P.	MN	16300087-001	11/10/1998	BOILERS, AUXILIARY, 2, FUEL OIL	104	MMBTU/H	HAS A NOX PREDICTIVE EMISSION	0.061	LB/MMBTU
LSP - COTTAGE GROVE, L.P.	MN	16300087-001	11/10/1998	BOILERS, AUXILIARY, 2, FUEL OIL	104	MMBTU/H	OF THE TIME. BOILERS ARE LIMITED	0.061	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - NO 6 FUEL OIL	150	MMBTU/H	GOOD COMBUSTION PRACTICES.	0.063	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 1 (LASALOCID OIL & NO. 2 OIL COMBINED)	35.5	MMBTU/H	NONE LISTED	0.084	LB/MMBTU
TECO-POLK POWER STATION/MULBERRY	FL	PSD-FL-194	12/23/2002	BOILER, NO 2 FUEL OIL	120	MMBTU/H	NONE INDICATED	0.1	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 6 FUEL OIL	238	MMBTU/H	BAGHOUSE	0.125	LB/MMBTU
ALABAMA POWER COMPANY	AL	108-0018-X001 AND -X002	12/17/1997	BOILER, FUEL OIL (NEW/USED)	190	MMBTU/H	NONE INDICATED	0.15	LB/MMBTU

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

4.4.2 BACT Demonstration for NO_x Emissions from the Auxiliary Boiler

NO_x is a byproduct of the combustion process and generally refers to both NO and NO_2. NO_x is formed by the oxidation of nitrogen contained in the fuel in the combustion process. Additionally, NO_x can be formed when elemental nitrogen and elemental oxygen are subjected to high temperatures in the combustion process. Temperature, residence time, excess air, and nitrogen availability impact the generation of NO_x.

Step 1 – Identify All Control Technologies

Combustion Controls

The use of combustion controls for NO_x emissions would be a lower pollutant emitting process, through managing the combustion process through the use of low NO_x burners to optimize the combustion process and reduce the generation of NO_x emissions. Important factors in proper combustion include proper fuel residence time, proper air to fuel ratios in the combustion chamber, and consistent proper temperatures in the combustion chamber.

Add-on Controls

The use of add-on controls for NO_x is discussed in Section 4.3.2. The potential add-on controls for the auxiliary boiler include:

- Low NO_x burners (already discussed in the combustion controls section)
- Selective catalytic reduction (SCR)
- Selective non-catalytic reduction (SNCR)
- $SCONO_x$
- Flue gas recirculation (FGR)

Step 2 – Eliminate Technically Infeasible Options

The use of add-on technology for control of NO_x emissions from the auxiliary boiler unit is not technically feasible. Use of add-on controls such as SCR, SNCR, or $SCONO_x$ has not been demonstrated in practice for control of NO_x emissions from auxiliary boilers. These controls require steady-state operations, which do not occur for units that are used for minimized timer periods, such as auxiliary boilers. Combustion controls, such as the proper combustion chamber with low NO_x burners, in conjunction with flue gas recirculation are demonstrated and

proven techniques for the reduction of NO_x emissions. Combustion controls are considered a demonstrated technology for auxiliary boiler NO_x emissions controls, and therefore considered technically feasible under the BACT evaluation process.

Step 3 – Rank Remaining Technically Feasible Control Options

Combustion controls are the only feasible technology for control of NO_x emissions. Combustion controls are designed to optimize the emissions of NO_x from an auxiliary boiler. Therefore, no energy or environmental impacts are associated with the implementation of combustion controls. Since combustion controls are now a standard part of the design process of a boiler, there are no economic impacts associated with their implementation.

Step 4 – Evaluate Remaining Control Technologies

No energy, environmental, or economic impacts are associated with the use of combustion controls, which would preclude combustion controls as BACT for NO_x emissions for an auxiliary boiler.

Step 5 – Selection of BACT

A summary of recent NO_x BACT evaluations conducted for similar projects is in Table 4-29. The proposed BACT for NO_x emissions was chosen as the implementation of combustion controls, including low NO_x burners and flue gas recirculation with an emission limit of 0.1 lb/MMBtu. This level of emissions was chosen as BACT on recent similar projects. Facilities with lower emission limits are using a different grade of fuel, or have not yet been demonstrated in practice.

Table 4-29 RBLC Listings for Nitrogen Oxide (NO_x) Emissions from Distillate Oil Boilers up to 250 MMBtu/hr

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit Unit
ARCHER DANIELS MIDLAND CO. - NORTHERN SUN VEG. OIL	ND	PTC98002	7/9/1998	BOILER, KEWAUNEE	13	MMBTU/H	NONE INDICATED	0.038	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU/H	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION	0.1	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU/H	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION	0.1	LB/MMBTU
TECO-POLK POWER STATION/MULBERRY	FL	PSD-FL-194	12/23/2002	BOILER, NO 2 FUEL OIL	120	MMBTU/H	LOW-NOX BURNERS	0.1	LB/MMBTU
LONGLEAF	GA	4911-099-0030-P-01-0	5/14/07	AUXILIARY BOILER	175	MMBTU/H		0.1	LB/MMBTU
TOQUOP	NV	AP4911-1146		AUXILIARY BOILER	86.4	MMBTU/H		0.11	LB/MMBTU
LSP - COTTAGE GROVE, L.P.	MN	16300087-001	11/10/1998	BOILERS, AUXILIARY, 2, FUEL OIL	104	MMBTU/H	LOW NOX BURNER. EACH BURNER HAS A NOX PREDICTIVE EMISSION MONITORING SYSTEM.	0.12	LB/MMBTU
OKEELANTA CORPORATION SUGAR MILL	FL	PSD-FL-169A	10/29/2001	BOILER, FUEL OIL	211	MMBTU/H	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION AND GOOD COMBUSTION	0.12	LB/MMBTU
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	1822-AOP-R0	5/5/1999	BOILER, FUEL OIL	346	MMBTU/H	LOW NOX BURNERS, FLUE GAS RECIRCULATION, AND GOOD COMBUSTION PRACTICES	0.14	LB/MMBTU
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILERS, AUXILIARY # 1 and 2	117	MMBTU/H	LOW NOX BURNERS, HOURLY OPERATION LIMIT	0.169	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #2 FUEL OIL, (3)	150.6	MMBTU/H	NONE INDICATED	0.2	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - DISTILLATE	150	MMBTU/H	GOOD COMBUSTION PRACTICES. LOW NOX COMBUSTION AND FGR. CEM SYSTEM.	0.2	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 1 (LASALOCID OIL & NO. 2 OIL COMBINED)	35.5	MMBTU/H	NOT LISTED	0.3	LB/MMBTU

Table 4-29 RBLC Listings for Nitrogen Oxide (NO_x) Emissions from Distillate Oil Boilers up to 250 MMBtu/hr (Continued)

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit Unit
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - NO 6 FUEL OIL	150	MMBTU/H	GOOD COMBUSTION PRACTICES. LOW NOX COMBUSTION AND FGR. CEM SYSTEM.	0.4	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #6 FUEL OIL, (3)	150.6	MMBTU/H	LOW NOX BURNERS, FLUE GAS RECIRCULATION, AND GOOD OPERATING PROCEDURES.	0.4	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 1 (NO. 2 OIL)	84.4	MMBTU/H	NONE LISTED	0.4	LB/MMBTU
RAYONIER, INC	FL	PSD-FL-256	12/17/1998	INDUSTRIAL BOILER, NO. 6 OIL	212	MMBTU/H	LOW-NOX BURNERS WITH FLUE GAS RECIRCULATION.	0.425	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 2 (NO. 2 OIL)	230.8	MMBTU/H	NONE LISTED	0.48	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 3 (NO. 2 OIL)	241.6	MMBTU/H	NONE LISTED	0.48	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 4 (NO. 2 OIL)	204.2	MMBTU/H	NONE LISTED	0.48	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 2 FUEL OIL	238	MMBTU/H	OVERFIRE AND SIDE FIRE AIR TO REDUCE FLAME TEMERATURE	0.7	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 6 FUEL OIL	238	MMBTU/H	OVERFIRE AND SIDE FIRE AIR TO REDUCE FLAME TEMERATURE	0.7	LB/MMBTU
NAVAL SURFACE WARFARE CENTER, CARDEROCK DIVISION	PA	AMS: 04108	10/28/2004	BOILERS, (5)	125	MMBTU/H		0.98	LB/MMBTU

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

4.4.3 BACT Demonstration for Carbon Monoxide (CO) Emissions from the Auxiliary Boiler

CO is a byproduct of the incomplete combustion of carbon in the fuel source, in this case coal, in the combustion unit in use. Control of CO is usually accomplished by providing proper fuel residence time and proper combustion conditions. However, factors to reduce CO emissions, such as addition of excess air to improve combustion, can lead to a resultant increase in NO_x emissions through thermal formation of NO_x emissions. Therefore, any evaluation of the reduction of CO emissions must consider the potential secondary impacts in reductions of CO emissions.

Step 1 – Identify All Control Technologies

Combustion Controls

The use of combustion controls for CO emissions would be a lower pollutant emitting process, through managing the combustion process to optimize the combustion process and reduce the generation of CO emissions. Important factors in proper combustion include proper fuel residence time, proper air-to-fuel ratios in the combustion chamber, and consistent proper temperatures in the combustion chamber. CO formation will be limited through use of a properly designed combustion chamber with adequate controls to regulate the combustion process. Proper maintenance is also necessary for proper combustion control. Proper operation of fuel feed systems, fans, system dampers, and other equipment will assist in minimization of CO emissions. However, as stated above, careful consideration is necessary in the process of combustion controls. Since increasing the combustion temperature or oxygen concentration in the combustion chamber would decrease CO emissions, it would likely increase the formation of thermal NO_x, and increase overall NO_x emissions.

Add-on Controls

No effective add-on controls currently exist for CO emissions from a boiler. Use of control technologies such as afterburners would use large quantities of natural gas and simply covert CO to carbon dioxide. Use of afterburners and other control devices, such as catalytic oxidation or flares, has not been demonstrated in practice in auxiliary boiler units. Any such control devices would lead to negative secondary environmental impacts (more NO_x emissions).

Step 2 – Eliminate Technically Infeasible Options

As discussed above, the use of add-on controls for control of CO emissions for the auxiliary boiler unit is not technically feasible. Use of add-on controls, such as flares, afterburners, catalytic oxidation, and external thermal oxidation, has not been demonstrated in practice for control of CO emissions from auxiliary boilers. Combustion controls, such as the proper combustion chamber and system design, and proper operation and maintenance, are demonstrated and proven techniques for the reduction of CO emissions. Combustion controls are considered a demonstrated technology for auxiliary boiler CO emissions controls, and therefore considered technically feasible under the BACT evaluation process.

Step 3 – Rank Remaining Technically Feasible Control Options

Combustion controls are the only feasible technology for CO emissions. Combustion controls are designed to optimize the emissions of CO (and consequently NO_x) from an auxiliary boiler. Therefore, no energy or environmental impacts are associated with the implementation of combustion controls. Since combustion controls are now a standard part of the design process of a boiler, there are no economic impacts associated with them.

Step 4 – Evaluate Remaining Control Technologies

No energy, environmental, or economic impacts are associated with the use of combustion controls which would preclude combustion controls as BACT for CO emissions for an auxiliary boiler.

Step 5 – Selection of BACT

A summary of recent CO BACT evaluations conducted for similar projects is in Table 4-30. BACT for CO emissions was chosen as the implementation of combustion controls and an emission limit of 0.04 lb/MMBtu. This level of BACT is comparable to the level chosen for recent similar projects.

Table 4-30 RBLC Listings for Carbon Monoxide (CO) Emissions from Distillate Oil Boilers Up To 250 MMBtu/hr

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Unit	Control Description	Emissions Limit	Emission Limit Unit
RAYONIER, INC	FL	PSD-FL-256	12/17/1998	INDUSTRIAL BOILER, NO. 6 OIL	212	MMBTU/H		0.033	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 6 FUEL OIL	238	MMBTU/H	NONE LISTED	0.034	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 1 (LASALOCID OIL & NO. 2 OIL COMBINED)	35.5	MMBTU/H	NONE LISTED	0.034	LB/MMBTU
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILERS, AUXILIARY # 1 and 2	117	MMBTU/H		0.035	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 2 FUEL OIL	238	MMBTU/H	NONE LISTED	0.036	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 2 (NO. 2 OIL)	230.8	MMBTU/H	NONE LISTED	0.036	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU/H	COMBUSTION CONTROLS	0.036	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU	COMBUSTION CONTROLS	0.036	LB/MMBTU
TOQUOP	NV	AP4911-1146		AUXILIARY BOILER	86.4	MMBTU/H		0.036	LB/MMBTU
ARCHER DANIELS MIDLAND CO. - NORTHERN SUN VEG. OIL	ND	PTC98002	7/9/1998	BOILER, KEWAUNEE	13	MMBTU/H	NONE LISTED	0.038	LB/MMBTU
LONGLEAF	GA	4911-099-0030-P-01	5/14/07	AUXILIARY BOILER	175	MMBTU/H		0.04	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 4 (NO. 2 OIL)	204.2	MMBTU/H	NONE LISTED	0.04	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 1 (NO. 2 OIL)	84.4	MMBTU/H	NONE LISTED	0.04	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 3 (NO. 2 OIL)	241.6	MMBTU/H	NONE LISTED	0.04	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #6 FUEL OIL, (3)	150.6	MMBTU/H	GOOD COMBUSTION PRACTICE	0.1	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #2 FUEL OIL, (3)	150.6	MMBTU/H	GOOD COMBUSTION PRACTICE	0.1	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - NO 6 FUEL OIL	150	MMBTU/H	GOOD COMBUSTION PRACTICES.	0.105	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - DISTILLATE	150	MMBTU	GOOD COMBUSTION PRACTICES.	0.105	LB/MMBTU
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	1822-AOP-R0	5/5/1999	BOILER, FUEL OIL	346	MMBTU/H	GOOD COMBUSTION PRACTICE	0.12	LB/MMBTU
ALABAMA POWER COMPANY	AL	108-0018-X001 AND -X002	12/17/1997	BOILER, FUEL OIL (NEW/USED)	190	MMBTU/H	NONE LISTED	0.18	LB/MMBTU
INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	GA	2631-115-0021-V-01-4	10/13/2004	BOILER, OIL-FIRED	192	MMBTU/H	GOOD COMBUSTION PRACTICES	0.2	LB/MMBTU

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

4.4.4 BACT Demonstration for VOC Emissions from the Auxiliary Boiler

VOC emissions are generated during a combustion process from incomplete combustion of the fuel, similar to CO emissions. Control of VOC emissions, therefore, is completed in the same manner as that of CO emissions, through providing adequate fuel residence time in the combustion chamber and maintaining a high temperature and sufficient oxygen in the combustion zone to ensure complete combustion. Excessive VOC emissions could result from below optimal combustion zone conditions. Low levels of VOC emissions are expected from properly operated boilers.

Step 1 – Identify All Control Technologies

Combustion Controls

The use of combustion controls for VOC emissions would be a lower pollutant emitting process, through managing the combustion process to optimize the combustion process and reduce the generation of VOC emissions. Important factors in proper combustion include proper fuel residence time, proper air-to-fuel ratios in the combustion chamber, and consistent proper temperatures in the combustion chamber. VOC formation will be limited through use of a properly designed combustion chamber with adequate controls to regulate the combustion process. Proper maintenance is also necessary for proper combustion control. Proper operation of fuel feed systems, fans, system dampers, and other equipment will assist in minimization of VOC emissions. However, as stated above, careful consideration is necessary in the process of combustion controls. Since increasing the combustion temperature or oxygen concentration in the combustion chamber would decrease VOC emissions, it would likely increase the formation of thermal NO_x, and increase overall NO_x emissions.

Add-on Controls

No effective add-on controls currently exist for VOC emissions from a boiler. Use of afterburners and other control devices, such as catalytic oxidation or flares, has not been demonstrated in practice in boiler units. Any such control devices would lead to negative secondary environmental impacts. The use of combustion controls is recognized as BACT for VOC emissions for boilers.

Step 2 – Eliminate Technically Infeasible Options

As discussed above, the use of add-on controls for VOC emissions for the PC boiler units is not technically feasible. Use of add-on controls, such as flares, afterburners, catalytic oxidation, and thermal oxidation, has not been demonstrated in practice for VOC emissions from auxiliary boiler units. Combustion controls, such as the proper combustion chamber and system design, and proper operation and maintenance, are demonstrated and proven techniques for the reduction of VOC emissions. Combustion controls are considered a demonstrated technology for auxiliary boiler VOC emissions controls, and therefore considered technically feasible under the BACT evaluation process.

Step 3 – Rank Remaining Technically Feasible Control Options

Combustion controls are the only feasible technology for VOC emissions. Combustion controls are designed to optimize the emissions of VOCs (and consequently NO_x) from a PC-fired boiler. Therefore, no energy or environmental impacts are associated with their implementation. Since combustion controls are now a standard part of the design process of a boiler, there are no economic impacts associated with their implementation.

Step 4 – Evaluate Remaining Control Technologies

No energy, environmental, or economic impacts are associated with the use of combustion controls which would preclude combustion controls as BACT for VOC emissions for an auxiliary boiler unit.

Step 5 – Selection of BACT

A summary of recent VOC BACT evaluations conducted for similar projects is in Table 4-31. BACT for VOC emissions is proposed as the implementation of combustion controls and an emission limit of 0.003 lb/MMBtu. This level of BACT is comparable to the level chosen for recent similar projects.

Table 4-31 RBLC Listings for Volatile Organic Compound (VOC) Emissions from Distillate Oil Boilers Up To 250 MMBtu/hr

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit Unit
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 2 (NO. 2 OIL)	230.8	MMBTU/H	NONE LISTED	0.001	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 4 (NO. 2 OIL)	204.2	MMBTU/H	NONE LISTED	0.001	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 1 (NO. 2 OIL)	84.4	MMBTU/H	NONE LISTED	0.001	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU/H	COMBUSTION CONTROLS	0.0015	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU	COMBUSTION CONTROLS	0.0015	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 2 FUEL OIL	238	MMBTU/H	NONE INDICATED	0.0016	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 3 (NO. 2 OIL)	241.6	MMBTU/H	NONE LISTED	0.002	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 1 (LASALOCID OIL & NO. 2 OIL COMBINED)	35.5	MMBTU/H	NONE LISTED	0.003	LB/MMBTU
TOQUOP	NV	AP4911-1146		AUXILIARY BOILER	86.4	MMBTU/H		0.003	LB/MMBTU
LONGLEAF	GA	4911-099-0030-P-01-0	5/14/07	AUXILIARY BOILER	175	MMBTU/H		0.003	LB/MMBTU
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	1822-AOP-R0	5/5/1999	BOILER, FUEL OIL	346	MMBTU/H	GOOD COMBUSTION PRACTICES	0.005	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 6 FUEL OIL	238	MMBTU/H	NONE INDICATED	0.005	LB/MMBTU
RAYONIER, INC	FL	PSD-FL-256	12/17/1998	INDUSTRIAL BOILER, NO. 6 OIL	212	MMBTU/H		0.00754	LB/MMBTU
ALABAMA POWER COMPANY	AL	108-0018-X001 AND -X002	12/17/1997	BOILER, FUEL OIL (NEW/USED)	190	MMBTU/H	NONE INDICATED	0.01	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - NO 6 FUEL OIL	150	MMBTU/H	GOOD COMBUSTION PRACTICES.	0.014	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - DISTILLATE	150	MMBTU	GOOD COMBUSTION PRACTICES.	0.014	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #6 FUEL OIL, (3)	150.6	MMBTU/H	GOOD COMBUSTION	0.014	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #2 FUEL OIL, (3)	150.6	MMBTU/H	COMBUSTION CONTROLS	0.014	LB/MMBTU
INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	GA	2631-115-0021-V-01-4	10/13/2004	BOILER, OIL-FIRED	192	MMBTU/H	GOOD COMBUSTION PRACTICES	0.02	LB/MMBTU
LSP - COTTAGE GROVE, L.P.	MN	16300087-001	11/10/1998	BOILERS, AUXILIARY, 2, FUEL OIL	104	MMBTU/H	NATURAL GAS LIMIT AND DISTILLATE FUEL OIL LIMIT.	0.03	LB/MMBTU

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

4.4.5 BACT Demonstration for Sulfur Dioxide (SO_2) Emissions from the Auxiliary Boiler

SO_2 emissions are generated during a combustion process from the combustion of sulfur contained in the fuel. Control of SO_2 emissions is primarily controlled through the sulfur content in the fuel. Since the auxiliary boiler will be fired on light distillate oil (diesel fuel), the fuel's sulfur content will be easily controlled.

Step 1 – Identify All Control Technologies

Fuel Selection

Firing of lower-sulfur fuel is a common lower-emission process/practice to lower SO_2 emissions.

Add-on Controls

Add-on controls for SO_2 are generally post-combustion and are similar to those discussed for the PC boiler. The add-on controls generally include wets scrubbers, dry scrubbers, sorbent injection, limestone injection, and activated carbon injection.

Step 2 – Eliminate Technically Infeasible Options

Each of the identified controls was reviewed and the infeasible options identified. For the purposes of the auxiliary boiler, only the low-sulfur fuel, dry scrubbers, and wet scrubbers were identified as technically feasible. Any control devices added to this unit would be ineffective due to the short duration in which they would be used.

Step 3 – Rank Remaining Technically Feasible Control Options

The RBLC identifies low-sulfur fuel as the most stringent limit for an auxiliary boiler combusting fuel oil. The combination of the low duty cycle (10 percent), in conjunction with the placement and configuration of the auxiliary boiler at a power plant, has generally eliminated consideration of emission controls. Since the primary purpose of the auxiliary boiler is for startup and shutdown of the PC boiler, its operational schedule generally precludes the use of on-site control systems.

Step 4 – Evaluate Remaining Control Technologies

No energy, environmental, or economic impacts are associated with the use of low-sulfur diesel fuel.

Step 5 – Selection of BACT

A summary of recent SO_2 BACT evaluations conducted for similar projects is in Table 4-32. Based on the preceding analysis, the proposed BACT for SO_2 emissions is combustion of ultra low-sulfur fuel (if commercially available). If ultra low sulfur fuel is not available the facility will utilize low sulfur fuel. Compliance with this limitation will be through fuel certification. The emission limit proposed as BACT would be 0.05 lb/MMBtu.

Table 4-32 RBLC Listings for Sulfur Dioxide (SO2) Emissions from Distillate Oil Boilers Up To 250 MMBtu/hr

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit Unit
TOQUOP	NV	AP4911-1146	Draft	AUXILIARY BOILER	86.4	MMBTU/H		0.002	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU/H	LOW SULFUR FUEL OIL	0.051	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU	LOW SULFUR FUEL OIL. SULFUR CONTENT < 0.05% S BY WT.	0.051	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 1 (NO. 2 OIL)	84.4	MMBTU/H	LOW SULFUR FUEL- 0.05% BY WEIGHT	0.051	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 3 (NO. 2 OIL)	241.6	MMBTU/H	FOR NO. 2 OIL; FUEL SULFUR LIMIT OF 0.05% BY WEIGHT	0.0513	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 4 (NO. 2 OIL)	204.2	MMBTU/H	FOR NO. 2 OIL; FUEL SULFUR	0.0514	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 2 (NO. 2 OIL)	230.8	MMBTU/H	FOR NO. 2 OIL, FUEL SULFUR	0.0516	LB/MMBTU
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	1822-AOP-R0	5/5/1999	BOILER, FUEL OIL	346	MMBTU/H	LOW S FUELS: < .05% BY WT S	0.052	LB/MMBTU
OKEELANTA CORPORATION SUGAR MILL	FL	PSD-FL-169A	10/29/2001	BOILER, FUEL OIL	211	MMBTU/H	FUEL SPECIFICATIONS: LOW SULFUR (0.05% S BY WT)	0.054	LB/MMBTU
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	MT	3182-00	7/21/2003	BOILER, AUXILIARY, # 1 & #2	117	MMBTU/H	USE OF LOW SULFUR FUEL OIL (0.05% S), LIMIT ON HOURS OF OPERATION.	0.055	LB/MMBTU
ROCHE VITAMINS	NJ	PCP980003--6	2/5/1999	BOILER 1 (LASALOCID OIL & NO. 2 OIL COMBINED)	35.5	MMBTU/H	LIMITED OPERATING HOURS FOR NO. 2 OIL; NO. 2 OIL	0.079	LB/MMBTU
PENN SPECIALTY CHEMICALS	TN	0274-04B	1/19/2001	BOILER, FUEL OIL, 4-C	250	MMBTU/H	CEMS/OPERATIONAL CONTROLS	0.1	LB/MMBTU
PROCTOR & GAMBLE MANUFACTURING COMPANY	TN	3P (SEE NOTES)	3/5/2001	UTILITY BOILER #2 (FUEL OIL)	183	MMBTU/H	FUEL SPEC: SULFUR CONTENT OF FUEL SHALL NOT EXCEED 0.2% BY WEIGHT.	0.217	LB/MMBTU
PROCTOR & GAMBLE MANUFACTURING COMPANY	TN	3P (SEE NOTES)	3/5/2001	UTILITY BOILER #50-1 (FUEL OIL)	225	MMBTU/H	FUEL SPEC: SULFUR CONTENT OF FUEL SHALL NOT EXCEED 0.2% BY WEIGHT.	0.217	LB/MMBTU
RAYONIER, INC	FL	PSD-FL-256	12/17/1998	INDUSTRIAL BOILER, NO. 6 OIL	212	MMBTU/H		0.2627	LB/MMBTU
ARCHER DANIELS MIDLAND CO. - NORTHERN SUN VEG. OIL	ND	PTC98002	7/9/1998	BOILER, KEWAUNEE	13	MMBTU/H		0.31	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #2 FUEL OIL, (3)	150.6	MMBTU/H	FUEL SULFUR LIMITS: < 0.05% S BY WEIGHT	0.5	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - NO 6 FUEL OIL	150	MMBTU/H	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	0.52	LB/MMBTU
VCU EAST PLANT	VA	VA-50126	3/31/2003	BOILER, #6 FUEL OIL, (3)	150.6	MMBTU/H	FUEL SULFUR LIMIT: < 0.5% S BY WT	0.52	LB/MMBTU
VCU EAST PLANT	VA	50126	3/31/2003	BOILER - DISTILLATE	150	MMBTU	PRACTICES. LOW SULFUR FUELS.	0.53	LB/MMBTU
TECO-POLK POWER STATION/MULBERRY	FL	PSD-FL-194	12/23/2002	BOILER, NO. 2 FUEL OIL	120	MMBTU/H	LOW SULFUR FUEL OIL, < 0.05% S BY WEIGHT	0.8	LB/MMBTU
MICHIGAN PAPERBOARD COMPANY	MI	288-03	9/8/2004	BOILER	185	MMBTU/H		1.51	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 6 FUEL OIL	238	MMBTU/H	NONE INDICATED	1.6	LB/MMBTU
MILLER BREWING COMPANY - TRENTON	OH	14-05515	5/27/2004	BOILER (2), NO. 2 FUEL OIL	238	MMBTU/H	NONE INDICATED	1.6	LB/MMBTU

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

4.4.6 BACT Demonstration for Sulfuric Acid Mist (H_2SO_4) Emissions from the Auxiliary Boiler

SAM is formed by the oxidation of a portion of the SO_2 in the stack gases to SO_3, which then reacts with water vapor in the flue gas to form H_2SO_4. Since the basis of the formation of SAM is SO_2 emissions, then the SO_2 BACT should also be considered BACT for SAM.

Step 1 – Identify All Control Technologies

Fuel Selection

Firing of lower-sulfur fuel is a common lower-emission process/practice to lower H_2SO_4 emissions.

Add-on Controls

Add-on controls for SO_2 are generally post-combustion and are similar to those discussed for the PC boiler. The add-on controls generally include wets scrubbers, dry scrubbers, sorbent injection, limestone injection, and activated carbon injection.

Step 2 – Eliminate Technically Infeasible Options

Each identified control was reviewed, and the infeasible options determined. For the purposes of the auxiliary boiler, only the low-sulfur fuel, dry scrubbers, and wet scrubbers were identified as technically feasible.

Step 3 – Rank Remaining Technically Feasible Control Options

The RBLC identifies low-sulfur fuel as the most stringent limit for an auxiliary boiler combusting fuel oil. The combination of the low duty cycle (10 percent), in conjunction with the placement and configuration of the auxiliary boiler at a power plant, has generally eliminated consideration of emission controls. Since the primary purpose of the auxiliary boiler is for startup and shutdown of the PC boiler, its operational schedule generally precludes the use of on-site control systems.

Step 4 – Evaluate Remaining Control Technologies

No energy, environmental, or economic impacts are associated with the use of low-sulfur diesel fuel.

Step 5 – Selection of BACT

A summary of recent SAM BACT evaluations conducted for similar projects is in Table 4-33. Based on the preceding analysis, the proposed BACT for SAM emissions is combustion of ultra low-sulfur fuel (if commercially available). If ultra low sulfur fuel is not available the facility will utilize low sulfur fuel. Compliance with this limitation will be through fuel certification. This level of BACT has been proposed on recent similar projects.

Table 4-33 RBLC Listings for Sulfuric Acid Mist (H_2SO_4) Emissions from Distillate Oil Boilers Up To 250 MMBtu/hr

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Unit	Control Description	Emissions Limit	Emission Limit Unit
LONGLEAF	GA	4911-099-0030-P-01-0	5/14/07	AUXILIARY BOILER	175	MMBTU/H		6.0E-05	LB/MMBTU
TOQUOP	NV	AP4911-1146	Draft	AUXILIARY BOILER	86.4	MMBTU/H		0.0004	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU/H	LOW SULFUR FUEL OIL	0.0008	LB/MMBTU
PLUM POINT ENERGY	AR	1995-AOP-R0	8/20/2003	AUXILIARY BOILER	175	MMBTU	LOW SULFUR FUEL OIL	0.0008	LB/MMBTU
LSP - COTTAGE GROVE, L.P.	MN	16300087-001	11/10/1998	BOILERS, AUXILIARY, 2, FUEL OIL	104	MMBTU/H	DISTILLATE FUEL OIL LIMIT.	0.0025	LB/MMBTU

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

4.5 Diesel Engine Generator and Fire Water Pump

The facility plans to install and operate a diesel-fired emergency backup generator and diesel-fired emergency fire pump. The two engines will operate only during emergencies and/or maintenance cycles. The facility plans to limit the operating hours of these engines to 500 hours per year for each engine. Typical maintenance operations range from 4 to 8 hours per month.

Step 1 – Identify All Control Technologies

Combustion is a thermal oxidation process that produces emissions as a byproduct of fuel combustion. Combustion of diesel fuel produces emissions of VOCs, CO, SO_2, $\mathbf{NO_x}$, PM, H_2SO_4, and trace amounts of fluorides and lead. Categories of potential control technologies to reduce these emissions were identified as: (1) prevent the formation of the emissions, (2) reduce the formation of the pollutant as low as technologically possible, or (3) treat the emissions once the pollutants have been formed. The identified technologies include the following:

Lower-emitting Process Practices

The process of controlling combustion conditions to reduce the formation of VOC, CO**,** NO_x, and PM is the generally accepted method for controlling these pollutants. Emissions of these pollutants are regulated under the New Source Performance Standard (NSPS) promulgated in 40 CFR 60 Subpart IIII.

Add-on Controls

Add-on controls could be used to control NO_x emissions from the operation of the diesel-fired engines. The two add-on controls identified included SCR and non-selective catalytic reduction (NSCR). These options are described in Section 4.3.2. No add-on controls were identified for SO_2 emissions in AP-42, Section 3.3, "Gasoline and Diesel Industrial Engines" and Section 3.4, "Large Stationary Diesel Engines," or the RBLC.

Refined Fuels

Refined fuels include use of low-sulfur diesel fuel. Traditionally, low-sulfur fuels have been limited to 0.5 percent sulfur content. Recently, lower-sulfur diesel fuel has been developed to further reduce sulfur

emissions from diesel-fired engines. As an added bonus, the low-sulfur fuel has also been identified as being a low-ash fuel, which also reduces emissions of PM in the diesel exhaust.

Step 2 – Eliminate Technically Infeasible Options

The operation of the emergency units will be limited to 500 hours per year, which translates into an operational duty cycle of 6 percent. In a review of the feasibility of the identified control technologies, add-on controls were determined to not be a feasible option for this type of operation. The add-on control units are considered infeasible based on the installation cost and limited operation and maintenance costs.

Step 3 – Rank Remaining Technically Feasible Control Options

Effective combustion practices are considered the only feasible control method for emissions of VOCs, CO, and NO_x. Combustion of low-sulfur fuel for reduction of SO_2, H_2SO_4, and PM is the only technically feasible control technology.

Step 4 – Evaluate Remaining Control Technologies

Good combustion practices are the most effective strategy for controlling emissions of VOCs, CO, and NO_x. Combustion of low-sulfur fuel for reducing the emissions of SO_2, H_2SO_4, and PM is the only technically feasible control technology. There are no energy, environmental, or economic impacts that would preclude the use of effective combustion controls or low-sulfur fuel.

Step 5 – Selection of BACT

The proposed BACT for the emergency backup generator and the emergency fire pump will be the use of good combustion controls and the use of ultra low-sulfur fuels (if commercially available). If ultra low sulfur fuel is not available the facility will utilize low sulfur fuel. The emergency backup generator and the emergency fire pump engine will comply with the emission limitations contained in 40 CFR 60 Subpart IIII. Additionally, the facility proposes to use low-sulfur diesel fuel. Compliance with these limits will be demonstrated by manufacturer's certification and fuel certification.

4.6 Cooling Towers

The cooling tower will be a multi-celled, back-to-back-style tower. The purpose of the cooling tower is to reduce the heat released by the condensed steam from the steam turbine. The cooling tower will

comprise 34 cells using drift eliminators for the reduction of drift, or the amount of water from the cooling tower carried into the ambient air in liquid form (emission points S-2 through S-35). Mineral matter in the water droplets released in the drift is considered PM emissions.

4.6.1 BACT Demonstration for PM Emissions from the Cooling Towers

Particulate emissions will be generated from the wet cooling towers in the form of drift. Drift is formed when droplets of water are entrained in the exhaust gas stream passing through the cooling tower. As the water in the droplets evaporates, the solids in the water become particulate matter.

The only control method available for wet cooling towers is drift eliminators. The design of the drift eliminators dictates their control efficiency. The efficiencies range from 0.05 to 0.0005 percent (gallons of drift per gallons of cooling water).

The proposed BACT for this project is the use of ultra-high-efficiency drift eliminators with an efficiency of 0.0005 percent. The proposed method of compliance for the drift eliminators is use of a manufacturer's guarantee and analysis of the quality of the total dissolved solids (TDS) in the cooling tower makeup water, limited to 3,300 mg/L. This drift limit is consistent with recent BACT evaluations for other power production facilities, and the RBLC database confirms BACT levels of 0.0005 percent. A review of the literature and the RBLC database indicates that this is the highest level of control at this time, as indicated in Table 4-34.

Table 4-34 RBLC Listings for Cooling Tower Drift

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit Unit
ADM CORN PROCESSING - CEDAR RAPIDS	IA	57-01-080	6/29/2007	INDUSTRIAL COOLING TOWER	150000	GALLON/MIN	DRIFT ELIMINATORS	0.0005	% DRIFT RATE
LA PAZ GENERATING FACILITY	AZ	1001743	9/4/2003	MECHANICAL DRAFT COOLING TOWERS FOR GE TURBINES	173870	GALLON/MIN	DRIFT ELIMINATORS	0.0005	% BY VOL
LA PAZ GENERATING FACILITY	AZ	1001743	9/4/2003	MECHANICAL DRAFT COOLING TOWERS FOR SIEMENS TURBINES	141400	GALLON/MIN	DRIFT ELIMINATORS	0.0005	% BY VOL
SPIRITWOOD STATION	ND	PTC07026	9/14/2007	COOLING TOWER	80000	GALLON/MIN	DRIFT ELIMINATOR	0.0005	% COOLING WATER FLOW
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	COOLING TOWER	UNKNOWN		DRIFT ELIMINATORS	0.0005	% DRIFT LOSS
TRIGEN-NASSAU ENERGY CORPORATION	NY	1-2820-01015/00009	3/31/2005	COOLING TOWER			NONE INDICATED	0.0005	% DRIFT
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	COOLING TOWER, F80 (07-A-979P)	50000	GALLON/MIN	DEMISTER	0.0005	% DRIFT LOSS
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	COOLING TOWER, F80 (07-A-979P)	50000	GALLON/MIN	DEMISTER	0.0005	% DRIFT LOSS
ADM CORN PROCESSING - CEDAR RAPIDS	IA	57-01-080	6/29/2007	INDUSTRIAL COOLING TOWER	150000	GALLON/MIN	DRIFT ELIMINATORS	0.0005	% EFF. DRIFT ELIMIN
COMANCHE STATION	CO	04UNITPB1015	38538	COOLING TOWER	140650	GALLON/MIN	ACHIEVE 0.0005 % DRIFT OR	0.0005	% DRIFT RATE
COMANCHE STATION	CO	04UNITPB1015	38538	COOLING TOWER	140650	GALLON/MIN	ACHIEVE 0.0005% DRIFT OR	0.0005	% DRIFT RATE
DICKERSON	MD	CPCN CASE NO. 8888	11/5/2004	COOLING TOWER	10	CELLS	MIST ELIMINATORS	0.001	% DRIFT RATE
HORSESHOE ENERGY PROJECT	OK	2001-156-C PSD	2/12/2002	COOLING TOWERS	111438	GALLON/MIN	DESIGN	0.001	% DRIFT
GENOVA ARKANSAS I, LLC	AR	2009-AOP-R0	8/23/2002	COOLING TOWER	11.4	MMGAL/H	DRIFT ELIMINATORS	0.001	% DRIFT LOSS
DARRINGTON ENERGY COGENERATION POWER PLANT	WA	PSD 03-04	38394	COOLING TOWER			ELIMINATORS WITH DRIFT	0.001	% DRIFT RATE
BP CHERRY POINT COGENERATION PROJECT	WA	EFSEC/2002-01	38363	COOLING TOWER			ELIMINATORS WITH DRIFT	0.001	% DRIFT RATE
BATON ROUGE REFINERY	LA	PSD-LA-667(M-1)	2/18/2004	COOLING TOWERS			DRIFT ELIMINATOR SYSTEM	0.003	% DRIFT
PLAQUEMINE COGENERATION FACILITY	LA	PSD-LA-659	12/26/2001	COOLING TOWER	0.01	% DRIFT RATE	PRACTICES	0.005	% DRIFT RATE
GARYVILLE REFINERY	LA	PSD-LA-719	12/27/2006	HYDROGEN PLANT COOLING TOWER (53-08)			ELIMINATORS	0.005	% DRIFT RATE
ROCKPORT WORKS	IN	147-6713-00041	2/13/1997	COOLING TOWERS (2), NON-CONTACT			DRIFT ELIMINATORS	0.005	% DRIFT
AUBURN NUGGET	IN	033-19475-00092	5/31/2005	COOLING TOWER	23450	GALLON/MIN	NONE INDICATED	0.005	% OF THROUGH PUT
NUCOR STEEL	NC	08680T09	11/23/2004	COOLING TOWERS			0.008 PERCENT DRIFT LOSS	0.008	% DRIFT RATE
NUCOR STEEL	NC	08680T09	38314	COOLING TOWERS			0.008 PERCENT DRIFT LOSS	0.008	% DRIFT RATE
ST. CHARLES REFINERY	LA	PSD-LA-619(M-2)	39121	COOLING TOWERS (2004-6, 2005-42, & 2005-43)			DRIFT ELIMINATORS	-	-
KELSON RIDGE	MD	CPCN CASE NO. 8843	37161	COOLING TOWERS			MIST ELIMINATORS	-	-
NUCOR STEEL	IN	107-12143-00038	36910	COOLING TOWER SYSTEM	12000	GALLON/MIN	NO NUMERICAL LIMIT	-	-

Prepared by: JDC 1/10/08
Checked by: JDF 11/26/08

4.7 Material Handling and Storage Facilities

Particulate emissions will be generated from material handling systems and storage facilities. In particular, emissions will result from handling systems for coal, limestone, storage facilities for coal and limestone, solid materials handling operations, and haul roads. The particulate sources can be grouped into the following categories: transfer points, storage piles, material processing, and haul roads. The permit application contains detailed descriptions of the material handling emissions points and associated emissions calculations.

Step 1 – Identify All Control Technologies

Control options for potential application to the material handling and storage facilities were identified by category. The potential controls include the following:

1) **Transfer Points**:
   Enclosed transfer point with dust suppression and/or dust collector
   Partially enclosed transfer point with dust suppression and/or dust collector
   Dust suppression (water sprays, and use of surfactants or crusting agents)

2) **Storage Piles**
   Full enclosure
   Partial enclosure
   Dust suppression (water sprays, surfactants, crusting agents, and seeding and covering)
   Telescopic chutes
   Lowering wells
   Contouring, compaction, and stabilization
   Minimized active cell area

3) **Material Processing**
   Enclosed processing operation with dust suppression and/or dust collector

4) **Haul Roads**
   Paving
   Dust suppression (water sprays and surfactants)

Step 2 – Eliminate Technically Infeasible Options

Transfer Points

Transfer points include coal railcar unloading, transfer point for PRB coal, transfer point for Illinois #6 coal, limestone railcar unloading, limestone transfer point, fly ash mechanical exhausters, bottom ash transfer point to storage bin, and bottom ash transfer point from bin to truck. In addition, the tripper deck, fly ash silo, Hg sorbent silo, SO_3 sorbent silo, pre-treatment soda ash silo, and pre-treatment hydrated lime silo also include transfer points.

Three control options were identified in Step 1 as potential control for transfer points. The total enclosure with dust suppression is not a technically feasible option for coal railcar unloading, limestone railcar unloading, transfer point for PRB coal, and transfer point for Illinois #6 coal because of railcar handling procedures and safety procedures. The other two options, partial enclosures with dust suppression and/or dust collectors, and dust suppression (use of water sprays, surfactants, or crusting agents), are considered technically feasible for the remainder of the transfer points.

Storage Piles

Storage piles include an active pile for PRB coal, an active pile for Illinois #6 coal, an inactive pile for PRB coal, an inactive pile for Illinois #6 coal, an active pile for limestone, a gypsum pile, and the solid materials handling operations. Seven potential options were identified in Step 1 for control of emissions from storage piles. Of the seven options identified, the full enclosure control strategy for the storage piles is not technically feasible.

Material Processing

Material processing areas on-site include coal and limestone preparation facilities. Both processing operations are to be enclosed inside a separate building. The control option identified in Step 1, enclosing processing operations and using dust suppression and/or a dust collector, is technically feasible.

Haul Roads

Haul roads on-site are primarily internal roadways used by the facility to transport combustion byproducts to the on-site storage facility. Particulate emissions are generated primarily from re-entrained road dust. The two control strategy options identified in Step 1 are technically feasible to control roadway dust.

Step 3 – Rank Remaining Technically Feasible Control Options

Transfer Points

Except the rail unloading operations and transfer to storage pile, the options for controlling particulate emissions from the transfer points, the three options are ranked in order of effectiveness as: (1) enclosed transfer point with dust suppression and/or dust collector, (2) partially enclosed transfer point with dust suppression and/or dust collector, and (3) dust suppression (water sprays or use of surfactants or crusting agents).

Material Processing

Since only one option was identified for on-site material processing, no ranking is required.

Storage Piles

The ranking of the control strategies for storage piles is similar to the ranking for transfer points. The full or partial enclosure is the most effective control strategy to minimize emissions, but is technically infeasible due to the size of the piles and potential hazardous environments that could be found inside such a structure. Dust suppression techniques such as water sprays with or without chemical additives such as surfactants and crusting agents will be the most effective control for the storage piles. Use of telescoping spouts and lowering wells will minimize the creation of particulates for materials being added to or removed from the piles. Dust suppression sprays are also effective during pile maintenance operations.

Particulate emissions from operations at the on-site storage facility (solid materials handling facility) will be most effectively controlled by a combination of physical control strategies, including contouring, compaction, stabilization, and cover, in conjunction with management practices, including minimizing the active work areas in the on-site storage facility. The operations and maintenance practice will be fully identified in the solid materials handling operations plan.

Haul Roads

The two options identified as control options for haul roads were paving and dust suppression through the use of water sprays and/or chemical additives. Since the facility is planning to implement both control strategies, no additional evaluation is required.

Step 4 – Evaluate Remaining Control Technologies

Transfer Points

Fully enclosed transfer point with dust suppression and/or dust collector provides the most effective controls for particulate emissions. Demonstrated BACT testing indicates that control efficiencies of 80 to 99 percent are achievable. Since the facility plans to use fully enclosed transfer points with dust controls where feasible, additional evaluation is not warranted.

Storage Piles

Use of dust suppression sprays with or without chemical additives is the most effective control strategy after full and partial enclosure was identified as being technically infeasible. The facility will use water sprays, surfactants, seeding agents, and contouring to obtain a control efficiency of 90 percent. Telescoping chutes and lowering well will also be used in the transfer point to further minimize emissions from storage pile operation. Covering, limiting the active cell area, and other best management practices (BMPs) will be used in the on-site storage facility to reduce particulate emissions.

Material Processing

The facility will use an enclosed building with fabric filter to control emissions for the coal and limestone processing area.

Haul Roads

Dust suppression techniques, including the use of water sprays, in conjunction with paving haul roads, will obtain a control efficiency of 90 percent. Regular cleaning and application of water sprays will also reduce roadway dust emissions.

Step 5 – Selection of BACT

Techniques to control emissions from material handling identified herein will be used to reduce particulate emissions from these processes. The proposed facility will use a combination of enclosures, dust collectors, telescopic chutes, lowering wells, wet suppression systems, covering, and crusting agents as BACT for material handling. Baghouses with flow rates greater than 1,000 acfm will have a maximum average outlet loading of 0.005 grain per dry standard cubic feet (gr/dscf).

Emissions from transfer points will be reduced by 90 percent using enclosures in conjunction with dust suppression.

Storage pile particulate emissions will be reduced 90 percent through the use of water sprays in conjunction with BMPs. Fugitive emissions from the coal storage piles will be reduced through the use of a retractable chute in conjunction with water sprays, surfactants, crusting agents, contouring, and covering. Fugitive emissions from the limestone stock pile will be reduced by 90 percent through the use of a lowering well when removing material from the pile.

Haul road emissions will be reduced by 90 percent by paving the haul road in conjunction with water sprays and surfactants. The emission limit of 0.005 gr/dscf and proposed control procedures are consistent with recently permitted facilities and those contained in the RBLC database, as shown in Table 4-35.

Table 4-35 RBLC Listings for Material Management Handling Sources

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit Unit
RICHARDTON PLANT	ND	4004	8/4/2004	COAL HANDLING	27	T/H	BAGHOUSE	0.004	GR/DSCF
ENERGY SERVICES OF MANITOWOC	WI	00-RV-092	6/26/2001	FUEL HANDLING			PULSE-JET BAGHOUSES, ENCL	0.004	GR/DSCF
ERIE NUGGET	MN	13700318-001	6/26/2005	COAL & FLUX UNLOADING	4000000	DSCF	FF	0.005	GR/DSCF
ERIE NUGGET	MN	13700318-001	6/26/2005	COAL & FLUX UNLOADING	4000000	DSCF	FF	0.005	GR/DSCF
UNIVERSITY OF NORTHERN IOWA	IA	02-111	5/3/2007	COAL SYSTEM - BUNKER #3 SILO	27.4	lbs/hr	BAGHOUSE	0.005	GR/DSCF
UNIVERSITY OF NORTHERN IOWA	IA	02-111	5/3/2007	COAL SYSTEM - BUNKER #3 SILO	27.4	lbs/hr	BAGHOUSE	0.005	GR/DSCF
GASCOYNE GENERATING STATION	ND	PTC 05005	6/3/2005	COAL HANDLING	400	T/H	BAGHOUSES	0.005	GR/DSCF
SPIRITWOOD STATION	ND	PTC07026	9/14/2007	COAL HANDLING	85.3	T/H	BAGHOUSE	0.005	GR/DSCF
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	GASIFIER COAL FEED BINS, S14 (07-A-959P)	15	tons	BAGHOUSE	0.005	GR/DSCF
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	COAL STORAGE SILOS, S15 (07-A-960P)	5000	tons	BAGHOUSE	0.005	GR/DSCF
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	COAL STORAGE RECLAIM SILO, S16 (07-A-961P)	5000	tons	BAGHOUSE	0.005	GR/DSCF
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	GASIFIER COAL FEED BINS, S14 (07-A-959P)	15	tons	BAGHOSUE	0.005	GR/DSCF
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	COAL STORAGE SILOS, S15 (07-A-960P)	5000	tons	BAGHOUSE	0.005	GR/DSCF
HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	07-A-955P TO 07-A-982P	8/8/2007	COAL STORAGE RECLAIM SILO, S16 (07-A-961P)	5000	tons	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	ROTARY CAR DUMPER	3500	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	TRANSFER CONVEYING BAY	1800	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	TRANSFER HOUSE 2	3500	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	TRANSFER HOUSE 4	3600	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	SILOS	900	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	ROTARY CAR DUMPER	3500	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	TRANSFER CONVEYING BAY	1800	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	TRANSFER HOUSE 2	3500	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	TRANSFER HOUSE 4	3600	TONS/HR	BAGHOUSE	0.005	GR/DSCF
MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	6/17/2003	SILOS	900	TONS/HR	BAGHOUSE	0.005	GR/DSCF
AUBURN NUGGET	IN	033-19475-00092	5/31/2005	COAL CAR UNLOADING	165	T/H	BAGHOUSE	0.0052	GR/DSCF
WYGEN 2	WY	CT-3030	9/25/2002	COAL HANDLING EQUIPMENT			FABRIC FILTER	0.009	GR/DSCF
ERIE NUGGET	MN	13700318-001	6/26/2005	COAL PULVERIZER #1	36	MMBTU/H	FF	0.01	GR/DSCF
ERIE NUGGET	MN	13700318-001	6/26/2005	COAL PULVERIZER #2	9	MMBTU/H	FF	0.01	GR/DSCF
IRON DYNAMICS, INC. (IDI)	IN	033-19160-00076	4/13/2005	COAL DRYER	25	mmbtu/h	BAGHOUSE	0.01	GR/DSCF
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	SILO, BOILER, PLANT COAL	8500	SCFM	8500 SCFM BAGHOUSE	0.01	GR/DCSF
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	DUMP POCKET, COAL	3000	SCFM	BAGHOUSE	0.01	GR/DSCF
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	SILO, COAL	6000	SCFM	BAGHOUSE	0.01	GR/DSCF
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/1998	CRUSHER, CONE, SECONDARY COAL	6000	SCFM	6000 SCFM BAGHOUSE	0.01	GR/DSCF
AUBURN NUGGET	IN	033-19475-00092	5/31/2005	COAL DRYERS	33	T (COAL)/H	BAGHOUSE	0.01	GR/DSCF
WESTERN GREENBRIER CO-GENERATION, LLC	WV	R14-0028	4/26/2006	COAL HANDLING	300	T/H	FABRIC FILTERS	0.01	GR/DSCF
GCC DACOTAH	SD	28.1101-PSD	4/10/2003	COAL SURGE BIN TOP (2)	400	T/H	FABRIC FILTER	0.01	GR/DSCF
GCC DACOTAH	SD	28.1101-PSD	4/10/2003	COAL TUNNEL TO COAL STACKER	400	T/H	FABRIC FILTER	0.01	GR/DSCF
GCC DACOTAH	SD	28.1101-PSD	4/10/2003	COAL TRANSFER	400	T/H	FABRIC FILTER	0.01	GR/DSCF
GCC DACOTAH	SD	28.1101-PSD	4/10/2003	COAL DRYER - FK PUMP	20	T/H	FABRIC FILTER	0.01	GR/DSCF
GCC DACOTAH	SD	28.1101-PSD	4/10/2003	COAL HOPPER TO CONVEYOR	400	T/H	FABRIC FILTER	0.01	GR/DSCF
LONE STAR INDUSTRIES, INC.	IN	133-10159	4/16/1999	CEMENT MANUFACTURING, COAL MILL	40	T/YR	FABRIC FILTER	0.01	GR/DSCF
SUWANNEE AMERICAN CEMENT COMPANY, INC.	FL	1210465-001-AC	6/1/2000	COAL MILL			BAGHOUSE	0.01	GR/DSCF
HUGO GENERATING STA	OK	97-058-C M-2 PSD	2/9/2007	MATERIAL HANDLING			FABRIC FILTER BAGHOUSE	0.01	GR/DSCF
TS POWER PLANT	NV	AP4911-1349	5/5/2005	COAL HANDLING OPERATIONS			FABRIC FILTER DUST COLLECT	0.01	GR/DSCF

Table 4-35 RBLC Listings for Material Management Handling Sources (Continued)

Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Throughput Unit	Control Description	Emissions Limit	Emission Limit Unit
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	SYSTEM 1 - NEW RECLAIM TUNNEL EXIT, #34 (P30, S30)			FABRIC FILTER BAGHOUSE	0.01	GR/DSCF
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	P41, S41, SYSTEM 2 - NEW JUNCTION HOUSE 2, #31 (13)			FABRIC FILTER BAGHOUSE	0.01	GR/DSCF
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	P42, S42, SYSTEM 3 - NEW JUNCTION HOUSE 3, #32			FABRIC FILTER BAGHOUSE	0.01	GR/DSCF
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	P43, S43, SYSTEM 4 - UNIT 4 SILO FILL SYSTEM #7			FABRIC FILTER BAGHOUSE	0.01	GR/DSCF
SUWANNEE AMERICAN CEMENT COMPANY, INC.	FL	1210465-001-AC	6/1/2000	COAL MILL			BAGHOUSE	0.01	GR/DSCF
ERIE NUGGET	MN	13700318-001	6/26/2005	COAL PULVERIZER #1	36	MMBTU/H	FF	0.015	GR/DSCF
ERIE NUGGET	MN	13700318-001	6/26/2005	COAL PULVERIZER #2	9	MMBTU/H	FF	0.015	GR/DSCF
AUBURN NUGGET	IN	033-19475-00092	5/31/2005	COAL DRYERS	33	T (COAL)/H	BAGHOUSE	0.015	GR/DSCF
ARKANSAS LIME COMPANY	AR	0045-AOP-R3	8/30/2005	COAL/COKE BIN VENT, SN-33Q #3			DUST COLLECTOR	0.015	GR/DSCF
WPS - WESTON PLANT	WI	04-RV-248	10/19/2004	P65, S65, P66, S66; PAC TRUCK UNLOADING, PAC SILO LOADING			FABRIC FILTER BAGHOUSE	0.02	GR/DSCF
MANITOWOC PUBLIC UTILITIES	WI	02-RV-147	12/3/2003	SOLID FUEL STORAGE SILO (P12 / S12)			BAGHOUSE	0.02	GR/DSCF
MANITOWOC PUBLIC UTILITIES	WI	02-RV-147	12/3/2003	ASH STORAGE SILO (P14, S14)			BAGHOUSE	0.02	GR/DSCF

Prepared by: JDC 1/10/08
Checked by: JDF 11/26/08

4.8 Storage Tanks

The facility will have three storage tanks used for storage of No. 2 distillate fuel oil. One of these storage tanks will be a 350,000-gallon tank used for storage of No. 2 distillate fuel oil to be used in the main facility boiler and auxiliary boiler during startup and shutdown operations. Another of these storage tanks will be a 750-gallon tank used for storage of No. 2 distillate fuel oil to be used as necessary for the emergency diesel generator. Also, the final storage tank will be a 250-gallon tank used for storage of No. 2 distillate fuel oil to be used as necessary in the facility emergency fire pump. The vapor pressure of No. 2 distillate fuel oil is low (<0.01 psia), so the VOC emissions from these tanks are minimal. At this low vapor pressure, no control device is economically viable due to the low rate of loss. Based on use of the USEPA TANKS Program (Version 4.0.9d), used for estimation of organic emissions from storage tanks, the total VOC emission from all storage tanks will be less than 200 lb/yr.

Work practices at the facility will be implemented to minimize VOC emissions from the facility storage tanks as much as possible. The proposed BACT for the storage tanks is use of conservation vent valves where applicable and BMPs to minimize emissions.

4.9 Opacity

Control methodologies established as BACT for this evaluation have also been established to minimize the formation of visible emissions from facility emission points. These controls are discussed in detail in the particular BACT section for each process.

Opacity is a measurement of visible emissions, and is defined as the amount of light blocked by a medium, such as smoke. Opacity of 0 percent means that all light passes through the medium, and opacity of 100 percent means that no light passes through the medium. Opacity can indicate the concentration of pollutants being discharged from a stack. The more particles emitted from a stack, the more light blocked by the particles (medium), resulting in a higher opacity percentage.

The facility is proposing a 10 percent opacity limit on a 6-minute average for those operations not already covered by a more stringent opacity standard (i.e., NSPS Subpart OOO). Compliance with this level will be maintained by:

- Proper control device maintenance and operation
- Dust suppression techniques to minimize fugitive emissions of particulate matter (PM)

5.0 PSD AMBIENT AIR QUALITY ANALYSIS

The proposed project triggers a PSD review for PM, NO_x, CO, SO_2, VOC, Sulfuric Acid Mist (SAM) and Fluorides (as HF) as indicated in Section 3.0. Part of this PSD review is to conduct an air quality modeling analysis for each pollutant except for VOCs and SAM, which is addressed in the air toxics analysis modeling evaluation in Section 6. The first step of the analysis is to run screening models. The Screening analyses indicates that the project will exceed the PSD Significant Impact Levels (SILs) for SO_2 while PM_{10}, NO_x, and CO concentrations will be below their corresponding levels. Since the significance level was exceeded for SO_2, refined modeling was completed. The results of the refined modeling analysis demonstrated that the project will not cause an exceedance of either the National Ambient Air Quality Standards (NAAQS) or PSD Increment consumption levels for SO_2 at any modeled receptor. The results of this analysis are summarized in the following sections. Electronic copies of the input and output files for the model runs are included on a disc in Exhibit D.

5.1 MODELING METHODOLOGY

The first step in air quality modeling is to run a screen model of all emission sources at the proposed facility. The screen model results for the PSD-triggered pollutants are used to determine whether the emission increases from the proposed facility will result in concentrations that exceed their respective SILs. Refined modeling will be required if significant levels are exceeded. Table 5-1 shows the SILs for PM_{10}, $PM_{2.5}$, NO_x, SO_2, and CO. Current USEPA guidelines call for $PM_{2.5}$ to be evaluated as a surrogate for PM_{10}. Currently there are no promulgated significant impact levels for $PM_{2.5}$, however, on September 21, 2007 the USEPA proposed significant impact levels for $PM_{2.5}$. This USEPA proposal includes three different levels being considered for $PM_{2.5}$ SILs. As a worst case evaluation, the modeling results for $PM_{2.5}$ are being compared to the lowest of the three options. This modeling is not a requirement for the permit application under current guidelines; however, the results are being included in order to demonstrate that the plant will have an insignificant impact on $PM_{2.5}$ concentrations in the area. The screen results were also compared to the lowest of the proposed $PM_{2.5}$ significant monitoring concentrations to determine whether a review for preconstruction monitoring will be required.

Table 5-1 Significant Impact Levels and Significant Monitoring Concentrations

Pollutant	Averaging Period	Significant Ambient Impact Level ($\mu g/m^3$)	Significant Monitoring Concentrations ($\mu g/m^3$)
$PM_{2.5}$[1]	24-hour	1.20	-
	Annual	0.30	-
PM_{10}	24-hour	5	10
	Annual	1	-
SO_2	3-hour	25	-
	24-hour	5	13
	Annual	1	-
NO_x	Annual	1	14
CO	8-hour	500	575
	1-hour	2,000	-
HF	24-hour	-	0.25

1. Lowest of the three proposed Significant Impact Levels.

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The concentrations used for comparison to significant levels calculated by the screen models were the highest concentrations predicted at any receptor for all averaging periods for each modeled pollutant. In screening and refined modeling, the maximum concentration predicted by the model was resolved to within the 100-meter receptor grid spacing to obtain a true maximum (if the initial maximum receptor was not already located in the 100-meter spacing portion). The USEPA AERMOD model was used for all pollutants for all averaging periods. The latest version of AERMOD (Version 07026) was downloaded from USEPA's Support Center for Regulatory Air Models (SCRAM) Web site for use in the modeling.

The latest USEPA's Building Profile Input Program for Prime (BPIP-PRIME model -version 04274) was used to calculate flow vectors based on 36 possible wind directions in order to allow for building downwash. A Cartesian receptor grid was used for the model runs. Receptors were spaced 100 meters apart along the fence line/patrolled property line and out to a distance of 2 kilometers from the property boundary. Receptors were spaced at 500 meters apart from 2 kilometers to 10 kilometers out from the property boundary. Figure 5-1 shows the receptors used in the PSD screen modeling. Digital Elevation Model (DEM) data obtained from the U.S. Geological Survey was used to determine receptor heights using USEPA's AERMAP (Version 06341) computer program.

As part of the project, Power4Georgians will be relocating the portion of Mayview road that currently goes through the property where the plant is to be located. With the relocation of this road, this portion of the plant property will not have public access and will not therefore be included in the modeling evaluation.

The proposed project will result in a potential VOC and NOx emission increase greater than 100 tons per year; therefore, the PSD air modeling guidelines require an evaluation to determine whether preconstruction monitoring is warranted. Preconstruction monitoring of ozone can be waived in the event that representative data for the area is available. The Georgia EPD operates ozone monitors at 24 locations across the state including one in Savannah, Georgia (Chatham County). The predominant wind direction from the site is in the southeast direction towards Savannah, therefore, the results from this ozone monitor can be considered to be representative of the current ozone background for the site. The Quality Assurance Unit that is part of the Georgia EPD conducts various quality assurance activities to ensure that data collected by the air quality monitors comply with the procedures and regulations set forth by the U.S. EPA so that the data collected by the monitors are considered good quality data and data for record.

The comparable 8-hour ozone monitor values for the most recent full year of data (2007) for the Savannah ozone monitor is 68 ppb, which is well below the respective ozone air quality standard of 75 ppb. As indicated by the contemporaneous ozone monitor data, photochemical smog is not considered a problem in this area of the state. Since emissions of NOx and VOC from the proposed project are less than 1.2% and 0.3% respectively of the total emissions from the region, ambient ozone concentrations are not expected to significantly increase from the project.

The regulatory default option and rural environment were used in the models. The Auer Method, which determines the characteristics of a modeling area, was used to confirm that the land use surrounding the proposed site in Washington County is rural, as shown in Table 5-2. Figure 5-1, an aerial photograph of the area surrounding the proposed plant, denotes land use within 3 kilometers.

Table 5-2 Land Use Analysis - Auer Method

Type	Use and Structure	Vegetation	50% of Land Use? (Y/N)
I1	**Heavy Industrial** Major chemical, steel, and fabrication industries; generally 3- to 5-story buildings with flat roofs	Grass and tree growth extremely rare. Less than 5% vegetation.	**N**
I2	**Light-moderate Industrial** Rail yards, truck depots, warehouses, industrial parks, and minor fabrications; generally 1- to 3-story buildings with flat roofs	Very limited grass; trees almost totally absent. Less than 5% vegetation.	**N**
C1	**Commercial** Office and apartment buildings and hotels; 10 stories and flat roofs	Limited grass and trees. Less than 5% vegetation.	**N**
R2	**Compact Residential** Single and some multiple family dwellings with close spacing; generally 2 stories with pitched roofs; garages (via alley) and ash pits; no driveways	Limited lawn sizes and shade trees. Less than 30% vegetation.	**N**
R3	**Compact Residential** Old multi-family dwellings with close (2-meter) lateral separation; generally 2-story, flat-roof structures; garages (via alley) and ash pits; no driveways	Limited lawn sizes and old, established shade tress. Less than 35% vegetation.	**N**
	Conclusion – Urban or Rural?		**Rural Modeling Area**

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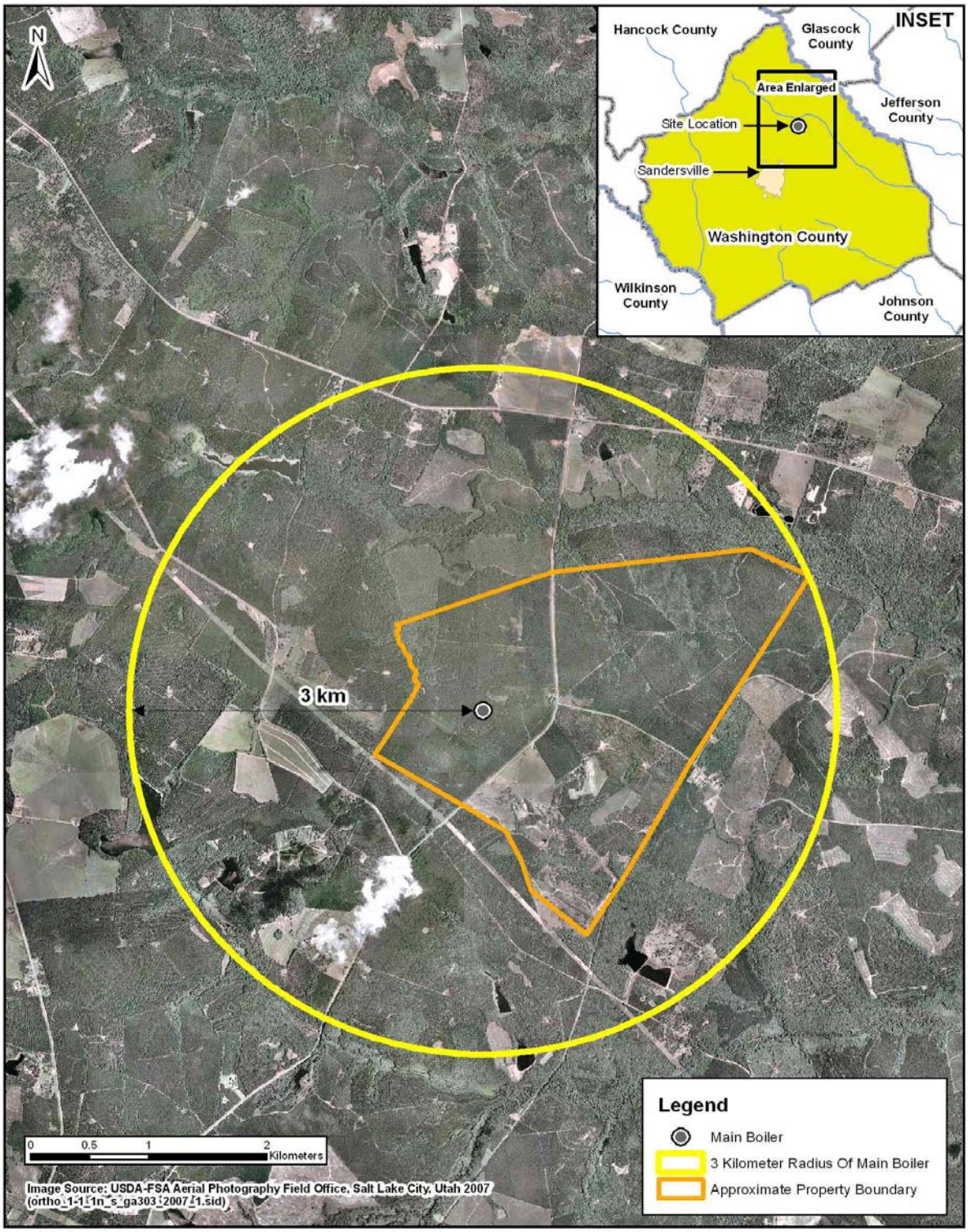
Each emission source was modeled at its maximum hourly emission rate for all modeled pollutants. Table 5-3 summarizes the emission rates and modeling parameters that were used for the on-site modeled emission sources in the screen model runs.

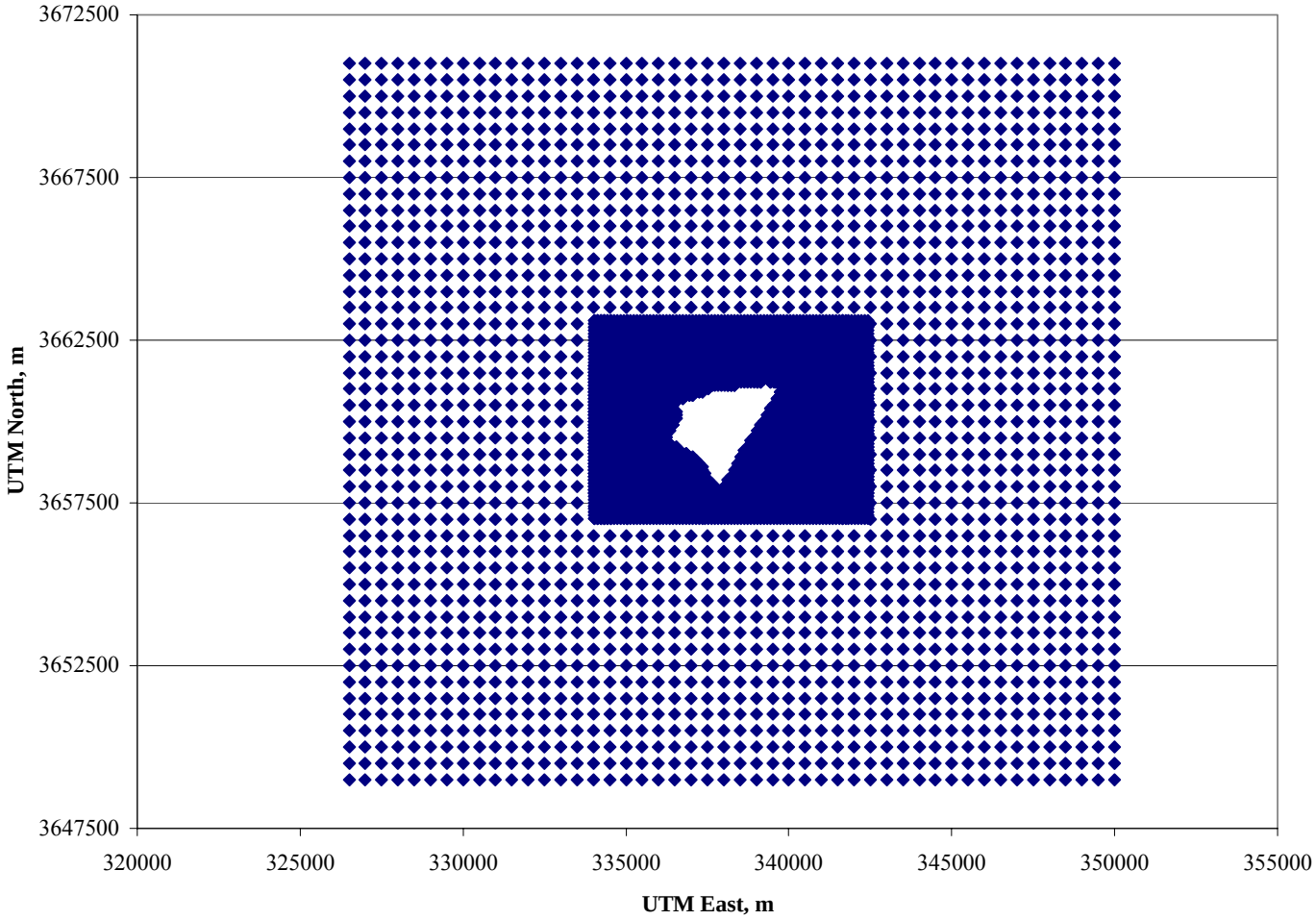
Several point sources at the plant have horizontal discharge stacks. As per the latest AERMOD modeling, these sources were modeled at an exhaust velocity of 0.001 m/s, without adjusting the stack diameter. For those sources which vent ambient air (baghouses, etc.) the exhaust temperature in the model was set at 0 K. When the exhaust temperature is set to 0 K, the AERMOD model uses the ambient temperature from the meteorological data set for the stack's exhaust temperature.

Figure 5-1 Aerial Photograph Showing 3-Kilometer Radius around Proposed Site



Prepared by: FC 11/26/08
Checked by: SAK 11/26/08

Figure 5-2 Entire Modeling Receptor Set



Prepared by: BSA 11/26/08
Checked by: SAK 11/26/08

Table 5-3 Screen Modeling Source Emissions

	UTM Coordinates		$PM_{2.5}$ 24 Hour	PM_{10} 24 Hour	SO_2 3 and 24 Hour	SO_2 Annual	NO_x	CO 1-Hour	CO 8-Hour	HF	H_2SO_4	Height	Diameter	Velocity	Temp
	East (m)	North (m)	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	m	m	m/s	K
Coal-fired Boiler	337088.13	3659815.90	12.93	18.82	120.83	54.38	52.29	313.74	104.58	0.28	4.18	137.16	9.14	18.55	333
Auxiliary Boiler	337338.40	3659776.00	3.53E-01	0.42	1.51	1.51	3.02	1.21E+00	1.21E+00	9.65E-07	1.81E-03	27.43	1.52	19.81	408
Cooling Tower No. 1	337021.84	3659703.97	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 2	337033.91	3659716.04	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 3	337033.91	3659691.90	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 4	337045.97	3659703.97	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 5	337045.97	3659679.83	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 6	337058.04	3659691.90	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 7	337058.04	3659667.76	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 8	337070.11	3659679.83	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 9	337070.11	3659655.69	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 10	337082.18	3659667.76	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 11	337082.18	3659643.62	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 12	337094.25	3659655.69	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 13	337094.25	3659631.55	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 14	337106.32	3659643.62	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 15	337106.32	3659619.48	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 16	337118.39	3659631.55	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 17	337118.39	3659607.41	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 18	337130.46	3659619.48	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 19	337130.46	3659595.34	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 20	337142.53	3659607.41	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 21	337142.53	3659583.27	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 22	337154.60	3659595.34	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 23	337154.60	3659571.20	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 24	337166.67	3659583.27	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 25	337166.67	3659559.13	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 26	337178.74	3659571.20	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 27	337178.74	3659547.06	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 28	337190.81	3659559.13	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 29	337190.81	3659534.99	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 30	337202.88	3659547.06	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 31	337202.88	3659522.92	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 32	337214.95	3659534.99	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 33	337214.95	3659510.86	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Cooling Tower No. 34	337227.02	3659522.92	2.78E-05	6.35E-03	-	-	-	-	-	-	-	15.24	12.19	6.07	0
Crusher House Dust Collector	337335.40	3660114.80	2.07E-02	0.130	-	-	-	-	-	-	-	30.48	0.91	17.25	0
Tripper Decker	337350.40	3659853.00	1.56E-02	9.72E-02	-	-	-	-	-	-	-	59.13	0.79	17.45	0
Limestone Preparation Building	337101.10	3659891.40	7.29E-03	2.70E-02	-	-	-	-	-	-	-	18.29	0.41	0.001	0
Fly Ash Mechanical Exhausters (Fly Ash Filter Seperator)	337222.30	3659877.30	6.89E-03	1.30E-02	-	-	-	-	-	-	-	47.24	0.25	0.001	399
Fly Ash Silo	337222.30	3659890.40	4.29E-03	8.10E-03	-	-	-	-	-	-	-	47.24	0.41	0.001	354
Mercury Storage and Handling	337237.60	3659870.40	2.03E-03	2.03E-03	-	-	-	-	-	-	-	22.86	0.41	0.001	0
SO_3 Storage and Handling	337228.50	3659870.40	2.03E-03	2.03E-03	-	-	-	-	-	-	-	22.86	0.41	0.001	0
Soda Ash Storage and Handling	337293.70	3659690.70	1.01E-03	1.01E-03	-	-	-	-	-	-	-	22.86	0.41	0.001	0
Hydrated Lime Storage and Handling	337293.70	3659684.60	2.73E-04	1.01E-03	-	-	-	-	-	-	-	22.86	0.41	0.001	0
PRB Stackout (Insertable Dust Collector)	337317.75	3660421.69	1.30E-03	8.10E-03	-	-	-	-	-	-	-	33.53	0.30	0.001	0
Illinois No. 6 Stackout (Insertable Dust Collector)	337313.30	3660516.57	1.30E-03	8.10E-03	-	-	-	-	-	-	-	27.43	0.30	0.001	0
Limestone Stackout (Insertable Dust Collector)	337169.45	3660003.07	2.19E-03	8.10E-03	-	-	-	-	-	-	-	21.34	0.30	0.001	0

Completed by: BSA 11/26/08
Checked by: SAK 11/26/08

Table 5-3 Screen Modeling Source Emissions (Continued)

	UTM Coordinates		$PM_{2.5}$ 24 Hour	PM_{10} 24 Hour	SO_2 3 and 24 Hour	SO_2 Annual	NO_x	CO 1-Hour	CO 8-Hour	HF	H_2SO_4	PM_{10} Emission Rate per Unit Area 24HR	$PM_{2.5}$ Emission Rate per Unit Area 24 HR	PM_{10} Emission Rate per Unit Area Annual	$PM_{2.5}$ Emission Rate per Unit Area Annual	Release Height	Number of Vertices or Radius	Release Height	Initial Lateral Dimension	Initial Vertical Dimension
	East (m)	North (m)	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/m^2-s	g/m^2-s	g/m^2-s	g/m^2-s	m		m	m	m
Bottom Ash Storage and Handling System	337315.58	3659846.66	1.11E-04	7.33E-04	-	-	-	-	-	-	-	2.85E-06	4.32E-07	2.85E-06	4.32E-07	3.05	4	-	-	-
Solid Material Handling-Ash	337801.37	3660642.88	5.21E-03	9.48E-03	-	-	-	-	-	-	-	1.99E-08	1.09E-08	1.99E-08	1.09E-08	6.86	8	-	-	-
Solid Material Handling-Gypsum	338256.02	3659829.94	5.21E-03	9.48E-03	-	-	-	-	-	-	-	8.78E-09	4.82E-09	8.78E-09	4.82E-09	6.86	16			
Limestone Rail Unloading	337262.54	3660047.50	3.90E-04	2.57E-03	-	-	-	-	-	-	-	1.53E-05	2.32E-06	1.53E-05	2.32E-06	4.57	4	-	-	-
Coal Rail Unloading	337509.97	3660430.83	5.85E-04	3.86E-03	-	-	-	-	-	-	-	2.31E-05	3.50E-06	2.31E-05	3.50E-06	4.57	4	-	-	-
Limestone Storage and Handling	337169.45	3660003.07	8.53E-04	5.68E-03	-	-	-	-	-	-	-	1.07E-05	1.61E-06	9.42E-07	1.43E-07	9.08	12.98 m	-	-	-
Inactive PRB Coal Pile Storage and Handling	337143.92	3660318.92	1.43E-04	9.44E-04	-	-	-	-	-	-	-	1.94E-08	2.94E-09	1.94E-08	2.94E-09	10.43	4	-	-	-
Inactive Illinois No. 6 Coal Pile Storage and Handling	337143.92	3660554.71	6.53E-04	4.31E-03	-	-	-	-	-	-	-	1.44E-07	2.18E-08	1.44E-07	2.18E-08	7.88	4	-	-	-
Active PRB Coal Pile	337317.75	3660421.69	5.33E-04	2.90E-02	-	-	-	-	-	-	-	1.96E-05	2.94E-06	8.07E-07	1.22E-07	15.21	21.73 m	-	-	-
Active Illinois No. 6 Coal Pile	337313.30	3660516.57	4.87E-03	3.24E-02	-	-	-	-	-	-	-	2.19E-05	3.28E-06	3.08E-06	4.66E-07	15.21	21.73 m	-	-	-
Solid Material Handling Haul Road Node 1	337237.54	3659890.21	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 2	337266.14	3659897.90	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 3	337294.15	3659907.74	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 4	337324.63	3659907.74	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 5	337355.11	3659907.74	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 6	337385.59	3659907.74	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 7	337416.07	3659907.74	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 8	337446.45	3659908.93	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 9	337467.28	3659930.67	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 10	337486.88	3659954.02	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 11	337507.83	3659976.08	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 12	337533.39	3659992.54	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 13	337562.23	3660002.17	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 14	337592.55	3660004.53	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 15	337623.03	3660004.53	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 16	337653.51	3660004.53	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 17	337683.99	3660004.53	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 18	337714.47	3660004.53	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 19	337744.95	3660004.53	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 20	337775.43	3660004.53	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Solid Material Handling Haul Road Node 21	337805.82	3660006.54	1.12E-04	7.48E-04	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 1	337317.75	3660421.69	1.26E-04	1.26E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 2	337291.1	3660406.9	1.26E-04	1.26E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 3	337264.45	3660392.1	1.26E-04	1.26E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 4	337237.81	3660377.31	1.26E-04	1.26E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 5	337211.16	3660362.52	1.26E-04	1.26E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 6	337184.51	3660347.72	1.26E-04	1.26E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 7	337157.86	3660332.93	1.26E-04	1.26E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 8	337131.22	3660318.14	1.26E-04	1.26E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 9	337313.3	3660516.57	1.44E-04	1.44E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 10	337283.88	3660524.53	1.44E-04	1.44E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 11	337254.46	3660532.5	1.44E-04	1.44E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 12	337225.04	3660540.46	1.44E-04	1.44E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 13	337195.62	3660548.42	1.44E-04	1.44E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 14	337166.2	3660556.39	1.44E-04	1.44E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7
Coal Handling Unpaved Road Node 15	337136.78	3660564.35	1.44E-04	1.44E-03	-	-	-	-	-	-	-	-	-			-	-	2.44	4.48	1.7

1. Based on Actual Vertical Dimension of 12 ft, Lateral Dimension of 14.70 ft, and Release Height of 8 ft.

Completed by: BSA 11/26/08
Checked by: SAK 11/26/08

5.2 FUGITIVE PARTICULATE MODELING

PM_{10} and $PM_{2.5}$ emissions from the paved Solid Material Handling Facility (SMHF) haul road and from the transport of coal to and from the active and inactive piles were calculated and modeled per the procedures outlined in the Georgia EPD "Guideline for assuring acceptable ambient concentration of PM_{10} in areas impacted by quarry operation producing crushed stones – October 15, 2004". Emissions from the SMHF haul road and from the transportation of coal between the various piles were estimated using AP-42 sections 13.2.1 (paved roads) and 13.2.2 (unpaved roads). Traffic of bulldozers and other equipment used to transport coal between the active and inactive piles will not follow a set path or occur on defined roads. For estimation purposes the typical path for this equipment was estimated as going from the center of each of the active piles (PRB and Illinois #6) to each of their associated inactive piles.

For emission estimation purposes the SMHF haul road was divided into segments and the amount of traffic through Plant Washington was estimated at each segment based on the amount of ash and gypsum generated from coal combustion. The coal transportation routes were similarly divided up and the amount of traffic was estimated based on maximum coal throughput and the maximum expected shifting among the active and inactive piles. The AP-42 calculations utilize average truck weights, number of wheels on the trucks, silt content, and silt moisture content to calculate the lbs of PM_{10}/ $PM_{2.5}$ emissions per vehicle mile traveled. Estimates for the number of trucks trips and the length of the SMHF haul road and typical coal transport distance were then used to calculate the total traveled distance. The total travel distance and PM emission factors were used to calculate emissions for each road segment. Calculations are included in Exhibit A of the permit application.

Once each road segment's PM_{10}/$PM_{2.5}$ emissions were calculated, each segment was divided into the appropriate volume sources as outlined in the EPD guidance referenced above. The site layout found in Exhibit B provides a map of the site, which locates all road segments included in the modeling analysis. The SMHF haul road and coal transportation route were both modeled as groups of 10 foot x 40 foot volume sources. The effective height for all road dust volume sources were estimated at 8 feet in accordance with modeling guidance.

Emissions from the SMHF were calculated based on emission factor equations obtained from AP-42 Table 11.9-1 for bulldozing operations. The emission factor equations utilize silt and moisture contents to calculate $PM_{10}/PM_{2.5}$ emission rates, which were obtained from AP-42 Table 11.9-3. Once emissions were calculated, each source was modeled as an area poly source as outlined in Section 3.3.2.3 of the AERMOD User Guide (September 2004).

Drop point emissions from Coal Rail Unloading, Limestone Rail Unloading, and Bottom Ash Transfer were calculated using the drop point emission factor equation found in AP-42 Section 13.2.4.3. The equation utilizes the mean wind speed and moisture content of the material being handled to calculate an emission per unit ton of material handled factor. After computing emission rates, each drop point was modeled as an area poly source according to Section 3.3.2.3 of the AERMOD User Guide (September 2004).

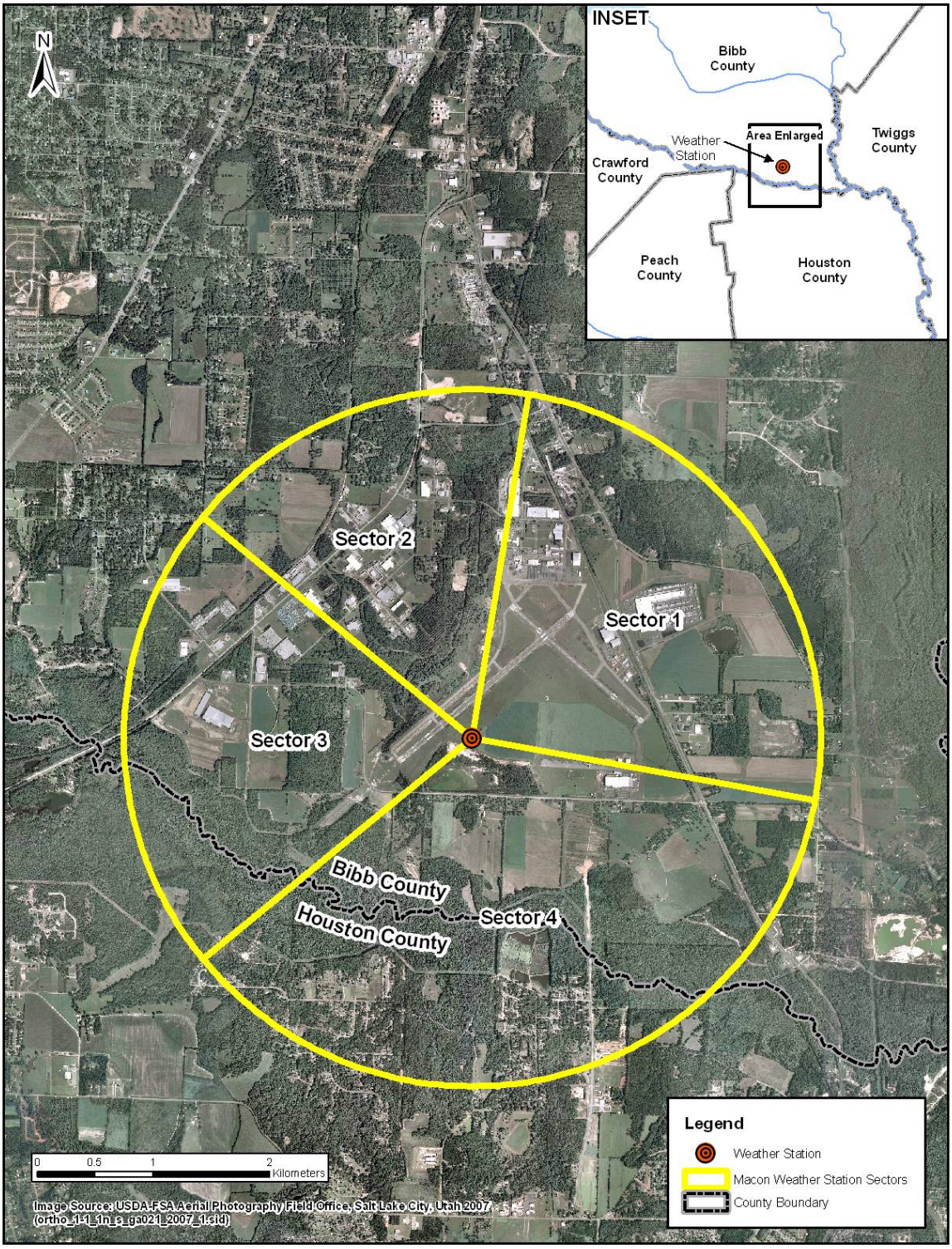
Emissions from the Powder River Basin and Illinois No. 6 Active and Inactive Piles were calculated using the Industrial Wind Erosion equations found in AP-42 (Section 13.2.5). In addition to emissions from wind erosion, the emissions from the dropping of coal from the transportation equipment at both the active and inactive piles were also calculated. These drop point emission calculations were based on the AP-42 emission factor from AP-42 section 13.2.4.3 that was also used for unloading operations. Per EPD guidance, the active and inactive piles as well as the lime piles were modeled as area sources in the model. For those piles that are cone shaped (the active coal piles and the lime piles), the modeled area was set at the area of the pile at the mid point height. These sources were modeled as circular areas. The inactive piles are trapezoidal shapes, therefore, their release heights were set to the height of the top of the pile as elevated planes.

5.3 METEOROLOGICAL DATA

The Georgia EPD provided MACTEC with AERMET (version 06341) pre-processed meteorological data files based on surface data for the Macon Airport meteorological station and upper air data from the Centreville meteorological station for the 1987-1991 five year period. The development of the AERMET data set requires the assessment of surface characteristics of the surface meteorological station. These characteristics include albedo, bowen ratio, and surface roughness. Albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption, bowen ratio is an indicator of surface moisture, and surface roughness length is related to the height of obstacles in relation to wind flow. The AERMET data was processed using the surface characteristics assessed by Georgia EPD. A comparative analysis of surface characteristics surrounding Plant Washington in Sandersville, Georgia and the surface meteorological station was conducted, according to the AERMOD Interim Guidance document.

The surface characteristics surrounding Plant Washington were compared to surface characteristics surrounding the surface meteorological station at the Macon Airport. Figure 5-3 is an aerial photo centered on the Macon airport surface meteorological data station and Figure 5-4 is an aerial photo of the Plant Washington. Each aerial photo was divided into the four sections: Section 1 from 350° to 80°, Section 2 from 80° to 140°, Section 3 from 140° to 220°, and Section 4 from 220° to 350°. These segments corresponded to the segments that were used in the AERMET processing. Table 5-4 shows a qualitative comparison between the surface characteristics at the proposed coal-fired power plant and the Macon Airport. Based on this comparative analysis, the Macon Airport justifiably represents the meteorological conditions at the proposed site.

Figure 5-3 Aerial View of Macon Surface Meteorological Station in Macon, Georgia



Prepared by: FC 11/26/08
Checked by: SAK 11/26/08

Figure 5-4 Equivalent Sectors of Plant Washington in Sandersville, Georgia

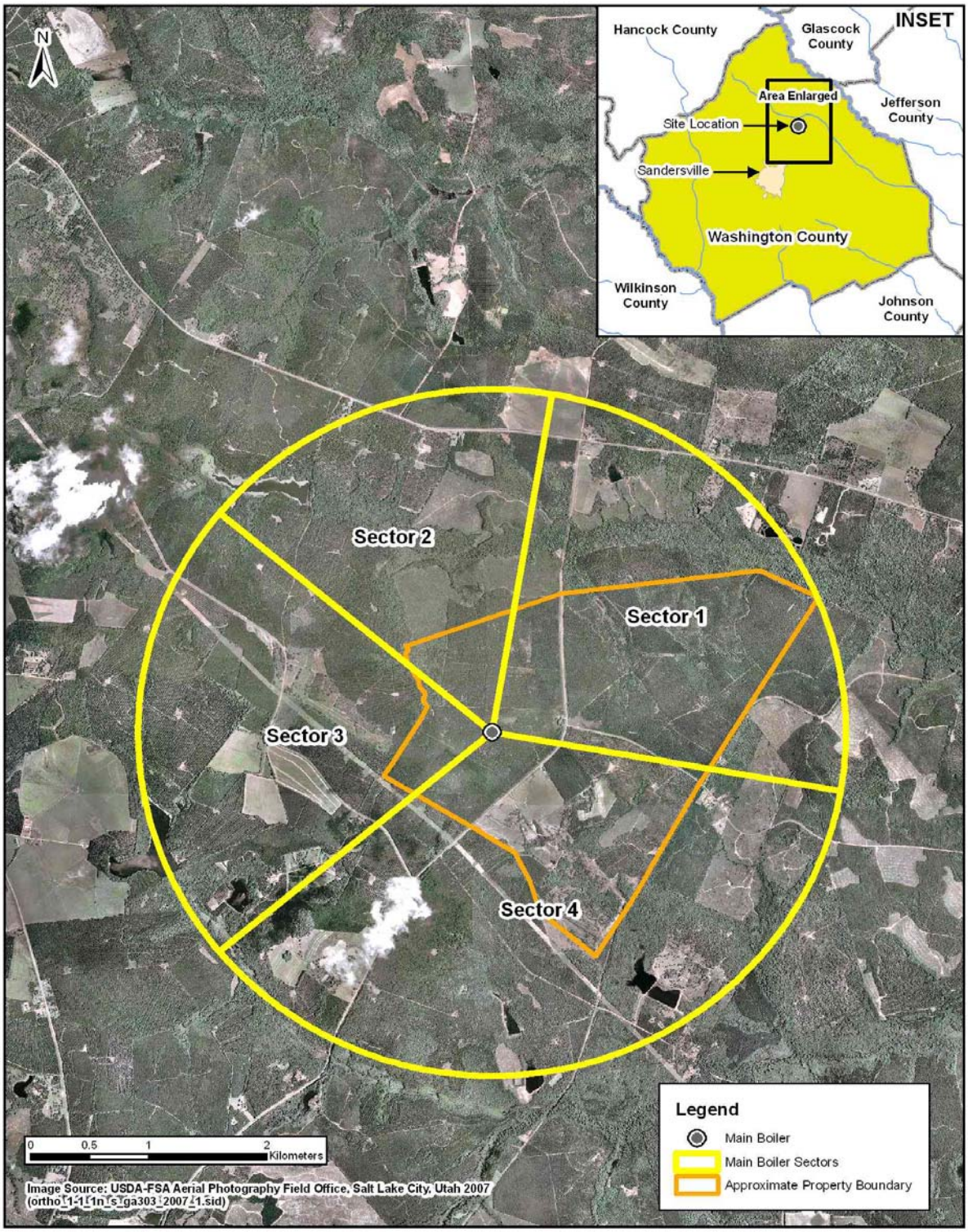


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Table 5-4 Qualitative Comparisons between the Surface Characteristics at Plant Washigton and the Macon Airport

Surface Characteristic	Macon Airport	Plant Washington
Albedo – Total incident radiation reflected back into space. 0.1 – Deciduous Forest 0.9 – White Snow	Green area except for a few buildings and roads 0.1 – 0.2	Green area except for a few buildings and roads 0.1 – 0.2
Bowen Ratio – Indication of surface moisture. 0.10 – Over water 10 – Over Desert	For Sectors 1 and 3 – Elevated surface with excellent surface run-off with little standing water ~2 For Sector 2 – Poor surface run-off due to depression and poor soil permeability due to red clay. < 1 For Sector 4 – Primarily vegetation with good surface run-off ~1	For Sectors 1 and 3 Excellent surface run-off with little standing water ~2 For Sector 2 – Poor infiltration due to concrete surface; therefore, a lot of standing water < 1 For Sector 4- Primarily vegetation with good surface run-off ~1
Surface Roughness Length – Height of obstacles in principal where horizontal wind velocity is zero. 0.001 m – Water >1 m - for Forest or Urban	For Sectors 1 and 4 trees and buildings are at an average height of 30 ft except for airport runway ~1 For Sectors 2 and 3 – areas are predominantly green fields <1	For Sectors 1 and 4 trees, are at an average height of 30 ft except for cultivated areas ~1 For Sectors 2 and 3 – areas are predominantly green fields and cultivated areas <1

Completed by: BSA 11/26/08
Checked by: SAK 11/26/08

5.4 PSD SCREEN MODELING RESULTS

The screen modeling for PM_{10}, $PM_{2.5}$, NO_x, CO, SO_2, VOC, and Fluorides (as HF) were used to determine whether the proposed emission increases result in concentrations that exceed the SILs or the significant monitoring levels. Refined modeling is required if these significant levels are exceeded. There are separate

significance levels to assess whether preconstruction monitoring is required. Tables 5-5 through 5-10 show the results of the screen modeling for each pollutant, which are discussed in more detail below.

5.4.1 $PM_{2.5}$ Screen Model Results

The screen modeling results for $PM_{2.5}$, as presented in Table 5-5, do not exceed the lowest recently proposed SILs for the 24-hour and annual averaging periods (option 3 under the USEPA proposal). This modeling evaluation is not a regulatory requirement under the current air quality rules; however, the results are included to demonstrate that the project will not have a significant impact on $PM_{2.5}$ concentrations in the area around the proposed plant. The lowest of the proposed preconstruction monitoring level was also not exceeded.

Table 5-5 $PM_{2.5}$ Screening Results

$PM_{2.5}$ 24-Hour Screen Results			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	1.17	338468.69	3658817.75
1988	1.08	336037.00	3659511.00
1989	1.01	336337.00	3658911.00
1990	1.11	336337.00	3659211.00
1991	1.10	338811.97	3659427.75
Significant Impact Level: 1.2 $\mu g/m^3$			
Significant Monitoring Level: 2.3 $\mu g/m^3$			
$PM_{2.5}$ Annual Screen Results			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	0.15	338468.69	3658817.75
1988	0.14	336977.31	3660784.50
1989	0.16	338864.69	3659512.75
1990	0.15	336237.00	3659111.00
1991	0.15	336137.00	3659111.00
Significant Impact Level: 0.3 $\mu g/m^3$			

$\mu g/m^3$ - micrograms per cubic meter

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Checked by: SAK 11/26/08

5.4.2 PM_{10} Screen Model Results

The screen modeling results for PM_{10}, as presented in Table 5-6, do not exceed the SILs for the 24-hour and annual averaging periods; therefore, refined modeling is not required for the pollutant. The preconstruction monitoring level was also not exceeded.

Table 5-6 PM_{10} Screening Results

PM_{10} 24-Hour Screen Results			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	3.19	337355.03	3660916.25
1988	3.52	336977.31	3660784.50
1989	4.57	337337.00	3660911.00
1990	2.97	337166.16	3660850.25
1991	3.25	337260.59	3660883.25
Significant Impact Level: 5 $\mu g/m^3$			
Significant Monitoring Level: 10 $\mu g/m^3$			
PM_{10} Annual Screen Results			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	0.57	337166.16	3660850.25
1988	0.65	336977.31	3660784.50
1989	0.71	337037.00	3660811.00
1990	0.65	337037.00	3660811.00
1991	0.51	337166.16	3660850.25
Significant Impact Level: 1 $\mu g/m^3$			

$\mu g/m^3$ - micrograms per cubic meter

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Checked by: SAK 11/26/08

5.4.3 NO_x Screen Model Results

The NO_x screen model results, as presented in Table 5-7 do not exceed the NO_x SIL on an annual averaging period basis; therefore a refined modeling evaluation is not required. The modeled results also did not exceed the significant monitoring concentration.

Table 5-7 NOx Screening Results

NO_x Annual Screen Results			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	0.54	338419.66	3658730.50
1988	0.51	338566.69	3658992.00
1989	0.54	338713.72	3659253.50
1990	0.54	336137.00	3659111.00
1991	0.54	336137.00	3659111.00
Significant Impact Level: 1 $\mu g/m^3$			
Significant Monitoring Level: 14 $\mu g/m^3$			

$\mu g/m^3$ - micrograms per cubic meter

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Checked by: SAK 11/26/08

5.4.4 CO Screen Model Results

As shown in Table 5-8, the modeled emissions do not exceed the CO SILs on a 1-hour or 8-hour averaging period. This result indicates that no further modeling is required. The significant monitoring concentration was also not exceeded; therefore, preconstruction monitoring is not required for CO.

Table 5-8 CO Screening Results

CO 1-Hour Screen Results			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	124.0	337937.00	3661211.00
1988	127.0	335337.00	3662311.00
1989	113.1	338037.00	3662011.00
1990	104.9	337437.00	3662711.00
1991	96.9	337037.00	3662211.00
Significant Impact Level: 2,000 $\mu g/m^3$			
CO 8-Hour Screen Results			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	55.1	336137.00	3659011.00
1988	59.6	336037.00	3659511.00
1989	54.9	336337.00	3659211.00
1990	50.3	336037.00	3659611.00
1991	51.6	337094.75	3658882.00
Significant Impact Level: 500 $\mu g/m^3$			
Significant Monitoring Level: 575 $\mu g/m^3$			

$\mu g/m^3$ - micrograms per cubic meter

Completed by: BSA 11/26/08
Checked by: SAK 11/26/08

5.4.5 SO_2 Screen Model Results

The SO_2 screen model results, as presented in Table 5-9, exceed the SO_2 SILs for all averaging periods; therefore, a refined modeling analysis is required. The modeled results do not exceed the significant monitoring concentration.

Table 5-9 SO_2 Screening Result

SO_2 3-Hour Screen Results				**Area of Impact Radius (km)**
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**		
		X	**Y**	
1987	27.79	336280.38	3659502.25	1.75
1988	26.62	336137.00	3659511.00	1.21
1989	29.03	336237.00	3659211.00	1.32
1990	28.54	336924.44	3658986.75	1.37
1991	29.28	336537.00	3658911.00	1.34
Significant Impact Level: 25 $\mu g/m^3$			MAX:	1.75
SO_2 24-Hour Screen Results				**Area of Impact Radius (km)**
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**		
		X	**Y**	
1987	10.66	338468.69	3658817.75	5.24
1988	9.56	336037.00	3659511.00	3.88
1989	9.03	338468.69	3658817.75	4.83
1990	9.56	336237.00	3659111.00	4.89
1991	10.03	338811.97	3659427.75	4.96
Significant Impact Level: 5 $\mu g/m^3$			MAX:	5.24
Significant Monitoring Level: 13 $\mu g/m^3$				
SO_2 Annual Screen Results				**Area of Impact Radius (km)**
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**		
		X	**Y**	
1987	1.26	338419.66	3658730.50	2.31
1988	1.17	338566.69	3658992.00	2.02
1989	1.25	338713.72	3659253.50	2.23
1990	1.24	336137.00	3659111.00	2.12
1991	1.25	336137.00	3659111.00	2.12
Significant Impact Level: 1 $\mu g/m^3$			MAX:	2.31

$\mu g/m^3$ - micrograms per cubic meter
km - Kilometer

Completed by: BSA 11/26/08
Checked by: SAK 11/26/08

5.4.6 Hydrogen Fluoride Screen Model Results

The HF screen model results, as presented in Table 5-10, did not exceed the HF significant monitoring concentration on a 24-hour averaging period basis.

Table 5-10 HF Screening Results

HF 24-Hour Screen Results			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	0.02461	338468.69	3658817.75
1988	0.02208	336037.00	3659511.00
1989	0.02086	338468.69	3658817.75
1990	0.02208	336237.00	3659111.00
1991	0.02316	338811.97	3659427.75
Significant Impact Level: 0.25 $\mu g/m^3$			

$\mu g/m^3$ - micrograms per cubic meter

Completed by: BSA 11/26/08
Checked by: SAK 11/26/08

5.4.7 Additional Modeling Evaluations

The primary goal of the above modeling evaluation was to demonstrate that the proposed plant will achieve compliance with all air quality standards during worst case base load operational conditions, which will occur during the majority of the time. Two additional operational modes (reduced load operation and startup operation) were evaluated for their potential impacts on air quality. The results from these evaluations are discussed in detail in the following sections.

5.4.7.1 Reduced Load Operational Evaluation

The proposed plant will at times operate at reduced loads (estimated at 40% production capacity) during the shoulder months (typically during spring and fall when power demands are below peak levels). The screen models were, therefore, rerun at this reduced operational load to evaluate the impact on air quality. The process (boiler/turbine) is less efficient at this reduced power production load. To produce 40% power the boiler will have to operate at approximately 50% fuel firing rate. This means that emissions and air flow rate from the main boiler stack will be at 50% of the previously modeled levels. The plant will continue to meet all its emission limits on a lb/MMBtu basis during this reduced loading period. Table 5-11 summarizes the

results of this modeling analysis. The results from this analysis found that the maximum impacts for all pollutants are below the significant impact levels, except for SO_2, for which a refined modeling analysis was completed.

Table 5-11 Full Load, 40% Load, and Startup Model Modeling Results

Pollutant	Avg. Period	Significant Impact Level (µg/m^3)	Full Load (µg/m^3)	40% Operational Load Mode (µg/m^3)	Startup Mode (µg/m^3)
$PM_{2.5}$	24-hr	1.2	1.17	0.88	1.06
$PM_{2.5}$	Annual	0.3	0.16	0.14	0.12
PM_{10}	24-hr	5	4.57	4.54	4.75
PM_{10}	Annual	1	0.71	0.70	0.70
SO_2	3-hr	25	29.28	22.79	28.87
SO_2	24-hr	5	10.66	7.92	9.88
SO_2	Annual	1	1.26	1.06	1.33
CO	8-hr	500	59.64	44.64	36.07
CO	1-hr	2,000	127.00	80.08	84.05
NOx	Annual	1	0.54	0.46	0.83

µg/m^3 - micrograms per cubic meter

Completed by: BSA 11/26/08
Checked by: SAK 11/26/08

5.4.7.2 Startup Modeling Results

In addition to the 40% load conditions a modeling evaluation was also completed for the startup of the main boiler. All pollution control equipment will be operated during the startup of the boiler except for the SCR system. The SCR is ineffective below a certain temperature (approx. 450 degrees F) and therefore would not reduce NO_x if operated. The injection of ammonia into the flue gas during cold conditions can result in the corrosion of the downstream pollution control equipment. For this reason, the SCR will not be operating at maximum capacity until the startup process is complete. The NO_x emissions during the startup will therefore have the potential to be greater than that at normal 100 percent load conditions for brief periods of time.

The wet scrubber will be operated during the startup period, however, the unit will not achieve its maximum control efficiency for SO_2 until the end of the startup period. The wet scrubber is designed to have an optimal liquid to gas ratio. This ratio is difficult to maintain during the significantly varying exhaust flow conditions during startup. For this reason it will take until the end of the startup before the scrubber meets its peak control efficiency.

Table 5-12 provides the firing and emission rates for both the auxiliary boiler and main boiler for a 24-hour period during which a startup would occur. The startup of the main boiler will take an estimated 14 hours to complete. The auxiliary boiler will operate 4 hours prior to the startup and for the first 5 hours of the startup period for the main boiler. The primary purpose of the auxiliary boiler operation is to provide steam to the turbine during the startup and shutdown periods so as to prevent damage to the unit, which could be caused by large swings in steam loading to the turbine.

The hour of day (HROFDY) function in the AERMOD model allows for the modeling of a given 24-hour period during which the emission rates are variable. The maximum emission rates for each pollutant was input into the model and the HROFDY function defines the ratio of the hourly emission rate to the maximum emission rate defined in the model. Table 5-13 provides the hourly emission rate ratio for each of the modeled pollutants for each hour of the modeled 24-hour period. The HROFDY function runs the startup over the meteorological conditions for each day of the year and therefore ensures that a worst case evaluation is completed. The results of the startup modeling are summarized in Table 5-11.

The results from the annual average models for the startup conditions are reported in Table 5-11, however, they will significantly over estimate actual annual concentrations of the pollutants because the HROFDAY function will assume that a startup will occur once per modeled day. When run over an annual period the model will therefore be based 365 startups per year. It is, however, expected that there will only be approximately 10 cold startups of the main boiler per year. For this reason the annual averaging period will significantly over estimate the potential modeled impact.

Table 5-12 Firing and Emission rates for both the Auxiliary boiler and Main boiler during startup

	Modeled Hours																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Aux Boiler Only				PC Boiler on Oil			1st Mill On					2nd Mill On				SCR & 3rd Mill On	4th & 5th Mills On						
Operational Status	**4 hours before startup**	**3 hours before startup**	**2 hours before startup**	**1 hour before startup**	**PC Boiler Startup Begns**	**Startup**	**Startup**	**Startup**	**Startup**	**Startup, Auxillary Boiler Goes Down**	**Startup**	**Startup**	**Startup**	**Startup**	**Startup**	**Startup**	**Startup**	**Startup**	**Boiler Reaches Full Load**	**Boiler Reaches Full Load**	**Boiler Reaches Full Load**	**Boiler Reaches Full Load**	**Boiler Reaches Full Load**	**Boiler Reaches Full Load**
PC Boiler Coal Heat Input (MMBtu/hr)	0	0	0	0	0	0	0	972	1,121	1,270	1,322	1,374	1,670	2,007	2,344	2,825	3,917	7,062	8,300	8,300	8,300	8,300	8,300	8,300
PC Boiler Fuel Oil Heat Input (MMBtu/hr)	0	0	0	0	885	885	885	797	708	708	708	708	620	531	531	531	472	148	0	0	0	0	0	0
PC Boiler Total Heat Input (MMBtu/hr)	0	0	0	0	885	885	885	1,769	1,829	1,978	2,030	2,082	2,290	2,538	2,875	3,356	4,389	7,210	8,300	8,300	8,300	8,300	8,300	8,300
Aux Boiler Heat Input	240	240	240	240	240	240	240	240	240	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PM_{10} - PC Boiler (lb/MMBtu)	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018
PM_{10} - Aux Boiler (lb/MMBtu)	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024
PM_{10} - PC Boiler (lb/hr)	0	0	0	0	15.93	15.93	15.93	31.84	32.92	35.60	36.54	37.48	41.22	45.68	51.75	60.41	79.00	129.78	149.40	149.40	149.40	149.40	149.40	149.40
PM_{10} - Aux Boiler (lb/hr)	5.76	5.76	5.76	5.76	5.76	5.76	5.76	5.76	5.76	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
$PM_{2.5}$ - PC Boiler (lb/MMBtu)	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124	0.0124
$PM_{2.5}$ - Fuel Oil (lb/MMBtu)	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
$PM_{2.5}$ - Aux Boiler (lb/MMBtu)	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
$PM_{2.5}$ - PC Boiler (lb/hr)	0	0	0	0	10.337	10.337	10.337	21.32	22.13	23.97	24.61	25.25	27.88	31.01	35.17	41.12	53.93	89.01	102.6	102.6	102.6	102.6	102.6	102.6
$PM_{2.5}$ - Aux Boiler (lb/hr)	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO_2 - Uncontrolled Coal Emissions - PC Boiler (lb/MMBtu)	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622	4.622
SO_2 - Uncontrolled Coal Emissions - Fuel Oil (lb/MMBtu)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
SO_2 - Control Efficiency - PC Boiler	-	-	-	-	0.0%	0.0%	0.0%	80.0%	82.0%	84.0%	84.0%	85.0%	88.0%	90.0%	91.0%	93.0%	95.0%	97.0%	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%
SO_2 - Aux Boiler (lb/MMBtu)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
SO_2 - PC Boiler (lb/hr)	0	0	0	0	44.3	44.3	44.3	906	939	945	983	958	930	930	977	916	906	979	959	959	959	959	959	959
SO_2 - Aux Boiler (lb/hr)	12	12	12	12	12	12	12	12	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOx - PC Boiler (lb/MMBtu)	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05
NOx - Fuel Oil (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
NOx - Aux Boiler (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
NOx - PC Boiler (lb/hr)	0	0	0	0	88.5	88.5	88.5	293.54	317.42	350.2	361.64	373.08	429.4	494.64	568.78	674.6	282.22	367.9	415	415	415	415	415	415
NOx - Aux Boiler (lb/hr)	24	24	24	24	24	24	24	24	24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO - PC Boiler (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
CO - Fuel Oil (lb/MMBtu)	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
CO - Aux Boiler (lb/MMBtu)	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
CO - PC Boiler (lb/hr)	0	0	0	0	35.4	35.4	35.4	323.5	364.6	409.3	424.9	440.5	525.8	623.3	724.4	868.7	1194	2125	2490	2490	2490	2490	2490	2490
CO - Aux Boiler (lb/hr)	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

*PC Boiler lb/hr emissions are reflective of both the Coal and Fuel Oil inputs.

Completed by: BSA 11/26/08
Checked by: SAK 11/26/08

Table 5-13 Hourly Emission Rate Ratio for each of the Modeled Pollutants for Main Boiler/Auxiliary Boiler (Fraction of Full Load)

	1	2	3	4	5	6	7	8	9	10	11	12
	Aux Boiler Only				PC Boiler on Oil			1st Mill On				
PC Boiler Ratios	4 hours before startup	3 hours before startup	2 hours before startup	1 hour before startup	PC Boiler Startup Begns	Startup	Startup	Startup	Startup	Startup, Auxillary Boiler Goes Down	Startup	Startup
PM_{10} - PC Boiler Ratio	0.00	0.00	0.00	0.00	0.11	0.11	0.11	0.21	0.22	0.24	0.24	0.25
$PM_{2.5}$ - PC Boiler Ratio	0.00	0.00	0.00	0.00	0.10	0.10	0.10	0.21	0.22	0.23	0.24	0.25
SO_2 - PC Boiler Ratio	0.00	0.00	0.00	0.00	0.05	0.05	0.05	0.95	0.98	0.99	1.03	1.00
NOx - PC Boiler Ratio	0.00	0.00	0.00	0.00	0.21	0.21	0.21	0.71	0.76	0.84	0.87	0.90
CO - PC Boiler Ratio	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.13	0.15	0.16	0.17	0.18

	13	14	15	16	17	18	19	20	21	22	23	24
	2nd Mill On				SCR & 3rd Mill On	4th & 5th Mills On						
PC Boiler Ratios	Startup	Startup	Startup	Startup	Startup	Startup	Boiler Reaches Full Load	Boiler Reaches Full Load	Boiler Reaches Full Load	Boiler Reaches Full Load	Boiler Reaches Full Load	Boiler Reaches Full Load
PM_{10} - PC Boiler Ratio	0.28	0.31	0.35	0.40	0.53	0.87	1.00	1.00	1.00	1.00	1.00	1.00
$PM_{2.5}$ - PC Boiler Ratio	0.27	0.30	0.34	0.40	0.53	0.87	1.00	1.00	1.00	1.00	1.00	1.00
SO_2 - PC Boiler Ratio	0.97	0.97	1.02	0.95	0.95	1.02	1.00	1.00	1.00	1.00	1.00	1.00
NOx - PC Boiler Ratio	1.03	1.19	1.37	1.63	0.68	0.89	1.00	1.00	1.00	1.00	1.00	1.00
CO - PC Boiler Ratio	0.21	0.25	0.29	0.35	0.48	0.85	1.00	1.00	1.00	1.00	1.00	1.00

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Checked by: SAK 11/26/08

Table 5-13 Hourly Emission Rate Ratio for each of the Modeled Pollutants for Main Boiler/Auxiliary Boiler (Continued)

	1	2	3	4	5	6	7	8	9	10	11	12
	Aux Boiler Only				PC Boiler on Oil			1st Mill On				
Auxiliary Boiler Ratios	**4 hours before startup**	**3 hours before startup**	**2 hours before startup**	**1 hour before startup**	**PC Boiler Startup Begns**	**Startup**	**Startup**	**Startup**	**Startup**	**Startup, Auxillary Boiler Goes Down**	**Startup**	**Startup**
PM_{10} - AUX Boiler Ratio	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00
$PM_{2.5}$ - AUX Boiler Ratio	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00
SO_2 - AUX Boiler Ratio	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00
NOx - AUX Boiler Ratio	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00
CO - AUX Boiler Ratio	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00

	13	14	15	16	17	18	19	20	21	22	23	24
	2nd Mill On				SCR & 3rd Mill On	4th & 5th Mills On						
Auxiliary Boiler Ratios	**Startup**	**Startup**	**Startup**	**Startup**	**Startup**	**Startup**	**Boiler Reaches Full Load**	**Boiler Reaches Full Load**	**Boiler Reaches Full Load**	**Boiler Reaches Full Load**	**Boiler Reaches Full Load**	**Boiler Reaches Full Load**
PM_{10} - AUX Boiler Ratio	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$PM_{2.5}$ - AUX Boiler Ratio	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO_2 - AUX Boiler Ratio	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NOx - AUX Boiler Ratio	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO - AUX Boiler Ratio	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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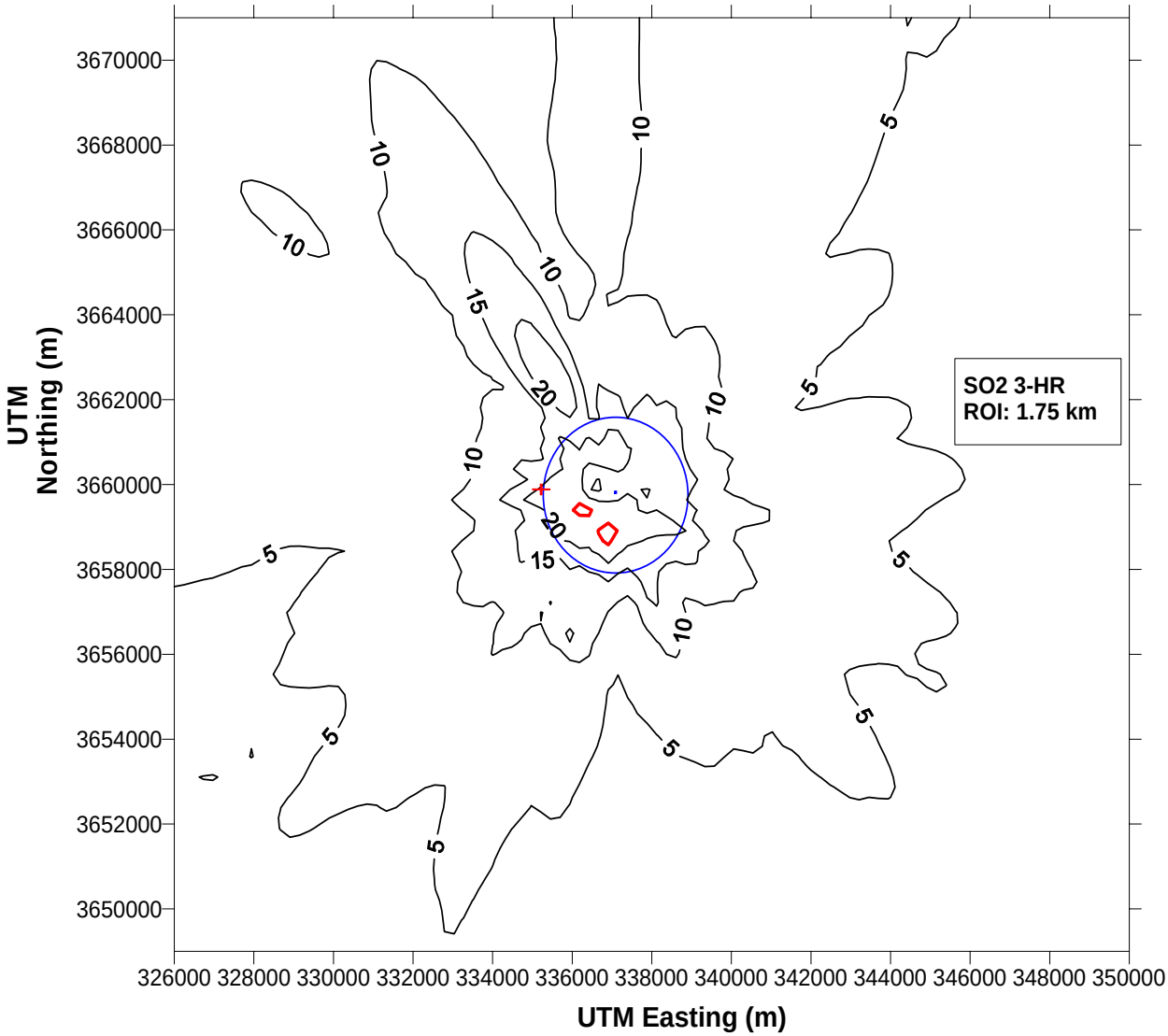
Checked by: SAK 11/26/08

5.5 SIGNIFICANT IMPACT AREA DETERMINATION AND DETERMINATION OF OFF-SITE EMISSIONS DATA FOR REFINED SO2 MODELING

The Area of Impact (AOI) was determined to be a circular area with the radius extending from the center of Plant Washington to the farthest point that exceeds the applicable SIL as predicted by the screen model. Refined modeling is required for all receptors within the AOI. Five years of meteorological data were used to determine the worst-case AOI for SO_2 and each averaging period. Figures 5-5 through 5-7 show the analysis output for each pollutant's averaging period for the corresponding worst-case years (largest AOI).

USEPA guidance states that 50 kilometers must be added to the impact radius to complete the off-site emission source retrieval. A list of sources emitting SO_2 within 56 kilometers of the proposed site was requested from GA EPD to determine the off-site sources that would be required to be included in the modeling. GA EPD provided spreadsheets that identified all sources within the SIA, along with their corresponding emission rates and stack parameters. These spreadsheets also identified the sources' status as "PSD increment consuming," or "PSD increment expander" for increment-modeling purposes. The PSD-increment-consuming sources were modeled as positive emission rates and the PSD-expanding sources were modeled as negative emission rates for the PSD increment models. For the purposes of completing the NAAQS modeling, the Georgia EPD provided the 2005 emission inventory database. All sources of SO_2 emissions in the database that are within 56 km of the proposed site were included in the modeling evaluation. The stack parameters from the database were used in the modeling analysis. The emission rates were based on a review of each plant's Title V permit applications and Title V permits. This data review was completed to determine the maximum allowable SO_2 emissions rate for each source being modeled. All NAAQS models included the increment consumers. Exhibit C provides the modeled data for all off site sources included in the refined SO_2 modeling.

Figure 5-5 Significant Impact Area: 1987 SO_2 Screening Results, 3-hour



Key:

+ **Farthest receptor above the 3-hr average significant impact level (25 µg/m3).**

SO2 Concentration Contours
Main Stack
25 µg/m3 SO2 Concentration Contour

ROI: Radius Of Impact, the distance from the center of the facility to the furthest point exceeding the significant impact level.

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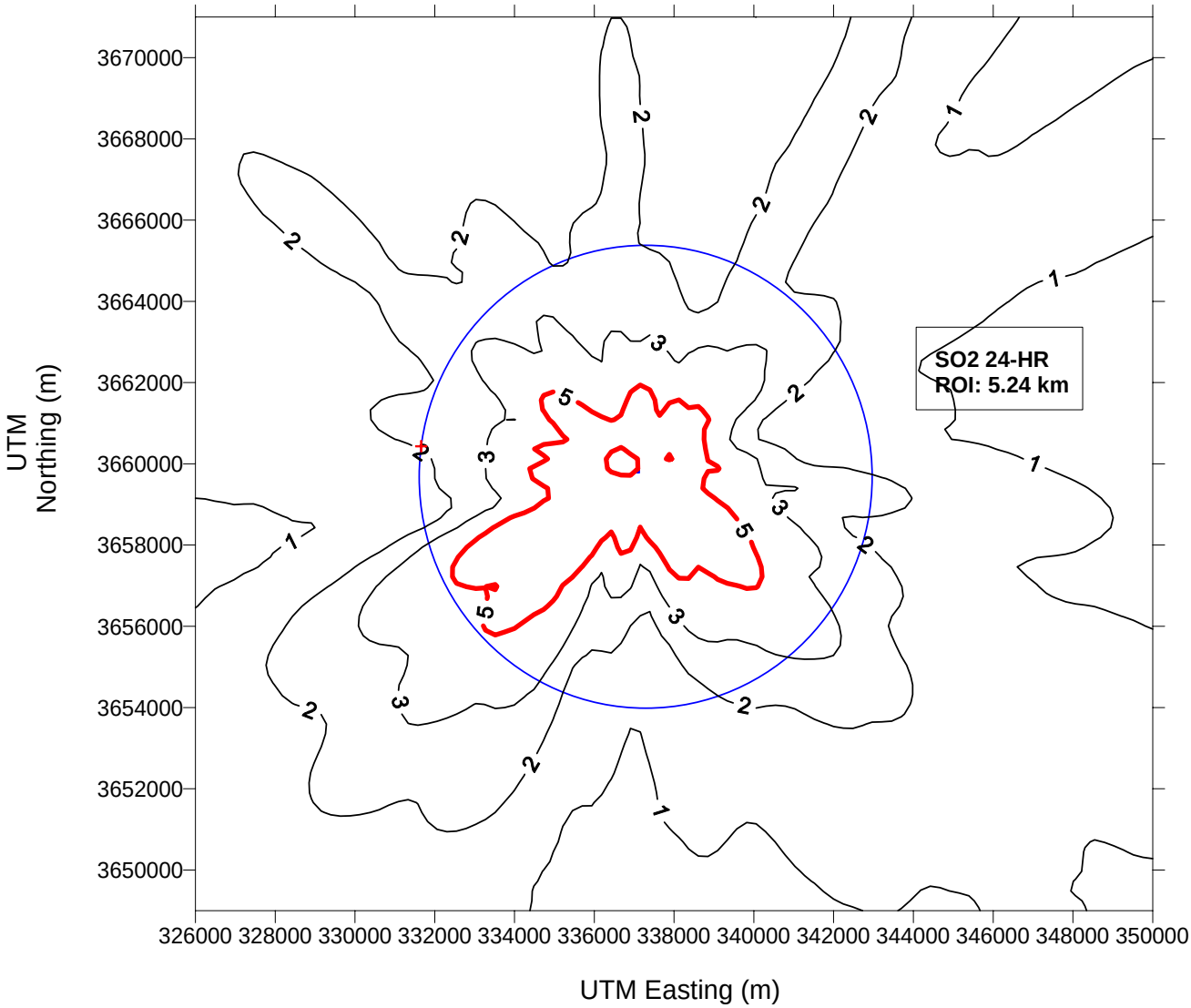
Checked by: SAK 11/26/08

Figure 5-6 Significant Impact Analysis: 1987 SO_2 Screening Results, 24-hour



Key:

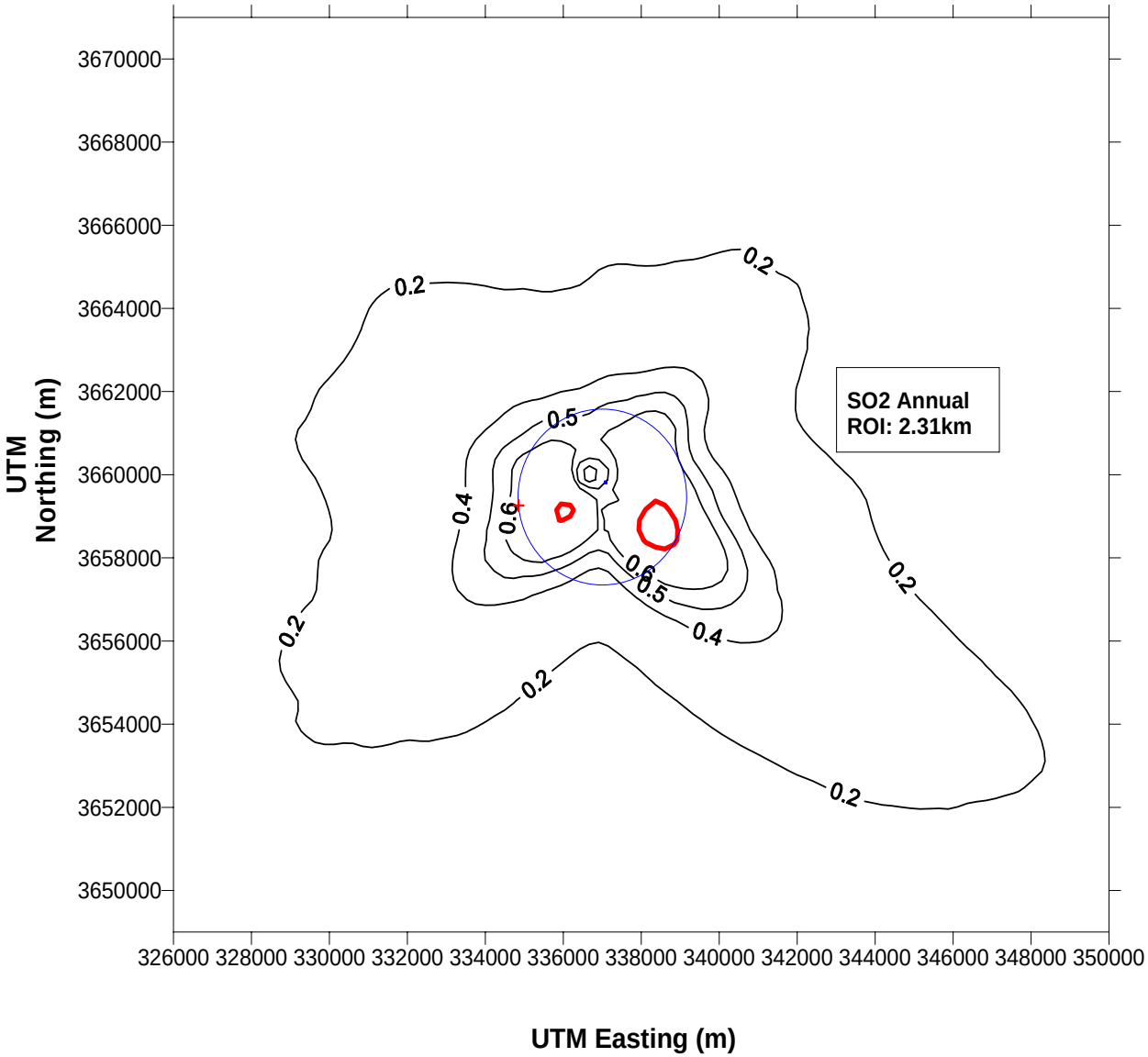
+ Farthest receptor above the 24-hr average significant impact level (5 µg/m3).

SO2 Concentration Contours
Main Stack
5 µg/m3 SO2 Concentration Contour

ROI: Radius Of Impact, the distance from the center of the facility to the furthest point exceeding the significant impact level.

Completed by: PBS 11/26/08
Checked by: SAK 11/26/08

Figure 5-7 Significant Impact Area: 1987 SO_2 Screening Results, Annual



Key:

+ **Farthest receptor above the annual average significant impact level (1 µg/m3).**

SO2 Concentration Contours
Main Stack
1 µg/m3 SO2 Concentration Contour

ROI: Radius Of Impact, the distance from the center of the facility to the furthest point exceeding the significant impact level.

Completed by: PBS 11/26/08
Checked by: SAK 11/26/08

5.6 REFINED MODELING ANALYSIS

Refined modeling was required for SO_2 based on the screen model results; therefore, modeling was performed to demonstrate compliance with the PSD increment and NAAQS standards, which are listed in Table 5-14. A background ambient concentration was obtained to determine compliance with the NAAQS standards for SO_2. This background concentration must be added to the NAAQS modeling results before a comparison to the standards can be made. The same meteorological data and receptor data used for the screen modeling was used for the refined modeling.

Table 5-14 Background, NAAQS, and PSD Increment Standards

Pollutant	Averaging Period	Background Concentration (µg/m^3)[1]	NAAQS (µg/m^3)	PSD Increment Standard (µg/m^3)
SO_2	3-hour	187	1,300	512
	24-hour	41	365	91
	Annual	8	80	20

µg/m^3 = micrograms per cubic meter

1. As provided by Georgia EPD

Completed by: BSA 11/26/08
Checked by: SAK 11/26/08

5.7 NATIONAL AMBIENT AIR QUALITY STANDARD MODELING RESULTS

The high-second-high modeled concentration was used for comparison to the standard for the SO_2 24-hour and 3-hour averaging periods. The high-second-high concentration is the highest of the second high results from each of the five years of modeled meteorological data. For the annual standards, each year of meteorological data was modeled and the highest value from all five models was compared to the annual standard. The NAAQS modeling included all proposed emission sources at their maximum hourly emission rates, as well as the off-site sources that are within the AOI. The refined SO_2 modeling (NAAQS and PSD Increment) included only those receptors that were within the largest calculated SIA for SO_2.

Table 5-15 presents the results for SO_2 and demonstrates compliance with the 3-hr, 24-hr, and annual standards. If the maximum result from all five years of models for each averaging period was located at a receptor which was not in the 100 meter spacing area, four additional receptors at 100 meter spacing were added around the maximum in order to ensure that the real maximum had been identified. The maximum result from all five of these receptors (the original plus the four additional receptors) is reported in the table.

Table 5-15 SO_2 NAAQS Modeling Summary

SO_2 3-Hour Results			
Year of Model Run	**2nd Highest Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	172.51	330000.00	3649000.00
1988	192.35	330000.00	3649000.00
1989	218.30	330100.00	3649000.00
1990	184.96	330000.00	3649000.00
1991	187.30	330000.00	3649000.00
Maximum Concentration: 218.30 $\mu g/m^3$			
Background Concentration: 187 $\mu g/m^3$			
Combined Concentration: 405.30 $\mu g/m^3$			
NAAQS Level: 1,300 $\mu g/m^3$			
SO_2 24-Hour Results			
Year of Model Run	**2nd Highest Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	107.40	330000.00	3649000.00
1988	104.24	330000.00	3649000.00
1989	141.06	330100.00	3649000.00
1990	115.00	330000.00	3649000.00
1991	121.11	330000.00	3649000.00
Maximum Concentration: 141.06 $\mu g/m^3$			
Background Concentration: 41 $\mu g/m^3$			
Combined Concentration: 182.06 $\mu g/m^3$			
NAAQS Level: 365 $\mu g/m^3$			
SO_2 Annual Results			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	28.18	330000.00	3649000.00
1988	29.21	330000.00	3649000.00
1989	30.43	330000.00	3649000.00
1990	30.52	330000.00	3649000.00
1991	33.45	330000.00	3649000.00
Maximum Concentration: 33.45 $\mu g/m^3$			
Background Concentration: 8 $\mu g/m^3$			
Combined Concentration: 41.45 $\mu g/m^3$			
NAAQS Level: 80 $\mu g/m^3$			

$\mu g/m^3$ - micrograms per cubic meter

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Checked by: SAK 11/26/08

5.8 PSD INCREMENT MODELING RESULTS

PSD increment modeling was completed in addition to NAAQS modeling. One goal of the PSD increment modeling is to determine the increase in ground-level concentrations of SO_2 since its established baseline date (1975). Another goal is to determine whether the increases exceed the allowable PSD increments for the corresponding pollutants. The proposed power plant is a green-field facility; therefore, all emission sources are new and consume PSD increment.

The PSD increment model also includes off-site emission sources, which are increment consumers or expanders. As discussed previously, the Georgia sources were identified as consumers or expanders in the spreadsheets provided by GA EPD. The consumers were modeled as positive sources, while the expanders were modeled as negative sources. The receptor grid and meteorological data used for the NAAQS modeling were used for the PSD increment consumption modeling. The refined SO_2 modeling (NAAQS and PSD Increment) included only those receptors that were within the largest calculated SIA for SO_2.

Table 5-16 compares the highest modeling results for the annual averaging period and the highest second high for the 3-hour and 24-hour to the PSD SO_2 increment standards. Compliance with all standards is demonstrated.

Table 5-16 SO_2 PSD Increment Modeling Summary

SO_2 3-Hour Results			
Year of Model Run	**2nd Highest Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	51.81	327000.00	3665500.00
1988	40.37	327000.00	3665500.00
1989	38.55	327000.00	3665500.00
1990	47.00	327000.00	3665500.00
1991	55.67	327000.00	3665600.00
PSD Increment Level: 55.67 $\mu g/m^3$			
PSD Increment Standard: 512 $\mu g/m^3$			
SO_2 24-Hour Results			
Year of Model Run	**2nd Highest Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	14.72	327000.00	3665500.00
1988	15.66	327000.00	3665500.00
1989	15.69	327000.00	3665500.00
1990	15.90	327000.00	3665500.00
1991	18.20	327000.00	3665600.00
PSD Increment Level: 18.20 $\mu g/m^3$			
PSD Increment Standard: 91 $\mu g/m^3$			
SO_2 Annual Results			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
		X	**Y**
1987	1.90	327000.00	3665500.00
1988	1.81	327000.00	3665500.00
1989	1.79	327000.00	3665500.00
1990	2.09	326900.00	3665500.00
1991	1.91	327000.00	3665500.00
PSD Increment Level: 2.09 $\mu g/m^3$			
PSD Increment Standard: 20 $\mu g/m^3$			

$\mu g/m^3$ - micrograms per cubic meter

Completed by: BSA 11/26/08
Checked by: SAK 11/26/08

6.0 AIR TOXICS MODELING

The proposed project was evaluated for compliance with the Georgia Air Toxics program using the "Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions" dated June 21, 1998. The first step was to calculate the potential emissions of all toxic pollutants from Plant Washington. The calculations are based on USEPA AP-42 emission factors for sub-bituminous coal and fuel oil (distillate) combustion and test report data from the study of Hazardous Air Pollutant emissions from Electric utility Steam Generating Units- Final report to congress. Exhibit A provides the toxic emission calculations and Exhibit C provides the development of the Allowable Ambient Concentrations (AACs) for the project.

For each toxic pollutant identified, an AAC was developed by following the Georgia guidelines. The Georgia guidelines prioritize the available resources for toxicity data. First priority is given to inhalation reference concentrations (RfC) and Risk Based Air Concentrations (RBAC), which are identified in the USEPA's Integrated Risk Information System (IRIS) database, followed by OSHA PEL standards, ACGIH TLVs, NIOSH RELs, and LD50 toxicity data. AACs developed from worker exposure levels are based on 40 hours/week of exposure and must be adjusted to account for the potential exposure of the public (7 days/week, 24 hours/day). This correction along with the application of a safety factor of 300 for known carcinogenic compounds and 100 for all others is utilized in the development of AACs from worker exposure standards. The safety factor is applied to account for persons who may be sensitive to exposure to these pollutants. Toxicity data taken from the IRIS database does not require any adjustments because exposures to persons with respiratory maladies, young children, or the elderly were taken into account in the determination of these values. Short-term exposures are addressed using OSHA, NIOSH, and ACGIH Short Term Exposure Limits (STEL), and ceiling limits. A safety factor of 10 is universally applied to all short-term standards.

The next step was a dispersion analysis. Each source of pollutants (main boiler and auxiliary boiler) was modeled using the USEPA SCREEN3 model assuming an emission rate of 1 g/s. Table 6-1 below shows the results of this modeling for each of the sources.

Table 6-1 SCREEN3 Modeling Results Summary

Source ID	Source	Stack Height (m)	Stack Dia. (m)	Stack Velocity (m/s)	Stack Temp. (K)	1-Hour MGLC from SCREEN3 Analysis ($\mu g/m^3$)
MAIN	Coal Fired Boiler	137.16	9.14	18.55	333	0.698
AUX	Auxiliary Boiler	27.43	1.52	19.81	408	6.02

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The SCREEN3 model result for each boiler was multiplied by its corresponding emission rate to determine the Maximum Ground Level Concentration (MGLC) for each. The MGLC for each boiler was then added together in order to determine the project's overall MGLC. It is likely that each boiler's MGLC would occur at a different location downwind because of the differing stack heights. Assuming the two MGLCs occur at the same location will, therefore, conservatively over estimates the overall MGLC. This analysis is additionally conservative because it assumes that the auxiliary boiler will be operating at the same time as the main boiler on a continuous basis. The auxiliary boiler will only operate up to 10% of the time on an annual basis.

Following the Georgia guidelines, the 1-hour concentration for the actual emission rate from each toxic was determined by a direct ratio of emission rates. The 1-hour MGLC from the SCREEN3 model was adjusted to an annual, 24-hr continuous, and short-term (15-min) concentration using the correction factors 0.08, 0.40, and 1.32, respectively. These annual and short-term MGLC's were then compared to the derived AACs and short-term limits. The results of this analysis are summarized in Table 6-2. A few of the evaluated toxics (sulfuric acid, arsenic trioxide, arsenic, hexavalent chromium, and carbon monoxide) were near or above their corresponding AACs. As per the Georgia guidelines, ISCST3 modeling was completed for these pollutants. The results of the analysis for the ISCST3 models are shown below in Table 6-3. The results of these models demonstrate compliance with the Georgia air toxics program.

Table 6-2 Toxic Emission Summary

Pollutant	Main Boiler (lb/hr)	Main Boiler (g/s)	Auxiliary Boiler (lb/hr)	Auxiliary Boiler (g/s)	Main Boiler 1-Hr MGLC (mg/m^3)	Auxiliary Boiler 1-Hr MGLC (mg/m^3)	Total 1-Hr MGLC (mg/m^3)	Annual MGLC (mg/m^3)[2]	AAC Annual (mg/m^3)	% of allowable AAC[1]	24-Hr MGLC (mg/m^3)[1]	AAC 24-hour (mg/m^3)	% of allowable AAC[1]	15-Min MGLC (mg/m^3)	Short (15-min) Term Limit (mg/m^3)	% of allowable Short Term Limit
Organics																
Acenaphthene	2.49E-04	3.14E-05	3.62E-05	4.56E-06	2.19E-08	2.75E-08	4.94E-08	3.95E-09	-	-	1.97E-08	0.04	0.00005%	6.52E-08	-	-
Acenaphthylene	1.22E-04	1.54E-05	4.34E-07	5.47E-08	1.07E-08	3.29E-10	1.11E-08	8.85E-10	-	-	4.42E-09	0.12	0.000004%	1.46E-08	-	-
Acetaldehyde	2.78E-01	3.50E-02	1.97E-03	2.48E-04	2.45E-05	1.50E-06	2.60E-05	2.08E-06	4.55E-03	0.05%	1.04E-05	-	-	3.43E-05	4.50	0.0008%
Acetophenone	7.32E-03	9.22E-04		-	6.44E-07		6.44E-07	5.15E-08		-	2.58E-07	0.12	0.0002%	8.50E-07	-	-
Acrolein	1.42E-01	1.78E-02		-	1.24E-05		1.24E-05	9.96E-07	2.00E-05	4.98%	4.98E-06	-	-	1.64E-05	0.02	0.07%
Ammonia	51.07	6.43E+00		-	4.49E-03		4.49E-03	3.59E-04	1.00E-01	0.36%	1.80E-03	-	-	5.93E-03	2.44	0.2432%
Anthracene	1.02E-04	1.29E-05	2.09E-06	2.64E-07	9.01E-09	1.59E-09	1.06E-08	8.48E-10		-	4.24E-09	4.76E-04	0.0009%	1.40E-08	-	-
Benzene	6.34E-01	7.99E-02	3.67E-04	4.63E-05	5.58E-05	2.79E-07	5.61E-05	4.49E-06	1.28E-04	3.50%	2.24E-05	-	-	7.40E-05	1.50	0.005%
Benzo(a)anthracene	3.90E-05	4.92E-06	6.87E-06	8.67E-07	3.43E-09	5.22E-09	8.66E-09	6.93E-10	-	-	3.46E-09	4.76E-04	0.001%	1.14E-08	-	-
Benzo(a)pyrene	1.85E-05	2.34E-06		-	1.63E-09		1.63E-09	1.30E-10	-	-	6.52E-10	4.76E-04	0.0001%	2.15E-09	-	-
Benzo(b)fluoranthene	6.64E-05	8.37E-06		-	5.84E-09		5.84E-09	4.67E-10	-	-	2.34E-09	4.76E-04	0.0005%	7.71E-09	-	-
Benzo(e)pyrene	8.30E-06	1.05E-06		-	7.30E-10		7.30E-10	5.84E-11	-	-	2.92E-10	6.21E-04	0.00005%	9.64E-10	-	-
Benzo(g,h,i)perylene	2.10E-05	2.64E-06	3.87E-06	4.89E-07	1.85E-09	2.94E-09	4.79E-09	3.83E-10	-	-	1.92E-09	6.21E-04	0.0003%	6.32E-09	-	-
Benzo(g,h,i)pyrene	1.32E-05	1.66E-06		-	1.16E-09		1.16E-09	9.27E-11	-	-	4.64E-10	6.21E-04	0.0001%	1.53E-09	-	-
Benzo(b,k)fluoranthene	5.37E-05	6.76E-06	2.54E-06	3.20E-07	4.72E-09	1.93E-09	6.65E-09	5.32E-10	-	-	2.66E-09	4.76E-04	0.001%	8.78E-09	-	-
Benzo(k)fluoranthene	3.32E-05	4.18E-06		-	2.92E-09		2.92E-09	2.34E-10	-	-	1.17E-09	4.76E-04	0.0002%	3.85E-09	-	-
Benzyl chloride	3.42E-01	4.30E-02		-	3.00E-05		3.00E-05	2.40E-06	-	-	1.20E-05	1.19E-02	0.101%	3.97E-05	0.50	0.008%
Biphenyl	1.49E-03	1.88E-04		-	1.31E-07		1.31E-07	1.05E-08	-	-	5.26E-08	2.38E-03	0.002%	1.73E-07	-	-
bis(2-Ethylhexyl)phthalate	3.56E-02	4.49E-03		-	3.13E-06		3.13E-06	2.51E-07	-	-	1.25E-06	1.19E-02	0.01%	4.14E-06	1.00	0.0004%
Bromoform	5.48E-02	6.90E-03		-	4.82E-06		4.82E-06	3.85E-07	9.09E-03	0.004%	1.93E-06	-	-	6.36E-06	-	-
2-Butanone (MEK)	1.90E-01	2.40E-02		-	1.67E-05		1.67E-05	1.34E-06	5.00	0.00003%	6.70E-06	-	-	2.21E-05	88.47	0.00002%
Carbon tetrachloride	2.70E-02	3.40E-03		-	2.37E-06		2.37E-06	1.90E-07	6.67E-04	0.03%	9.49E-07	-	-	3.13E-06	15.73	0.00002%
Carbon disulfide	6.34E-02	7.99E-03		-	5.58E-06		5.58E-06	4.46E-07	0.70	0.0001%	2.23E-06	-	-	7.37E-06	9.33	0.0001%
Chlorobenzene	2.64E-02	3.33E-03		-	2.32E-06		2.32E-06	1.86E-07	-	-	9.29E-07	0.83	0.0001%	3.06E-06	-	-
Chloroform	2.88E-02	3.63E-03		-	2.53E-06		2.53E-06	2.03E-07	4.35E-04	0.05%	1.01E-06	-	-	3.34E-06	24.00	0.00001%
Chloromethane	2.59E-01	3.26E-02		-	2.28E-05		2.28E-05	1.82E-06	0.09	0.002%	9.10E-06	-		3.00E-05	41.40	0.0001%
2-Chloronaphthalene	3.32E-04	4.18E-05		-	2.92E-08		2.92E-08	2.34E-09	3.01E-03	0.0001%	1.17E-08	-	-	3.85E-08	7.86	0.0000005%
2-Chloroacetophenone	3.42E-03	4.30E-04		-	3.00E-07		3.00E-07	2.40E-08	3.00E-05	0.08%	1.20E-07	-	-	3.97E-07	-	-
Chrysene	4.88E-05	6.15E-06	4.08E-06	5.15E-07	4.29E-09	3.10E-09	7.39E-09	5.91E-10	-	-	2.96E-09	4.76E-04	0.001%	9.76E-09	-	-
Cumene	2.59E-03	3.26E-04		-	2.28E-07		2.28E-07	1.82E-08	0.40	0.000005%	9.10E-08	-	-	3.00E-07	-	-
Cyanide	1.22E+00	1.54E-01		-	1.07E-04		1.07E-04	8.58E-06		-	4.29E-05	1.19E-02	0.3606%	1.42E-04		-
Dibenzo(a,h)anthracene	1.55E-05	1.95E-06	2.86E-06	3.61E-07	1.36E-09	2.17E-09	3.54E-09	2.83E-10	-	-	1.42E-09	4.76E-04	0.0003%	4.67E-09	-	-
Di-nbutylphthalate	2.32E-02	2.93E-03		-	2.04E-06		2.04E-06	1.64E-07	-		8.18E-07	0.01	0.007%	2.70E-06	-	-
Dimethyl sulfate	2.34E-02	2.95E-03		-	2.06E-06		2.06E-06	1.65E-07	-	-	8.24E-07	1.19E-02	0.01%	2.72E-06	-	-
7,12-Dimethylbenz(a)anthracene	4.88E-06	6.15E-07		-	4.29E-10		4.29E-10	3.44E-11	-	-	1.72E-10	4.76E-04	0.00004%	5.67E-10	-	-
2,4-Dinitrotoluene	1.37E-04	1.72E-05		-	1.20E-08		1.20E-08	9.62E-10	-	-	4.81E-09	3.57E-03	0.0001%	1.59E-08	-	-
Ethylbenzene	4.59E-02	5.78E-03	1.09E-04	1.37E-05	4.03E-06	8.28E-08	4.12E-06	3.29E-07	1.00	0.00003%	1.65E-06	-	-	5.44E-06	54.27	0.00001%
Ethyl Chloride	2.05E-02	2.58E-03		-	1.80E-06		1.80E-06	1.44E-07	10.00	0.000001%	7.21E-07	-	-	2.38E-06	-	-
Ethylene dichloride	2.57E-02	3.24E-03		-	2.26E-06		2.26E-06	1.81E-07	3.85E-04	0.05%	9.05E-07	-		2.99E-06	40.48	0.00001%
Ethylene dibromide	5.86E-04	7.38E-05		-	5.15E-08		5.15E-08	4.12E-09	1.67E-06	0.25%	2.06E-08	-		6.80E-08	23.06	0.0000003%
Fluoranthene	3.46E-04	4.37E-05	8.30E-06	1.05E-06	3.05E-08	6.30E-09	3.68E-08	2.94E-09	-	-	1.47E-08	0.01	0.0002%	4.85E-08	-	-
Fluorene	4.44E-04	5.60E-05	7.66E-06	9.66E-07	3.91E-08	5.82E-09	4.49E-08	3.59E-09	-	-	1.80E-08	4.76E-04	0.0038%	5.92E-08	-	-
Formaldehyde	3.06E-01	3.86E-02	5.66E-02	7.13E-03	2.70E-05	4.30E-05	6.99E-05	5.59E-06	7.69E-04	0.73%	2.80E-05	-	-	9.23E-05	0.25	0.04%
Hexane	3.27E-02	4.12E-03		-	2.88E-06		2.88E-06	2.30E-07	0.70	0.00003%	1.15E-06	-	-	3.80E-06	-	
Hydrogen chloride	2.40E+01	3.03E+00		-	2.11E-03		2.11E-03	1.69E-04	2.00E-02	0.84%	8.45E-04	-	-	2.79E-03	0.70	0.40%
Indeno(1,2,3,c,d)pyrene	2.98E-05	3.75E-06	3.67E-06	4.63E-07	2.62E-09	2.79E-09	5.41E-09	4.32E-10	-	-	2.16E-09	4.76E-04	0.0005%	7.14E-09	-	-
Isophorone	2.83E-01	3.57E-02		-	2.49E-05		2.49E-05	1.99E-06	-	-	9.96E-06	0.33	0.003%	3.29E-05	2.83	0.001%

Completed by : PBS 11/26/2008
Checked by :SAK 11/26/2008

Table 6-2 Toxic Emission Summary

Pollutant	Main Boiler (lb/hr)	Main Boiler (g/s)	Auxiliary Boiler (lb/hr)	Auxiliary Boiler (g/s)	Main Boiler 1-Hr MGLC (mg/m^3)	Auxiliary Boiler 1-Hr MGLC (mg/m^3)	Total 1-Hr MGLC (mg/m^3)	Annual MGLC (mg/m^3)[2]	AAC Annual (mg/m^3)	% of allowable AAC[1]	24-Hr MGLC (mg/m^3)[1]	AAC 24-hour (mg/m^3)	% of allowable AAC[1]	15-Min MGLC (mg/m^3)	Short (15-min) Term Limit (mg/m^3)	% of allowable Short Term Limit
Methyl Bromide	7.81E-02	9.84E-03		-	6.87E-06		6.87E-06	5.49E-07	0.005	0.01%	2.75E-06	-		9.07E-06	8.00	0.0001%
Methyl Chloroform	2.84E-02	3.58E-03	1.82E-03	2.30E-04	2.50E-06	1.39E-06	3.88E-06	3.11E-07		-	1.55E-06	4.52	0.00003%	5.12E-06	246.00	0.000002%
Methyl hydrazine	8.30E-02	1.05E-02		-	7.30E-06		7.30E-06	5.84E-07	-	-	2.92E-06	4.52E-05	6.45%	9.63E-06	0.04	0.03%
MIBK	4.07E-02	5.12E-03		-	3.58E-06		3.58E-06	2.86E-07	3.00	0.00001%	1.43E-06	-	-	4.72E-06	30.72	0.00002%
MMA	9.76E-03	1.23E-03		-	8.58E-07		8.58E-07	6.87E-08	0.70	0.00001%	3.43E-07	-	-	1.13E-06	40.95	0.000003%
2-Methylnaphthalene	2.66E-04	3.35E-05	4.08E-06	5.15E-07	2.34E-08	3.10E-09	2.65E-08	2.12E-09	-	-	1.06E-08	0.01	0.0002%	3.49E-08	-	-
3-Methylchloranthrene	5.49E-07	6.92E-08		-	4.83E-11		4.83E-11	3.87E-12	-	-	1.93E-11	6.90E-03	0.0000003%	6.38E-11	-	-
MTBE	1.71E-02	2.15E-03		-	1.50E-06		1.50E-06	1.20E-07	3.00	0.000004%	6.01E-07	-	-	1.98E-06	-	-
Methylene chloride	1.42E-01	1.78E-02	7.74E-03	9.76E-04	1.24E-05	5.88E-06	1.83E-05	1.47E-06	2.13E-02	0.01%	7.33E-06	-	-	2.42E-05	43.42	0.0001%
Naphthalene	1.05E-02	1.32E-03	1.94E-03	2.44E-04	9.23E-07	1.47E-06	2.39E-06	1.92E-07	3.00E-03	0.01%	9.58E-07	-	-	3.16E-06	7.86	0.00004%
5-Methyl chrysene	1.07E-05	1.35E-06		-	9.44E-10		9.44E-10	7.55E-11	-	-	3.78E-10	4.76E-04	0.0001%	1.25E-09	-	-
OCDD	2.88E-08	3.63E-09		-	2.53E-12		2.53E-12	2.03E-13		-	1.01E-12	6.90E-02	0.000000001%	3.34E-12	-	-
Phenanthrene	1.32E-03	1.66E-04	1.80E-05	2.27E-06	1.16E-07	1.37E-08	1.30E-07	1.04E-08	-	-	5.18E-08	4.76E-04	0.01%	1.71E-07	-	-
Phenol	5.06E-02	6.38E-03	5.83E-03	7.35E-04	4.45E-06	4.43E-06	8.88E-06	7.11E-07	-	-	3.55E-06	4.52E-02	0.01%	1.17E-05	6.00	0.0002%
Propionaldehyde	1.85E-01	2.34E-02		-	1.63E-05		1.63E-05	1.30E-06	-	-	6.52E-06	0.11	0.01%	2.15E-05	-	-
Pyrene	1.61E-04	2.03E-05	7.29E-06	9.19E-07	1.42E-08	5.53E-09	1.97E-08	1.58E-09	-	-	7.88E-09	4.76E-04	0.002%	2.60E-08	-	-
Styrene	2.57E-02	3.24E-03		-	2.26E-06		2.26E-06	1.81E-07	1.00	0.00002%	9.05E-07	-	-	2.99E-06	85.20	0.000004%
Sulfuric Acid (H_2SO_4)[1]	3.32E+01	4.18E+00	1.44E-02	1.82E-03	2.92E-03	1.09E-05	2.93E-03	2.34E-04	-	-	**2.42E-04**	2.38E-03	**49.24 % / 10.15%**	3.87E-03	-	-
Tetrachloroethylene	2.57E-02	3.24E-03	1.32E-04	1.66E-05	2.26E-06	1.00E-07	2.36E-06	1.89E-07	-	-	9.45E-07	1.61	0.0001%	3.12E-06	135.60	0.000002%
Toluene	1.17E-01	1.48E-02	1.06E-02	1.34E-03	1.03E-05	8.07E-06	1.84E-05	1.47E-06	5.00	0.00003%	7.35E-06	-	-	2.43E-05	113.00	0.00002%
1,1,1-Trichloroethane	9.76E-03	1.23E-03	4.05E-04	5.10E-05	8.58E-07	3.07E-07	1.17E-06	9.33E-08	-		4.66E-07	4.52	0.00001%	1.54E-06	246.00	0.000001%
1,1,2-Trichloroethane	3.90E-02	4.92E-03		-	3.43E-06		3.43E-06	2.75E-07	6.25E-03	0.004%	1.37E-06	-	-	4.53E-06	-	-
1,2.4-Trichlorobenzene	1.25E-02	1.58E-03		-	1.10E-06		1.10E-06	8.81E-08		-	4.40E-07	-	-	1.45E-06	3.70	0.00004%
Trichloroethylene	2.57E-02	3.24E-03		-	2.26E-06		2.26E-06	1.81E-07	-	-	9.05E-07	1.28	0.0001%	2.99E-06	107.50	0.000003%
Vinyl acetate	3.71E-03	4.67E-04	1.24E-03	1.56E-04	3.26E-07	9.39E-07	1.27E-06	1.01E-07	0.20	0.00005%	5.06E-07	-	-	1.67E-06	5.28	0.00003%
Xylene	3.86E-02	4.86E-03	3.26E-04	4.11E-05	3.39E-06	2.47E-07	3.64E-06	2.91E-07	0.10	0.00029%	1.46E-06	-	-	4.81E-06	65.10	0.00001%
m-Xylene	1.20E-02	1.52E-03		-	1.06E-06		1.06E-06	8.47E-08	0.10	0.00008%	4.23E-07		-	1.40E-06	65.10	0.000002%
o-Xylene	6.72E-03	8.47E-04		-	5.91E-07		5.91E-07	4.73E-08	0.10	0.00005%	2.37E-07		-	7.81E-07	65.10	0.000001%
p-Xylene	1.20E-02	1.52E-03		-	1.06E-06		1.06E-06	8.47E-08	0.10	0.00008%	4.23E-07		-	1.40E-06	65.10	0.000002%
P-cresol	7.89E-03	9.94E-04		-	6.94E-07		6.94E-07	5.55E-08		-	2.77E-07	0.05	0.0005%	9.16E-07		-
Pentachlorophenol	6.64E-05	8.37E-06		-	5.84E-09		5.84E-09	4.67E-10	-		2.34E-09	1.19E-03	0.0002%	7.71E-09		-
Hexachlorobenzene	6.64E-04	8.37E-05		-	5.84E-08		5.84E-08	4.67E-09	2.17E-05	0.02%	2.34E-08		-	7.71E-08		-
Methyl iodide	3.32E-03	4.18E-04		-	2.92E-07		2.92E-07	2.34E-08		-	1.17E-07	0.07	0.0002%	3.85E-07		-
1,3-Butadiene	3.08E-03	3.88E-04		-	2.71E-07		2.71E-07	2.17E-08	3.33E-05	0.07%	1.08E-07		-	3.58E-07	1.10	0.00003%
1,3-Dichloropropene	5.48E-03	6.91E-04		-	4.82E-07		4.82E-07	3.86E-08	2.50E-03	0.002%	1.93E-07		-	6.37E-07		-
1,4-Dichlorobenzene	8.76E-03	1.10E-03		-	7.71E-07		7.71E-07	6.16E-08	0.80	0.00001%	3.08E-07		-	1.02E-06		-
2,4,6-Trichlorophenol	6.64E-06	8.37E-07		-	5.84E-10		5.84E-10	4.68E-11	3.23E-03	0.000001%	2.34E-10		-	7.71E-10		-
2,4-Dinitrophenol	8.92E-05	1.12E-05		-	7.85E-09		7.85E-09	6.28E-10		-	3.14E-09	8.98E-04	0.0003%	1.04E-08		-
4-Nitrophenol	3.32E-05	4.19E-06		-	2.92E-09		2.92E-09	2.34E-10		-	1.17E-09	5.18E-03	0.00002%	3.86E-09		-
Allyl Chloride	6.66E-02	8.40E-03		-	5.86E-06		5.86E-06	4.69E-07	1.00E-03	0.05%	2.34E-06		-	7.74E-06	0.60	0.0013%
Arsenic Trioxide	2.47E-01	3.11E-02		-	2.17E-05		2.17E-05	1.74E-06		-	**1.79E-06**	2.38E-05	**36.50 % / 7.52%**	2.87E-05		-
Cadmium Oxide	2.66E-02	3.35E-03		-	2.34E-06		2.34E-06	1.87E-07		-	9.35E-07	4.97E-03	0.02%	3.09E-06		-
Calcium Cyanamide	2.81E-02	3.54E-03		-	2.47E-06		2.47E-06	1.98E-07	-		9.89E-07	1.19E-03	0.0831%	3.26E-06		-
Chromic Acid (VI)	6.91E-02	8.70E-03		-	6.08E-06		6.08E-06	4.86E-07		-	2.43E-06	1.19E-04	2.04%	8.02E-06	0.01	0.08%
Chromic Oxide	2.02E-01	2.55E-02		-	1.78E-05		1.78E-05	1.42E-06		-	7.12E-06	1.19E-03	0.60%	2.35E-05		-
Dibenzo[a,j]Acridine	4.25E-03	5.35E-04		-	3.74E-07		3.74E-07	2.99E-08		-	1.49E-07	0.03	0.0004%	4.93E-07		-
Dibenzofuran	4.75E-03	5.99E-04		-	4.18E-07		4.18E-07	3.34E-08		-	1.67E-07		-	5.52E-07		-
Diethyl Sulfate	1.94E-02	2.44E-03		-	1.70E-06		1.70E-06	1.36E-07		-	6.81E-07	0.04	0.002%	2.25E-06		-

Completed by : PBS 11/26/2008
Checked by :SAK 11/26/2008

Table 6-2 Toxic Emission Summary

Pollutant	Main Boiler (lb/hr)	Main Boiler (g/s)	Auxiliary Boiler (lb/hr)	Auxiliary Boiler (g/s)	Main Boiler 1-Hr MGLC (mg/m^3)	Auxiliary Boiler 1-Hr MGLC (mg/m^3)	Total 1-Hr MGLC (mg/m^3)	Annual MGLC (mg/m^3)[2]	AAC Annual (mg/m^3)	% of allowable AAC[1]	24-Hr MGLC (mg/m^3)[1]	AAC 24-hour (mg/m^3)	% of allowable AAC[1]	15-Min MGLC (mg/m^3)	Short (15-min) Term Limit (mg/m^3)	% of allowable Short Term Limit
Dimethyl Phthalate	8.00E-04	1.01E-04		-	7.04E-08		7.04E-08	5.63E-09		-	2.82E-08	0.01	0.0002%	9.29E-08		-
Manganese Dioxide	3.54E-01	4.46E-02		-	3.11E-05		3.11E-05	2.49E-06		-	1.24E-05	0.24	0.005%	4.11E-05		-
Polychlorinated Biphenyls	1.14E-04	1.44E-05		-	1.00E-08		1.00E-08	8.02E-10		-	4.01E-09	0.07	0.00001%	1.32E-08		-
Polycyclic Organic Matter	5.16E-02	6.50E-03		-	4.54E-06		4.54E-06	3.63E-07		-	1.81E-06		-	5.99E-06		-
Propylene Dichloride	9.97E-03	1.26E-03		-	8.77E-07		8.77E-07	7.01E-08	4.00E-03	0.002%	3.51E-07		-	1.16E-06	50.80	0.000002%
Sodium Cyanide	6.71E-01	8.46E-02		-	5.90E-05		5.90E-05	4.72E-06	-		2.36E-05	0.012	0.1984%	7.79E-05	0.50	0.02%
Toluene-2,4-Diamine	1.14E-04	1.44E-05		-	1.00E-08		1.00E-08	8.04E-10		-	4.02E-09	5.52E-03	0.0001%	1.33E-08		-
Vinyl Chloride	5.92E-03	7.46E-04		-	5.21E-07		5.21E-07	4.17E-08	1.14E-04	0.04%	2.08E-07		-	6.88E-07	1.28	0.0001%
Dioxins (Total)	8.03E-08	1.01E-08	2.11E-09	2.66E-10	7.07E-12	1.60E-12	8.67E-12	6.94E-13		-	3.47E-12	1.52E-06	0.0002%	1.14E-11		-
Metals																
Antimony	1.46E-02	1.83E-03		-	1.28E-06		1.28E-06	1.02E-07	-	-	5.12E-07	1.19E-03	0.04%	1.69E-06	-	-
Arsenic	3.13E-01	3.94E-02	9.60E-04	1.21E-04	2.75E-05	7.29E-07	2.82E-05	**1.00E-07**	2.33E-07	**970.46 % / 43.00%**	1.13E-05	-	-	3.73E-05	2.00E-04	18.63%
Beryllium	2.85E-02	3.59E-03	7.20E-04	9.08E-05	2.50E-06	5.47E-07	3.05E-06	2.44E-07	4.17E-06	5.86%	1.22E-06	-	-	4.03E-06	5.00E-04	0.81%
Cadmium	5.35E-02	6.74E-03	7.20E-04	9.08E-05	4.71E-06	5.47E-07	5.25E-06	4.20E-07	5.56E-06	7.56%	2.10E-06	-	-	6.93E-06	3.00E-02	0.02%
Chromium, total	1.57E-01	1.97E-02	7.20E-04	9.08E-05	1.38E-05	5.47E-07	1.43E-05	1.15E-06	-	-	5.73E-06	2.38E-03	0.24%	1.89E-05	-	-
Chromium, hexavalent	3.86E-02	4.86E-03		-	3.39E-06		3.39E-06	**1.00E-08**	8.33E-08	**325.54 % / 12.00%**	1.36E-06	-	-	4.48E-06	0.01	0.04%
Cobalt	4.88E-02	6.15E-03		-	4.29E-06		4.29E-06	3.43E-07	-	-	1.72E-06	2.38E-04	0.72%	5.67E-06	-	-
Copper	7.80E-03	9.83E-04	1.44E-03	1.82E-04	6.86E-07	1.09E-06	1.78E-06	1.42E-07	-	-	7.12E-07	2.38E-04	0.30%	2.35E-06	-	-
Lead	1.33E-01	1.67E-02	2.16E-03	2.72E-04	1.17E-05	1.64E-06	1.33E-05	1.07E-06	-	-	5.33E-06	1.19E-04	4.48%	1.76E-05	-	-
Mercury	1.39E-02	1.75E-03	7.20E-04	9.08E-05	1.22E-06	5.47E-07	1.77E-06	1.42E-07	3.00E-04	0.05%	7.08E-07	-	-	2.34E-06	0.01	0.02%
Magnesium	5.37E+00	6.76E-01		-	4.72E-04		4.72E-04	3.78E-05	-	-	1.89E-04	0.02	0.79%	6.23E-04	-	-
Manganese	9.35E-01	1.18E-01	1.44E-03	1.82E-04	8.22E-05	1.09E-06	8.33E-05	6.66E-06	5.00E-05	13.33%	3.33E-05	-	-	1.10E-04	0.50	0.02%
Nickel	1.64E-01	2.07E-02	7.20E-04	9.08E-05	1.45E-05	5.47E-07	1.50E-05	1.20E-06	-	-	6.00E-06	2.38E-03	0.25%	1.98E-05	-	-
Phosphorus	2.61E-01	3.29E-02	2.68E-02	3.39E-03	2.30E-05	2.04E-05	4.34E-05	3.47E-06	-	-	1.74E-05	2.38E-04	7.29%	5.73E-05	-	-
Selenium	6.34E-01	7.99E-02	3.60E-03	4.54E-04	5.58E-05	2.73E-06	5.85E-05	4.68E-06	-	-	2.34E-05	4.76E-04	4.92%	7.73E-05	-	-
Zinc	5.20E-03	6.55E-04	9.60E-04	1.21E-04	4.57E-07	7.29E-07	1.19E-06	9.49E-08	-	-	4.75E-07	4.76E-03	9.97E-03 %	1.57E-06	1.00	0.0002%
Additional Evaluations																
Carbon Monoxide	2.49E+03	3.14E+02	9.60E+00	1.21E+00	2.19E-01	7.29E-03	2.26E-01	1.81E-02	-	-	**1.85E-02**	0.13	**69.13 % / 14.12%**	2.99E-01	22.90	1.30%
Hydrogen Fluoride, as F	2.22E+00	2.80E-01	2.23E-03	2.82E-04	1.95E-04	1.70E-06	1.97E-04	1.58E-05	-	-	7.88E-05	0.01	1.32%	2.60E-04	1.64E-01	0.16%
Cumulative Impact										**92.91%**			**63.06%**			**21.90%**

1. The model results in the highlighted cells are based on ISCST modeling and not the Screen3 results.The corresponding % of allowable ACC values for each of these concentrations shows the % of AAC when using the Screen3 model (1st) and % of AAC when using the ISCST model (2nd). See Table 6-3 for ISCST modeling results.

Sample1-hr MGLC Calculations for Acenaphthene

Main Boiler Emission	3.14E-05	g/s
Auxiliary Boiler Emission	4.56E-06	g/s
Main Boiler Screen 3 Modeling result	6.98E-04	mg/m^3
Auxiliary Boiler Screen 3 Modeling result	6.02E-03	mg/m^3

1-Hr MGLC Calculations

3.14E-5 g/s * 6.98E-04 mg/m3 + 4.56E-6 g/s * 6.02E-03 mg/m3 = 4.94E-08 mg/m3

Completed by : PBS 11/26/2008
Checked by :SAK 11/26/2008

Table 6-3 ISCST3 Toxics Modeling Results

Arsenic : Annual Average Period			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
1974	1.00E-04	340137	3657911
1975	8.00E-05	333000	3660000
1976	9.00E-05	340137	3657811
1977	1.00E-04	333000	3660000
1978	1.00E-04	334037	3659811
Maximum Concentration: 1.00E-04 $\mu g/m^3$			
Allowable Concentration : 2.33E-04 $\mu g/m^3$			
% of Allowable AAC: 43 %			
Hexavalent Chromium : Annual Average Period			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
1974	1.00E-05	340137	3657911
1975	1.00E-05	333000	3660000
1976	1.00E-05	340137	3657811
1977	1.00E-05	333000	3660000
1978	1.00E-05	333000	3659500
Maximum Concentration: 1.00E-05 $\mu g/m^3$			
Allowable Concentration : 8.33E-05 $\mu g/m^3$			
% of Allowable AAC: 12 %			
Sulfuric Acid (H_2SO_4) : 24-hr Average Period			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
1974	0.236	336537	3660811
1975	0.232	336137	3659711
1976	0.222	340237	3661411
1977	0.236	336237	3659311
1978	0.242	336137	3659911
Maximum Concentration: 0.242 $\mu g/m^3$			
Allowable Concentration : 2.38 $\mu g/m^3$			
% of Allowable AAC: 10.15 %			
Arsenic Trioxide : 24-hr Average Period			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
1974	1.75E-03	336537	3660811
1975	1.72E-03	336137	3659711
1976	1.65E-03	340237	3661411
1977	1.75E-03	336237	3659311
1978	1.79E-03	336137	3659911
Maximum Concentration: 1.79E-03 $\mu g/m^3$			
Allowable Concentration : 2.38E-02 $\mu g/m^3$			
% of Allowable AAC: 7.52 %			

$\mu g/m^3$ - micrograms per cubic meter

Completed by: PBS 11/26/08
Checked by: SAK 11/26/08

Table 6-3 ISCST3 Toxics Modeling Results (Continued)

Carbon Monoxide : 24-hr Average Period			
Year of Model Run	**Maximum Concentration ($\mu g/m^3$)**	**Location of Receptors (UTM)**	
1974	17.78	336537	3660811
1975	17.80	336137	3659711
1976	16.83	340237	3661411
1977	17.97	336237	3659311
1978	18.49	336137	3659911
Maximum Concentration: 18.49 $\mu g/m^3$			
Allowable Concentration : 131 $\mu g/m^3$			
% of Allowable AAC: 14.12 %			

$\mu g/m^3$ - micrograms per cubic meter

Completed by: PBS 11/26/08
Checked by: SAK 11/26/08

The Georgia Air Toxics program also requires an evaluation to ensure that the cumulative/ synergistic impacts from all toxics combined does not exceed safe levels. This is to ensure that a group of toxics that impact the same organ system do not have an accumulative or synergistic impact above safe levels. To evaluate the potential synergistic impacts from a group of toxics, the guideline requires summing the percent of each individual AAC that is consumed (i.e. the MGLC divided by the AAC) for each emitted toxic, which impacts the same organ system. As long as the combined total is less than 100%, the combined impact is considered acceptable. For this evaluation the percent of the AAC was summed for each averaging period for all pollutants regardless of which organ it affects and the results are shown at the bottom of Table 6-2. As shown the cumulative impact from all toxics emitted for the annual, 24-hour, and 15-minute average are all below 100% (92.91%, 63.06%, and 21.89% respectively). It should be noted that most of the toxics affect different organ systems, therefore, the above analysis is very conservative in that it assumes all toxics would be impacting the same system.

7.0 CLASS I AREA MODELING

A Class I modeling evaluation was completed in order to assess the projects impact on Class I areas within 300 km of the site. The PSD permit coordinator with the Federal Land Manager (FLM) was contacted to determine what analyses should be completed in order to assess the project's impact on these Class I areas. The PSD coordinator indicated that a visibility impairment analysis, a deposition analysis, and an initial screening analysis should be completed per the FLM Air Quality Related Values Workgroup (FLAG) Phase I document. The latest version of this documented dated July 2008 was used to evaluate the proposed facility's impact on each of the Class I areas.

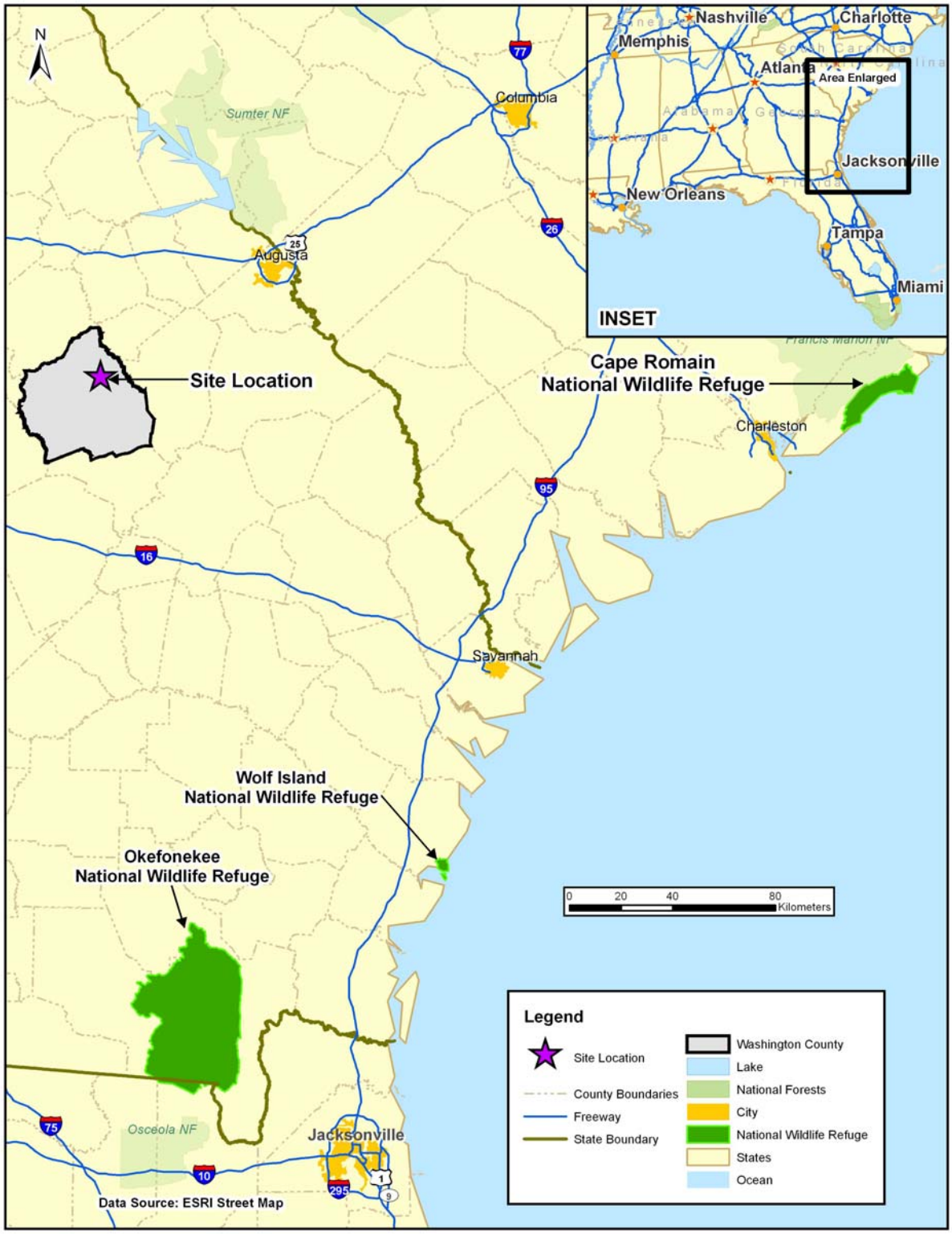
Plant Washington is located near several Class I areas. Table 7-1 below lists each Class I area and the distance to the point closest to Plant Washington. Figures 7-1 and 7-2 show the location of the Class I areas in relation to Plant Washington.

Table 7-1 Class I Areas within 300 km Plant Washington

Class I Area	Distance to Plant Washington (km)
Cape Romain	289
Cohutta Wilderness	261
Great Smokey Mountains	273
Joyce Kilmer-Slickrock Wilderness	276
Okefenokee	252
Shining Rock	232
Wolf Island	228

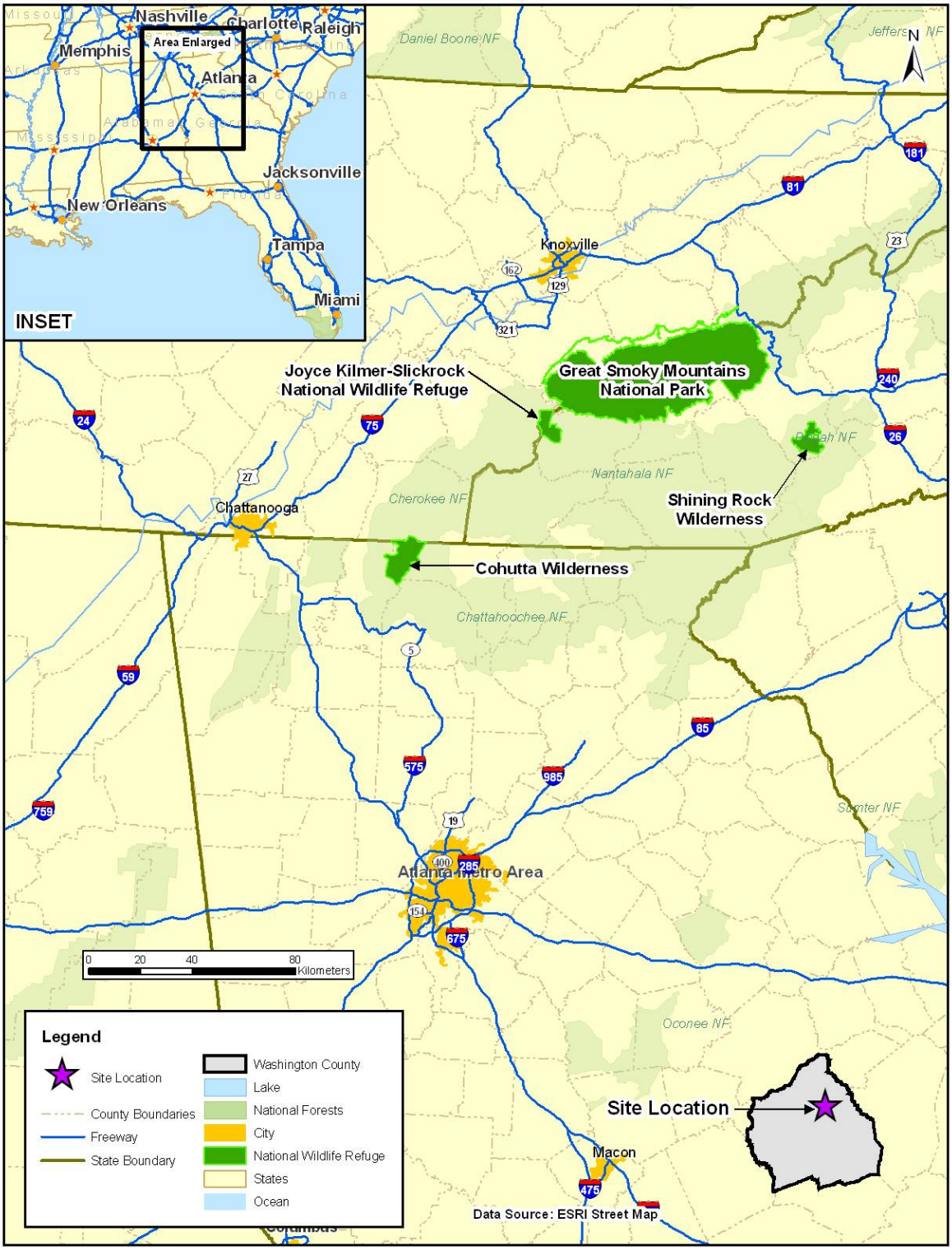
Completed by: BSA 11/26/08
Checked by: SAK 11/26/08

Figure 7-1 Relative Location Map of Site to the Class I Area



Prepared by: FC 11/26/08
Checked by: SAK 11/26/08

Figure 7-2 Relative Location Map of Site to the Class I Area



Prepared by: FC 11/26/08
Checked by: SAK 11/26/08

In April 2003, EPA designated the CALPUFF model as a preferred model for Long Range Transport (LRT) (i.e., beyond 50km). Because the seven sites being evaluated for Class I air quality assessments for Plant Washington are all greater than 50 km away from the proposed plant site, the refined modeling is considered to be Long Range Transport. Therefore the CALPUFF (version 5.8, level 070623) POSTUTIL (version 1.52, level 060412) and CALPOST (version 5.6394, level 070622) models were used to complete this analysis

The CALPUFF modeling was completed using three years (2001 – 2003) of 4-kilometer grid meteorological data, which was provided by the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) via South Carolina Department of Health and Environmental Control (SC DHEC). VISTAS generated the meteorological data in July 2007 using CALMET version 5.7. The receptor sets for the Class I areas were downloaded from the U.S. National Park Service (USNPS) web site and converted to the Lambert Conformal Conic (LCC) coordinate system, which is the coordinate system used by the VISTAS meteorological dataset. The National Park Service Convert Class 1 Areas program downloaded from the USNPS website was used to convert Plant Washington emission source UTM coordinates into the LCC coordinate system. In accordance with FLAG modeling documents, the modeling evaluation did not include building downwash because the Class I areas being evaluated are greater than 50 kilometers from the site.

7.1 CLASS I AREAS: VISIBILITY

The most recent FLAG guidance document indicates that if the modeled impact from the proposed project results in a change in β-extinction below the visibility threshold of 5% then it is presumed by the FLM that the project will have no adverse impact. The visibility modeling was completing using the CALPUFF model. As per the latest FLAG guidance the change in β-extinction was calculated using the Interagency Monitoring of Protected Visual Environments (IMPROVE) equation. The new IMPROVE equation takes into account the difference in the light scattering from large and small particles of sulfates, nitrates, and organics; as well visibility impacts from sea salt contributions and changes in Rayleigh Scattering from site to site. The current EPA approved version of CALPOST does not utilize the new IMPROVE equation, so a spreadsheet was developed to process the CALPOST output. The previous FLAG guidance utilized a method which used hour by hour relative humidity adjustment factors. The latest guidance is to use a monthly f(RH) values for each of the Class I areas. A copy of the IMPROVE equation spreadsheet used to calculate β-extinction for each modeled year for each Class I area is included in Exhibit D.

The modeled species included in computing light extinction were small and large sulfate particles, small and large nitrate particles, small and large organic mass, sea salt, and fine particulate, which were identified as PM_{10} in the model runs. The FLAG document dated July 2008 requires the use of monthly relative humidity adjustment factors (for small, large, and sea salt particles).

In the CALPOST post processor, the MISBK parameter was set to 6 and the background hygroscopic and non-hygroscopic aerosol levels take from FLAG (2008) are entered for the corresponding Class I area. Table 7-2 shows the background levels of the seven calculated background species, as well as the Rayleigh Scattering number for each site. The background concentration of ammonia was set to 0.5 ppb as per the designation of this use by FLAG (2008) for forested land.

Table 7-2 Background Concentration for the Modeled Class I Areas

Class I Area	$(NH_4)_2SO_4$ µg/m^3	NH_4NO_3 µg/m^3	Organic Matter µg/m^3	Elemental Carbon µg/m^3	Soil µg/m^3	Coarse Matter µg/m^3	Sea Salt µg/m^3	Rayleigh Mm^{-1}	Type
Cape Romain	0.23	0.10	1.80	0.02	0.45	3.00	0.20	12	Annual
Cohutta Wilderness	0.23	0.10	1.71	0.02	0.50	2.45	0.02	11	Annual
Great Smokey Mountains	0.23	0.10	1.80	0.02	0.48	2.92	0.02	11	Annual
Joyce Kilmer-Slickrock Wilderness	0.23	0.10	1.80	0.02	0.48	2.92	0.02	11	Annual
Okefenokee	0.23	0.10	1.80	0.02	0.50	3.00	0.08	11	Annual
Shining Rock	0.23	0.10	1.76	0.02	0.50	1.76	0.02	10	Annual
Wolf Island	0.23	0.10	1.80	0.02	0.50	3.00	0.08	11	Annual

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Checked by: SAK 11/26/08

In order to use this equation with the current generated output of the EPA approved model of CALPUFF, the output of the CALPOST post processor was refined by using the monthly f(RH) values for small, large, and sea salt particles for each site. Tables 7-2, 7-3, and 7-4 show the monthly $f_L(RH)$, $f_S(RH)$, and $f_{SS}(RH)$ relative humidity adjustment factors respectively for the seven Class I areas evaluated.

Table 7-3 Monthly $f_L(RH)$ – Large $(NH_4)_2SO_4$ and NH_4NO_3 Relative Humidity Adjustment Factors

Class I Area	January	February	March	April	May	June
Cape Romain	2.66	2.47	2.42	2.32	2.56	2.80
Cohutta Wilderness	2.84	2.61	2.49	2.36	2.72	2.97
Great Smokey Mountains	2.85	2.57	2.51	2.35	2.72	2.98
Joyce Kilmer-Slickrock Wilderness	2.86	2.58	2.51	2.36	2.71	2.97
Okefenokee	2.94	2.73	2.73	2.65	2.74	3.11
Shining Rock	2.78	2.56	2.48	2.33	2.72	2.98
Wolf Island	2.86	2.67	2.61	2.54	2.63	2.96
	July	**August**	**September**	**October**	**November**	**December**
Cape Romain	2.82	3.04	3.03	2.86	2.65	2.70
Cohutta Wilderness	3.00	3.07	3.08	2.89	2.72	2.85
Great Smokey Mountains	2.98	3.08	3.10	2.87	2.71	2.85
Joyce Kilmer-Slickrock Wilderness	2.98	3.06	3.08	2.87	2.72	2.85
Okefenokee	3.00	3.17	3.16	3.05	2.96	3.03
Shining Rock	3.02	3.17	3.15	2.91	2.68	2.79
Wolf Island	2.94	3.13	3.12	2.99	2.88	2.95

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Checked by: SAK 11/26/08

Table 7-4 Monthly $f_S(RH)$ –Small $(NH_4)_2SO_4$ and NH_4NO_3 Relative Humidity Adjustment Factors

Class I Area	January	February	March	April	May	June
Cape Romain	3.66	3.33	3.24	3.07	3.46	3.88
Cohutta Wilderness	3.99	3.59	3.38	3.16	3.76	4.19
Great Smokey Mountains	4.01	3.52	3.43	3.14	3.76	4.20
Joyce Kilmer-Slickrock Wilderness	4.02	3.54	3.42	3.15	3.74	4.19
Okefenokee	4.16	3.79	3.80	3.65	3.79	4.46
Shining Rock	3.89	3.51	3.37	3.11	3.77	4.22
Wolf Island	4.02	3.68	3.58	3.45	3.59	4.17
	July	**August**	**September**	**October**	**November**	**December**
Cape Romain	3.91	4.31	4.30	4.00	3.62	3.73
Cohutta Wilderness	4.24	4.37	4.41	4.09	3.77	4.00
Great Smokey Mountains	4.21	4.39	4.45	4.05	3.79	3.99
Joyce Kilmer-Slickrock Wilderness	4.21	4.35	4.41	4.04	3.77	4.00
Okefenokee	4.24	4.55	4.55	4.35	4.18	4.33
Shining Rock	4.29	4.58	4.60	4.12	3.69	3.88
Wolf Island	4.13	4.47	4.46	4.23	4.05	4.18

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Checked by: SAK 11/26/08

Table 7-5 Monthly $f_L(RH)$ – Sea Salt Relative Humidity Adjustment Factors

Class I Area	January	February	March	April	May	June
Cape Romain	3.74	3.44	3.37	3.23	3.62	3.99
Cohutta Wilderness	3.97	3.62	3.44	3.26	3.82	4.20
Great Smokey Mountains	4.01	3.57	3.47	3.22	3.82	4.23
Joyce Kilmer-Slickrock Wilderness	4.01	3.58	3.46	3.24	3.81	4.22
Okefenokee	4.13	3.83	3.82	3.69	3.85	4.38
Shining Rock	3.90	3.55	3.43	3.21	3.82	4.22
Wolf Island	4.03	3.74	3.66	3.55	3.72	4.20
	July	**August**	**September**	**October**	**November**	**December**
Cape Romain	4.04	4.32	4.29	4.03	3.74	3.81
Cohutta Wilderness	4.24	4.35	4.35	4.05	3.82	4.02
Great Smokey Mountains	4.24	4.37	4.38	4.03	3.81	4.02
Joyce Kilmer-Slickrock Wilderness	4.23	4.35	4.35	4.03	3.82	4.02
Okefenokee	4.28	4.51	4.48	4.31	4.18	4.27
Shining Rock	4.28	4.48	4.48	4.06	3.76	3.92
Wolf Island	4.20	4.46	4.42	4.22	4.08	4.15

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In the CALPUFF model, an emission rate for elemental carbon was estimated as 1% of the total PM, based on a report published by Pacific Environmental Services, Inc. dated September 29, 2003, and available on the USEPA Technology Transfer Network web site. This report evaluates speciation data of $PM_{2.5}$ emissions from coal fired boilers. The value of 1% is conservative since the value of 1% was derived from the total PM emissions, not the $PM_{2.5}$ emissions. The sulfate (SO_4) emission rate for the main boiler was calculated from the maximum 3-hour emission rate for sulfuric acid test and the molecular weight ratio of sulfates to sulfuric acid mist (H_2SO_4) -96/98. This assumes all sulfuric acid mist will form SO_4 after exiting the stack.

The CALPUFF model also has an input parameter for organic carbon (OC), processed as secondary organic aerosols (SOA) using the SOA module of CALPUFF. However, as discussed in the *Protocol for the Application of the CALPUFF Model for Analyses of Best Available Retrofit Technology (BART) (8/31/06)*, the developers (of CALPUFF) "view the SOA module as needing more testing and evaluation." The SOA module relies on the fact that only hydrocarbons with more than 6 carbon atoms can form significant SOA, and is best suited for evaluation of biogenic organics.

The visibility threshold for the project (5%) is not exceeded if the 98th percentile change in light extinction is less than 5% for each modeled year. The 98th percentile value translates to the 8th highest daily value for each modeled year. Table 7-6 provides 8th highest values for each site and each year and as shown all values are below the 5% screening threshold.

Table 7-6 CALPUFF Method 6 Modeling Results for Class I Areas near Plant Washington

Class I Area	Model Year			Max Result	Screen Level	Below Screen Level?
	2001	2002	2003			
Cape Romain	1.26%	1.42%	1.30%	1.42%	5%	Yes
Cohutta Wilderness	1.15%	1.24%	1.37%	1.37%	5%	Yes
Great Smokey Mountains	0.93%	0.91%	1.05%	1.05%	5%	Yes
Joyce Kilmer-Slickrock Wilderness	0.90%	0.75%	0.99%	0.99%	5%	Yes
Okefenokee	1.03%	1.39%	0.85%	1.39%	5%	Yes
Shining Rock	1.25%	1.08%	1.40%	1.40%	5%	Yes
Wolf Island	1.06%	1.18%	1.32%	1.32%	5%	Yes

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Checked by: SAK 11/26/08

7.2 CLASS I AREAS: DEPOSITION

The SO_2 and NO_x emissions increases from the project were used to estimate sulfur and nitrogen deposition impacts on the Class I modeling areas under review. The CALPUFF model was used to create the wet and dry flux data files, which were processed further using the POSTUTIL program to generate a deposition flux file. The flux file is processed using the CALPOST post processor in order to determine total nitrogen (N) and sulfur (S) deposition. The units of the fluxes are in $g/m^2/s$. The modeling results were compared to the Class I Deposition Analysis Thresholds (DATs) recommended by the Federal Land Manager of 0.01 kg/ha/yr N or S as specified in the "Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds" document posted on the National Park Service website dated August 2001. Exceedance of DAT does not necessarily indicate an adverse impact, but rather that additional analyses of deposition impacts may be requested. Values below the DAT indicate a level of impact that is considered insignificant. Table 7-7 presents the results from all three modeled years. As indicated the modeling results for the nitrogen and sulfur deposition analysis are below the thresholds except for a few that are slightly above the DAT levels.

Table 7-7 Class I Increment Deposition Results

Class I Area	N Increment Results kg/ha/yr			S Increment Results kg/ha/yr		
	2001	2002	2003	2001	2002	2003
Cape Romain	3.15E-03	2.38E-03	1.88E-03	1.16E-02	1.02E-02	8.23E-03
Cohutta Wilderness	2.90E-03	4.12E-03	3.95E-03	8.50E-03	1.34E-02	1.16E-02
Great Smokey Mountains	2.73E-03	2.72E-03	3.80E-03	8.72E-03	8.47E-03	1.09E-02
Joyce Kilmer Slickrock	2.72E-03	2.99E-03	3.31E-03	8.20E-03	8.85E-03	9.98E-03
Okefenokee	1.43E-03	1.46E-03	7.30E-04	5.15E-03	4.99E-03	2.72E-03
Shining Rock	2.85E-03	2.79E-03	4.45E-03	8.62E-03	8.72E-03	1.15E-02
Wolf Island	2.54E-03	1.65E-03	7.31E-04	9.37E-03	7.10E-03	4.63E-03

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7.3 CLASS I AREAS: CLASS I INCREMENT EVALUATION

An initial screening analysis was done to determine whether Plant Washington will have a significant impact on the concentration of pollutants in the ambient air at the seven Class I areas under evaluation. The CALPUFF model included all emission sources at the proposed Plant Washington site (point and fugitive sources). The CALPUFF model created concentration data files, which were processed using the CALPOST post processor to determine the maximum concentration at all receptors within the Class I areas. Tables 7-8, 7-9, and 7-10 present the Class I screening analysis results for PM_{10}, SO_2 and NO_x respectively, for all averaging periods and for all three years of meteorological data. Each of the computed maximum concentrations for each pollutant's averaging periods was below their respective significant impact levels currently established by USEPA, except for the 24-hr concentration for SO_2 at Wolf Island. A refined SO_2 PSD increment modeling analysis for Wolf Island was therefore completed.

Currently, there is not an official Class I screening level for $PM_{2.5}$. The EPA has, however, proposed three options for $PM_{2.5}$ Class I screening levels under its rule proposed on September 21, 2007. Under this proposed rule, the lowest option would be a Class I significance level of 0.04 $\mu g/m^3$ and 0.08 $\mu g/m^3$ for the annual and 24-hour averaging period. The modeled concentrations for PM_{10} are below these levels, therefore, because $PM_{2.5}$ is a subset of PM_{10}, the modeled $PM_{2.5}$ concentrations would also be below these levels. No additional modeling for $PM_{2.5}$ was therefore required.

7.4 WOLF ISLAND: REFINED SO_2 MODELING

In accordance with FLM guidelines an emission database of all SO_2 increment consuming sources within 300 km of Wolf Island was created with data received from Florida Department of Environmental Protection, South Carolina Department of Health and Environmental Control and Georgia Environmental Protection

Division. As is allowed for PSD increment modeling, some of the sources were modeled at their actual emissions based on their emission rates in the Georgia and National Emission Inventories (NEI). Because the CALPUFF model is unable to run with more than 200 emission sources at a time the emission sources were split into six groups of 200 or less. All of the individual models were then combined using the CALSUM utility. These results are summarized in Table 7-11 and as indicated the results are below the Class I PSD SO_2 increment levels.

Table 7-8 CALPUFF Class I PM_{10} Screening Analysis

Annual PM_{10} Screening Results						
	Model Year			Max. Conc.	Level	Below Screening
Class I Area	2001	2002	2003	(µg/m^3)	(µg/m^3)	Level?
Cape Romain	2.32E-03	2.52E-03	2.39E-03	2.52E-03	0.2	Yes
Cohutta Wilderness	1.34E-03	1.81E-03	1.83E-03	1.83E-03	0.2	Yes
Great Smokey Mountains	1.02E-03	1.11E-03	1.55E-03	1.55E-03	0.2	Yes
Joyce Kilmer Slickrock	9.84E-04	1.17E-03	1.43E-03	1.43E-03	0.2	Yes
Okefenokee	1.42E-03	1.64E-03	1.01E-03	1.64E-03	0.2	Yes
Shining Rock	1.34E-03	1.53E-03	1.86E-03	1.86E-03	0.2	Yes
Wolf Island	1.97E-03	2.10E-03	1.84E-03	2.10E-03	0.2	Yes
24-Hour PM_{10} Screening Results						
	Model Year			Max. Conc.	Level	Below Screening
Class I Area	2001	2002	2003	(µg/m^3)	(µg/m^3)	Level?
Cape Romain	2.77E-02	3.85E-02	4.21E-02	4.21E-02	0.3	Yes
Cohutta Wilderness	2.92E-02	2.89E-02	3.52E-02	3.52E-02	0.3	Yes
Great Smokey Mountains	2.42E-02	1.95E-02	4.08E-02	4.08E-02	0.3	Yes
Joyce Kilmer Slickrock	2.14E-02	1.80E-02	4.30E-02	4.30E-02	0.3	Yes
Okefenokee	3.61E-02	3.34E-02	2.62E-02	3.61E-02	0.3	Yes
Shining Rock	3.32E-02	3.18E-02	3.78E-02	3.78E-02	0.3	Yes
Wolf Island	3.44E-02	3.47E-02	5.69E-02	5.69E-02	0.3	Yes

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Table 7-9 CALPUFF Class I SO_2 Screening Analysis

Annual SO_2 Results						
Class I Area	Model Year 2001	Model Year 2002	Model Year 2003	Max. Conc. (µg/m^3)	Screening Level (µg/m^3)	Below Screening Level?
Cape Romain	7.61E-03	7.54E-03	7.56E-03	7.61E-03	0.1	Yes
Cohutta Wilderness	3.82E-03	4.66E-03	4.40E-03	4.66E-03	0.1	Yes
Great Smokey Mountains	2.32E-03	2.29E-03	2.81E-03	2.81E-03	0.1	Yes
Joyce Kilmer Slickrock	2.32E-03	2.43E-03	2.68E-03	2.68E-03	0.1	Yes
Okefenokee	4.51E-03	4.91E-03	2.89E-03	4.91E-03	0.1	Yes
Shining Rock	3.54E-03	3.24E-03	4.26E-03	4.26E-03	0.1	Yes
Wolf Island	7.11E-03	7.80E-03	7.28E-03	7.80E-03	0.1	Yes
24-Hour SO_2 Results						
Class I Area	Model Year 2001	Model Year 2002	Model Year 2003	Max. Conc. (µg/m^3)	Screening Level (µg/m^3)	Below Screening Level?
Cape Romain	0.1052	0.1583	0.1398	0.16	0.2	Yes
Cohutta Wilderness	0.1211	0.1094	0.1319	0.13	0.2	Yes
Great Smokey Mountains	0.0955	0.0731	0.0795	0.10	0.2	Yes
Joyce Kilmer Slickrock	0.0713	0.0611	0.0631	0.07	0.2	Yes
Okefenokee	0.1080	0.1069	0.0986	0.11	0.2	Yes
Shining Rock	0.1571	0.1186	0.1511	0.16	0.2	Yes
Wolf Island	0.1734	0.1694	0.2863	0.29	0.2	No
3-Hour SO_2 Results						
Class I Area	Model Year 2001	Model Year 2002	Model Year 2003	Max. Conc. (µg/m^3)	Screening Level (µg/m^3)	Below Screening Level?
Cape Romain	0.32	0.43	0.48	0.48	1	Yes
Cohutta Wilderness	0.55	0.71	0.48	0.71	1	Yes
Great Smokey Mountains	0.27	0.30	0.53	0.53	1	Yes
Joyce Kilmer Slickrock	0.27	0.25	0.29	0.29	1	Yes
Okefenokee	0.65	0.41	0.35	0.65	1	Yes
Shining Rock	0.39	0.35	0.58	0.58	1	Yes
Wolf Island	0.41	0.55	0.59	0.59	1	Yes

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Table 7-10 CALPUFF Class I NO_x Screening Analysis

Class I Area	Model Year 2001	Model Year 2002	Model Year 2003	Max. Conc. (µg/m^3)	Screening Level (µg/m^3)	Below Screening Level?
Cape Romain	1.05E-03	1.32E-03	1.20E-03	1.32E-03	0.1	Yes
Cohutta Wilderness	6.12E-04	1.11E-03	9.52E-04	1.11E-03	0.1	Yes
Great Smokey Mountains	3.93E-04	4.01E-04	5.94E-04	5.94E-04	0.1	Yes
Joyce Kilmer Slickrock	3.17E-04	4.55E-04	6.06E-04	6.06E-04	0.1	Yes
Okefenokee	8.54E-04	7.99E-04	5.28E-04	8.54E-04	0.1	Yes
Shining Rock	7.55E-04	6.36E-04	9.74E-04	9.74E-04	0.1	Yes
Wolf Island	1.37E-03	1.92E-03	1.70E-03	1.92E-03	0.1	Yes

Completed by: BSA 11/26/08
Checked by: SAK 11/26/08

Table 7-11 CALPUFF SO_2 PSD Increment Modeling Results for Wolf Island Class I Area

Averaging Period	2nd High Concentrations (Except For Annual) 2001 (µg/m^3)	2002 (µg/m^3)	2003 (µg/m^3)	Class 1 PSD Increment (µg/m^3)
3-hr	10.66	10.28	11.51	25
24-hr	3.428	3.470	3.516	5
Annual	0	0	0	2

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Checked by: SAK 11/26/08

8.0 OTHER IMPACT ANALYSIS

In addition to evaluating the project's air quality impacts, the permit application addresses other potential impacts. This included impacts on local Class II visibility, secondary impacts on soils and vegetation, demographic impacts, and construction impacts as required by the PSD guidelines. In addition, this evaluation includes an evaluation of the projects impact on water consumption as well as on green house gas (GHG) emissions.

8.1 CLASS II VISIBILITY

The proposed project's impacts on Class II visibility were evaluated as part of the permit application. Per EPD guidance, Class II visibility analyses only have to be performed for airports, state or national parks, or state historical sites located within the project's largest calculated Area of Impact (AOI) as determined by the PSD modeling evaluation. As indicated in Section 5, only one pollutant exceeded its significant impact levels (SO_2). The largest AOI for SO_2 was 5.24 km. A review of the area around the plant found that there are no airports, state or national parks, or historical sites located within 5.24 km, therefore a Class II Visibility analysis is not required for the proposed project.

8.2 SECONDARY IMPACTS ON SOIL AND VEGETATION

PSD regulations require an assessment of other possible impacts, including any secondary impacts on soils and vegetation. An analysis was completed to assess the potential impact of vegetative stress in the area of the proposed plant as outlined in the USEPA document "A Screening Procedure for the Impact of Air Pollution sources on Plants, Soils, and Animals". This document provides ambient concentration levels of SO_2, NOx, CO, Fluorine, Beryllium and Lead which can be used for screening levels to determine if there is a potential for vegetative stress.

As a first step an intensive surveillance of the area surrounding the proposed plant site was conducted. The proposed plant is located in a rural area which is surrounded by wooded tracts and small farms. The vegetation present was identified and compared to the listing presented in the guidance document as being potentially sensitive to the compounds of concern (Tables B.1 through B.4 of the USEPA Screening document). No plant species were identified as being sensitive to nitrogen dioxide, however, there were species identified that are sensitive to sulfur dioxide and ozone. The area is in attainment with the ozone air quality standard and the proposed

plant is not expected to change the attainment status of the area so the only species that could potentially be impacted are those identified as being sensitive for SO_2. The following is a listing of the sensitive vegetation found:

Crop Species sensitive to Sulfur Dioxide:

Blackberry (not a planted crop, only present as wild species)

Natural Vegetation sensitive to Sulfur Dioxide:

Ash
Tulip Tree (Tulip Poplar a.k.a. Yellow Poplar (liriodendeon tulipifera))
Black Willow

Some Natural Vegetation with Intermediate sensitivity to Sulfur Dioxide:

Boxelder
American Elm
White Oak

Some Natural Vegetation Resistant to Sulfur Dioxide:

Black gum
Dogwood
Red Oak
American Sycamore

Because vegetation is present that could potentially be stressed, an evaluation was completed using the modeled emissions calculated in the previous sections. Table 8-1 below summarizes the modeled concentrations for each pollutant and compares them to the screening level as taken from Table 3.1 of the USEPA screening procedure document. As indicated in Table 8-1, the maximum ground level concentrations for all pollutants for all averaging periods are well below the screening levels. With this demonstration it is apparent that not only is existing vegetation

safe from potential vegetative stress but also any potential new crops that may be planted in the area will be as well.

Table 8-1 Screening Concentrations for Exposure to Ambient Air Concentrations

Pollutant	Averaging Period	Basis	Modeled Result (µg/m^3) 1987	1988	1989	1990	1991	Maximum Modeled Result (µg/m^3)	Background Concentration (µg/m^3)	Maximum Modeled Concentration plus Background (µg/m^3)[6]	Screening Level (µg/m^3)	Below Screening Level?
SO_2	1 hr[1]	PSD Screening Modeling	47.76	48.91	43.56	40.40	37.34	48.91	225	273.9	917	Yes
	3- hr	PSD Screening Modeling	27.79	26.62	29.03	28.54	29.28	29.28	187	216.3	786	Yes
	Annual	PSD Screening Modeling	1.259	1.172	1.249	1.240	1.252	1.259	8	9.259	18	Yes
NO_x	4 hr	PSD Screening Modeling	10.45	11.55	11.27	11.39	11.95	11.95	112	124.0	3760	Yes
	8 hr	PSD Screening Modeling	9.184	9.940	9.144	8.392	8.602	9.940	98.9	108.8	3760	Yes
	1 month[2]	Conversion from PSD Screening Modeling	4.366	4.824	4.707	4.757	4.993	4.993	46.6	51.59	564	Yes
	Annual	PSD Screening Modeling	0.5450	0.5074	0.5407	0.5366	0.5416	0.5450	11.3	11.84	94	Yes
CO	1 week[3]	Conversion from PSD Screening Modeling	52.08	53.34	47.50	44.06	40.72	53.34	5371	5424	1,800,000	Yes
Fluorine[5]	10 days[4]	Conversion from PSD Screening Modeling	0.0165	0.0148	0.0140	0.0148	0.0156	0.0165	see note 5	0.0165	0.5	Yes
Beryllium[7]	1 month[2]	Other Impacts Analysis Modeling	4.95E-04	5.05E-04	4.52E-04	3.80E-04	6.67E-04	6.67E-04	3.00E-05	6.97E-04	1.00E-02	Yes
Lead[8]	3 months[9]	Other Impacts Analysis Modeling	0.00686	0.007	0.00624	0.00589	0.00605	0.007	0.008	0.015	1.5	Yes

1. The 1-hour background concentration for SO_2 was calculated by dividing the 3-hour background concentration provided by the Georgia EPD by the 0.83 time averaging concentration factor for converting from 1 hour to 3 hour averages

2. The AERMOD model does not allow for 1 month averaging modeling. The results from the 4-hour average modeling were converted to 1-hour average by dividing by the 0.79 conversion factor and then converted to a monthly average by using the 0.33 1-hour to monthy conversion factor. This factor was derived using the equation on page 55 of the EPA screening guidance

3. The AERMOD model does not allow for 1 week averaging modeling. The results from the 1-hour average modeling were converted to the 7-day averaging modeling by using the 0.42 1-hr to 7-day conversion factor. This factor was derived using the equation on page 55 of the EPA screening guidance. The same value was used to convert the 1-hour background concentration data, which was provided by the Georgia EPD documentation "2006 Georgia Annual Air Quality Report".

4. The AERMOD model does not allow for 10 day averaging modeling. The results from the PSD screening completed for fluorides was converted to 10-day averaging by dividing by the 0.58 1-hour to 24-hour conversion factor and then multiplying by the 0.39 1-day to 10-day conversion factor. Both conversion factors come from Table A.2 in the EPA screening guidance.

5. No data was available for the Fluorine background concentration.

6. The background SO_2 and NO_x concentrations were provided by the Georgia EPD. The 3-hour background concentration for SO_2 was converted to the 1-hour concentration by dividing by the 0.83 1-hour to 3-hour conversion factor. The conversion factors for 1-hour to annual (0.08), 1-hour to 4-hour (0.79), 1-hour to 8-hour (0.70), and 1-hour to monthly (0.33) were used to convert the NOx annual background to the 4-hour and 8-hour averages.

7. Background concentration for beryllium was based on the maximum result for all beryllium monitors in the state of Georgia for 2006.

8. Background concentration for lead is based on the maximum result for the closest lead monitor to the site (Milledgeville) for 2006.

9. The AERMOD model does not allow for 3-month averaging modeling. The results from the 1-hour averaging modeling were used.

Prepared by: BSA 11/26/08
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The USEPA Screening documents also outlines an evaluation for metals impacts. All these metals along with all other known toxics being emitted from the boiler were evaluated as part of the Georgia Air Toxics program in Section 6 of the permit application. The conclusion of that evaluation was that the plant demonstrates compliance with the Georgia toxics program, therefore, no further evaluation is being conducted in this section.

8.3 DEMOGRAPHICS

The proposed plant is expected to employ an estimated 100 to 150 people during operation. This workforce is expected to come from local communities, therefore, growth impacts are expected to be minimal and should not adversely affect the ambient air quality in the surrounding area. No additional automobile roadways are planned for the project.

8.4 CONSTRUCTION IMPACTS

During the construction phase of the proposed plant, there will be two primary sources of air emissions: 1) pollutants emitted from construction equipment and 2) fugitive dust emissions associated with the construction activities.

Typically, large gasoline and diesel powered construction equipment emit small amounts of VOCs, CO, SO_2, NO_x, and PM. Emissions due to the operation of this equipment are expected to cause only localized increases in pollutant levels. These increases will be only temporary and are not expected to cause any long-term adverse impacts on the construction area or the surrounding communities.

The fugitive dust emissions created from the construction activities will be more visible than the other pollutant emissions from the equipment. Site grading and preparation activities will create dust emissions. The greatest impact of the fugitive dust emissions will be confined to the construction site, and the effects on the surrounding properties are expected to be minimal. The extent of fugitive emissions will vary day to day, depending on the amount of construction activity and the weather. Standard engineering and construction practices will be implemented in order to minimize fugitive dust emissions (such as watering haul roads).

8.5 MINIMIZATION OF WATER USE

A coal-fired power plant like any other power generating facility burns fuel to produce electricity. This is accomplished by producing steam in a boiler and then having that steam pass through turbines which in turn generates electricity.

The plant will have three main uses of water: 1) boiler makeup and non-contact cooling tower blowdown; 2) the flue gas desulfuring units (wet scrubbers); and 3) non-contact cooling. The water used to feed the boiler to produce steam is actually the smallest demand in the plant since most of the steam is collected, condensed, and re-circulated back into the boiler. The water required for this purpose is a relatively small amount of make-up water necessary to replace the water lost in the steam handling process and for boiler blowdown. The second highest demand for water will befor operation of the wet scrubber that is used to remove SO_2 from the flue gases (wet flue gas desulfurization). There is a constant feed of water into this control device that replenishes the scrubant (pulverized slurried limestone) in the flue gas desulfuring units. Here, SO_2 reacts with the limestone to form gypsum ($CaSO_4$ 2HO). The third (and largest) use will be for non-contact cooling water supplied to the cooling towers. Steam is condensed in the power generation process. The resulting condensate will be recirculated (recycled) back into the boiler to conserve heat and water. Steam itself cannot be injected back into the boiler so it needs to be condensed back into water for that purpose. The heat generated from the condensing steam is dissipated in the cooling towers by evaporation of water. The cooling towers will use, on average, approximately 12.6 MGD of water, of which approximately 10.8 MGD of water will be evaporated in the cooling towers with the remainder being discharged to the river.

It should be noted that typical existing power plants use more water per unit of power generated than what is being proposed for this plant, which has a much more efficient design. The process of producing power does not convert all of the energy from burning the coal into electrical energy. The remainder portion of the heat is either vented out the stack or lost in the cooling tower. Plant Washington will be a supercritical unit that operates at much higher temperatures and pressures and consequently will be more efficient. This means that this plant will use approximately 15 percent less water than a comparable existing plant. Also consequently 15% less pollutants will be generated including green house gases on a per unit of power basis.

A potential technology exists that could further reduce water consumption called “dry cooling”. In dry cooling, steam is condensed by passing it through a finned heat exchanger similar to a

radiator used in automobiles. Rather than cooling by evaporation, the steam is condensed in heat exchangers which are cooled by blowing ambient air across the fins and exhausting the sensible heat directly to the atmosphere. Dry cooling technology is not common and only a few such operations for coal fired generation plants are either being planned or under construction. None are currently operational in the southeastern United States, so it is a technology yet to be demonstrated in this area for this application. One such facility being planned is the Touquop Power Plant which is proposed to be built in Lincoln County Nevada. The proposed project consists of a supercritical unit similar to this project but of slightly smaller design (750 MW). A hybrid dry and wet cooling system is being proposed which would consist of a large hyperbolic cooling tower that encloses the fin radiators and air blowers. Due to the high temperature in the southwest during the summer months, the ambient air must be pre-cooled prior to being introduced into the cooling tower in order for the system to be effective. This cooling is accomplished using water sprays and consequently cools the air by evaporation. In this case 'dry cooling' means a reduction in water use, but not its elimination.

Dry cooling comes at a cost however. An engineering study was conducted to determine its feasibility for Plant Washington. The results of this study indicate that the use of a dry cooling system would result in a 41 to 44 MW reduction in the net output of the plant (due to the fact that the system would cause back pressure on the turbines essentially de-rating their capabilities). In addition, these systems would add $142 to $148 million in capital system cost additions and $45 to $51 million in incremental operational and maintenance (O&M) cost. If installed this cost would have to be passed on to the customer, increasing the power rate; and the additional power lost by operating the system would be unavailable to customers and have to be generated elsewhere. If this 41 to 44 MW "lost power" were to be provided by another power plant or by increasing the size of Plant Washington even more air emissions would result (roughly equivalent to 34 TPY PM_{10}, 95 TPY SO_2, 92 TPY NO_x and 182 TPY CO).

Power4Georgians takes seriously the need to conserve water in any operation. To that end a water conservation plan has been developed. The current water management strategy involves an integrated approach combining surface water and groundwater to provide a sustainable water supply. If river flow drops below a certain level, operation of the surface water intake will cease and Plant Washington will switch to groundwater withdrawal or on-site storage. Groundwater withdrawal will continue until a sustained flow above the minimum level in the river is expected.

Using this approach, surface water will be used when there is adequate availability and groundwater will be used intermittently to avoid depleting this resource.

8.6 GREENHOUSE GAS (GHG) MINIMIZATION

Coal fired power plants are major producers of GHG's primarily in the form of carbon dioxide. There is no proven technology that prevents this. The Department of Energy is currently funding a project that will attempt to inject the carbon dioxide back into the earth. This project called "Future Gen" is still undergoing permitting (www.futuregenalliance.org) but if given the permission to proceed is scheduled to be on line in 2012. The pilot testing is expected to take another 5 years before conclusive results are found regarding the feasibility of this technology. Until this occurs other methods must be found to minimize the formation of GHG's.

No current commercially demonstrated technologies are available for carbon capture and sequestration from a coal fired utility boiler. However, the Plant Washington facility will be designed to be "carbon capture ready" should these technologies become available and/or required.

Power4Georgians, being comprised of a consortium of member Georgia EMCs, already have in place programs for their customers to conserve energy and in that way promote reduction of GHGs. These programs are ongoing and will become even more innovative as opportunities present themselves. The member companies see this opportunity to construct a new state-of-the-art power plant as being a part of a solution to the GHG problem by constructing a more efficient plant that will produce power that will emit less GHG on a per unit basis then existing comparable units. However, other options are also being developed. These options include: Carbon Footprint Reduction Program (CFRP), Home Energy Efficiency Program (HEEP), Solar Photovoltaic Program (SPVP), Keeping Forests in Forests (KFIF) and others that are described below:

Carbon Footprint Reduction Program (CFRP)

Power4Georgians EMC will begin working with its customers to develop and implement a carbon footprint reduction program. The CFRP will be designed to help residential customers quantify their household carbon footprint and then provide those customers with the opportunity to reduce their carbon footprint through a number of programs, services and activities. The quantification of a customer's household carbon footprint will take into account the number of people living in the household, the amount of electricity, natural gas and fuel oil consumed in the house, the amount of waste produced within the house and the vehicular miles driven by members of the household and the average fuel economy of the vehicles. Once a customer quantifies their household carbon footprint, the CFRP program will offer a number of avenues to help the customer either reduce or possibly even eliminate their carbon footprint. These mechanisms include participating in Power4Georgians Carbon Sequestering Program (CSP), Power4Georgians EMC's Solar Photovoltaic Program (SPP), and/or Power4Georgians EMC's Carbon Sequestering Program (CSP).

Home Energy Efficiency Program (HEEP)

Customers can reduce the carbon footprint of their household energy consumption by implementing various energy efficiency projects in and around their home. Power4Georgians will develop informational sheets for the following energy efficiency measures: ceiling insulation, energy efficient windows, window film, caulking and weather-stripping, compact fluorescent lamps, programmable thermostats and high efficiency air conditioning and heat pump systems. Each measure will be quantified as its estimated reduction of carbon footprint. In addition, the customer's local EMC may offer or provide access to programs that provide financing for selected energy efficiency measures, including: ceiling insulation, energy efficient windows and high efficiency air conditioning and heat pump systems.

Solar Photovoltaic Program (SPP)

Customers can reduce the carbon footprint of their household energy consumption by satisfying a portion of their electrical usage with renewable solar energy. Power4Georgians EMC will work with the customer's local EMC to develop an incentive program for solar photovoltaic cells. The

solar photovoltaic system will reduce consumption of electricity and thereby, reduce the home's carbon footprint.

Keeping Forests In Forests (KFIF)

(KFIF) is a program that provides a way for Georgia EMCs and their members to offset their carbon footprints by using Georgia's forests to capture and store carbon.

Carbon sequestration is the process of capturing and storing atmospheric carbon into plants, soils, and water so that the buildup of carbon dioxide concentration in the atmosphere will reduce or slow. One of the primary plants used in the sequestration process is trees. Especially effective are evergreen trees like those found here in Georgia's forests.

The carbon offset program provides funding to preserve, protect and manage Georgia's pine forests, thereby helping to sequester atmospheric carbon. To be sure there is a sound, viable and realistic program, we have collaborated with the forestry experts at Duke University and the University of Georgia to provide scientific background and validation of our methodology and measurability tools.

Each year an independent auditing firm along with forest professionals at Duke University and the University of Georgia will review the program to verify that carbon offset contributions match with grants to our forest partners, the related acres of forests under management and resulting carbon sequestration. These findings will be reported annually.

Wells Timberland, a forest real estate investment firm, has initially designated 50,000 acres for the program while Carbon Treebank, LLC, will act as a middleman for the EMCs, distributing consumers' offset payments to participating timberland owners as incentive to preserve and manage their forests.

Beneficial Reuse of Fly Ash and Gypsum will reduce GHG from Cement and Wallboard Plant use

The Power4Georgians supports reuse of waste materials from our processes. Fly ash is a prominent component in the making of cement. Power4Georgians will retain and store fly ash on site for use by cement manufactures. Additionally, our process produces a gypsum product that

can be used in the manufacture of wallboard or dry wall. We will retain these materials on site until a suitable partner can be found. Both of these efforts could reduce cement and gypsum manufactures from producing GHG in the production of like materials.

Reduction of Open Burning:

Power4Georgians will work with the Washington County Economic Development Authority and County Officials on the issue of open burning which contributes to particulate emissions in the area as well as GHG's. Potential ideas include spraying versus burning for forest brush clearing, landfill collection versus burning of leaves and other creative ideas.

Providing SE Georgia Firefighting Support to avert Wildfires

During 2007 wildfires in the Okefenokee national forest and other areas of southeast Georgia contributed immense quantities of particulate and GHG's to Georgia's air quality. Power4Georgians will contribute fire fighting equipment to the appropriate fire fighting departments for use in containing future fires in attempts to prevent such disasters from re-occurring.

Participation in Available Bio-Mass Projects

Some members of Power4Georgians will participate in the Yellow Pine Bio-Mass project that is expected to be built near Ft. Gaines, Georgia. When in commercial operation, this plant will produce approximately 110 MW of power using wood chips as the primary fuel source.

Develop Improvements in Technical Training and Emission Control

Power4Georgians will work with local technical schools to develop training programs that focus on environmental and emissions technology. In addition, Power4Georgians will work with Georgia's University System to establish a research program on improving emissions control technology.

9.0 GEORGIA EPD FORMS

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program
4244 International Parkway, Suite 120
Atlanta, Georgia 30354
404/363-7000
Fax: 404/363-7100

SIP AIR PERMIT APPLICATION

EPD Use Only

Date Received: _____ Application No. _____

FORM 1.00: GENERAL INFORMATION

1. Facility Information

Facility Name: Plant Washington

AIRS No. (if known): 04-13- -

Facility Location: Street: Mayview Road

City: Sandersville Georgia Zip: 31082 County: Washington

2. Facility Coordinates

Latitude: 33° 03' 53" **NORTH** Longitude: 82° 44' 42" **WEST**

UTM Coordinates: 337088 **EAST** 3659816 **NORTH** **ZONE** 17

3. Facility Owner

Name of Owner: Power4Georgians, LLC

Owner Address Street: 258 N. Harris Street

City: Sandersville State: GA Zip: 31082

4. Permitting Contact and Mailing Address

Contact Person: Bobby Tucker or Brian A. Toole Title: Sr. Manager / Manager

Telephone No.: 770-763-4906 or 763-4922 Ext. _____ Fax No.: 770-763-4949

Email Address: BTucker@ecg-llc.com or BToole@ecg-llc.com

Mailing Address: Same as: Facility Location: ☐ Owner Address: ☐ Other: ☒

If Other: Street Address: 3625 Cumberland Blvd., Suite 1525

City: Atlanta State: GA Zip: 30339

5. Authorized Official

Name: * See attached signature page Title: Management Committee Members

Address of Official Street: 258 N. Harris Street

City: Sandersville State: GA Zip: 31082

This application is submitted in accordance with the provisions of the Georgia Rules for Air Quality Control and, to the best of my knowledge, is complete and correct.

Signature: _____ Date: _____

Signature Page Included In Submittal on January 17, 2008

6. **Reason for Application: (Check all that apply)**

☒ New Facility (to be constructed)

☐ Existing Facility (initial or modification application)

☒ Permit to Construct

☒ Permit to Operate

☐ Change of Location

☐ Permit to Modify Existing Equipment: Affected Permit No.: _____

☐ Revision of Data Submitted in an Earlier Application

Application No.: _____

Date of Original Submittal: _____

7. **Permitting Exemption Activities (for permitted facilities only):**

Have any exempt modifications based on emission level per Georgia Rule 391-3-1-.03(6)(i)(3) been performed at the facility that have not been previously incorporated in a permit?

☒ **No** ☐ **Yes, please fill out the SIP Exemption Attachment** (See Instructions for the attachment download)

8. **Has assistance been provided to you for any part of this application?**

☐ **No** ☐ **Yes, SBAP** ☒ **Yes, a consultant has been employed or will be employed.**

If yes, please provide the following information:

Name of Consulting Company: MACTEC Engineering and Consulting, Inc.

Name of Contact: Daniel A. Lovingood

Telephone No.: 770-499-6842 Fax No.: 770-421-3486

Email Address: DALOVINGOOD@mactec.com

Mailing Address: Street: 3200 Town Point Drive NW, Suite 100

City: Kennesaw State: GA Zip: 30144

Describe the Consultant's Involvement:

Prepared the Application

9. **Submitted Application Forms:** Select only the necessary forms for the facility application that will be submitted.

No. of Forms	Form
2	2.00 Emission Unit List
1	2.01 Boilers and Fuel Burning Equipment
1	2.02 Storage Tank Physical Data
0	2.03 Printing Operations
0	2.04 Surface Coating Operations
0	2.05 Waste Incinerators (solid/liquid waste destruction)
1	2.06 Manufacturing and Operational Data
1	3.00 Air Pollution Control Devices (APCD)
1	3.01 Scrubbers
1	3.02 Baghouses & Other Filter Collectors
0	3.03 Electrostatic Precipitators
5	4.00 Emissions Data
1	5.00 Monitoring Information
1	6.00 Fugitive Emission Sources
2	7.00 Air Modeling Information

10. **Construction or Modification Date**

Estimated Start Date: 4th quarter 2009

11. If confidential information is being submitted in this application, were the guidelines followed in the "Procedures for Requesting that Submitted Information be treated as Confidential"?

☐ No ☐ Yes **N/A**

12. New Facility Emissions Summary

Criteria Pollutant	New Facility	
	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)	3,642	3,642
Nitrogen oxides (NOx)	1,836	1,836
Particulate Matter (PM)	695	695
PM <10 microns (PM10)	678	678
PM <2.5 microns (PM2.5)	453	453
Sulfur dioxide (SO_2)	1,896	1,896
Volatile Organic Compounds (VOC)	110	110
Total Hazardous Air Pollutants (HAPs)	See Attachment (Exhibit) A	See Attachment (Exhibit) A
Individual HAPs Listed Below:		
See Attachment (Exhibit) A		

13. Existing Facility Emissions Summary

Criteria Pollutant	Current Facility		After Modification	
	Potential (tpy)	Actual (tpy)	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)				
Nitrogen oxides (NOx)				
Particulate Matter (PM)				
PM <10 microns (PM10)				
PM <2.5 microns (PM2.5)				
Sulfur dioxide (SO_2)				
Volatile Organic Compounds (VOC)				
Total Hazardous Air Pollutants (HAPs)				
Individual HAPs Listed Below:				

14. 4-Digit Facility Identification Code:

SIC Code:	4911	SIC Description:	Electric Services - Electric Power Generation By Fossil Fuels
NAICS Code:	221112	NAICS Description:	Fossil Fuel Electric Power Generation

15. Description of general production process and operation for which a permit is being requested. If necessary, attach additional sheets to give an adequate description. Include layout drawings, as necessary, to describe each process. References should be made to source codes used in the application.

See Section 2 Process Description

16. Additional information provided in attachments as listed below:

Attachment A - Emissions Calculations

Attachment B - Site Layout

Attachment C - Modeling Information

Attachment D - Models

Attachment E - Case-By-Case MACT Reference Documentation

Attachment F -

17. Additional Information: Unless previously submitted, include the following two items:

☒ Plot plan/map of facility location or date of previous submittal: See Attachment (Exhibit) B

☒ Flow Diagram or date of previous submittal: See Chapter 2 Process Description

Facility Name: Plant Washington **Date of Application:** November 26, 2008 – Supplemental Data

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
MAIN	SCPC Boiler	Babcock-Wilcox variable pressure, once through, supercritical boiler (or equivalent)	Babcock-Wilcox variable pressure, once through, supercritical boiler with LNB & OFA (or equivalent)
AUX	Auxiliary Boiler	TBD	Auxiliary Boiler for combustion of LS Diesel fuel.
COOL1-COOL34	Cooling Towers 1 - 34	TBD	Wet Cooling Towers With Ultra High Efficient Drift Eliminators.
CRUSH	Coal Crusher House	TBD	Coal Crusher House – enclosed with dust collection
LIMEPR	Limestone Preparation	TBD	Limestone Preparation House – enclosed with dust collection
ASHEXE	Ash Exhausters	TBD	Mechanical Fly Ash Exhausters (2)
FLYASH	Fly Ash Silo	TBD	Fly Ash Silo – equipped with bin vent filter
HGSILO	Hg Sorbent Silo	TBD	Hg Sorbent Silo – equipped with bin vent filter
SO3SILO	SO_3 Sorbent Silo	TBD	SO3 Sorbent Silo – equipped with bin vent filter
SODAASH	Soda Ash Silo	TBD	Soda Ash Silo – equipped with bin vent filter
LSILO	Lime Silo	TBD	Lime Silo – equipped with bin vent filter
PRBSO	Coal Insert #1	TBD	Insertable Filter at coal unloading drop point
IL6SO	Coal Insert #2	TBD	Insertable Filter at coal unloading drop point
LIMESO	Limestone Insert #1	TBD	Insertable Filter at limestone unloading drop point

Facility Name: Plant Washington **Date of Application:** November 26, 2008 – Supplemental Data

FORM 2.01 – BOILERS AND FUEL BURNING EQUIPMENT

Emission Unit ID	Type of Burner	Type of Draft[1]	Design Capacity of Unit (MMBtu/hr Input)	Percent Excess Air	Dates		Date & Description of Last Modification
					Construction	Installation	
MAIN	Supercritical Boiler with LNB/OFA	Induced	8300 MMBtu/hr	12	2013	2014	New Plant
AUX	LNB with FGR	unknown	240 MMBtu/hr	12	2013	2014	New Plant

[1] This column does not have to be completed for natural gas only fired equipment.

Facility Name: Plant Washington

Date of Application: November 26, 2008 – Supplemental Data

FUEL DATA

Emission Unit ID	Fuel Type	Potential Annual Consumption				Hourly Consumption		Heat Content		Percent Sulfur		Percent Ash in Solid Fuel	
		Total Quantity		Percent Use by Season									
		Amount	Units	Ozone Season May 1 - Sept 30	Non-ozone Season Oct 1 - Apr 30	Max.	Avg.	Min.	Avg.	Max.	Avg.	Max.	Avg.
MAIN	Coal-50/50 Blend	3,653,670	TPY	41.6%	59.3%	430 ton	417 ton	9650	9950	2.23	1.72	7.63	7.49
MAIN	Coal - PRB	4,276,940	TPY	41.6%	59.3%	500 ton	488 ton	8300	8500	0.53	0.32	5.46	3.65
MAIN	Low SulfurDiesel	651,200	Gal/yr	41.6%	59.3%	9286 gal	9286 gal	140,000	140,000	0.05	0.05		
AUX	Low SulfurDiesel	1,501,460	Gal/yr	41.6%	59.3%	1714 gal	1714 gal	140,000	140,000	0.05	0.05		

Fuel Supplier Information

Fuel Type	Name of Supplier	Phone Number	Supplier Location			
			Address	City	State	Zip
Coal	TBD					
Diesel	TBD					

Note: Ultra Low Sulfur Diesel will be utilized if commercially available.

Facility Name: Plant Washington **Date of Application:** November 26, 2008 Supplemental Data

FORM 2.02 – ORGANIC COMPOUND STORAGE TANK

Emission Unit ID	Emission Unit Name	Capacity (gal)	Material Stored	Maximum True Vapor Pressure (psi @ °F)	Storage Temp. (°F)	Filling Method	Construction/ Modification Date	Roof Type	Seal Type
AUX	TNK1	350,000	Low Sulfur Diesel	See Tanks	Ambient	Submerged Fill	2013	Fixed Roof	TBD
Emer gency Gener.	TNK2	750	Low Sulfur Diesel	See Tanks	Ambient	Submerged Fill	2013	Fixed Roof	TBD
Fire Pump	TNK3	250	Low Sulfur Diesel	See Tanks	Ambient	Submerged Fill	2013	Fixed Roof	TBD

Note: Ultra Low Sulfur Diesel will be utilized if commercially available.

Facility Name: Plant Washington

Date of Application: November 26, 2008 – Supplemental Data

FORM 2.06 – MANUFACTURING AND OPERATIONAL DATA

Normal Operating Schedule: 24 hours/day 7 days/week 52 weeks/yr

Additional Data Attached? ☒ - No ☐ - Yes, please include the attachment in list on Form 1.00, Item 16.

Seasonal and/or Peak Operating Periods: N/A

Dates of Annually Occurring Shutdowns: TBD

PRODUCTION INPUT FACTORS

Emission Unit ID	Emission Unit Name	Const. Date	Input Raw Material(s)	Annual Input	Hourly Process Input Rate		
					Design	Normal	Maximum
MAIN	SCPC Boiler	2013	Coal (PRB)	4,276,940 tpy	488 ton/hr	488 ton/hr	500 ton/hr
MAIN	SCPC Boiler	2013	Coal (50/50 Blend)	3,653,670 tpy	417 ton/hr	417 ton/hr	430 ton/hr
MAIN	SCPC Boiler	2013	Low Sulfur Diesel	651,200 gallons	9286 gal/hr	9286 gal/hr	9286 gal/hr

PRODUCTS OF MANUFACTURING

Emission Unit ID	Description of Product	Production Schedule		Hourly Production Rate (Give units: e.g. lb/hr, ton/hr)			
		Tons/yr	Hr/yr	Design	Normal	Maximum	Units
MAIN	Electricity	N/A	N/A	850 Net	850 Net	850 Net	MW

Note: Ultra Low Sulfur Diesel will be utilized if commercially available.

Facility Name: Plant Washington

Date of Application: November 26, 2008 – Supplemental Data

Form 3.00 – AIR POLLUTION CONTROL DEVICES - PART A: GENERAL EQUIPMENT INFORMATION

APCD Unit ID	Emission Unit ID	APCD Type (Baghouse, ESP, Scrubber etc)	Date Installed	Make & Model Number (Attach Mfg. Specifications & Literature)	Unit Modified from Mfg Specifications?	Gas Temp. °F		Inlet Gas Flow Rate (acfm)
						Inlet	Outlet	
C01	MAIN	Baghouse	2013	TBD	No	320	300	2,580,200
C02	MAIN	SCR	2013	TBD	No	300	300	2,580,200
C03	MAIN	Wet Scrubber	2013	TBD	No	300	140	2,580,200
C04	SO3SILO	Bin Vent Filter	2013	TBD	No	68	68	1500
C05	FLYASH	Bin Vent Filter	2013	TBD	No	68	68	1500
C06	HGSILO	Bin Vent Filter	2013	TBD	No	68	68	1500
C07	LSILO	Bin Vent Filter	2013	TBD	No	68	68	1500
C08	CRUSH	Baghouse	2013	TBD	No	68	68	24000
C09	TRIP	Baghouse	2013	TBD	No	68	68	18000
C10	LIMEPR	Baghouse	2013	TBD	No	68	68	5000
C11	ASHEXH	Baghouse	2013	TBD	No	258	258	4814
C12	SODAASH	Bin Vent Filter	2013	TBD	No	68	68	1500
C13	PRBSO	Insertable Filter	2013	TBD	No	68	68	1500
C14	IL6SO	Insertable Filter	2013	TBD	No	68	68	1500
C15	LIMESO	Insertable Filter	2013	TBD	No	68	68	1500

Facility Name: Plant Washington

Date of Application: November 26, 2008 – Supplemental Data

Form 3.00 – AIR POLLUTION CONTROL DEVICES – PART B: EMISSION INFORMATION

APCD Unit ID	Pollutants Controlled	Percent Control Efficiency		Inlet Stream To APCD		Exit Stream From APCD		Pressure Drop Across Unit (Inches of water)
		Design	Actual	lb/hr	Method of Determination	lb/hr	Method of Determination	
C01	PM10	99.9	99.9	149,000	Engr Est	149	Eng Est	12
C02	NOx	77	77	1826	Engr Est	415	Eng Est	8-12
C03	SO2	97.5-98.5	97.5-98.5	28,800	Engr Est	432	Eng Est	10
C04	PM10	99.9	99.9	16	Engr Est	0.016	Eng Est	8
C05	PM10	99.9	99.9	64	Engr Est	0.064	Eng Est	8
C06	PM10	99.9	99.9	16	Engr Est	0.016	Eng Est	8
C07	PM10	99.9	99.9	8	Engr Est	0.008	Eng Est	8
C08	PM10	99.9	99.9	1,030	Engr Est	1.03	Eng Est	8
C09	PM10	99.9	99.9	770	Engr Est	0.77	Eng Est	8
C10	PM10	99.9	99.9	214	Engr Est	0.214	Eng Est	8
C11	PM10	99.9	99.9	103	Engr Est	0.103	Eng Est	8
C12	PM10	99.9	99.9	8	Engr Est	0.008	Eng Est	8
C13	PM10	99.9	99.9	60	Engr Est	0.06	Eng Est	8
C14	PM10	99.9	99.9	60	Engr Est	0.06	Eng Est	8
C15	PM10	99.9	99.9	60	Engr Est	0.06	Eng Est	8

Facility Name: Plant Washington

Date of Application: November 26, 2008 - Supplemental Data

FORM 3.01 – SCRUBBERS

APCD Unit ID	Scrubber Type	Materials of Construction (Plastic, 1040 steel, etc.)	Scrubbant	pH Range	Pressure Drop Range (inches of H2O)	Minimum Scrubbant Flow Rate (Gal/min)	Is Scrubbant Recirculated?	Minimum Makeup Rate (Gal/min)	Size of Pond or Holding Tank (Acre-ft or gal)
C02	SCR	TBD	NH3			TBD	☐		
C02	Wet Scrubber	TBD	Water	4.5-6.0	10	~200,000	☒	1500	1,500,000 gal
							☐		
							☐		
							☐		
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Facility Name: Plant Washington **Date of Application:** November 26, 2008 - Supplemental Data

FORM 3.02 – BAGHOUSES & OTHER FILTER COLLECTORS

APCD ID	Filter Surface Area (ft^2)	No. of Bags	Inlet Gas Dew Point Temp. (°F)	Inlet Gas Temp. (°F)	Bag or Filter Material	Pressure Drop (inches of water)	Cleaning Method	Gas Cooling Method	Leak Detection System Type
C01	TBD	32,000	280	320	TBD	12	PJ	TBD	Pressure Drop

Attach a physical description, dimensions and drawings for each baghouse and any additional information available such as particle size, maintenance schedules, monitoring procedures and breakdown/by-pass procedures. Explain how collected material is disposed of or utilized. Include the attachment in the list on Form 1.00 *General Information*, Item 16

Facility Name: Plant Washington **Date of Application:** November 26, 2008 – Supplemental Data

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
MAIN	C01,02, 03	S01	PM	149	149	654	654	BACT
MAIN	C01,02, 03	S01	PM_{10}	149	149	654	654	BACT
MAIN	C01,02, 03	S01	SO_2	432	432	1890	1890	BACT
MAIN	C01,02, 03	S01	H_2SO_4	33	33	145	145	BACT
MAIN	C01,02, 03	S01	HF	2.22	2.22	9.72	9.72	BACT
MAIN	C01,02, 03	S01	Pb	0.13	0.13	0.58	0.58	PSD Avoidance
MAIN	C01,02, 03	S01	NO_X	415	415	1818	1818	BACT
MAIN	C01,02, 03	S01	VOC	25	25	109.1	109.1	BACT
MAIN	C01,02, 03	S01	CO	830	830	3635	3635	BACT
MAIN	C01,02,03	S01	Hg	0.014	0.014	0.06	0.06	BACT
AUX	--	S45	PM	5.76	5.76	2.52	2.52	BACT
AUX	--	S45	PM_{10}	5.76	5.76	2.52	2.52	BACT
AUX	--	S45	SO_2	12	12	5.26	5.26	BACT
AUX	--	S45	H_2SO_4	0.014	0.014	6.31E-03	6.31E-03	BACT
AUX	--	S45	Pb	2.16E-03	2.16E-03	9.46E-04	9.46E-04	BACT
AUX	--	S45	NO_X	24	24	10.51	10.51	BACT
AUX	--	S45	Hg	7.19E-04	7.19E-04	3.15E-04	3.15E-04	BACT

Facility Name: Plant Washington **Date of Application:** November 26, 2008 – Supplemental Data

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
AUX	--	S45	VOC	0.72	0.72	0.32	0.32	BACT
AUX	--	S45	CO	9.6	9.6	4.2	4.2	BACT
COOL1-COOL34	--	S02-S35	PM	3.72	3.72	16.28	16.28	BACT
COOL1-COOL34	--	S02-S35	PM_{10}	1.71	1.71	7.51	7.51	BACT
CRUSH	C08	S40	PM	1.03	1.03	4.51	4.51	BACT
CRUSH	C08	S40	PM_{10}	1.03	1.03	4.51	4.51	BACT
TRIP	C09	S41	PM	0.77	0.77	3.38	3.38	BACT
TRIP	C09	S41	PM_{10}	0.77	0.77	3.38	3.38	BACT
LIMEPR	C09	S42	PM	0.21	0.21	0.94	0.94	BACT
LIMEPR	C09	S42	PM_{10}	0.21	0.21	0.94	0.94	BACT
ASHEX	C11	S43	PM	0.10	0.10	0.45	0.45	BACT
ASHEX	C11	S43	PM_{10}	0.10	0.10	0.45	0.45	BACT

Facility Name: Plant Washington **Date of Application:** November 26, 2008 – Supplemental Data

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
FLYASH	C05	S37	PM	0.06	0.06	0.28	0.28	BACT
FLYASH	C05	S37	PM_{10}	0.06	0.06	0.28	0.28	BACT
HGSILO	C06	S38	PM	1.61E-02	1.61E-02	7.04E-02	7.04E-02	BACT
HGSILO	C06	S38	PM_{10}	1.61E-02	1.61E-02	7.04E-02	7.04E-02	BACT
SO3SILO	C04	S36	PM	1.61E-02	1.61E-02	7.04E-02	7.04E-02	BACT
SO3SILO	C04	S36	PM_{10}	1.61E-02	1.61E-02	7.04E-02	7.04E-02	BACT
SODAASH	C12	S44	PM	8.04E-03	8.04E-03	3.52E-02	3.52E-02	BACT
SODAASH	C12	S44	PM_{10}	8.04E-03	8.04E-03	3.52E-02	3.52E-02	BACT
LSILO	C07	S39	PM	8.04E-03	8.04E-03	3.52E-02	3.52E-02	BACT
LSILO	C07	S39	PM_{10}	8.04E-03	8.04E-03	3.52E-02	3.52E-02	BACT
PRBSO	C13	S46	PM	0.06	0.06	0.28	0.28	BACT
PRBSO	C13	S46	PM_{10}	0.06	0.06	0.28	0.28	BACT

Facility Name: Plant Washington **Date of Application:** November 26, 2008 – Supplemental Data

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
IL6SO	C14	S47	PM	0.06	0.06	0.28	0.28	BACT
IL6SO	C14	S47	PM_{10}	0.06	0.06	0.28	0.28	BACT
LIMESO	C15	S48	PM	0.06	0.06	0.28	0.28	BACT
LIMESO	C15	S48	PM_{10}	0.06	0.06	0.28	0.28	BACT
ASHBUNK	--	A3	PM	1.27E-02	1.27E-02	5.56E-02	5.56E-02	AP-42
ASHBUNK	--	A3	PM_{10}	6.01E-03	6.01E-03	0.026	0.026	AP-42
LANDASH	--	A1	PM	0.39	0.39	1.73	1.73	AP-42
LANDASH	--	A1	PM_{10}	0.08	0.08	0.33	0.33	AP-42
LANDGYP	--	A2	PM	0.39	0.39	1.73	1.73	AP-42
LANDGYP	--	A2	PM_{10}	0.08	0.08	0.33	0.33	AP-42
LIMERAIL	--	A5	PM	4.32E-03	4.32 E-03	1.89E-01	1.89E-01	AP-42
LIMERAIL	--	A5	PM_{10}	2.04E-02	2.04E-02	8.95E-02	8.95E-02	AP-42

Facility Name: Plant Washington **Date of Application:** November 26, 2008 – Supplemental Data

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
COALRAIL	--	A4	PM	6.48E-02	6.48E-02	2.84E-01	2.84E-01	AP-42
COALRAIL	--	A4	PM_{10}	3.06E-02	3.06E-02	1.34E-01	1.34E-01	AP-42
LIMEPILE	--	A10	PM	9.09E-02	9.09E-02	3.98E-01	3.98E-01	AP-42
LIMEPILE	--	A10	PM_{10}	4.08E-03	4.08E-03	1.79E-02	1.79E-02	AP-42
PRBINAC	--	A6	PM	1.64E-02	1.64E-02	0.07	0.07	AP-42
PRBINAC	--	A6	PM_{10}	7.74E-03	7.74E-03	0.03	0.03	AP-42
IL6INAC	--	A7	PM	7.48E-02	7.48E-02	0.33	0.33	AP-42
IL6INAC	--	A7	PM_{10}	3.54E-02	3.54E-02	0.15	0.15	AP-42
PRBACTIV	--	A8	PM	4.62E-01	4.62E-01	2.02	2.02	AP-42
PRBACTIV	--	A8	PM_{10}	9.75E-03	9.75E-03	4.27E-02	4.27E-02	AP-42
IL6ACTIV	--	A9	PM	5.21E-01	5.21E-01	2.28	2.28	AP-42
IL6ACTIV	--	A9	PM_{10}	3.74E-02	3.74E-02	1.64E-01	1.64E-01	AP-42
PAVED	--	P1-P21	PM	0.12	0.12	0.55	0.55	AP-42
PAVED	--	P1-P21	PM_{10}	0.12	0.12	0.55	0.55	AP-42
UPAVED	--	U1-U15	PM	0.3	0.3	1.31	1.31	AP-42
UPAVED	--	U1-U15	PM_{10}	0.08	0.08	0.349	0.349	AP-42

Facility Name: Plant Washington **Date of Application:** November 26, 2008 - Supplemental Data

FORM 5.00 MONITORING INFORMATION

Emission Unit ID/ APCD ID	Emission Unit/APCD Name	Monitored Parameter		Monitoring Frequency
		Parameter	Units	
S01	SCPC Boiler	NOx	PPM	CEM
S01	SCPC Boiler	SO2	PPM	CEM
S01	SCPC Boiler	CO	PPM	CEM
S01	SCPC Boiler	Hg	PPM	CEM
MISC	PM Transfer Points	VE	% Opacity	Quarterly
S2-S35	Cooling Tower	TDS	ppm	Quarterly

Comments:

Facility Name: Plant Washington

Date of Application: November 26, 2008 - Supplemental Data

FORM 6.00 – FUGITIVE EMISSION SOURCES

Fugitive Emission Source ID	Description of Source	Emission Reduction Precautions	Pot. Fugitive Emissions	
			Amount (tpy)	Pollutant
A3	Bottom Ash Storage/Handling	Contouring, Compaction, Stabilization & Cover	5.56E-02	PM
A1	Ash Solid Materials Handling Facility	Contouring, Compaction, Stabilization & Cover	1.73	PM
A2	Gypsum Solid Materials Handling Facility	Contouring, Compaction, Stabilization & Cover	1.73	PM
A5	Limestone Rail Unloading	Partial Enclosure & Water Spray	0.189	PM
A4	Coal Rail Unloading	Partial Enclosure & Water Spray	0.284	PM
A10	Limestone Storage/Handling	Lowering Well & Water Spray	0.398	PM
A6	Inactive PRB Coal Pile Storage/Handling	Cover & Best Management Practices	0.07	PM
A7	Inactive ILL6 Coal Pile Storage/Handling	Cover & Best MAnagement Practices	0.33	PM
A8	Active PRB Coal Pile	Retractable Chute, Water Spray, Crusting agents, Contouring	2.02	PM
A9	Active ILL6 Coal Pile	Retractable Chute, Water Spray, Crusting agents, Contouring	2.28	PM
P1-P21	Solid Materials Handling Facility Haul Road Segments (for modeling)	Road Paving & Water Spray/Surfactants	0.55	PM
U1-U15	Fugitive Road Sources between Coal Piles Unpaved Road	Water Spray/Surfactants	1.31	PM

Facility Name: Plant Washington **Date of Application:** November 26, 2008 – Supplemental Data

FORM 7.00 – AIR MODELING INFORMATION: Stack Data

Stack ID	Emission Unit ID(s)	Stack Information			Dimensions of largest Structure Near Stack		Exit Gas Conditions at Maximum Emission Rate			
		Height Above Grade (ft)	Inside Diameter (ft)	Exhaust Direction	Height (ft)	Longest Side (ft)	Velocity (ft/sec)	Temperature (°F)	Flow Rate (acfm) Average	Flow Rate (acfm) Maximum
S1	MAIN	450	30	VERT	292	203	60.84	140	2,580,200	2,580,200
S2-S35	COOL1-COOL34	50	40	VERT	292	203	19.92	68	1,501,171	1,501,171
S36	SO3SILO	75	1.35	HORZ	292	203	0.00328	68	1500	1500
S37	FLYASH	155	1.35	HORZ	292	203	0.00328	177	1500	1500
S38	HGSILO	75	1.35	HORZ	292	203	0.00328	68	1500	1500
S39	LSILO	75	1.35	HORZ	292	203	0.00328	68	1500	1500
S40	CRUSH	100	3	VERT	292	203	56.59	68	24000	24000
S41	TRIP	194	2.583	VERT	292	203	57.25	68	18000	18000
S42	LIMEPR	60	1.35	HORZ	292	203	0.00328	68	5000	5000
S43	ASHEXH	155	0.833	HORZ	292	203	73.6	258	4814	4814
S44	SODAASH	75	1.35	HORZ	292	203	0.00328	68	1500	1500
S45	AUXBOIL	90	5	VERT	292	203	65	275	76,560	76,560
S46	CINSERT 1	110	1.00	HORZ	292	203	0.00328	68	1500	1500

NOTE: If emissions are not vented through a stack, describe point of discharge below and, if necessary, include an attachment. List the attachment in Form 1.00 *General Information*, Item 16.

- Horizontal sources were modeled with a velocity of 0.00328 ft/sec per modeling guidance.
- Ambient temperature conditions listed above (68° F) modeled at 0° K.

Facility Name: Plant Washington **Date of Application:** November 26, 2008 – Supplemental Data

FORM 7.00 – AIR MODELING INFORMATION: Stack Data

Stack ID	Emission Unit ID(s)	Stack Information			Dimensions of largest Structure Near Stack		Exit Gas Conditions at Maximum Emission Rate			
		Height Above Grade (ft)	Inside Diameter (ft)	Exhaust Direction	Height (ft)	Longest Side (ft)	Velocity (ft/sec)	Temperature (°F)	Flow Rate (acfm)	
									Average	Maximum
S47	CINSERT 2	90	1.00	HORZ	292	203	0.00328	68	1500	1500
S48	LINSERT1	70	1.00	HORZ	292	203	0.00328	68	1500	1500

NOTE: If emissions are not vented through a stack, describe point of discharge below and, if necessary, include an attachment. List the attachment in Form 1.00 *General Information*, Item 16.

- Horizontal sources were modeled with a velocity of 0.00328 ft/sec per modeling guidance.
- Ambient temperature conditions listed above (68° F) modeled at 0° K.

Facility Name: Plant Washington **Date of Application:** _____

FORM 7.00 AIR MODELING INFORMATION: Chemicals Data

Chemical	Potential Emission Rate (lb/hr)	Toxicity	Reference	MSDS Attached
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10.0 CASE-BY-CASE MACT ANALYSIS

10.1 INTRODUCTION

MACTEC originally prepared and submitted the PSD Air Permit Application for Plant Washington to the GA EPD on January 17, 2008. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit issued a decision vacating USEPA's rule de-listing electric utility steam generating units from Section 112(c) of the Clean Air Act. The D.C. Circuit, in turn, also vacated USEPA's Clean Air Mercury Rule (CAMR). The D.C. Circuit's decision has effectively reinstated electric utility steam generating units to the list of Section 112(c) source categories and, as a result, the decision implies that such units are now required to submit a Section 112(g) Maximum Achievable Control Technology (MACT) analysis for applicable HAPs. This Case-By-Case MACT analysis was prepared due to the D.C. Circuit's recent decision. It is assumed, based on current guidance, that Plant Washington would be subject to a Section 112 (g) MACT analysis for the main utility boiler.

This Case-By-Case MACT analysis was prepared in accordance with the requirements of 40 CFR 63, Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j). These regulations are incorporated by reference in the Georgia Rules for Air Quality Control, Chapter 391-1-3-.02(9)(b). Also, the USEPA guidance document *Guidelines for MACT Determinations under Section 112(j) Requirements (February 2002)* was referenced in preparation of this Case-By-Case MACT analysis.

This section contains the following information. Section 10.2 includes the general information required in 40 CFR 63 Subpart B for the Case-By-Case MACT analysis. Section 10.3 provides estimated HAP emissions information as required by the Case-By-Case MACT analysis. Section 10.4 includes the Case-By-Case MACT analysis for the Main Boiler. Section 10.5 includes the Case-By-Case MACT analysis for the Auxiliary Boiler.

Exhibit A includes calculations to support the findings of the Case-By-Case MACT analysis, as well as coal quality design basis data for Plant Washington, including information obtained from the U.S. Geological Society's (USGS) Coal Quality (COALQUAL) database. Exhibit E includes reference information discussed in the Case-By-Case MACT analysis and used for reference in preparation of the Case-By-Case MACT analysis.

Table 10-1 indicates the requirements of a Case-By-Case MACT analysis outlined in 40 CFR 63 Subpart B, and the sections in which these requirement are addressed in this report.

Table 10-1 112 (g) Requirements Per 40 CFR 63 Subpart B

40 CFR 63.43	Requirement	Section #
General Principles of a Case-By-Case MACT Analysis		
(d)(1)	The MACT emission limitation or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source, as determined by the permitting authority.	Section 10.4
(d)(2)	Based upon available information, as defined in this subpart, the MACT emission limitation and control technology (including any requirements under paragraph (d)(3) of this section) recommended by the applicant and approved by the permitting authority shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.	Section 10.4
(d)(3)	The applicant may recommend a specific design, equipment, work practice, or operational standard, or a combination thereof, and the permitting authority may approve such a standard if the permitting authority specifically determines that it is not feasible to prescribe or enforce an emission limitation under the criteria set forth in Section 112(h)(2) of the Act.	Section 10.4, 10.5
(d)(4)	If the administrator has either proposed a relevant emission standard pursuant to section 112(d) or section 112(h) of the Act or adopted a presumptive MACT determination for the source category which includes the constructed or reconstructed major source, then the MACT requirements applied to the constructed or reconstructed major source shall have considered those MACT emission limitations and requirements of the proposed standard or presumptive MACT determination.	Section 10.4, 10.5

Table 10-1 112 (g) Requirements Per 40 CFR 63 Subpart B (Continued)

40 CFR 63.43	Requirement	Section #
Application Requirements For A Case-By-Case MACT Determination		
(e)(1)	An application for a MACT determination (whether a permit application under Title V of the Act, an application for a Notice of MACT Approval, or other document specified by the permitting authority under paragraph (c)(2)(ii) of this section) shall specify a control technology selected by the owner or operator that, if properly operated and maintained, will meet the MACT emission limitation or standard as determined according to the principles set forth in paragraph (d) of this section.	Section 10.4
e(2)(i)	The name and address (physical location) of the major source to be constructed or reconstructed.	Section 10.2
e(2)(ii)	A brief description of the major source to be constructed or reconstructed, and identification of any listed source category or categories in which it is included.	Section 10.2
e(2)(iii)	The expected commencement date for the construction or reconstruction of the major source.	Section 10.2
e(2)(iv)	The expected completion date for construction or reconstruction of the major source.	Section 10.2
e(2)(v)	The anticipated date of start-up for the constructed or reconstructed major source.	Section 10.2
e(2)(vi)	The HAP emitted by the constructed or reconstructed major source, and the estimated emission rate for each such HAP, to the extent this information is needed by the permitting authority to determine MACT.	Section 10.3, 10.4
e(2)(vii)	Any federally enforceable emissions limitations applicable to the constructed or reconstructed major source.	Section 10.2
e(2)(viii)	The maximum and expected utilization of capacity of the constructed or reconstructed major source, and the associated uncontrolled emission rates for that source, to the extent this information is needed by the permitting authority to determine MACT.	Section 10.3, 10.4
e(2)(ix)	The controlled emissions for the constructed or reconstructed major source in tons/yr at expected and maximum utilization of capacity, to the extent this information is needed by the permitting authority to determine MACT.	Section 10.3, 10.4
e(2)(x)	A recommended emissions limitation for the constructed or reconstructed major source consistent with the principles set forth in paragraph (d) of this section.	Sections 10.4, 10.5
e(2)(xi)	The selected control technology to the meet the recommended MACT emission limitation, including technical information on the design, operation, size, estimated control efficiency of the control technology (and the manufacturer's name, address, telephone number, and relevant specifications and drawings, if requested by the permitting authority).	Section 10.4, 10.5

Table 10-1 112 (g) Requirements Per 40 CFR 63 Subpart B (Continued)

40 CFR 63.43	Requirement	Section #
Application Requirements For A Case-By-Case MACT Determination		
(e)(2)(xii)	Supporting documentation including identification of alternative control technologies considered by the applicant to meet the emission limitation, and analysis of cost and non-air quality health environmental impacts or energy requirements for the selected control technology.	Sections 10.4, 10.5
e(2)(xiii)	Any other relevant information required pursuant to Subpart A.	Sections 10.4, 10.5

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

The general principles of Case-By-Case MACT determinations are defined in 40 CFR Part 63.43(d)(1) through 40 CFR Part 63.43(d)(4). Section (d)(1) identifies the determination of the MACT floor, while Section (d)(2) addresses the "Beyond the Floor" analysis. Section (d)(3) identifies the specification of work practices or other standards if the permitting authority determines it is not feasible to enforce an emission limitation, and Section (d)(4) identifies the requirement to review relevant emission standards or MACT determinations for similar source categories.

10.2 CASE-BY-CASE MACT ANALYSIS GENERAL INFORMATION

40 CFR 63.43(e)(2)(i)

Name: Power4Georgians, LLC
Plant Washington

Physical Location: Mayview Road
Sandersville, GA 31082 (Washington County)

40 CFR 63.43(e)(2)(ii)

The proposed Plant Washington facility is a greenfield coal-fired electric generating plant designed with a supercritical pulverized coal main boiler rated at 8,300 MMBtu/hr and a net output capacity of 850 MW. Electric utility steam generating units are subject to specific requirements of the Clean Air Act, which are set forth in Section 112(n). Based on the utility Report to Congress (RTC) in 1998, the USEPA made an initial determination that Hg emissions were the only HAPs from coal-fired electric utility steam generating units that would require regulation. This determination was followed in the CAMR rulemaking. The proposed facility also includes a 240 MMBtu/hr fuel-oil fired auxiliary boiler. The auxiliary boiler would have been subject to the *National Emission Standards for*

Industrial/Commercial/Institutional Boilers and Process Heaters. Final MACT standards were promulgated for this source category in 2004, but were vacated and remanded by the U.S. Court of Appeals for the D.C. Circuit in June 2007.

40 CFR 63.43(e)(2)(iii)

Construction of Plant Washington will begin upon receipt of the necessary regulatory approvals, including issuance of the final PSD permit for the site, which is anticipated to occur in the fourth quarter of 2009.

40 CFR 63.43(e)(2)(iv)

Construction will be completed in approximately five years, with estimated completion in 2014.

40 CFR 63.43(e)(2)(v)

Startup of Plant Washington will occur upon completion of construction, which is estimated to occur in 2014.

40 CFR 63.43(e)(2)(vii)

The final permit issued will be a PSD construction permit. The terms and conditions of the final permit will include federally enforceable emissions limitations for the main boiler, including those required by PSD, New Source Performance Standards (NSPS), and National Emissions Standards for Hazardous Air Pollutants (NESHAP).

10.3 CASE-BY-CASE MACT ANALYSIS HAP EMISSIONS INFORMATION

40 CFR 63.43(e)(2)(vi); 40 CFR 63.43(e)(2)(viii); 40 CFR 63.43(e)(2)(ix)

The main boiler at the Plant Washington facility is designed to be a base load unit with a maximum and expected capacity factor of 100 percent. However, the proposed plant will at times operate at reduced loads (estimated at 40 percent production capacity) during shoulder months (spring and fall), when power demands are below peak levels. The auxiliary boiler present at the facility will support startup and shutdown operations of the main boiler.

HAP Emission Estimate Resources

HAP Emissions calculations, included in Exhibit A, include emissions estimate information for the facility's main boiler obtained or derived from five sources, including (1) the USEPA publication AP-42; (2) the *Study of Hazardous Air Pollutant Emissions From Electric Utility Steam Generating Units – USEPA (1998)*; (3) data derived from the USEPA National Emissions Inventory (NEI) HAP Emissions Inventory Database, 2002 NEI V3, last updated September 2007; (4) the USEPA Toxic Release Inventory (TRI) program; and (5) the USGS COALQUAL database. Data from the USEPA NEI HAP Database and TRI Database was provided in emissions estimates of tons per year. These data, along with 2006 actual heat consumption values (in MMBtu per year) obtained from the USEPA Clean Air Markets Web site, were used to provide an estimate of the lb MMBtu emission rate of the HAP in question. Although the NEI HAP Database was based on calendar year 2002 emissions data, the database has been updated through 2007. To establish an adequate basis of comparison with 2006 TRI Database information, 2006 heat consumption values were used as a baseline estimate for annual (MMBtu per year) heat consumption of facility units.

Organic HAP emission estimates were derived from AP-42; the *Study of Hazardous Air Pollutant Emissions From Electric Utility Steam Generating Units – USEPA (1998)*; data derived from the USEPA National Emissions Inventory (NEI) HAP Emissions Inventory Database, 2002 NEI V3, last updated September 2007; and the USEPA Toxic Release Inventory (TRI) program. Emission estimates for mercury, specific non-mercury metal HAPs, and the acid gases HF and HCl are based on coal quality analysis data from the USGS COALQUAL database and project specification coal data.

A listing of the HAPs identified from the various sources reviewed is provided below. Both data from AP-42 and the *Study of Hazardous Air Pollutant Emissions From Electric Utility Steam Generating Units – USEPA (1998)* were used as the baseline for HAP emission estimates. Additional HAPs identified through review of data from the NEI HAP Database, the TRI Database, and the USGS COALQUAL database were subsequently added to the list of HAPs. The following HAPs are listed by the HAP categories of Organic HAPs, Metal HAPs (including mercury), and Acid Gases.

One hundred-thirteen HAPs were identified as present in emissions from the facility main boiler. This listing is more comprehensive than the 67 HAPs identified in the *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – USEPA (1998).* The following is a list of the HAPs identified through review of the indicated references.

Organic HAPs

Acenapthene
Acenapthylene
Acetaldehyde
Acetophenone
Acrolein
Anthracene
Benzene
Benzo(a)anthracene
Benzo(a)pyrene
Benzo(b)fluoranthene
Benzo(e)pyrene
Benzo(g,h,i)perylene
Benzo(b,k)fluoranthene
Benzo(k)fluoranthene
Benzyl Chloride
Biphenyl
Bis(2-Ethylhexyl)phthalate
Bromoform
Carbon Disulfide
Carbon Tetrachloride
Chlorobenzene
Chloroform
Chloromethane
2-Chloroacetophenone
2-Chloronaphthalene
Chrysene
Cumene
Hydrogen Cyanide (Note: This compound is also an acid gas but evaluated as an organic)
Dibenzo(a,h)anthracene
Dibutyl Phthalate
Dimethyl Sulfate
Dioxins (Total)
2,4-Dinitrotoluene
Ethylbenzene
Ethyl Chloride
Ethylene Dichloride
Ethylene Dibromide
Fluoranthene
Fluorene
Formaldehyde
Hexachlorobenzene
Hexane
Indeno(1,2,3,c,d)pyrene
Isophorone
Methyl Bromide
Methyl Hydrazine
MMA
MTBE

Methylene Chloride
Methyl Chloroform
Methyl Iodine
2-Methyl Naphthalene
Naphthalene
5-Methyl Chrysene
OCDD
P-Cresol
Perylene
Pentachlorophenol
Phenanthrene
Phenol
Phosphorous
Propionaldehyde
Pyrene
Styrene
Tetrachloroethylene
Trichloroethylene
Toluene
1,1,1-Trichloroethane
1,1,2-Trichloroethane
Vinyl Acetate
m-xylene
o-xylene
p-xylene
Xylene
1,2,4-Trichlorobenzene
1,3-Butadiene
1,3-Dichloropropene
1,4-Dichlorobenzene
2,4,6-Trichlorophenol
2,4-Dinitrophenol
3-Methylcholanthrene
4-Nitrophenol
7,12-Dimethylbenz[a]Anthracene Allyl Chloride
Calcium Cyanamide
Dibenzo(a,j)Acridine
Dibenzofuran
Diethyl Sulfate
Dimethyl Phthalate
Methyl Isobutyl Ketone
Polychlorinated Biphenyls
Polycyclic Organic Matter
Propylene Dichloride
Sodium Cyanamide
Toluene-2,4-Diamine
Vinyl Chloride

Metals and Compounds

Antimony
Arsenic
Beryllium
Cadmium
Chromium, Total
Chromium, Hexavalent
Cobalt
Lead
Mercury
Manganese
Nickel
Selenium
Arsenic Trioxide
Cadmium Oxide
Chromic Acid (VI)
Chromic Oxide
Manganese Dioxide

Acid Gases

Hydrogen Chloride
Hydrogen Fluoride

Organic HAP Emission Estimates

Exhibit A summarizes data obtained from the USEPA NEI HAP Emissions Inventory Database, the TRI Database, AP-42, and the *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – USEPA (1998),* which were utilized to estimate emissions of Organic HAPs. Annual MMBtu data obtained from the USEPA Clean Air Markets Web site was used to prepare an estimated emission factor for the organic HAPs identified from the NEI HAP Emissions Inventory Database and the TRI Database, as data reported in these resources was indicated as a ton/yr value. Emissions data for multiple facilities were then averaged for each HAP to develop an approximate level of emissions of each organic HAP irrespective of the proposed emission level. These average factors were then used to estimate emissions of the HAPs identified from the NEI HAP and TRI Database resources. The indicated organic HAP emissions estimates in Exhibit A serve as approximations of the relative quantities of each HAP and verifies the facility is a major source for HAPs.

As discussed in Section 10.4, uncontrolled emissions of organic HAPs are difficult to determine. The effective method for control of these HAPs (combustion controls) is a part of the combustion process, and the efficiency of these systems is difficult to determine. AP-42 emission factors are indicated as

controlled emissions estimates. Emissions estimates from the *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – USEPA (1998)*, which was based on actual stack testing data, and data derived from the USEPA NEI HAP Emissions Inventory Database and TRI Database are also controlled emissions. Therefore, emissions estimates indicated in Exhibit A represent controlled emissions estimates from the resource in question.

Metal and Acid Gas HAP Emission Estimates

Coal quality data from the USGS COALQUAL database were reviewed to determine the potential non-mercury metals, mercury, chlorine (HCl), and fluorine (HF) concentrations present in the PRB and Illinois #6 coals planned for use at the facility in order to estimate controlled and uncontrolled emissions of those HAPs. Chlorine concentration data evaluated for PRB coals is based on USGS COALQUAL data, while chlorine concentrations for Illinois #6 coals are based on project specification coal data for Plant Washington, as no chlorine concentration data was listed for Illinois coals in the COALQUAL database.

Illinois #6 coals were assumed to be the coals identified as all coals from the Illinois Basin in the COALQUAL database, where PRB coals were assumed to be those coals identified as originating from Wyoming and Montana in the database. Analysis data for non-mercury metal HAPs, mercury, fluorine, and chlorine was evaluated to determine both an average and standard deviation value from the database for PRB and Illinois coals.

Calculations to determine both the uncontrolled and controlled emissions estimates for mercury, non-mercury metal HAPs, and the acid gases HCl and HF (derived from chlorine and fluorine) are included in Exhibit A. Demonstration calculations in Exhibit A contain a moisture correction for the USGS COALQUAL database trace element concentrations. Evaluations by others of the USGS COALQUAL database have indicated that the trace element values were based on either a “dry” basis or a “wet” basis. However, the USGS was contacted to discuss this issue, and it was discovered that trace element concentrations in the USGS COALQUAL database are not reported on a “dry” or a “wet” basis, but are instead reported on an “as determined basis.” Coal sample results indicated in the COALQUAL database are air-dried prior to analysis, and still contain residual moisture. Discussions with the USGS indicated that this was a common point of confusion since typical analytical reports provide trace element results on a “dry” basis.

However, the COALQUAL database information also contains information on the air dry loss (%) from the coal sample air drying procedure, thereby making it possible to estimate the residual moisture present in coal samples analyzed for the COALQUAL database. The residual moisture values were then calculated, when data was available, for PRB and Illinois Basin coals in the COALQUAL database. An average ratio of the residual moisture to total moisture was then developed. This ratio was then used to determine the proper moisture correction to apply to USGS COALQUAL database trace element value during estimation of uncontrolled and controlled emission estimates. Therefore, moisture corrections to COALQUAL database information made in Exhibit A are not from a "dry" basis to an as received "wet" basis, but are instead from a "semi-dry" to a "wet" basis. Calculations indicating the derivation of the moisture correction values utilized can be found in Exhibit A.

Permit Limit Assessment

Specific emissions limits were derived for several HAPs as part of this Case-By-Case MACT evaluation for the main facility boiler, based on uncontrolled emissions estimated from project specifications (including coal quality data from the COALQUAL database found in Exhibit A of this report), and the MACT floor control efficiencies determined in Section 10.4 of this report.

The concentration of the HAP in the coal was calculated differently between cases where a short-term limit for a HAP would be common (compliance demonstration during a 3-hr. stack test), or in cases where a pollutant would be continuously monitored and the result would be reported as a 12-month rolling average rather than a peak 3-hr limit. For the short term the upper bound of 90 percent confidence level concentration value (in parts per million, ppm) was determined to account for variability in the coal that could be received at the Plant Washington facility. The 90 percent confidence level is equal to the average ppm concentration derived from the USGS COALQUAL database plus the standard deviation of the sample set multiplied by the one-tail "t statistic" corresponding to the 90% confidence level. The proposed MACT emission limits for the acid gases HF and HCl are based on the 90 percent confidence level assessment.

For pollutants which will have emission limits established on a 12-month rolling average, the 95% Upper Confidence Level (UCL) ppm concentration derived from the USGS COALQUAL database for PRB and Illinois coals will be used. The 95% UCL is derived from the average ppm concentration derived from the USGS COALQUAL database, plus the one-tail t statistic corresponding to 95% confidence multiplied by the standard deviation of the sample set, and divided by the square root of the number of samples

present in the sample set. The proposed MACT emission limit for mercury is based on a 95% UCL derived value.

Table 10-2 summarizes data obtained form the USGS COALQUAL database used to estimate uncontrolled emissions of mercury, non-mercury metals, and the acid gases HF and HCl in this analysis. Since the auxiliary boiler at the facility will not use any add-on pollution control equipment except engineering combustion controls, controlled emissions for the auxiliary boiler have not been determined. HAP emission estimates listed in Table 10-4 for the auxiliary boiler are based on uncontrolled emissions.

Proposed MACT emission limits for the main facility boiler and auxiliary boiler are summarized in Table 10-3. Facility wide total and individual HAP emissions estimates for the facility are included in Table 10-4. Demonstration calculations for the values in Table 10-3 and Table 10-4 can be found in Exhibit A.

Table 10-2 Coal Quality Analysis Data

Elements	PRB Coal Average	Standard Deviation	90% Confidence Level PRB Coal	Illinois #6 Coal Average	Standard Deviation	90% Confidence Level Illinois #6 Coal	PRB-Illinois # 6 Coal 50-50 Blend Average	90% Confidence Level 50-50 Blend
Antimony (Sb) Emission Factor	0.67 ppm	0.90 ppm	1.82 ppm	0.89 ppm	0.97 ppm	2.14 ppm	0.78 ppm	1.98 ppm
Arsenic (As) Emission Factor	7.10 ppm	25.82 ppm	40.15 ppm	7.50 ppm	10.47 ppm	20.90 ppm	7.30 ppm	30.52 ppm
Beryllium (Be) Emission Factor	0.95 ppm	1.01 ppm	2.24 ppm	2.59 ppm	2.26 ppm	5.49 ppm	1.77 ppm	3.87 ppm
Cadmium (Cd) Emission Factor	0.14 ppm	0.19 ppm	0.38 ppm	3.41 ppm	8.40 ppm	14.16 ppm	1.77 ppm	7.27 ppm
Chlorine (Cl) Emission Factor	97.52 ppm	97.62 ppm	222.48 ppm	2700.00 ppm	---	4000 ppm	1398.76 ppm	2111.24 ppm
Chromium (Cr) Emission Factor	7.19 ppm	7.16 ppm	16.35 ppm	16.63 ppm	7.47 ppm	26.19 ppm	11.91 ppm	21.27 ppm
Cobalt (Co) Emission Factor	2.17 ppm	2.36 ppm	5.18 ppm	3.45 ppm	1.39 ppm	5.23 ppm	2.81 ppm	5.21 ppm
Fluorine (F) Emission Factor	76.76 ppm	81.51 ppm	181.09 ppm	80.38 ppm	33.95 ppm	123.83 ppm	78.57 ppm	152.46 ppm
Manganese (Mn) Emission Factor	47.80 ppm	56.45 ppm	120.05 ppm	56.75 ppm	32.74 ppm	98.66 ppm	52.27 ppm	109.36 ppm
Mercury (Hg) Emission Factor	0.10 ppm	0.11 ppm	0.25 ppm	0.09 ppm	0.05 ppm	0.15 ppm	0.10 ppm	0.20 ppm
Nickel (Ni) Emission Factor	6.04 ppm	7.43 ppm	15.56 ppm	15.65 ppm	10.53 ppm	29.12 ppm	10.85 ppm	22.34 ppm
Lead (Pb) Emission Factor	4.63 ppm	4.79 ppm	10.77 ppm	10.76 ppm	11.37 ppm	25.31 ppm	7.70 ppm	18.04 ppm
Selenium (Se) Emission Factor	1.09 ppm	0.94 ppm	2.30 ppm	2.28 ppm	1.10 ppm	3.69 ppm	1.68 ppm	2.99 ppm

Note: Concentrations listed above are from the USGS COALQUAL database with one exception. Chlorine concentration values for Illinois #6 coals listed above are based on coal design basis information. Concentration values provided in the COALQUAL database shown above are not on a "dry" basis but on a semi-dry basis, with residual moisture remaining after air drying prior to sample analysis. .

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

Table 10-3 Case-By-Case MACT Evaluation Summary for the Main Facility Boiler and Auxiliary Boiler

Pollutant	Control Technology	Control Efficiency	Proposed MACT Emission Limit	
Main Boiler				
Mercury	Multi-pollutant controls; SCR, fabric filter baghouse, wet scrubber, with activated carbon injection	84%	1.68×10^{-6} lb/MMBtu 15×10^{-6} lb/MW-hr Annual average	
Non-Mercury Metal HAPs	Fabric filter baghouse	99%	Surrogate CEM Monitoring Facility PM filterable emissions limit 0.012 lb/MMBtu 24-hr average	
Organic HAPs	Engineering combustion controls (Good Combustion Practices)	---	Surrogate CEM monitoring Facility BACT CO emission limit 0.10 lb/MMBtu 30-day rolling average (100 ppm)	
HF	Wet scrubber and fabric filter baghouse	98.5%	2.68×10^{-4} lb/MMBtu 3-hr. avg.	
HCl	Wet scrubber and fabric filter baghouse	98.5%	3.22×10^{-4} lb/MMBtu (PRB) 3-hr. avg.	2.89×10^{-3} lb/MMBtu (50/50 Coal Blend) 3-hr. avg.
Auxiliary Boiler				
Inorganic HAPs	Engineering combustion controls and fuel selection	N/A	Work practice standard (fuel specification) including low sulfur/low ash fuel	
Organic HAP	Engineering combustion controls	N/A	Surrogate CEM Facility BACT CO emission limit 0.04 lb/MMBtu 24-hr. average	
HCl	Fuel selection and fuel specifications	N/A	Work practice standard (fuel specification) including low sulfur/low ash fuel	

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

Table 10-4 Total Facility HAP Emissions Estimate

Source	Pollutant[1]	Emissions (ton/yr)
Main Boiler	Non-Mercury Metal HAPs	2.65
	Acid Gases	7.79
	Mercury	0.06
	Organic HAPs and Others	30.3
Auxiliary Boiler	Total HAPs	0.057
Total Facility Wide HAP Emission Estimate		40.9

[1] Pollutant emission calculations shown in Exhibit A. Emissions of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, and nickel represent non-mercury metal HAPs, and HF and HCl represent acid gas HAPs. Total ton/yr emissions of non-mercury metal HAPs and Acid Gas HAPs based on average ppm concentration values as derived from the USGS COALQUAL database. Organic HAP calculations for PRB coal shown in Exhibit A. Organics HAPs and Others value includes phosphorous and several metal compounds (i.e. arsenic trioxide).

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Checked by: JDF 11/26/08

Total facility HAP emissions estimates indicated in Table 10-4 are based on use of PRB coal alone. Use of PRB coal alone, versus a blend of PRB and bituminous coals, is a worst case scenario for emissions of most HAPs due to the lower Higher Heating Value (HHV – Btu/lb) for PRB coal, requiring combustion of more coal than use of a blend of PRB and bituminous coals. The only significant exception is estimated annual emissions of HCl. Facility HCl emissions are dependent on the amount of chlorine present in the coal upon combustion. PRB coals typically contain a low chlorine content, where bituminous coals contain a high chlorine content. PRB coal design data has indicated an average PRB coal chlorine concentration of 100 ppm, while design data for Illinois #6 (bituminous) coals has indicated an average chlorine content of 2700 ppm. Therefore, use of a blend of PRB and bituminous coals would lead to higher estimated emissions of HCl than those values indicated in Table 10-4.

10.4 CASE-BY-CASE MACT ANALYSIS FOR THE MAIN BOILER

40 CFR 63.43(e)(2)(x); 40 CFR 63.43(e)(2)(xii); 40 CFR 63.43(e)(1), 40 CFR 63.43(e)(2)(xi), 40 CFR 63.43e(2)(xiii)

The proposed Plant Washington facility will use a supercritical pulverized coal-fired boiler with a heat input capacity of 8,300 MMBtu/hr. The main boiler's fuel design basis is use of 100 percent sub-bituminous coals (PRB), or up to a 50/50 blend of sub-bituminous and bituminous coals (PRB/Illinois #6).

In Section 4.3 of this application a BACT determination was prepared for mercury in accordance with the Georgia Rules for Air Quality Control, Chapter 391-3-1. Georgia Rule 391-3-1-.02(ttt) requires application of BACT to mercury emissions from new coal-fired electric utility steam generating units installed after January 1, 2007, that generate greater than 25 MW of electricity for sale. A BACT analysis was also conducted in Section 4.3 for fluorides reported as the acid gas HF. These assessments are referred to in the Case-By-Case MACT analysis for these two pollutants.

The USEPA prepared the *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report To Congress (February 1998)*. The results of this study formed the basis for the USEPA's regulatory finding on the emissions of HAPs from electric utility steam generating units in 2000, and the subsequent proposed NESHAP, NSPS, and CAMR regulations for electric utility steam generating units. As part of this study, emissions test data were obtained from 52 units by EPRI, the Department of Energy (DOE), the Northern States Power Company, and USEPA. The testing program was designed to incorporate a wide variety of facility types and facility control scenarios to obtain data representative of the utility industry.

From the testing, approximately 67 HAPs were identified. These 67 HAPs were then carefully evaluated in a screening assessment, which considered inhalation and non-inhalation exposure routes to identify priority HAPs for more detailed assessment. To screen for inhalation exposures, USEPA used the Human Exposure Model (HEM) to model the 67 HAPs from the 684 utility plants in the study. This model used conservative assumptions that overestimated health risks. These models provided an estimate of inhalation risks for maximally exposed individuals (MEIs). If the MEI risk was above a minimum measure of $1/10^{th}$ the inhalation reference concentration (RfC) or cancer risk greater than 1 chance in 10 million, then the HAP was chosen for more study. For non-inhalation exposures, the 67 HAPs were prioritized based on five criteria including persistence, tendency to bioaccumulate, toxicity, emissions quantity, and radioactivity.

Based on the screening assessment, 14 priority HAPs were identified. The other 53 HAPs were not evaluated beyond the screening assessment. The 14 HAPs identified included arsenic, beryllium, cadmium, chromium, lead, manganese, Hg, nickel, hydrogen chloride, hydrogen fluoride, acrolein, dioxins, formaldehyde, and radionuclides. Arsenic, Hg, dioxins, and radionuclides were identified as the highest priority to assess for multipathway exposure and risks.

Following further study and review, the USEPA indicated that Hg was the HAP of greatest concern from coal-fired utilities. The USEPA also indicated that dioxins and arsenic were of potential concern from coal-fired power plants, nickel emissions were of potential concern from oil-fired utilities, and that significant uncertainties still existed regarding the nickel forms emitted from utilities and the health effects of those various forms. This work conducted by the USEPA lead to the issuance of the NSPS Subpart Da regulations for mercury and the Clean Air Mercury Rule (CAMR).

This Case-By-Case MACT evaluation includes emissions of HAPs identified through reference documentation such as the USEPA collection of emission factors termed AP-42, the USEPA NEI HAP database for coal-fired utility units, and the USEPA TRI database. The emissions limits proposed in this MACT evaluation include control of the 14 pollutants identified as priority HAPs in the USEPA report, and several additional non-mercury metal HAPs. Along with surrogate parameters to address control of organic HAPs, HAPs that do not have a proposed or established limit will also be controlled through the proposed emission control strategy for Plant Washington. The MACT emission limits proposed in this section are based on requirements for reduction of all HAP emissions.

The specific HAPs evaluated in this Case-By-Case MACT analysis include mercury, non-mercury metal HAPs including antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium, acid gases including HF and HCl, and organic HAPs which include compounds of interest such as acrolein, dioxins, and formaldehyde. Radionuclides are addressed through the Case-By-Case MACT analysis for non-mercury metals. Regulatory evaluations have identified that by controlling the HAP categories of mercury, non-mercury metal HAPs, acid gases, and organic HAPs all HAPs from the main boiler will be effectively controlled.

10.4.1 Mercury MACT Determination For The Main Boiler

Mercury is in coal in trace amounts, and is released into the main boiler exhaust flue gas during combustion. According to the USEPA document *Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update* (2005), the mercury content in typical coals is approximately 0.1 parts per million (ppm) on average. A specific evaluation of coal analysis data for PRB and Illinois coals from the USGS COALQUAL database indicates that the average mercury content for both PRB and Illinois coals is approximately 0.1 ppm. Therefore, it is expected that most bituminous and sub-bituminous coals planned for use at Plant Washington would have approximately this same level of mercury on average.

Hg is present in the flue gas stream in one of three different forms, as (1) an elemental Hg vapor, (2) particle-bound Hg, or (3) vapor of an oxidized Hg species (Hg^{2+}), and is typically present in all three forms. The chemical form of the Hg in the flue gas stream can have a significant impact on the effectiveness of the control strategies employed for control of Hg emissions. Elemental Hg is regarded as the most difficult form of Hg to control since it cannot be scrubbed or filtered out. Particulate bound mercury is effectively controlled by particulate matter (PM) control strategies, such as a fabric filter baghouse or ESP. Oxidized mercury is more effectively controlled by gas scrubbing techniques (i.e. wet scrubber). Studies have found that sorbent injection systems can be designed for effective capture of elemental mercury.

Establishing a MACT Floor

10.4.1.1 Identification of Best Demonstrated Technology (BDT)

Control technologies for the control of mercury emissions have been identified and evaluated in the BACT analysis for mercury in Section 4. EPA determined through regulatory actions such as the proposed MACT standard for electric utility boilers, and the New Source Performance Standards (NSPS) for mercury for electric utility steam generating units, that the Best Demonstrated Technology (BDT) for control of mercury emissions included those controls generally installed for control of SO_2 and PM emissions, including use of fabric filter baghouse, ESP, SCR, and dry and wet scrubber systems. These findings correspond with the results of the BACT analysis in Section 4. The control technology for control of mercury emissions to be utilized at Plant Washington will include;

- Use of an SCR for oxidation of elemental mercury
- Use of a fabric filter baghouse for control of particulate bound mercury
- Use of a wet scrubber for control of gas phase (oxidized) mercury
- Use of activated carbon injection for control of elemental mercury
- Purchase of bituminous (Illinois #6) coals that have been washed

Fuel blending, through use of a blend of sub-bituminous (PRB) and bituminous (Illinois #6) coals will also be used at the facility, potentially reducing mercury emissions. However, studies to date on the effectiveness of fuel blending have shown mixed results.

10.4.1.2 Evaluation of Information for the MACT Floor

A wide range of control efficiencies could be expected when evaluating emissions of Hg, due to the variability of coal specifications, design and efficiencies of combination controls (i.e., fabric filter baghouses and SCR), and combustion design of the boiler. For example, the USEPA *Mercury Study Report To Congress (1997)* indicated that a WFGD system would remove approximately 90 percent of the Hg^{2+}, and a WFGD system working with a fabric filter baghouse could remove approximately 88 to 92 percent of the total Hg from bituminous coals. Also, the *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report To Congress – USEPA (1998)* indicated that both WFGD and dry FGD systems could remove over 90 percent of Hg^{2+}, and up to 70 percent of elemental Hg. The USEPA report *Performance and Cost of Mercury and Multi-pollutant Emission Control Technology Applications on Electric Utility Boilers (2003)* found that total mercury removal from units equipped with dry FGD systems ranged from 2 to 98 percent, and with WFGD systems total Hg removal ranged from 10 to 98 percent.

In preparation of the proposed Utility MACT (2004), USEPA reviewed Information Collection Request (ICR) data for stack testing evaluations of mercury emissions from 81 coal-fired utility units (referred to as ICR-3). A review of this data indicated that, of 30 coal fired utility units evaluated, the total mercury removal estimated (coal to stack) varied from no effective mercury control up to 86% mercury control. Units tested utilized emission controls such as ESPs, fabric filter baghouses, dry scrubbers, wet scrubbers, etc. Testing evaluations of two utility boilers utilizing only fabric filter baghouse controls and sub-bituminous coals, the Clay Boswell Unit 2 and Comanche Unit 2, was conducted as part of the ICR-3 assessment. The estimated removal effectiveness of mercury for the Clay Boswell Unit 2 facility was approximately 86%, and for the Comanche 2 facility was 66%. Therefore, significant variability in the control effectiveness of mercury has been observed for similar units utilizing similar coals.

The following Table 10-5 is taken from the USEPA document *Control of Mercury Emissions From Coal-Fired Electric Utility Boilers (2004)*, and demonstrates the variability found in mercury testing studies for different emission control strategies and for different coal types utilized during testing.

Table 10-5 Average Mercury Capture By Existing Post-Combustion Control Configurations Used For Pulverized Coal Boilers

Post-combustion Control Strategy	Post-combustion Emission Control Device Configuration	Average Mercury Capture by Control Configuration		
		Coal Burned in Pulverized-coal-fired Boiler Unit		
		Bituminous Coal	Subbituminous Coal	Lignite
PM Control Only	CS-ESP	36 %	3%	0 %
	HS-ESP	9 %	6 %	not tested
	FF	90 %	72 %	not tested
	PS	not tested	9 %	not tested
PM Control and Spray Dryer Adsorber	SDA+CS-ESP	not tested	35 %	not tested
	SDA+FF	98 %	24 %	0 %
	SDA+FF+SCR	98 %	not tested	not tested
PM Control and Wet FGD System[a]	PS+FGD	12 %	0 %	33%
	CS-ESP+FGD	75 %	29 %	44 %
	HS-ESP+FGD	49 %	29 %	not tested
	FF+FGD	98 %	not tested	not tested

CS-ESP = cold-side electrostatic precipitator
HS-ESP = hot-side electrostatic precipitator
FF = fabric filter
PS = particle scrubber
SDA = spray dryer absorber system

(a) Estimated capture across both control devices

A limited amount of data exist for the effectiveness of Hg emission control using sub-bituminous coals (such as PRB) with a fabric filter and wet scrubber, and using those controls with a direct mercury control strategy such as activated carbon injection. In *Control of Mercury Emissions from Coal-fired Electric Utility Boilers (2004)*, prepared by the USEPA Office of Research and Development, Table 1 (referenced above as Table 10-5) indicated that a 98 percent removal of total Hg from bituminous coals could be expected by a system using a fabric filter with a wet scrubber. The report also indicated that a 29 percent removal of total Hg could be expected from an ESP and wet scrubber, if using sub-bituminous coals. Table 2 of that report also indicated that using activated carbon injection system with an ESP for sub-bituminous coals could reduce Hg emissions by approximately 60 percent over using an ESP alone.

As can be seen in Table 10-5, the control effectiveness of mercury emissions during use of sub-bituminous coals has been found to not be as high as the control effectiveness of use of bituminous coals alone. This has been postulated to be due to circumstances such as the higher chlorine content of bituminous coals, promoting increased oxidation and more effective capture of elemental mercury. Also, since sub-bituminous coals, such as PRB coals, contain much lower ash or pyritic "rock" content than

bituminous coals, bituminous coals can contain higher quantities of particle bound mercury, which can be more effectively captured by standard particulate matter control devices than other forms of mercury.

Reference data reviewed indicates that washing of coals can reduced mercury content anywhere from 5% to 39%, correlating with the pyritic sulfur content removal achievable through coal washing. Illinois #6 coals purchased by the facility will be washed prior to shipment to Plant Washington. However, as discussed in the mercury BACT analysis in Section 4, PRB coals have so little pyritic sulfur or "rock content" that washing of PRB coals is ineffective. Therefore, coal washing for removal of mercury from PRB coals is not considered.

As stated above, limited information is available on the control efficiency that can be expected for the combination of controls planned for the Plant Washington facility. Testing data for existing sources was also reviewed in this analysis for determination of the MACT floor. Table 10-6 indicates those sources which have undergone recent stack testing for mercury emissions, which were evaluated as similar sources. Those facilities included a supercritical pulverized coal-fired boiler unit installed at the Mid-American Energy Center (Council Bluffs Energy Center – Walter Scott Jr. Energy Center) Unit 4 in Iowa, and a pulverized coal fired boiler unit at the Santee Cooper Cross Generating Station in South Carolina (Unit 3). The Walter Scott Jr. Energy Center Unit 4 is a 790 MW net boiler utilizing SCR, a fabric filter baghouse, a dry scrubber, and activated carbon injection for control of mercury emissions while burning sub-bituminous coal (PRB coal at the time of testing). Santee Cooper Cross Unit 3 is a 660 MW net boiler utilizing SCR, an ESP, and a wet scrubber for control of mercury emissions while burning bituminous coals. These two pulverized coal-fired boilers recently came online in calendar year 2007, and are utilizing modern pollutant emission controls. An evaluation of the performance testing of these two (2) facilities, with one utilizing sub-bituminous (PRB), and the other utilizing bituminous coals, is an effective point of comparison for this analysis.

Table 10-6 Mercury Stack Testing Results Reviewed For Evaluation of the MACT Floor

Facility	Coal Type	Testing Date	Testing Results (3-run Avg.) Emission Rate	Permitted Limit[1]	Equivalent Emission Rate During Stack Testing[2]
Santee Cooper Cross Unit 3	Bituminous)	January 2007	7.2×10^{-7} lb/MMBtu 4.2×10^{-3} lb/hr	3.6×10^{-6} lb/MMBtu	7.2×10^{-6} lb/MW-hr
Walter Scott Jr. Energy Center Unit 4	Sub-bituminous (PRB)	August 2007	1.23×10^{-6} lb/MMBtu 9.1×10^{-3} lb/hr	1.7×10^{-6} lb/MMBtu	10.5×10^{-6} lb/MW-hr

[1] The permitted limit indicated for the Walter Scott Jr. Energy Center Unit 4 boiler was the 112(g) limit included in the original PSD permit issued for the facility in June 2003. A subsequent permit revision in May 2007 removed the 112(g) limits from the permit, including the indicated permitted limit for mercury.

[2] The equivalent lb/MW-hr emission rate during stack testing indicated for the Walter Scott Jr. Energy Center Unit 4 based on an average reported MW output of the facility during stack testing of 868.8 MW. The equivalent lb/MW-hr emission rate indicated for the Santee Cooper Cross Unit 3 facility based on an average reported MW output of the facility during stack testing of 586.8 MW. Electronic copies of stack testing reports referenced above can be found in Exhibit E.

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

Table 10-7 Coal-Fired Utility Units 112(g) Determination for Mercury

Facility	Hg Control Strategy	Coal Type	Emission Rate	Facility Status
Thoroughbred Generating Station	Multi-pollutant controls including SCR, fabric filter baghouse, wet scrubber, wet ESP	Bituminous (Illinois)	3.26×10^{-6} lb/MMBtu	Not Yet Constructed
Roundup Power Project	Multi-pollutant controls including SCR, SDA, fabric filter baghouse	Sub-bituminous	2.69×10^{-6} lb/MMBtu	Not Yet Constructed
Midamerican Energy Company – Walter Scott Jr. Energy Center CBEC4 Boiler	Multi-pollutant controls including SCR, SDA, fabric filter baghouse, with sorbent injection (activated carbon injection)	Sub-bituminous (PRB)	1.7×10^{-6} lb/MMbtu	Operational
Santee Cooper Cross Generating Station	Multi-pollutant controls including SCR, ESP, and WFGD	Bituminous	3.6×10^{-6} lb/MMBtu	Operational
LS Power Longleaf	Multi-pollutant controls including SDA and fabric filter baghouse, with activated carbon injection	Sub-bituminous and Bituminous	Sub-bituminous: 15×10^{-6} lb/MW-hr Bituminous: 6×10^{-6} lb/MW-hr	Not Yet Constructed
Tuscon Electric Power Company Springerville Generating Station	Multi-pollutant controls including SCR, SDA, and fabric filter baghouse	Sub-bituminous	6.9×10^{-6} lb/MMbtu	Operational
Corn Belt Energy Corporation – Elkhart	Multi-pollutant controls including SCR, WFGD, and ESP	Bituminous (Illinois)	4.0×10^{-6} lb/MMBtu	Not Yet Constructed
LS Power Plum Point	Multi pollutant controls including SCR, SDA, and fabric filter baghouse	Sub-bituminous (PRB)	12.8×10^{-6} lb/MMBtu	Not Yet Constructed
City Utilities Springfield Southwest Station	Multi pollutant controls including SCR, SDA, and fabric filter baghouse, activated carbon injection optional	Sub-bituminous	7.5×10^{-6} lb/MMBtu	Not Yet Constructed
Omaha Public Power District	Multi-pollutant controls including SCR, SDA, fabric filter baghouse, with activated carbon injection	Sub-bituminous	18×10^{-6} lb/MW-hr	Not Yet Constructed

Table 10-7 Coal-Fired Utility Units 112(g) Determination for Mercury (Continued)

Facility	Hg Control Strategy	Coal Type	Emission Rate	Facility Status
AMP Meigs	Multi-pollutant controls including SCR, fabric filter baghouse, wet scrubber, wet ESP	Bituminous	1.9×10^{-6} lb/MMBtu Determined for State BACT	Not Yet Constructed
Intermountain Unit 3	Multi-pollutant controls including SCR, WFGD, and fabric filter baghouse	Sub-bituminous and Bituminous	Sub-bituminous: 20×10^{-6} lb/MW-hr Bituminous: 6×10^{-6} lb/MW-hr	Not Yet Constructed
WE Elm Road	Multi-pollutant controls including SCR, fabric filter baghouse, wet scrubber, wet ESP	Bituminous	1.12×10^{-6} lb/MMBtu	Not Yet Constructed
Weston Unit 4	Multi-pollutant controls including SCR, dry scrubber, fabric filter baghouse, and activated carbon injection	Sub-bituminous (PRB)	1.70×10^{-6} lb/MMBtu	Operational
Longview Power (Maidsville)	Multi-pollutant controls including SCR, WFGD, fabric filter baghouse, and duct sorbent injection	Bituminous	2.39×10^{-6} lb/MMBtu	Not Yet Constructed
Wygen Unit 2	Multi-pollutant controls including SCR, dry scrubber, fabric filter baghouse, and activated carbon injection	Sub-bituminous	20×10^{-6} lb/MW-hr	Operational
Santee Cooper Pee Dee Generating Station	Multi-pollutant controls including SCR, WFGD, and fabric filter baghouse	Bituminous	8×10^{-6} lb/MW-hr (46.3 lbs/yr)	Not Yet Constructed
Trimble County Generating Station	Multi-pollutant controls including SCR, WFGD, ESP, fabric filter baghouse, and wet ESP	Sub-bituminous and Bituminous – Performance Coal 70/30 Bit/Sub Split	13×10^{-6} lb/MW-hr	Not Yet Constructed

Table 10-7 Coal-Fired Utility Units 112(g) Determination for Mercury (Continued)

Facility	Hg Control Strategy	Coal Type	Emission Rate	Facility Status
Cliffside Station Unit 6	Multi-pollutant controls including SCR, dry scrubber, fabric filter baghouse, and wet scrubber	Primary Fuel Bituminous – Up To a 50/50 Blend of Bituminous and Sub-Bituminous	14×10^{-6} lb/MW-hr	Not Yet Constructed
John W. Turk Jr.	Multi-pollutant controls including SCR, dry scrubber, fabric filter baghouse, and activated carbon injection	Sub-bituminous	1.7×10^{-6} lb/MMBtu	Not Yet Constructed
Consumers Energy (ASPC)	Multi-pollutant controls including SCR, wet scrubber, fabric filter baghouse, and activated carbon injection	Sub-Bituminous and Bituminous – Up to a 50/50 Coal Blend	7.9×10^{-6} lb/MW-hr	Not Yet Constructed

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

An emissions test conducted in January 2007 at the Santee Cooper Cross facility Unit 3 (South Carolina) was reviewed. The Santee Cooper Cross generating facility, tested in January 2007, was combusting an eastern bituminous coal during source testing, utilizing SCR, an ESP, and a wet scrubber and achieved an emissions level of 7.2 x 10^{-7} lb/MMBtu on a 3-hr. average during the stack test, equivalent to approximately 7.2 x 10^{-6} lb/MW-hr based on provided boiler load conditions during the test. An emissions test conducted at the Walter Scott Jr. Energy Center Unit 4 in Iowa in August 2007 was also reviewed. This facility was utilizing PRB coal during the stack test, utilizing an SCR, dry scrubber, fabric filter baghouse, and activated carbon injection. The Walter Scott Jr. Energy Center achieved an emission level of 1.23 x 10^{-6} lb/MMBtu on a 3-hr. average during the stack test, equivalent to approximately 10.5 x 10^{-6} lb/MW-hr based on boiler load data provided during the test.

Tables 10-7 illustrates those units identified as conducting 112(g) determinations for Hg considered similar sources, which were pulverized coal fired boiler units utilizing either sub-bituminous coals, bituminous coals, or a blend of sub-bituminous and bituminous coals. Table 10-7 indicates the indicated unit's control strategy, type of fuel combusted (i.e. bituminous, sub-bituminous), and Hg emission limit. RBLC and draft permit listings for BACT determinations for Hg emissions can be found in Table 4-25 in Section 4.3. Many of the facilities indicated in Table 4-25 in Section 4.3, and Table 10-7 above, have not yet been constructed. Many facilities are proposing the same emissions control strategies for control of mercury.

Numerous reference documents were researched in conducting the MACT evaluation for Hg emissions. A list and copies of these documents are in Exhibit E of this report. The USEPA *Regulatory Finding on Emissions of HAPs From Electric Utility Steam Generating Units (FR Volume 65 No. 245 – 2000)* determined that the post combustion controls for the criteria pollutants PM, SO_2, and NO_x were effective in removal of Hg emissions. This determination was also made in the *Proposed NESHAP*, and in the *Alternative, Proposed NSPS for New and Existing Electric Utility Steam Generating Units – USEPA (FR Volume 69 No. 20 – 2004)*, also indicating that actual Hg removal would be based on coal characteristics. The promulgated NSPS for electric utility steam generating units determined different Hg limits for bituminous coals and sub-bituminous coals, with different limits for sub-bituminous coals by regional area (determined as wet or dry). Also, the promulgated NSPS standards indicated the effective controls for control of mercury included WFGD and dry FGD, fabric filter baghouses, ESP, and SCR. Therefore, use of an SCR, a fabric filter baghouse, a wet scrubber, and activated carbon injection is determined as the best controlled similar source for control of mercury emissions.

The Proposed National Emission Standards For Hazardous Air Pollutants (NESHAP) for Electric Utility Units (2004) proposed mercury emission limits for coal-fired utility boilers (new affected sources) of 20 x 10^{-6} lb/MW-hr for use of sub-bituminous coals, 6 x 10^{-6} lb/MW-hr for use of bituminous coals, and 1.1 x 10^{-6} lb/MW-hr for use of coal refuse (coal waste). The NSPS and CAMR regulations specified mercury emission limits for new units of either 66 x 10^{-6} lb/MW-hr or 97 x 10^{-6} lb/MW-hr for units utilizing sub-bituminous coals, 20 x 10^{-6} lb/MW-hr for units utilizing bituminous coals, and 16 x 10^{-6} lb/MW-hr for units utilizing coal refuse (coal waste). Emission limits for the above discussed EPA regulatory actions were based on the coal type, or coal rank being combusted as opposed to the type of combustion unit (with the exception of IGCC units).

EPA determined through the above listed regulatory actions that the Best Demonstrated Technology (BDT) for control of mercury emissions included those controls generally installed for control of SO_2 and PM emissions, including use of fabric filter baghouse, ESP, SCR, and dry and wet scrubber systems. The EPA addressed the option of determining mercury removal across the system (mercury removal efficiency) and use such requirements as a demonstration of compliance, which would promote and give credit for mercury reduction from coal preparation practices such as coal washing. However, EPA found that such a requirement would lead to tracking the mercury concentration in coal from receipt to stack, not just before and after the control device, and could be difficult to implement. EPA determined that evaluation of emission rates would be the most effective for regulatory compliance.

Utilizing coal refuse, or waste coal, can result in low mercury emissions. Statements made by the EPA in the January 2004 proposed MACT standard for utility boilers indicated "Available data indicate that emissions from the combustion of coal refuse tends to result almost entirely in particulate bound Hg (greater than 99 percent for both units tested in the 1999 EPA ICR)." Therefore, with such a high percentage of mercury present in the particulate phase in coal refuse, significant removal efficiencies (i.e. 98%+) are possible for total mercury when combusting waste coal. Waste coal was evaluated as a separate coal rank in the development of the NSPS standards for mercury (Subpart Da), the Clean Air Mercury Rule (CAMR), and the draft MACT standards for utility boilers.

These characteristics of coal refuse allow for much lower mercury limits for units combusting coal refuse. A recent MACT analysis for a Dominion Circulating Fluidized Bed (CFB) boiler indicated a mercury limit of 49 lb/yr, based on a removal efficiency of 98% for total mercury. This limit was based on the use of waste coal at the facility. CFB units are capable of combustion of waste coal, where standard pulverized coal-fired boilers are not due to the high level of impurities present in the waste coal.

Combustion of waste coal leads to increased emissions of other pollutants such as SO_2. Therefore, for the above discussed reasons, the mercury emissions performance of CFB units combusting waste coal will no longer be considered in this MACT analysis.

Additional data available for State regulations involving mercury emissions were also reviewed. The State of Connecticut currently has the most stringent removal requirement in place for mercury of 90% or 6×10^{-6} lb/MW-hr. However, these regulations are not applicable in this analysis due to the fact that the regulations allow for the permitting authority to allow for alternative limits if an emission unit fails to meet the required mercury emission limitation.

10.4.1.3 Determine the MACT Floor

Based on a thorough review of the available information in accordance with 40 CFR 63.43, the combined use of a mercury specific control technology, sorbent injection using activated carbon, and multi-pollutant control technologies including SCR, fabric filter baghouse, and a wet scrubber is the MACT floor for control of mercury emissions for the Plant Washington facility, and is representative of the best controlled similar source. Limited data is available from resources reviewed on the effective control efficiency for mercury for the planned coals and combination of pollutant controls planned for Plant Washington.

An evaluation of the recent stack testing data reviewed for the MACT floor indicated emissions from the Walter Scott Jr. Energy Center, Unit 4, a unit utilizing PRB coal, SCR, dry scrubber, fabric filter baghouse, and activated carbon injection for control of mercury emissions, of approximately 1.23×10^{-6} lb/MMBtu, or an equivalent of approximately 10.5×10^{-6} lb/MW-hr. These results were based on a 3-hr. average stack test, and are not representative of long-term source operation. The proposed MACT emission limit for Plant Washington will be based on an annual (12-month rolling) emission limit, and the Walter Scott Jr. Energy Center Unit 4 test results do not provide any indication of the long term mercury emissions performance of the unit. Long term performance of mercury emission control strategies should be taken into account when evaluating a singular stack testing result.

An evaluation of recent mercury CEMS monitor certification data for the Wygen II facility, a facility utilizing PRB coal and SCR, a dry scrubber, and a fabric filter baghouse for control of mercury emissions, indicated a relative accuracy of the mercury CEMS device of 17.9%, just under the standard of 20% relative accuracy (present in the now vacated mercury monitoring provisions of 40 CFR Part 60 and 75). The mercury CEMS device consistently provided higher readings than the stack testing results, with stack

testing correlation testing utilizing USEPA Method 4 and 30B. This information indicates that a mercury CEMS device could indicate higher emissions than a standard stack test. These circumstances need to be taken into account since Plant Washington will utilize a mercury CEMS device for determination of compliance with the main boiler mercury limit. An electronic copy of the referenced CEMS monitor certification for the Wygen II facility can be found in Exhibit E.

The Information Collection Request (ICR) data collected by the USEPA in their development of mercury regulations, including speciated mercury stack testing data acquired from 81 utility boilers in 1999, was reviewed. A review of summary stack testing results for 30 units utilizing sub-bituminous coals, as part of the ICR, indicated average mercury emissions of approximately 4.7×10^{-6} lb/MMBtu for those 30 units reviewed. This data was determined not to be as up to date as the recent stack testing data reviewed in this analysis, and did not include units utilizing activated carbon injection for control of mercury emissions (while utilizing sub-bituminous coals).

Taking the above issues into consideration, the MACT floor emission limit for mercury emissions is determined to be 1.68×10^{-6} lb/MMBtu, equivalent to 15×10^{-6} lb/MW-hr for Plant Washington for use of sub-bituminous coals. This value corresponds to the lowest permitted limit of 1.7×10^{-6} lb/MMBtu (for sub-bituminous coals) for the Walter Scott Jr. Energy Center, Unit 4 which has demonstrated compliance. A MACT floor emission limit for sub-bituminous coals for Plant Washington of 1.68×10^{-6} lb/MMBtu represents an approximately 84% reduction in uncontrolled mercury emissions from sub-bituminous (PRB) coals, based on the 95% UCL value derived from the USGS COALQUAL database for PRB coals of 0.11 ppm.

A floor level has not been calculated for the blend of bituminous and sub-bituminous coals planned for use at Plant Washington because it is uncertain whether any improvement over the sub-bituminous level would result by blending of sub-bituminous and bituminous coal. The following section provides more information about this fuel scenario.

10.4.1.4 Beyond The Floor Analysis

The Consumers Energy facility has recently proposed a MACT emission limit for mercury of 7.9×10^{-6} lb/MW-hr, including use of sub-bituminous coals. However, a review of the August 2008 Case-By-Case MACT submittal for the Consumers Energy facility indicates that the facility has also proposed an optimization study be included in the MACT decision. The optimization study would evaluate the

impacts of fuel blending, activated carbon injection rates, halide addition or the use of halogenated activated carbon, etc. to comply with the mercury limit. The report also states "If the optimization study indicates that the ASCPC unit cannot achieve the 0.0079 lb/GWh, the limits established as MACT may need to be revised to reflect the levels that can be achieved with the highly sophisticated air pollution control system that will be utilized." Therefore, if an optimization study is granted as part of the MACT analysis then this limit is not directly comparable to the limits proposed by Plant Washington.

Also, the Consumers Energy facility has indicated in their application a much lower uncontrolled mercury emission rate for PRB coal, of 6.96 x 10^{-6} lb/MMBtu. Consumers Energy based the uncontrolled mercury emissions rate on five years of coal mercury analysis data for coals shipped to their facilities, and indicated that this estimate was less than half of the uncontrolled mercury emissions estimate derived from USGS COALQUAL data for PRB coals. Therefore, when comparing mercury removal efficiency, or final proposed emission limits for mercury for facilities, special attention should be made to the indicated uncontrolled mercury emission rate (or mercury concentration in the coal) from which removal efficiencies or applicable limits are derived.

The U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL), in conjunction with the U.S. EPA and Electric Power Research Institute (EPRI), state and local agencies, power plant facilities, and others manages a significant research and development program for control of mercury emissions from coal fired power generation facilities. DOE/NETL initiated a research and development program in the 1990s evaluating mercury specific control technologies such as sorbent injection and mercury oxidation concepts. The research and development program has been implemented in separate phases, with Phase II of the research and development program completed in 2007. Phase III projects were initiated in 2006 and have not yet been completed.

The following Table 10-8 is a summary of the information available to date on the DOE/NETL Phase II and Phase III studies, indicating the average total mercury removal (from co-benefit controls and new technology), the technology under investigation, the coal type utilized during the testing, and the standard emission controls (i.e. ESP, fabric filter baghouse, etc.) in use at the facility. Data indicated in Table 10-8 was taken from the document *An Update on DOE/NETL's Mercury Control Technology Field Testing Program (July 2008)*, and background DOE/NETL test reports and presentations prepared during field testing and evaluations of the units in question. Units indicated in Table 10-8 are those units studied in Phase II and Phase III for which data is available and which utilized either sub-bituminous (i.e. PRB), and a blend of sub-bituminous and bituminous coals during testing evaluations.

Table 10-8 DOE/NETL Testing Program Results

Facility	Technology Under Review	Coal Type In Use	Control Technology In Use	Average Total Mercury Removal[1]
Holcomb Unit 1	Blending Coal Coal Additives Enhanced Activated Carbon	PRB PRB and Bituminous During Blending Evaluations	Spray Dryer Absorber and Fabric Filter	93%
Meramec Unit 2	Coal Additives Enhanced Activated Carbon	PRB	Cold Side ESP	92.6%
Laramie River Unit 3	Blending Coal Coal Additives Enhanced Activated Carbon	PRB PRB and Bituminous During Blending Evaluations	Spray Dryer Absorber and Cold Side ESP	> 90%
Monroe Unit 4	Blending Coal SCR System Enhanced Activated Carbon	PRB/Bituminous Blend	SCR and Cold Side ESP	81%
Labadie Unit 2	Enhanced Activated Carbon – Impacts of SO_3	PRB	Cold Side ESP	50% - > 90%
Stanton Unit 1	Enhanced Activated Carbon	PRB	Cold Side ESP	85%
St. Clair Unit 1	Enhanced Activated Carbon	PRB/Bituminous Blend	Cold Side ESP	94%
Monticello Unit 3	Oxidation Catalysts Injection of Halogen Salts Wet Scrubber Additives	Texas Lignite/PRB Blend	Cold Side ESP and Wet Scrubber	65% - 92%
Big Brown Unit 2	Enhanced Powdered Activated Carbon and TOXECON	Texas Lignite/PRB Blend	Cold Side ESP and COHPAC Fabric Filter	74%
Dave Johnston Unit 3	Enhanced Powdered Activated Carbon and Mer-Cure	PRB	Cold Side ESP	92%
Independence Unit 1	Enhanced Powdered Activated Carbon and TOXECON II	PRB	Cold Side ESP	60% - 90%
Louisa Unit 1	Coal Additives	PRB	Hot Side ESP	No Increase In Mercury Removal Due to Use of Additive
Crawford Unit 7	Enhanced Powdered Activated Carbon	PRB	Cold Side ESP	81%
Will County Unit 3	Enhanced Powdered Activated Carbon	PRB	Cold Side ESP	60% - 73%

[1] Note: Average total mercury removal indicated is the maximum mercury removal determined during field studies at the site. Please see the summaries given below for details on the testing evaluations conducted at the indicated sites.

Table 10-8 DOE/NETL Testing Program Results (Continued)

Facility	Technology Under Review	Coal Type In Use	Control Technology In Use	Average Total Mercury Removal[1]
Fayette Unit 3	Enhanced Powdered Activated Carbon	PRB	Cold Side ESP and Wet Scrubber	80% - 90%
Hawthorne Unit 5	Enhanced Powdered Activated Carbon	PRB	SCR, Spray Dryer Absorber and Fabric Filter Baghouse	> 90%
Hardin Station	Long Term Evaluation Activated Carbon Injection	PRB	Spray Dryer Absorber and Fabric Filter	90%
Limestone Station Unit 1	Enhanced Powdered Activated Carbon and TOXECON II	Texas Lignite/PRB Blend	Cold Side ESP and Wet Scrubber	60% - 90%

[1] Note: Average total mercury removal indicated is the maximum mercury removal determined during field studies at the site. Please see the summaries given below for details on the testing evaluations conducted at the indicated sites.

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

While Table 10-8 provides the concluding results of the Phase II and Phase III study results, the following summaries provide additional details on the results summarized in Table 10-8.

Sunflower Electric Holcomb Unit 1

Holcomb Unit 1 conducted a 30-day long term field test of DARCO Hg-LH while utilizing PRB coal. DARCO Hg-LH is a proprietary product of Norit Americas, Inc., which is an impregnated lignite coal based activated carbon (bromine enhanced) manufactured specifically for the removal of mercury from coal fired utility units. Total mercury capture across the spray dryer absorber and fabric filter configuration at Holcomb Unit 1 averaged 93% with injection of DARCO Hg-LH at 1.2 lb/MMacf. For the first 6 days of testing, the injection concentration was increased until 90% removal was achieved. The average total mercury removal for the entire 30 day test was 91%, with the average removal from day 6 to 30, following increasing the sorbent injection rate to 1.2 lb/MMacf, was 93%. The average mercury outlet concentration from day 6 to day 30 was 0.83 x 10^{-6} lb/MMBtu, with a standard deviation of 0.30 x 10^{-6} lb/MMBtu.

Additional short term evaluations were also conducted at Holcomb Unit 1. These evaluations included an evaluation of the effects of mercury removal by blending western bituminous coal with PRB coal, and chemical addition to the coal to enhance the performance of standard activated carbon. Mercury removal increased to almost 80% by coal blending alone (without sorbent injection), and mercury removal of 86%

was achieved at a carbon feed rate of 1.0 lb/MMacf when adding a proprietary chemical (KNX - a halogen based additive), to the coal. However, the topical report prepared for the Holcomb Station Unit 1 study, *titled Evaluation of Sorbent Injection For Mercury Control, Topical Report For: Sunflower Electric's Holcomb Station (June 2005)*, stressed that these test studies were conducted for very brief periods, and additional longer-term tests were needed to fully evaluate the mercury removal capabilities of the fuel blending and coal additive strategies. Also, during portions of the study the mercury CEM was not properly operating and some of the results from the study are suspect.

AmerenUE's Meramec Unit 2

Meramec Unit 2 also conducted a 30-day long term field test of DARCO Hg-LH while utilizing PRB coal. The total mercury capture achieved across the cold side ESP in use on unit 2 was an average of 93% with sorbent injection at 3.3 lb/MMacf. The average inlet and outlet mercury concentrations were 5.98 x 10^{-6} lb/MMBtu, and 0.44 x 10^{-6} lb/MMBtu respectively over the 30-day testing period, with an approximate removal efficiency based on these values of 92.6%. Fly-ash samples collected from the ESP during the testing period, subjected to two different leaching protocols, did not indicate mercury above detection limits in any of the samples evaluated.

An additional short term evaluation was conducted at Meramec Unit 2 involving the use of a coal additive for mercury control (KNX). Greater than 80% total mercury removal was determined (without carbon injection) through use of KNX. However, the topical report for the Meramec Unit 2 study, titled *Evaluation of Sorbent Injection For Mercury Control, Topical Report For: AmerenUE's Meramec Station Unit 2 (September 2005)*, cautioned that the coal additive testing was conducted over a short period, and conditions during testing may not be able to be replicated by other units burning PRB coals. The report indicated that total mercury removal through use of coal additives at another site (Laramie Unit 3) was less than 20%, and additional long term testing needs to be conducted before the limits of the coal additive technology are fully understood.

Missouri Basin Power Project's Laramie River Unit 3

Evaluations at the Laramie River Unit 3 involved evaluation of field testing of sorbent injection utilizing DARCO Hg-LH while utilizing PRB coal, chemical addition to the coal (KNX), and fuel blending of PRB and western bituminous coals. The Laramie River Unit 3 utilized a cold side ESP and a spray dryer absorber during the field tests. As discussed in the Laramie River Unit 3 topical report, titled *Evaluation*

of Sorbent Injection For Mercury Control, Topical Report For: Basin Electric Power Cooperative's Laramie River Station (January 2006), during testing fuel blending was not found to significantly improve mercury removal to above baseline (non-sorbent injection) controls. Coal additive evaluations indicated that, although the speciated fraction of oxidized mercury in the gas stream increased, total mercury removal across the system due to use of coal additives was less than 20%. Sorbent injection through use of DARCO Hg-LH resulted in mercury removal in excess of 90% at injection concentrations of 4.5 lb/MMacf during short term parametric testing. No long-term tests were conducted at Laramie River.

DTE Energy's Monroe Unit 4

Testing at Monroe Power Plant Unit 4, utilizing a cold side ESP and SCR, was conducted to evaluate the effects of injecting a sorbent material for control of mercury when using a small to moderate size ESP, the effects of use of an SCR system on mercury speciation and sorbent effectiveness, and mercury speciation and removal effects when blending PRB and eastern bituminous coals. Based on summary information from the topical report *Evaluation of Sorbent Injection For Mercury Control, Topical Report For DTE Energy's Monroe Station (December 2006)*, no significant changes in mercury speciation or removal were noted when blending of PRB and bituminous coals (60% PRB, 40% bituminous). Also, the SCR was effective at increasing the fraction of oxidized mercury from 20 to 40% to greater than 85% when the SCR was online. Also, similar performance in mercury removal through use of DARCO Hg-LH was observed when the SCR was both online and offline, and an average vapor phase mercury capture of 87% (84% due to sorbent injection) was achieved at an average sorbent injection concentration of 5.9 lb/MMacf during long term testing. Long term testing was conducted at full boiler load conditions, using a blend of PRB and eastern bituminous coal (typically 60% PRB 40% bituminous). The determined change in total mercury emissions from baseline to long term testing was 81%.

AmerenUE's Labadie Unit 2

Testing at Labadie Unit 2 was conducted to evaluate the impacts of sulfur trioxide (SO_3) injection on use of sorbent injection on a unit utilizing SO_3 injection for flue gas conditioning with use of a cold side ESP. The coal type utilized during testing was PRB coal. Turning off the SO_3 flue gas conditioning increased total mercury removal from 50% to 80% when using DARCO Hg-LH sorbent injection at an injection rate of 8 lb/MMacf. Greater than 90% control was observed with no SO_3 injection and injection of 5

lb/MMacf sorbent upstream of the air preheater. This testing demonstrated that activated carbon injection could be impacted by injection of SO_3, or high concentrations of SO_3, in the exhaust gas stream.

Great River Energy's Stanton Unit 1

Stanton Unit 1 utilizes a cold side ESP with use of PRB coal. Phase II field testing activities at the site investigated use of Sorbent Technologies Corporation (STC) brominated mercury sorbent B-PAC on the control of mercury. Over a 30-day long term test at Stanton Unit 1, 85% average total mercury removal was determined with use of B-PAC at an injection rate of 1.7 lb/MMacf.

DTE Energy's St. Clair Unit 1

DTE Energy's St. Clair Unit 1 utilizes a cold side ESP while combusting a blend of PRB and bituminous coal. During long term testing the unit burned a blend of 85% PRB and 15% bituminous coals, while evaluating use of Sorbent Technologies Corporation B-PAC sorbent. At St. Clair Unit 1 94% average total mercury removal was determined across the system at a sorbent injection rate of 3 lb/MMacf.

Luminant Power's Monticello Unit 3

Monticello Unit 3 utilizes a cold side ESP and wet scrubber (wet FGD) system, while burning a blend of Texas lignite and PRB coals. The facility has been involved in evaluations involving mercury oxidation catalysts, furnace injection of halogen salts to increase mercury oxidation and improve wet scrubber mercury removal, and field testing of wet scrubber additives for mercury control enhancement. Four oxidation catalysts were installed downstream of the ESP, including gold, SCR catalyst, regenerated Pd#1, and fresh Pd#1. Tests completed in April 2005 indicated total mercury capture across a pilot scale wet scrubber varied from 76% to 87%. This represented an approximate 70% increase in mercury capture above baseline conditions due to use of the catalysts. Evaluation of a wet scrubber additive, Degussa Corporation's TMT-15, to determine if the additive could precipitate absorbed mercury as a stable salt, minimizing mercury re-emissions across the wet scrubber and reducing wet scrubber wastewater mercury concentrations, was inconclusive at a pilot scale. Also, evaluation of furnace injection of halogen salts determined that total mercury removals varied from 65 to 92% (from a baseline of 10 to 40% mercury control) with increasing concentrations of calcium chloride and calcium bromide injected into the furnace.

Luminant Power's Big Brown Unit 2

Big Brown Unit 2 fires a blend of Texas lignite and PRB coal, and utilizes a cold side ESP and COHPAC fabric filter system. During the Phase II program the TOXECON configuration was evaluated at Big Brown Unit 2. During testing, the united fired a blend of 70% lignite and 30% PRB coal. The 30-day long term evaluation, conducted with enhanced Powdered Activated Carbon (PAC), demonstrated a total mercury capture average of 74% with a sorbent injection rate of 1.5 lb/MMacf.

PacifiCorp's Dave Johnston Unit 3

The Dave Johnston Unit 3 facility utilizes a cold side ESP while combusting PRB coal. The facility completed a 30-day long term study of mercury removal by utilizing the Mer-Cure process, a unique process where sorbent injection takes place in the high temperature region upstream of the air preheater and the process utilizes a proprietary processor to create uniform sorbent dispersion. Chemically treated Mer-Clean injection rates of 0.63 lb/MMacf achieved a total mercury removal of 92% across the system.

Entergy's Independence Unit 1

Long term field testing in 2005 at Independence Unit 1, a unit utilizing PRB coal and a cold side ESP, evaluated use of TOXECON II technology on control of mercury. TOXECON II technology injects sorbents directly into the downstream fields of an ESP, thereby reducing the amount of spent sorbent in collected ash. During field testing in 2005 about 60% average total mercury removal was observed with DARCO Hg-LH injection at 4 to 5 lb/MMacf. Subsequent field testing in 2007, with use of a new sorbent injection lance design, improved the average mercury removal efficiency to 90% while injecting 5.5 lb/MMacf of sorbent.

Midamerican's Louisa Unit 1

Louisa Unit 1 utilizes a hot side ESP while utilizing PRB coal. At this facility the impact on mercury removal of adding high temperature liquid sorbents (KNX) to the precombusted coal was evaluated. While the coal additive promoted mercury oxidation, the lack of SO_2/scrubber control lead to no increase in total mercury removal.

Midwestern Generation's Crawford Unit 7

Crawford Unit 7 utilizes a cold side ESP and PRB coal. Sorbent Technologies conducted a 30-day long term test at the site using a brominated concrete friendly sorbent (C-PAC). Total mercury removal at a sorbent injection rate of 4.6 lb/MMacf was found to be 81%. Fly ash samples collected during the evaluation indicated that the fly ash would be suitable for reuse in concrete production.

Midwestern Generation's Will County Unit 3

Will County Unit 3 utilizes a hot side ESP and PRB coal. Sorbent Technologies conducted filed testing at the facility using a brominated concrete friendly sorbent (C-PAC). Using a recently developed injection lance design, 73% mercury removal was achieved during parametric testing with C-PAC injection at 5 lb/MMacf. Mercury removal ranged from 60% to 73% over a six day continuous test.

Lower Colorado River Authority's Fayette Unit 3

Fayette Unit 3 utilizes a cold side ESP and wet scrubber, and utilizes PRB coal. The facility began a full scale field test in May 2008 of a gold based mercury oxidation catalyst. The results from this testing are not yet available. A Phase III evaluation of Mer-Cure was completed at Unit 3 in 2007. Activated carbon injection mercury capture was 80% with injection of 0.4 to 0.5 lb/MMacf sorbent, and increased to 90% mercury capture with use of 0.8 lb/MMacf Mer-Clean sorbent and eSorb, designed to preserve fly ash quality.

Kansas City Power & Light's Hawthorne Unit 5

Hawthorne Unit 5 utilizes an SCR, spray dryer absorber and fabric filter baghouse with use of PRB coal. During parametric testing on the unit greater than 90% total mercury capture was achieved with a sorbent enhancement additive added to the coal and injection of DARCO Hg-LH sorbent. Testing is still ongoing at the facility.

Rocky Mountain Power's Hardin Station

Hardin Station utilizes PRB coal and a spray dryer absorber and fabric filter emission controls. The facility is undergoing Phase III evaluations to evaluate the mercury removal performance, long term

emissions variability, and operation and maintenance of a PAC injection system for greater than 90% mercury control for a 10 to 12 month demonstration. Preliminary results indicate that lower PAC injection rates are required to maintain 90% removal at lower load conditions, possibly due to a higher fraction of oxidized mercury believed produced at the lower load.

NRG Texas Power LLC's Limestone Station Unit 1

Limestone Station Unit 1 utilizes a 70/30 blend of Texas lignite and PRB coal, while utilizing a cold side ESP and wet scrubber. Phase III testing at the site evaluated use of low ash impact sorbent injection and TOXECON II. B-PAC and DARCO Hg-LH sorbents performed similarly with around 90% total mercury removal at a sorbent injection rate of 2 to 3 lb/MMacf. Parametric trials with the unit utilizing 100% PRB coal and the TOXECON II system only achieved 60% total mercury removal. The study is still ongoing.

DOE/NETL Phase II and Phase III Results Evaluation

Although many of the DOE/NETL Phase II and Phase II studies have indicated removal efficiencies of 90% or greater for total mercury when utilizing PRB coals, the emission controls in use at the majority of these facilities did not include the full range of control technologies that will be in use at Plant Washington. Also, the document An Update on *DOE/NETL's Mercury Control Technology Field Testing Program (July 2008)* states the following;

"Although 30-day long term tests were conducted in Phase II, the test period was not sufficient to answer many fundamental questions about long term consistency of mercury removal and reliability of the system with plant processes."

The closing statements of the same technical paper indicate the following;

"while the results achieved during NETL's field tests met or exceeded program goals, only through experience gained during long-term continuous operation of these advanced technologies in a range of full-scale commercial applications will there actual costs and performance be determined."

Assessment of Control Technology

Therefore, although the Phase II and Phase III studies to date have promising results, the long term effective performance of these units is still unknown. The Plant Washington emissions control scheme consisting of an SCR, fabric filter baghouse, and a wet scrubber has been determined as an effective method for the control of mercury. These controls were determined to be the Best Demonstrated Technology (BDT) for control of mercury emissions by the USEPA in development of the NSPS and CAMR mercury regulations. Use of these control strategies, in conjunction with sorbent injection techniques, can be used to implement all of the previously discussed emission control techniques in the DOE/NETL studies and the control strategies discussed in Step 1 and Step 2 of this analysis.

While one study conducted indicated that blending of coals does improve mercury removal efficiency, other Phase II studies conducted at the Monroe and Laramie River facilities indicated that blending of PRB and bituminous coals, as would be done at Plant Washington, showed no marked improvement in total mercury capture with use over PRB coal alone. This is an important finding and supports the possibility that blending of PRB and Illinois #6 coals may not improve the mercury capture efficiency over use of PRB coal alone.

Studies at Labadie Unit 2 tend to indicate that sorbent injection effectiveness can be affected by the concentration of SO_3 present in the flue gas stream. Therefore, with a higher SO_3 duct concentration during consumption of a blend of PRB and bituminous coals (due to the higher sulfur bituminous coals), the additional SO_3 could affect the mercury capture efficiency with use of activated carbon. Additional concerns for Plant Washington include use of the wet scrubber for SO_2 control, and the possible re-emission of mercury through conversion of oxidized mercury back to elemental mercury across the wet scrubber.

The pollutant control strategy for Plant Washington, including use of SCR, a fabric filter baghouse, a wet scrubber, and sorbent injection for control of mercury emissions were determined to be the Best Available Control Technology (BACT) for control of mercury emissions. The current plan for the facility is use of powdered activated carbon for sorbent injection. Plant Washington will continue to monitor the development of alternative control strategies and their control effectiveness for control of mercury.

It is important to note that the mercury control strategies evaluated by the DOE/NETL testing programs are capable of implementation at Plant Washington, as the majority of the programs involve evaluation of

different types of materials (i.e. calcium chloride), different forms of powdered activated carbon (i.e. DARCO Hg-LH), use of coal additives (i.e. KNX), or use of mercury specific oxidation catalysts, which could be implemented at Plant Washington. Therefore, if in the future a sorbent material currently under evaluation, or a new sorbent not yet being evaluated, indicates superior performance to the powdered activated carbon planned for use at Plant Washington use of those new sorbents or mercury control techniques will be evaluated for use at Plant Washington. At this time, emission limits or technologies identified beyond the MACT floor are not warranted.

10.4.1.5 MACT Determination For Mercury

Table 10-9 indicates the determined MACT emission limits for Hg. Exhibit A contains calculations which detail how these values were derived.

Table 10-9 Proposed MACT Emission Limits for Mercury

Control Technology	Control Efficiency[1]	Proposed MACT Emission Limit
Multi-Pollutant controls; SCR, fabric filter baghouse, wet scrubber with activated carbon injection	84%	1.68×10^{-6} lb/MMBtu 15×10^{-6} lb/MW-hr annual average

[1] 84% reduction in uncontrolled mercury emissions from sub-bituminous (PRB) coals, based on the 95% UCL value derived from the USGS COALQUAL database for PRB coals of 0.11 ppm.

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It is unknown whether the intrinsic properties of bituminous coals that allow for higher mercury removal, would be effective in improving mercury removal over use of sub-bituminous coal alone. Several DOE/NETL case studies indicate that blending bituminous coals with PRB did not improve the mercury removal efficiency, and the overall efficiency is not linear with the blend proportions. Therefore, Plant Washington is proposing a singular limit for mercury equivalent to the use of 100% sub-bituminous coals (i.e. PRB coal).

10.4.2 Non-Mercury Metals MACT Determination for the Main Boiler

Non-mercury metals are emitted during fossil fuel combustion from trace amounts present in the fuel ash. During the combustion process, metals can be vaporized and later condensed or adsorbed by the fly ash suspended in the flue gas. As such, non-mercury metals are primarily emitted as PM from a pulverized

coal fired boiler. PM control technologies are effective in removing trace metals from fossil fuel combustion. Compliance testing conducted at the Wygen II facility in Wyoming in January 2008 clearly demonstrated that those non-mercury metal HAPs evaluated were removed at high efficiencies based on stack testing data (> 90%) through use of a fabric filter baghouse, and therefore existed in the particulate phase as PM. Testing at the Wygen II facility evaluated the removal efficiencies of non-mercury metal HAPs by conducting sampling both before and after facility control devices. Testing ports at the inlet duct to the dry scrubber vessel were used to provide inlet sampling measurements. Due to a lack of a sufficient sampling location prior to the SCR, the removal efficiencies indicated in the test report are indicative of the effective non-mercury metal HAPS removal efficiency across the dry scrubber and fabric filter baghouse, and the effects of SCR removal efficiency are not represented in the test report.

To provide an example of results found during the efficiency tests, testing at the Wygen II facility indicated an estimated lead removal efficiency of approximately 96 percent (average of three test runs) through use of a fabric filter baghouse. One of the three test runs estimated lead removal efficiency was greater than 99.5 percent. While this was only a single stack test, the results of this testing indicate that removal efficiencies greater than 95 percent can be achieved by a fabric filter baghouse, and that the primary form of lead in the flue gas stream will be in the particulate form. Therefore, the presumption that non-mercury metal HAPs will be effectively removed through use of PM control technologies is justified. An electronic copy of the efficiency test reports referenced for the Wygen II facility can be found in Exhibit E.

This MACT evaluation will focus on those non-mercury metals identified as priority metals through the *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report To Congress – USEPA (1998)*, including arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel. Although emissions of other trace metal HAPs (i.e., cobalt) are present in the exhaust gas stream, controlling the priority metal HAPs will also control these additional non-mercury metals.

Establishing a MACT Floor

10.4.2.1 Identification of Best Demonstrated Technology (BDT)

As discussed above, non-mercury metal HAPs will exist in the particulate phase in the exhaust flue gas stream at Plant Washington, and will therefore be effectively controlled by use of PM control technologies. Control technologies for the control of particulate matter (PM) emissions have been

identified and evaluated in the BACT analysis for PM in Section 4. The most effective control technologies evaluated were determined to be use of ESP and fabric filter baghouses. ESPs and fabric filter technology have similar removal capabilities of non-mercury metals, with additional benefit from use of a fabric filter with other HAPs (i.e., Hg). WESP technology is no more efficient in terms of filterable PM and metals removal than fabric filter technology, as both technologies achieve greater than 99 percent removal of PM based on USEPA fact sheets. Statements in both the USEPA fact sheets for WESP and fabric filter technologies refer to comparable removal efficiencies.

Therefore, the removal efficiencies are comparable between WESP and fabric filter technology. Since the collateral impacts of a WESP unit are significantly greater (i.e., wastewater stream), and no examples were found where a WESP unit was successfully applied to a large scale coal-fired electric utility boiler for control of metal emissions, fabric filter technology is considered the best demonstrated technology for non-mercury metal emission control.

The Best Demonstrated Technology (BDT) for control of non-mercury metal HAP emissions to be utilized at Plant Washington will include;

- Use of a fabric filter baghouse for control of particulate phase non-mercury metal HAPs
- Purchase of only washed bituminous (Illinois #6) coals

10.4.2.2 Evaluation of Information for the MACT Floor

It is technically feasible to use PM controls, and specifically a fabric filter baghouse, for control of non-mercury metal HAP emissions. The pollution control scheme at Plant Washington will include a fabric filter baghouse for PM emission control. Use of PM controls for the effective control of non-mercury metals have been identified, evaluated, and proposed by other sources. While other technologies may be technically feasible, research information indicates that use of PM controls are the Best Demonstrated Technology (BDT) for control of non-mercury metal HAP emissions.

Coal cleaning was also evaluated in this analysis. PRB coals are not typically washed due to the low ash content of PRB coals in comparison to other coals. Since coal washing is effective at removing ash and mineral content bound in rock and non-combustible material, and PRB coals are typically mined from thick coal seams with little overburden, rock, and non-combustible material, coal washing to improve the non-mercury metals content of PRB coals would not be highly effective. Therefore, coal washing for

PRB coals will no longer be considered in this analysis. However, coal washing will be conducted for the bituminous (Illinois #6 coals) used at Plant Washington.

Recent initial compliance testing conducted at the Wygen II facility in January 2008 included both inlet and outlet stack testing of non-mercury metal HAPs to determine the removal efficiency of the individual metal HAPs evaluated. A summary of the stack test efficiency results from the Wygen II facility can be found in Table 10-10.

Table 10-10 Wygen II Non-Mercury Metal HAPs Removal Efficiency Evaluation

Non-Mercury Metal HAP	Maximum Removal Efficiency[1]	Average Removal Efficiency
Antimony	93.4 %	93.0 %
Arsenic	99.3 %	99.1 %
Beryllium	96.6 %	96.1%
Cadmium	61.6 %	48.6 %
Chromium	99.5 %	98.7 %
Cobalt	99.2 %	99.1 %
Lead	99.5 %	95.9 %
Manganese	99.9 %	99.9 %
Nickel	99.6 %	99.2 %
Selenium	98.9 %	98.8 %

[1] Maximum removal efficiency indicated is the highest removal efficiency indicated for each of the three test runs of the removal efficiency evaluation. Testing conducted involved three test runs, with each test run of approximately 2-hrs resulting in 6 hrs of total testing. Boiler system operated at maximum load (99 of 100 MW) during stack testing. Unit controls include SCR, dry scrubber, and fabric filter baghouse.

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The results of the testing indicated in Table 10-10 demonstrate that the non-mercury metal HAPs present in the exhaust gas stream will exist primarily in the particulate matter phase. Estimated capture efficiencies for all non-mercury metal HAPs were greater than 90%, with some non-mercury metal HAPs removed at greater than 99%, with the exception of cadmium. The maximum cadmium removal efficiency found during testing was approximately 62%. It is unknown why cadmium was not collected as efficiently as the other non-mercury metal HAPs evaluated. The lower removal efficiency of cadmium does not appear related to the chemical properties of cadmium, as other metals evaluated during the compliance testing, such as thallium, achieved a slightly lower removal efficiency during testing (39.6%), while having a much lower vapor pressure and melting point than cadmium. Testing results may have been influenced by the limits of analysis detection, as one of the three runs from the cadmium analysis was found to be below the detection limit of the test, reported as less than 0.0006 lb/hr.

In the *Study of Hazardous Air Pollutant Emissions From Electric Utility Steam Generating Units – Final Report to Congress (February 1998 – Volume 1)*, the effective removal of PM control devices at the control of particulate phase HAPs (i.e. non-mercury metal HAPs) was evaluated. Section 2.4 of the referenced report evaluated HAP collection through PM control devices and indicated the following;

"As PM is formed during the combustion process and moves through the boiler system, HAPs can be condensed or adsorbed on particle surfaces. Although most particles are formed in the 3 micrometer to 50 micrometer range (on a mass basis), HAPs tend to concentrate preferentially on those around 0.3 micrometers. Because of this preferential concentration, high collection efficiency for fine particles is an important factor in evaluating HAP control from PM collection devices."

The report then went on to evaluate the typical mass removal efficiency, and removal efficiency at 0.3 micrometers, for mutlicyclones, ESPs, particulate scrubbers, and fabric filter baghouses. In Table 2-1 of the report, fabric filter baghouses were found to have superior removal efficiencies when compared to other controls, with a 99% to 99.8% removal efficiency at 0.3 micrometers. The report stated "Because of its high collection efficiency for small particles, the baghouse should be particularly effective for removing particles that have been enriched with HAPs."

Two facilities, the Walter Scott Jr. Energy Center (Unit 4), and Santee Cooper Cross Unit 3, have conducted compliance testing to demonstrate compliance with permitted facility limits for non-mercury metal HAPs. Santee Cooper Cross Unit 3 has permitted emission limits for antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium. The Walter Scott Jr. Energy Center, Unit 4, established an emission limit for Total Select Metals (TSM) of 1.04×10^{-4} lb/MMBtu, indicating that TSM was comprised of arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium. The following Table 10-11 provides a table indicating the permitted limits and tested values for the referenced facilities. The Walter Scott Jr. Energy Center Unit 4 facility utilized PRB coal during source testing, while Santee Cooper Cross Unit 3 utilized bituminous coal during testing. Both facilities utilized USEPA Method 29 during compliance testing.

Table 10-11 Coal-Fired Utility Units Emissions Testing Summary For Non Mercury Metals

Facility	Pollutant	Tested Emission Rate (lb/MMBtu)	Permit Limit (lb/MMBtu)
Walter Scott Jr. Energy Center Unit 4	Total Select Metals (TSM)	3.1×10^{-5}	1.04×10^{-4}
Santee Cooper Cross Unit 3	Antimony	$< 1.4 \times 10^{-7}$	7.0×10^{-7}
	Arsenic	2.5×10^{-6}	1.6×10^{-5}
	Beryllium	3.4×10^{-8}	8.44×10^{-7}
	Cadmium	7.5×10^{-7}	2.1×10^{-6}
	Chromium	3.5×10^{-6}	1.4×10^{-5}
	Cobalt	2.7×10^{-7}	4.0×10^{-6}
	Lead	2.2×10^{-6}	1.69×10^{-5}
	Manganese	4.7×10^{-5}	2.0×10^{-5}
	Nickel	6.3×10^{-6}	1.1×10^{-5}
	Selenium	3.2×10^{-5}	5.2×10^{-5}

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A review of documentation for the Walter Scott Jr. Energy Center, Unit 4 indicated the TSM limit selected was based on the maximum reported concentration of each metal of interest in coal analysis data submitted and a control efficiency of 99.6% for all metals of interest, except selenium, for which a removal efficiency of 90% was used. Using the 90% confidence levels derived from the USGS COALQUAL database for Plant Washington, for the non-mercury metal HAPs of interest, and utilizing the same removal efficiency estimates as the Walter Scott Jr. Energy Center, the comparable derived permit limit for TSM for Plant Washington would be 9.87×10^{-5} lb/MMBtu, slightly lower than the limit derived for the Walter Scott Jr. Energy Center.

Although testing results for both facilities indicated emissions of non-mercury metal HAPs well below permitted limits, caution should be used in utilizing the above data since both tests were single tests of short duration (3 1-hr. test runs). Therefore, the above indicated values would not be representative of long term performance. Also, it is important to note that the Santee Cooper Cross Unit 3 facility did not indicate compliance with the facility's permitted limit for manganese during compliance testing.

Table 10-12 indicates the findings of other Case-By-Case MACT evaluations for non-mercury metal HAPs. Historic 112(g) determinations, as the one performed for the Midamerican Energy Center Walter Scott Jr. Energy Center CBEC4 Boiler, included a limitation for total trace metals or for specific non-mercury metal HAPs. Recent 112(g) determinations have shifted to determinations of surrogate monitoring of filterable particulate matter (PM) for compliance demonstration for non-mercury metal HAPs.

Table 10-12 Coal-Fired Utility Units 112(g) Determinations for Non Mercury Metals

Facility	Non-Mercury Metal Control Strategy	Reduction	Non-Mercury Metal	Emission Limit
Thoroughbred Generating Station	ESP, WFGD, and WESP	98%	Beryllium	9.4×10^{-7} lb/MMBtu
			Lead	3.86×10^{-6} lb/MMBtu
Roundup Power Project	Fabric filter technology	95%	Arsenic	9.41×10^{-7} lb/MMBtu
			Beryllium	3×10^{-8} lb/MMBtu
			Cadmium	6.3×10^{-7} lb/MMBtu
			Chromium	2.79×10^{-6} lb/MMBtu
			Lead	3.36×10^{-6} lb/MMBtu
			Manganese	7.81×10^{-6} lb/MMBtu
			Nickel	2.73×10^{-6} lb/MMBtu
Midamerican Energy Company – Walter Scott Jr. Energy Center CBEC4 Boiler[1]	Fabric filter technology	Not indicated	Total Select Metals (TSM)	1.04×10^{-4} lb/MMBtu
Santee Cooper Cross Generating Station[1]	ESP	Not indicated	Antimony	7.0×10^{-7} lb/MMBtu
			Arsenic	1.6×10^{-5} lb/MMBtu
			Beryllium	8.44×10^{-7} lb/MMBtu
			Cadmium	2.1×10^{-6} lb/MMBtu
			Chromium	1.4×10^{-5} lb/MMbtu
			Cobalt	4.0×10^{-6} lb/MMBtu
			Lead	1.69×10^{-5} lb/MMBtu
			Manganese	2.0×10^{-5} lb/MMBtu
			Nickel	1.1×10^{-5} lb/MMBtu
			Selenium	5.2×10^{-5} lb/MMBtu

[1] Walter Scott Jr. Energy Center and Santee Cooper Cross Generating Station have conducted compliance testing with the indicated 112(g) limits for non-mercury metal HAPs. The 112(g) limit indicated for the Walter Scott Jr. Energy Center, Unit 4 was later removed in a permitting action in May 2007. Total Trace Metals for the Walter Scott Jr. Energy Center includes arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium.

Table 10-12 Coal-Fired Utility Units 112(g) Determinations for Non-Mercury Metals (Continued)

Facility	Non-Mercury Metal Control Strategy	Reduction	Non-Mercury Metal	Emission Limit
LS Power Longleaf	Fabric filter baghouse	99%	N/A	PM Surrogate Limit 0.10 lb/MMBtu Filterable PM Compliance Per CEM
John W Turk Jr	Fabric Filter Baghouse	99%	N/A	PM Surrogate Limit 0.012 lb/MMBtu Filterable PM_{10} 0.025 lb/MMBtu Total PM_{10} Compliance Per Annual 3-hr. Stack Test
Santee Cooper Pee Dee Generating Station	Fabric Filter Baghouse	99%	N/A	PM Surrogate Limit 0.012 lb/MMBtu Filterable PM_{10} Compliance Per Annual Stack Test and Bag Leak Detection System (BLDS)
Consumers Energy Karn/Weadock Generating Station	Fabric Filter Baghouse	99%	N/A	PM Surrogate Limit 0.012 lb/MMBtu Filterable PM Compliance Per Continuous Opacity Monitoring System (COMS), BLDS, or CEM
Cliffside Station Unit 6	Fabric Filter Baghouse	99%	N/A	PM Surrogate Limit 0.012 lb/MMBtu Filterable PM Compliance Per Periodic Stack Test (3-hr.)
Hunter Unit 4	Fabric Filter Baghouse	99%	N/A	PM Surrogate Limit 0.015 lb/MMBtu Filterable PM_{10} Compliance Per Stack Test (3-hr.)

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

The RBLC database was also reviewed to determine the lowest filterable PM emission limits which have demonstrated compliance. Three facilities, the TS Power Plant (Newmont), the Hardin Generating Station, and the Wygen II facility have demonstrated compliance with a filterable PM_{10} emission limit of 0.012 lb/MMBtu. It should be noted that this compliance testing was conducted per stack testing and not a CEM device. Each of these facilities utilizes a fabric filter baghouse and a dry scrubber for control of SO_2 emissions.

10.4.2.3 Determine the MACT Floor

A review of available information indicated that the Best Demonstrated Technology (BDT) for control of non-mercury metal HAPs was use of a fabric filter baghouse. Use of a fabric filter baghouse for control of non-mercury metals is representative of the best controlled similar source. Testing provided by the Wygen II facility, and EPA documentation reviewed, indicated that a removal efficiency of 99% for non-mercury metal HAPs was achievable and has been demonstrated in practice.

When evaluating an appropriate PM filterable limit for a surrogacy approach, three facilities have demonstrated compliance with a filterable PM limit of 0.012 lb/MMBtu. However, these facilities conducted only a short term compliance test (3 test runs of a maximum of 2 hours per each test run), and these results would not be indicative of long term performance of these units. At Plant Washington, compliance with the permitted filterable PM limit will be on a continuous basis, with the filterable PM limit established on a 24-hr. block average basis.

Also, these facilities were effectively demonstrating compliance following a fabric filter baghouse. At Plant Washington, the facility baghouse will be followed by a wet scrubber, since Plant Washington will utilize a wet scrubber for control of SO_2 emissions. On occasion the mist generated in the wet scrubber could introduce a small amount of filterable particulate into the flue gas stream. This phenomenon has been observed in wet scrubber units utilizing multiple spray levels for SO_2 control, where the mist eliminators in the wet scrubber were not as effective in eliminating mist at times depending on operating conditions. The wet scrubber would potentially add PM to the exhaust gas stream, not HAPs.

Even though Plant Washington will have a wet scrubber, a surrogate floor MACT limit of 0.012 lb/MMBtu is chosen for filterable PM. The MACT floor is also determined as use of a fabric filter baghouse, in conjunction with a removal efficiency of 99% for non-mercury metal HAPs. A review of

available information indicates that fabric filter technology for non-mercury metal HAPs control and a removal efficiency of 99 percent would be considered the best controlled similar source.

10.4.2.4 Beyond The Floor Analysis

No beyond the floor technologies were identified which would be more effective at non-mercury metal HAPs removal than use of a fabric filter baghouse. Alternate control technologies, such as agglomerators and electro-catalytic oxidation, were reviewed in the PM BACT analysis in Section 4.3 and were eliminated from consideration. There is no evidence that an additional control technology, in combination with a fabric filter baghouse, would improve the removal of non-mercury metal HAPs.

Proposed permit limits and permitting decisions were reviewed to determine if a PM filterable limit beyond the MACT floor would be achievable. Although two recent permitting decisions for the Desert Rock facility and Toquop Energy facility established filterable PM emission limits of 0.01 lb/MMBtu, achieving these filterable emission limits consistently, on a short term 24-hr block average, would be difficult with the control strategy currently employed for PM emissions at Plant Washington. Since those facilities identified with permit limits for filterable PM within the 0.012 lb/MMBtu range were not required to maintain continuous compliance of the limit, establishment of a filterable PM limit below 0.012 lb/MMBtu has not yet demonstrated compliance (in practice) on a long term basis outside of a single stack test. Based on an uncontrolled emission rate of fly ash (PM) of 6.42 lb/MMBtu for PRB coal, derived from coal design data ash content of PRB coal, a filterable PM limit of 0.012 lb/MMBtu would represent a removal efficiency of approximately 99.8% of filterable PM, while an emission limit of 0.01 lb/MMBtu would represent essentially the same removal efficiency. At such low outlet permitted levels, a reduction in filterable PM would lead to only a minimal additional reduction in the estimated PM removal efficiency.

While PM CEMS are currently proposed for facilities such as the Desert Rock and Longleaf facilities with a low filterable PM limit (0.01 lb/MMBtu), achieving such low limits with the control strategy planned for Plant Washington, on a long term consistent basis, has not yet been demonstrated. Therefore, selection of a lower filterable PM limit for surrogate monitoring is determined to be infeasible at this time.

10.4.2.5 MACT Determination For Non-Mercury Metal HAPs

Based on a thorough review of available information in accordance with 40 CFR 63.43, using a fabric filter baghouse with a control efficiency for non-mercury metal HAPs of 99 percent is considered MACT. Also a filterable PM emission limit of 0.012 lb/MMBtu is also considered as a surrogate limit. This control strategy and removal efficiency is determined to be MACT for reducing emissions of non-mercury metal HAPs.

Section 10.3 discusses the methodologies for calculating the uncontrolled and controlled non-mercury metal HAP emissions for the facility's main boiler. In reviewing documentation for 112(g) determinations for non-mercury metal HAPs to date, a wide variety of methods were used to estimate the uncontrolled non-mercury metal HAP emissions from their facilities. Methodologies used included uncontrolled emissions estimated from specific coal quality data for design coals planned for the site, AP-42 emission factors, and the USGS COALQUAL database for the specific coal to be used (i.e., PRB) at the facility.

For this analysis, the uncontrolled emissions of non-mercury metals were estimated based on analysis data from the USGS COALQUAL database for use of 100 percent PRB and a 50/50 coal blend of PRB and Illinois #6 coals. The 90 percent confidence level ppm concentration value was determined to account for variability in the coal that could be received at the Plant Washington facility. Analysis data are included in the coal quality data found in Exhibit A of this report. The analysis data summary used to determine facility emission limits can be found in Exhibit A of this report.

Exhibit A also includes calculations indicating the uncontrolled emissions of the trace metal HAPs of interest. Coal quality data for the design coals can be found in Exhibit A of this report. Controlled emissions for non-mercury metal HAPs were determined by applying a control efficiency of 99 percent to uncontrolled emissions determined in Exhibit A. Uncontrolled emission estimates for non-mercury metal HAPs indicated in Table 10-13 are based on the 90% confidence level metals concentrations derived for the non-mercury metals of interest from the USGS COALQUAL database.

Emission estimates derived for non-mercury metals for both use of 100 percent PRB coal and the 50/50 blend (by weight) of PRB and Illinois #6 coals is shown in Table 10-13. The proposed MACT emission limit for non-mercury metals can be found in Table 10-14.

Table 10-13 Uncontrolled and Controlled Emissions Estimates for Non Mercury Metals

Pollutant	Uncontrolled Emission (lb/MMBtu) PRB Coal	Uncontrolled Emission (lb/MMBtu) 50/50 Coal Blend	Control Efficiency	Controlled Emission (lb/MMBtu) PRB Coal[1]	Controlled Emissions (lb/MMBtu) 50/50 Coal Blend[1]
Antimony	1.71×10^{-4}	1.75×10^{-4}	99%	1.71×10^{-6}	1.75×10^{-6}
Arsenic	3.77×10^{-3}	2.71×10^{-3}	99%	3.77×10^{-5}	2.71×10^{-5}
Beryllium	2.11×10^{-4}	3.43×10^{-4}	99%	2.11×10^{-6}	3.43×10^{-6}
Cadmium	3.53×10^{-5}	6.45×10^{-4}	99%	3.53×10^{-7}	6.45×10^{-6}
Chromium	1.53×10^{-3}	1.89×10^{-3}	99%	1.53×10^{-5}	1.89×10^{-5}
Cobalt	4.86×10^{-4}	4.62×10^{-4}	99%	4.86×10^{-6}	4.62×10^{-6}
Lead	1.01×10^{-3}	1.60×10^{-3}	99%	1.01×10^{-5}	1.60×10^{-5}
Manganese	1.13×10^{-2}	9.70×10^{-3}	99%	1.13×10^{-4}	9.70×10^{-5}
Nickel	1.46×10^{-3}	1.98×10^{-3}	99%	1.46×10^{-5}	1.98×10^{-5}
Selenium	2.15×10^{-4}	2.65×10^{-4}	99%	2.15×10^{-6}	2.65×10^{-6}

[1] Please note that uncontrolled and controlled emission estimates are based on the 90% confidence level values derived from trace metal concentration values from the COALQUAL database.

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

Table 10-14 Proposed MACT Emission Limit For Non-Mercury Metal HAPs

Pollutant	Proposed MACT Emission Limit
Non-Mercury Metal HAPs	Surrogate Approach PM Filterable 0.012 lb/MMBtu 24-hr. block average (CEM)

Prepared by: PBS 6/18/08
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The proposed compliance determination for non-mercury metal HAPs includes surrogate monitoring of filterable PM using a CEM device. The proposed filterable PM limit for Plant Washington is 0.012 lb/MMBtu on a 24-hour block average basis, using a PM CEM device to demonstrate compliance. Compliance with these limitations is also chosen as a surrogate for emissions of radionuclides, which is emitted in particulate form from coal combustion sources and is a priority HAP of concern identified in the *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final RTC – USEPA (1998)*.

Surrogate monitoring of filterable PM for control of non-mercury metal HAPs is consistent with the approach evaluated by the EPA and other state permitting authorities currently reviewing Case-By-Case MACT determinations. The recent Notice of MACT Approval issued by South Carolina DHEC in

September 2008 for the Santee Cooper Pee Dee Generating Station determined that surrogate monitoring of PM emissions was appropriate as a surrogate for non-mercury metal HAPs. The United States Court of Appeals, D.C. Circuit has affirmed the use of surrogate PM monitoring of metal HAPs in prior judgments, including *National Lime Association v. EPA*. In *National Lime*, the D.C. Circuit confirmed that "EPA may use a surrogate to regulate pollutants if it is 'reasonable' to do so." The D.C. Circuit indicated that it was 'reasonable' to utilize PM as a surrogate for HAPs if a 3 part analysis was met. The criteria indicated included if the HAP metals are present in PM, if the PM control technology indiscriminately captures HAP metals along with PM, and PM controls are the means by which facilities achieve reductions in HAP metal emissions. The EPA has responded to public comments regarding the surrogacy approach indicating that the Clean Air Act "does not prohibit us from using an appropriate surrogate pollutant for individual HAP species to confirm the proper use of MACT." Therefore, use of surrogate monitoring of filterable PM for non-mercury metal HAPs is considered justified.

10.4.3 Acid Gases (HCl and HF) MACT Determination for the Main Boiler

The acid gases HCl and HF represent most HAP emissions from the facility's main boiler. HCl and HF emissions result from fossil fuel combustion through the oxidation of fluorine and chlorine present in the fuel source. HCl and HF can be controlled by acid gas scrubbing systems, including those used to control SO_2 emissions. Based on the *Mercury Study Report To Congress – USEPA (1997)*, HCl and HF emissions are efficiently controlled by SO_2 control technologies. Therefore, the determination of MACT for HCl and HF are based on a determination of the best available SO_2 control technology applicable, an emission limit based on the appropriate removal efficiency for HCl and HF, and the fluorine and chlorine content of coals (as determined in the COALQUAL database information found in Exhibit A of this report).

Establishing a MACT Floor

10.4.3.1 Identification of Best Demonstrated Technology (BDT)

Control technologies for the control of HF, which also control emissions of HCl, have been identified and evaluated in the BACT analysis for HF in Section 4.

A dry scrubber and a wet scrubber are identified as the most effective control technologies for the reduction of emissions of the acid gases HCl and HF. Recent data in the USEPA RBLC and 112(g)

determinations indicate that the removal efficiency of acid gases for both dry scrubbers and wet scrubbers could be 95 percent or more. In 1999, the Maryland Department of Natural Resources funded a study to evaluate the emissions of HCl from coal-fired electric utility boilers in the State of Maryland. This study indicated that both wet scrubbers and dry scrubbers could remove greater than 90 percent of the HCl emissions from coal-fired boilers.

Based on data provided by an engineering design company and an evaluation of available research data, an assumption was made that the removal efficiency for the acid gases HF and HCl using a wet scrubber would be the same as the removal efficiency for SO_2 emissions of 98.5 percent.

Compliance testing conducted at the Wygen II facility in January 2008, a facility utilizing a dry scrubber and fabric filter baghouse while combusting PRB coal, included inlet and outlet measurement sampling of HCl and HF providing estimated removal efficiencies of HCl and HF for three test runs of one-hour duration each. Results of the removal efficiency analysis indicated a three test run average of 49% removal of HF, with a maximum removal efficiency during testing of approximately 90% removal of HF. Results also indicated a three test run average of approximately 58% removal of HCl, with a maximum removal efficiency during testing of approximately 61%. It is important to note, however, that removal efficiency evaluations at the Wygen II facility were only representative of the three hours of data gathered, and not representative of long term performance. Also, removal efficiency evaluations for HF for two of the three test runs were affected by the low HF concentrations in the flue gas stream, leading to removal efficiencies of > 24%, and > 34%. This was due to the inlet and outlet concentrations for HF for two of the three runs being below the detection limits for HF. Therefore, the removal efficiencies determined for HF during testing may be underestimated.

Based on a review of available documentation, including a review of efficiency testing results for HF and HCl with use of a dry scrubber, and discussions with an engineering design company regarding the capable removal efficiencies for HF and HCl for a wet scrubber, a wet scrubber is considered the most effective control device for control of the acid gases HF and HCl. Therefore, the Best Demonstrated Technology (BDT) for control of the acid gases HF and HCl is determined as;

- Use of a wet scrubber

10.4.3.2 Evaluation of Information for the MACT Floor

It is technically feasible to use SO_2 controls, and specifically a wet scrubber, for control of the HAP acid gases HF and HCl. The pollution control scheme at Plant Washington will include a wet scrubber for control of emissions. Use of SO_2 control devices, including wet scrubbers, have been identified, evaluated, and proposed by other sources. While other technologies may be technically feasible, research information indicates that use of PM controls are the Best Demonstrated Technology (BDT) for control of non-mercury metal HAP emissions.

Two facilities, the Walter Scott Jr. Energy Center (Unit 4) and the Santee Cooper Cross Generating Station (Unit 3) have recently conducted compliance testing with 112(g) limits for HF and HCl. The Walter Scott Jr. Energy Center (Unit 4) is a facility utilizing SCR, dry scrubber, and fabric filter baghouse while utilizing PRB coal. The Santee Cooper Cross Generating Station, Unit 3, is a facility utilizing SCR, an ESP, and a wet scrubber while utilizing bituminous coal. A summary of the stack testing results for HF and HCl from these facilities is provided in Table 10-15.

Table 10-15 Coal Fired Utility Units Emissions Testing Summary for Acid Gases HCl and HF

Facility	Pollutant	Emission Test Result	Emission Limit
Walter Scott Jr. Energy Center Unit 4	HF	2.9×10^{-5} lb/MMBtu	9.0×10^{-4} lb/MMBtu
	HCl	5.77×10^{-5} lb/MMBtu	2.9×10^{-3} lb/MMBtu
Santee Cooper Cross Generating Station Unit 3	HF	4.15×10^{-5} lb/MMBtu	3.0×10^{-4} lb/MMBtu
	HCl	2.77×10^{-4} lb/MMBtu	2.4×10^{-3} lb/MMBtu

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Testing at the Walter Scott Jr. Energy Center, Unit 4 utilized USEPA Method 13A for fluoride emissions (as HF), and USEPA Method 26A for HCl. Testing at the Santee Cooper Cross facility, Unit 3, utilized USEPA Method 26A for HF and HCl emissions. Although testing results for both facilities indicated emissions well below permitted limits, caution should be used in utilizing the above data since both tests were single tests of short duration (3 one hour test runs). Therefore, the above indicated values would not be representative of long term performance.

Table 10-16 provides data for coal fired utility unit 112(g) determinations for acid gases. Section 4.3 provides BACT determination data for HF from the USEPA RBLC database.

Table 10-16 Coal Fired Utility Units 112(g) Determinations for Acid Gases HCl and HF

Facility	Acid Gas Control Strategy	HCl/HF Reduction	Emission Limit[2]
Thoroughbred Generating Station	WFGD and WESP	98%	HF: 1.59 x 10^{-4} lb/MMBtu HCl: no limit
Roundup Power Project	Dry scrubber and fabric filter	90%	HF: 3.2 x 10^{-4} lb/MMBtu
Midamerican Energy Company – Walter Scott Jr. Energy Center CBEC4 Boiler[1]	Dry scrubber and fabric filter	96%	HF: 9 x 10^{-4} lb/MMBtu HCl: 2.9 x 10^{-3} lb/MMBtu
Santee Cooper Cross Generating Station [1]	WFGD	95%	HF: 3 x 10^{-4} lb/MMBtu HCl: 2.4 x 10^{-3} lb/MMBtu
LS Power Longleaf	Dry Scrubber and Fabric Filter	Note Indicated 98% to 99% Estimated Based on Uncontrolled and Controlled Rates	HF: 2.0x 10^{-4} lb/MMBtu HCl: 6.0 x 10^{-3} lb/MMBtu PRB coal 2.4 x 10^{-3} lb/MMBtu CAPP coal
Tuscon Electric Power Company Springerville Generating Station [1]	Dry scrubber and fabric filter	Not Indicated	HF: 4.4 x 10^{-4} lb/MMBtu HCl: no limit
Cliffside Station Unit 6	Dry scrubber and fabric filter	Not Indicated	Surrogate Limit For HF and HCl SO_2 0.12 lb/MMBtu 30-Day Rolling Avg.
Santee Cooper Pee Dee Generating Station	Wet Scrubber	Not Indicated	HF: 3.4 x 10^{-4} lb/MMBtu HCl: 2.72 x 10-3 lb/MMBtu Identified Limits For Initial Compliance – Continued Compliance Through Surrogate Monitoring SO2 0.12 lb/MMBtu 30-Day Rolling Avg.
Consumers Energy Karn/Weadock Generating Station	Wet Scrubber	97%	HF: 3.0 x 10^{-4} lb/MMBtu HCl: 4.0 x 10^{-3} lb/MMBtu
John W. Turk Jr.	Dry scrubber and fabric filter	Not Indicated	HF: 2.0 x 10^{-4} lb/MMBtu HCl: 6.0 x 10^{-4} lb/MMBtu

[1] Indicated facilities have conducted compliance demonstrations for the indicated limits.
[2] Emission limits based on a stack test (3-hr. average) unless otherwise noted.

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10.4.3.3 Determination of the MACT Floor

Based on a thorough review of the data available, use of a wet scrubber for control of the acid gases HF and HCl with a removal efficiency of 98.5% is determined to be representative of the best controlled similar source, and the MACT floor for the control of the acid gases HF and HCl.

10.4.3.4 Beyond the Floor Analysis

Available literature has indicated that use of a wet electrostatic precipitator (WESP) has historically been used to control acid mists in the metals industry, so there have been a few instances of a WESP being installed on a power plant for this purpose. EPRI pilot studies of WESP operation have indicated that 35%/45% of the HCl/HF was removed.

The cost of a full scale WESP unit was evaluated in Section 4.3 of this application, and it was found that a WESP unit is not economically feasible for the facility due to the high capital cost (approximately $290 million) for a unit of the size necessary for Plant Washington. Considering the high costs and relatively low removal efficiencies, a WESP unit is considered ineffective for this application and a wet scrubber has been found to be the best demonstrated technology for control of HF and HCl emissions.

10.4.3.5 MACT Determination for HF and HCl Emissions

Based on a thorough review of the available information in accordance with 40 CFR 63.43, use of a wet scrubber (WFGD system) with a removal efficiency of 98.5 percent for HCl and HF is determined as the MACT floor. Coal cleaning will also be conducted for the Illinois #6 coals planned for use at the facility. This control strategy and removal efficiency is determined to be MACT for reducing emissions of the acid gases HCl and HF.

Emissions calculations, shown in Exhibit A and described in Section 10.3 of this report, indicate the methodologies used to calculate the uncontrolled and controlled HCl and HF emissions for the facility's main boiler. For this analysis, the uncontrolled emissions of HCl and HF were estimated from analysis data obtained from fluorine and chlorine concentrations from the USGS COALQUAL database and coal design basis data, included in Exhibit A of this report. A summary of the analysis data is in Exhibit A of this report.

Emissions calculations indicating the uncontrolled emissions of HCl and HF can be found in Exhibit A of this report. Coal quality data used in this evaluation can also be found in Exhibit A of this report. Controlled emissions were determined by applying a control efficiency of 98.5 percent to uncontrolled emissions determined in Exhibit A.

The proposed MACT emission limits for the acid gases of concern are indicated in Table 10-17.

Table 10-17 Proposed MACT Emission Limits for Acid Gases HF and HCl

Pollutant	Uncontrolled Emission (lb/MMBtu) PRB Coal	Uncontrolled Emission (lb/MMBtu) 50/50 Coal Blend	Control Efficiency	Proposed MACT Emission Limit (lb/MMBtu) PRB Coal[1]	Proposed MACT Emission Limit (lb/MMBtu) 50/50 Coal Blend[1]
HF	1.78×10^{-2}	1.42×10^{-2}	98.5%	2.68×10^{-4}	
HCl	2.15×10^{-2}	1.93×10^{-1}	98.5%	3.22×10^{-4}	2.89×10^{-3}

[1] Please note that uncontrolled and controlled emission estimates are based on the 90% confidence level values derived from fluorine and chlorine concentration values from the COALQUAL database, with the exception of chlorine concentrations for Illinois #6 coals. Chlorine concentrations of Illinois #6 coals, used in derivation of the uncontrolled emissions permit limit for the 50/50 blend for HCl, based on project design data.

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Compliance with the emission limits will be determined through stack testing (three hour average) using USEPA Methods 13A and/or 26A. Continuous compliance can be determined using SO_2 as a surrogate monitoring compound for compliance with the applicable HF and HCl emission limits, and pH monitoring of the facility wet scrubber.

10.4.4 Organic HAPs MACT Determination For The Main Boiler

Volatile organic compounds (VOC), Carbon Monoxide (CO), and organic HAP emissions result from incomplete combustion of fuel. Because organic HAPs are emitted as VOC from the main facility boiler, and VOC emissions result from incomplete combustion of the fuel, carbon monoxide (CO) emissions can be used as a surrogate for the MACT analysis. CO is a more effective surrogate than VOC emissions since VOC emissions will be monitored on a continuous basis, where VOC emissions would be monitored during a stack test (3-hr. average). CO and organic HAPs can be controlled in a combustion system by providing adequate fuel residence time in the combustion chamber and maintaining a high temperature and sufficient oxygen in the combustion zone to ensure complete combustion. Low levels of CO, VOC, and organic HAP emissions are expected from properly operated pulverized coal fired boilers.

Establishing a MACT Floor

10.4.4.1 Identification of Best Demonstrated Technology (BDT)

The review of available information identified the following control technologies for organic HAPs, which correlate to VOC and CO emission controls.

Combustion Controls

By optimizing the combustion process, VOC and CO emissions would be reduced. This process would also reduce organic HAP emissions from the main boiler. CO, VOC, and organic HAP formation will be limited through a properly designed combustion chamber with adequate controls to regulate the combustion process. Important factors in proper combustion include proper fuel residence time, proper air to fuel ratios in the combustion chamber, and consistent proper temperatures in the combustion chamber. Proper operation and maintenance of fuel feed systems, fans, system dampers, and other equipment will assist in reducing CO, VOC, and organic HAP emissions. For additional information please refer to the CO and VOC BACT analyses in Section 4.3.3 and 4.3.4.

Add-On Controls

No effective add-on controls currently exist for CO or VOC emissions from a coal-fired utility boiler. Afterburners, and other control devices such as catalytic oxidation or flares used for destruction of organic compounds, have not been demonstrated in pulverized coal boiler units. Any such control devices would cause negative secondary environmental impacts, such as higher NO_x emissions. Good combustion controls are widely recognized as the effective control for CO, VOC, and organic HAPs emissions for pulverized coal fired boilers. For additional information please refer to the CO and VOC BACT analyses in Section 4.3.3 and 4.3.4.

10.4.4.2 Evaluation of Information for the MACT Floor and Determination of the MACT Floor

Plant Washington will use combustion controls and proper boiler design to control organic HAP emissions, emitted as VOC emissions, from the main boiler. A review of available information, including 112(g) determinations conducted for other sources, and review of BACT determinations and information from the RACT/BACT/LAER Clearinghouse, indicated good combustion practices (GCP, or good combustion controls) and proper boiler design is representative of the best controlled similar sources for organic HAP emissions, and is determined to be the MACT floor. Information is not readily available

regarding the control efficiency of organic HAPs (and VOC emissions) using GCP and proper boiler design, as the controls prevent the formation of the pollutants, making an estimate of uncontrolled emissions difficult to accurately determine. As a result, an estimate of uncontrolled organic HAP emissions (as VOC), and the removal efficiency using the proposed controls cannot be determined.

The following Table 10-18 is a listing of 112(g) determinations for organic HAPs for similar sources. Recent BACT determinations for a surrogate monitoring pollutant for organic HAPs, CO, can be found in the BACT analysis for CO emissions for the main boiler in Section 4.3.3.

Table 10-18 Coal-Fired Utility Units 112(g) Determinations for Organic HAPs

Facility	Organic HAPs Control Strategy	Emission Limit
Cliffside Station Unit 6	Good Combustion Controls	Surrogate CO Monitoring 0.10 lb/MMBtu Compliance Determination Per Stack Test
Consumers Energy Karn/Weadock Generating Station	Good Combustion Controls	Surrogate CO Monitoring 0.125 lb/MMBtu 30-Day Rolling Avg.
John W Turk Jr.	Good Combustion Controls	Surrogate VOC Monitoring 0.0025 lb/MMBtu 3-hr. Avg.
Santee Cooper Cross Generating Station[1]	Good Combustion Controls	Surrogate CO and VOC Monitoring CO: 0.16 lb/MMBtu VOC: 0.0024 lb/MMBtu Compliance Determination Per Stack Test
Midamerican Energy Company – Walter Scott Jr. Energy Center CBEC4 Boiler[1]	Good Combustion Controls	Surrogate CO Monitoring 0.154 lb/MMBtu 24-hr. block average (180 ppm)
Roundup Power Project	Good Combustion Controls	Surrogate CO Monitoring 0.15 lb/MMBtu
Santee Cooper Pee Dee Generating Station	Good Combustion Controls	Surrogate CO Monitoring 0.15 lb/MMBtu 30-Day Rolling Avg.

[1] Indicated facilities have conducted compliance demonstrations for the indicated limits.

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The organic HAP emissions from the main boiler are primarily dependent on the organic content of the fuel and what is formed in the combustion chamber. In either case, the level of organic HAP emissions is directly dependent on achieving good combustion within the combustion chamber. The objective of good combustion is to release all the energy in the fuel while minimizing heat losses from combustion imperfections and excess air. This is achieved through the proper combination of the fuel and air mixture. Too little air-to-fuel ratio causes some of the fuel to be only partially combusted. Too high of an air-to-fuel ratio causes abnormally high NO_x emissions, which reduces flame temperature where again incomplete combustion occurs. There are three main factors (known as the three T's) that promote good combustion:

1. **Time**: Sufficient residence time in the combustion chamber to allow complete combustion
2. **Temperature:** the temperature inside the combustion chamber must be high enough to combust all the fuel
3. **Turbulence:** in the combustion chamber, turbulence must be such that air and fuel are well mixed so that no areas are oxygen starved

GCP for boilers could be described as several general work practices and design principles. Some of these considered by USEPA in developing the MACT rules are:

- Providing adequate excess air with use of oxygen CEM and feedback air input control
- Providing adequate fuel/air mixing
- Homogenizing fuels (by blending or size reduction) to control combustion upsets due to high or low volatile content wastes
- Regulating waste and air feed rates to ensure proper combustion temperature and residence time
- Characterizing waste before burning for combustion-related composition (including parameters such as heating value, volatile content, liquid waste viscosity, etc.)
- Ensuring the source is operated by qualified, experienced operators
- Periodic inspection and maintenance of combustion system components such as burners, fuel and air supply lines, injection nozzles, etc.

In preparation of the Industrial Boiler MACT (Subpart DDDDD), USEPA considered these factors and concluded there are so many interdependent parameters that affect combustion efficiency that they were not able to quantify GCP. They concluded in the preamble of this rule that "consequently, any uniform

requirements or set of work practices that would meaningfully reflect the use of good combustion practices, or that could be meaningfully implemented across any subcategory of boilers and process heaters could not be identified." Additionally, few of the GCPs have been documented to reduce organic HAP emissions, and they could not be considered in the MACT analysis.

USEPA chose to use an indicator parameter to measure the degree of combustion. CO, the parameter chosen by USEPA, can be measured in stack gases and continuously monitored and recorded. Complete combustion of carbon results in carbon dioxide, so the presence of CO indicates incomplete combustion.

USEPA, in developing the Industrial Boiler MACT, chose a level of 400 ppm CO as a level that would correspond to GCP. However, USEPA was preparing a regulation that encompassed all solid fuel boilers, which included wood-fired boilers. Wood-fired boilers generally emit more CO than a comparable coal-fired boiler, so that standard may be unnecessarily high. As a comparison, other similar MACT rules were reviewed. The Hazardous Waste Combustor (HWC) MACT in 40 CFR Parts 63.261 and 270 also uses CO as an indicator parameter for complete combustion. In that regulation, the level of CO is limited to 100 ppm. USEPA bases its conclusion for this level on the following assessment:

> We found that, in the vast majority of DRE test conditions, if a unit operated with carbon monoxide levels of less than 100 ppmv [parts per million by volume] and hydrocarbon emissions of less than 10 ppmv, the unit met or surpassed four-nines DRE. In some test conditions, units emitted carbon monoxide and hydrocarbons at levels less than 100 and 10 ppmv respectively, but failed to meet four-nines DRE. Most failed test conditions were either due to questionable test results or faulty test design.
>
> Taken from Draft Technical Support Document for HWC MACT Standards (NODA), Volume II: Evaluation of CO/HC and DRE Database, April 1997.

Proper design of the coal pulverizers, burners, over-fire-air and furnace geometry will enable the unit to achieve GCP. The operators will continuously monitor the fuel being fed to the boiler and the excess air to ensure that CO emissions are 100 ppm or less at 6 percent excess oxygen. This limit approximately corresponds to the proposed BACT limit for CO of 0.10 lb/MMBtu, which will be attained on a 30-day rolling average basis. CO will be measured using a CEM and recorded into the plants digital control system that will continuously update the 30-day rolling average calculation.

In the HWC MACT, USEPA includes the criteria that hydrocarbon emissions should be less than ten times the CO emissions. The VOC proposed BACT level is 0.0030 lb/MMBtu versus the CO level of 0.10 lb/MMBtu, which is a ratio of over 40 times less. The VOC is well below the 10 ppm specified in

the HWC MACT, so meeting the CO limit will likely ensure meeting the VOC emission limit. Therefore, hydrocarbon emissions will not be monitored since such monitors are unreliable and must be tuned to specific compounds. Monitoring CO will ensure GCP (good combustion controls). VOC emissions will be measured via a stack test and compared to the continuous CO readings at the time of the test.

The MACT floor for organic HAPs is determined to be good combustion controls, with surrogate CO monitoring with a limit of 0.10 lb/MMBtu on a 30-day rolling average basis, equivalent to 100 ppm at 6 percent excess oxygen. CO will be monitored using a CEM device.

10.4.4.3 Beyond the Floor Analysis

No controls beyond use of good combustion practices were identified for control of organic HAP emissions. Use of oxidation catalysts, discussed in Section 4.3.3, were determined infeasible due to system conditions. No add-on control technologies, such as flares or catalyst units, are technically feasible for Plant Washington. A review of recent permit limits in the RBLC database and in 112(g) permit limitations indicated that the proposed CO surrogate monitoring limit of 0.10 lb/MMBtu on a 30-day rolling average basis (100 ppm) is the most stringent limit currently proposed. Therefore, any organic HAP emissions control beyond the MACT floor is determined to be infeasible.

10.4.4.4 MACT Determination For Organic HAPs

MACT for organic HAPs is determined to be good combustion practices, with surrogate CO monitoring with a limit of 0.10 lb/MMBtu on a 30-day rolling average basis, equivalent to 100 ppm at 6 percent excess oxygen. CO will be monitored using a CEM device.

Compliance with the above limitations is also chosen as a surrogate for emissions of dioxins, acrolein, and formaldehyde, which are emitted as organic HAPs from coal combustion sources and are priority HAPs of concern identified in the *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report To Congress – USEPA (1998)*.

10.4.5 Main Boiler Case-By-Case MACT Summary

Table 10-19 summarizes the Case-By-Case MACT determinations for the main boiler at the facility.

Table 10-19 Case By Case MACT Evaluation Summary for The Main Boiler

Pollutant	Control Technology	Control Efficiency	Proposed MACT Emission Limit (lb/MMBtu) PRB Coal	Proposed MACT Emission Limit (lb/MMBtu) 50/50 Coal Blend
Mercury	Multi-pollutant controls; SCR, fabric filter baghouse, wet scrubber, with activated carbon injection	84%	1.68×10^{-6} lb/MMBtu 15×10^{-6} lb/MW-hr Annual average	
Non-Mercury Metal HAPs	Fabric filter baghouse	99%	Surrogate CEM Monitoring Facility PM filterable emissions limit 0.012 lb/MMBtu 24-hr average	
Organic HAPs	Engineering combustion controls (Good Combustion Practices)	---	Surrogate CEM monitoring Facility BACT CO emission limit 0.10 lb/MMBtu 30-day rolling average (100 ppm)	
HF	Wet scrubber	98.5%	2.68×10^{-4} 3-hr. avg.	
HCl	Wet scrubber	98.5%	3.23×10^{-4} 3-hr. avg.	2.89×10^{-3} 3-hr. avg.

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

The compliance strategy for the emissions limits proposed for the main boiler is described in the following section.

10.4.5.1 Main Boiler Summary

Mercury Emissions

The control strategy for Hg emissions includes multi-pollutant controls using sorbent injection (activated carbon injection) with a fabric filter baghouse, a wet scrubber, and a SCR for Hg oxidation.

Compliance with the limits indicated in Table 10-19 will be achieved using a Hg CEM system.

Non-Mercury Metal Emissions

The control strategy for non-mercury metal emissions includes a fabric filter baghouse.

The proposed compliance determination for the limits in Table 10-19 would include the facility filterable PM limit as a surrogate of 0.012 lb/MMBtu, which would be achieved using CEM on a 24-hour block average. Compliance with the proposed limitations is also chosen as a surrogate for emissions of radionuclides, which are emitted in particulate form from coal combustion sources and are a priority HAP

of concern identified in the *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final RTC – USEPA (1998).*

Organic HAPs

The control strategy for organic HAPs involves engineering combustion controls (good combustion practices).

Compliance with MACT for organic HAPs will be determined through surrogate compliance with a CO CEM system with an emission limit of 0.10 lb/MMBtu CO on a 30-day rolling average basis. Compliance with this limit is also chosen as a surrogate for emissions of dioxins, acrolein, and formaldehyde which are emitted as organic HAPs from coal combustion sources and are priority HAPs of concern identified in the *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report To Congress – USEPA (1998).*

Acid Gas Emissions – HF and HCl

The control strategy for the acid gases HF and HCl involve using a wet limestone scrubber with a removal efficiency of 98.5% for the acid gas HAPs HF and HCl.

Compliance with the emission limits for HF and HCl will be through stack testing using USEPA Methods 13A and/or 26A. Ongoing compliance will be determined by using SO_2 as a surrogate monitoring compound with the applicable HF and HCl emission limits, and pH monitoring of the facility scrubber

10.5 CASE-BY-CASE MACT ANALYSIS FOR THE AUXILIARY BOILER

40 CFR 63.43(e)(2)(x); 40 CFR 63.43(e)(2)(xii); 40 CFR 63.43(e)(1), 40 CFR 63.43(e)(2)(xi), 40 CFR 63.43e(2)(xiii)

The proposed Plant Washington facility includes a 240 MMBtu/hr fuel-oil fired auxiliary boiler. This auxiliary boiler will only be used during startup and shutdown operations of the main facility boiler. A regulation to consider in conducting a Case-By-Case MACT evaluation for the auxiliary boiler would be the *National Emission Standards for Industrial/Commercial/Institutional Boilers and Process Heaters* source category. MACT standards for this source category, specifically 40 CFR Part 63 Subpart DDDDD, were adopted in September 2004. In 2007, the U.S. Court of Appeals for the D.C. Circuit issued a decision remanding and vacating Subpart DDDDD. The court remanded the rule based on the

finding that the USEPA had improperly narrowed the listing of sources subject to the Commercial and Industrial Solid Waste Incineration (CISWI) MACT standard. Based on that ruling, the court then found that the Industrial Boiler MACT (Subpart DDDDD) would require substantial revisions, and that many sources under the Industrial Boiler MACT would be regulated under the CISWI MACT.

The following Case-By-Case MACT analysis includes an analysis for those HAPs included in total PM (i.e., condensable HAPs), for organic HAPs using CO as a surrogate, and HCl. Evaluation of these pollutants corresponds to the determinations found in the Industrial Boiler MACT, which established PM, CO, and HCl emission limits for the category of industrial boilers in which Plant Washington's auxiliary boiler lies: liquid-fuel fired limited-use boiler.

10.5.1 Total PM (Inorganic HAPs) MACT Determination for the Auxiliary Boiler

Trace amounts of inorganic HAPs can be emitted from fuel oil combustion as PM. Total PM emissions from the auxiliary boiler will be used as a surrogate for inorganic HAP emissions in this MACT analysis. Post combustion technologies are not used on auxiliary boilers at coal-fired utility plants because their use is limited and intermittent.

10.5.1.1 Identification of Best Demonstrated Technology (BDT)

Fuel Selection

The only applicable lower emitting process or practice is using low sulfur distillate fuel oil (0.05 percent) for the auxiliary boiler. Using low sulfur distillate fuel oil for combustion results in lower PM emissions than heavier residual oils.

Fabric Filter Baghouse

Fabric filters are used for PM control in a wide variety of industries, including pulverized coal fired boilers, and can achieve control efficiencies of 99 percent or greater. They have not been installed on distillate oil fired auxiliary boiler units due to the minor amounts of particulate matter that might be collected.

Dry Electrostatic Precipitator

Dry ESPs are used in a wide variety of source categories for control of PM emissions, and can achieve control efficiencies of 99 percent or greater. They have not been installed on distillate oil fired auxiliary boiler units due to the minor amounts of particulate matter that might be collected.

Wet Electrostatic Precipitator

A WESP is commonly used when a dry ESP is not viable, such as when the material to be collected is wet, flammable, or is not easily removed from the collection plate. WESPs are commonly used by the wood products and metallurgical industries, and can achieve PM control efficiencies of greater than 99 percent. They have not been installed on distillate oil fired auxiliary boiler units due to the minor amounts of particulate matter that might be collected.

After a review of the above discussed control technologies, use of fuel selection and good combustion practices is considered representative of the best demonstrated technology for control of inorganic HAPs (PM) from the auxiliary boiler.

10.5.1.2 Evaluation of Information for the MACT Floor and Determination of the MACT Floor

The combination of the low duty cycle, less than 10 percent use per year, and use of low sulfur fuel, with the placement and configuration of the auxiliary boiler at a power plant have generally eliminated consideration of add-on emission control devices. Since the primary purpose of the auxiliary boiler is for start up and shut downs of the pulverized coal-fired boiler, its operational schedule generally precludes using onsite control systems.

Fuel selection and GCP will control inorganic HAP emissions from the facility auxiliary boiler and is determined as the MACT floor and best controlled similar source.

10.5.1.3 Beyond the Floor Analysis

No controls were identified to be effective for use on the auxiliary boiler other than fuel selection and good combustion practices. Therefore, use of additional controls for the limited use auxiliary boiler are not justified.

10.5.1.4 MACT Determination for Inorganic HAPs

Based on the review of available information, fuel selection (low sulfur low ash fuel) and GCP is determined as MACT for inorganic HAPs from the auxiliary boiler.

10.5.2 Organic HAPs MACT Determination for the Auxiliary Boiler

The incomplete combustion of fuel results in VOC and corresponding organic HAP emissions. Organic HAP emissions are controlled the same as VOC and HAP emissions, by ensuring complete combustion. In general, post combustion control technologies are not used for auxiliary boilers at coal utility plants because their use is limited and intermittent.

10.5.2.1 Identification of Best Demonstrated Technology (BDT)

Combustion Controls

Combustion controls for VOC and organic HAP emissions would be a lower pollutant emitting process. VOC and organic HAP formation will be limited through a properly designed combustion chamber with adequate controls to regulate the combustion process. Proper operation and maintenance of fuel feed systems, fans, system dampers, and other equipment will assist in reducing VOC emissions.

Add-On Controls

No effective add-on controls currently exist for VOC and organic HAP emissions from a boiler. Afterburners and other control devices, such as catalytic oxidation or flares, have not been demonstrated in practice on auxiliary boiler units. Any such control devices would lead to negative secondary environmental impacts. Combustion controls are widely recognized as the most effective VOC and organic HAP emission controls for boilers.

After a review of the above discussed control technologies, use of good combustion practices is considered representative of the best demonstrated technology for control of organic HAPs from the auxiliary boiler.

10.5.2.2 Evaluation of Information for the MACT Floor and Determination of the MACT Floor

Plant Washington will use combustion controls and proper boiler design to control organic HAP emissions, emitted as VOC emissions, from the auxiliary boiler. A review of available information,

including 112(g) determinations conducted for other sources, and review of BACT determinations and information from the RBLC database, indicated the use of GCP and proper boiler design is representative of the best controlled similar sources for organic HAP emissions. Therefore, use of good combustion practices is identified as the MACT floor for control of organic HAPs from the facility auxiliary

10.5.2.3 Beyond the Floor Analysis

No controls were identified to be effective for use on the auxiliary boiler other than good combustion practices and combustion controls. Therefore, use of additional controls for the limited use auxiliary boiler is not justified.

10.5.2.4 MACT Determination for Organic HAPs

Estimated emissions of organic HAPs from the facility can be found in Exhibit A of this report. These estimates were prepared from AP-42 emission factors and data from the 1998 Utility Report to Congress. These indicated emissions are estimates only, and not representative of a proposed limit for individual organic HAPs present.

As stated above, organic HAP emissions will be emitted as VOCs from the facility's auxiliary boiler. Therefore, monitoring the auxiliary boiler CO emissions to ensure GCP will serve as surrogate monitoring to demonstrate compliance with the Case-By-Case MACT determination for organic HAPs. The proposed BACT emission limit for the auxiliary boiler at the facility, which will serve as the MACT emission limit, is 0.04 lb/MMBtu CO.

Compliance with the MACT organic HAP requirements will be demonstrated through surrogate compliance with a CO CEM system with a proposed BACT emission limit for CO of 0.04 lb/MMBtu on a 24-hr. block average basis. CEM monitoring will ensure proper combustion occurs in the auxiliary boiler, minimizing organic HAP emissions.

10.5.3 HCl and HF MACT Determination For The Auxiliary Boiler

Emissions of the acid gas HCl and HF will occur from the facility's auxiliary boiler. HCl and HF emissions result from fuel oil combustion through the oxidation of chlorine present in the fuel source. Emissions of HCl and HF are controlled through SO_2 control technologies. In general, post combustion

control technologies are not used for auxiliary boilers at coal utility plants because their use is limited and intermittent.

10.5.3.1 Identification of Best Demonstrated Technology (BDT)

Fuel Selection

Firing of lower sulfur fuel is a common lower emission process/practice to reduce SO_2 emissions. Proper selection of low sulfur/low ash fuel can reduce the chlorine and fluorine content of the fuel purchased. Generally the distillation process will remove inorganic salts and minerals from the oil.

Add-On Controls

Add-on controls for SO_2 are generally similar to those for the main boiler. The add-on controls include wet scrubbers, dry scrubbers, sorbent injection, limestone injection, and activated carbon injection. Since emissions of SO_2 are estimated to be less than 6 tons/yr, any additional controls would be highly cost ineffective and potentially ineffective at the low SO_2 concentrations having to be treated. The same is true for HF and HCl.

After a review of the above discussed control technologies, use of fuel selection is considered representative of the best demonstrated technology for control of inorganic HAPs (PM) from the auxiliary boiler.

10.5.3.2 Evaluation of Information for the MACT Floor and Determination of the MACT Floor

Plant Washington will use fuel selection and fuel specifications to control HCl and HF emissions from the auxiliary boiler. A review of available information, including 112(g) determinations conducted for other sources, indicated fuel selection and fuel specifications as representative of the best controlled similar sources for HCl and HF emissions.

10.5.3.3 Beyond the Floor Analysis

No controls were identified to be effective for use on the auxiliary boiler other than good combustion practices and fuel selection. Therefore, use of additional controls for the limited use auxiliary boiler is not justified.

10.5.3.4 MACT Determination for HCl and HF

Estimated emissions of HCl and HF from the facility auxiliary boiler can be found in Exhibit A of this report. As discussed in Section 10.3, these emission estimates for the auxiliary boiler were prepared from AP-42 emission factors. These indicated emissions are meant to serve as emission estimates only, and not representative of a proposed limit for HF or HCl emissions from the auxiliary boiler.

MACT for HCl and HF are determined to be selection of a distillate fuel. Compliance with the HCl and HF emissions limit will be attained through appropriate fuel specifications.

10.5.4 Auxiliary Boiler Case-By-Case MACT Determination Summary

Table 10-20 summarizes the Case-By-Case MACT determinations for the facility auxiliary boiler.

Table 10-20 Case By Case MACT Evaluation Summary for the Auxilary Boiler

Pollutant	Control Technology	Proposed MACT Emission Limit (lb/MMBtu)
Inorganic HAPs	Engineering combustion controls (Good Combustion Practices) and fuel selection	Work practice standard (fuel specification) including low sulfur/low ash fuel
Organic HAP	Engineering combustion controls (Good Combustion Practices)	Surrogate CEM Monitoring Facility BACT CO emission limit 0.04 lb/MMBtu 24-hr. block average
HCl	Fuel selection and fuel specifications	Work practice standard (fuel specification) including low sulfur/low ash fuel

Prepared by: PBS 6/18/08
Checked by: JDF 11/26/08

The compliance strategy for the emissions limits proposed for the auxiliary boiler described in the following section.

10.5.4.1 Auxiliary Boiler

PM (Inorganic HAPs)

The control strategy for inorganic HAPs from the auxiliary boiler will involve engineering combustion controls and fuel selection. Compliance with the auxiliary boiler inorganics HAP MACT limit will be demonstrated through fuel selection and fuel specification (work practice standards).

Organic (HAP) Emissions

The control strategy for organic HAP emissions will include engineering combustion controls.

Compliance with the MACT organic HAP requirements will be demonstrated through surrogate compliance with a CO CEM system with a proposed BACT emission limit for CO of 0.04 lb/MMBtu on a 24-hr. block average basis. CEM will ensure proper combustion occurs in the auxiliary boiler, reducing organic HAP emissions.

HCl and HF

Compliance with the MACT work practice standard identified will include fuel selection and fuel specifications.

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EXHIBIT A

EMISSIONS CALCULATIONS

EXHIBIT A

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ADDITIONAL INFORMATION

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1 Coal Fired Boiler - Stack S1

Basis	Value	Units	Reference
Gross Power Rating - Full Load	930	MW	Plant Washington Specification
Maximum Heat Input - Full Load	8300	MMBtu/hr	Plant Washington Specification
Fuel Oil Burner Rating	1300	MMBtu/hr	Plant Washington Specification
Maximum Expected Hours of Operation	8760	hr/yr	Plant Washington Specification
PM Emission Factor - Coal	0.018	lb/MMBtu	BACT
PM_{10} Emission Factor - Coal	0.018	lb/MMBtu	BACT
PM_{10} Emission Factor Filterable- Coal	0.012	lb/MMBtu	BACT
$PM_{2.5}$ Percentage-Filterable	53.00%		AP 42, Section 1.1 - Particulate Matter Size Distribution
Condensable $PM_{2.5}$ Emission Factor	0.006	lb/MMBtu	Engineering Estimate
SO_2 Emission Factor - Coal	959	lb/hr	BACT (3 hour averaging period) - Section 4.3.5
SO_2 Emission Factor - Coal	0.052	lb/MMBtu	BACT (annual averaging period)
NO_X Emission Factor - Coal	0.05	lb/MMBtu	BACT (30-Day Rolling averaging period)
CO Emission Factor - Coal	0.10	lb/MMBtu	BACT (30-Day Rolling averaging period)
CO Emission Factor - Coal	0.30	lb/MMBtu	BACT (1-hour averaging period)
VOC Coal Emission Factor - Coal	0.003	lb/MMBtu	BACT
H_2SO_4 Emission Factor - Coal	0.004	lb/MMBtu	BACT
Pb Emission Factor - Coal	1.60E-05	lb/MMBtu	BACT-PSD Avoidance Limit
Hg Emission Factor - Coal	1.68E-06	lb/MMBtu	BACT
HF Emission Factor - Coal	2.68E-04	lb/MMBtu	BACT
Exhaust Flow Rate	1,927,690	dscfm	Vendor Specification
Ammonia Slip Concentration	10	ppm	Vendor Guarantee

PM Emissions - Full Load

8300 MMBtu/hr * 0.018 lb/MMBtu / 2,000 lb/ton * 8,760 hr/yr = 654 ton/yr

PM_{10} Emissions - Full Load

8300 MMBtu/hr * 0.018 lb/MMBtu / 2,000 lb/ton * 8,760 hr/yr = 654 ton/yr

PM_{10} (Filterable) Emissions - Full Load

8300 MMBtu/hr * 0.012 lb/MMBtu / 2,000 lb/ton * 8,760 hr/yr = 436 ton/yr

$PM_{2.5}$ (Filterable) Emissions

436 ton/yr * 53.00% = 231 ton/yr

$PM_{2.5}$ (Condensable) Emissions

8300 MMBtu/hr * 0.006 lb/MMBtu / 2,000 lb/ton * 8,760 hr/yr = 218 ton/yr

$PM_{2.5}$ (Filterable + Condensable) Emissions

231 ton/yr + 218 ton/yr = 449 ton/yr

SO_2 Emissions - Full Load (3 hr and 24 hr averaging periods)

959 lb/hr * 8760 hr/yr / 2,000 lb/ton = 4,200 ton/yr

SO_2 Emissions - Full Load (annual averaging periods)

8300 MMBtu/hr * 0.052 lb/MMBtu / 2,000 lb/ton * 8,760 hr/yr = 1,890 ton/yr

NO_X Emissions - Full Load

8300 MMBtu/hr * 0.05 lb/MMBtu / 2,000 lb/ton * 8,760 hr/yr = 1,818 ton/yr

CO Emissions - Full Load (Annual)

8300 MMBtu/hr * 0.10 lb/MMBtu / 2,000 lb/ton * 8,760 hr/yr = 3635.40 ton/yr

CO Emissions - Full Load (1 hr averaging period)

8300 MMBtu/hr * 0.30 lb/MMBtu = 2,490 lb/hr

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

VOC Emissions - Full Load

8300 MMBtu/hr	*	0.003 lb/MMBtu	/	2,000 lb/ton	*	8,760 hr/yr	=	109.1 ton/yr

H_2SO_4 Emissions - Full Load

8300 MMBtu/hr	*	0.004 lb/MMBtu	/	2,000 lb/ton	*	8,760 hr/yr	=	145.4 ton/yr

HF Emissions - Full Load

8300 MMBtu/hr	*	2.68E-04 lb/MMBtu	/	2,000 lb/ton	*	8,760 hr/yr	=	9.74 ton/yr

Pb Emissions - Full Load

8300 MMBtu/hr	*	1.60E-05 lb/MMBtu	/	2,000 lb/ton	*	8,760 hr/yr	=	0.58 ton/yr

Hg Emissions - Full Load

8300 MMBtu/hr	*	1.68E-06 lb/MMBtu	/	2,000 lb/ton	*	8,760 hr/yr	=	0.06 ton/yr

Ammonia Emissions - Full Load

1,927,690 dscfm	*	10 ppm	/	385 dscf/lb-mole	*	17 lb/lb-mole	*	60 min/hr	=	51.07 lb/hr

51.07 lb/hr	/	2,000 lb/ton	*	8,760 hr/yr	=	223.7 ton/yr

2 **Auxiliary Boiler - Stack S45**

Basis	Value	Units	Reference
Boiler Rating	240	MMBtu/hr	Plant Washington Specification
Maximum Hours of Operation	876	hr/yr	Plant Washington Specification
PM Emission Factor - Fuel Oil	0.024	lb/MMBtu	BACT
PM_{10} Emission Factor - Fuel Oil	0.024	lb/MMBtu	BACT
PM_{10} Emission Factor Filterable - Fuel Oil	0.014	lb/MMBtu	BACT
$PM_{2.5}$ Percentage Filterable - Fuel Oil	12.0%	of PM_{10}	AP-42, Table 1.3-6
Condensable $PM_{2.5}$ Emission Factor	0.010	lb/MMBtu	Engineering Estimate
SO_2 Emission Factor - Fuel Oil	0.05	lb/MMBtu	BACT
NO_X Emission Factor - Fuel	0.10	lb/MMBtu	BACT
CO Emission Factor - Fuel Oil	0.04	lb/MMBtu	BACT
VOC Coal Emission Factor - Fuel Oil	0.003	lb/MMBtu	BACT
H_2SO_4 Emission Factor - Fuel Oil	6.00E-05	lb/MMBtu	BACT
HF Emission Factor - Fuel Oil	3.19E-08	lb/MMBtu	AP-42 Table 1.3-9
Pb Emission Factor - Fuel Oil	9.00E-06	lb/MMBtu	AP-42, Table 1.3-10
Hg Emission Factor - Fuel Oil	3.00E-06	lb/MMBtu	AP-42, Table 1.3-10

PM Emissions
Fuel Oil

240 MMBtu/hr	*	0.024 lb/MMBtu	/	2,000 lb/ton	*	876 hr / yr	=	2.52 ton/yr

PM_{10} Emissions
Fuel Oil

240 MMBtu/hr	*	0.024 lb/MMBtu	/	2,000 lb/ton	*	876 hr / yr	=	2.52 ton/yr

PM_{10} (Filterable) Emissions - Full Load
Fuel Oil

240 MMBtu/hr	*	0.014 lb/MMBtu	/	2,000 lb/ton	*	876 hr/yr	=	1.472 ton/yr

$PM_{2.5}$ (Filterable) Emissions
Fuel Oil

1.472 ton/yr	*	12.00%	=	0.177 ton/yr

$PM_{2.5}$ (Condensable) Emissions
Fuel Oil

240 MMBtu/hr	*	0.010 lb/MMBtu	/	2,000 lb/ton	*	876 hr/yr	=	1.051 ton/yr

$PM_{2.5}$ (Filterable + Condensable) Emissions
Fuel Oil

0.177 ton/yr	+	1.051 ton/yr	=	1.228 ton/yr

SO_2 Emissions
Fuel Oil

240 MMBtu/hr	*	0.050 lb/MMBtu	/	2,000 lb/ton	*	876 hr/yr	=	5.26 ton/yr

NO_x Emissions
Fuel Oil

240 MMBtu/hr	*	0.10 lb/MMBtu	/	2,000 lb/ton	*	876 hr/yr	=	10.51 ton/yr

CO Emissions
Fuel Oil

240 MMBtu/hr	*	0.04 lb/MMBtu	/	2,000 lb/ton	*	876 hr/yr	=	4.20 ton/yr

VOC Emissions
Fuel Oil

240 MMBtu/hr	*	0.0030 lb/MMBtu	/	2,000 lb/ton	*	876 hr/yr	=	0.32 ton/yr

H_2SO_4 Emissions
Fuel Oil

240 MMBtu/hr	*	6.00E-05 lb/MMBtu	/	2,000 lb/ton	*	876 hr/yr	=	6.31E-03 ton/yr

HF Emissions
Fuel Oil

240 MMBtu/hr	*	3.19E-08 lb/MMBtu	/	2,000 lb/ton	*	876 hr/yr	=	3.35E-06 ton/yr

Pb Emissions
Fuel Oil

240 MMBtu/hr	*	9.00E-06 lb/MMBtu	/	2,000 lb/ton	*	876 hr/yr	=	9.46E-04 ton.yr

Hg Emissions
Fuel Oil

240 MMBtu/hr	*	3.00E-06 Btu	/	2,000 lb/ton	*	876 hr/yr	=	3.15E-04 ton.yr

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

3 Diesel Fired Equipment

Basis	Value	Units	Reference
Diesel-Fuel Engine Rating	1500	HP	Plant Washington Specification
Diesel-Fuel Fire Water Pump Rating	350	HP	Plant Washington Specification
Maximum Diesel Engine Hours of Operation	500	hr/yr	Plant Washington Specification
Maximum Fire Water Pump Hours of Operation	500	hr/yr	Plant Washington Specification
Fire Water Pump PM/PM_{10} Emission Factor	2.20E-03	lb/hp-hr	AP-42, Table 3.3-1
Fire Water Pump SO_2 Emission Factor	2.05E-03	lb/hp-hr	AP-42, Table 3.3-1
Fire Water Pump NO_X Emission Factor	0.031	lb/hp-hr	AP-42, Table 3.3-1
Fire Water Pump CO Emission Factor	6.68E-03	lb/hp-hr	AP-42, Table 3.3-1
Fire Water Pump VOC Emission Factor	2.47E-03	lb/hp-hr	AP-42, Table 3.3-1
Diesel Engine PM/PM_{10} Emission Factor	7.00E-04	lb/hp-hr	AP-42, Table 3.4-1
Diesel Engine SO_2 Emission Factor	4.05E-04	lb/hp-hr	AP-42, Table 3.4-1, Assuming Diesel Fuel has 0.05% Sulfur Content
Diesel Engine NO_X Emission Factor	0.013	lb/hp-hr	AP-42, Table 3.4-1, Controlled
Diesel Engine CO Emission Factor	5.50E-03	lb/hp-hr	AP-42, Table 3.4-1
Diesel Engine VOC Emission Factor	7.05E-04	lb/hp-hr	AP-42, Table 3.4-1

PM/PM_{10} Emissions

Diesel Fuel Engine

1500 HP	*	7.00E-04 lb/hp-hr	/	2,000 lb/ton	*	500 hr/yr	=	0.26 ton/yr

Diesel Fuel Fire Water Pump

350 HP	*	2.20E-03 lb/hp-hr	/	2,000 lb/ton	*	500 hr/yr	=	0.193 ton/yr

Total Emissions

0.19 ton/yr	+	0.26 ton/yr	=	0.46 ton/yr

SO_2 Emissions

Diesel Fuel Engine

1500 HP	*	4.05E-04 lb/hp-hr	/	2,000 lb/ton	*	500 hr/yr	=	0.15 ton/yr

Diesel Fuel Fire Water Pump

350 HP	*	2.05E-03 lb/hp-hr	/	2,000 lb/ton	*	500 hr/yr	=	0.18 ton/yr

Total Emissions

0.15 ton/yr	+	0.18 ton/yr	=	0.33 ton/yr

NO_X Emissions

Diesel Fuel Engine

1500 HP	*	1.30E-02 lb/hp-hr	/	2,000 lb/ton	*	500 hr/yr	=	4.88 ton/yr

Diesel Fuel Fire Water Pump

350 HP	*	3.10E-02 lb/hp-hr	/	2,000 lb/ton	*	500 hr/yr	=	2.71 ton/yr

Total Emissions

4.88 ton/yr	+	2.71 ton/yr	=	7.59 ton/yr

CO Emissions

Diesel Fuel Engine

1500 HP	*	5.50E-03 lb/hp-hr	/	2,000 lb/ton	*	500 hr/yr	=	2.06 ton/yr

Diesel Fuel Fire Water Pump

350 HP	*	6.68E-03 lb/hp-hr	/	2,000 lb/ton	*	500 hr/yr	=	0.58 ton/yr

Total Emissions

2.06 ton/yr	+	0.58 ton/yr	=	2.65 ton/yr

VOC Emissions

Diesel Fuel Engine

1500 HP	*	7.05E-04 lb/hp-hr	/	2,000 lb/ton	*	500 hr/yr	=	0.26 ton/yr

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Diesel Fuel Fire Water Pump

350 HP	*	2.47E-03 lb/hp-hr	/	2,000 lb/ton	*	500 hr/yr	=	0.22 ton/yr	

Total Emissions

0.26 ton/yr	+	0.22 ton/yr	=	0.48 ton/yr

4 **Cooling Tower - Stack S2 - S35**

Basis:	Value	Reference:
Water Flow Rate	450,000 gal/min	Plant Washington Specification
Operating hours	8,760 hr/yr	Plant Washington Specification
Total Drift %	0.0005%	Plant Washington Specification
Total Dissolved Solids	3300 ppm	Plant Washington Specification
Density of Water	1 g/mL	Constant
PM_{10} Percentage	46.10%	Riesman, Joel and Gordon Frisbie. "Calculating Realistic PM_{10} from Cooling Towers."
$PM_{2.5}$ Percentage	0.20%	Riesman, Joel and Gordon Frisbie. "Calculating Realistic PM_{10} from Cooling Towers."

Total Liquid Drift

450,000 gal/min	*	0.0005%	*	3.785 L / gal	=	8.52 L/min				

PM Emission

3300 g / 1000000 g	*	1 g/mL	*	1000 mL / 1 L	*	8.52 L/min	*	1 lb / 453.59 g	=	0.06 lb/min

0.06 lb/min	*	60 min / hr	*	8,760 hr/yr	/	2,000 lb/ton	=	16.28 ton/yr

PM_{10} Emissions

16.28 ton/yr	*	46.10%	=	7.51 ton/yr

$PM_{2.5}$ Emissions

16.28 ton/yr	*	0.20%	=	3.29E-02 ton/yr

Table A-1 : Cooling Tower $PM_{10}/PM_{2.5}$ Percentage Evaluation

Solid Particles Same Density as Sodium Chloride (2.2 g/cm^3) - Assumption
Drift Water Droplets Have a Density of Water (1.0 g/cm^3) - Assumption
TDS 3300 mg/L - Project Design Specification
Particle density 2.2 g/cm^3

EPRI Droplet Diameter (um)	Droplet Volume (um^3)	Droplet Mass (ug)	Particle Mass Solids (ug)	Solid Particle Volume (um^3)	Solid Particle Diameter (um)	EPRI % Mass Smaller
10	524	5.24E-04	1.73E-06	0.79	1.145	0
20	4189	4.19E-03	1.38E-05	6.28	2.289	0.196
30	14137	1.41E-02	4.67E-05	21.21	3.434	0.226
40	33510	3.35E-02	1.11E-04	50.27	4.579	0.514
50	65450	6.54E-02	2.16E-04	98.17	5.724	1.816
60	113097	1.13E-01	3.73E-04	169.65	6.868	5.702
70	179594	1.80E-01	5.93E-04	269.39	8.013	21.348
90	381704	3.82E-01	1.26E-03	572.56	10.302	49.812
110	696910	6.97E-01	2.30E-03	1045.36	12.592	70.509
130	1150347	1.15E+00	3.80E-03	1725.52	14.881	82.023
150	1767146	1.77E+00	5.83E-03	2650.72	17.171	88.012
180	3053628	3.05E+00	1.01E-02	4580.44	20.605	91.032
210	4849048	4.85E+00	1.60E-02	7273.57	24.039	92.468
240	7238229	7.24E+00	2.39E-02	10857.34	27.473	94.091
270	10305995	1.03E+01	3.40E-02	15458.99	30.907	94.689
300	14137167	1.41E+01	4.67E-02	21205.75	34.341	96.288
350	22449298	2.24E+01	7.41E-02	33673.95	40.065	97.011
400	33510322	3.35E+01	1.11E-01	50265.48	45.789	98.34
450	47712938	4.77E+01	1.57E-01	71569.41	51.512	99.071
500	65449847	6.54E+01	2.16E-01	98174.77	57.236	99.071
600	113097336	1.13E+02	3.73E-01	169646.00	68.683	100
$PM_{2.5}$	0.202 %					
PM_{10}	46.1 %					

Completed by: JFD 11/26/2008
Checked by: SAK 11/26/2008

5 Particulate Matter Baghouse Sources

Source	Stack ID	Model ID	Emission Factor gr/dscf	Air Flowrate (cfm)	PM/PM_{10} Emissions (lb/hr)	PM/PM_{10} Emissions (ton/yr)	$PM_{2.5}$ Emissions (lb/hr)	$PM_{2.5}$ Emissions (ton/yr)
Crusher House Dust Collector	S40	CRUSH	0.005	24,000	1.03	4.51	0.16	0.72
Tripper Deck	S41	TRIP	0.005	18,000	0.77	3.38	0.12	0.54
Limestone Preparation Building Silo	S42	LIMEPR	0.005	5,000	0.21	0.94	5.79E-02	0.25
Fly Ash Filter Separator (Fly Ash Mechanical Exhausters)	S43	ASHEXH	0.005	2,407	0.10	0.45	0.05	0.24
Fly Ash Silo	S37	FLYASH	0.005	1,500	0.06	0.28	0.03	0.15
Mercury Sorbent Silo	S38*	HGSILO	0.005	1,500	1.61E-02	7.04E-02	1.61E-02	7.04E-02
SO_3 Sorbent Silo	S36*	SO3SILO	0.005	1,500	1.61E-02	7.04E-02	1.61E-02	7.04E-02
Pre-Treatment Soda Ash Silo	S44*	SODAASH	0.005	1,500	8.04E-03	3.52E-02	8.04E-03	3.52E-02
Pre-Treatment Hydrated Lime Silo	S39*	LSILO	0.005	1,500	8.04E-03	3.52E-02	2.17E-03	9.50E-03
PRB Stackout (Insertable Dust Collector)	S46	PRBSO	0.005	1,500	0.06	0.28	1.03E-02	4.51E-02
Illinois No. 6 Stackout (Insertable Dust Collector)	S47	IL6SO	0.005	1,500	0.06	0.28	1.03E-02	4.51E-02
Limestone Stackout (Insertable Dust Collector)	S48	LIMESO	0.005	1,500	0.06	0.28	1.74E-02	7.60E-02

* lb/hr emission rate reflects the average hourly emission rate over a 24-hr period (The sorbent silos are expected to vent only 6 hours per day and the soda ash and lime silos will operate only 3 hours per day)

Parameters

Basis	Value	Reference
PM Emission Factor	0.0050 gr/dscf	Vendor Design Basis
Crusher House Dust Collector Operating Hours	8,760 hr/yr	Project Specification
Tripper Deck Operating Hours	8,760 hr/yr	Project Specification
Limestone Preparation Building Operating Hours	8,760 hr/yr	Project Specification
Fly Ash Mechanical Exhausters Operating Hours	8,760 hr/yr	Project Specification
Fly Ash Silo Operating Hours	8,760 hr/yr	Project Specification
Mercury Sorbent Silo Operating Hours	2,190 hr/yr	Project Specification
SO_3 Sorbent Silo Operating Hours	2,190 hr/yr	Project Specification
Pre-Treatment Soda Ash Silo Operating Hours	1,095 hr/yr	Project Specification
Pre-Treatment Hydrated Lime Silo Operating Hours	1,095 hr/yr	Project Specification
Ash $PM_{2.5}$ Percentage	53.00%	AP 42, Section 1.1 - Particulate Matter Size Distribution
Lime $PM_{2.5}$ Percentage	27.00%	AP 42, Table 11.17-7 - PM Size Distribution for Rotary Kiln with Fabric Filter
Coal $PM_{2.5}$ Percentage	16.00%	AP-42, Appendix B.1 (Section 11.10 Coal Cleaning: Dry Process)

Sample Emissions Calculations (Crusher House Dust Collector):

Hourly:

$$0.005\ \text{gr/dscf} * \frac{24{,}000\ \text{dscf}}{\text{min}} * \frac{\text{lb}}{7{,}000\ \text{gr}} * \frac{60\ \text{min}}{\text{hr}} = \frac{1.029\ \text{lb}}{\text{hr}}$$

Yearly:

$$\frac{1.029\ \text{lb}}{\text{hr}} * 8{,}760\ \text{hr/yr} / 2{,}000\ \text{lb/ton} = \frac{4.51\ \text{ton}}{\text{yr}}$$

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

Table A-2 : Coal Design Data

Item (%) As Received (Wet Basis)	PRB		50/50 Blend		Illinois #6	
	Average	Abnormal	Average	Abnormal	Average	Abnormal
Moisture	29.61	32.05	19.81	21.19	10	10.32
Carbon	49.16	47.66	55.24	53.89	61.32	60.12
Hydrogen	3.43	3.29	4.45	4.10	5.46	4.9
Oxygen	11.31	12.25	9.75	9.77	8.19	7.28
Nitrogen	0.71	0.57	1.55	1.21	2.38	1.85
Sulfur	0.32	0.53	1.72	2.23	3.11	3.93
Ash	5.46	3.65	7.49	7.63	9.52	11.6
HHV (Btu/lb)	8500	8300	9950	9650	11,400	11,000
Trace Analysis (ppm) (Dry Basis)						
Chlorine	100	220	1400	2110	2700	4000
Fluorine	77	181	79	152	80	124
Mercury	0.1	0.25	0.1	0.2	0.09	0.15
Lead	4.63	10.8	7.7	18	10.8	25.3

Completed by : JDF 11/26/2008
Checked by: SAK 11/26/2008

6 PM Drop Point Emission Factors for Material Handling

Emission Description	Source ID	Pollutant			Units	Reference
		TSP	PM_{10}	$PM_{2.5}$		
Coal Rail Unloading (indoor)	A4	4.32E-05	2.04E-05	3.09E-06	lb/ton	AP-42, 13.2.4.3, Eqn (1)
Transfer Point for PRB Coal (outdoor)	A6, A8	7.59E-05	3.59E-05	5.44E-06	lb/ton	AP-42, 13.2.4.3, Eqn (1)
Transfer Point for Illinois Basin Coal (outdoor)	A7, A9	3.47E-04	1.64E-04	2.49E-05	lb/ton	AP-42, 13.2.4.3, Eqn (1)
Limestone Rail Unloading (indoor)	A5	4.32E-05	2.04E-05	3.09E-06	lb/ton	AP-42, 13.2.4.3, Eqn (1)
Limestone Transfer Point (outdoor)	A10	3.47E-04	1.64E-04	2.49E-05	lb/ton	AP-42, 13.2.4.3, Eqn (1)
Bottom Ash Transfer Point to Bottom Ash Bin (outdoor)	A3	1.97E-04	9.31E-05	1.41E-05	lb/ton	AP-42, 13.2.4.3, Eqn (1)
Bottom Ash Transfer Point from Bin to Truck (outdoor)	A3	1.97E-04	9.31E-05	1.41E-05	lb/ton	AP-42, 13.2.4.3, Eqn (1)

Parameter	Value		Reference
Coal Moisture Content PRB Coal	29.61	%	Typical for PRB from Project Specification
Coal Moisture Content Illinois Basin Coal	10		Typical for Illinois #6 from Project Specification
Limestone Moisture Content	10	%	Plant Washington Specification
Bottom Ash Moisture Content	15	%	Plant Washington Specification
Gypsum Moisture Content	20	%	Plant Washington Specification
Fly Ash Moisture Content	15	%	Plant Washington Specification
Mercury Sorbent Moisture	12	%	Plant Washington Specification
Hydrated Lime Moisture	1	%	Plant Washington Specification
Soda Ash Moisture	1	%	Plant Washington Specification
SO_3 Sorbent Moisture	10	%	Plant Washington Specification
Wind Speed, Outdoor	6.46 mph		Based on average wind speed of 2.89 m/s for Macon, GA (1987-1991)
Wind Speed, Indoor	1.3 mph		Lower bound for emission equation AP-42, 13.2.4(1)
Percent of the time wind is greater than 12 mph	6	%	Based on Macon/Centerville Weather Data 1987-1991

Notes:

Material Handling Emission Factor — AP-42 Section 13.2.4.3, Equation (1)

$$E = k\ (0.0032)\ ((U/5)^{1.3} / (M/2)^{1.4})$$

Where:
E = Emissions in lb/tons
k = Particle Size Multiplier
U = Mean Wind Speed (mph)
M = Material Moisture Content (%)

Aerodynamic Particle Species	k
Total Suspended Particle (TSP)	0.74
PM_{10}	0.35
$PM_{2.5}$	0.053

Sample Calculations (TSP for Rail Unloading):

$$0.74 * 0.0032 * \left(\frac{1.3\ \text{mph}}{5}\right)^{\wedge} 1.3 \ / \left(\frac{29.61\%}{2}\right)^{\wedge} 1.4 = 9.45\text{E-06 lb/ton}$$

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Particulate Matter Drop Point Emissions

Emission Description	Source ID	Pollutant			Units
		TSP	PM_{10}	$PM_{2.5}$	
Rail Unloading	A4	2.84E-01	1.34E-01	2.03E-02	ton/yr
Transfer Point for PRB Coal	A6, A8	0.07	3.28E-02	4.97E-03	ton/yr
Transfer Point for Illinois Basin Coal	A7, A9	0.32	1.50E-01	2.27E-02	ton/yr
Limestone Unloading	A5	1.89E-01	8.95E-02	1.35E-02	ton/yr
Limestone Transfer Point	A10	3.45E-02	1.63E-02	2.47E-03	ton/yr
Bottom Ash Transfer Point to Bottom Ash Bin	A3	2.69E-02	1.27E-02	1.93E-03	ton/yr
Bottom Ash Transfer Point from Bin to Truck	A3	2.69E-02	1.27E-02	1.93E-03	ton/yr

Material Throughput

Parameter	Value	Reference
Powder River Basin Coal Throughput	1,826,834 ton/yr	Typical 50/50 Blend - Plant Washington Specification
Illinois No. 6 Coal Throughput	1,826,834 ton/yr	Typical 50/50 Blend - Plant Washington Specification
Limestone Throughput	198,923 ton/yr	Plant Washington Specification
Ash Throughput	273,660 ton/yr	Typical 50/50 Blend - Plant Washington Specification
Rail unloading rate	1,500 ton/hr	Plant Washington Specification
Limestone unloading rate	1,000 ton/hr	Plant Washington Specification

Sample Emission Calculations (TSP for Rail Unloading):

$$13{,}140{,}000 \text{ ton/yr} * 4.32\text{E-}05 \text{ lb/ton} * \frac{1 \text{ ton}}{2000 \text{ lb}} = 2.84\text{E-}01 \text{ ton/yr}$$

Area Emission Rate

Bottom Ash Storage and Handling System

PM_{10} Emission Rate	2.55E-2 ton/yr
$PM_{2.5}$ Emission Rate	3.86E-3 ton/yr
Modeled Area	257 m^2

PM_{10} Emission Rate

$$2.55\text{E-}2 \text{ ton/yr} * \frac{2000 \text{ lb/ton}}{8760 \text{ hr/yr}} * \frac{453.6 \text{ g/lb}}{3600 \text{ sec/hr}} / 257 \text{ m}^2 = \boxed{2.85\text{E-}06 \text{ g/(s-m}^2)}$$

$PM_{2.5}$ Emission Rate

$$3.86\text{E-}3 \text{ ton/yr} * \frac{2000 \text{ lb/ton}}{8760 \text{ hr/yr}} * \frac{453.6 \text{ g/lb}}{3600 \text{ sec/hr}} / 257 \text{ m}^2 = \boxed{4.32\text{E-}07 \text{ g/(s-m}^2)}$$

Limestone Rail Unloading

PM_{10} Emission Rate	8.95E-2 ton/yr
$PM_{2.5}$ Emission Rate	1.35E-2 ton/yr
Modeled Area	168 m^2

PM_{10} Emission Rate

$$8.95\text{E-}2 \text{ ton/yr} * \frac{2000 \text{ lb/ton}}{8760 \text{ hr/yr}} * \frac{453.6 \text{ g/lb}}{3600 \text{ sec/hr}} / 168 \text{ m}^2 = \boxed{1.53\text{E-}05 \text{ g/(s-m}^2)}$$

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$PM_{2.5}$ Emission Rate

1.35E-2 ton/yr	*	2000 lb/ton 8760 hr/yr	*	453.6 g/lb 3600 sec/hr	/	168 m^2	=	2.32E-06 g/(s-m^2)

Coal Rail Unlading

PM_{10} Emission Rate	1.34E-1 ton/yr
$PM_{2.5}$ Emission Rate	2.03E-2 ton/yr
Modeled Area	167 m^2

PM_{10} Emission Rate

1.34E-1 ton/yr	*	2000 lb/ton 8760 hr/yr	*	453.6 g/lb 3600 sec/hr	/	167 m^2	=	2.31E-05 g/(s-m^2)

$PM_{2.5}$ Emission Rate

2.03E-2 ton/yr	*	2000 lb/ton 8760 hr/yr	*	453.6 g/lb 3600 sec/hr	/	167 m^2	=	3.50E-06 g/(s-m^2)

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

7 Solid Material Handling Facility Fugitive Dust Emissions

Emissions form Earth Moving Operations-Ash Portion of SMHF - Source A1

Basis	Value	Units	Reference
PM_{10} Scaling Factor, k	0.75		AP-42, Table 11.9-1 Bulldozing (Overburden)
$PM_{2.5}$ Scaling Factor, k	0.105		AP-42, Table 11.9-1 Bulldozing (Overburden)
Silt Content	6.9	%	AP-42, Table 11.9-3 Bulldozers (Overburden)
Moisture Content	7.9	%	AP-42, Table 11.9-3 Bulldozers (Overburden)
Control Efficiency	90	%	Plant Washington Specification
Solid Material Handling Area	118	acres	Plant Washington Specification
Acre to m^2 Conversion	4046.86	m^2/Acre	Conversion Factor

PM Emissions

5.7 * (6.9 ^ 1.2) / (7.9 ^ 1.3) = 3.94 lb/hr

3.94 lb/hr * (1 ton / 2000 lb) * 8,760 hr/yr * ((100%-90%) / 100%) = **1.73 ton/yr**

PM_{10} Emission Rate

0.75 * 1 * (6.9 ^ 1.5) / (7.9 ^ 1.4) = 0.75 lb/hr

0.75 lb/hr * (1 ton / 2000 lb) * 8,760 hr/yr * ((100%-90%) / 100%) = **0.33 ton/yr**

Area Emission Rate

0.33 ton/yr * (2000 lb / 1 ton) / 8,760 hr/yr * (1 hr / 3600 s) * (453.5 g / 1 lb) = 0.01 g/s

(0.01 g/s / 118 acre) / (4.05E+03 m^2 / acre) = **1.99E-08 g/(s-m^2)**

$PM_{2.5}$ Emission Rate

0.105 * 5.7 * (6.9 ^ 1.2) / (7.9 ^ 1.3) = 0.41 lb/hr

0.41 lb/hr * (1 ton / 2000 lb) * 8,760 hr/yr * ((100%-90%) / 100%) = **0.18 ton/yr**

Area Emission Rate

0.18 ton/yr * (2000 lb / 1 ton) / 8,760 hr/yr * (1 hr / 3600 s) * (453.5 g / 1 lb) = 5.21E-03 g/s

(5.21E-03 g/s / 118 acre) / (4.05E+03 m^2 / acre) = **1.09E-08 g/(s-m^2)**

Completed by: BSA11/26/2008
Checked by: SAK 11/26/2008

Emissions form Earth Moving Operations-Gypsum Portion of SMHF - Source A2

Basis	Value	Units	Reference
PM_{10} Scaling Factor, k	0.75		AP-42, Table 11.9-1 Bulldozing (Overburden)
$PM_{2.5}$ Scaling Factor, k	0.105		AP-42, Table 11.9-1 Bulldozing (Overburden)
Silt Content	6.9	%	AP-42, Table 11.9-3 Bulldozers (Overburden)
Moisture Content	7.9	%	AP-42, Table 11.9-3 Bulldozers (Overburden)
Control Efficiency	90	%	Plant Washington Specification
Solid Material Handling Area	267	acres	Plant Washington Specification
Acre to m^2 Conversion	4046.86	m^2/Acre	Conversion Factor

PM Emissions

5.7 * (6.9 ^ 1.2) / (7.9 ^ 1.3) = 3.94 lb/hr

3.94 lb/hr * (1 ton / 2000 lb) * 8,760 hr/yr * ((100%-90%) / 100%) = **1.73 ton/yr**

PM_{10} Emission Rate

0.75 * 1 * (6.9 ^ 1.5) / (7.9 ^ 1.4) = 0.75 lb/hr

0.75 lb/hr * (1 ton / 2000 lb) * 8,760 hr/yr * ((100%-90%) / 100%) = **0.33 ton/yr**

Area Emission Rate

0.33 ton/yr * (2000 lb / 1 ton) / 8,760 hr/yr * (1 hr / 3600 s) * (453.5 g / 1 lb) = 0.01 g/s

(0.01 g/s / 267 acre) / (4.05E+03 m^2 / acre) = **8.78E-09 g/(s-m^2)**

$PM_{2.5}$ Emission Rate

0.105 * 5.7 * (6.9 ^ 1.2) / (7.9 ^ 1.3) = 0.41 lb/hr

0.41 lb/hr * (1 ton / 2000 lb) * 8,760 hr/yr * ((100%-90%) / 100%) = **0.18 ton/yr**

Area Emission Rate

0.18 ton/yr * (2000 lb / 1 ton) / 8,760 hr/yr * (1 hr / 3600 s) * (453.5 g / 1 lb) = 5.21E-03 g/s

(5.21E-03 g/s / 267 acre) / (4.05E+03 m^2 / acre) = **4.82E-09 g/(s-m^2)**

Completed by: BSA11/26/2008
Checked by: SAK 11/26/2008

8 InActive PRB Coal Storage Pile Emission Calculations - Source A6

Basis	Value		Reference
Pile Volume	20,422,395	ft^3	Plant Washington Specification- Based on Trapezoidal-elevated Plane Shape
Base Width	900	ft	Plant Washington Specification
Base length	750	ft	Plant Washington Specification
Top Width	802	ft	Plant Washington Specification
Top length	652	ft	Plant Washington Specification
Pile Height	34.2	ft	Plant Washington Specification
Threshold Velocity	1.12	m/s	Table 13.2.5-2 AP-42 for wind erosion from piles
Surface Area	705,977 ft^2 =	65,581 m^2	

Modeled Area at top of pile 802 ft * 652 ft = 523,058 ft^2 = 48,589 m^2

Pile B2 from Fig 13..2.5-2 is the selected Pile Configuration for wind contours because the prevailing wind is WNW. According to the figure, the maximum shear velocity is 1.1 times ten percent of the prevailing wind; therefore, wind erosion occurs whenever the fastest 2 minute wind exceeds the following value:

$$V = \frac{1.12}{0.11} = 10.2 \text{ m/s} = 22.78 \text{ mph}$$

Sample Calculation:
Erosion Potentials were calculated for the dates where the normalized wind surface wind speeds exceeded the threshold velocity for uncrusted coal piles (1.12 m/s)
Erosion Potential ((AP-42, 13.2.5-3, Equation 3)
$P=58(u^*-u^*_t)^2+25(u^*-u^*_t)$ g/m^2
where:
P = Erosion Potential
u^* = Friction velocity = 0.1 u
u^*_t = Threshold Friction Velocity
u_s = Surface Wind Speed
u_t = Approach Wind Speed
December 1, 2006 - 1.1 Wind Contour

$$P = 58 * (1.13 - 1.12)^2 + 25 * (1.13 - 1.12) = 0.28 \text{ g/m^2}$$

Emissions are computed by multiplying the Erosion Potential by the surface area of the pile, the Aerodynamic Particle Size Multiplier to speciate the PM size, and the fraction of the pile subarea that is subject to a specified wind contour. Emissions from the pile are controlled to 90% by dust suppressant

Emission rates multiplied by k = 0.5 to reduce emissions to just PM_{10} and k = 0.075 to $PM_{2.5}$ (AP-42, 13.2.5-3)
Fraction of Pile Subarea Subject to 0.9 Contour of Normalized Surface Wind Speed = 0
Fraction of Pile Subarea Subject to 1.1 Contour of Normalized Surface Wind Speed = 0
December 1, 2006 - PM10 Emissions for 1.1 Wind Contour

$$0.28 \text{ g/m^2} * 65{,}581 \text{ m^2} * 0.5 * 0 * \frac{(100\%-90\%)}{100\%} = 0.00 \text{ g/d}$$

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

InActive PRB Coal Storage Pile Emission Calculations - Source A6

Daily records of fastest mile from 12/1/06 through 11/30/07 and it exceeded the calculated threshold on the following dates:(10 m anemometer)

	Wind Speed	Wind Speed	Normalized Surface Wind Speeds				Erosion Potential $P=58(u^*-u^*_t)^2+25(u^*-u^*_t)$ g/m^2 (AP-42, 13.2.5-3, Equation 3)		Daily PM_{10} Erosion Potential		Daily PM_{10} Erosion Potential Summation	Daily $PM_{2.5}$ Erosion Potential		Daily $PM_{2.5}$ Erosion Potential Summation
Date	mph	m/s	$u_t/u_t = 0.2$	$u_t/u_t = 0.6$	$u_t/u_t = 0.9$	$u_t/u_t = 1.1$	P(0.9)	P(1.1)	P(0.9)	P(1.1)		P(0.9)	P(1.1)	
20061201	23	10.28	0.21	0.62	0.93	1.13					0.00		0.00	0.00
20061207	24	10.73	0.21	0.64	0.97	1.18					0		0.00	0.00
20061225	26	11.62	0.23	0.70	1.05	1.28					0		0.00	0.00
20061226	23	10.28	0.21	0.62	0.93	1.13					0.00		0.00	0.00
20061231	24	10.73	0.21	0.64	0.97	1.18					0		0.00	0.00
20070108	23	10.28	0.21	0.62	0.93	1.13					0		0.00	0.00
20070109	28	12.52	0.25	0.75	1.13	1.38					0	0.00	0.00	0
20070128	24	10.73	0.21	0.64	0.97	1.18					0		0.00	0.00
20070213	31	13.86	0.28	0.83	1.25	1.52					0	0	0.00	0
20070218	23	10.28	0.21	0.62	0.93	1.13					0.00		0.00	0.00
20070301	32	14.30	0.29	0.86	1.29	1.57					0	0	0.00	0
20070302	30	13.41	0.27	0.80	1.21	1.48					0	0	0.00	0
20070316	29	12.96	0.26	0.78	1.17	1.43					0	0	0.00	0
20070404	33	14.75	0.30	0.89	1.33	1.62					0	0	0.00	0
20070415	32	14.30	0.29	0.86	1.29	1.57					0	0	0.00	0
20070416	28	12.52	0.25	0.75	1.13	1.38					0	0	0.00	0.00
20070508	23	10.28	0.21	0.62	0.93	1.13					0.00		0.00	0.00
20070603	23	10.28	0.21	0.62	0.93	1.13					0.00		0.00	0.00
20070629	32	14.30	0.29	0.86	1.29	1.57					0	0	0.00	0
20070701	28	12.52	0.25	0.75	1.13	1.38					0	0	0.00	0
20070711	25	11.18	0.22	0.67	1.01	1.23					0		0.00	0.00
20070720	38	16.99	0.34	1.02	1.53	1.87					0	0	0.00	0
20070806	23	10.28	0.21	0.62	0.93	1.13					0		0.00	0.00
20070816	25	11.18	0.22	0.67	1.01	1.23					0		0.00	0.00
20070817	41	18.33	0.37	1.10	1.65	2.02					0	0	0.00	0
20070824	26	11.62	0.23	0.70	1.05	1.28					0		0.00	0.00
20071115	25	11.18	0.22	0.67	1.01	1.23					0		0.00	0.00
								Subtotal	0	0 g/yr	0 g/d	0 g/yr	0 g/yr	0 g/d

Annual Emission Rate	0 g/yr 0.00E+00 ton/yr	**Annual Emission Rate**	0 g/yr 0.00E+00 ton/yr
24 Hour Emission Rate	0 g/d 0.00 ton/yr	**24 Hour Emission Rate**	0 g/d 0.00E+00 ton/yr

The shape (Trapezoidal-elevated plane) of the inactive pile is such that no contours of 0.9 or greater will occur on the pile. None of the 0.2 or 0.6 contours exceed the 1.12 threshold velocity. Wind erosion emission from the inactive pile are therefore zero.

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

InActive PRB Coal Storage Pile Emission Calculations - Source A6

Area Emission Rate (Drop Point Emissions and Wind Erosion)

Basis	Value	Reference
PM_{10} Drop Point Emission Rate	3.28E-02 ton/yr	See calculation 6
$PM_{2.5}$ Drop Point Emission Rate	4.97E-03 ton/yr	See calculation 6
PM_{10} Annual Emission Rate-Wind Erosion	0.00E+00 ton/yr	See calculation above
$PM_{2.5}$ Annual Emission Rate-Wind Erosion	0.00E+00 ton/yr	See calculation above
PM_{10} 24-Hr Emission Rate-Wind Erosion	0.00E+00 ton/yr	See calculation above
$PM_{2.5}$ 24-Hr Emission Rate-Wind Erosion	0.00E+00 ton/yr	See calculation above
Area at Half Height- Modeled Area	48,589 m^2	See calculation above

PM_{10} Emission Rate- Annual

3.28E-02 ton/yr + 0.00E+00 ton/yr = 3.28E-02 ton/yr

3.28E-02 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 48,589 m^2 = 1.94E-08 g/(s-m^2)

$PM_{2.5}$ Emission Rate- Annual

4.97E-03 ton/yr + 0.00E+00 ton/yr = 4.97E-03 ton/yr

4.97E-03 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 48,589 m^2 = 2.94E-09 g/(s-m^2)

PM_{10} Emission Rate- 24-Hr

3.28E-02 ton/yr + 0.00E+00 ton/yr = 3.28E-02 ton/yr

3.28E-02 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 48,589 m^2 = 1.94E-08 g/(s-m^2)

$PM_{2.5}$ Emission Rate- 24-Hr

4.97E-03 ton/yr + 0.00E+00 ton/yr = 4.97E-03 ton/yr

4.97E-03 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 48,589 m^2 = 2.94E-09 g/(s-m^2)

9 InActive Illinois No. 6 Coal Storage Pile Emission Calculations - Source A7

Basis	Value		Reference
Pile Volume	9,465,546	ft^3	Plant Washington Specification- Based on Trapezoidal-elevated Plane Shape
Base Width	750	ft	Plant Washington Specification
Base length	550	ft	Plant Washington Specification
Top Width	676	ft	Plant Washington Specification
Top length	476	ft	Plant Washington Specification
Pile Height	25.9	ft	Plant Washington Specification
Threshold Velocity	1.12	m/s	Table 13.2.5-2 AP-42 for wind erosion from piles
Surface Area	431,063 ft^2 =	40,043 m^2	

Modeled Area at top of pile 676 ft * 476 ft = 321,874 ft^2 = 29,900 m^2

Pile B2 from Fig 13..2.5-2 is the selected Pile Configuration for wind contours because the prevailing wind is WNW. According to the figure, the maximum shear velocity is 1.1 times ten percent of the prevailing wind; therefore, wind erosion occurs whenever the fastest 2 minute wind exceeds the following value:

$$V = \frac{1.12}{0.11} = 10.2 \text{ m/s} = 22.78 \text{ mph}$$

Sample Calculation:
Erosion Potentials were calculated for the dates where the normalized wind surface wind speeds exceeded the threshold velocity for uncrusted coal piles (1.12 m/s)
Erosion Potential ((AP-42, 13.2.5-3, Equation 3)
$P=58(u^*-u^*_t)^2+25(u^*-u^*_t)$ g/m^2
where:
P = Erosion Potential
u^* = Friction velocity = 0.1 u
u^*_t = Threshold Friction Velocity
u_t = Surface Wind Speed
u_t = Approach Wind Speed
December 1, 2006 - 1.1 Wind Contour

$$P = 58 * (1.13 - 1.12)^2 + 25 * (1.13 - 1.12) = 0.28 \text{ g/m^2}$$

Emissions are computed by multiplying the Erosion Potential by the surface area of the pile, the Aerodynamic Particle Size Multiplier to speciate the PM size, and the fraction of the pile subarea that is subject to a specified wind contour. Emissions from the pile are controlled to 90% by dust suppressant

Emission rates multiplied by k = 0.5 to reduce emissions to just PM_{10} and k = 0.075 to $PM_{2.5}$ (AP-42, 13.2.5-3)
Fraction of Pile Subarea Subject to 0.9 Contour of Normalized Surface Wind Speed = 0.0
Fraction of Pile Subarea Subject to 1.1 Contour of Normalized Surface Wind Speed = 0.0
December 1, 2006 - PM10 Emissions for 1.1 Wind Contour

$$0.28 \text{ g/m^2} * 40{,}043 \text{ m^2} * 0.5 * 0 * \frac{(100\%-90\%)}{100\%} = 0.00 \text{ g/d}$$

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

InActive Illinois No. 6 Coal Storage Pile Emission Calculations - Source A7

Daily records of fastest mile from 12/1/06 through 11/30/07 and it exceeded the calculated threshold on the following dates:(10 m anemometer)

	Wind Speed	Wind Speed	Normalized Surface Wind Speeds				Erosion Potential $P=58(u^*-u^*_t)^2+25(u^*-u^*_t)$ g/m^2 (AP-42, 13.2.5-3, Equation 3)		Daily PM_{10} Erosion Potential		Daily PM_{10} Erosion Potential Summation	Daily $PM_{2.5}$ Erosion Potential		Daily $PM_{2.5}$ Erosion Potential Summation
Date	mph	m/s	$u_t/u_t = 0.2$	$u_t/u_t = 0.6$	$u_t/u_t = 0.9$	$u_t/u_t = 1.1$	P(0.9)	P(1.1)	P(0.9)	P(1.1)		P(0.9)	P(1.1)	
20061201	23	10.28	0.21	0.62	0.93	1.13					0.00		0.00	0.00
20061207	24	10.73	0.21	0.64	0.97	1.18					0		0.00	0.00
20061225	26	11.62	0.23	0.70	1.05	1.28					0		0.00	0.00
20061226	23	10.28	0.21	0.62	0.93	1.13					0.00		0.00	0.00
20061231	24	10.73	0.21	0.64	0.97	1.18					0		0.00	0.00
20070108	23	10.28	0.21	0.62	0.93	1.13					0		0.00	0.00
20070109	28	12.52	0.25	0.75	1.13	1.38					0	0.00	0.00	0
20070128	24	10.73	0.21	0.64	0.97	1.18					0		0.00	0.00
20070213	31	13.86	0.28	0.83	1.25	1.52					0	0	0.00	0
20070218	23	10.28	0.21	0.62	0.93	1.13					0.00		0.00	0.00
20070301	32	14.30	0.29	0.86	1.29	1.57					0	0	0.00	0
20070302	30	13.41	0.27	0.80	1.21	1.48					0	0	0.00	0
20070316	29	12.96	0.26	0.78	1.17	1.43					0	0	0.00	0
20070404	33	14.75	0.30	0.89	1.33	1.62					0	0	0.00	0
20070415	32	14.30	0.29	0.86	1.29	1.57					0	0	0.00	0
20070416	28	12.52	0.25	0.75	1.13	1.38					0	0	0.00	0.00
20070508	23	10.28	0.21	0.62	0.93	1.13					0.00		0.00	0.00
20070603	23	10.28	0.21	0.62	0.93	1.13					0.00		0.00	0.00
20070629	32	14.30	0.29	0.86	1.29	1.57					0	0	0.00	0
20070701	28	12.52	0.25	0.75	1.13	1.38					0	0	0.00	0
20070711	25	11.18	0.22	0.67	1.01	1.23					0		0.00	0.00
20070720	38	16.99	0.34	1.02	1.53	1.87					0	0	0.00	0
20070806	23	10.28	0.21	0.62	0.93	1.13					0		0.00	0.00
20070816	25	11.18	0.22	0.67	1.01	1.23					0		0.00	0.00
20070817	41	18.33	0.37	1.10	1.65	2.02					0	0	0.00	0
20070824	26	11.62	0.23	0.70	1.05	1.28					0		0.00	0.00
20071115	25	11.18	0.22	0.67	1.01	1.23					0		0.00	0.00
								Subtotal	0 g/yr	0 g/yr	0 g/d	0 g/yr	0 g/yr	0 g/d
								Annual Emission Rate		0 g/yr 0.00E+00 ton/yr	**Annual Emission Rate**		0 g/yr 0.00E+00 ton/yr	
								24 Hour Emission Rate		0 g/d 0.00 ton/yr	**24 Hour Emission Rate**		0 g/d 0.00E+00 ton/yr	

The shape (Trapezoidal-elevated plane) of the inactive pile is such that no contours of 0.9 or greater will occur on the pile. None of the 0.2 or 0.6 contours exceed the 1.12 threshold velocity. Wind erosion emission from the inactive pile are therefore zero.

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

InActive Illinois No. 6 Coal Storage Pile Emission Calculations - Source A7

Area Emission Rate (Drop Point Emissions and Wind Erosion)

Basis	Value	Reference
PM_{10} Drop Point Emission Rate	1.50E-01 ton/yr	See calculation 6
$PM_{2.5}$ Drop Point Emission Rate	2.27E-02 ton/yr	See calculation 6
PM_{10} Annual Emission Rate-Wind Erosion	0.00E+00 ton/yr	See calculation above
$PM_{2.5}$ Annual Emission Rate-Wind Erosion	0.00E+00 ton/yr	See calculation above
PM_{10} 24-Hr Emission Rate-Wind Erosion	0.00E+00 ton/yr	See calculation above
$PM_{2.5}$ 24-Hr Emission Rate-Wind Erosion	0.00E+00 ton/yr	See calculation above
Area at Half Height- Modeled Area	29,900 m^2	See calculation above

PM_{10} Emission Rate- Annual

1.50E-01 ton/yr + 0.00E+00 ton/yr = 1.50E-01 ton/yr

1.50E-01 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 29,900 m^2 = 1.44E-07 g/(s-m^2)

$PM_{2.5}$ Emission Rate- Annual

2.27E-02 ton/yr + 0.00E+00 ton/yr = 2.27E-02 ton/yr

2.27E-02 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 29,900 m^2 = 2.18E-08 g/(s-m^2)

PM_{10} Emission Rate- 24-Hr

1.50E-01 ton/yr + 0.00E+00 ton/yr = 1.50E-01 ton/yr

1.50E-01 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 29,900 m^2 = 1.44E-07 g/(s-m^2)

$PM_{2.5}$ Emission Rate- 24-Hr

2.27E-02 ton/yr + 0.00E+00 ton/yr = 2.27E-02 ton/yr

2.27E-02 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 29,900 m^2 = 2.18E-08 g/(s-m^2)

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

10 Active PRB Coal Storage Pile Emission Calculations - Source A8

Basis	Value		Reference
Pile Volume	2,137,605	ft^3	Plant Washington Specification
Pile Diameter	286	feet	Plant Washington Specification
Threshold Velocity	1.12	m/s	Table 13.2.5-2 AP-42 for wind erosion from piles

Pile Dimension Calculations

Assumed cone shape V=1/3*h*Area of base

Surface Area = 1/2*(perimeter of base* slant height)

slant height = $SQRT(h^2+(L/2)^2)$

Area of Base π * 286 ft ^ 2 / 4 = 64,242 ft^2

Height 3 * 2,137,605 ft^3 / 64,242 ft^2 = 100 ft

Radius at Half Height 71.30 ft

Area at Half Height 15,963 ft^2 = 1,483 m^2

Slant Height SQRT (143 ft ² + 100 ft ²) = 174 ft

Surface Area ((π * 286 ft) * 174 ft) * 0.5 = 78,346 ft^2 = 7,278 m^2

Pile B2 from Fig 13..2.5-2 is the selected Pile Configuration for wind contours because the prevailing wind is WNW. According to the figure, the maximum shear velocity is 1.1 times ten percent of the prevailing wind; therefore, wind erosion occurs whenever the fastest 2 minute wind exceeds the following value:

$$V = \frac{1.12}{0.11} = 10.2 \text{ m/s} = 22.78 \text{ mph}$$

Sample Calculation:

Erosion Potentials were calculated for the dates where the normalized wind surface wind speeds exceeded the threshold velocity for uncrusted coal piles (1.12 m/s)

Erosion Potential ((AP-42, 13.2.5-3, Equation 3)

$P=58(u^*-u^*_t)^2+25(u^*-u^*_t)$ g/m^2

where:

P = Erosion Potential

u^* = Friction velocity = 0.1 u

u^*_t = Threshold Friction Velocity

u_s = Surface Wind Speed

u_r = Approach Wind Speed

December 1, 2006 - 1.1 Wind Contour

$$P = 58 * (1.13 - 1.12)^2 + 25 * (1.13 - 1.12) = 0.28 \text{ g/m}^2$$

Emissions are computed by multiplying the Erosion Potential by the surface area of the pile, the Aerodynamic Particle Size Multiplier to speciate the PM size, and the fraction of the pile subarea that is subject to a specified wind contour. Emissions from the pile are controlled to 90% by dust suppressant

Emission rates multiplied by k = 0.5 to reduce emissions to just PM_{10} and k = 0.075 to $PM_{2.5}$ (AP-42, 13.2.5-3)

Fraction of Pile Subarea Subject to 0.9 Contour of Normalized Surface Wind Speed = 0.17

Fraction of Pile Subarea Subject to 1.1 Contour of Normalized Surface Wind Speed = 0.024

December 1, 2006 - PM10 Emissions for 1.1 Wind Contour

$$0.28 \text{ g/m}^2 * 7{,}278 \text{ m}^2 * 0.5 * 0.024 * \frac{(100\%-90\%)}{100\%} = 2.45 \text{ g/d}$$

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

Active PRB Coal Storage Pile Emission Calculations - Source A8

Daily records of fastest mile from 12/1/06 through 11/30/07 and it exceeded the calculated threshold on the following dates:(10 m anemometer)

	Wind Speed	Wind Speed	Normalized Surface Wind Speeds				Erosion Potential $P=58(u^*-u^*_t)^2+25(u^*-u^*_t)$ g/m^2 (AP-42, 13.2.5-3, Equation 3)		Daily PM_{10} Erosion Potential		Daily PM_{10} Erosion Potential Summation	Daily $PM_{2.5}$ Erosion Potential		Daily $PM_{2.5}$ Erosion Potential Summation
Date	mph	m/s	$u_s/u_t = 0.2$	$u_s/u_t = 0.6$	$u_s/u_t = 0.9$	$u_s/u_t = 1.1$	P(0.9)	P(1.1)	P(0.9)	P(1.1)		P(0.9)	P(1.1)	
20061201	23	10.28	0.21	0.62	0.93	1.13		0.28		2.45	2.45		0.37	0.37
20061207	24	10.73	0.21	0.64	0.97	1.18		1.71		15	15		2.24	2.24
20061225	26	11.62	0.23	0.70	1.05	1.28		5.42		47	47		7.10	7.10
20061226	23	10.28	0.21	0.62	0.93	1.13		0.28		2.45	2.45		0.37	0.37
20061231	24	10.73	0.21	0.64	0.97	1.18		1.71		15	15		2.24	2.24
20070108	23	10.28	0.21	0.62	0.93	1.13		0.28		2	2		0.37	0.37
20070109	28	12.52	0.25	0.75	1.13	1.38	0.16	10.25	10.18	89	100	1.53	13.42	15
20070128	24	10.73	0.21	0.64	0.97	1.18		1.71		15	15		2.24	2.24
20070213	31	13.86	0.28	0.83	1.25	1.52	4.12	19.59	255	171	426	38	25.7	64
20070218	23	10.28	0.21	0.62	0.93	1.13		0.28		2.45	2.45		0.37	0.37
20070301	32	14.30	0.29	0.86	1.29	1.57	5.81	23.27	359	203	563	54	30.5	84
20070302	30	13.41	0.27	0.80	1.21	1.48	2.61	16.20	162	141	303	24	21.2	45
20070316	29	12.96	0.26	0.78	1.17	1.43	1.29	13.08	80	114	194	12	17.1	29
20070404	33	14.75	0.30	0.89	1.33	1.62	7.69	27.22	476	238	714	71	35.7	107
20070415	32	14.30	0.29	0.86	1.29	1.57	5.81	23.27	359	203	563	54	30.5	84
20070416	28	12.52	0.25	0.75	1.13	1.38	0.16	10.25	10.18	89	100	1.53	13.42	14.95
20070508	23	10.28	0.21	0.62	0.93	1.13		0.28		2.45	2.45		0.37	0.37
20070603	23	10.28	0.21	0.62	0.93	1.13		0.28		2.45	2.45		0.37	0.37
20070629	32	14.30	0.29	0.86	1.29	1.57	5.81	23.27	359	203	563	54	30.5	84
20070701	28	12.52	0.25	0.75	1.13	1.38	0.16	10.25	10.18	89	100	1.53	13.42	15
20070711	25	11.18	0.22	0.67	1.01	1.23		3.43		30	30		4.49	4.49
20070720	38	16.99	0.34	1.02	1.53	1.87	19.91	51.21	1,232	447	1,679	185	67.1	252
20070806	23	10.28	0.21	0.62	0.93	1.13		0.28		2	2		0.37	0.37
20070816	25	11.18	0.22	0.67	1.01	1.23		3.43		30	30		4.49	4.49
20070817	41	18.33	0.37	1.10	1.65	2.02	29.50	68.97	1,825	602	2,427	274	90.4	364
20070824	26	11.62	0.23	0.70	1.05	1.28		5.42		47	47		7.10	7.10
20071115	25	11.18	0.22	0.67	1.01	1.23		3.43		30	30		4.49	4.49
								Subtotal	5,138	2,839 g/yr	2,427 g/d	771 g/yr	426 g/yr	364 g/d
								Annual Emission Rate		7,977 g/yr	**Annual Emission Rate**		1,196 g/yr	
										8.79E-03 ton/yr			1.32E-03 ton/yr	
								24 Hour Emission Rate		2,427 g/d	**24 Hour Emission Rate**		364 g/d	
										0.98 ton/yr			1.46E-01 ton/yr	

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

Active PRB Coal Storage Pile Emission Calculations - Source A8

Area Emission Rate (Drop Point Emissions and Wind Erosion)

Basis	Value	Reference
PM_{10} Drop Point Emission Rate	3.28E-02 ton/yr	See calculation 6
$PM_{2.5}$ Drop Point Emission Rate	4.97E-03 ton/yr	See calculation 6
PM_{10} Annual Emission Rate-Wind Erosion	8.79E-03 ton/yr	See calculation above
$PM_{2.5}$ Annual Emission Rate-Wind Erosion	1.32E-03 ton/yr	See calculation above
PM_{10} 24-Hr Emission Rate-Wind Erosion	9.77E-01 ton/yr	See calculation above
$PM_{2.5}$ 24-Hr Emission Rate-Wind Erosion	1.46E-01 ton/yr	See calculation above
Area at Half Height- Modeled Area	1,483 m^2	See calculation above

PM_{10} Emission Rate- Annual

3.28E-02 ton/yr + 8.79E-03 ton/yr = 4.16E-02 ton/yr

4.16E-02 ton/yr * (2000 lb/ton / 8760 hr/yr) * (453.6 g/lb / 3600 sec/hr) / 1,483 m^2 = **8.07E-07 g/(s-m^2)**

$PM_{2.5}$ Emission Rate- Annual

4.97E-03 ton/yr + 1.32E-03 ton/yr = 6.29E-03 ton/yr

6.29E-03 ton/yr * (2000 lb/ton / 8760 hr/yr) * (453.6 g/lb / 3600 sec/hr) / 1,483 m^2 = **1.22E-07 g/(s-m^2)**

PM_{10} Emission Rate- 24-Hr

3.28E-02 ton/yr + 9.77E-01 ton/yr = 1.01E+00 ton/yr

1.01E+00 ton/yr * (2000 lb/ton / 8760 hr/yr) * (453.6 g/lb / 3600 sec/hr) / 1,483 m^2 = **1.96E-05 g/(s-m^2)**

$PM_{2.5}$ Emission Rate- 24-Hr

4.97E-03 ton/yr + 1.46E-01 ton/yr = 1.51E-01 ton/yr

1.51E-01 ton/yr * (2000 lb/ton / 8760 hr/yr) * (453.6 g/lb / 3600 sec/hr) / 1,483 m^2 = **2.94E-06 g/(s-m^2)**

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

11 Active Illinois No. 6 Coal Storage Pile Emission Calculations - Source A9

Basis	Value		Reference
Pile Volume	2,137,605	ft^3	Plant Washington Specification
Pile Diameter	286	feet	Plant Washington Specification
Threshold Velocity	1.12	m/s	Table 13.2.5-2 AP-42 for wind erosion from piles
N	365	days	Daily fresh coal applied to the Main Inactive pile

Pile Dimension Calculations

Assumed cone shape V=1/3*h*Area of base

Surface Area = 1/2*(perimeter of base* slant height)

slant height = SQRT(h^2+$(L/2)^2$)

Area of Base π * 286 ft ^ 2 / 4 = 64,242 ft^2

Height 3 * 2,137,605 ft^3 / 64,242 ft^2 = 100 ft

Radius at Half Height 71.30 ft

Area at Half Height 15,963 ft^2 = 1,483 m^2

Slant Height SQRT [143 ft ^{2} + 100 ft ^{2}] = 174 ft

Surface Area [[π * 286 ft] * 174 ft] * 0.5 = 78,346 ft^2 = 7,278 m^2

Pile B2 from Fig 13..2.5-2 is the selected Pile Configuration for wind contours because the prevailing wind is WNW. According to the figure, the maximum shear velocity is 1.1 times ten percent of the prevailing wind; therefore, wind erosion occurs whenever the fastest 2 minute wind exceeds the following value:

$$V = \frac{1.12}{0.11} = 10.2 \text{ m/s} = 22.78 \text{ mph}$$

Sample Calculation:

Erosion Potentials were calculated for the dates where the normalized wind surface wind speeds exceeded the threshold velocity for uncrusted coal piles (1.12 m/s)

Erosion Potential ((AP-42, 13.2.5-3, Equation 3)

$P=58(u^*-u^*_t)^2+25(u^*-u^*_t)$ g/m^2

where:

P = Erosion Potential

u* = Friction velocity = 0.1 u

u^*_t = Threshold Friction Velocity

u_s = Surface Wind Speed

u_t = Approach Wind Speed

December 1, 2006 - 1.1 Wind Contour

$$P = 58 * (1.13 - 1.12)^2 + 25 * (1.13 - 1.12) = 0.28 \text{ g/m}^2$$

Emissions are computed by multiplying the Erosion Potential by the surface area of the pile, the Aerodynamic Particle Size Multiplier to speciate the PM size, and the fraction of the pile subarea that is subject to a specified wind contour. Emissions from the pile are controlled to 90% by dust suppressant

Emission rates multiplied by k = 0.5 to reduce emissions to just PM_{10} and k = 0.075 to $PM_{2.5}$ (AP-42, 13.2.5-3)

Fraction of Pile Subarea Subject to 0.9 Contour of Normalized Surface Wind Speed = 0.17

Fraction of Pile Subarea Subject to 1.1 Contour of Normalized Surface Wind Speed = 0.024

December 1, 2006 - PM10 Emissions for 1.1 Wind Contour

$$0.28 \text{ g/m}^2 * 7{,}278 \text{ m}^2 * 0.5 * 0.024 * \frac{(100\%-90\%)}{100\%} = 2.45 \text{ g/d}$$

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

Active Illinois No. 6 Coal Storage Pile Emission Calculations - Source A9

Daily records of fastest mile from 12/1/06 through 11/30/07 and it exceeded the calculated threshold on the following dates:(10 m anemometer)

	Wind Speed	Wind Speed	Normalized Surface Wind Speeds				Erosion Potential $P=58(u^*-u^*_t)^2+25(u^*-u^*_t)$ g/m^2 (AP-42, 13.2.5-3, Equation 3)		Daily PM_{10} Erosion Potential		Daily PM_{10} Erosion Potential Summation	Daily $PM_{2.5}$ Erosion Potential		Daily $PM_{2.5}$ Erosion Potential Summation
Date	mph	m/s	$u_s/u_t = 0.2$	$u_s/u_t = 0.6$	$u_s/u_t = 0.9$	$u_s/u_t = 1.1$	P(0.9)	P(1.1)	P(0.9)	P(1.1)		P(0.9)	P(1.1)	
20061201	23	10.28	0.21	0.62	0.93	1.13		0.28		2.45	2.45		0.37	0.37
20061207	24	10.73	0.21	0.64	0.97	1.18		1.71		15	15		2.24	2.24
20061225	26	11.62	0.23	0.70	1.05	1.28		5.42		47	47		7.10	7.10
20061226	23	10.28	0.21	0.62	0.93	1.13		0.28		2.45	2.45		0.37	0.37
20061231	24	10.73	0.21	0.64	0.97	1.18		1.71		15	15		2.24	2.24
20070108	23	10.28	0.21	0.62	0.93	1.13		0.28		2	2		0.37	0.37
20070109	28	12.52	0.25	0.75	1.13	1.38	0.16	10.25	10.18	89	100	1.53	13.42	15
20070128	24	10.73	0.21	0.64	0.97	1.18		1.71		15	15		2.24	2.24
20070213	31	13.86	0.28	0.83	1.25	1.52	4.12	19.59	255	171	426	38	25.7	64
20070218	23	10.28	0.21	0.62	0.93	1.13		0.28		2.45	2.45		0.37	0.37
20070301	32	14.30	0.29	0.86	1.29	1.57	5.81	23.27	359	203	563	54	30.5	84
20070302	30	13.41	0.27	0.80	1.21	1.48	2.61	16.20	162	141	303	24	21.2	45
20070316	29	12.96	0.26	0.78	1.17	1.43	1.29	13.08	80	114	194	12	17.1	29
20070404	33	14.75	0.30	0.89	1.33	1.62	7.69	27.22	476	238	714	71	35.7	107
20070415	32	14.30	0.29	0.86	1.29	1.57	5.81	23.27	359	203	563	54	30.5	84
20070416	28	12.52	0.25	0.75	1.13	1.38	0.16	10.25	10.18	89	100	1.53	13.42	14.95
20070508	23	10.28	0.21	0.62	0.93	1.13		0.28		2.45	2.45		0.37	0.37
20070603	23	10.28	0.21	0.62	0.93	1.13		0.28		2.45	2.45		0.37	0.37
20070629	32	14.30	0.29	0.86	1.29	1.57	5.81	23.27	359	203	563	54	30.5	84
20070701	28	12.52	0.25	0.75	1.13	1.38	0.16	10.25	10.18	89	100	1.53	13.42	15
20070711	25	11.18	0.22	0.67	1.01	1.23		3.43		30	30		4.49	4.49
20070720	38	16.99	0.34	1.02	1.53	1.87	19.91	51.21	1,232	447	1,679	185	67.1	252
20070806	23	10.28	0.21	0.62	0.93	1.13		0.28		2	2		0.37	0.37
20070816	25	11.18	0.22	0.67	1.01	1.23		3.43		30	30		4.49	4.49
20070817	41	18.33	0.37	1.10	1.65	2.02	29.50	68.97	1,825	602	2,427	274	90.4	364
20070824	26	11.62	0.23	0.70	1.05	1.28		5.42		47	47		7.10	7.10
20071115	25	11.18	0.22	0.67	1.01	1.23		3.43		30	30		4.49	4.49
								Subtotal	5,138 g/yr	2,839 g/yr	2,427 g/d	771 g/yr	426 g/yr	364 g/d
								Annual Emission Rate		7,977 g/yr	Annual Emission Rate		1,196 g/yr	
										8.79E-03 ton/yr			1.32E-03 ton/yr	
								24 Hour Emission Rate		2,427 g/d	24 Hour Emission Rate		364 g/d	
										0.98 ton/yr			1.46E-01 ton/yr	

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

Active Illinois No. 6 Coal Storage Pile Emission Calculations - Source A9

Area Emission Rate (Drop Point Emissions and Wind Erosion)

Basis	Value	Reference
PM_{10} Drop Point Emission Rate	1.50E-01 ton/yr	See calculation 6
$PM_{2.5}$ Drop Point Emission Rate	2.27E-02 ton/yr	See calculation 6
PM_{10} Annual Emission Rate-Wind Erosion	8.79E-03 ton/yr	See calculation above
$PM_{2.5}$ Annual Emission Rate-Wind Erosion	1.32E-03 ton/yr	See calculation above
PM_{10} 24-Hr Emission Rate-Wind Erosion	9.77E-01 ton/yr	See calculation above
$PM_{2.5}$ 24-Hr Emission Rate-Wind Erosion	1.46E-01 ton/yr	See calculation above
Area at Half Height- Modeled Area	1,483 m^2	See calculation above

PM_{10} Emission Rate- Annual

1.50E-01 ton/yr + 8.79E-03 ton/yr = 1.59E-01 ton/yr

1.59E-01 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 1,483 m^2 = 3.08E-06 g/(s-m^2)

$PM_{2.5}$ Emission Rate- Annual

2.27E-02 ton/yr + 1.32E-03 ton/yr = 2.40E-02 ton/yr

2.40E-02 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 1,483 m^2 = 4.66E-07 g/(s-m^2)

PM_{10} Emission Rate- 24-Hr

1.50E-01 ton/yr + 9.77E-01 ton/yr = 1.13E+00 ton/yr

1.13E+00 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 1,483 m^2 = 2.19E-05 g/(s-m^2)

$PM_{2.5}$ Emission Rate- 24-Hr

2.27E-02 ton/yr + 1.46E-01 ton/yr = 1.69E-01 ton/yr

1.69E-01 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 1,483 m^2 = 3.28E-06 g/(s-m^2)

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

12 Limestone Storage Pile Emission Calculations -Source A10

Basis	Value		Reference
Pile Volume	461,723	ft^3	Plant Washington Specification
Pile Base Diameter	172	feet	Plant Washington Specification
Threshold Velocity	1.33	m/s	Table 13.2.5-2 AP-42 for wind erosion from piles
N	365	days	Daily fresh coal applied to the Main Inactive pile

Pile Dimension Calculations

Assumed cone shape V=1/3*h*Area of base

Surface Area = 1/2*(perimeter of base* slant height)

slant height = $SQRT(h^2+(L/2)^2)$

Area of Base π * 172 ft ^ 2 / 4 = 23,235 ft^2

Height 3 * 461,723 ft^3 / 23,235 ft^2 = 60 ft

Radius at Half Height 42.58 ft

Area at Half Height 5,694 ft^2 = 529 m^2

Slant Height SQRT [86 ft ^2 + 60 ft ^2] = 105 ft

Surface Area [[π * 172 ft] * 105 ft] * 0.5 = 28,272 ft^2 = 2,626 m^2

Pile B2 from Fig 13..2.5-2 is the selected Pile Configuration for wind contours because the prevailing wind is WNW. According to the figure, the maximum shear velocity is 1.1 times ten percent of the prevailing wind; therefore, wind erosion occurs whenever the fastest 2 minute wind exceeds the following value:

$$V = \frac{1.33}{0.11} = 12.1 \text{ m/s} = 27.05 \text{ mph}$$

Sample Calculation:

Erosion Potentials were calculated for the dates where the normalized wind surface wind speeds exceeded the threshold velocity for a limestone pile (1.33 m/s)

Erosion Potential ((AP-42, 13.2.5-3, Equation 3)

$P=58(u^*-u^*_t)^2+25(u^*-u^*_t)$ g/m^2

where:

P = Erosion Potential

u^* = Friction velocity = 0.1 u

u^*_t = Threshold Friction Velocity

u_s = Surface Wind Speed

u_t = Approach Wind Speed

January 9, 2007 - 1.1 Wind Contour

$$P = 58 * (1.38 - 1.33)^2 + 25 * (1.38 - 1.33) = 1.30 \text{ g/m^2}$$

Emissions are computed by multiplying the Erosion Potential by the surface area of the pile, the Aerodynamic Particle Size Multiplier to speciate the PM size, and the fraction of the pile subarea that is subject to a specified wind contour. Emissions from the pile are controlled to 90% by dust suppressant

Emission rates multiplied by k = 0.5 to reduce emissions to just PM_{10} and k = 0.075 to $PM_{2.5}$ (AP-42, 13.2.5-3)

Fraction of Pile Subarea Subject to 0.9 Contour of Normalized Surface Wind Speed = 0.17

Fraction of Pile Subarea Subject to 1.1 Contour of Normalized Surface Wind Speed = 0.024

January 9, 2007 - PM10 Emissions for 1.1 Wind Contour

$$1.30 \text{ g/m^2} * 2{,}626 \text{ m^2} * 0.5 * 0.024 * \frac{(100\%-90\%)}{100\%} = 4 \text{ g/d}$$

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

Limestone Storage Pile Emission Calculations -Source A10

Daily records of fastest mile from 12/1/06 through 11/30/07 and it exceeded the calculated threshold on the following dates:(10 m anemometer)

	Wind Speed	Wind Speed	Normalized Surface Wind Speeds				Erosion Potential $P=58(u^*-u^*_t)^2+25(u^*-u^*_t)$ g/m^2 (AP-42, 13.2.5-3, Equation 3)		Daily PM_{10} Erosion Potential		Daily PM_{10} Erosion Potential Summation	Daily $PM_{2.5}$ Erosion Potential		Daily $PM_{2.5}$ Erosion Potential Summation
Date	mph	m/s	$u_r/u_t = 0.2$	$u_r/u_t = 0.6$	$u_r/u_t = 0.9$	$u_r/u_t = 1.1$	P(0.9)	P(1.1)	P(0.9)	P(1.1)		P(0.9)	P(1.1)	
20061201	23	10.28	0.21	0.62	0.93	1.13								
20061207	24	10.73	0.21	0.64	0.97	1.18								
20061225	26	11.62	0.23	0.70	1.05	1.28								
20061226	23	10.28	0.21	0.62	0.93	1.13								
20061231	24	10.73	0.21	0.64	0.97	1.18								
20070108	23	10.28	0.21	0.62	0.93	1.13								
20070109	28	12.52	0.25	0.75	1.13	1.38		1.30		4	4		0.61	0.61
20070128	24	10.73	0.21	0.64	0.97	1.18								
20070213	31	13.86	0.28	0.83	1.25	1.52		7.05		22	22		3.33	3.33
20070218	23	10.28	0.21	0.62	0.93	1.13								
20070301	32	14.30	0.29	0.86	1.29	1.57		9.53		30	30		4.50	4.50
20070302	30	13.41	0.27	0.80	1.21	1.48		4.85		15	15		2.29	2.29
20070316	29	12.96	0.26	0.78	1.17	1.43		2.93		9	9		1.39	1.39
20070404	33	14.75	0.30	0.89	1.328	1.62		12.29		39	39		5.81	5.81
20070415	32	14.30	0.29	0.86	1.29	1.57		9.53		30	30		4.50	4.50
20070416	28	12.52	0.25	0.75	1.13	1.38		1.30		4	4		0.61	0.61
20070508	23	10.28	0.21	0.62	0.93	1.13								
20070603	23	10.28	0.21	0.62	0.93	1.13								
20070629	32	14.30	0.29	0.86	1.29	1.57		9.53		30	30		4.50	4.50
20070701	28	12.52	0.25	0.75	1.13	1.38		1.30		4	4		0.61	0.61
20070711	25	11.18	0.22	0.67	1.01	1.23								
20070720	38	16.99	0.34	1.02	1.53	1.87	7.26	30.28	162	95	258	24	14	39
20070806	23	10.28	0.21	0.62	0.93	1.13								
20070816	25	11.18	0.22	0.67	1.01	1.23								
20070817	41	18.33	0.37	1.10	1.65	2.02	13.91	44.45	310	140	451	47	21	68
20070824	26	11.62	0.23	0.70	1.05	1.28								
20071115	25	11.18	0.22	0.67	1.01	1.23								
								Subtotal	473 g/yr	423 g/yr	451 g/d	71 g/yr	64 g/yr	68 g/d
								Annual Emission Rate		896 g/yr 9.88E-04 ton/yr	**Annual Emission Rate**		134 g/yr 1.48E-04 ton/yr	
								24 Hour Emission Rate		451 g/d 0.18 ton/yr	**24 Hour Emission Rate**		68 g/d 2.72E-02 ton/yr	

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

Limestone Storage Pile Emission Calculations -Source A10

Area Emission Rate (Drop Point Emissions and Wind Erosion)

Basis	Value	Reference
PM_{10} Drop Point Emission Rate	1.63E-02 ton/yr	See calculation 6
$PM_{2.5}$ Drop Point Emission Rate	2.47E-03 ton/yr	See calculation 6
PM_{10} Annual Emission Rate-Wind Erosion	9.88E-04 ton/yr	See calculation above
$PM_{2.5}$ Annual Emission Rate-Wind Erosion	1.48E-04 ton/yr	See calculation above
PM_{10} 24-Hr Emission Rate-Wind Erosion	1.81E-01 ton/yr	See calculation above
$PM_{2.5}$ 24-Hr Emission Rate-Wind Erosion	2.72E-02 ton/yr	See calculation above
Area at Half Height- Modeled Area	529 m^2	See calculation above

PM_{10} Emission Rate- Annual

1.63E-02 ton/yr + 9.88E-04 ton/yr = 1.73E-02 ton/yr

1.73E-02 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 529 m^2 = 9.42E-07 g/(s-m^2)

$PM_{2.5}$ Emission Rate- Annual

2.47E-03 ton/yr + 1.48E-04 ton/yr = 2.62E-03 ton/yr

2.62E-03 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 529 m^2 = 1.43E-07 g/(s-m^2)

PM_{10} Emission Rate- 24-Hr

1.63E-02 ton/yr + 1.81E-01 ton/yr = 1.98E-01 ton/yr

1.98E-01 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 529 m^2 = 1.07E-05 g/(s-m^2)

$PM_{2.5}$ Emission Rate- 24-Hr

2.47E-03 ton/yr + 2.72E-02 ton/yr = 2.97E-02 ton/yr

2.97E-02 ton/yr * 2000 lb/ton / 8760 hr/yr * 453.6 g/lb / 3600 sec/hr / 529 m^2 = 1.61E-06 g/(s-m^2)

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

13 Total Vehicle Miles Traveled for Paved Road

Basis	Value	Units	Reference
Daily Number of Trucks	126	Trucks	Plant Washington Specification
Length of Paved Road	0.380	Miles	Plant Washington Specification
Number of Trips on Road	2		Accounts for Distance to and from Solid Materials Handling Facility

Total Vehicle Miles Traveled to and from Land Fill

126 Trucks/day * 0.380 Miles/Truck * 2 = 95.73 miles/day

95.73 miles/day * 365 days/year = 34,943 miles/year

14 Fugitive Emission Calculations for Paved Road - Source P1-P21

Basis	Value	Units	Reference
Road Surface Silt Loading (sL)	8.2	g/m^2	EPD specifications
Mean Vehicle Weight (W)	12.5	tons	Average Weight of vehicles
k (empircal constant) - PM_{10}	0.016	lb/VMT	AP-42 constant for paved road
k (empircal constant) - $PM_{2.5}$	0.0024	lb/VMT	AP-42 constant for paved road
Number of wet days in a year (P)	120	days/year	AP-42 table (number of days in a year with at least 0.01 inch of precipitation)
Total Miles traveled on a road segment	34,943 miles/year		Based on Segment Distance and Number of Trips
Control Efficiency	90	%	Projected Control Efficiency
Number of Days in Averaging Period	365	days	Number of Days in Averaging Period

PM_{10} Emission Factor (E)

$$k * \frac{sL}{2} \wedge 0.65 * \frac{W}{3} \wedge 1.5$$

$$0.016 * \frac{8.2}{2} \wedge 0.65 * \frac{12.5}{3} \wedge 1.5 = 0.34 \text{ lb/VMT}$$

PM_{10} Emissions

$$0.34 \text{ lb/VMT} * 34{,}943 \text{ miles/year} * \frac{1 \text{ ton}}{2000 \text{ lb}} * (1-120/(4*365)) * \frac{(100\%-90\%)}{100\%} = 0.55 \text{ ton/yr}$$

$PM_{2.5}$ Emission Factor (E)

$$k * \frac{sL}{2} \wedge 0.65 * \frac{W}{3} \wedge 1.5$$

$$0.0024 * \frac{8.2}{2} \wedge 0.65 * \frac{12.5}{3} \wedge 1.5 = 0.05 \text{ lb/VMT}$$

$PM_{2.5}$ Emissions

$$0.05 \text{ lb/VMT} * 34{,}943 \text{ miles/year} * \frac{1 \text{ ton}}{2000 \text{ lb}} * (1-120/(4*365)) * \frac{(100\%-90\%)}{100\%} = 8.19 \text{ E-02 ton/yr}$$

Completed by: BSA11/26/2008
Checked by: SAK 11/26/2008

15 Fugitive Emission Calculations for Unpaved Road - Source U1-U15

Basis	Value	Units	Reference
Mean Vehicle Weight (W)	50	tons	Average Weight of vehicles, Project Specification
Surface Material Silt Content (s)	6	%	AP-42, Table 11.9-3 Bulldozers (Coal)
k (empirical constant) - TSP	4.9	lb/VMT	AP-42 constant for unpaved road
k (empirical constant) - PM_{10}	1.5	lb/VMT	AP-42 constant for unpaved road
k (empirical constant) - $PM_{2.5}$	0.15	lb/VMT	AP-42 constant for unpaved road
a (empirical constant) - TSP	0.7		AP-42 constant for unpaved road
a (empirical constant) - PM_{10}	0.9		AP-42 constant for unpaved road
a (empirical constant) - $PM_{2.5}$	0.9		AP-42 constant for unpaved road
b (empirical constant) - TSP	0.45		AP-42 constant for unpaved road
b (empirical constant) - PM_{10}	0.45		AP-42 constant for unpaved road
b (empirical constant) - $PM_{2.5}$	0.45		AP-42 constant for unpaved road
Number of wet days in a year (P)	120	days/year	AP-42 table (number of days in a year with at least 0.01 inch of precipitation)
Total Miles traveled on a road segment	730 miles/year		Project Specification
Control Efficiency	50	%	Projected Control Efficiency
Number of Days in Averaging Period	120	days	Number of Days in Averaging Period

TSP Emission Factor (E)

$$k * \frac{s}{12} \wedge a * \frac{W}{3} \wedge b * 1\text{-}f * \frac{(365\text{-}P)}{365} = E$$

$$4.9 * \frac{6}{12} \wedge 0.7 * \frac{50}{3} \wedge 0.45 * 0.5 * \frac{245}{365} = 3.59 \text{ lb/VMT}$$

TSP Emissions

$$3.59 \text{ lb/VMT} * 730 \text{ miles/year} * \frac{1 \text{ ton}}{2000 \text{ lb}} = \boxed{1.31 \text{ ton/yr}}$$

PM_{10} Emission Factor (E)

$$k * \frac{s}{12} \wedge a * \frac{W}{3} \wedge b * 1\text{-}f * \frac{(365\text{-}P)}{365} = E$$

$$1.5 * \frac{6}{12} \wedge 0.9 * \frac{50}{3} \wedge 0.45 * 0.5 * \frac{245}{365} = 0.96 \text{ lb/VMT}$$

PM_{10} Emissions

$$0.96 \text{ lb/VMT} * 730 \text{ miles/year} * \frac{1 \text{ ton}}{2000 \text{ lb}} = \boxed{0.35 \text{ ton/yr}}$$

$PM_{2.5}$ Emission Factor (E)

$$k * \frac{s}{12} \wedge a * \frac{W}{3} \wedge b * 1\text{-}f * \frac{(365\text{-}P)}{365} = E$$

$$0.15 * \frac{6}{12} \wedge 0.9 * \frac{50}{3} \wedge 0.45 * 0.5 * \frac{245}{365} = 9.57\text{E-}02 \text{ lb/VMT}$$

$PM_{2.5}$ Emissions

$$9.57\text{E-}02 \text{ lb/VMT} * 730 \text{ miles/year} * \frac{1 \text{ ton}}{2000 \text{ lb}} = \boxed{3.49\text{E-}2 \text{ ton/yr}}$$

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

CASE-BY-CASE MACT CALCULATIONS

Table A-3: USGS COALQUAL Summary Data for PRB and Illinois No. 6

Elements	PRB Coal Average	Standard Deviation	90% Confidence Level PRB	Illinois #6 Coal Average	Standard Deviation	90% Confidence Level Illinois #6 Coal	PRB-Illinois # 6 Coal 50-50 Blend Average	90% Confidence Level 50-50 Blend
Antimony (Sb) Emission Factor	0.67 ppm	0.90 ppm	1.82 ppm	0.89 ppm	0.97 ppm	2.14 ppm	0.78 ppm	1.98 ppm
Arsenic (As) Emission Factor	7.10 ppm	25.82 ppm	40.15 ppm	7.50 ppm	10.47 ppm	20.90 ppm	7.30 ppm	30.52 ppm
Beryllium (Be) Emission Factor	0.95 ppm	1.01 ppm	2.24 ppm	2.59 ppm	2.26 ppm	5.49 ppm	1.77 ppm	3.87 ppm
Cadmium (Cd) Emission Factor	0.14 ppm	0.19 ppm	0.38 ppm	3.41 ppm	8.40 ppm	14.16 ppm	1.77 ppm	7.27 ppm
Chlorine (Cl) Emission Factor	97.52 ppm	97.62 ppm	222.48 ppm	2700 ppm	---	4000 ppm	1398.76 ppm	2111.24 ppm
Chromium (Cr) Emission Factor	7.19 ppm	7.16 ppm	16.35 ppm	16.63 ppm	7.47 ppm	26.19 ppm	11.91 ppm	21.27 ppm
Cobalt (Co) Emission Factor	2.17 ppm	2.36 ppm	5.18 ppm	3.45 ppm	1.39 ppm	5.23 ppm	2.81 ppm	5.21 ppm
Fluorine (F) Emission Factor	76.76 ppm	81.51 ppm	181.09 ppm	80.38 ppm	33.95 ppm	123.83 ppm	78.57 ppm	152.46 ppm
Manganese (Mn) Emission Fact	47.80 ppm	56.45 ppm	120.05 ppm	56.75 ppm	32.74 ppm	98.66 ppm	52.27 ppm	109.36 ppm
Mercury (Hg) Emission Factor	0.10 ppm	0.11 ppm	0.25 ppm	0.09 ppm	0.05 ppm	0.15 ppm	0.10 ppm	0.20 ppm
Nickel (Ni) Emission Factor	6.04 ppm	7.43 ppm	15.56 ppm	15.65 ppm	10.53 ppm	29.12 ppm	10.85 ppm	22.34 ppm
Lead (Pb) Emission Factor	4.63 ppm	4.79 ppm	10.77 ppm	10.76 ppm	11.37 ppm	25.31 ppm	7.70 ppm	18.04 ppm
Selenium (Se) Emission Factor	1.09 ppm	0.94 ppm	2.30 ppm	2.28 ppm	1.10 ppm	3.69 ppm	1.68 ppm	2.99 ppm

Note: Fluorine and Chlorine ppm values used to determine uncontrolled emissions of HF and HCl. Raw coal quality analysis data can be found in Exhibit A. Chlorine concentration values indicated for Illinois #6 coals based on coal design basis data and not USGS COALQUAL data.

Completed by: BSA 11/26/2008
Checked by: SAK 11/26/2008

Table A-4 : Moisture Data Correction

Coal	Total Moisture (%)	Average Ratio of Residual Moisture to Total Moisture[1]	Residual Moisture (%)[2]	Moisture Correction[3]
PRB	29.61	0.3957	11.72	0.7973
Illinois # 6	10	0.6546	6.55	0.9630
50-50 Blend	19.81		9.13	0.8825

1. Value derived from USGS COALQUAL Data as described in Section 10.
2. Residual moisture (%) of project coal is moisture (%) * average ratio of Residual moisture to Total moisture.
3. Moisture correction is (100 - Total Moisture)/ (100 - Residual moisture).

Completed by: JDF 11/26/2008
Checked by: SAK 11/26/2008

16 **PRB Coal Case-By-Case MACT 90% Confidence Level Emission Rate Calculations - Main Boiler (Stack S1)**

Basis	Value	Units	
Exhaust Flow Rate	1,927,690	dscf/min	Project Specification
Maximum Heat Input - Full Load	8300	MMBtu/hr	Project Specification
Antimony (Sb) Emission Factor	1.82	ppm	90% Confidence level from Coal Analysis Data
Arsenic (As) Emission Factor	40.15	ppm	90% Confidence level from Coal Analysis Data
Beryllium (Be) Emission Factor	2.24	ppm	90% Confidence level from Coal Analysis Data
Cadmium (Cd) Emission Factor	0.38	ppm	90% Confidence level from Coal Analysis Data
Chromium (Cr) Emission Factor	16.35	ppm	90% Confidence level from Coal Analysis Data
Cobalt (Co) Emission Factor	5.18	ppm	90% Confidence level from Coal Analysis Data
Manganese (Mn) Emission Factor	120.05	ppm	90% Confidence level from Coal Analysis Data
Nickel (Ni) Emission Factor	15.56	ppm	90% Confidence level from Coal Analysis Data
Lead (Pb) Emission Factor	10.77	ppm	90% Confidence level from Coal Analysis Data
Selenium (Se) Emission Factor	2.30	ppm	90% Confidence level from Coal Analysis Data
Fluorine Fuel Content	0.018109094	lb F per 100 lb coal	Project Specification
Chlorine Fuel Content	0.02224787	lb Cl per 100 lb coal	Project Specification
MACT Floor Metals Control Efficiency	99	%	
MACT Floor Acid Gas (HCl, HF) Control Efficiency	98.5	%	
Moisture Correction Factor	0.7973		From Table A-4
Coal Heating Value	8500	Btu/lb	
lb HCl per lb Cl	1.03	lb	
lb HF per lb F	1.05	lb	
kg per ton	907.18	kg/ton	
mg per lb	453592.37	mg/lb	
Coal Flow Rate For PRB	488	ton/hr	

Antimony (Sb) Emissions

Estimated Uncontrolled Emissions

$$\frac{1.82\ \text{mg}}{\text{kg}} * \frac{907.18\ \text{kg}}{\text{ton}} * \frac{1\ \text{lb}}{453592.37\ \text{mg}} * \frac{488\ \text{ton}}{\text{hr}} * 0.7973 * \frac{1\ \text{hr}}{8300\ \text{MMBtu}} = \boxed{\textbf{1.71E-04 lb/MMBtu}}$$

Estimated Controlled Emissions

1.71E-04 lb/MMBtu * 99 % Removal = **1.71E-06 lb/MMBtu**

Arsenic (As) Emissions

Estimated Uncontrolled Emissions

$$\frac{40.15\ \text{mg}}{\text{kg}} * \frac{907.18\ \text{kg}}{\text{ton}} * \frac{1\ \text{lb}}{453592.37\ \text{mg}} * \frac{488\ \text{ton}}{\text{hr}} * 0.7973 * \frac{1\ \text{hr}}{8300\ \text{MMBtu}} = \boxed{\textbf{3.77E-03 lb/MMBtu}}$$

Estimated Controlled Emissions

3.77E-03 lb/MMBtu * 99 % Removal = **3.77E-05 lb/MMBtu**

Completed by : BSA 11/26/2008
Checked by: SAK 11/26/2008

Beryllium (Be) Emissions

Estimated Uncontrolled Emissions

$\frac{2.24\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{488\ ton}{hr} * 0.7973 * \frac{1\ hr}{8300\ MMBtu} =$ **2.11E-04 lb/MMBtu**

Estimated Controlled Emissions

2.11E-04 lb/MMBtu * 99 % Removal = **2.11E-06 lb/MMBtu**

Cadmium (Cd) Emissions

Estimated Uncontrolled Emissions

$\frac{0.38\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{488\ ton}{hr} * 0.7973 * \frac{1\ hr}{8300\ MMBtu} =$ **3.53E-05 lb/MMBtu**

Estimated Controlled Emissions

3.53E-05 lb/MMBtu * 99 % Removal = **3.53E-07 lb/MMBtu**

Chromium (Cr) Emissions

Estimated Uncontrolled Emissions

$\frac{16.35\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{488\ ton}{hr} * 0.7973 * \frac{1\ hr}{8300\ MMBtu} =$ **1.53E-03 lb/MMBtu**

Estimated Controlled Emissions

1.53E-03 lb/MMBtu * 99 % Removal = **1.53E-05 lb/MMBtu**

Cobalt (Co) Emissions

Estimated Uncontrolled Emissions

$\frac{5.18\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{488\ ton}{hr} * 0.7973 * \frac{1\ hr}{8300\ MMBtu} =$ **4.86E-04 lb/MMBtu**

Estimated Controlled Emissions

4.86E-04 lb/MMBtu * 99 % Removal = **4.86E-06 lb/MMBtu**

Manganese (Mn) Emissions

Estimated Uncontrolled Emissions

$\frac{120.05\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{488\ ton}{hr} * 0.7973 * \frac{1\ hr}{8300\ MMBtu} =$ **1.13E-02 lb/MMBtu**

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Estimated Controlled Emissions

1.13E-02 lb/MMBtu * 99 % Removal = **1.13E-04 lb/MMBtu**

Nickel (Ni) Emissions

Estimated Uncontrolled Emissions

$\frac{15.56\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{488\ ton}{hr} * 0.7973 * \frac{1\ hr}{8300\ MMBtu}$ = **1.46E-03 lb/MMBtu**

Estimated Controlled Emissions

1.46E-03 lb/MMBtu * 99 % Removal = **1.46E-05 lb/MMBtu**

Lead (Pb) Emissions

Estimated Uncontrolled Emissions

$\frac{10.77\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{488\ ton}{hr} * 0.7973 * \frac{1\ hr}{8300\ MMBtu}$ = **1.01E-03 lb/MMBtu**

Estimated Controlled Emissions

1.01E-03 lb/MMBtu * 99 % Removal = **1.01E-05 lb/MMBtu**

Selenium (Se) Emissions

Estimated Uncontrolled Emissions

$\frac{2.30\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{488\ ton}{hr} * 0.7973 * \frac{1\ hr}{8300\ MMBtu}$ = **2.15E-04 lb/MMBtu**

Estimated Controlled Emissions

2.15E-04 lb/MMBtu * 99 % Removal = **2.15E-06 lb/MMBtu**

Hydrogen Chloride (HCl) Emissions

Estimated Uncontrolled Emissions

$\frac{0.02\ lb\ Cl}{100\ lb\ coal} * \frac{1\ lb}{8500\ Btu} * \frac{1 \times 10^6\ Btu}{MMBtu} * \frac{1.03\ lb\ HCl}{lb\ Cl} * 0.7973$ = **2.15E-02 lb/MMBtu**

Estimated Controlled Emissions

2.15E-02 lb/MMBtu * 98.5 % Removal = **3.22E-04 lb/MMBtu**

Completed by : BSA 11/26/2008
Checked by: SAK 11/26/2008

Hydrogen Fluoride (HF) Emissions

Estimated Uncontrolled Emissions

$$\frac{0.0181 \text{ lb F}}{100 \text{ lb coal}} * \frac{1 \text{ lb}}{8500 \text{ Btu}} * \frac{1 \times 10^6 \text{ Btu}}{\text{MMBtu}} * \frac{1.05 \text{ lb HF}}{\text{lb F}} * 0.7973 = \boxed{\textbf{1.78E-02 lb/MMBtu}}$$

Estimated Controlled Emissions

1.78E-02 lb/MMBtu * 98.5 % Removal = **2.68E-04 lb/MMBtu**

Completed by : BSA 11/26/2008
Checked by: SAK 11/26/2008

17 PRB Coal 95% UCL Mercury Calculations - Main Boiler (Stack S1)

Basis	Value	Units	
Exhaust Flow Rate	1,927,690	dscf/min	Project Specification
Maximum Heat Input - Full Load	8300	MMBtu/hr	Project Specification
Mercury (Hg) Emission Factor (PRB Coal Avg.)	0.11	ppm	95% UCL from Coal Analysis Data
MACT Floor Mercury Control Efficiency	83.6	%	
Moisture Correction Factor	0.7973		From Table A-4
Coal Heating Value	8500	Btu/lb	From Coal Analysis Data
kg per ton	907.18	kg/ton	
mg per lb	453592.37	mg/lb	
Coal Flow Rate For PRB	488	ton/hr	
Plant Gross Output Capacity	930	MW	

Mercury (Hg) Emissions (PRB Coal Avg.)

Estimated Uncontrolled Emissions

$$\frac{0.11\ \text{mg}}{\text{kg}} * \frac{907.18\ \text{kg}}{\text{ton}} * \frac{1\ \text{lb}}{453592.37\ \text{mg}} * \frac{488\ \text{ton}}{\text{hr}} * 0.7973 * \frac{1\ \text{hr}}{8300\ \text{MMBtu}} = \boxed{\mathbf{1.02E\text{-}05\ lb/MMBtu}}$$

Estimated Controlled Emissions

1.02E-05 lb/MMBtu * 84 % Removal = **1.68E-06 lb/MMBtu**

1.68E-06 lb/MMBtu * 8300 MMBtu/hr ÷ 930 MW = **1.50E-05 lb/MW-hr**

Completed by : BSA11/26/2008
Checked by : SAK 11/26/2008

18 50-50 Blend of PRB Coals and Illinois No. 6 Coals 90% Confidence Level Emission Rate Calculations - Main Boiler (Stack S1)

Basis	Value	Units	
Exhaust Flow Rate	1,927,690	dscf/min	Project Specification
Maximum Heat Input - Full Load	8300	MMBtu/hr	Project Specification
Antimony (Sb) Emission Factor	1.98	ppm	90% Confidence level from Coal Analysis Data
Arsenic (As) Emission Factor	30.52	ppm	90% Confidence level from Coal Analysis Data
Beryllium (Be) Emission Factor	3.87	ppm	90% Confidence level from Coal Analysis Data
Cadmium (Cd) Emission Factor	7.27	ppm	90% Confidence level from Coal Analysis Data
Chromium (Cr) Emission Factor	21.27	ppm	90% Confidence level from Coal Analysis Data
Cobalt (Co) Emission Factor	5.21	ppm	90% Confidence level from Coal Analysis Data
Manganese (Mn) Emission Factor	109.36	ppm	90% Confidence level from Coal Analysis Data
Nickel (Ni) Emission Factor	22.34	ppm	90% Confidence level from Coal Analysis Data
Lead (Pb) Emission Factor	18.04	ppm	90% Confidence level from Coal Analysis Data
Selenium (Se) Emission Factor	2.99	ppm	90% Confidence level from Coal Analysis Data
Fluorine Fuel Content	0.015246016	lb F per 100 lb coal	Project Specification
Chlorine Fuel Content	0.211123935	lb Cl per 100 lb coal	Project Specification
MACT Floor Metals Control Efficiency	99	%	
MACT Floor Acid Gas (HCl, HF) Control Efficien	98.5	%	
Moisture Correction Factor	0.8825		From Table A-4
Coal Heating Value	9950	Btu/lb	
lb HCl per lb Cl	1.03	lb	
lb HF per lb F	1.05	lb	
kg per ton	907.18	kg/ton	
mg per lb	453592.37	mg/lb	
Coal Flow Rate For 50/50 Blend	417	ton/hr	

Antimony (Sb) Emissions

Estimated Uncontrolled Emissions

$$\frac{1.98\ \text{mg}}{\text{kg}} * \frac{907.18\ \text{kg}}{\text{ton}} * \frac{1\ \text{lb}}{453592.37\ \text{mg}} * \frac{417\ \text{ton}}{\text{hr}} * \frac{1\ \text{hr}}{8300\ \text{MMBtu}} * 0.8825 = \boxed{\textbf{1.75E-04 lb/MMBtu}}$$

Estimated Controlled Emissions

1.75E-04 lb/MMBtu * 99 % Removal = **1.75E-06 lb/MMBtu**

Arsenic (As) Emissions

Estimated Uncontrolled Emissions

$$\frac{30.52\ \text{mg}}{\text{kg}} * \frac{907.18\ \text{kg}}{\text{ton}} * \frac{1\ \text{lb}}{453592.37\ \text{mg}} * \frac{417\ \text{ton}}{\text{hr}} * \frac{1\ \text{hr}}{8300\ \text{MMBtu}} * 0.8825 = \boxed{\textbf{2.71E-03 lb/MMBtu}}$$

Estimated Controlled Emissions

2.71E-03 lb/MMBtu * 99 % Removal = **2.71E-05 lb/MMBtu**

Beryllium (Be) Emissions

Estimated Uncontrolled Emissions

$\frac{3.87\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{417\ ton}{hr} * \frac{1\ hr}{8300\ MMBtu} * 0.8825 =$ **3.43E-04 lb/MMBtu**

Estimated Controlled Emissions

3.43E-04 lb/MMBtu * 99 % Removal = **3.43E-06 lb/MMBtu**

Cadmium (Cd) Emissions

Estimated Uncontrolled Emissions

$\frac{7.27\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{417\ ton}{hr} * \frac{1\ hr}{8300\ MMBtu} * 0.8825 =$ **6.45E-04 lb/MMBtu**

Estimated Controlled Emissions

6.45E-04 lb/MMBtu * 99 % Removal = **6.45E-06 lb/MMBtu**

Chromium (Cr) Emissions

Estimated Uncontrolled Emissions

$\frac{21.27\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{417\ ton}{hr} * \frac{1\ hr}{8300\ MMBtu} * 0.8825 =$ **1.89E-03 lb/MMBtu**

Estimated Controlled Emissions

1.89E-03 lb/MMBtu * 99 % Removal = **1.89E-05 lb/MMBtu**

Cobalt (Co) Emissions

Estimated Uncontrolled Emissions

$\frac{5.21\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{417\ ton}{hr} * \frac{1\ hr}{8300\ MMBtu} * (100\% - 88.25\%) =$ **4.62E-04 lb/MMBtu**

Estimated Controlled Emissions

4.62E-04 lb/MMBtu * 99 % Removal = **4.62E-06 lb/MMBtu**

Manganese (Mn) Emissions

Estimated Uncontrolled Emissions

$\frac{109.36\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{417\ ton}{hr} * \frac{1\ hr}{8300\ MMBtu} * 0.8825 =$ **9.70E-03 lb/MMBtu**

Estimated Controlled Emissions

9.70E-03 lb/MMBtu * 99 % Removal = **9.70E-05 lb/MMBtu**

Nickel (Ni) Emissions

Estimated Uncontrolled Emissions

$$\frac{22.34\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{417\ ton}{hr} * \frac{1\ hr}{8300\ MMBtu} * 0.8825 = \mathbf{1.98E\text{-}03\ lb/MMBtu}$$

Estimated Controlled Emissions

1.98E-03 lb/MMBtu * 99 % Removal = **1.98E-05 lb/MMBtu**

Lead (Pb) Emissions

Estimated Uncontrolled Emissions

$$\frac{18.04\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{417\ ton}{hr} * \frac{1\ hr}{8300\ MMBtu} * 0.8825 = \mathbf{1.60E\text{-}03\ lb/MMBtu}$$

Estimated Controlled Emissions

1.60E-03 lb/MMBtu * 99 % Removal = **1.60E-05 lb/MMBtu**

Selenium (Se) Emissions

Estimated Uncontrolled Emissions

$$\frac{2.99\ mg}{kg} * \frac{907.18\ kg}{ton} * \frac{1\ lb}{453592.37\ mg} * \frac{417\ ton}{hr} * \frac{1\ hr}{8300\ MMBtu} * 0.8825 = \mathbf{2.65E\text{-}04\ lb/MMBtu}$$

Estimated Controlled Emissions

2.65E-04 lb/MMBtu * 99 % Removal = **2.65E-06 lb/MMBtu**

Hydrogen Chloride (HCl) Emissions

Estimated Uncontrolled Emissions

$$\frac{0.21\ lb\ Cl}{100\ lb\ coal} * \frac{1\ lb}{9950\ Btu} * \frac{1 \times 10^{6}\ Btu}{MMBtu} * \frac{1.03\ lb\ HCl}{lb\ Cl} * 0.8825 = \mathbf{1.93E\text{-}01\ lb/MMBtu}$$

Estimated Controlled Emissions

1.93E-01 lb/MMBtu * 98.5 % Removal = **2.89E-03 lb/MMBtu**

Hydrogen Fluoride (HF) Emissions

Estimated Uncontrolled Emissions

$$\frac{0.0152 \text{ lb F}}{100 \text{ lb coal}} * \frac{1 \text{ lb}}{9950 \text{ Btu}} * \frac{1 \times 10^6 \text{ Btu}}{\text{MMBtu}} * \frac{1.05 \text{ lb HF}}{\text{lb F}} * 0.8825 = \boxed{\textbf{1.42E-02 lb/MMBtu}}$$

Estimated Controlled Emissions

1.42E-02 lb/MMBtu * 98.5 % Removal = **2.13E-04 lb/MMBtu**

Table A-5: Organic HAP (and Others) Emission Calculations: Main Boiler - 100% PRB Coal

Basis:

Coal Consumption Rate	488	ton Coal/hr
Fuel Oil Consumption Rate	9286	gal/hr
Maximum heat Input	8.30E-03	Trillion Btu/hr

Compound	Pulverized Coal [1] - AP42			Fuel Oil [2] - AP42			Pulverized Coal [3] - Utility Report to Congress, NEI Database, TRI Database			Worst Case Emissions (lb/hr)	Worst Case Emissions (tpy)
	Emission Factor	Units	Hourly Emissions (lb/hr)	Emission Factor	Units	Hourly Emissions (lb/hr)	Emission Factor	Units	Hourly Emissions (lb/hr)		
Organics											
Acenaphthene	5.10E-07	lb/ton	2.49E-04	2.1E-05	lb/1,000 gal	2.0E-04	0.013	lb/trillion btu	1.08E-04	2.5E-04	1.1E-03
Acenaphthylene	2.50E-07	lb/ton	1.22E-04	2.5E-07	lb/1,000 gal	2.3E-06	0.004	lb/trillion btu	3.32E-05	1.2E-04	5.3E-04
Acetaldehyde	5.70E-04	lb/ton	2.78E-01				6.75	lb/trillion btu	5.60E-02	2.8E-01	1.2E+00
Acetophenone	1.50E-05	lb/ton	7.32E-03				0.68	lb/trillion btu	5.64E-03	7.3E-03	3.2E-02
Acrolein	2.90E-04	lb/ton	1.42E-01				3.25	lb/trillion btu	2.70E-02	1.4E-01	6.2E-01
Anthracene	2.10E-07	lb/ton	1.02E-04	1.2E-06	lb/1,000 gal	1.1E-05	0.004	lb/trillion btu	3.32E-05	1.0E-04	4.5E-04
Benzene	1.30E-03	lb/ton	6.34E-01	2.14E-04	lb/1,000 gal	2.0E-03	2.5	lb/trillion btu	2.08E-02	6.3E-01	2.8E+00
Benzo(a)anthracene	8.00E-08	lb/ton	3.90E-05	4.0E-06	lb/1,000 gal	3.7E-05	0.002	lb/trillion btu	1.66E-05	3.9E-05	1.7E-04
Benzo(a)pyrene	3.80E-08	lb/ton	1.85E-05				0.001	lb/trillion btu	8.30E-06	1.9E-05	8.1E-05
Benzo(b)fluoranthene			-				0.008	lb/trillion btu	6.64E-05	6.6E-05	2.9E-04
Benzo(e)pyrene			-				0.001	lb/trillion btu	8.30E-06	8.3E-06	3.6E-05
Benzo(g,h,i)perylene			-	2.26E-06	lb/1,000 gal	2.1E-05	0.002	lb/trillion btu	1.66E-05	2.1E-05	9.2E-05
Benzo(g,h,i)pyrene	2.70E-08	lb/ton	1.32E-05							1.3E-05	5.8E-05
Benzo(b,k)fluoranthene	1.10E-07	lb/ton	5.37E-05	1.48E-06	lb/1,000 gal	1.4E-05	0.004	lb/trillion btu	3.32E-05	5.4E-05	2.4E-04
Benzo(k)fluoranthene			-				0.004	lb/trillion btu	3.32E-05	3.3E-05	1.5E-04
Benzyl chloride	7.00E-04	lb/ton	3.42E-01				0.006	lb/trillion btu	4.98E-05	3.4E-01	1.5E+00
Biphenyl	1.70E-06	lb/ton	8.30E-04				0.18	lb/trillion btu	1.49E-03	1.5E-03	6.5E-03
bis(2-Ethylhexyl)phthalate	7.30E-05	lb/ton	3.56E-02				4.1	lb/trillion btu	3.40E-02	3.6E-02	1.6E-01
Bromoform	3.90E-05	lb/ton	1.90E-02				6.6	lb/trillion btu	5.48E-02	5.5E-02	2.4E-01
Carbon tetrachloride			-				3.25	lb/trillion btu	2.70E-02	2.7E-02	1.2E-01
Carbon disulfide	1.30E-04	lb/ton	6.34E-02				4.3	lb/trillion btu	3.57E-02	6.3E-02	2.8E-01
Chlorobenzene	2.20E-05	lb/ton	1.07E-02				3.18	lb/trillion btu	2.64E-02	2.6E-02	1.2E-01
Chloroform	5.90E-05	lb/ton	2.88E-02				3.2	lb/trillion btu	2.66E-02	2.9E-02	1.3E-01
Chloromethane	5.30E-04	lb/ton	2.59E-01				5.9	lb/trillion btu	4.90E-02	2.6E-01	1.1E+00
2-Chloronaphthalene			-				0.04	lb/trillion btu	3.32E-04	3.3E-04	1.5E-03
2-Chloroacetophenone	7.00E-06	lb/ton	3.42E-03				0.29	lb/trillion btu	2.41E-03	3.4E-03	1.5E-02
Chrysene	1.00E-07	lb/ton	4.88E-05	2.4E-06	lb/1,000 gal	2.2E-05	0.003	lb/trillion btu	2.49E-05	4.9E-05	2.1E-04
Cumene	5.30E-06	lb/ton	2.59E-03				0.29	lb/trillion btu	2.41E-03	2.6E-03	1.1E-02
Hydrogen Cyanide	2.50E-03	lb/ton	1.22E+00				28.00	lb/trillion btu	2.32E-01	1.2E+00	5.3E+00
Dibenzo(a,h)anthracene			-	1.7E-06	lb/1,000 gal	1.6E-05	0.001	lb/trillion btu	8.30E-06	1.6E-05	6.8E-05
Dibutyl phthalate							2.8	lb/trillion btu	2.32E-02	2.3E-02	1.0E-01
Dimethyl sulfate	4.80E-05	lb/ton	2.34E-02							2.3E-02	1.0E-01
2,4-Dinitrotoluene	2.80E-07	lb/ton	1.37E-04				0.015	lb/trillion btu	1.25E-04	1.4E-04	6.0E-04
Ethylbenzene	9.40E-05	lb/ton	4.59E-02	6.36E-05	lb/1,000 gal	5.9E-04	0.41	lb/trillion btu	3.40E-03	4.6E-02	2.0E-01
Ethyl Chloride	4.20E-05	lb/ton	2.05E-02				2.4	lb/trillion btu	1.99E-02	2.0E-02	9.0E-02
Ethylene dichloride	4.00E-05	lb/ton	1.95E-02				3.1	lb/trillion btu	2.57E-02	2.6E-02	1.1E-01
Ethylene dibromide	1.20E-06	lb/ton	5.86E-04							5.9E-04	2.6E-03
Fluoranthene	7.10E-07	lb/ton	3.46E-04	4.8E-06	lb/1,000 gal	4.5E-05	0.016	lb/trillion btu	1.33E-04	3.5E-04	1.5E-03
Fluorene	9.10E-07	lb/ton	4.44E-04	4.5E-06	lb/1,000 gal	4.2E-05	0.013	lb/trillion btu	1.08E-04	4.4E-04	1.9E-03
Formaldehyde	2.40E-04	lb/ton	1.17E-01	3.3E-02	lb/1,000 gal	3.1E-01	4.0	lb/trillion btu	3.32E-02	3.1E-01	1.3E+00
Hexane	6.70E-05	lb/ton	3.27E-02				0.83	lb/trillion btu	6.89E-03	3.3E-02	1.4E-01
Indeno(1,2,3,c,d)pyrene	6.10E-08	lb/ton	2.98E-05	2.1E-06	lb/1,000 gal	2.0E-05	0.003	lb/trillion btu	2.49E-05	3.0E-05	1.3E-04
Isophorone	5.80E-04	lb/ton	2.83E-01				24	lb/trillion btu	1.99E-01	2.8E-01	1.2E+00
Methyl Bromide	1.60E-04	lb/ton	7.81E-02				0.89	lb/trillion btu	7.39E-03	7.8E-02	3.4E-01
Methyl hydrazine	1.70E-04	lb/ton	8.30E-02							8.3E-02	3.6E-01
MMA	2.00E-03	lb/ton	9.76E-03				1.1	lb/trillion btu	9.13E-03	9.8E-03	4.3E-02
2-Methylnaphthalene			-				0.032	lb/trillion btu	2.66E-04	2.7E-04	1.2E-03
MTBE	3.50E-05	lb/ton	1.71E-02				1.4	lb/trillion btu	1.16E-02	1.7E-02	7.5E-02
Methylene chloride	2.90E-04	lb/ton	1.42E-01				13	lb/trillion btu	1.08E-01	1.4E-01	6.2E-01
Naphthalene	1.30E-03	lb/ton	6.34E-03	1.13E-03	lb/1,000 gal	1.0E-02	0.77	lb/trillion btu	6.39E-03	1.0E-02	4.6E-02
5-Methyl chrysene	2.20E-08	lb/ton	1.07E-05							1.1E-05	4.7E-05
OCDD				3.10E-09	lb/1,000 gal	2.9E-08				2.9E-08	1.3E-07
Phenanthrene	2.70E-06	lb/ton	1.32E-03	1.1E-05	lb/1,000 gal	9.8E-05	0.032	lb/trillion btu	2.66E-04	1.3E-03	5.8E-03
Phenol	1.60E-05	lb/ton	7.81E-03				6.1	lb/trillion btu	5.06E-02	5.1E-02	2.2E-01
Propionaldehyde	3.80E-04	lb/ton	1.85E-01				10.35	lb/trillion btu	8.59E-02	1.9E-01	8.1E-01
Pyrene	3.30E-07	lb/ton	1.61E-04	4.3E-06	lb/1,000 gal	3.9E-05	0.012	lb/trillion btu	9.96E-05	1.6E-04	7.1E-04
Styrene	2.50E-05	lb/ton	1.22E-02				3.1	lb/trillion btu	2.57E-02	2.6E-02	1.1E-01
Tetrachloroethylene	4.30E-05	lb/ton	2.10E-02				3.1	lb/trillion btu	2.57E-02	2.6E-02	1.1E-01
Toluene	2.40E-04	lb/ton	1.17E-01	6.20E-03	lb/1,000 gal	5.8E-02	3.6	lb/trillion btu	2.99E-02	1.2E-01	5.1E-01
1,1,1-Trichloroethane	2.00E-05	lb/ton	9.76E-03	2.36E-04	lb/1,000 gal	2.2E-03				9.8E-03	4.3E-02
1,1,2-Trichloroethane			-				4.7	lb/trillion btu	3.90E-02	3.9E-02	1.7E-01
Trichloroethylene			-				3.1	lb/trillion btu	2.57E-02	2.6E-02	1.1E-01
Vinyl acetate	7.60E-06	lb/ton	3.71E-03				0.42	lb/trillion btu	3.49E-03	3.7E-03	1.6E-02
Xylene	3.70E-05	lb/ton	1.81E-02	1.09E-04	lb/1,000 gal	1.0E-03	4.65	lb/trillion btu	3.86E-02	3.9E-02	1.7E-01
m-xylene			-				1.45	lb/trillion btu	1.20E-02	1.2E-02	5.3E-02
o-xylene							0.81	lb/trillion btu	6.72E-03	6.7E-03	2.9E-02
p-xylene							1.45	lb/trillion btu	1.20E-02	1.2E-02	5.3E-02
Dioxins (Total)							9.68E-06	lb/trillion btu	8.03E-08	8.0E-08	3.5E-07
P-Cresol							0.95	lb/trillion btu	7.89E-03	7.9E-03	3.5E-02
perylene							0.075	lb/trillion btu	6.23E-04	6.2E-04	2.7E-03
Pentachlorophenol							0.008	lb/trillion btu	6.64E-05	6.6E-05	2.9E-04
Hexachlorobenzene							0.08	lb/trillion btu	6.64E-04	6.6E-04	2.9E-03
Methyl chloroform							3.42	lb/trillion btu	2.84E-02	2.8E-02	1.2E-01
Methyl iodine							0.4	lb/trillion btu	3.32E-03	3.3E-03	1.5E-02
Methyl isobutyl ketone							4.9	lb/trillion btu	4.07E-02	4.1E-02	1.8E-01
1,2,4-Trichlorobenzene	-	-	-	-	-	-	1.51E-06	lb/MMBtu	1.25E-02	1.3E-02	5.5E-02
1,3-Butadiene	-	-	-	-	-	-	3.71E-07	lb/MMBtu	3.08E-03	3.1E-03	1.3E-02
1,3-Dichloropropene	-	-	-	-	-	-	6.61E-07	lb/MMBtu	5.48E-03	5.5E-03	2.4E-02
1,4-Dichlorobenzene	-	-	-	-	-	-	1.06E-06	lb/MMBtu	8.76E-03	8.8E-03	3.8E-02
2,4,6-Trichlorophenol	-	-	-	-	-	-	8.01E-10	lb/MMBtu	6.64E-06	6.6E-06	2.9E-05
2,4-Dinitrophenol	-	-	-	-	-	-	1.08E-08	lb/MMBtu	8.92E-05	8.9E-05	3.9E-04
3-Methylcholanthrene	-	-	-	-	-	-	6.62E-11	lb/MMBtu	5.49E-07	5.5E-07	2.4E-06
4-Nitrophenol	-	-	-	-	-	-	4.00E-09	lb/MMBtu	3.32E-03	3.3E-05	1.5E-04
7,12-Dimethylbenz(a)Anthracene	-	-	-	-	-	-	5.88E-10	lb/MMBtu	4.88E-06	4.9E-06	2.1E-05
Allyl Chloride	-	-	-	-	-	-	8.03E-06	lb/MMBtu	6.66E-02	6.7E-02	2.9E-01
Arsenic Trioxide	-	-	-	-	-	-	2.98E-05	lb/MMBtu	2.47E-01	2.5E-01	1.1E+00
Cadmium Oxide	-	-	-	-	-	-	3.20E-06	lb/MMBtu	2.66E-02	2.7E-02	1.2E-01
Calcium Cyanamide	-	-	-	-	-	-	3.39E-06	lb/MMBtu	2.81E-02	2.8E-02	1.2E-01
Chromic Acid (VI)	-	-	-	-	-	-	8.32E-06	lb/MMBtu	6.91E-02	6.9E-02	3.0E-01
Chromic Oxide	-	-	-	-	-	-	2.44E-05	lb/MMBtu	2.02E-01	2.0E-01	8.9E-01

Table A-5: Organic HAP (and Others) Emission Calculations: Main Boiler - 100% PRB Coal

Basis:

Coal Consumption Rate	488	ton Coal/hr
Fuel Oil Consumption Rate	9286	gal/hr
Maximum heat Input	8.30E-03	Trillion Btu/hr

Compound	Pulverized Coal [1] - AP42			Fuel Oil [2] - AP42			Pulverized Coal [3] - Utility Report to Congress, NEI Database, TRI Database			Worst Case Emissions (lb/hr)	Worst Case Emissions (tpy)
	Emission Factor	Units	Hourly Emissions (lb/hr)	Emission Factor	Units	Hourly Emissions (lb/hr)	Emission Factor	Units	Hourly Emissions (lb/hr)		
Dibenzo[a,j]Acridine	-	-	-	-	-	-	5.12E-07	lb/MMBtu	4.25E-03	4.2E-03	1.9E-02
Dibenzofuran	-	-	-	-	-	-	5.73E-07	lb/MMBtu	4.75E-03	4.8E-03	2.1E-02
Diethyl Sulfate	-	-	-	-	-	-	2.33E-06	lb/MMBtu	1.94E-02	1.9E-02	8.5E-02
Dimethyl Phthalate	-	-	-	-	-	-	9.64E-08	lb/MMBtu	8.00E-04	8.0E-04	3.5E-03
Manganese Dioxide	-	-	-	-	-	-	4.26E-05	lb/MMBtu	3.54E-01	3.5E-01	1.5E+00
Polychlorinated Biphenyls	-	-	-	-	-	-	1.37E-08	lb/MMBtu	1.14E-04	1.1E-04	5.0E-04
Polycyclic Organic Matter	-	-	-	-	-	-	6.21E-06	lb/MMBtu	5.16E-02	5.2E-02	2.3E-01
Propylene Dichloride	-	-	-	-	-	-	1.20E-06	lb/MMBtu	9.97E-03	1.0E-02	4.4E-02
Sodium Cyanide	-	-	-	-	-	-	8.09E-05	lb/MMBtu	6.71E-01	6.7E-01	2.9E+00
Toluene-2,4-Diamine	-	-	-	-	-	-	1.38E-08	lb/MMBtu	1.14E-04	1.1E-04	5.0E-04
Vinyl Chloride	-	-	-	-	-	-	7.14E-07	lb/MMBtu	5.92E-03	5.9E-03	2.6E-02
Phosphorus							31.50	lb/trillion btu	2.61E-01	2.6E-01	1.1E+00
										Total (ton/yr)	30.30

1)AP-42 Table 1.1-13, 1.1-14, & 1.1-18

2)AP-42 Tables 1.3-9 & 1.3-10

3) Test Report Data Table A-1 and A-4 from the study of Hazardous Air Pollutant emissions from Electric Utility Steam Generating Units- Final report to Congress (1998) and Data derived from EPA NEI HAP emissions inventory data - 2002 NEI V3 last updated September 2007 and TRI Database.

Table A-6 : EPA NEI HAP Database and TRI Database Emissions Information and EPA Clean Markets MMBtu/hr Values

STATE	FacilityName	Emission Unit ID	Boiler ID	Emission Release Point ID	Pollutant	Emissions (TPY)	HEAT INPUT (MMBtu)	Emission Rate (lb/MMBtu)	Avg. Emission Rate (lb/MMBtu)
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU003	3	SV001	1,2,4-Trichlorobenzene	0.0044	6302333	1.40E-06	1.28E-06
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU004	4	SV001	1,2,4-Trichlorobenzene	0.007045	12188405	1.16E-06	
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU001	6	SV002	1,2,4-Trichlorobenzene	0.00394	4388784	1.80E-06	1.75E-06
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU002	7	SV002	1,2,4-Trichlorobenzene	0.003965	4670969	1.70E-06	
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU003	8	SV003	1,2,4-Trichlorobenzene	0.011335	12939421	1.75E-06	
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU003	5	SV001	1,2,4-Trichlorobenzene	0.00402	6154367	1.31E-06	1.39E-06
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU004	6	SV001	1,2,4-Trichlorobenzene	0.006455	8744882	1.48E-06	
MN	NSP - SHERBURNE GENERATING PLANT	EU001	1	SV001	1,2,4-Trichlorobenzene	0.03807	53500053	1.42E-06	1.37E-06
MN	NSP - SHERBURNE GENERATING PLANT	EU002	2	SV001	1,2,4-Trichlorobenzene	0.035535	46259012	1.54E-06	
MN	NSP - SHERBURNE GENERATING PLANT	EU003	3	SV002	1,2,4-Trichlorobenzene	0.043815	75715065	1.16E-06	
MN	XCEL ENERGY - ALLEN S KING GENERATING	EU001	1	SV001	1,2,4-Trichlorobenzene	0.02459	18096637	2.72E-06	2.72E-06
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-1	3	S-3	1,2,4-Trichlorobenzene	0.032	29979755	2.13E-06	1.74E-06
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-2	4	S-4	1,2,4-Trichlorobenzene	0.033	32692109	2.02E-06	
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-4	1	S-1	1,2,4-Trichlorobenzene	0.0165	24152709	1.37E-06	
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-5	2	S-2	1,2,4-Trichlorobenzene	0.0175	24537935	1.43E-06	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-187	1	S-1	1,2,4-Trichlorobenzene	0.0039	4629725	1.68E-06	1.41E-06
NC	L V SUTTON STEAM ELECTRIC PLANT	G-188	2	S-1	1,2,4-Trichlorobenzene	0.00305	5203884	1.17E-06	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-189	3	S-2	1,2,4-Trichlorobenzene	0.0145	20975938	1.38E-06	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-29	1	S-1	1,2,4-Trichlorobenzene	0.013	25494527	1.02E-06	1.39E-06
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-30	2	S-2	1,2,4-Trichlorobenzene	0.031	47033163	1.32E-06	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-35	MULTI	S-3	1,2,4-Trichlorobenzene	0.031	35494009	1.75E-06	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-36	MULTI	S-4	1,2,4-Trichlorobenzene	0.03	40155873	1.49E-06	
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-21	3	S-3	1,2,4-Trichlorobenzene	0.0015	6642892	4.52E-07	5.34E-07
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-22	1	S-1	1,2,4-Trichlorobenzene	0.0005	2817682	3.55E-07	
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-23	2	S-2	1,2,4-Trichlorobenzene	0.001	2513404	7.96E-07	
NC	DUKE ENERGY CORP - BELEWS CREEK STEAM STATION	G-17	1	S-1	1,2,4-Trichlorobenzene	0.062	67835959	1.83E-06	1.68E-06
NC	DUKE ENERGY CORP - BELEWS CREEK STEAM STATION	G-18	2	S-2	1,2,4-Trichlorobenzene	0.053	68954797	1.54E-06	
NC	PROGRESS ENERGY - F LEE PLANT	G-2	1	S-1	1,2,4-Trichlorobenzene	0.0031	4016709	1.54E-06	1.48E-06
NC	PROGRESS ENERGY - F LEE PLANT	G-3	2	S-1	1,2,4-Trichlorobenzene	0.003	3913221	1.53E-06	
NC	PROGRESS ENERGY - F LEE PLANT	G-4	3	S-2	1,2,4-Trichlorobenzene	0.0095	13970082	1.36E-06	
TN	ALLEN FOSSIL PLANT	Boilr1	1	Stack1	1,2,4-Trichlorobenzene	0.0109	20568457	1.06E-06	1.37E-06
TN	ALLEN FOSSIL PLANT	Boilr2	2	Stack2	1,2,4-Trichlorobenzene	0.0127	19131766	1.33E-06	
TN	ALLEN FOSSIL PLANT	Boilr3	3	Stack3	1,2,4-Trichlorobenzene	0.014	16183389	1.73E-06	
								Total Avg.	1.51E-06
NC	PROGRESS ENERGY CAROLINAS - CAPE FEAR PLANT	G-1	5	S-1	1,3-Butadiene	0.0003	8135544	7.38E-08	1.05E-07
NC	PROGRESS ENERGY CAROLINAS - CAPE FEAR PLANT	G-2	6	S-2	1,3-Butadiene	0.00075	11041675	1.36E-07	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-187	1	S-1	1,3-Butadiene	0.0013	4629725	5.62E-07	4.87E-07
NC	L V SUTTON STEAM ELECTRIC PLANT	G-188	2	S-1	1,3-Butadiene	0.00135	5203884	5.19E-07	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-189	3	S-2	1,3-Butadiene	0.004	20975938	3.81E-07	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-29	1	S-1	1,3-Butadiene	0.002	25494527	1.57E-07	1.49E-07
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-30	2	S-2	1,3-Butadiene	0.0035	47033163	1.49E-07	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-35	MULTI	S-3	1,3-Butadiene	0.0025	35494009	1.41E-07	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-36	MULTI	S-4	1,3-Butadiene	0.003	40155873	1.49E-07	
NC	CP&L - MAYO FACILITY	G-46	MULTI	S-1	1,3-Butadiene	0.006	46476354	2.58E-07	2.58E-07
NC	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	G-24	1	S-1	1,3-Butadiene	0.00035	2047727	3.42E-07	3.60E-07
NC	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	G-25	2	S-1	1,3-Butadiene	0.0004	2120634	3.77E-07	
NC	PROGRESS ENERGY - F LEE PLANT	G-2	1	S-1	1,3-Butadiene	0.0015	4016709	7.47E-07	8.68E-07
NC	PROGRESS ENERGY - F LEE PLANT	G-3	2	S-1	1,3-Butadiene	0.0026	3913221	1.33E-06	
NC	PROGRESS ENERGY - F LEE PLANT	G-4	3	S-2	1,3-Butadiene	0.0037	13970082	5.30E-07	
								Total Avg.	3.71E-07
TN	ALLEN FOSSIL PLANT	Boilr1	1	Stack1	1,3-Dichloropropene	0.00525	20568457	5.10E-07	6.61E-07
TN	ALLEN FOSSIL PLANT	Boilr2	2	Stack2	1,3-Dichloropropene	0.0061	19131766	6.38E-07	
TN	ALLEN FOSSIL PLANT	Boilr3	3	Stack3	1,3-Dichloropropene	0.00675	16183389	8.34E-07	
								Total Avg.	6.61E-07
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU003	3	SV001	1,4-Dichlorobenzene	0.003225	6302333	1.02E-06	9.35E-07
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU004	4	SV001	1,4-Dichlorobenzene	0.005165	12188405	8.48E-07	
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU001	6	SV002	1,4-Dichlorobenzene	0.00289	4388784	1.32E-06	1.28E-06
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU002	7	SV002	1,4-Dichlorobenzene	0.002905	4670969	1.24E-06	
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU003	8	SV003	1,4-Dichlorobenzene	0.00831	12939421	1.28E-06	
MN	OTTER TAIL POWER CO - HOOT LAKE PLANT	EU002	2	SV002	1,4-Dichlorobenzene	0.00241	4758198	1.01E-06	1.08E-06
MN	OTTER TAIL POWER CO - HOOT LAKE PLANT	EU003	3	SV002	1,4-Dichlorobenzene	0.003285	5695698	1.15E-06	
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU003	5	SV001	1,4-Dichlorobenzene	0.00295	6154367	9.59E-07	1.02E-06
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU004	6	SV001	1,4-Dichlorobenzene	0.004735	8744882	1.08E-06	
MN	NSP - SHERBURNE GENERATING PLANT	EU001	1	SV001	1,4-Dichlorobenzene	0.02792	53500053	1.04E-06	1.01E-06
MN	NSP - SHERBURNE GENERATING PLANT	EU002	2	SV001	1,4-Dichlorobenzene	0.02606	46259012	1.13E-06	
MN	NSP - SHERBURNE GENERATING PLANT	EU003	3	SV002	1,4-Dichlorobenzene	0.03213	75715065	8.49E-07	
MN	XCEL ENERGY - ALLEN S KING GENERATING	EU001	1	SV001	1,4-Dichlorobenzene	0.01803	18096637	1.99E-06	1.99E-06
NC	PROGRESS ENERGY CAROLINAS - CAPE FEAR PLANT	G-1	5	S-1	1,4-Dichlorobenzene	0.0049	8135544	1.20E-06	1.10E-06
NC	PROGRESS ENERGY CAROLINAS - CAPE FEAR PLANT	G-2	6	S-2	1,4-Dichlorobenzene	0.0055	11041675	9.96E-07	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-187	1	S-1	1,4-Dichlorobenzene	0.00285	4629725	1.23E-06	1.03E-06
NC	L V SUTTON STEAM ELECTRIC PLANT	G-188	2	S-1	1,4-Dichlorobenzene	0.00225	5203884	8.65E-07	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-189	3	S-2	1,4-Dichlorobenzene	0.0105	20975938	1.00E-06	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-29	1	S-1	1,4-Dichlorobenzene	0.0095	25494527	7.45E-07	1.02E-06
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-30	2	S-2	1,4-Dichlorobenzene	0.0225	47033163	9.57E-07	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-35	MULTI	S-3	1,4-Dichlorobenzene	0.0225	35494009	1.27E-06	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-36	MULTI	S-4	1,4-Dichlorobenzene	0.022	40155873	1.10E-06	
NC	CP&L - MAYO FACILITY	G-46	MULTI	S-1	1,4-Dichlorobenzene	0.0265	46476354	1.14E-06	1.14E-06
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-21	3	S-3	1,4-Dichlorobenzene	0.001	6642892	3.01E-07	3.51E-07
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-22	1	S-1	1,4-Dichlorobenzene	0.0005	2817682	3.55E-07	
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-23	2	S-2	1,4-Dichlorobenzene	0.0005	2513404	3.98E-07	
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-83	2	S-2	1,4-Dichlorobenzene	0.0005	1575124	6.35E-07	6.36E-07
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-84	3	S-3	1,4-Dichlorobenzene	0.0005	2069663	4.83E-07	
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-86	5	S-5	1,4-Dichlorobenzene	0.013	32959329	7.89E-07	
NC	DUKE ENERGY CORP - BELEWS CREEK STEAM STATION	G-18	2	S-2	1,4-Dichlorobenzene	0.039	68954797	1.13E-06	1.13E-06
NC	PROGRESS ENERGY - F LEE PLANT	G-2	1	S-1	1,4-Dichlorobenzene	0.0023	4016709	1.15E-06	1.10E-06
NC	PROGRESS ENERGY - F LEE PLANT	G-3	2	S-1	1,4-Dichlorobenzene	0.0022	3913221	1.12E-06	
NC	PROGRESS ENERGY - F LEE PLANT	G-4	3	S-2	1,4-Dichlorobenzene	0.0071	13970082	1.02E-06	
TN	ALLEN FOSSIL PLANT	Boilr1	1	Stack1	1,4-Dichlorobenzene	0.008	20568457	7.78E-07	1.01E-06
TN	ALLEN FOSSIL PLANT	Boilr2	2	Stack2	1,4-Dichlorobenzene	0.0093	19131766	9.72E-07	
TN	ALLEN FOSSIL PLANT	Boilr3	3	Stack3	1,4-Dichlorobenzene	0.0103	16183389	1.27E-06	
								Total Avg.	1.06E-06
NY	AES GREENIDGE LLC	G00004	6	00004	2,4,6-Trichlorophenol	0.000002024	5056599	8.01E-10	8.01E-10
								Total Avg.	8.01E-10
NY	AES GREENIDGE LLC	G00004	6	00004	2,4-Dinitrophenol	0.00001656	5056599	6.55E-09	6.55E-09
UT	HUNTINGTON POWER PLANT	4034	2	1285	2,4-Dinitrophenol	0.0012	26754943	1.50E-08	1.50E-08
								Total Avg.	1.08E-08
OH	DP&L, O.H. HUTCHINGS GENERATING STATION	H-1	H-1	001	3-Methylcholanthrene	4.9E-09	238277	4.11E-11	6.62E-11
OH	DP&L, O.H. HUTCHINGS GENERATING STATION	H-2	H-2	002	3-Methylcholanthrene	1.29E-08	206693	1.25E-10	
OH	DP&L, O.H. HUTCHINGS GENERATING STATION	H-3	H-3	003	3-Methylcholanthrene	2.85E-08	773126	7.37E-11	
OH	DP&L, O.H. HUTCHINGS GENERATING STATION	H-4	H-4	004	3-Methylcholanthrene	3.17E-08	1115965	5.68E-11	
OH	DP&L, O.H. HUTCHINGS GENERATING STATION	H-5	H-5	005	3-Methylcholanthrene	2.91E-08	1162990	5.00E-11	
OH	DP&L, O.H. HUTCHINGS GENERATING STATION	H-6	H-6	006	3-Methylcholanthrene	3.22E-08	1271630	5.06E-11	
								Total Avg.	6.62E-11

Completed by: JDE 11-26-2008
Checked by: SAK 11-26-2008

Table A-6 : EPA NEI HAP Database and TRI Database Emissions Information and EPA Clean Markets MMBtu/hr Values

STATE	FacilityName	Emission Unit ID	Boiler ID	Emission Release Point ID	Pollutant	Emissions (TPY)	HEAT INPUT (MMBtu)	Emission Rate (lb/MMBtu)	Avg. Emission Rate (lb/MMBtu)
NY	AES GREENIDGE LLC	G00004	6	00004	4-Nitrophenol	0.00001012	5056599	4.00E-09	4.00E-09
								Total Avg.	4.00E-09
OH	DP&L, O.H. HUTCHINGS GENERATING STATION	H-1	H-1	001	7,12-Dimethylbenz[a]Anthracene	4.34E-08	238277	3.64E-10	5.88E-10
OH	DP&L, O.H. HUTCHINGS GENERATING STATION	H-2	H-2	002	7,12-Dimethylbenz[a]Anthracene	1.146E-07	206693	1.11E-09	
OH	DP&L, O.H. HUTCHINGS GENERATING STATION	H-3	H-3	003	7,12-Dimethylbenz[a]Anthracene	2.534E-07	773126	6.56E-10	
OH	DP&L, O.H. HUTCHINGS GENERATING STATION	H-4	H-4	004	7,12-Dimethylbenz[a]Anthracene	2.819E-07	1115965	5.05E-10	
OH	DP&L, O.H. HUTCHINGS GENERATING STATION	H-5	H-5	005	7,12-Dimethylbenz[a]Anthracene	2.586E-07	1162990	4.45E-10	
OH	DP&L, O.H. HUTCHINGS GENERATING STATION	H-6	H-6	006	7,12-Dimethylbenz[a]Anthracene	2.863E-07	1271630	4.50E-10	
								Total Avg.	5.88E-10
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-1	3	S-3	Allyl Chloride	0.1925	29979755	1.28E-05	1.05E-05
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-2	4	S-4	Allyl Chloride	0.199	32692109	1.22E-05	
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-4	1	S-1	Allyl Chloride	0.1	24152709	8.28E-06	
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-5	2	S-2	Allyl Chloride	0.1055	24537935	8.60E-06	
NC	PROGRESS ENERGY CAROLINAS - CAPE FEAR PLANT	G-1	5	S-1	Allyl Chloride	0.0405	8135544	9.96E-06	9.01E-06
NC	PROGRESS ENERGY CAROLINAS - CAPE FEAR PLANT	G-2	6	S-2	Allyl Chloride	0.0445	11041675	8.06E-06	
NC	DUKE ENERGY CORPORATION - ALLEN STEAM STATION	G-14	1	S-1	Allyl Chloride	0.0285	8399352	6.79E-06	7.13E-06
NC	DUKE ENERGY CORPORATION - ALLEN STEAM STATION	G-15	2	S-2	Allyl Chloride	0.0265	9210552	5.75E-06	
NC	DUKE ENERGY CORPORATION - ALLEN STEAM STATION	G-16	3	S-3	Allyl Chloride	0.0445	15956865	5.58E-06	
NC	DUKE ENERGY CORPORATION - ALLEN STEAM STATION	G-17	4	S-4	Allyl Chloride	0.061	14172222	8.61E-06	
NC	DUKE ENERGY CORPORATION - ALLEN STEAM STATION	G-18	5	S-5	Allyl Chloride	0.064	14313317	8.94E-06	
NC	DUKE ENERGY CORPORATION - RIVERBEND STEAM STATION	G-17	7	S-5	Allyl Chloride	0.012	4128778	5.81E-06	7.82E-06
NC	DUKE ENERGY CORPORATION - RIVERBEND STEAM STATION	G-18	8	S-6	Allyl Chloride	0.016	4012669	7.97E-06	
NC	DUKE ENERGY CORPORATION - RIVERBEND STEAM STATION	G-19	9	S-7	Allyl Chloride	0.023	5731728	8.03E-06	
NC	DUKE ENERGY CORPORATION - RIVERBEND STEAM STATION	G-20	10	S-8	Allyl Chloride	0.0285	6028904	9.45E-06	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-187	1	S-1	Allyl Chloride	0.0235	4629725	1.02E-05	8.52E-06
NC	L V SUTTON STEAM ELECTRIC PLANT	G-188	2	S-1	Allyl Chloride	0.0185	5203884	7.11E-06	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-189	3	S-2	Allyl Chloride	0.087	20975938	8.30E-06	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-29	1	S-1	Allyl Chloride	0.08	25494527	6.28E-06	8.48E-06
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-30	2	S-2	Allyl Chloride	0.1865	47033163	7.93E-06	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-35	MULTI	S-3	Allyl Chloride	0.1875	35494009	1.06E-05	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-36	MULTI	S-4	Allyl Chloride	0.1835	40155873	9.14E-06	
NC	CP&L - MAYO FACILITY	G-46	MULTI	S-1	Allyl Chloride	0.2195	46476354	9.45E-06	9.45E-06
NC	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	G-24	1	S-1	Allyl Chloride	0.012	2047727	1.17E-05	1.10E-05
NC	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	G-25	2	S-1	Allyl Chloride	0.011	2120634	1.04E-05	
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-21	3	S-3	Allyl Chloride	0.009	6642892	2.71E-06	2.92E-06
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-22	1	S-1	Allyl Chloride	0.0035	2817682	2.48E-06	
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-23	2	S-2	Allyl Chloride	0.0045	2513404	3.58E-06	
NC	DUKE ENERGY CORPORATION - BUCK STEAM STATION	G-1	5	S-2	Allyl Chloride	0.0025	1223835	4.09E-06	5.58E-06
NC	DUKE ENERGY CORPORATION - BUCK STEAM STATION	G-2	6	S-3	Allyl Chloride	0.0025	1362075	3.67E-06	
NC	DUKE ENERGY CORPORATION - BUCK STEAM STATION	G-3	7	S-6	Allyl Chloride	0.003	1603389	3.74E-06	
NC	DUKE ENERGY CORPORATION - BUCK STEAM STATION	G-4	8	S-6	Allyl Chloride	0.0245	6291656	7.79E-06	
NC	DUKE ENERGY CORPORATION - BUCK STEAM STATION	G-5	9	S-6	Allyl Chloride	0.0275	6379286	8.62E-06	
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-82	1	S-1	Allyl Chloride	0.001	1649132	1.21E-06	4.44E-06
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-83	2	S-2	Allyl Chloride	0.003	1575124	3.81E-06	
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-84	3	S-3	Allyl Chloride	0.0055	2069663	5.31E-06	
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-85	4	S-4	Allyl Chloride	0.0055	2103923	5.23E-06	
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-86	5	S-5	Allyl Chloride	0.109	32959329	6.61E-06	
NC	DUKE ENERGY CORP - BELEWS CREEK STEAM STATION	G-17	1	S-1	Allyl Chloride	0.3745	67835959	1.10E-05	1.02E-05
NC	DUKE ENERGY CORP - BELEWS CREEK STEAM STATION	G-18	2	S-2	Allyl Chloride	0.3225	68954797	9.35E-06	
NC	PROGRESS ENERGY - F LEE PLANT	G-2	1	S-1	Allyl Chloride	0.019	4016709	9.46E-06	9.01E-06
NC	PROGRESS ENERGY - F LEE PLANT	G-3	2	S-1	Allyl Chloride	0.018	3913221	9.20E-06	
NC	PROGRESS ENERGY - F LEE PLANT	G-4	3	S-2	Allyl Chloride	0.0585	13970082	8.38E-06	
TN	ALLEN FOSSIL PLANT	Boilr1	1	Stack1	Allyl Chloride	0.066	20568457	6.42E-06	8.32E-06
TN	ALLEN FOSSIL PLANT	Boilr2	2	Stack2	Allyl Chloride	0.077	19131766	8.05E-06	
TN	ALLEN FOSSIL PLANT	Boilr3	3	Stack3	Allyl Chloride	0.085	16183389	1.05E-05	
								Total Avg.	8.03E-06
TX	GIBBONS CREEK	000002	1	000002	Arsenic Trioxide	0.525	35281328	2.98E-05	2.98E-05
								Total Avg.	2.98E-05
TX	GIBBONS CREEK	000002	1	000002	Cadmium Oxide	0.0565	35281328	3.20E-06	3.20E-06
								Total Avg.	3.20E-06
IA	MIDAMERICAN ENERGY CO. - LOUISA STATION	147281	101	117487	Calcium Cyanamide	0.08	47240697	3.39E-06	3.39E-06
								Total Avg.	3.39E-06
CO	TRI STATE GENERATION CRAIG	001	C1	001	Chlorine	8.9685	34560386	5.19E-04	4.05E-04
CO	TRI STATE GENERATION CRAIG	002	C2	002	Chlorine	9.2345	41101830	4.49E-04	
CO	TRI STATE GENERATION CRAIG	003	C3	003	Chlorine	4.3095	34695350	2.48E-04	
NE	NPPD SHELDON STATION	001	MULTI	001	Chlorine	7.52	8720555	1.72E-03	1.72E-03
NY	AES GREENIDGE LLC	G00004	6	00004	Chlorine	0.07268	5056599	2.87E-05	2.87E-05
PA	EXELON GENERATION CO/CROMBY GENERATION STATION	031	1	S01	Chlorine	9	8697485	2.07E-03	2.07E-03
TX	TOLK STATION	000001	171B	000001	Chlorine	3.9	30985535	2.52E-04	2.25E-04
TX	TOLK STATION	000002	172B	000002	Chlorine	3.8	38451725	1.98E-04	
TX	HARRINGTON STATION	000004	061B	000007	Chlorine	3.9	29124807	2.68E-04	2.25E-04
TX	HARRINGTON STATION	000005	062B	000008	Chlorine	2.6	30559917	1.70E-04	
TX	HARRINGTON STATION	000007	063B	000009	Chlorine	2.7	22717892	2.38E-04	
VA	DOMINION - SOUTHAMPTON POWER STATION	1	1	1	Chlorine	8.758	1994216	8.78E-03	8.78E-03
								Total Avg.	1.92E-03
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-82	1	S-1	Chromic Acid (VI)	0.0015	1649132	1.82E-06	8.32E-06
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-83	2	S-2	Chromic Acid (VI)	0.005	1575124	6.35E-06	
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-84	3	S-3	Chromic Acid (VI)	0.0095	2069663	9.18E-06	
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-85	4	S-4	Chromic Acid (VI)	0.011	2103923	1.05E-05	
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-86	5	S-5	Chromic Acid (VI)	0.2275	32959329	1.38E-05	
								Total Avg.	8.32E-06
TX	GIBBONS CREEK	000002	1	000002	Chromic Oxide	0.4299	35281328	2.44E-05	2.44E-05
								Total Avg.	2.44E-05
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU003	3	SV001	Dibenzo[a,j]Acridine	0.00293486	6302333	9.31E-07	8.51E-07
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU004	4	SV001	Dibenzo[a,j]Acridine	0.00469816	12188405	7.71E-07	
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU001	6	SV002	Dibenzo[a,j]Acridine	0.00262881	4388784	1.20E-06	7.77E-07
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU002	7	SV002	Dibenzo[a,j]Acridine	0.00264414	4670969	1.13E-06	
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU003	8	SV003	Dibenzo[a,j]Acridine	0.000805	12939421	7.73E-10	
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU003	5	SV001	Dibenzo[a,j]Acridine	0.00268254	6154367	8.72E-07	9.28E-07
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU004	6	SV001	Dibenzo[a,j]Acridine	0.00430514	8744882	9.85E-07	
MN	NSP - SHERBURNE GENERATING PLANT	EU001	1	SV001	Dibenzo[a,j]Acridine	0.000025	53500053	9.35E-10	8.20E-10
MN	NSP - SHERBURNE GENERATING PLANT	EU002	2	SV001	Dibenzo[a,j]Acridine	0.00002	46259012	8.65E-10	
MN	NSP - SHERBURNE GENERATING PLANT	EU003	3	SV002	Dibenzo[a,j]Acridine	0.000025	75715065	6.60E-10	
MN	XCEL ENERGY - ALLEN S KING GENERATING	EU001	1	SV001	Dibenzo[a,j]Acridine	0.000015	18096637	1.66E-09	1.66E-09
								Total Avg.	5.12E-07

Completed by: JDF 11.26.2008
Checked by: SAK 11.26.2008

Table A-6 : EPA NEI HAP Database and TRI Database Emissions Information and EPA Clean Markets MMBtu/hr Values

STATE	FacilityName	Emission Unit ID	Boiler ID	Emission Release Point ID	Pollutant	Emissions (TPY)	HEAT INPUT (MMBtu)	Emission Rate (lb/MMBtu)	Avg. Emission Rate (lb/MMBtu)
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU003	3	SV001	Dibenzofuran	0.0017	6302333	5.39E-07	4.93E-07
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU004	4	SV001	Dibenzofuran	0.00272	12188405	4.46E-07	
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU001	6	SV002	Dibenzofuran	0.00152	4388784	6.93E-07	6.75E-07
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU002	7	SV002	Dibenzofuran	0.00153	4670969	6.55E-07	
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU003	8	SV003	Dibenzofuran	0.00438	12939421	6.77E-07	
MN	OTTER TAIL POWER CO - HOOT LAKE PLANT	EU002	2	SV002	Dibenzofuran	0.00127	4758198	5.34E-07	5.71E-07
MN	OTTER TAIL POWER CO - HOOT LAKE PLANT	EU003	3	SV002	Dibenzofuran	0.00173	5695698	6.07E-07	
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU003	5	SV001	Dibenzofuran	0.001555	6154367	5.05E-07	5.38E-07
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU004	6	SV001	Dibenzofuran	0.002495	8744882	5.71E-07	
MN	NSP - SHERBURNE GENERATING PLANT	EU001	1	SV001	Dibenzofuran	0.01472	53500053	5.50E-07	5.31E-07
MN	NSP - SHERBURNE GENERATING PLANT	EU002	2	SV001	Dibenzofuran	0.01374	46259012	5.94E-07	
MN	NSP - SHERBURNE GENERATING PLANT	EU003	3	SV002	Dibenzofuran	0.01694	75715065	4.47E-07	
MN	XCEL ENERGY - ALLEN S KING GENERATING	EU001	1	SV001	Dibenzofuran	0.009505	18096637	1.05E-06	1.05E-06
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-1	3	S-3	Dibenzofuran	0.0125	29979755	8.34E-07	6.67E-07
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-2	4	S-4	Dibenzofuran	0.0125	32692109	7.65E-07	
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-4	1	S-1	Dibenzofuran	0.0065	24152709	5.38E-07	
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-5	2	S-2	Dibenzofuran	0.0065	24537935	5.30E-07	
NC	PROGRESS ENERGY CAROLINAS - CAPE FEAR PLANT	G-1	5	S-1	Dibenzofuran	0.0026	8135544	6.39E-07	5.78E-07
NC	PROGRESS ENERGY CAROLINAS - CAPE FEAR PLANT	G-2	6	S-2	Dibenzofuran	0.00285	11041675	5.16E-07	
NC	DUKE ENERGY CORPORATION - RIVERBEND STEAM STATION	G-17	7	S-5	Dibenzofuran	0.001	4128778	4.84E-07	5.42E-07
NC	DUKE ENERGY CORPORATION - RIVERBEND STEAM STATION	G-18	8	S-6	Dibenzofuran	0.001	4012669	4.98E-07	
NC	DUKE ENERGY CORPORATION - RIVERBEND STEAM STATION	G-19	9	S-7	Dibenzofuran	0.0015	5731728	5.23E-07	
NC	DUKE ENERGY CORPORATION - RIVERBEND STEAM STATION	G-20	10	S-8	Dibenzofuran	0.002	6028904	6.63E-07	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-187	1	S-1	Dibenzofuran	0.0015	4629725	6.48E-07	5.46E-07
NC	L V SUTTON STEAM ELECTRIC PLANT	G-188	2	S-1	Dibenzofuran	0.0012	5203884	4.61E-07	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-189	3	S-2	Dibenzofuran	0.00555	20975938	5.29E-07	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-29	1	S-1	Dibenzofuran	0.005	25494527	3.92E-07	5.38E-07
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-30	2	S-2	Dibenzofuran	0.012	47033163	5.10E-07	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-35	MULTI	S-3	Dibenzofuran	0.012	35494009	6.76E-07	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-36	MULTI	S-4	Dibenzofuran	0.0115	40155873	5.73E-07	
NC	CP&L - MAYO FACILITY	G-46	MULTI	S-1	Dibenzofuran	0.014	46476354	6.02E-07	6.02E-07
NC	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	G-24	1	S-1	Dibenzofuran	0.00075	2047727	7.33E-07	6.37E-07
NC	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	G-25	2	S-1	Dibenzofuran	0.0007	2120634	6.60E-07	
NC	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	G-26	3	S-2	Dibenzofuran	0.0012	4620806	5.19E-07	
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-21	3	S-3	Dibenzofuran	0.0005	6642892	1.51E-07	2.74E-07
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-23	2	S-2	Dibenzofuran	0.0005	2513404	3.98E-07	
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-84	3	S-3	Dibenzofuran	0.0005	2069663	4.83E-07	4.61E-07
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-85	4	S-4	Dibenzofuran	0.0005	2103923	4.75E-07	
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-86	5	S-5	Dibenzofuran	0.007	32959329	4.25E-07	
NC	DUKE ENERGY CORP - BELEWS CREEK STEAM STATION	G-17	1	S-1	Dibenzofuran	0.024	67835959	7.08E-07	7.08E-07
NC	PROGRESS ENERGY - F LEE PLANT	G-2	1	S-1	Dibenzofuran	0.0012	4016709	5.98E-07	5.93E-07
NC	PROGRESS ENERGY - F LEE PLANT	G-3	2	S-1	Dibenzofuran	0.00115	3913221	5.88E-07	
PA	EXELON GENERATION CO CROMBY GENERATION STATION	031	1	S01	Dibenzofuran	0.0015	8697485	3.45E-07	3.45E-07
TN	ALLEN FOSSIL PLANT	Boilr1	1	Stack1	Dibenzofuran	0.00421	20568457	4.09E-07	5.32E-07
TN	ALLEN FOSSIL PLANT	Boilr2	2	Stack2	Dibenzofuran	0.00491	19131766	5.13E-07	
TN	ALLEN FOSSIL PLANT	Boilr3	3	Stack3	Dibenzofuran	0.00545	16183389	6.74E-07	
								Total Avg.	5.73E-07
MO	KANSAS CITY POWER & LIGHT CO-MONTROSE GENERATING S	7847	3	10060	Diethyl Sulfate	0.0099	12220708	1.62E-06	2.21E-06
MO	KANSAS CITY POWER & LIGHT CO-MONTROSE GENERATING S	7848	2	10063	Diethyl Sulfate	0.0156	11907048	2.62E-06	
MO	KANSAS CITY POWER & LIGHT CO-MONTROSE GENERATING S	7849	1	10065	Diethyl Sulfate	0.0155	12946678	2.39E-06	
MO	KANSAS CITY POWER & LIGHT CO-HAWTHORN STATION	24676	5A	47800	Diethyl Sulfate	0.05645	41839589	2.70E-06	2.70E-06
MO	KANSAS CITY POWER & LIGHT CO-IATAN GENERATING STAT	16912	1	21121	Diethyl Sulfate	0.055	52608092	2.09E-06	2.09E-06
								Total Avg.	2.33E-06
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU003	3	SV001	Dimethyl Phthalate	0.00026	6302333	8.25E-08	7.57E-08
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU004	4	SV001	Dimethyl Phthalate	0.00042	12188405	6.89E-08	
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU001	6	SV002	Dimethyl Phthalate	0.000235	4388784	1.07E-07	1.04E-07
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU002	7	SV002	Dimethyl Phthalate	0.000235	4670969	1.01E-07	
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU003	8	SV003	Dimethyl Phthalate	0.00068	12939421	1.05E-07	
MN	OTTER TAIL POWER CO - HOOT LAKE PLANT	EU002	2	SV002	Dimethyl Phthalate	0.000195	4758198	8.20E-08	8.75E-08
MN	OTTER TAIL POWER CO - HOOT LAKE PLANT	EU003	3	SV002	Dimethyl Phthalate	0.000265	5695698	9.31E-08	
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU003	5	SV001	Dimethyl Phthalate	0.00024	6154367	7.80E-08	8.30E-08
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU004	6	SV001	Dimethyl Phthalate	0.000385	8744882	8.81E-08	
MN	NSP - SHERBURNE GENERATING PLANT	EU001	1	SV001	Dimethyl Phthalate	0.00228	53500053	8.52E-08	8.22E-08
MN	NSP - SHERBURNE GENERATING PLANT	EU002	2	SV001	Dimethyl Phthalate	0.00213	46259012	9.21E-08	
MN	NSP - SHERBURNE GENERATING PLANT	EU003	3	SV002	Dimethyl Phthalate	0.002625	75715065	6.93E-08	
MN	XCEL ENERGY - ALLEN S KING GENERATING	EU001	1	SV001	Dimethyl Phthalate	0.001475	18096637	1.63E-07	1.63E-07
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-1	3	S-3	Dimethyl Phthalate	0.002	29979755	1.33E-07	1.05E-07
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-2	4	S-4	Dimethyl Phthalate	0.002	32692109	1.22E-07	
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-4	1	S-1	Dimethyl Phthalate	0.001	24152709	8.28E-08	
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-5	2	S-2	Dimethyl Phthalate	0.001	24537935	8.15E-08	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-187	1	S-1	Dimethyl Phthalate	0.00025	4629725	1.08E-07	8.86E-08
NC	L V SUTTON STEAM ELECTRIC PLANT	G-188	2	S-1	Dimethyl Phthalate	0.0002	5203884	7.69E-08	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-189	3	S-2	Dimethyl Phthalate	0.00085	20975938	8.10E-08	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-29	1	S-1	Dimethyl Phthalate	0.001	25494527	7.84E-08	9.40E-08
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-30	2	S-2	Dimethyl Phthalate	0.002	47033163	8.50E-08	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-35	MULTI	S-3	Dimethyl Phthalate	0.002	35494009	1.13E-07	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-36	MULTI	S-4	Dimethyl Phthalate	0.002	40155873	9.96E-08	
NC	DUKE ENERGY CORP - BELEWS CREEK STEAM STATION	G-17	1	S-1	Dimethyl Phthalate	0.0035	67835959	1.03E-07	9.51E-08
NC	DUKE ENERGY CORP - BELEWS CREEK STEAM STATION	G-18	2	S-2	Dimethyl Phthalate	0.003	68954797	8.70E-08	
NC	PROGRESS ENERGY - F LEE PLANT	G-2	1	S-1	Dimethyl Phthalate	0.0002	4016709	9.96E-08	9.59E-08
NC	PROGRESS ENERGY - F LEE PLANT	G-3	2	S-1	Dimethyl Phthalate	0.0002	3913221	1.02E-07	
NC	PROGRESS ENERGY - F LEE PLANT	G-4	3	S-2	Dimethyl Phthalate	0.0006	13970082	8.59E-08	
TN	ALLEN FOSSIL PLANT	Boilr1	1	Stack1	Dimethyl Phthalate	0.000655	20568457	6.37E-08	8.25E-08
TN	ALLEN FOSSIL PLANT	Boilr2	2	Stack2	Dimethyl Phthalate	0.00076	19131766	7.94E-08	
TN	ALLEN FOSSIL PLANT	Boilr3	3	Stack3	Dimethyl Phthalate	0.000845	16183389	1.04E-07	
								Total Avg.	9.64E-08
TX	GIBBONS CREEK	000002	1	000002	Manganese Dioxide	0.752	35281328	4.26E-05	4.26E-05
								Total Avg.	4.26E-05
TN	ALLEN FOSSIL PLANT	Boilr1	1	Stack1	Polychlorinated Biphenyls	0.000109	20568457	1.06E-08	1.37E-08
TN	ALLEN FOSSIL PLANT	Boilr2	2	Stack2	Polychlorinated Biphenyls	0.000127	19131766	1.33E-08	
TN	ALLEN FOSSIL PLANT	Boilr3	3	Stack3	Polychlorinated Biphenyls	0.00014	16183389	1.73E-08	
								Total Avg.	1.37E-08

Completed by: JDE 11/26/2008
Checked by: SAK 11/26/2008

Table A-6 : EPA NEI HAP Database and TRI Database Emissions Information and EPA Clean Markets MMBtu/hr Values

STATE	FacilityName	Emission Unit ID	Boiler ID	Emission Release Point ID	Pollutant	Emissions (TPY)	HEAT INPUT (MMBtu)	Emission Rate (lb/MMBtu)	Avg. Emission Rate (lb/MMBtu)
IA	IPL - LANSING GENERATING STATION	145136	4	114991	Polycyclic Organic Matter	0.0137	14456441	1.90E-06	1.90E-06
IA	IPL - M.L. KAPP GENERATING STATION	144559	2	114945	Polycyclic Organic Matter	0.0174	11586035	3.00E-06	3.00E-06
IA	IPL - BURLINGTON GENERATING STATION	145381	1	115078	Polycyclic Organic Matter	0.0138	14304675	1.93E-06	1.93E-06
IA	IPL - PRAIRIE CREEK GENERATING STATION	144096	4	114824	Polycyclic Organic Matter	0.00854	8096263	2.11E-06	2.11E-06
IA	MIDAMERICAN ENERGY CO. - LOUISA STATION	147281	101	117487	Polycyclic Organic Matter	0.05	47240697	2.12E-06	2.12E-06
IA	MUSCATINE POWER & WATER	163415	9	130857	Polycyclic Organic Matter	0.003849	12758228	6.03E-07	3.54E-07
IA	MUSCATINE POWER & WATER	163419	8	130911	Polycyclic Organic Matter	0.000354	6793436	1.04E-07	
IA	MIDAMERICAN ENERGY CO. - COUNCIL BLUFFS ENERGY CTR	143797	2	114672	Polycyclic Organic Matter	0.01	6281538	3.18E-06	2.69E-06
IA	MIDAMERICAN ENERGY CO. - COUNCIL BLUFFS ENERGY CTR	143798	3	114673	Polycyclic Organic Matter	0.05	45431195	2.20E-06	
IA	MIDAMERICAN ENERGY CO. - RIVERSIDE STATION	147465	9	131993	Polycyclic Organic Matter	0.01	6246921	3.20E-06	3.20E-06
IA	IPL - OTTUMWA GENERATING STATION	143977	1	114771	Polycyclic Organic Matter	0.0504	45946302	2.19E-06	2.19E-06
IA	MIDAMERICAN ENERGY CO. - GEORGE NEAL NORTH	148764	1	118711	Polycyclic Organic Matter	0.01	9662316	2.07E-06	1.97E-06
IA	MIDAMERICAN ENERGY CO. - GEORGE NEAL NORTH	148765	2	118712	Polycyclic Organic Matter	0.02	18870064	2.12E-06	
IA	MIDAMERICAN ENERGY CO. - GEORGE NEAL NORTH	148766	3	118713	Polycyclic Organic Matter	0.03	40185308	1.49E-06	
IA	MIDAMERICAN ENERGY CO. - GEORGE NEAL SOUTH	147140	4	117334	Polycyclic Organic Matter	0.05	45569716	2.19E-06	
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU003	3	SV001	Polycyclic Organic Matter	0.00704	6302333	2.23E-06	2.04E-06
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU004	4	SV001	Polycyclic Organic Matter	0.011275	12188405	1.85E-06	
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU001	6	SV002	Polycyclic Organic Matter	0.005465	4388784	2.49E-06	2.42E-06
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU002	7	SV002	Polycyclic Organic Matter	0.005495	4670969	2.35E-06	
MN	MINNESOTA POWER INC - BOSWELL ENERGY CTR	EU001	1	SV001	Polycyclic Organic Matter	0.004215	5984583	1.41E-06	2.05E-06
MN	MINNESOTA POWER INC - BOSWELL ENERGY CTR	EU002	2	SV001	Polycyclic Organic Matter	0.004825	5815310	1.66E-06	
MN	MINNESOTA POWER INC - BOSWELL ENERGY CTR	EU003	3	SV003	Polycyclic Organic Matter	0.032735	26268955	2.49E-06	
MN	MINNESOTA POWER INC - BOSWELL ENERGY CTR	EU004	4	SV004	Polycyclic Organic Matter	0.054025	40948377	2.64E-06	
MN	ROCHESTER PUBLIC UTILITIES - SILVER LAKE	EU004	4	SV003	Polycyclic Organic Matter	0.00111	1668283	1.33E-06	1.33E-06
MN	OTTER TAIL POWER CO - HOOT LAKE PLANT	EU002	2	SV002	Polycyclic Organic Matter	0.00526	4758198	2.21E-06	2.20E-06
MN	OTTER TAIL POWER CO - HOOT LAKE PLANT	EU003	3	SV002	Polycyclic Organic Matter	0.006215	5695698	2.18E-06	
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU003	5	SV001	Polycyclic Organic Matter	0.005575	6154367	1.81E-06	1.93E-06
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU004	6	SV001	Polycyclic Organic Matter	0.00895	8744882	2.05E-06	
MN	MINNESOTA POWER INC - LASKIN ENERGY CTR	EU001	1	SV001	Polycyclic Organic Matter	0.004605	5141510	1.79E-06	2.04E-06
MN	MINNESOTA POWER INC - LASKIN ENERGY CTR	EU002	2	SV001	Polycyclic Organic Matter	0.00461	4031832	2.29E-06	
NE	OMAHA PUBLIC POWER DISTRICT - NORTH OMAHA POWER ST	01	MULTI	01	Polycyclic Organic Matter	0.0415	5101641	1.63E-05	1.63E-05
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-1	3	S-3	Polycyclic Organic Matter	0.0008	29979755	5.34E-08	4.38E-08
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-2	4	S-4	Polycyclic Organic Matter	0.00085	32692109	5.20E-08	
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-4	1	S-1	Polycyclic Organic Matter	0.0004	24152709	3.31E-08	
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-5	2	S-2	Polycyclic Organic Matter	0.00045	24537935	3.67E-08	
NC	PROGRESS ENERGY CAROLINAS - CAPE FEAR PLANT	G-1	5	S-1	Polycyclic Organic Matter	0.147	8135544	3.61E-05	3.26E-05
NC	PROGRESS ENERGY CAROLINAS - CAPE FEAR PLANT	G-2	6	S-2	Polycyclic Organic Matter	0.1605	11041675	2.91E-05	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-187	1	S-1	Polycyclic Organic Matter	0.0855	4629725	3.69E-05	3.09E-05
NC	L V SUTTON STEAM ELECTRIC PLANT	G-188	2	S-1	Polycyclic Organic Matter	0.067	5203884	2.57E-05	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-189	3	S-2	Polycyclic Organic Matter	0.3145	20975938	3.00E-05	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-29	1	S-1	Polycyclic Organic Matter	0.2885	25494527	2.26E-05	3.06E-05
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-30	2	S-2	Polycyclic Organic Matter	0.675	47033163	2.87E-05	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-35	MULTI	S-3	Polycyclic Organic Matter	0.6775	35494009	3.82E-05	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-36	MULTI	S-4	Polycyclic Organic Matter	0.663	40155873	3.30E-05	
NC	CP&L - MAYO FACILITY	G-46	MULTI	S-1	Polycyclic Organic Matter	0.7925	46476354	3.41E-05	3.41E-05
NC	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	G-24	1	S-1	Polycyclic Organic Matter	0.0435	2047727	4.25E-05	3.64E-05
NC	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	G-25	2	S-1	Polycyclic Organic Matter	0.04	2120634	3.77E-05	
NC	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	G-26	3	S-2	Polycyclic Organic Matter	0.067	4620806	2.90E-05	
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-21	3	S-3	Polycyclic Organic Matter	0.000025	6642892	7.53E-09	7.53E-09
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-21	3	S-4	Polycyclic Organic Matter	0.000025	6642892	7.53E-09	
NC	DUKE ENERGY CORP - BELEWS CREEK STEAM STATION	G-17	1	S-1	Polycyclic Organic Matter	0.00155	67835959	4.57E-08	4.24E-08
NC	DUKE ENERGY CORP - BELEWS CREEK STEAM STATION	G-18	2	S-2	Polycyclic Organic Matter	0.00135	68954797	3.92E-08	
NC	PROGRESS ENERGY - F LEE PLANT	G-2	1	S-1	Polycyclic Organic Matter	0.0685	4016709	3.41E-05	3.28E-05
NC	PROGRESS ENERGY - F LEE PLANT	G-3	2	S-1	Polycyclic Organic Matter	0.066	3913221	3.37E-05	
NC	PROGRESS ENERGY - F LEE PLANT	G-4	3	S-2	Polycyclic Organic Matter	0.2125	13970082	3.04E-05	
OH	DP&L, J.M. STUART GENERATING STATION	B001	1	000002	Polycyclic Organic Matter	0.0446226	30646464	2.91E-06	2.91E-06
OH	DP&L, J.M. STUART GENERATING STATION	B002	2	000003	Polycyclic Organic Matter	0.0419861	34601223	2.43E-06	2.41E-06
OH	DP&L, J.M. STUART GENERATING STATION	B003	3	000004	Polycyclic Organic Matter	0.0401248	37740832	2.13E-06	
OH	DP&L, J.M. STUART GENERATING STATION	B004	4	000005	Polycyclic Organic Matter	0.040821	30645557	2.66E-06	
OH	DP&L, KILLEN GENERATING STATION	B001	2	000002	Polycyclic Organic Matter	0.0381063	41790006	1.82E-06	1.82E-06
OH	CLEVELAND ELECTRIC ILLUMINATING CO., ASHTABULA PLA	B008	7	000001	Polycyclic Organic Matter	0.0182955	18695534	1.96E-06	1.96E-06
OH	R. E. BURGER PLANT	B011	7	000001	Polycyclic Organic Matter	0.00994653	9584154	2.08E-06	1.91E-06
OH	R. E. BURGER PLANT	B012	8	000001	Polycyclic Organic Matter	0.00818502	9424262	1.74E-06	
OH	CITY OF HAMILTON DEPARTMENT OF PUBLIC UTILITIES	B009	9	000003	Polycyclic Organic Matter	0.0029383	3410328	1.72E-06	1.72E-06
OH	CINCINNATI GAS & ELECTRIC CO., WM. H. ZIMMER	B006	1	000021	Polycyclic Organic Matter	0.0972063	83026148	2.34E-06	2.34E-06
OH	CONESVILLE POWER PLANT	B003	3	000006	Polycyclic Organic Matter	0.0083408	5002365	3.33E-06	3.33E-06
OH	GAVIN POWER PLANT	B003	1	000003	Polycyclic Organic Matter	0.0861381	71980848	2.39E-06	2.06E-06
OH	GAVIN POWER PLANT	B004	2	000004	Polycyclic Organic Matter	0.0807236	93686331	1.72E-06	
OH	CARDINAL POWER PLANT (CARDINAL OPERATING COMPANY)	B001	1	000005	Polycyclic Organic Matter	0.0283875	31028035	1.83E-06	1.69E-06
OH	CARDINAL POWER PLANT (CARDINAL OPERATING COMPANY)	B002	2	000007	Polycyclic Organic Matter	0.0347251	36636142	1.90E-06	
OH	CARDINAL POWER PLANT (CARDINAL OPERATING COMPANY)	B009	3	000009	Polycyclic Organic Matter	0.0263268	39408868	1.34E-06	
OH	W. H. SAMMIS PLANT	B007	1	000007	Polycyclic Organic Matter	0.0151319	12507034	2.42E-06	2.26E-06
OH	W. H. SAMMIS PLANT	B008	2	000007	Polycyclic Organic Matter	0.0115695	11855430	1.95E-06	
OH	W. H. SAMMIS PLANT	B009	3	000008	Polycyclic Organic Matter	0.0150304	11170922	2.69E-06	
OH	W. H. SAMMIS PLANT	B010	4	000008	Polycyclic Organic Matter	0.0146131	10549109	2.77E-06	
OH	W. H. SAMMIS PLANT	B011	5	000010	Polycyclic Organic Matter	0.0217377	18902199	2.30E-06	
OH	W. H. SAMMIS PLANT	B012	6	000010	Polycyclic Organic Matter	0.0448171	43024605	2.08E-06	
OH	W. H. SAMMIS PLANT	B013	7	000009	Polycyclic Organic Matter	0.0370883	45614013	1.63E-06	
OH	CLEVELAND ELECTRIC ILLUMINATING CO., EASTLAKE PLA	B001	1	000001	Polycyclic Organic Matter	0.00856319	6610984	2.59E-06	2.02E-06
OH	CLEVELAND ELECTRIC ILLUMINATING CO., EASTLAKE PLA	B002	2	000002	Polycyclic Organic Matter	0.00902711	9582228	1.88E-06	
OH	CLEVELAND ELECTRIC ILLUMINATING CO., EASTLAKE PLA	B003	3	000003	Polycyclic Organic Matter	0.00853363	8606980	1.98E-06	
OH	CLEVELAND ELECTRIC ILLUMINATING CO., EASTLAKE PLA	B004	4	000004	Polycyclic Organic Matter	0.0164113	17644289	1.86E-06	
OH	CLEVELAND ELECTRIC ILLUMINATING CO., EASTLAKE PLA	B005	5	000005	Polycyclic Organic Matter	0.037805	42648146	1.77E-06	
OH	AVON LAKE POWER PLANT	B010	10	000001	Polycyclic Organic Matter	0.00532514	3406103	3.13E-06	2.81E-06
OH	AVON LAKE POWER PLANT	B012	12	000002	Polycyclic Organic Matter	0.0394663	31705425	2.49E-06	
OH	TOLEDO EDISON CO., BAY SHORE POWER PLANT	B002	2	000002	Polycyclic Organic Matter	0.0111379	9642914	2.31E-06	1.99E-06
OH	TOLEDO EDISON CO., BAY SHORE POWER PLANT	B003	3	000002	Polycyclic Organic Matter	0.00953528	10364396	1.84E-06	
OH	TOLEDO EDISON CO., BAY SHORE POWER PLANT	B004	4	000002	Polycyclic Organic Matter	0.0160941	17544350	1.83E-06	
OH	MUSKINGUM RIVER POWER PLANT	B006	5	000004	Polycyclic Organic Matter	0.0412772	35301392	2.34E-06	2.34E-06
OH	R. H. GORSUCH STATION	B001	1	000007	Polycyclic Organic Matter	0.00530254	3621082	2.93E-06	2.86E-06
OH	R. H. GORSUCH STATION	B002	2	000007	Polycyclic Organic Matter	0.00508074	4003690	2.54E-06	
OH	R. H. GORSUCH STATION	B003	3	000007	Polycyclic Organic Matter	0.00467331	3229962	2.89E-06	
OH	R. H. GORSUCH STATION	B004	4	000007	Polycyclic Organic Matter	0.00517807	3373420	3.07E-06	
PA	ALLEGHENY ENERGY SUPPLY CO ARMSTRONG POWER STATION	031	1	S03	Polycyclic Organic Matter	0.011	8744228	2.52E-06	2.49E-06
PA	ALLEGHENY ENERGY SUPPLY CO ARMSTRONG POWER STATION	032	2	S04	Polycyclic Organic Matter	0.0115	9341468	2.46E-06	
SC	DUKE ENERGY:LEE	001	1	1	Polycyclic Organic Matter	0.004701	3146584	2.99E-06	2.45E-06
SC	DUKE ENERGY:LEE	002	2	2	Polycyclic Organic Matter	0.004605	3298670	2.79E-06	
SC	DUKE ENERGY:LEE	003	3	3	Polycyclic Organic Matter	0.005551	7049954	1.57E-06	
TN	ALLEN FOSSIL PLANT	Boilr1	1	Stack1	Polycyclic Organic Matter	0.0098	20568457	9.53E-07	1.24E-06
TN	ALLEN FOSSIL PLANT	Boilr2	2	Stack2	Polycyclic Organic Matter	0.0114	19131766	1.19E-06	
TN	ALLEN FOSSIL PLANT	Boilr3	3	Stack3	Polycyclic Organic Matter	0.0128	16183389	1.58E-06	
TX	GIBBONS CREEK	000002	1	000002	Polycyclic Organic Matter	0.0029	35281328	1.64E-07	1.64E-07
								Total Avg	6.21E-06
NY	AES GREENIDGE LLC	GT00004	6	00004	Propylene Dichloride	0.003036	5056599	1.20E-06	1.20E-06

Completed by: JDL 11.26.2008
Checked by: SAK 11.26.2008

Table A-6 : EPA NEI HAP Database and TRI Database Emissions Information and EPA Clean Markets MMBtu/hr Values

STATE	FacilityName	Emission Unit ID	Boiler ID	Emission Release Point ID	Pollutant	Emissions (TPY)	HEAT INPUT (MMBtu)	Emission Rate (lb/MMBtu)	Avg. Emission Rate (lb/MMBtu)
								Total Avg.	1.20E-06
UT	CARBON POWER PLANT	3974	1	1001	Sodium Cyanide	0.31635	6740398	9.39E-05	9.74E-05
UT	CARBON POWER PLANT	3976	2	1002	Sodium Cyanide	0.46915	9300537	1.01E-04	
UT	HUNTER POWER PLANT	4026	1	1281	Sodium Cyanide	1.0747	37638145	5.71E-05	8.98E-05
UT	HUNTER POWER PLANT	4028	2	1282	Sodium Cyanide	1.71355	32252702	1.06E-04	
UT	HUNTER POWER PLANT	4030	3	1283	Sodium Cyanide	1.828	34434000	1.06E-04	
UT	HUNTINGTON POWER PLANT	4032	1	1284	Sodium Cyanide	1.5591	32929773	9.47E-05	1.14E-04
UT	HUNTINGTON POWER PLANT	4034	2	1285	Sodium Cyanide	1.7858	26754943	1.33E-04	
UT	INTERMOUNTAIN GENERATION STATION	2381	1SGA	1709	Sodium Cyanide	0.88393	83006107	2.13E-05	2.21E-05
UT	INTERMOUNTAIN GENERATION STATION	2382	2SGA	1710	Sodium Cyanide	0.840831	73285622	2.29E-05	
								Total Avg.	8.09E-05
MO	KANSAS CITY POWER & LIGHT CO-MONTROSE GENERATING S	7848	2	10063	Toluene-2,4-Diamine	0.0001	11907048	1.68E-08	1.61E-08
MO	KANSAS CITY POWER & LIGHT CO-MONTROSE GENERATING S	7849	1	10065	Toluene-2,4-Diamine	0.0001	12946678	1.54E-08	
MO	KANSAS CITY POWER & LIGHT CO-IATAN GENERATING STAT	16912	1	21121	Toluene-2,4-Diamine	0.0003	52608092	1.14E-08	1.14E-08
								Total Avg.	1.38E-08
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU003	3	SV001	Vinyl Chloride	0.00214	6302333	6.79E-07	6.21E-07
MN	NSP DBA XCEL ENERGY - BLACK DOG	EU004	4	SV001	Vinyl Chloride	0.003425	12188405	5.62E-07	
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU001	6	SV002	Vinyl Chloride	0.001915	4388784	8.73E-07	8.50E-07
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU002	7	SV002	Vinyl Chloride	0.00193	4670969	8.26E-07	
MN	XCEL ENERGY - RIVERSIDE GENERATING PLANT	EU003	8	SV003	Vinyl Chloride	0.005515	12939421	8.52E-07	
MN	OTTER TAIL POWER CO - HOOT LAKE PLANT	EU002	2	SV002	Vinyl Chloride	0.0016	4758198	6.73E-07	7.19E-07
MN	OTTER TAIL POWER CO - HOOT LAKE PLANT	EU003	3	SV002	Vinyl Chloride	0.00218	5695698	7.65E-07	
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU003	5	SV001	Vinyl Chloride	0.001955	6154367	6.35E-07	6.77E-07
MN	XCEL ENERGY - HIGH BRIDGE GENERATING	EU004	6	SV001	Vinyl Chloride	0.00314	8744882	7.18E-07	
MN	NSP - SHERBURNE GENERATING PLANT	EU001	1	SV001	Vinyl Chloride	0.018525	53500053	6.93E-07	6.68E-07
MN	NSP - SHERBURNE GENERATING PLANT	EU002	2	SV001	Vinyl Chloride	0.01729	46259012	7.48E-07	
MN	NSP - SHERBURNE GENERATING PLANT	EU003	3	SV002	Vinyl Chloride	0.02132	75715065	5.63E-07	
MN	XCEL ENERGY - ALLEN S KING GENERATING	EU001	1	SV001	Vinyl Chloride	0.011965	18096637	1.32E-06	1.32E-06
NY	AES GREENIDGE LLC	G00004	6	00004	Vinyl Chloride	0.001656	5056599	6.55E-07	6.55E-07
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-1	3	S-3	Vinyl Chloride	0.0155	29979755	1.03E-06	8.42E-07
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-2	4	S-4	Vinyl Chloride	0.016	32692109	9.79E-07	
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-4	1	S-1	Vinyl Chloride	0.008	24152709	6.62E-07	
NC	DUKE ENERGY CORPORATION - MARSHALL STEAM STATION	G-5	2	S-2	Vinyl Chloride	0.0085	24537935	6.93E-07	
NC	PROGRESS ENERGY CAROLINAS - CAPE FEAR PLANT	G-1	5	S-1	Vinyl Chloride	0.00325	8135544	7.99E-07	7.16E-07
NC	PROGRESS ENERGY CAROLINAS - CAPE FEAR PLANT	G-2	6	S-2	Vinyl Chloride	0.0035	11041675	6.34E-07	
NC	DUKE ENERGY CORPORATION - ALLEN STEAM STATION	G-14	1	S-1	Vinyl Chloride	0.0025	8399352	5.95E-07	5.75E-07
NC	DUKE ENERGY CORPORATION - ALLEN STEAM STATION	G-15	2	S-2	Vinyl Chloride	0.002	9210552	4.34E-07	
NC	DUKE ENERGY CORPORATION - ALLEN STEAM STATION	G-16	3	S-3	Vinyl Chloride	0.0035	15956865	4.39E-07	
NC	DUKE ENERGY CORPORATION - ALLEN STEAM STATION	G-17	4	S-4	Vinyl Chloride	0.005	14172222	7.06E-07	
NC	DUKE ENERGY CORPORATION - ALLEN STEAM STATION	G-18	5	S-5	Vinyl Chloride	0.005	14313317	6.99E-07	
NC	DUKE ENERGY CORPORATION - RIVERBEND STEAM STATION	G-18	8	S-6	Vinyl Chloride	0.0015	4012669	7.48E-07	7.58E-07
NC	DUKE ENERGY CORPORATION - RIVERBEND STEAM STATION	G-19	9	S-7	Vinyl Chloride	0.002	5737728	6.98E-07	
NC	DUKE ENERGY CORPORATION - RIVERBEND STEAM STATION	G-20	10	S-8	Vinyl Chloride	0.0025	6028904	8.29E-07	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-187	1	S-1	Vinyl Chloride	0.0019	4629725	8.21E-07	6.88E-07
NC	L V SUTTON STEAM ELECTRIC PLANT	G-188	2	S-1	Vinyl Chloride	0.0015	5203884	5.76E-07	
NC	L V SUTTON STEAM ELECTRIC PLANT	G-189	3	S-2	Vinyl Chloride	0.007	20975938	6.67E-07	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-29	1	S-1	Vinyl Chloride	0.0065	25494527	5.10E-07	6.79E-07
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-30	2	S-2	Vinyl Chloride	0.015	47033163	6.38E-07	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-35	MULTI	S-3	Vinyl Chloride	0.015	35494009	8.45E-07	
NC	CP&L - ROXBORO STEAM ELECTRIC PLANT	G-36	MULTI	S-4	Vinyl Chloride	0.0145	40155873	7.22E-07	
NC	CP&L - MAYO FACILITY	G-46	MULTI	S-1	Vinyl Chloride	0.0175	46476354	7.53E-07	7.53E-07
NC	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	G-24	1	S-1	Vinyl Chloride	0.00095	2047727	9.28E-07	8.09E-07
NC	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	G-25	2	S-1	Vinyl Chloride	0.0009	2120634	8.49E-07	
NC	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	G-26	3	S-2	Vinyl Chloride	0.0015	4620806	6.49E-07	
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-21	3	S-3	Vinyl Chloride	0.00075	6642892	2.26E-07	3.26E-07
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-22	1	S-1	Vinyl Chloride	0.0005	2817682	3.55E-07	
NC	DUKE ENERGY CORP - DAN RIVER STEAM STATION	G-23	2	S-2	Vinyl Chloride	0.0005	2513404	3.98E-07	
NC	DUKE ENERGY CORPORATION - BUCK STEAM STATION	G-3	7	S-6	Vinyl Chloride	0.0005	1603389	6.24E-07	6.29E-07
NC	DUKE ENERGY CORPORATION - BUCK STEAM STATION	G-4	8	S-6	Vinyl Chloride	0.002	6291656	6.36E-07	
NC	DUKE ENERGY CORPORATION - BUCK STEAM STATION	G-5	9	S-6	Vinyl Chloride	0.002	6379286	6.27E-07	
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-84	3	S-3	Vinyl Chloride	0.0005	2069663	4.83E-07	4.91E-07
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-85	4	S-4	Vinyl Chloride	0.0005	2103923	4.75E-07	
NC	DUKE ENERGY CORPORATION - CLIFFSIDE STEAM STATION	G-86	5	S-5	Vinyl Chloride	0.0085	32959329	5.16E-07	
NC	DUKE ENERGY CORP - BELEWS CREEK STEAM STATION	G-17	1	S-1	Vinyl Chloride	0.03	67835959	8.84E-07	8.19E-07
NC	DUKE ENERGY CORP - BELEWS CREEK STEAM STATION	G-18	2	S-2	Vinyl Chloride	0.026	68954797	7.54E-07	
NC	PROGRESS ENERGY - F LEE PLANT	G-2	1	S-1	Vinyl Chloride	0.0015	4016709	7.47E-07	7.20E-07
NC	PROGRESS ENERGY - F LEE PLANT	G-3	2	S-1	Vinyl Chloride	0.00145	3913221	7.41E-07	
NC	PROGRESS ENERGY - F LEE PLANT	G-4	3	S-2	Vinyl Chloride	0.0047	13970082	6.73E-07	
TN	ALLEN FOSSIL PLANT	Boilr1	1	Stack1	Vinyl Chloride	0.0053	20568457	5.15E-07	6.70E-07
TN	ALLEN FOSSIL PLANT	Boilr2	2	Stack2	Vinyl Chloride	0.0062	19131766	6.48E-07	
TN	ALLEN FOSSIL PLANT	Boilr3	3	Stack3	Vinyl Chloride	0.00685	16183389	8.47E-07	
								Total Avg.	7.14E-07

Completed by: JDF 11-26-2008
Checked by: SAK 11-26-2008

TOXIC EMISSION CALCULATIONS

Table A-7: Toxic Emission Calculations: Main Boiler

Basis:

PRB Coal Consumption Rate	488	ton Coal/hr
50-50 Blend Coal Consumption rate	417	ton Coal/hr
Fuel Oil Consumption Rate	9286	gal/hr
Maximum heat Input	8.30E-03	Trillion Btu/hr

Compound	Pulverized Coal [1] -AP-42				Fuel Oil [2]-AP-42			Pulverized Coal [3]-Utility report to Congress, NEI Database, TRI Database			Pulverized Coal[4] -MACT Analysis						Worst Case Emissions (lb/hr)	Worst Case Emissions (tpy)[5]
	Emission Factor	Units	Hourly Emissions (lb/hr) (PRB Coal)	Hourly Emissions (lb/hr) 50-50 Blend	Emission Factor	Units	Hourly Emissions (lb/hr)	Emission Factor	Units	Hourly Emissions (lb/hr)	Emission Factor (PRB Coal)	Units	Hourly Emissions (lb/hr) (PRB Coal)	Emission Factor (50-50 Blend Coal)	Units	Hourly Emissions (lb/hr) 50-50 Blend		
Organics																		
Acenaphthene	5.10E-07	lb/ton	2.49E-04	2.13E-04	2.1E-05	lb/1,000 gal	2.0E-04	0.013	lb/trillion btu	1.08E-04							2.49E-04	1.1E-03
Acenaphthylene	2.50E-07	lb/ton	1.22E-04	1.04E-04	2.5E-07	lb/1,000 gal	2.3E-06	0.004	lb/trillion btu	3.32E-05							1.22E-04	5.3E-04
Acetaldehyde	5.70E-04	lb/ton	2.78E-01	2.38E-01				6.75	lb/trillion btu	5.60E-02							2.78E-01	1.2E+00
Acetophenone	1.50E-05	lb/ton	7.32E-03	6.26E-03				0.68	lb/trillion btu	5.64E-03							7.32E-03	3.2E-02
Acrolein	2.90E-04	lb/ton	1.42E-01	1.21E-01				3.25	lb/trillion btu	2.70E-02							1.42E-01	6.2E-01
Anthracene	2.10E-07	lb/ton	1.02E-04	8.76E-05	1.2E-06	lb/1,000 gal	1.1E-05	0.004	lb/trillion btu	3.32E-05							1.02E-04	4.5E-04
Benzene	1.30E-03	lb/ton	6.34E-01	5.42E-01	2.14E-04	lb/1,000 gal	2.0E-03	2.5	lb/trillion btu	2.08E-02							6.34E-01	2.8E+00
Benzo(a)anthracene	8.00E-08	lb/ton	3.90E-05	3.34E-05	4.0E-06	lb/1,000 gal	3.7E-05	0.002	lb/trillion btu	1.66E-05							3.90E-05	1.7E-04
Benzo(a)pyrene	3.80E-08	lb/ton	1.85E-05	1.58E-05				0.001	lb/trillion btu	8.30E-06							1.85E-05	8.1E-05
Benzo(b)fluoranthene			-	-				0.008	lb/trillion btu	6.64E-05							6.64E-05	2.9E-04
Benzo(e)pyrene			-	-				0.001	lb/trillion btu	8.30E-06							8.30E-06	3.6E-05
Benzo(g,h,i)perylene			-	-	2.26E-06	lb/1,000 gal	2.1E-05	0.002	lb/trillion btu	1.66E-05							2.10E-05	9.2E-05
Benzo(g,h,i)pyrene	2.70E-08	lb/ton	1.32E-05	1.13E-05													1.32E-05	5.8E-05
Benzo(b,k)fluoranthene	1.10E-07	lb/ton	5.37E-05	4.59E-05	1.48E-06	lb/1,000 gal	1.4E-05	0.004	lb/trillion btu	3.32E-05							5.37E-05	2.4E-04
Benzo(k)fluoranthene			-	-				0.004	lb/trillion btu	3.32E-05							3.32E-05	1.5E-04
Benzyl chloride	7.00E-04	lb/ton	3.42E-01	2.92E-01				0.006	lb/trillion btu	4.98E-05							3.42E-01	1.5E+00
Biphenyl	1.70E-06	lb/ton	8.30E-04	7.09E-04				0.18	lb/trillion btu	1.49E-03							1.49E-03	6.5E-03
bis(2-Ethylhexyl)phthalate	7.30E-05	lb/ton	3.56E-02	3.04E-02				4.1	lb/trillion btu	3.40E-02							3.56E-02	1.6E-01
Bromoform	3.90E-05	lb/ton	1.90E-02	1.63E-02				6.6	lb/trillion btu	5.48E-02							5.48E-02	2.4E-01
2-Butanone (MEK)	3.90E-04	lb/ton	1.90E-01	1.63E-01													1.90E-01	
Carbon tetrachloride			-	-				3.25	lb/trillion btu	2.70E-02							2.70E-02	1.2E-01
Carbon disulfide	1.30E-04	lb/ton	6.34E-02	5.42E-02				4.3	lb/trillion btu	3.57E-02							6.34E-02	2.8E-01
Chlorobenzene	2.20E-05	lb/ton	1.07E-02	9.17E-03				3.18	lb/trillion btu	2.64E-02							2.64E-02	1.2E-01
Chloroform	5.90E-05	lb/ton	2.88E-02	2.46E-02				3.2	lb/trillion btu	2.66E-02							2.88E-02	1.3E-01
Chloromethane	5.30E-04	lb/ton	2.59E-01	2.21E-01				5.9	lb/trillion btu	4.90E-02							2.59E-01	1.1E+00
2-Chloronaphthalene			-					0.04	lb/trillion btu	3.32E-04							3.32E-04	1.5E-03
2-Chloroacetophenone	7.00E-06	lb/ton	3.42E-03	2.92E-03				0.29	lb/trillion btu	2.41E-03							3.42E-03	1.5E-02
Chrysene	1.00E-07	lb/ton	4.88E-05	4.17E-05	2.4E-06	lb/1,000 gal	2.2E-05	0.003	lb/trillion btu	2.49E-05							4.88E-05	2.1E-04
Cumene	5.30E-06	lb/ton	2.59E-03	2.21E-03				0.29	lb/trillion btu	2.41E-03							2.59E-03	1.1E-02
Cyanide	2.50E-03	lb/ton	1.22E+00	1.04E+00				28.00	lb/trillion btu	2.32E-01							1.22E+00	5.3E+00
Dibenzo(a,h)anthracene			-	-	1.7E-06	lb/1,000 gal	1.6E-05	0.001	lb/trillion btu	8.30E-06							1.55E-05	6.8E-05
Dibutyl phthalate				-				2.8	lb/trillion btu	2.32E-02							2.32E-02	1.0E-01
Dimethyl sulfate	4.80E-05	lb/ton	2.34E-02	2.00E-02													2.34E-02	1.0E-01
2,4-Dinitrotoluene	2.80E-07	lb/ton	1.37E-04	1.17E-04				0.015	lb/trillion btu	1.25E-04							1.37E-04	6.0E-04
Ethylbenzene	9.40E-05	lb/ton	4.59E-02	3.92E-02	6.36E-05	lb/1,000 gal	5.9E-04	0.41	lb/trillion btu	3.40E-03							4.59E-02	2.0E-01
Ethyl Chloride	4.20E-05	lb/ton	2.05E-02	1.75E-02				2.4	lb/trillion btu	1.99E-02							2.05E-02	9.0E-02
Ethylene dichloride	4.00E-05	lb/ton	1.95E-02	1.67E-02				3.1	lb/trillion btu	2.57E-02							2.57E-02	1.1E-01
Ethylene dibromide	1.20E-06	lb/ton	5.86E-04	5.00E-04													5.86E-04	2.6E-03
Fluoranthene	7.10E-07	lb/ton	3.46E-04	2.96E-04	4.8E-06	lb/1,000 gal	4.5E-05	0.016	lb/trillion btu	1.33E-04							3.46E-04	1.5E-03
Fluorene	9.10E-07	lb/ton	4.44E-04	3.79E-04	4.5E-06	lb/1,000 gal	4.2E-05	0.013	lb/trillion btu	1.08E-04							4.44E-04	1.9E-03
Formaldehyde	2.40E-04	lb/ton	1.17E-01	1.00E-01	3.3E-02	lb/1,000 gal	3.1E-01	4.0	lb/trillion btu	3.32E-02							3.06E-01	1.3E+00
Hexane	6.70E-05	lb/ton	3.27E-02	2.79E-02				0.83	lb/trillion btu	6.89E-03							3.27E-02	1.4E-01
Hydrogen chloride	1.20E+00	lb/ton	5.86E+02	5.00E+02				13634.6623	lb/trillion btu	1.13E+02	3.22E-04	lb/MMBtu	2.68E+00	2.89E-03	lb/MMBtu	2.40E+01	2.40E+01	1.1E+02
Hydrogen Fluoride	1.50E-01	lb/ton	7.32E+01	6.26E+01				2260.714975	lb/trillion btu	1.88E+01	2.68E-04	lb/MMBtu	2.22E+00	2.13E-04	lb/MMBtu	1.77E+00	2.22E+00	9.7E+00
Indeno(1,2,3,c,d)pyrene	6.10E-08	lb/ton	2.98E-05	2.54E-05	2.1E-06	lb/1,000 gal	2.0E-05	0.003	lb/trillion btu	2.49E-05							2.98E-05	1.3E-04
Isophorone	5.80E-04	lb/ton	2.83E-01	2.42E-01				24	lb/trillion btu	1.99E-01							2.83E-01	1.2E+00
Methyl Bromide	1.60E-04	lb/ton	7.81E-02	6.67E-02				0.89	lb/trillion btu	7.39E-03							7.81E-02	3.4E-01
Methyl hydrazine	1.70E-04	lb/ton	8.30E-02	7.09E-02													8.30E-02	3.6E-01
MMA	2.00E-05	lb/ton	9.76E-03	8.34E-03				1.1	lb/trillion btu	9.13E-03							9.76E-03	4.3E-02
2-Methylnaphthalene			-	-				0.032	lb/trillion btu	2.66E-04							2.66E-04	1.2E-03
MTBE	3.50E-05	lb/ton	1.71E-02	1.46E-02				1.4	lb/trillion btu	1.16E-02							1.71E-02	7.5E-02
Methylene chloride	2.90E-04	lb/ton	1.42E-01	1.21E-01				13	lb/trillion btu	1.08E-01							1.42E-01	6.2E-01
Naphthalene	1.30E-05	lb/ton	6.34E-03	5.42E-03	1.13E-03	lb/1,000 gal	1.0E-02	0.77	lb/trillion btu	6.39E-03							1.05E-02	4.6E-02
5-Methyl chrysene	2.20E-08	lb/ton	1.07E-05	9.17E-06													1.07E-05	4.7E-05
OCDD					3.10E-09	lb/1,000 gal	2.9E-08										2.88E-08	1.3E-07
Phenanthrene	2.70E-06	lb/ton	1.32E-03	1.13E-03	1.1E-05	lb/1,000 gal	9.8E-05	0.032	lb/trillion btu	2.66E-04							1.32E-03	5.8E-03
Phenol	1.60E-05	lb/ton	7.81E-03	6.67E-03				6.1	lb/trillion btu	5.06E-02							5.06E-02	2.2E-01
Propionaldehyde	3.80E-04	lb/ton	1.85E-01	1.58E-01				10.35	lb/trillion btu	8.59E-02							1.85E-01	8.1E-01
Pyrene	3.30E-07	lb/ton	1.61E-04	1.38E-04	4.3E-06	lb/1,000 gal	3.9E-05	0.012	lb/trillion btu	9.96E-05							1.61E-04	7.1E-04
Styrene	2.50E-05	lb/ton	1.22E-02	1.04E-02				3.1	lb/trillion btu	2.57E-02							2.57E-02	1.1E-01
Tetrachloroethylene	4.30E-05	lb/ton	2.10E-02	1.79E-02				3.1	lb/trillion btu	2.57E-02							2.57E-02	1.1E-01
Toluene	2.40E-04	lb/ton	1.17E-01	1.00E-01	6.20E-03	lb/1,000 gal	5.8E-02	3.6	lb/trillion btu	2.99E-02							1.17E-01	5.1E-01
1,1,1-Trichloroethane	2.00E-05	lb/ton	9.76E-03	8.34E-03	2.36E-04	lb/1,000 gal	2.2E-03										9.76E-03	4.3E-02
1,1,2-Trichloroethane			-	-				4.7	lb/trillion btu	3.90E-02							3.90E-02	1.7E-01
Trichloroethylene			-	-				3.1	lb/trillion btu	2.57E-02							2.57E-02	1.1E-01
Vinyl acetate	7.60E-06	lb/ton	3.71E-03	3.17E-03				0.42	lb/trillion btu	3.49E-03							3.71E-03	1.6E-02

Completed by: PBS 11/26/08
Checked by: SAK 11/26/08

Table A-7: Toxic Emission Calculations: Main Boiler

Basis:

PRB Coal Consumption Rate	488	ton Coal/hr
50-50 Blend Coal Consumption rate	417	ton Coal/hr
Fuel Oil Consumption Rate	9286	gal/hr
Maximum heat Input	8.30E-03	Trillion Btu/hr

Compound	Pulverized Coal [1] -AP-42				Fuel Oil [2]-AP-42			Pulverized Coal [3]-Utility report to Congress, NEI Database, TRI Database			Pulverized Coal[4] -MACT Analysis						Worst Case Emissions (lb/hr)	Worst Case Emissions (tpy)[5]
	Emission Factor	Units	Hourly Emissions (lb/hr) (PRB Coal)	Hourly Emissions (lb/hr) 50-50 Blend	Emission Factor	Units	Hourly Emissions (lb/hr)	Emission Factor	Units	Hourly Emissions (lb/hr)	Emission Factor (PRB Coal)	Units	Hourly Emissions (lb/hr) (PRB Coal)	Emission Factor (50-50 Blend Coal)	Units	Hourly Emissions (lb/hr) 50-50 Blend		
Xylene	3.70E-05	lb/ton	1.81E-02	1.54E-02	1.09E-04	lb/1,000 gal	1.0E-03	4.65	lb/trillion btu	3.86E-02							3.86E-02	1.7E-01
m-xylene	-	-	-	-	-	-	-	1.45	lb/trillion btu	1.20E-02							1.20E-02	5.3E-02
o-xylene	-	-	-	-	1.09E-04	lb/1,000 gal	1.0E-03	0.81	lb/trillion btu	6.72E-03							6.72E-03	2.9E-02
p-xylene	-	-	-	-	-	-	-	1.45	lb/trillion btu	1.20E-02							1.20E-02	5.3E-02
Dioxins (Total)	-	-	-	-	-	-	-	9.68E-06	lb/trillion btu	8.03E-08							8.03E-08	3.5E-07
P-Cresol	-	-	-	-	-	-	-	0.95	lb/trillion btu	7.89E-03							7.89E-03	3.5E-02
Pentachlorophenol	-	-	-	-	-	-	-	0.008	lb/trillion btu	6.64E-05							6.64E-05	2.9E-04
Hexachlorobenzene	-	-	-	-	-	-	-	0.08	lb/trillion btu	6.64E-04							6.64E-04	2.9E-03
Methyl chloroform	-	-	-	-	-	-	-	3.42	lb/trillion btu	2.84E-02							2.84E-02	1.2E-01
Methyl iodine	-	-	-	-	-	-	-	0.4	lb/trillion btu	3.32E-03							3.32E-03	1.5E-02
Methyl isobutyl ketone	-	-	-	-	-	-	-	4.9	lb/trillion btu	4.07E-02							4.07E-02	1.8E-01
1,2,4-Trichlorobenzene	-	-	-	-	-	-	-	1.51E-06	lb/MMBtu	1.25E-02							1.25E-02	5.5E-02
1,3-Butadiene	-	-	-	-	-	-	-	3.71E-07	lb/MMBtu	3.08E-03							3.08E-03	1.3E-02
1,3-Dichloropropene	-	-	-	-	-	-	-	6.61E-07	lb/MMBtu	5.48E-03							5.48E-03	2.4E-02
1,4-Dichlorobenzene	-	-	-	-	-	-	-	1.06E-06	lb/MMBtu	8.76E-03							8.76E-03	3.8E-02
2,4,6-Trichlorophenol	-	-	-	-	-	-	-	8.01E-10	lb/MMBtu	6.64E-06							6.64E-06	2.9E-05
2,4-Dinitrophenol	-	-	-	-	-	-	-	1.08E-08	lb/MMBtu	8.92E-05							8.92E-05	3.9E-04
3-Methylcholanthrene	-	-	-	-	-	-	-	6.62E-11	lb/MMBtu	5.49E-07							5.49E-07	2.4E-06
4-Nitrophenol	-	-	-	-	-	-	-	4.00E-09	lb/MMBtu	3.32E-05							3.32E-05	1.5E-04
7,12-Dimethylbenz[a]Anthracene	-	-	-	-	-	-	-	5.88E-10	lb/MMBtu	4.88E-06							4.88E-06	2.1E-05
Allyl Chloride	-	-	-	-	-	-	-	8.03E-06	lb/MMBtu	6.66E-02							6.66E-02	2.9E-01
Arsenic Trioxide	-	-	-	-	-	-	-	2.98E-05	lb/MMBtu	2.47E-01							2.47E-01	1.1E+00
Cadmium Oxide	-	-	-	-	-	-	-	3.20E-06	lb/MMBtu	2.66E-02							2.66E-02	1.2E-01
Calcium Cyanamide	-	-	-	-	-	-	-	3.39E-06	lb/MMBtu	2.81E-02							2.81E-02	1.2E-01
Chromic Acid (VI)	-	-	-	-	-	-	-	8.32E-06	lb/MMBtu	6.91E-02							6.91E-02	3.0E-01
Chromic Oxide	-	-	-	-	-	-	-	2.44E-05	lb/MMBtu	2.02E-01							2.02E-01	8.9E-01
Dibenzo[a,j]Acridine	-	-	-	-	-	-	-	5.12E-07	lb/MMBtu	4.25E-03							4.25E-03	1.9E-02
Dibenzofuran	-	-	-	-	-	-	-	5.73E-07	lb/MMBtu	4.75E-03							4.75E-03	2.1E-02
Diethyl Sulfate	-	-	-	-	-	-	-	2.33E-06	lb/MMBtu	1.94E-02							1.94E-02	8.5E-02
Dimethyl Phthalate	-	-	-	-	-	-	-	9.64E-08	lb/MMBtu	8.00E-04							8.00E-04	3.5E-03
Manganese Dioxide	-	-	-	-	-	-	-	4.26E-05	lb/MMBtu	3.54E-01							3.54E-01	1.5E+00
Polychlorinated Biphenyls	-	-	-	-	-	-	-	1.37E-08	lb/MMBtu	1.14E-04							1.14E-04	5.0E-04
Polycyclic Organic Matter	-	-	-	-	-	-	-	6.21E-06	lb/MMBtu	5.16E-02							5.16E-02	2.3E-01
Propylene Dichloride	-	-	-	-	-	-	-	1.20E-06	lb/MMBtu	9.97E-03							9.97E-03	4.4E-02
Sodium Cyanide	-	-	-	-	-	-	-	8.09E-05	lb/MMBtu	6.71E-01							6.71E-01	2.9E+00
Toluene-2,4-Diamine	-	-	-	-	-	-	-	1.38E-08	lb/MMBtu	1.14E-04							1.14E-04	5.0E-04
Vinyl Chloride	-	-	-	-	-	-	-	7.14E-07	lb/MMBtu	5.92E-03							5.92E-03	2.6E-02
Metals																		
Antimony	1.80E-05	lb/ton	8.78E-03	7.51E-03				0.87	lb/trillion btu	7.25E-03	1.71E-06	lb/MMBtu	1.42E-02	1.75E-06	lb/MMBtu	1.46E-02	1.46E-02	6.4E-02
Arsenic	4.10E-04	lb/ton	2.00E-01	1.71E-01	5.6E-04	lb/1,000 gal	5.2E-03	6.21	lb/trillion btu	5.16E-02	3.77E-05	lb/MMBtu	3.13E-01	2.71E-05	lb/MMBtu	2.25E-01	3.13E-01	1.4E+00
Beryllium	2.10E-05	lb/ton	1.02E-02	8.76E-03	4.2E-04	lb/1,000 gal	3.9E-03	0.72	lb/trillion btu	5.99E-03	2.11E-06	lb/MMBtu	1.75E-02	3.43E-06	lb/MMBtu	2.85E-02	2.85E-02	1.2E-01
Cadmium	5.10E-05	lb/ton	2.49E-02	2.13E-02	4.2E-04	lb/1,000 gal	3.9E-03	0.34	lb/trillion btu	2.79E-03	3.53E-07	lb/MMBtu	2.93E-03	6.45E-06	lb/MMBtu	5.35E-02	5.35E-02	2.3E-01
Chromium, total	2.60E-04	lb/ton	1.27E-01	1.08E-01	4.2E-04	lb/1,000 gal	3.9E-03	7.69	lb/trillion btu	6.38E-02	1.53E-05	lb/MMBtu	1.27E-01	1.89E-05	lb/MMBtu	1.57E-01	1.57E-01	6.9E-01
Chromium, hexavalent	7.90E-05	lb/ton	3.86E-02	3.29E-02													3.86E-02	1.7E-01
Cobalt	1.00E-04	lb/ton	4.88E-02	4.17E-02				2.38	lb/trillion btu	1.98E-02	4.86E-06	lb/MMBtu	4.04E-02	4.62E-06	lb/MMBtu	3.83E-02	4.88E-02	2.1E-01
Copper			-	-	8.4E-04	lb/1,000 gal	7.8E-03										7.80E-03	
Lead	4.20E-04	lb/ton	2.05E-01	1.75E-01	1.3E-03	lb/1,000 gal	1.2E-02	7.64	lb/trillion btu	6.34E-02	1.01E-05	lb/MMBtu	8.38E-02	1.60E-05	lb/MMBtu	1.33E-01	1.33E-01	5.8E-01
Mercury	8.30E-05	lb/ton	4.05E-02	3.46E-02	4.2E-04	lb/1,000 gal	3.9E-03	5.26	lb/trillion btu	4.36E-02	1.68E-06	lb/MMBtu	1.39E-02				1.39E-02	6.E-02
Magnesium	1.10E-02	lb/ton	5.37E+00	4.59E+00													5.37E+00	
Manganese	4.90E-04	lb/ton	2.39E-01	2.04E-01	8.4E-04	lb/1,000 gal	7.8E-03	19.27	lb/trillion btu	1.60E-01	1.13E-04	lb/MMBtu	9.35E-01	9.70E-05	lb/MMBtu	8.05E-01	9.35E-01	4.1E+00
Nickel	2.80E-04	lb/ton	1.37E-01	1.17E-01	4.2E-04	lb/1,000 gal		6.04	lb/trillion btu	5.01E-02	1.46E-05	lb/MMBtu	1.21E-01	1.98E-05	lb/MMBtu	1.64E-01	1.64E-01	7.2E-01
Phosphorus			-	-				31.50	lb/trillion btu	2.61E-01							2.61E-01	1.1E+00
Selenium	1.30E-03	lb/ton	6.34E-01	5.42E-01	2.1E-03	lb/1,000 gal	2.0E-02	18.76	lb/trillion btu	1.56E-01	2.15E-06	lb/MMBtu	1.79E-02	2.65E-06	lb/MMBtu	2.20E-02	6.34E-01	2.8E+00
Zinc			-		5.6E-04	lb/1,000 gal	5.2E-03										5.20E-03	

1)AP-42 Table 1.1-13, 1.1-14, & 1.1-18

2)AP-42 Tables 1.3-9 & 1.3-10

3) Test Report Data Table A-1 and A-4 from the study of Hazardous Air Pollutant emissions from Electric Utility Steam Generating Units- Final report to Congress (1998) and Data derived from EPA NEI HAP emissions inventory data - 2002 NEI V3 last updated September 2007 and 2006 TRI Database

4) MACT Analysis HAP Emissions rate data derived from USGS COALQUAL Data as indicated in Sections 17, 18, and 19 of calculations.

5) Worst case ton/yr emissions indicated for HAPs. Emissions indicated worst case value of emission estimate resources reviewed with four exceptions. Value indicated for HF, HCl, mercury, and lead representative of emission limits proposed for Plant Washington.

Completed by: PBS 11/26/08
Checked by: SAK 11/26/08

Table A-8: Toxic Emission Calculations: Auxiliary Boiler

Basis:

Fuel Oil Consumption	1,714	gal/hr
Auxiliary Boiler Capacity	240	MMBtu/hr
Annual Operating Hours	876	hrs/yr

Compound	Fuel Oil [1]			
	Emission Factor	Units	Hourly Emissions (lb/hr)	Total Emissions (tpy)2
Organics				
Acenaphthene	2.1E-05	lb/1,000 gal	3.62E-05	1.58E-05
Acenaphthylene	2.5E-07	lb/1,000 gal	4.34E-07	1.90E-07
Anthracene	1.2E-06	lb/1,000 gal	2.09E-06	9.16E-07
Benzene	2.14E-04	lb/1,000 gal	3.67E-04	1.61E-04
Benzo(a)anthracene	4.0E-06	lb/1,000 gal	6.87E-06	3.01E-06
Benzo(g,h,i)perylene	2.26E-06	lb/1,000 gal	3.87E-06	1.70E-06
Benzo(b,k)fluoranthene	1.48E-06	lb/1,000 gal	2.54E-06	1.11E-06
Chrysene	2.4E-06	lb/1,000 gal	4.08E-06	1.79E-06
Dibenzo(a,h)anthracene	1.7E-06	lb/1,000 gal	2.86E-06	1.25E-06
Ethylbenzene	6.36E-05	lb/1,000 gal	1.09E-04	4.78E-05
Fluoranthene	4.8E-06	lb/1,000 gal	8.30E-06	3.63E-06
Fluorene	4.5E-06	lb/1,000 gal	7.66E-06	3.36E-06
Formaldehyde	3.3E-02	lb/1,000 gal	5.66E-02	2.48E-02
Indeno(1,2,3,c,d)pyrene	2.1E-06	lb/1,000 gal	3.67E-06	1.61E-06
Naphthalene	1.13E-03	lb/1,000 gal	1.94E-03	8.48E-04
Phenanthrene	1.1E-05	lb/1,000 gal	1.80E-05	7.88E-06
Pyrene	4.3E-06	lb/1,000 gal	7.29E-06	3.19E-06
Toluene	6.20E-03	lb/1,000 gal	1.06E-02	4.66E-03
1,1,1-Trichloroethane	2.36E-04	lb/1,000 gal	4.05E-04	1.77E-04
Xylene	1.90E-04	lb/1,000 gal	3.26E-04	1.43E-04
Hydrogen fluoride	9.31E-06	lb/MMBtu	2.23E-03	9.79E-04
Phosphorous	1.12E+02	lb/TBtu	2.68E-02	1.18E-02
Acetaldehyde	8.20E+00	lb/TBtu	1.97E-03	8.62E-04
Methyl Chloroform	7.60E+00	lb/TBtu	1.82E-03	7.99E-04
Methylene chloride	3.23E+01	lb/TBtu	7.74E-03	3.39E-03
Phenol	2.43E+01	lb/TBtu	5.83E-03	2.55E-03
Tetrachloroethylene	5.50E-01	lb/TBtu	1.32E-04	5.78E-05
Vinyl acetate	5.15E+00	lb/TBtu	1.24E-03	5.41E-04
Dioxins (Total)	8.80E-06	lb/TBtu	2.11E-09	9.25E-10
2-Methylnaphthalene	1.70E-02	lb/TBtu	4.08E-06	1.79E-06
Metals				
Arsenic	5.6E-04	lb/1,000 gal	9.60E-04	4.20E-04
Beryllium	4.2E-04	lb/1,000 gal	7.20E-04	3.15E-04
Cadmium	4.2E-04	lb/1,000 gal	7.20E-04	3.15E-04
Chromium, total	4.2E-04	lb/1,000 gal	7.20E-04	3.15E-04
Copper	8.4E-04	lb/1,000 gal	1.44E-03	
Lead	1.3E-03	lb/1,000 gal	2.16E-03	9.46E-04
Mercury	4.2E-04	lb/1,000 gal	7.20E-04	3.15E-04
Manganese	8.4E-04	lb/1,000 gal	1.44E-03	6.31E-04
Nickel	4.2E-04	lb/1,000 gal	7.20E-04	3.15E-04
Selenium	2.1E-03	lb/1,000 gal	3.60E-03	1.58E-03
Zinc	5.6E-04	lb/1,000 gal	9.60E-04	4.20E-04

Notes:
1) AP-42 Table 1.3-9 and 1.3-10 and USEPA Utility Report To Congress
2) Total ton/yr emissions indicated for HAPs

Completed by: PBS 11/26/08
Checked by: SAK 11/26/08

TANKS 4.0.9
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	TNK1
City:	Sandersville
State:	Georgia
Company:	Plant Washington
Type of Tank:	Vertical Fixed Roof Tank
Description:	No.2 Fuel Oil Storage Tank-350,000 gal

Tank Dimensions

Shell Height (ft):		45.00
Diameter (ft):		40.00
Liquid Height (ft) :		37.23
Avg. Liquid Height (ft):		37.23
Volume (gallons):		349,974.25
Turnovers:		10.00
Net Throughput(gal/yr):		3,499,742.54
Is Tank Heated (y/n):	N	

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Cone	
Height (ft)		0.00
Slope (ft/ft) (Cone Roof)		0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Macon, Georgia (Avg Atmospheric Pressure = 14.57 psia)

TANKS 4.0.9
Emissions Report - Summary Format
Liquid Contents of Storage Tank

TNK1 - Vertical Fixed Roof Tank
Sandersville, Georgia

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	66.31	60.27	72.35	64.36	0.0081	0.0066	0.0097	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009

TANKS 4.0.9
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

TNK1 - Vertical Fixed Roof Tank
Sandersville, Georgia

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	87.49	29.26	116.75

TANKS 4.0.9
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	TNK2
City:	Sandersville
State:	Georgia
Company:	Plant Washington
Type of Tank:	Vertical Fixed Roof Tank
Description:	Emergency General Fuel Storage Tank-750 gal

Tank Dimensions

Shell Height (ft):		7.00
Diameter (ft):		4.50
Liquid Height (ft) :		6.00
Avg. Liquid Height (ft):		5.00
Volume (gallons):		713.84
Turnovers:		1.00
Net Throughput(gal/yr):		713.84
Is Tank Heated (y/n):	N	

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Cone	
Height (ft)		0.00
Slope (ft/ft) (Cone Roof)		0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Macon, Georgia (Avg Atmospheric Pressure = 14.57 psia)

TANKS 4.0.9
Emissions Report - Summary Format
Liquid Contents of Storage Tank

TNK2 - Vertical Fixed Roof Tank
Sandersville, Georgia

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	66.31	60.27	72.35	64.36	0.0081	0.0066	0.0097	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009

TANKS 4.0.9
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

TNK2 - Vertical Fixed Roof Tank
Sandersville, Georgia

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	0.02	0.09	0.11

TANKS 4.0.9
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	TNK3
City:	Sandersville
State:	Georgia
Company:	Plant Washington
Type of Tank:	Horizontal Tank
Description:	Fire Water Pump Fuel Storage Tank-250 gal

Tank Dimensions

Shell Length (ft):		5.00
Diameter (ft):		3.00
Volume (gallons):		250.00
Turnovers:		1.00
Net Throughput(gal/yr):		250.00
Is Tank Heated (y/n):	N	
Is Tank Underground (y/n):	N	

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Macon, Georgia (Avg Atmospheric Pressure = 14.57 psia)

TANKS 4.0.9
Emissions Report - Summary Format
Liquid Contents of Storage Tank

TNK3 - Horizontal Tank
Sandersville, Georgia

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	66.31	60.27	72.35	64.36	0.0061	0.0066	0.0097	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009

TANKS 4.0.9
Emissions Report - Summary Format
Individual Tank Emission Totals

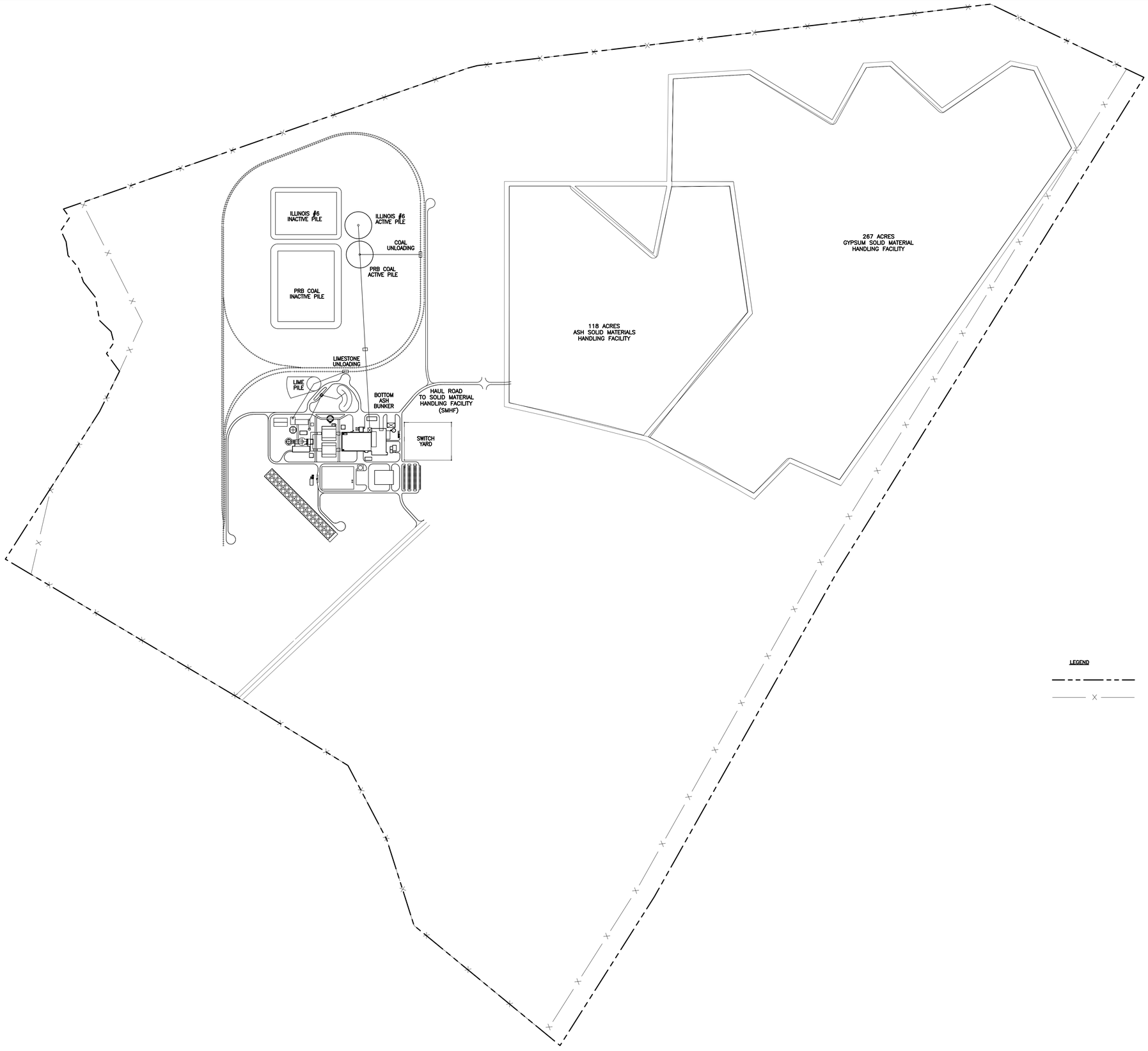
Emissions Report for: Annual

TNK3 - Horizontal Tank
Sandersville, Georgia

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	0.01	0.06	0.07

EXHIBIT B

SITE LAYOUT



LEGEND

PROPERTY LINE

FENCE LINE

DISTANCE IN METERS
0 100 200

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REV	DATE	BY	SUB	APP	DESCRIPTION	REV	DATE	BY	SUB	APP	DESCRIPTION

DESIGNED B. ARNOLD
DRAWN T. GLADSTONE
CHECKED A. KEELEY
IN CHARGE K. HILTGEN
DATE 11/11/2008

PLANT WASHINGTON
SANDERSVILLE, GEORGIA

MACTEC

MACTEC Engineering and Consulting, Inc.
3200 TOWN POINT DRIVE, SUITE 100
KENNESAW, GEORGIA 30144 (770) 421-3400

SITE LAYOUT MAP

SCALE AS SHOWN
CONTRACT 6122-07-0007
DWG. NO. | REV | PAGE NO.

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AREA SOURCE LOCATIONS *			
MAP LOCATION ID	MODEL ID	UTM EAST	UTM WEST
A1	LANDASH	337801.03	3659941.79
A2	LANDGYP	338256.02	3659829.94
A3	ASHBUNK	337315.58	3659846.66
A4	COALRAIL	337509.97	3660430.83
A5	LIMERAIL	337262.54	3660047.50
A6	PRBINAC	337046.64	3660204.08
A7	IL6INAC	337041.51	3660489.69
A8	PRBACTIV	337317.75	3660421.69
A9	IL6ACTIV	337313.30	3660516.57
A10	LIMEPILE	337169.45	3660003.07

* LISTED LOCATION FOR AREA SOURCE IS THE SOUTHWEST CORNER OF MODELED AREA.

SMHF HAUL ROAD FUGITIVE VOLUME SOURCE LOCATIONS **			
MAP LOCATION	MODEL ID	UTM EAST	UTM NORTH
P1	PAVED 1	337237.54	3659890.21
P2	PAVED 2	337266.14	3659897.90
P3	PAVED 3	337294.15	3659907.74
P4	PAVED 4	337324.63	3659907.74
P5	PAVED 5	337355.11	3659907.74
P6	PAVED 6	337385.59	3659907.74
P7	PAVED 7	337416.07	3659907.74
P8	PAVED 8	337446.45	3659908.93
P9	PAVED 9	337467.28	3659930.67
P10	PAVED 10	337486.88	3659954.02
P11	PAVED 11	337507.83	3659976.08
P12	PAVED 12	337533.39	3659992.54
P13	PAVED 13	337562.23	3660002.17
P14	PAVED 14	337592.55	3660004.53
P15	PAVED 15	337623.03	3660004.53
P16	PAVED 16	337653.51	3660004.53
P17	PAVED 17	337683.99	3660004.53
P18	PAVED 18	337714.47	3660004.53
P19	PAVED 19	337744.95	3660004.53
P20	PAVED 20	337775.43	3660004.53
P21	PAVED 21	337805.82	3660006.54

** LISTED LOCATION FOR VOLUME SOURCE IS CENTER OF VOLUME.

POINT SOURCE LOCATIONS			
MAP LOCATION ID	MODEL ID	UTM EAST	UTM NORTH
S1	MAIN	337088.13	3659815.90
S2	COOL1	337021.84	3659703.97
S3	COOL2	337033.91	3659716.04
S4	COOL3	337033.91	3659691.90
S5	COOL4	337045.97	3659703.97
S6	COOL5	337045.97	3659679.83
S7	COOL6	337058.04	3659691.90
S8	COOL7	337058.04	3659667.76
S9	COOL8	337070.11	3659679.83
S10	COOL9	337070.11	3659655.69
S11	COOL10	337082.18	3659667.76
S12	COOL11	337082.18	3659643.62
S13	COOL12	337094.25	3659655.69
S14	COOL13	337094.25	3659631.55
S15	COOL14	337106.32	3659643.62
S16	COOL15	337106.32	3659619.48
S17	COOL16	337118.39	3659631.55
S18	COOL17	337118.39	3659607.41
S19	COOL18	337130.46	3659619.48
S20	COOL19	337130.46	3659595.34
S21	COOL20	337142.53	3659607.41
S22	COOL21	337142.53	3659583.27
S23	COOL22	337154.60	3659595.34
S24	COOL23	337154.60	3659571.20
S25	COOL24	337166.67	3659583.27
S26	COOL25	337166.67	3659559.13
S27	COOL26	337178.74	3659571.20
S28	COOL27	337178.74	3659547.06
S29	COOL28	337190.81	3659559.13
S30	COOL29	337190.81	3659534.99
S31	COOL30	337202.88	3659547.06
S32	COOL31	337202.88	3659522.92
S33	COOL32	337214.95	3659534.99
S34	COOL33	337214.95	3659510.86
S35	COOL34	337227.02	3659522.92
S36	SO3SILO	337228.50	3659870.40
S37	FLYASH	337222.30	3659890.40
S38	HGSILO	337237.60	3659870.40
S39	LSILO	337293.70	3659684.60
S40	CRUSH	337335.40	3660114.80
S41	TRIP	337350.40	3659853.00
S42	LIMEPR	337101.10	3659891.40
S43	ASHEXH	337222.30	3659877.30
S44	SODAASH	337293.70	3659690.70
S45	AUX	337338.40	3659776.00
S46	PRBSO	337317.75	3660421.69
S47	IL6SO	337313.30	3660516.57
S48	LIMESO	337169.45	3660003.07

COAL PILE TRANSPORTATION FUGITIVE - VOLUME SOURCE LOCATIONS			
MAP LOCATION ID	MODEL ID	UTM EAST	UTM WEST
U1	UPAVED1	337317.75	3660421.69
U2	UPAVED2	337291.10	3660406.90
U3	UPAVED3	337264.45	3660392.10
U4	UPAVED4	337237.81	3660377.31
U5	UPAVED5	337211.16	3660362.52
U6	UPAVED6	337184.51	3660347.72
U7	UPAVED7	337157.86	3660332.93
U8	UPAVED8	337131.22	3660318.14
U9	UPAVED9	337313.30	3660516.57
U10	UPAVED10	337283.88	3660524.53
U11	UPAVED11	337254.46	3660532.50
U12	UPAVED12	337225.04	3660540.46
U13	UPAVED13	337195.62	3660548.42
U14	UPAVED14	337166.20	3660556.39
U15	UPAVED15	337136.78	3660564.35

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DESIGNED	B. ARNOLD
DRAWN	T. GLADSTONE
CHECKED	A. KEELEY
IN CHARGE	K. HILTGEN
DATE	11/11/2008

REV | DATE | BY | SUB | APP | DESCRIPTION | REV | DATE | BY | SUB | APP | DESCRIPTION

PLANT WASHINGTON
SANDERSVILLE, GEORGIA

MACTEC

MACTEC Engineering and Consulting, Inc.
3200 TOWN POINT DRIVE, SUITE 100
KENNESAW, GEORGIA 30144 (770) 421-3400

SITE LOCATION MAP
STACK IDs AND HAUL ROAD

SCALE 1:2000

CONTRACT 6122-07-0007

DWG. NO. | REV | PAGE NO

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BPIP Building/Structure Corner UTM Coordinates

1- Coal Fired Boiler		2- Steam Turbine		3- Selective Catalytic Reduction		4 - Fuel Oil Tank		5 - No. 1 Baghouse		6 - No. 2 Baghouse		7 - Wet Flue Gas Desulfurization Support Bldg.	
UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North
337294.04	3659846.66	337407.66	3659781.39	337259.14	3659785.11	337310.72	3659740.78	337195.48	3659766.15	337195.48	3659865.61	337099.96	3659782.19
337343.92	3659846.66	337407.66	3659772.55	337259.14	3659846.66	337329.43	3659740.78	337241.20	3659766.15	337241.20	3659865.64	337156.27	3659782.19
337343.92	3659860.62	337356.07	3659772.55	337288.56	3659846.66	337329.43	3659721.87	337241.20	3659812.24	337241.20	3659819.55	337156.27	3659801.33
337356.11	3659860.62	337356.07	3659859.02	337288.56	3659848.48	337310.72	3659721.87	337195.48	3659812.24	337195.48	3659819.55	337099.96	3659801.33
337356.07	3659785.11	337403.73	3659859.02	337294.04	3659848.48								
337344.49	3659785.11	337403.73	3659781.39	337294.04	3659846.66								
337344.49	3659780.54			337294.04	3659785.11								
337334.58	3659780.54												
337334.58	3659785.11												
337294.04	3659785.11												

8 - Ammonia Storage		9 - Gypsum Pile				10 - SO_3 Sorbent Silo		11 - Mercury Silo		12 - Fly Ash Silo		13 - Ash Solid Material Handling Facility	
UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North
337156.53	3659674.81	337248.94	3660000.91	337277.99	3659926.64	337225.94	3659870.40	337237.65	3659872.96	337217.91	3659901.05	337801.37	3660642.88
337166.89	3659674.81	337257.03	3660005.87	337266.96	3659921.31	337228.50	3659867.57	337240.21	3659870.40	337226.75	3659901.05	337999.27	3660642.88
337166.89	3659695.54	337267.51	3660004.40	337255.56	3659926.27	337231.06	3659870.40	337237.65	3659867.84	337233.00	3659894.81	338276.03	3660411.92
337168.72	3659702.57	337275.04	3659998.89	337251.88	3659935.46	337228.50	3659872.96	337235.09	3659870.40	337233.00	3659885.97	338327.06	3660639.99
337158.51	3659702.57	337283.32	3659990.98	337254.82	3659945.76					337226.75	3659879.72	338514.69	3660642.55
337158.51	3659697.84	337289.02	3659981.05	337261.26	3659954.76					337217.91	3659879.72	338573.29	3660235.31
337156.53	3659695.54	337292.69	3659969.47	337262.18	3659965.98					337211.66	3659885.97	338256.02	3659829.94
		337292.88	3659957.89	337256.85	3659974.99					337211.66	3659894.81	337801.03	3659941.79
		337290.30	3659944.65	337250.23	3659979.40								
		337285.16	3659935.09	337245.08	3659989.88								

14 - Emergency Diesel Generator		15 - Pretreatment Belt Presses, Diesel Fire Pump, Lime and Soda Ash Silos		16 - Limestone Preparation and Gypsum Dewater Building		17 - Limestone Slurry Tank		18 - Auxiliary Boiler		19 - Condensate Storage		20 - Administration and Control Building	
UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North
337416.05	3659800.42	337194.97	3659661.86	337093.64	3659895.57	337097.16	3659864.95	337334.86	3659765.91	337425.46	3659858.46	337403.73	3659851.40
337424.07	3659800.42	337298.60	3659661.86	337108.60	3659895.57	337106.25	3659864.95	337357.11	3659765.91	337430.51	3659858.46	337415.92	3659851.40
337424.07	3659804.34	337298.60	3659735.02	337108.60	3659887.64	337112.68	3659858.52	337357.11	3659755.24	337434.08	3659854.89	337415.92	3659823.97
337436.44	3659804.34	337194.97	3659735.02	337150.93	3659887.64	337112.68	3659849.43	337334.86	3659755.24	337434.08	3659849.84	337403.73	3659823.97
337436.44	3659786.12			337150.93	3659871.10	337106.25	3659843.00			337430.51	3659846.27		
337424.38	3659786.12			337108.60	3659871.10	337097.16	3659843.00			337425.46	3659846.27		
337424.38	3659779.59			337093.64	3659871.10	337090.73	3659849.43			337421.89	3659849.84		
337416.05	3659779.59					337090.73	3659858.52			337421.89	3659854.89		

21 - Maintenance Warehouse		22 - Cooling Towers		23 - Flue Gas Desulfurization Wastewater Building belt Press		24 - Illinois No. 6 Active Pile		25 - Powder River Basin Coal Active Pile		26 - Illinois No. 6 Inactive Pile		27 - Powder River Basin Coal Inactive Pile	
UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North
337365.93	3659722.82	337034.01	3659729.29	337039.49	3659891.86	337313.30	3660560.16	337317.75	3660465.28	337044.86	3660623.29	337052.48	3660433.22
337426.89	3659722.82	337130.46	3659632.84	337083.48	3659891.86	337344.12	3660547.39	337348.58	3660452.51	337242.98	3660623.29	337235.36	3660433.22
337426.89	3659677.10	337143.39	3659645.77	337083.48	3659865.39	337356.89	3660516.57	337361.34	3660421.69	337242.98	3660486.13	337235.36	3660204.62
337365.93	3659677.10	337156.32	3659632.84	337039.49	3659865.39	337344.12	3660485.74	337348.58	3660390.86	337044.86	3660486.13	337052.48	3660204.62
		337143.39	3659619.91			337313.30	3660472.98	337317.75	3660378.10				
		337239.84	3659523.46			337282.48	3660485.74	337286.93	3660390.86				
		337214.41	3659498.03			337269.71	3660516.57	337274.16	3660421.69				
		337008.58	3659703.86			337282.48	3660547.39	337286.93	3660452.51				

28 - Coal Rail Unloading		29 - Limestone Rail Unloading		30 - Limestone Pile		31 - Gypsum-Solid Material Handling Facility				32 - Wet Scrubber Tower	
UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North	UTM East	UTM North
337509.97	3660430.83	337262.54	3660047.50	337169.18	3660033.28	338256.02	3659829.94	339034.22	3661031.31	337121.12	3659823.53
337519.11	3660430.83	337280.83	3660047.50	337185.05	3660027.33	338573.29	3660235.31	339204.12	3660880.77	337129.53	3659828.40
337519.11	3660412.54	337280.83	3660038.35	337192.76	3660011.02	338514.69	3660642.55	339427.42	3661032.15	337138.87	3659825.94
337509.97	3660412.54	337262.54	3660038.35	337185.49	3659993.62	338327.06	3660639.99	339500.02	3661016.84	337143.74	3659817.60
				337170.94	3659987.45	338332.24	3660990.23	339621.72	3660766.41	337141.28	3659808.26
				337154.20	3659994.06	338578.55	3661004.65	338870.34	3659692.55	337132.94	3659803.39
				337147.36	3660009.26	338848.44	3660842.65	338709.47	3659762.47	337123.60	3659805.85
				337153.31	3660025.79	338957.86	3661026.84	338593.08	3659648.78	337118.73	3659814.19

ITEM	BPIP ID	DESCRIPTION	Height (m)
1	BOILER	Coal Fired Boiler	89.91
2	TURBINE	Steam Turbine	17.07
3	SCR	Selective Catalytic Reduction	47.24
4	FUELTANK	Fuel Oil Tank	12.19
5	BAG1	No. 1 Baghouse	22.56
6	BAG2	No. 2 Baghouse	22.56
7	WETFGD	Wet Flue Gas Desulfurization Support Building	6.40
8	NH3STORE	Ammonia Storage	4.57
9	GYPSUM	Gypsum Pile	10.67
10	SO3SILO	SO_3 Sorbent Silo	22.87
11	HGSILO	Mercury Silo	22.87
12	FLYASH	Fly Ash Silo	47.24
13	LANDASH	Ash Solid Material Handling Facility	13.72
14	DIESEL	Emergency Diesel Generator	12.19
15	STORAGE	Pretreatment Belt Presses, Diesel Fire Pump, Lime and Soda Ash Silos	22.87
16	LIMEPREP	Limestone Preparation and Gypsum Dewater Building	18.29
17	LIMETANK	Limestone Slurry Tank	22.87
18	AUXBOIL	Auxiliary Boiler	27.40
19	CONDSTOR	Condensate Storage	7.31
20	ADMIN	Administration and Control Building	9.14
21	MAINWARE	Maintenance Warehouse	10.37
22	COOL	Cooling Towers	15.24
23	FGDBELT	Flue Gas Desulfurization Wastewater Building Belt Press	9.15
24	IL6ACTIV	Illinois No. 6 Active Pile	30.42
25	PRBACTIV	Powder River Basin Coal Active Pile	30.42
26	IL6INACT	Illinois No. 6 Inactive Pile	7.88
27	PRBINACT	Powder River Basin Coal Inactive Pile	10.43
28	RAIL	Coal Rail Unloading	9.14
29	LIMERAIL	Limestone Rail Unloading	9.14
30	LIMEPILE	Limestone Pile	18.17
31	LANDGYP	Gypsum-Solid Material Handling Facility	13.72
32	SCRUBBER TOWER	Wet Scrubber Tower	53.03

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REV | DATE | BY | SUB | APP | DESCRIPTION | REV | DATE | BY | SUB | APP | DESCRIPTION

DESIGNED B. ARNOLD
DRAWN T. GLADSTONE
CHECKED A. KEELEY
IN CHARGE K. HILTGEN
DATE 11/11/2008

PLANT WASHINGTON

SANDERSVILLE, GEORGIA

MACTEC Engineering and Consulting, Inc.
3200 TOWN POINT DRIVE, SUITE 100
KENNESAW, GEORGIA 30144 (770) 421-3400

BUILDING HEIGHTS AND DIMENSIONS

SCALE AS SHOWN

CONTRACT 6122-07-0007

DWG. NO. | REV | PAGE NO

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EXHIBIT C

MODELING INFORMATION

Table C-1: Offsite Data Used For SO_2 NAAQS Modeling

Stack Description	Modeled Source ID	UTM Easting (km)		UTM Northing (km)		Base Elev. (m)	SO_2 Emission Rate (g/s)		Stack Height (m)		Temp. (K)		Exit Vel. (m/s)		Stack Diam. (m)	
DUKE ENERGY SANDERSVILLE, L.L.C, SANDERSVILLE (WASHINGTON COUNTY)																
Turbine No. 1	DES01	326.449	1	3665.732	1	138.0	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 2	DES02	326.421	1	3665.768	1	136.9	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 3	DES03	326.408	1	3665.785	1	136.3	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 4	DES04	326.379	1	3665.821	1	134.2	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 5	DES05	326.366	1	3665.838	1	135.2	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 6	DES06	326.338	1	3665.874	1	135.6	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 7	DES07	326.325	1	3665.891	1	135.3	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 8	DES08	326.297	1	3665.927	1	134.0	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
PROGRESS ENERGY, WASHINGTON COUNTY POWER SANDERSVILLE (WASHINGTON COUNTY)																
Turbines T1-T5	PES01	322.784	1	3663.077	1	119.2	16.6	1	27.43	1	877.4	1	48.46	1	5.64	1
Heater H1	PES02	322.784	1	3663.077	1	119.2	0.01	1	3.05	1	688.6	1	4.88	1	0.40	1
Heater H2	PES03	322.784	7	3663.077	7	119.2	0.01	7	3.05	7	688.6	7	4.88	7	0.40	7
ENGELHARD CORPORATION, EDGAR'S PLANT, McINTYRE (WILKINSON COUNTY)																
4S	EHS01	292.8614	9	3636.4593	9	88.0	1.72	8	36.57	9	377.4	9	36.61	9	0.81	9
6S	EHS02	292.8614	9	3636.4593	9	88.0	3.31	8	25.91	9	377.4	9	17.06	9	1.68	9
10	EHS03	292.8614	9	3636.4593	9	88.0	2.07	8	45.72	9	349.7	9	19.56	9	0.61	9
30S	EHS04	292.8614	9	3636.4593	9	88.0	2.74	8	22.86	9	349.7	9	14.33	9	0.84	9
50S	EHS05	292.8614	9	3636.4593	9	88.0	2.74	8	45.72	9	355.2	9	14.01	9	0.91	9
70S	EHS06	292.8614	9	3636.4593	9	88.0	2.76	8	32.00	9	344.1	9	21.56	9	0.91	9
90	EHS07	292.8614	9	3636.4593	9	88.0	1.15	8	47.24	9	341.3	9	18.94	9	0.76	9
110S	EHS08	292.8614	9	3636.4593	9	88.0	1.27	9	60.96	9	343.0	9	14.54	9	0.76	9
120	EHS09	292.475	1	3636.497	1	91.0	4.04	1	60.35	1	394.1	1	21.82	1	1.22	1
130S	EHS10	292.8614	9	3636.4593	9	88.0	1.32	9	60.35	9	349.7	9	33.20	9	0.91	9
140	EHS11	292.446	1	3636.449	1	91.1	4.04	1	60.35	1	394.1	1	33.16	1	1.22	1
170	EHS12	292.8614	9	3636.4593	9	88.0	0.61	8	15.24	9	291.9	9	17.87	9	0.71	9
171S	EHS13	292.8614	9	3636.4593	9	88.0	0.61	8	15.24	9	291.9	9	17.87	9	0.71	9
210S	EHS14	292.8614	9	3636.4593	9	88.0	3.11	8	30.48	9	344.1	9	7.33	9	0.91	9
218	EHS15	292.8614	9	3636.4593	9	88.0	0.98	8	28.65	9	291.9	9	9.80	9	1.22	9
230	EHS16	292.779	1	3636.389	1	91.1	1.45	1	36.57	1	344.1	1	40.54	1	0.76	1
15B Spray Dryer (242)	EHS17	292.752	1	3636.377	1	90.9	1.64	1	22.86	1	394.1	1	26.27	1	1.22	1
248	EHS18	292.440	1	3636.521	1	91.0	0.31	2	48.77	1	343.6	1	29.05	1	0.91	1
GEORGIA POWER																
Stack 1 (SG01+ SG02)	GPS01	285.5874	9	3674.9538	9	116.0	3855.60	10	304.79	9	394.1	9	24.99	9	6.86	9
Stack 2 (SG03 + SG04)	GPS03	285.5874	9	3674.9538	9	116.0	7015.68	10	304.79	9	399.7	9	23.47	9	8.84	9
SOUTHERN NATURAL GAS COMPANY, HIGHWAY 17 NORTH, WRENS (JEFFERSON CO.)																
Compressor No. 1	SNS01	368.459	11	3679.751	11	140.5	5.76E-04	8	5.18	8	731.9	11	12.80	11	1.07	11
Compressor No. 2	SNS02	368.449	11	3679.751	11	140.8	5.76E-04	8	5.18	8	731.9	11	12.80	11	1.07	11
Compressor No. 3	SNS03	368.449	11	3679.751	11	140.8	8.63E-04	8	4.88	8	731.9	11	12.80	11	1.07	11
Compressor No. 5	SNS04	368.449	1	3679.751	1	140.8	2.02E-03	8	11.28	8	731.9	1	12.80	1	1.07	1

Table C-1: Offsite Data Used For SO_2 NAAQS Modeling

Stack Description	Modeled Source ID	UTM Easting (km)		UTM Northing (km)		Base Elev. (m)	SO_2 Emission Rate (g/s)		Stack Height (m)		Temp. (K)		Exit Vel. (m/s)		Stack Diam. (m)	
SOUTHERN NATURAL GAS COMPANY, 180 J.M. WALKER ROAD, MILLEGEVILLE (BALDWIN CO.)																
Compresser No. 1	SNS05	308.135	12	3659.791	12	127.9	3.73E-03	8	12.19	8	731.9	12	17.43	12	0.91	12
Compresser No.2	SNS06	308.135	12	3659.791	12	127.9	3.73E-03	8	12.19	8	731.9	12	17.43	12	0.91	12
Compresser No. 3	SNS07	308.135	1	3659.791	1	127.9	2.58E-03	8	6.10	8	731.9	1	17.43	1	0.91	1
THIELE KAOLIN CO., REEDY CREEK, GA 296 N, WRENS (GLASCOCK COUNTY)																
Spray Dryer	TKS01	366.50	1	3682.50	1	147.2	1.10E-01	2	27.43	1	383.0	1	17.74	1	1.68	1
Boiler SB2	TKS02	366.500	1	3682.500	1	147.2	2.1	1	9.14	1	488.6	1	11.89	1	0.70	1
Spray Dryer No. 2	TKS03	364.956	1	3681.604	1	153.7	2.6	1	38.10	1	366.3	1	19.23	1	1.68	1
Roller Mill System No. 1 Stack	TKS04	365.99	18	3682.20	18	140.0	1.39E-03	2	13.56	9	340.8	9	14.26	9	0.67	9
Roller Mill System No. 2 Stack	TKS05	365.99	18	3682.20	18	140.0	1.39E-03	2	13.56	9	340.8	9	14.26	9	0.67	9
ACM 200 Mill Stack	TKS06	365.99	18	3682.20	18	140.0	1.10E-01	2	10.97	9	327.4	9	6.58	9	0.67	9
HUBER ENGINEERED PRODUCT																
Mine Boiler	HES01	369.3611	9	3682.6517	9	137.4	0.75	13	4.88	9	327.4	9	4.57	9	0.26	9
Plant/Mine Generators	HES02	369.3611	9	3682.6517	9	137.4	6.15	13	3.35	9	327.4	9	4.57	9	0.26	9
Structured Pigment Boiler	HES03	369.3611	9	3682.6517	9	137.4	5.51	13	15.85	9	327.4	9	3.66	9	1.07	9
No. 2 Spray Dryer Stack	HES04	369.3611	9	3682.6517	9	137.4	4.79	13	23.16	9	371.9	9	63.09	9	0.72	9
No. 3 Spray Dryer Stack	HES05	369.3611	9	3682.6517	9	137.4	6.05	13	29.56	9	386.3	9	10.06	9	1.83	9
Evaporator Boiler	HES06	369.3611	9	3682.6517	9	137.4	1.81	13	11.58	9	327.4	9	0.91	9	0.61	9
No. 1 Spray Dryer Stack	HES07	369.3611	9	3682.6517	9	137.4	4.18	13	22.86	9	371.9	9	60.96	9	0.70	9
J. M. HUBER, HUBER WRENS CALCINE PILANT, WRENS																
Spray Dryer Stack	JMS01	366.4064	9	3680.4122	9	145.3	1.51E-03	9	45.72	9	399.7	9	18.29	9	1.22	9
Spray Dryer #3	JMS02	367.366	3	3682.487	3	144.4	2.7	3	29.56	3	388.6	3	11.83	3	1.92	3
SAMS Boiler	JMS03	367.366	3	3682.487	3	144.4	0.3	3	15.85	3	546.9	3	14.63	3	1.07	3
Evap. Boiler	JMS04	367.366	3	3682.487	3	144.4	1.6	3	11.58	3	463.0	3	12.80	3	0.61	3
TIN, INC., dba TEMPLE-INLAND, THOMSON																
Four Dryers with RTO	TIS06	362.185	1	3703.674	1	160.7	7.2E-01	1	15.24	1	374.8	1	17.11	1	1.68	1
Boiler SB-1 (Projected)	TIS07	362.200	1	3703.760	1	163.7	4.3E-01	1	12.19	1	421.8	1	4.28	1	1.68	1
ESP stack	TIS08	362.5466	9	3703.879	9	170.0	2.27E-02	9	18.29	9	471.9	9	4.57	9	1.07	9
4 Multiclones & RTO	TIS09	362.5466	9	3703.879	9	170.0	3.40E-02	9	24.77	9	338.6	9	12.19	9	2.54	9
ENGELHARD CORPORATION, TODDSVILLE PLANT, VINSON ROAD, MCINTYRE (WILKINSON COUNTY)																
2A SPRAY DRYER (1)	EHS19	291.3935	9	3637.1682	9	87.0	1.79E+00	8	22.86	9	371.9	9	30.77	9	0.97	9
2B SPRAY DRYER (2)	EHS20	291.3935	9	3637.1682	9	87.0	1.79E+00	8	19.81	9	371.9	9	30.77	9	0.97	9
2C SPRAY DRYER (3)	EHS21	291.3935	9	3637.1682	9	87.0	1.79E+00	8	19.81	9	371.9	9	30.77	9	0.97	9
2D SPRAY DRYER (4)	EHS22	291.3935	9	3637.1682	9	87.0	2.88E+00	8	23.47	9	380.2	9	21.46	9	1.27	9
2F SPRAY DRYER (5)	EHS23	291.3935	9	3637.1682	9	87.0	4.70E+00	8	39.62	9	383.0	9	26.52	9	1.52	9
SARGENT DRYER (9)	EHS24	291.3935	9	3637.1682	9	87.0	3.45E-01	8	12.19	9	371.9	9	387.43	9	0.36	9
8D BOILER (98)	EHS25	291.3935	9	3637.1682	9	87.0	5.73E-01	8	7.01	9	377.4	9	17.25	9	0.46	9
8C BOILER (99)	EHS26	291.3935	9	3637.1682	9	87.0	5.73E-01	8	5.79	9	377.4	9	17.25	9	0.46	9
8B BOILER (104)	EHS27	291.3935	9	3637.1682	9	87.0	7.25E-01	8	6.10	9	377.4	9	17.25	9	0.46	9
TODDVILLE BOILER (105)	EHS28	291.3935	9	3637.1682	9	87.0	5.51E-01	8	6.10	9	377.4	9	8.62	9	0.46	9
Flash Dryer #3	EHS29	291.025	3	3636.985	3	94.1	3.5	3	36.57	3	421.9	3	11.28	3	0.91	3
Flash Dryers 4 & 5	EHS30	291.025	3	3636.985	3	94.1	9.3	3	39.62	3	402.4	3	15.24	3	0.76	3
No. 6 Boiler	EHS31	291.025	3	3636.985	3	94.1	18.1	3	30.48	3	533.0	3	1.74	3	1.83	3

Table C-1: Offsite Data Used For SO_2 NAAQS Modeling

Stack Description	Modeled Source ID	UTM Easting (km)		UTM Northing (km)		Base Elev. (m)	SO_2 Emission Rate (g/s)		Stack Height (m)		Temp. (K)		Exit Vel. (m/s)		Stack Diam. (m)	
ENGELHARD CORPORATION, GORDON																
#4 SPRAY DRYER	EHS32	281.1903	9	3640.4092	9	107.1	3.34	14	41.15	9	377.4	9	16.46	9	1.68	9
#6 CALCINER	EHS33	281.1903	9	3640.4092	9	107.1	1.04	14	30.48	9	344.1	9	27.08	9	0.52	9
BOILER	EHS34	281.1903	9	3640.4092	9	107.1	1.16	14	9.75	9	394.1	9	11.32	9	0.61	9
SLIP HEATER #2	EHS35	281.1903	9	3640.4092	9	107.1	0.46	14	9.14	9	338.6	9	7.42	9	1.01	9
SLIP HEATER #1	EHS36	281.1903	9	3640.4092	9	107.1	0.46	14	9.14	9	338.6	9	7.42	9	1.01	9
THERMAL #3	EHS37	281.1903	9	3640.4092	9	107.1	0.75	14	13.11	9	338.6	9	7.42	9	1.01	9
THERMAL #2	EHS38	281.1903	9	3640.4092	9	107.1	0.75	14	13.11	9	338.6	9	7.42	9	1.01	9
#3 SPRAY DRYER	EHS39	281.1903	9	3640.4092	9	107.1	2.59	14	23.77	9	377.4	9	20.90	9	1.28	9
#2 SPRAY DRYER	EHS40	281.1903	9	3640.4092	9	107.1	2.59	14	23.77	9	377.4	9	20.90	9	1.28	9
#1 SPRAY DRYER	EHS41	281.1903	9	3640.4092	9	107.1	1.71	14	24.38	9	377.4	9	19.54	9	1.07	9
#2 CALCINER	EHS42	281.1903	9	3640.4092	9	107.1	0.58	14	17.68	9	338.6	9	13.39	9	0.40	9
#1 CALCINER	EHS43	281.1903	9	3640.4092	9	107.1	0.46	14	17.68	9	338.6	9	13.39	9	0.40	9
#3 CALCINER	EHS44	281.1903	9	3640.4092	9	107.1	0.75	14	21.03	9	344.1	9	6.50	9	0.84	9
#4 CALCINER	EHS45	281.1903	9	3640.4092	9	107.1	0.86	14	21.03	9	344.1	9	6.50	9	0.84	9
#5 CALCINER	EHS46	281.1903	9	3640.4092	9	107.1	0.86	14	21.03	9	344.1	9	6.50	9	0.84	9
BURGESS PIGMENT COMPANY, BECK BOULEVARD, SANDERSVILLE																
# 1 Calciner stack	BPS01	329.7873	9	3649.6186	9	132.8	0.77	8	13.72	9	305.8	9	20.73	9	0.38	9
# 2 Calciner stack	BPS02	329.7873	9	3649.6186	9	132.8	1.48	8	20.73	9	328.6	9	20.42	9	0.55	9
# 4 Calciner stack	BPS03	329.7873	9	3649.6186	9	132.8	1.44	8	19.81	9	348.0	9	32.00	9	0.73	9
# 5 Calciner stack	BPS04	329.7873	9	3649.6186	9	132.8	1.08	8	31.09	9	356.9	9	14.39	9	0.70	9
# 6 Calciner stack	BPS05	329.7873	9	3649.6186	9	132.8	0.28	9	40.54	9	389.1	9	25.91	9	0.91	9
# 7 Calciner stack	BPS06	329.7873	9	3649.6186	9	132.8	0.75	9	30.48	9	396.9	9	20.54	9	0.70	9
Boiler stack	BPS07	329.7873	9	3649.6186	9	132.8	0.00	9	9.45	9	588.6	9	3.23	9	0.30	9
IMERYS PIGMENTS, INC., PLANT 2, SANSERSVILLE (ECC # 2)																
SPRAY DRYER NO. 1 (WITH HEAT RECOVERY) (D1)	ECS01	324.3895	9	3655.7	9	127.5	1.78	8	24.69	9	335.8	9	15.85	9	1.07	9
SPRAY DRYER NO. 2 (WITH HEAT RECOVERY) (D2)	ECS02	324.3895	9	3655.7	9	127.5	2.03	8	27.43	9	335.8	9	15.54	9	1.58	9
SPRAY DRYER NO. 3 (WITH HEAT RECOVERY) (D3)	ECS03	324.3895	9	3655.7	9	127.5	2.03	8	27.43	9	335.8	9	15.54	9	1.58	9
SPRAY DRYER NO. 4 (WITH HEAT RECOVERY) (D4)	ECS04	324.3895	9	3655.7	9	127.5	2.03	8	27.43	9	335.8	9	15.54	9	1.58	9
APRON DRYER - NORTH STACK NO. 1 (D5)	ECS05	324.3895	9	3655.7	9	127.5	0.42	15	9.14	9	418.0	9	10.64	9	0.76	9
APRON DRYER - NORTH STACK NO. 2 (D5)	ECS06	324.3895	9	3655.7	9	127.5	0.42	15	9.14	9	418.0	9	10.64	9	0.76	9
APRON DRYER - SOUTH STACK (D5)	ECS07	324.3895	9	3655.7	9	127.5	0.42	15	9.14	9	377.4	9	11.31	9	0.91	9
BOILER NO. 3 (BL3)	ECS08	324.3895	9	3655.7	9	127.5	0.80	8	10.97	16	449.7	16	13.08	16	0.61	16
BOILER NO.4 (BL4)	ECS09	324.3895	9	3655.7	9	127.5	0.80	8	10.97	9	449.7	9	13.08	9	0.61	9
BOILER NO. 5 (BL5)	ECS10	324.3895	9	3655.7	9	127.5	0.93	8	10.97	16	449.7	16	13.08	16	0.61	16
THIELE KAOLINE, SANDERSVILLE																
DC1 on SD1 Stack (15)	TK07	330.1428	9	3649.1503	9	142.1	1.90	8	19.81	9	391.9	9	31.58	9	0.91	9
Stack for DC2 (Dust Collector for SD2) (16)	TK08	330.1428	9	3649.1503	9	142.1	1.90	8	17.07	9	381.9	9	17.98	9	0.91	9
Stack for DC3 (Dust Collector for SD3) (17)	TK09	330.1428	9	3649.1503	9	142.1	1.90	8	18.90	9	362.4	9	14.86	9	1.01	9
Stack for DC4 (Dust Collector for SD4) (18)	TK10	330.1428	9	3649.1503	9	142.1	1.15	2	48.77	9	365.8	9	17.31	9	1.68	9
No. 5 Stack for DC5 (dust collector for SD5) (1)	TK11	330.1428	9	3649.1503	9	142.1	1.15	8	53.34	9	366.3	9	16.61	9	1.68	9
Calciner Nos 1& 2, Spray Dryer Nos 6 & 7 (8)	TK12	330.1428	9	3649.1503	9	142.1	1.15	2	53.34	9	324.7	9	8.63	9	1.52	9
Stack for Old Boiler (30)	TK13	330.1428	9	3649.1503	9	142.1	1.27	8	9.14	9	460.8	9	7.38	9	0.70	9
Stack for New Boiler (36)	TK14	330.1428	9	3649.1503	9	142.1	1.60	8	9.14	9	460.8	9	7.38	9	0.70	9

Table C-1: Offsite Data Used For SO_2 NAAQS Modeling

Stack Description	Modeled Source ID	UTM Easting (km)		UTM Northing (km)		Base Elev. (m)	SO_2 Emission Rate (g/s)		Stack Height (m)		Temp. (K)		Exit Vel. (m/s)		Stack Diam. (m)	
							0.13									
IMERYS CLAYS, INC. - SANDERSVILLE CALCINE PLANT, SANDERSVILLE (ECC # 1)																
CALCINER NO. 1 (C1)	ECS11	329.7253	9	3649.0343	9	136.0	0.65	8	42.67	9	344.1	9	11.40	9	0.61	9
CALCINER NO. 2 (C2)	ECS12	329.7253	9	3649.0343	9	136.0	1.08	8	45.72	9	339.1	9	12.59	9	0.61	9
CALCINER NO. 3 (C3)	ECS13	329.7253	9	3649.0343	9	136.0	1.08	8	45.72	9	339.1	9	12.59	9	0.61	9
CALCINER NO. 4 (C4)	ECS14	329.7253	9	3649.0343	9	136.0	1.15	2	61.57	9	339.1	9	12.01	9	0.84	9
SPRAY DRYER NO. 3 (SD3)	ECS15	329.7253	9	3649.0343	9	136.0	2.33	8	41.15	9	365.8	9	27.43	9	1.01	9
SPRAY DRYER NO. 4 (SD4)	ECS16	329.7253	9	3649.0343	9	136.0	2.56	8	41.15	9	365.8	9	27.43	9	1.01	9
GEORGIA -PACIFIC WOOD PRODUCTS LLC - WARRENTON																
Boiler Electrostatic Precipitator	GPS01	346.9569	9	3697.7667	9	170.3	0.27	8	22.86	9	533.0	9	17.98	9	1.30	9
SANDERSVILLE ETHANOL, LLC, SANDERSVILLE, GEORGIA																
DDGS Dryer System	S10	334.40811	5	3648.94283	5	134.2	2.34	5	38.10	5	421.9	5	14.00	5	3.07	5
GRIFFIN INDUSTRIES, INC., HIGHWAY 80, EAST DUBLIN																
Boiler F2	GISO1	326.063	4	3603.064	4	73.9	6.6	4	9.60	4	477.4	4	10.97	4	0.61	4
Boiler F3	GISO2	326.063	4	3603.064	4	73.9	9.9	4	10.97	4	444.1	4	10.55	4	1.01	4
FORSTMANN & COMPANY, INC., NATHANIEL DRIVE, E. DUBLIN (LAURENS CO.)																
Nos. 2 & 3 Boilers	FTS01	327.890	1	3602.690	1	79.0	4.8	1	38.10	1	510.8	1	2.41	1	2.13	1
No. 4 Boiler	FTS02	327.890	1	3602.690	1	79.0	4.0	1	28.95	1	460.2	1	8.99	1	1.22	1

1. PSD Increment Inventory Database
2. Based on a Title V Permit Limit of 40 tpy
3. Major Source Database
4. Minor Source Database
5. Permit Application forms for newly proposed Etanol plant as provided by EPD
6. Stack diameter and Exit Velocity for Baseline Dryer Stacks based on EPA Region II method for horizontal stack
7. Emission rate and Stack parameters for Heater 2 are considered same as of Heater 1
8.Title V Permit Application Forms
9. NEI Database
10. Calculations based on 3% S and Maximum Hourly Coal Consumption rate of 118 tons, 137 tons, 220 tons, and 244 tons for Steam Generators SG01-SG04 respectively. Stack ST1 is for SG01 and SG02 and ST2 for SG03 and SG04
11. Locations and Temperature, Velocity and Diameter for Compressors 1, 2, and 3 are considered same as of Compressor 5
12. Locations and Temperature, Velocity and Diameter for Compressors 1, and 2 are considered same as of Compressor 3
13. Calculations based on fuel oil being used with 0.5% S at a Maximum Hourly Oil consumption of 74.5 gallons, 610 gallons, 547 gallons, 475 gallons, 600 gallons, 180 gallons, 415 gallons for the seven listed sources.
14. Calculations based on fuel oil being used with 0.5% S and Maximum Hourly Oil consumption for each unit, which is based on the maximum design capacity for each unit.
15. 43.5 ton/yr emission rate from Title V permit application divided equally among three stacks.
16. Stack parameters for Boiler # 3 and Boiler # 5 are considered same as of Boiler # 3
17. Temple-Inland Forest Products Corporation PSD Review (May 1997)
18. Average of Increment Locations

Table C-2: Off-Site SO_2 Sources Used in PSD Increment Modeling

Stack Description	Modeled Source ID	UTM Easting (km)		UTM Northing (km)		Base Elev. (m)	SO_2 Emission Rate (g/s)		Stack Height (m)		Temp. (K)		Exit Vel. (m/s)		Stack Diam. (m)	
DUKE ENERGY SANDERSVILLE, L.L.C, SANDERSVILLE (WASHINGTON COUNTY)																
Turbine No. 1	DES01	326.449	1	3665.732	1	138.0	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 2	DES02	326.421	1	3665.768	1	136.9	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 3	DES03	326.408	1	3665.785	1	136.3	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 4	DES04	326.379	1	3665.821	1	134.2	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 5	DES05	326.366	1	3665.838	1	135.2	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 6	DES06	326.338	1	3665.874	1	135.6	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 7	DES07	326.325	1	3665.891	1	135.3	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
Turbine No. 8	DES08	326.297	1	3665.927	1	134.0	7.7	1	28.04	1	783.6	1	29.56	1	4.57	1
PROGRESS ENERGY, WASHINGTON COUNTY POWER SANDERSVILLE (WASHINGTON COUNTY)																
Turbines T1-T5	PES01	322.784	1	3663.077	1	119.2	16.6	1	27.43	1	877.4	1	48.46	1	5.64	1
Heater H1	PES02	322.784	1	3663.077	1	119.2	0.01	1	3.05	1	688.6	1	4.88	1	0.40	1
ENGELHARD CORPORATION, EDGAR'S PLANT, McINTYRE (WILKINSON COUNTY)																
120	EHE09	292.475	1	3636.497	1	91.0	4.0	1	60.35	1	394.1	1	21.82	1	1.22	1
140	EHE11	292.446	1	3636.449	1	91.1	4.0	1	60.35	1	394.1	1	33.16	1	1.22	1
230	EHE16	292.779	1	3636.389	1	91.1	1.4	1	36.57	1	344.1	1	40.54	1	0.76	1
242	EHE17	292.752	1	3636.377	1	90.9	1.6	1	22.86	1	394.1	1	26.27	1	1.22	1
248	EHE18	292.440	1	3636.521	1	91.0	1.15E+00	2	48.77	1	343.6	1	29.05	1	0.91	1
TEMPLE-INLAND FOREST PRODUCTS CORP., 1241 HARRISON ROAD, THOMSON (McDUFFIE CO.)																
Dryer #1 (Baseline)	TIS01	362.197	1	3703.709	1	162.4	-1.26E-02	1	19.05	1	343.8	1	9.14E-04	6	119.90	6
Dryer #2 (Baseline)	TIS02	362.205	1	3703.710	1	162.7	-1.26E-02	1	19.05	1	343.8	1	9.14E-04	6	119.90	6
Dryer #3 (Baseline)	TIS03	362.209	1	3703.711	1	162.9	-1.26E-02	1	19.81	1	349.8	1	9.14E-04	6	140.29	6
Dryer #4 (Baseline)	TIS04	362.214	1	3703.713	1	163.0	-1.26E-02	1	19.81	1	349.8	1	9.14E-04	6	140.29	6
Boiler SB-1 (Baseline)	TIS05	362.200	1	3703.760	1	163.7	-3.53E-02	1	12.19	1	421.8	1	4.28	1	1.68	1
Four Dryers with RTO	TIS06	362.185	1	3703.674	1	160.7	7.2E-01	1	15.24	1	374.8	1	17.11	1	1.68	1
Boiler SB-1 (Projected)	TIS07	362.200	1	3703.760	1	163.7	4.3E-01	1	12.19	1	421.8	1	4.28	1	1.68	1
J.M. HUBER CORPORATION, HIGHWAY 17, WRENS (JEFFERSON COUNTY)																
Spray Dryer #3	JMS02	367.366	3	3682.487	3	144.4	2.7	3	29.56	3	388.6	3	11.83	3	1.92	3
SAMS Boiler	JMS03	367.366	3	3682.487	3	144.4	0.3	3	15.85	3	546.9	3	14.63	3	1.07	3
Evap. Boiler	JMS04	367.366	3	3682.487	3	144.4	1.6	3	11.58	3	463.0	3	12.80	3	0.61	3
ENGELHARD CORPORATION, TODDSVILLE PLANT, VINSON ROAD, MCINTYRE (WILKINSON COUNTY)																
Flash Dryer #3	EHS29	291.025	3	3636.985	3	94.1	3.5	3	36.57	3	421.9	3	11.28	3	0.91	3
Flash Dryers 4 & 5	EHS30	291.025	3	3636.985	3	94.1	9.3	3	39.62	3	402.4	3	15.24	3	0.76	3
No. 6 Boiler	EHS31	291.025	3	3636.985	3	94.1	18.1	3	30.48	3	533.0	3	1.74	3	1.83	3
GRIFFIN INDUSTRIES, INC., HIGHWAY 80, EAST DUBLIN																
Boiler F2	GISO1	326.063	4	3603.064	4	73.9	6.6	4	9.60	4	477.4	4	10.97	4	0.61	4
Boiler F3	GISO2	326.063	4	3603.064	4	73.9	9.9	4	10.97	4	444.1	4	10.55	4	1.01	4

Table C-2: Off-Site SO_2 Sources Used in PSD Increment Modeling

Stack Description	Modeled Source ID	UTM Easting (km)		UTM Northing (km)		Base Elev. (m)	SO_2 Emission Rate (g/s)		Stack Height (m)		Temp. (K)		Exit Vel. (m/s)		Stack Diam. (m)	
THIELE KAOLIN CO., REEDY CREEK, GA 296 N, WRENS (GLASCOCK COUNTY)																
Boiler SB2	TKS02	366.500	1	3682.500	1	147.2	2.1	1	9.14	1	488.6	1	11.89	1	0.70	1
Spray Dryer No. 2	TKS03	364.956	1	3681.604	1	153.7	2.6	1	38.10	1	366.3	1	19.23	1	1.68	1
FORSTMANN & COMPANY, INC., NATHANIEL DRIVE, E. DUBLIN (LAURENS CO.)																
Nos. 2 & 3 Boilers	FTS01	327.890	1	3602.690	1	79.0	4.8	1	38.10	1	510.8	1	2.41	1	2.13	1
No. 4 Boiler	FTS02	327.890	1	3602.690	1	79.0	4.0	1	28.95	1	460.2	1	8.99	1	1.22	1
SANDERSVILLE ETHANOL, LLC, SANDERSVILLE, GEORGIA																
DDGS Dryer System	S10	334.40811	5	3648.94283	5	134.2	2.34	5	38.10	5	421.9	5	14.00	5	3.07	5

1. PSD Increment Inventory Database
2. Based on Title V Permit Limit of 39.9 tpy
3. Major Source Database
4. Minor Source Database
5. Permit Application forms for newly proposed Etanol plant as provided by EPD
6. Stack diameter and Exit Velocity for Baseline Dryer Stacks based on EPA Region II method for horizontal stack

Table C-3 Georgia Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
OGLETHORPE POWER CORP.	Heaters SH1 & SH2	GA001	1222.462	-688.549	3.7	162	0.5	26.0	811	1.26E-02	1	A
OGLETHORPE POWER CORP.	Turbines T1 & T2	GA002	1222.462	-688.549	27.4	162	5.5	33.5	807	1.94E+00	1	A
OGLETHORPE POWER CORP.	Turbines T3 & T4	GA003	1222.462	-688.549	27.4	162	6.3	29.9	810	2.34E+00	1	A
MASONITE CORPORATION	Oven (S23)	GA004	1242.938	-799.898	22.0	90	0.5	14.0	422	2.52E-04	1	A
MASONITE CORPORATION	Oven (S24)	GA005	1242.936	-799.889	22.0	90	0.8	10.5	533	3.78E-04	1	A
MASONITE CORPORATION	Cooler (S29)	GA006	1242.933	-799.874	22.0	90	0.6	12.9	533	5.04E-04	1	A
MASONITE CORPORATION	Cooler (S30)	GA007	1242.933	-799.874	22.3	90	0.6	11.6	533	2.52E-04	1	A
MASONITE CORPORATION	Cooler (S31)	GA008	1242.931	-799.855	23.8	90	0.8	12.4	533	5.04E-04	1	A
MASONITE CORPORATION	Cooler (S32)	GA009	1242.931	-799.855	22.1	90	0.6	11.6	533	2.52E-04	1	A
MASONITE CORPORATION	Cooler (S33)	GA010	1242.947	-799.878	23.2	90	0.6	11.6	533	2.52E-04	1	A
MASONITE CORPORATION	Cooler (S35)	GA011	1242.946	-799.866	24.1	90	1.1	11.6	422	5.04E-04	1	A
MASONITE CORPORATION	Oven (S25)	GA012	1242.952	-799.887	22.0	90	0.6	11.6	533	2.52E-04	1	A
MASONITE CORPORATION	Oven (S26)	GA013	1242.951	-799.883	22.0	90	0.6	11.6	533	2.52E-04	1	A
MASONITE CORPORATION	Cooler (S36)	GA014	1242.951	-799.865	23.8	90	0.8	13.4	422	5.04E-04	1	A
MASONITE CORPORATION	Cooler (S37)	GA015	1242.960	-799.876	23.8	90	0.8	13.4	422	5.04E-04	1	A
MASONITE CORPORATION	Oven (S27)	GA016	1242.965	-799.885	22.0	90	0.6	11.6	533	2.52E-04	1	A
MASONITE CORPORATION	Oven (S28)	GA017	1242.964	-799.882	22.0	90	0.8	12.4	533	3.78E-04	1	A
MASONITE CORPORATION	Oven (S22)	GA018	1242.998	-799.892	22.0	90	0.3	8.1	533	1.26E-04	1	A
MASONITE CORPORATION	Oven (S21)	GA019	1243.039	-799.886	22.0	90	0.6	8.1	533	1.26E-04	1	A
MASONITE CORPORATION	Cooler (S34)	GA020	1243.052	-799.860	22.1	90	0.6	11.6	533	2.52E-04	1	A
MASONITE CORPORATION	Oven (S20)	GA021	1243.081	-799.899	22.0	90	0.8	12.4	533	3.78E-04	1	A
MASONITE CORPORATION	Oven (S19)	GA022	1243.119	-799.909	22.0	91	0.5	14.0	422	2.52E-04	1	A
MASONITE CORPORATION	Oven (S18)	GA023	1243.166	-799.902	22.0	91	0.8	12.4	533	3.78E-04	1	A
MASONITE CORPORATION	Oven (S17)	GA024	1243.162	-799.878	22.0	90	0.5	11.2	422	2.52E-04	1	A
MASONITE CORPORATION	Oven (S16)	GA025	1243.217	-799.870	22.0	91	0.5	11.2	422	2.52E-04	1	A
VOUGHT AIRCRAFT INDUSTRIES	Boilers B1-B3	GA026	1239.723	-741.168	10.7	118	0.6	8.2	450	3.29E+00	1	A
TOLLESON LUMBER COMPANY	New Boilers 1-3	GA027	1241.372	-745.393	10.7	98	0.8	13.6	440	8.82E-02	1	A
TOLLESON LUMBER COMPANY	Retired Boilers B1 & B2	GA028	1241.372	-745.393	10.7	98	0.6	10.4	505	0.00E+00	1	A
COASTAL ASPHALT & CONSTRUCTION	Drum Dryer	GA029	1243.235	-717.128	8.2	107	1.1	15.9	347	0.00E+00	1	A
DYKA	Fugitive	GA030	1244.116	-716.686	1.0	110	1.0	0.001	0.001	0.00E+00	1	A
CERMEX	Kiln System	GA031	1251.975	-748.066	63.7	91	2.1	34.8	366	7.77E+01	1	A
RIVERWOOD INTERNATIONAL CORP.	Paper Machine 1	GA032	1245.897	-708.947	18.1	94	1.0	0.001	0.001	2.07E-02	1	A
RIVERWOOD INTERNATIONAL CORP.	Paper Machine 2	GA033	1245.893	-708.923	18.1	94	1.0	0.001	0.001	4.91E-02	1	A
RIVERWOOD INTERNATIONAL CORP.	Bark Boiler 2	GA034	1245.963	-708.991	91.5	92	3.0	15.8	325	1.54E+01	1	A
RIVERWOOD INTERNATIONAL CORP.	No. 3 Smelt Dissolv. Tank	GA035	1245.969	-709.021	67.1	89	1.5	11.3	339	2.21E-01	1	A
RIVERWOOD INTERNATIONAL CORP.	No. 3 Recovery Boiler	GA036	1245.980	-709.036	91.5	88	3.4	20.0	456	2.47E+01	1	A
RIVERWOOD INTERNATIONAL CORP.	No.2 Power Boiler	GA037	1245.996	-708.988	91.5	93	3.2	12.2	325	9.52E+00	1	A
RIVERWOOD INTERNATIONAL CORP.	No. 1 Power Boiler	GA038	1245.995	-708.982	91.5	93	3.2	12.2	325	8.11E+00	1	A
RIVERWOOD INTERNATIONAL CORP.	No. 1 Recovery Boiler	GA039	1246.000	-709.006	91.5	92	2.8	11.3	411	-1.53E+01	1	F
RIVERWOOD INTERNATIONAL CORP.	No. 2 Recovery Boiler	GA040	1246.000	-709.006	91.5	92	2.8	9.5	415	-1.55E+01	1	F
RIVERWOOD INTERNATIONAL CORP.	Bark Boiler 1	GA041	1246.000	-709.005	91.5	92	3.0	15.8	325	-1.13E-04	1	F
Armstrong World Industries Inc	FF Fluid Heater	GA042	1245.086	-703.488	12.2	99	0.2	16.3	505	1.26E-01	1	A
Armstrong World Industries Inc	FF Process Boiler	GA043	1245.086	-703.488	45.7	99	1.0	16.3	484	1.19E+01	1	A
Armstrong World Industries Inc	SF Fluid Heater	GA044	1245.086	-703.488	12.2	99	0.2	16.3	505	1.26E-01	1	A

Table C-3 Georgia Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
Armstrong World Industries Inc	SF Process Boiler	GA045	1245.086	-703.488	45.7	99	1.0	16.3	484	1.19E+01	1	A
RIVERWOOD INTERNATIONAL CORP.	No. 2 Smelt Dissolv. Tank	GA046	1246.063	-708.971	33.5	94	1.2	5.5	350	-5.92E-02	1	F
RIVERWOOD INTERNATIONAL CORP.	No. 1 Smelt Dissolv. Tank	GA047	1246.060	-708.953	33.5	94	1.2	5.2	349	-5.29E-02	1	F
SHEPHERD CONSTRUCTION CO.	Feed Hopper ES1	GA048	1253.467	-751.544	7.1	124	1.1	22.6	411	2.43E+01	1	A
RIVERWOOD INTERNATIONAL CORP.	Lime Kiln No. 2	GA049	1246.112	-709.060	15.5	94	1.0	10.5	345	5.24E+00	1	A
RIVERWOOD INTERNATIONAL CORP.	Lime Kiln No. 1	GA050	1246.110	-709.052	15.5	94	1.0	10.4	340	5.24E+00	1	A
BORAL BRICKS	Tunnel Kiln	GA051	1245.912	-703.271	10.4	91	0.9	56.7	478	8.06E-01	1	A
FRITO-LAY	Boiler #1(based on fuel oil)	GA052	1252.554	-740.677	18.3	97	1.0	16.9	547	5.04E+00	1	A
BIBB YARNS	Boilers 1,3, & 4	GA053	1245.707	-701.178	45.7	91	2.0	1.5	505	7.96E+00	1	A
FRITO-LAY	Baked Potato Chips (BLLl2)	GA054	1252.562	-740.675	1.0	97	1.0	0.001	0.001	2.02E-03	1	A
FRITO-LAY	Baked Tortilla Chips (BL1)	GA055	1252.562	-740.675	1.0	97	1.0	0.001	0.001	1.89E-03	1	A
FRITO-LAY	Boiler #2(based on fuel oil)	GA056	1252.562	-740.675	18.3	97	1.0	16.9	547	5.04E+00	1	A
FRITO-LAY	Pretzel Line #1 (PL1)	GA057	1252.562	-740.675	1.0	97	1.0	0.001	0.001	6.30E-04	1	A
FRITO-LAY	Pretzel Line #2 (PL2)	GA058	1252.562	-740.675	1.0	97	1.0	0.001	0.001	6.30E-04	1	A
FRITO-LAY	ROTC 1 (10/11/95)	GA059	1252.562	-740.675	1.0	97	1.0	0.001	0.001	1.26E-03	1	A
FRITO-LAY	ROTC 2 (10/11/95)	GA060	1252.562	-740.675	1.0	97	1.0	0.001	0.001	1.26E-03	1	A
GANDY'S INDUSTRIES	Fugitive	GA061	1246.366	-702.797	1.0	88	1.0	0.001	0.001	0.00E+00	1	A
MID-GEORGIA COGEN	Aux. Boiler (B1)	GA062	1252.981	-740.173	48.8	95	0.9	17.1	439	5.62E-01	1	A
MID-GEORGIA COGEN	Turbine (T1)	GA063	1252.981	-740.173	48.8	95	4.9	16.7	434	9.32E+00	1	A
MID-GEORGIA COGEN	Turbine (T2)	GA064	1252.981	-740.173	48.8	95	4.9	16.7	434	9.32E+00	1	A
ROBBINS AIR FORCE BASE	Generators G13S-G16S	GA065	1251.320	-725.364	36.6	93	0.3	54.3	731	3.73E+00	1	A
DUKE ENERGY TIFT	Auxiliary Boiler	GA066	1273.851	-849.949	15.2	99	0.8	12.2	476	2.52E-02	1	A
DUKE ENERGY TIFT	CCCT No. 1	GA067	1273.893	-849.989	49.1	99	5.5	21.1	366	1.80E+00	1	A
DUKE ENERGY TIFT	CCCT No. 2	GA068	1273.929	-850.014	49.1	98	5.5	21.1	366	1.80E+00	1	A
GEORGIA POWER CO.	Combustion Turbine #1	GA069	1253.441	-729.526	17.1	81	4.3	56.7	779	7.71E+01	1	A
GEORGIA POWER CO.	Combustion Turbine #2	GA070	1253.436	-729.493	17.1	81	4.3	56.7	779	7.71E+01	1	A
TEXPRINT	Boiler B3	GA071	1251.293	-704.158	23.8	98	0.6	13.1	505	3.28E+00	1	A
J.M. HUBER CORPORATION	No. 3 Spray Dryer	GA072	1253.910	-715.732	12.2	82	1.5	18.3	394	0.00E+00	1	A
J.M. HUBER CORPORATION	No. 4 Spray Dryer	GA073	1253.910	-715.732	33.5	82	1.8	18.4	339	3.28E+00	1	A
R J Reynolds Tobacco Co.	BOILER3	GA074	1251.908	-703.629	45.7	105	2.2	3.3	450	-4.28E+01	1	F
R J Reynolds Tobacco Co.	BOILER345	GA075	1251.908	-703.629	45.7	105	2.2	10.1	443	1.07E+02	1	A
R J Reynolds Tobacco Co.	BOILER12	GA076	1251.946	-703.627	65.2	103	1.7	8.7	522	-2.91E+01	1	F
DRY BRANCH KAOLIN CO.	CDPP (Pilot Plant Dryer)	GA077	1260.115	-703.723	22.9	141	0.3	18.6	394	3.53E-01	1	A
DRY BRANCH KAOLIN CO.	D15 (Impact Mill)	GA078	1260.115	-703.723	22.9	141	1.2	12.1	358	6.98E-01	1	A
DRY BRANCH KAOLIN CO.	FD9 (Flash Dryer No. 9)	GA079	1260.115	-703.723	21.3	141	0.6	29.0	394	3.93E-01	1	A
DRY BRANCH KAOLIN CO.	SD14 (Spray Dryer No. 14)	GA080	1260.115	-703.723	41.2	141	1.7	19.8	319	2.08E+00	1	A
DRY BRANCH KAOLIN CO.	CA4 (Calciner No. 4)	GA081	1260.142	-703.325	45.7	128	1.1	21.1	589	2.38E+00	1	A
DRY BRANCH KAOLIN CO.	BL2 (Boiler No. 2)	GA082	1260.223	-703.426	8.8	140	0.6	16.8	455	8.28E-01	1	A
SCRUGGS COMPANY	Drum Mixer	GA083	1302.393	-908.029	11.6	61	1.2	18.4	394	5.62E+00	1	A
PACKAGING CORPORATION OF AMERICA	CBSS	GA084	1310.630	-933.389	67.1	60	3.4	12.2	342	8.44E-01	1	A
PACKAGING CORPORATION OF AMERICA	No. 2 lime Kiln	GA085	1310.630	-933.389	24.1	60	1.3	6.7	328	-2.52E-01	1	F
PACKAGING CORPORATION OF AMERICA	No. 3 Lime Kiln	GA086	1310.630	-933.389	18.3	60	1.1	17.7	333	-1.95E+00	1	F
PACKAGING CORPORATION OF AMERICA	No. 4 Lime Kiln	GA087	1310.630	-933.389	61.0	60	1.5	14.8	464	2.52E+00	1	A
PACKAGING CORPORATION OF AMERICA	TRS Incinerator	GA088	1310.630	-933.389	45.7	60	0.6	30.1	355	1.15E+00	1	A

Table C-3 Georgia Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
SHAW INDUSTRIES	Boiler B02	GA089	1311.206	-921.030	8.2	61	0.8	3.8	408	7.94E-01	1	A
HOOVER	Dryer	GA090	1312.715	-916.595	6.3	61	0.7	0.0	361	4.41E+00	1	A
ARCHER DANIELS MIDLAND CO.	Backup Boiler?	GA091	1313.733	-917.441	16.8	61	1.5	19.6	478	7.06E-01	1	A
ARCHER DANIELS MIDLAND CO.	Refinery Boiler?	GA092	1313.733	-917.441	24.4	61	0.8	0.244	0.001	4.16E-01	1	A
ARCHER DANIELS MIDLAND CO.	Wood Waste Boiler	GA093	1313.733	-917.441	17.7	61	1.4	12.4	355	8.57E+00	1	A
ENGELHARD CORPORATION	Flash Dryer #3	GA094	1281.242	-694.550	36.6	94	0.9	11.3	422	3.53E+00	1	A
ENGELHARD CORPORATION	Flash Dryers 4 & 5	GA095	1281.242	-694.550	39.6	94	0.8	15.2	403	9.32E+00	1	A
ENGELHARD CORPORATION	No. 6 Boiler	GA096	1281.242	-694.550	30.5	94	1.8	1.7	533	1.81E+01	1	A
Engelhard Corp. - Edgar Plant	248.000	GA097	1282.713	-694.766	48.8	91	0.9	29.1	344	1.26E-03	1	A
Engelhard Corp. - Edgar Plant	11G Spray Dryer (140)	GA098	1282.731	-694.836	60.4	91	1.2	33.2	394	4.04E+00	1	A
Engelhard Corp. - Edgar Plant	11F Spray Dryer (120)	GA099	1282.751	-694.783	60.4	91	1.2	21.8	394	4.04E+00	1	A
Engelhard Corp. - Edgar Plant	15B Spray Dryer (242)	GA100	1283.044	-694.854	22.9	91	1.2	26.3	394	1.64E+00	1	A
Engelhard Corp. - Edgar Plant	230	GA101	1283.069	-694.838	36.6	91	0.8	40.5	344	1.45E+00	1	A
DUKE ENERGY BUFFALO CREEK	CCCT 1	GA102	1300.828	-663.808	49.1	111	5.5	21.1	369	1.83E+00	1	A
DUKE ENERGY BUFFALO CREEK	CCCT 2	GA103	1300.874	-663.805	49.1	110	5.5	21.1	369	1.83E+00	1	A
DUKE ENERGY BUFFALO CREEK	Auxiliary Boiler	GA104	1300.931	-663.779	9.8	110	0.8	13.7	483	3.28E-02	1	A
PROGRESS ENERGY	Heater H1	GA105	1307.957	-663.328	3.0	119	0.4	4.9	689	1.26E-02	1	A
PROGRESS ENERGY	Turbines T1-T5	GA106	1307.957	-663.328	27.4	119	5.6	48.5	878	1.66E+01	1	A
GRIFFIN INDUSTRIES	Boiler F2	GA107	1321.545	-722.047	9.6	74	0.6	11.0	478	6.63E+00	1	A
GRIFFIN INDUSTRIES	Boiler F3	GA108	1321.545	-722.047	11.0	74	1.0	10.5	444	9.93E+00	1	A
DUKE ENERGY SANDERSVILLE	Turbine No. 8	GA109	1310.916	-659.909	28.0	134	4.6	29.6	784	7.69E+00	1	A
DUKE ENERGY SANDERSVILLE	Turbine No. 7	GA110	1310.950	-659.940	28.0	135	4.6	29.6	784	7.69E+00	1	A
DUKE ENERGY SANDERSVILLE	Turbine No. 6	GA111	1310.966	-659.955	28.0	136	4.6	29.6	784	7.69E+00	1	A
DUKE ENERGY SANDERSVILLE	Turbine No. 5	GA112	1310.999	-659.985	28.0	135	4.6	29.6	784	7.69E+00	1	A
DUKE ENERGY SANDERSVILLE	Turbine No. 4	GA113	1311.015	-660.000	28.0	134	4.6	29.6	784	7.69E+00	1	A
DUKE ENERGY SANDERSVILLE	Turbine No. 3	GA114	1311.050	-660.030	28.0	136	4.6	29.6	784	7.69E+00	1	A
DUKE ENERGY SANDERSVILLE	Turbine No. 2	GA115	1311.066	-660.045	28.0	137	4.6	29.6	784	7.69E+00	1	A
DUKE ENERGY SANDERSVILLE	Turbine No. 1	GA116	1311.099	-660.076	28.0	138	4.6	29.6	784	7.69E+00	1	A
SP NEWSPRINT COMPANY	Gas Turbine/Heat Boiler	GA117	1322.954	-727.571	21.3	55	3.6	19.4	416	4.25E-01	2	A
SP NEWSPRINT COMPANY	No. 1 Power Boiler	GA118	1322.954	-727.571	47.3	55	3.0	7.0	436	5.04E+01	2	A
SP NEWSPRINT COMPANY	No. 2 Power Boiler	GA119	1322.954	-727.571	54.9	55	2.7	17.6	416	1.99E+01	2	A
FORSTMANN & COMPANY	No. 4 Boiler	GA120	1323.407	-722.103	29.0	79	1.2	9.0	460	3.99E+00	1	A
FORSTMANN & COMPANY	Nos. 2 & 3 Boilers	GA121	1323.407	-722.103	38.1	79	2.1	2.4	511	4.80E+00	1	A
TEMPLE-INLAND FOREST PRODUCTS CORP.	Four Dryers with RTO	GA122	1339.636	-616.467	15.2	161	1.7	17.1	375	7.18E-01	1	A
TEMPLE-INLAND FOREST PRODUCTS CORP.	Dryer #1 (Baseline)	GA123	1339.641	-616.431	19.1	162	119.9	0.001	344	-1.26E-02	1	F
TEMPLE-INLAND FOREST PRODUCTS CORP.	Boiler SB-1 (Baseline)	GA124	1339.635	-616.380	12.2	164	1.7	4.3	422	-3.53E-02	1	F
TEMPLE-INLAND FOREST PRODUCTS CORP.	Boiler SB-1 (Projected)	GA125	1339.635	-616.380	12.2	164	1.7	4.3	422	4.31E-01	1	A
TEMPLE-INLAND FOREST PRODUCTS CORP.	Dryer #2 (Baseline)	GA126	1339.649	-616.428	19.1	163	119.9	0.001	344	-1.26E-02	1	F
TEMPLE-INLAND FOREST PRODUCTS CORP.	Dryer #3 (Baseline)	GA127	1339.653	-616.427	19.8	163	140.3	0.001	350	-1.26E-02	1	F
TEMPLE-INLAND FOREST PRODUCTS CORP.	Dryer #4 (Baseline)	GA128	1339.657	-616.424	19.8	163	140.3	0.001	350	-1.26E-02	1	F
THIELE KAOLIN CO.	Boiler SB2	GA129	1346.184	-637.768	9.1	154	0.7	11.9	489	2.11E+00	1	A
THIELE KAOLIN CO.	Spray Dryer No. 2	GA130	1346.184	-637.768	38.1	154	1.7	19.2	366	2.56E+00	1	A
J.M. HUBER CORPORATION	Evap. Boiler	GA131	1348.398	-636.480	11.6	144	0.6	12.8	463	1.63E+00	1	A
J.M. HUBER CORPORATION	SAMS Boiler	GA132	1348.398	-636.480	15.9	144	1.1	14.6	547	2.90E-01	1	A

Table C-3 Georgia Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
J.M. HUBER CORPORATION	Spray Dryer #3	GA133	1348.398	-636.480	29.6	144	1.9	11.8	389	2.70E+00	1	A
APAC-GEORGIA	Dryer	GA134	1358.767	-609.217	9.4	110	1.2	26.2	394	6.44E+00	1	A
REEVES CONSTRUCTION COMPAY	Drum Mixer	GA135	1360.341	-607.365	11.6	115	0.9	17.6	422	1.46E+01	1	A
UNITED CATALYSTS	Cage Mill	GA136	1375.263	-627.616	4.3	109	1.2	18.3	328	5.42E-01	1	A
UNITED CATALYSTS	Roller Mill	GA137	1375.263	-627.616	15.5	109	0.8	16.2	355	2.02E-01	1	A
RINGIER AMERICA	Boilers (2)	GA138	1371.510	-602.486	28.7	114	1.1	63.0	584	3.10E+01	1	A
AMOCO PERFORMANCE PRODUCTS	Boiler A21	GA139	1384.057	-620.120	15.2	71	0.8	27.4	550	3.83E+00	1	A
AMOCO PERFORMANCE PRODUCTS	Heaters S1 & S2	GA140	1384.057	-620.120	19.2	71	1.2	4.0	450	4.30E+00	1	A
AMOCO PERFORMANCE PRODUCTS	Hot Oil Heater	GA141	1384.057	-620.120	36.6	71	1.2	3.6	478	1.31E+00	1	A
AMOCO PERFORMANCE PRODUCTS	S8A, S12, S74, & S5	GA142	1384.057	-620.120	15.2	71	0.8	0.001	0.001	2.21E+00	1	A
AMOCO PERFORMANCE PRODUCTS	Waste Fuel Boiler	GA143	1384.057	-620.120	24.4	71	0.6	18.3	478	1.26E+00	1	A
AMITY DYEING & FINISHING CO.	Boilers	GA144	1384.797	-609.204	29.0	45	1.4	0.0	505	1.69E+00	1	A
AMITY DYEING & FINISHING CO.	Dryers	GA145	1384.797	-609.204	10.7	45	0.6	0.0	433	0.00E+00	1	A
AMITY DYEING & FINISHING CO.	Heaters	GA146	1384.797	-609.204	29.0	45	1.4	0.0	533	3.15E-01	1	A
KENDALL HEALTHCARE CORPORATION	No. 2 Boiler	GA147	1386.498	-616.742	15.2	42	0.6	20.2	450	2.14E+00	1	A
CSR-KNOX RIVERS	Dryer	GA148	1386.529	-611.449	11.6	36	1.1	23.0	394	1.19E+00	1	A
AUGUSTA RECYCLING ASSOCIATES	Boilers B1 & B2	GA149	1388.861	-620.884	45.7	41	1.3	13.4	450	1.51E+01	1	A
PEACHTREE GENERATING CORPORATION	Boiler IIA	GA150	1389.950	-623.800	60.7	37	2.5	11.0	339	-4.69E+01	1	F
PEACHTREE GENERATING CORPORATION	Boiler IIB	GA151	1389.950	-623.800	60.7	37	5.3	4.1	422	-9.65E+01	1	F
INTERNATIONAL FLAVORS & FRAGANCES	P11	GA152	1389.823	-622.726	9.5	45	0.9	1.3	293	3.53E-01	1	A
PQ (PHILADELPHIA QUARTZ) CORPORATION	Dryer	GA153	1390.164	-622.575	27.4	42	0.6	12.9	350	1.26E-02	1	A
PQ (PHILADELPHIA QUARTZ) CORPORATION	Small Boilers	GA154	1390.164	-622.575	6.1	42	0.8	9.6	478	7.56E-02	1	A
INTERNATIONAL PAPER CO.	No. 1 Smelt tank	GA155	1390.586	-623.511	60.7	49	1.1	6.9	354	-2.65E-01	1	F
Augusta Newsprint Co	Package Boiler	GA156	1390.510	-622.941	36.6	47	2.1	22.6	637	3.89E+00	1	A
Augusta Newsprint Co	Woodwaste Boiler, B1	GA157	1390.510	-622.941	42.7	47	3.0	8.8	341	3.75E+01	1	A
INTERNATIONAL PAPER CO.	No. 1 Recovery Boiler	GA158	1390.609	-623.475	39.6	49	2.1	12.6	433	-1.31E+01	1	F
INTERNATIONAL PAPER CO.	No. 1 Power Boiler	GA159	1390.585	-623.292	61.0	49	2.5	17.5	330	2.71E+01	1	A
INTERNATIONAL PAPER CO.	No. 2 Power Boiler	GA160	1390.582	-623.258	61.0	49	2.7	20.5	519	5.48E+01	1	A
INTERNATIONAL PAPER CO.	# 3 Power Boil.(was #1 RB)	GA161	1390.608	-623.294	61.0	49	3.0	17.9	450	1.80E+01	1	A
DEERFIELD SPECIALTY PAPERS	Package Boiler	GA162	1390.805	-624.377	33.5	35	1.1	13.2	422	2.46E+01	1	A
INTERNATIONAL PAPER CO.	Calciner	GA163	1390.691	-623.623	21.1	46	1.2	9.6	349	-1.35E+00	1	F
INTERNATIONAL PAPER CO.	No. 3 Recovery Boiler	GA164	1390.637	-623.314	64.0	49	3.0	32.0	469	8.96E+01	1	A
INTERNATIONAL PAPER CO.	No. 3 Smelt Tank	GA165	1390.654	-623.336	64.0	49	1.8	5.2	352	8.19E-01	1	A
INTERNATIONAL PAPER CO.	No. 2 RB (modified)	GA166	1390.648	-623.294	61.0	49	2.4	21.8	431	2.82E+01	1	A
INTERNATIONAL PAPER CO.	No. 2 Recovery Boiler	GA167	1390.648	-623.294	39.6	49	2.1	14.4	448	-1.40E+01	1	F
INTERNATIONAL PAPER CO.	No. 3 Lime Kiln	GA168	1390.790	-623.626	30.5	45	2.1	10.7	349	1.71E+00	1	A
INTERNATIONAL PAPER CO.	No. 1 Lime Kiln	GA169	1390.786	-623.411	20.3	48	1.1	10.0	349	-1.12E+00	1	F
INTERNATIONAL PAPER CO.	No. 1 LK (modified)	GA170	1390.786	-623.411	59.8	48	1.2	10.1	346	7.06E-01	1	A
INTERNATIONAL PAPER CO.	No. 2 Lime Kiln	GA171	1390.801	-623.392	62.9	48	1.6	15.4	345	1.76E+00	1	A
MONSANTO COMPANY DAIRY	Boiler B1	GA172	1389.629	-613.903	30.5	35	0.9	17.8	461	4.66E+00	1	A
Nutrasweet Kelco Co	Waste boiler (173)	GA173	1390.010	-612.650	30.5	37	0.6	12.2	344	3.59E-01	1	A
Nutrasweet Kelco Co	Waste boiler (192)	GA174	1390.010	-612.650	30.5	37	1.0	14.6	347	5.04E-02	1	A
Nutrasweet Kelco Co	Zurn boiler (101)	GA175	1390.010	-612.650	45.7	37	1.7	9.1	408	2.68E+01	1	A
AUGUSTA ENERGY	3 Combustion Turbine Sets	GA176	1389.968	-610.892	53.4	38	5.8	13.0	370	3.74E+01	1	A

Table C-3 Georgia Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
GENERAL CHEMICAL CORPORATION	New Sulfur Burner	GA177	1390.182	-611.590	45.7	39	1.2	15.8	344	1.83E+01	1	A
GENERAL CHEMICAL CORPORATION	Old Burner	GA178	1390.182	-611.590	53.4	39	1.8	9.6	347	0.00E+00	1	A
DSM CHEMICALS NORTH AMERICA	Auxiliary Boiler	GA179	1390.425	-610.391	67.1	37	3.6	7.9	589	8.88E+00	1	A
DSM CHEMICALS NORTH AMERICA	Furncace & Flaker	GA180	1390.425	-610.391	10.7	37	0.8	6.6	616	3.78E-01	1	A
PCS NITROGEN FERTILIZER	Boiler	GA181	1390.420	-610.205	31.7	38	1.5	22.0	643	7.36E+00	1	A
RAYONIER SPECIALTY PULP PRODUCTS	Recovery Furnace No. 6	GA182	1431.545	-805.374	91.5	28	4.9	12.8	451	3.35E-01	1	A
RAYONIER SPECIALTY PULP PRODUCTS	NCG Incinerator	GA183	1431.641	-805.121	41.2	27	1.2	4.6	351	1.01E-02	1	A
RAYONIER SPECIALTY PULP PRODUCTS	Package Boiler	GA184	1431.641	-805.037	76.2	27	4.3	11.8	426	2.73E-01	1	A
KING FINISHING COMPANY	Coal-Fired Boiler	GA185	1423.696	-699.822	44.2	44	1.4	23.5	450	4.41E+01	1	A
KING FINISHING COMPANY	Oil-Fired Boiler No. 1	GA186	1423.964	-699.595	24.4	45	1.2	10.1	505	2.38E+01	1	A
KING FINISHING COMPANY	Oil-Fired Boiler No. 2	GA187	1423.964	-699.595	44.5	45	1.5	13.4	533	4.64E+01	1	A
APAC-GEORGIA	Dryer	GA188	1456.587	-881.013	9.4	6	1.2	26.2	394	7.47E+00	1	A
UNDERGROUND UTILITY CONTRACTORS	Dryer	GA189	1460.538	-893.461	6.2	1	1.5	9.4	400	5.17E-01	1	A
J. F. CLECKLEY & COMPANY	Burner	GA190	1430.372	-675.720	6.7	37	1.0	29.0	438	7.18E+00	1	A
LIVE OAK COMPANY	Gas Heater	GA191	1464.932	-841.556	18.3	5	0.6	21.3	644	5.04E-03	1	A
LIVE OAK COMPANY	HRSG No. 1	GA192	1465.095	-841.569	47.3	5	5.9	18.1	359	1.63E+00	1	A
LIVE OAK COMPANY	HRSG No. 2	GA193	1465.119	-841.607	47.3	5	5.9	18.1	359	1.63E+00	1	A
MILLENNIUM SPECIALTY CHEMICALS	Boiler No. 1	GA194	1469.135	-860.721	13.7	3	1.1	11.1	589	1.84E-03	2	A
MILLENNIUM SPECIALTY CHEMICALS	Boiler No. 2	GA195	1469.135	-860.721	30.5	3	2.1	3.9	455	6.50E+00	1	A
GILMAN PAPER COMPANY	Multi-Fuel Boiler (SC E01)	GA196	1476.985	-901.163	45.7	4	2.1	13.9	347	-1.15E+00	1	F
APAC-GEORGIA	Burner	GA197	1469.789	-860.293	9.3	3	1.2	24.9	394	2.47E+00	1	A
GILMAN PAPER COMPANY	Coal Boiler No. 1 (SC 16)	GA198	1477.019	-900.743	45.7	5	3.0	33.5	325	-1.15E+02	3	F
GILMAN PAPER COMPANY	Power Boiler No. 5 (SC 17)	GA199	1477.019	-900.743	83.8	5	4.3	9.3	446	-1.39E+01	3	F
NAVAL SUBMARINE SUPPORT BASE	Boiler B4	GA200	1476.138	-894.604	19.5	4	0.5	11.0	533	3.91E-01	1	A
NAVAL SUBMARINE SUPPORT BASE	Boiler G4	GA201	1476.138	-894.604	19.5	4	0.5	11.0	533	4.16E-01	1	A
NAVAL SUBMARINE SUPPORT BASE	Boilers G1-G3	GA202	1476.138	-894.604	19.5	4	1.2	9.1	478	5.67E+00	1	A
NAVAL SUBMARINE SUPPORT BASE	Diesel Generator G6	GA203	1476.138	-894.604	5.5	4	0.5	39.9	611	1.26E-02	1	A
NAVAL SUBMARINE SUPPORT BASE	Diesel Generators D1-D11	GA204	1476.138	-894.604	5.2	4	0.5	42.7	616	2.22E+01	1	A
RHONE POULENCE AG CO.	Boiler	GA205	1474.751	-878.119	45.0	4	1.2	8.0	463	3.24E+01	1	A
RHONE POULENCE AG CO.	Process?	GA206	1474.751	-878.119	15.0	4	1.2	7.0	303	2.14E-01	1	A
UNION CARBIDE AG. PRODUCTS CO.	UNION CARBIDE	GA207	1475.393	-880.662	14.9	3	1.2	7.0	303	2.14E-01	1	A
UNION CARBIDE AG. PRODUCTS CO.	UNION CARBIDE	GA208	1475.393	-880.662	45.1	3	1.2	8.0	463	3.24E+01	1	A
BRUNSWICK PULP & PAPER COMPANY	No. 4 Lime Kiln	GA209	1470.878	-853.336	30.8	1	1.5	12.9	348	-1.51E-01	1	F
BRUNSWICK PULP & PAPER COMPANY	No. 4 Recovery Boiler	GA210	1470.878	-853.336	80.5	1	3.7	13.5	444	-2.52E+01	1	F
BRUNSWICK PULP & PAPER COMPANY	No. 4 Smelt Tank	GA211	1470.878	-853.336	80.5	1	1.4	5.8	339	-9.45E-01	1	F
BRUNSWICK PULP & PAPER COMPANY	No. 5 Lime Kiln (86)	GA212	1470.878	-853.336	64.9	1	2.4	10.6	347	2.90E-01	1	A
BRUNSWICK PULP & PAPER COMPANY	No. 5 Power Boiler	GA213	1470.878	-853.336	1.0	1	1.0	0.001	0.001	2.87E+00	1	A
BRUNSWICK PULP & PAPER COMPANY	No. 6 Recovery Boiler	GA214	1470.878	-853.336	83.5	1	4.3	16.8	461	6.17E-01	1	A
BRUNSWICK PULP & PAPER COMPANY	No. 6 Smelt Tank	GA215	1470.878	-853.336	83.5	1	2.3	6.0	339	7.18E-01	1	A
BRUNSWICK PULP & PAPER COMPANY	TRS Control System	GA216	1470.878	-853.336	1.0	1	1.0	0.001	0.001	2.65E-01	1	A
HERCULES	Boiler B-10	GA217	1474.884	-853.548	53.7	2	3.7	4.5	692	2.88E-02	2	A
HERCULES	Boiler No. 9	GA218	1474.884	-853.548	45.7	2	1.8	14.0	338	1.24E+00	2	A
HERCULES	Heater and B-1	GA219	1474.884	-853.548	6.1	2	0.6	2.5	533	3.40E-01	1	A
HERCULES	Vaporizer	GA220	1474.884	-853.548	18.3	2	0.6	3.9	644	2.14E-01	1	A

Table C-3 Georgia Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
FEDERAL LAW ENFORECEMENT TRAINING CENTER	Boilers B1 and B2	GA221	1474.094	-846.532	10.7	6	0.5	6.3	450	2.52E-03	1	A
INTERSTATE PAPER CORPORATION	Multi-fuel Boiler	GA222	1470.681	-788.873	38.7	4	1.7	17.1	338	3.45E+00	1	A
INTERSTATE PAPER CORPORATION	Power Boiler	GA223	1470.712	-789.031	46.0	4	2.0	10.7	457	7.94E+00	1	A
INTERSTATE PAPER CORPORATION	Recovery Boiler	GA224	1470.714	-789.026	46.0	4	2.7	8.3	353	1.01E-01	1	A
INTERSTATE PAPER CORPORATION	Lime Kiln	GA225	1470.714	-788.897	15.2	4	1.5	3.6	348	8.82E-02	1	A
PEACH STATE ASPHALT	Dryer	GA226	1465.100	-716.835	9.1	23	1.0	32.0	391	9.83E-01	1	A
EFFINGHAM COUNTY POWER LLC	Preheater	GA227	1471.683	-727.921	5.9	23	0.6	2.8	714	3.78E-03	1	B
EFFINGHAM COUNTY POWER LLC	Auxiliary Boiler	GA228	1471.885	-728.026	36.6	23	0.7	2.3	499	7.56E-03	1	B
EFFINGHAM COUNTY POWER LLC	Combined-Cycle CTGs	GA229	1471.890	-728.001	50.3	23	5.8	13.4	355	1.66E+00	1	B
DAIMLER CHRYSLER MANUFACTURING	Primer Thermal Oxidizer	GA230	1481.329	-748.949	28.0	5	0.8	14.3	473	1.26E-03	1	B
DAIMLER CHRYSLER MANUFACTURING	Guidecoat Ovens TO	GA231	1481.377	-749.086	28.0	6	0.8	14.3	473	2.52E-03	1	B
DAIMLER CHRYSLER MANUFACTURING	Basecoat Spray Booths	GA232	1481.379	-749.011	40.0	6	4.6	8.9	295	1.26E-03	1	B
DAIMLER CHRYSLER MANUFACTURING	Guidecoat Spray Booths	GA233	1481.374	-748.950	40.0	6	4.3	9.1	295	2.52E-03	1	B
DAIMLER CHRYSLER MANUFACTURING	Clearcoat Spray Booths	GA234	1481.370	-748.899	40.0	5	4.6	9.0	295	1.26E-03	1	B
DAIMLER CHRYSLER MANUFACTURING	Topcoat Ovens TO	GA235	1481.408	-748.959	28.0	6	0.8	14.3	473	1.26E-03	1	B
DAIMLER CHRYSLER MANUFACTURING	Hot Water Generators 4, 5	GA236	1481.547	-748.704	20.0	4	0.8	12.0	425	2.52E-03	1	B
DAIMLER CHRYSLER MANUFACTURING	Hot Water Generators 1-3	GA237	1481.556	-748.704	20.0	4	0.8	11.9	441	1.13E-02	1	B
FORT JAMES OPERATING CO.	Paper Dryer 19W, EP24	GA238	1478.330	-720.925	31.4	20	1.8	18.3	322	2.27E-03	1	B
FORT JAMES OPERATING CO.	Paper Dryer 19D, EP37	GA239	1478.361	-720.951	31.4	20	1.8	18.3	322	2.27E-03	1	B
FORT JAMES OPERATING CO.	Paper Dryer 18W, EP03	GA240	1478.376	-720.886	31.4	20	1.8	18.3	322	3.15E-03	1	B
FORT JAMES OPERATING CO.	Paper Dryer 18D, EP14	GA241	1478.407	-720.912	31.4	20	1.8	18.3	322	3.15E-03	1	B
FORT JAMES OPERATING CO.	Paper Dryer 17W, EP66	GA242	1478.423	-720.846	31.4	20	1.8	18.3	322	3.15E-03	1	B
FORT JAMES OPERATING CO.	Paper Dryer 17D, EP67	GA243	1478.454	-720.872	31.4	20	1.8	18.3	322	3.15E-03	1	B
FORT JAMES OPERATING CO.	Paper Dryer 16W, EP45	GA244	1478.438	-720.781	31.4	20	1.8	18.3	322	2.90E-03	1	B
FORT JAMES OPERATING CO.	Paper Dryer 16D, EP56	GA245	1478.494	-720.802	31.4	20	1.8	18.3	322	2.90E-03	1	B
FORT JAMES OPERATING CO.	Combustion Turbine CT1	GA246	1478.489	-720.772	50.3	20	3.3	24.7	700	2.42E+00	1	B
FORT JAMES OPERATING CO.	Combustion Turbine CT2	GA247	1478.489	-720.772	50.3	20	3.3	24.7	700	2.42E+00	1	B
FORT JAMES OPERATING CO.	Boiler #3	GA248	1478.514	-720.768	109.0	20	2.2	20.1	419	6.19E+01	1	B
FORT JAMES OPERATING CO.	Boiler #4	GA249	1478.540	-720.763	109.0	20	2.2	20.1	419	4.81E+01	1	B
FORT JAMES OPERATING CO.	Boiler #5	GA250	1478.566	-720.758	109.0	20	2.2	20.1	419	4.81E+01	1	B
FORT JAMES OPERATING CO.	Boiler #6	GA251	1478.574	-720.726	109.0	20	2.2	20.1	419	6.38E+01	1	B
FORT JAMES OPERATING CO.	Package Boiler PB1	GA252	1478.574	-720.726	24.4	20	1.3	17.4	439	6.17E+00	1	B
FORT JAMES OPERATING CO.	Paper Dryer 20D, EP30	GA253	1478.574	-720.726	1.0	20	1.0	0.001	0.001	2.77E-03	1	B
FORT JAMES OPERATING CO.	Paper Dryer 20W, EP28	GA254	1478.574	-720.726	31.4	20	1.8	18.3	340	2.77E-03	1	B
GENPOWER MACINTOSH	Auxiliary Boiler	GA255	1480.485	-729.716	30.5	5	1.2	24.4	450	1.76E-02	1	B
GENPOWER MACINTOSH	Gas Turbine S	GA256	1480.529	-729.769	50.3	5	5.5	20.1	361	5.04E-01	1	B
GENPOWER MACINTOSH	Gas Turbine N	GA257	1480.529	-729.685	50.3	5	5.5	20.1	361	5.04E-01	1	B
PAVE-TEC	Drum Cooler	GA258	1483.817	-747.783	6.7	6	0.8	30.1	411	1.13E-01	1	B
WESTBURY CO.	Dryer	GA259	1482.939	-741.875	6.1	12	0.4	25.9	436	7.81E-01	1	B
GEORGIA-PACIFIC CORP. (PLYWOOD PLANT)	New boiler	GA260	1484.551	-747.717	23.3	3	1.7	3.7	336	1.51E-01	1	B
GEORGIA-PACIFIC CORP. (PLYWOOD PLANT)	Old boiler (removed)	GA261	1484.551	-747.717	1.0	3	1.0	0.001	0.001	-5.92E-01	1	F
EMD CHEMICALS	Drying equipment	GA262	1482.903	-736.072	21.3	6	0.3	19.4	325	8.82E-02	1	B
SAVANNAH ELECTRIC & POWER CO.	CT10A & DB10A	GA263	1479.945	-718.670	48.8	18	5.8	19.4	406	1.36E+01	1	B
SAVANNAH ELECTRIC & POWER CO.	CT10B & DB10B	GA264	1479.982	-718.670	48.8	18	5.8	19.4	406	1.36E+01	1	B

Table C-3 Georgia Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
SAVANNAH ELECTRIC & POWER CO.	CT11A & DB11A	GA265	1480.093	-718.673	48.8	18	5.8	19.4	406	1.36E+01	1	B
SAVANNAH ELECTRIC & POWER CO.	CT11B & DB11B	GA266	1480.130	-718.673	48.8	18	5.8	19.4	406	1.36E+01	1	B
SAVANNAH ELECTRIC & POWER CO.	Combustion Turbine 8	GA267	1480.833	-717.767	19.2	12	4.6	36.6	609	7.20E-02	2	B
SAVANNAH ELECTRIC & POWER CO.	Combustion Turbine 7	GA268	1480.846	-717.740	19.2	10	4.6	36.6	609	0.00E+00	2	B
SAVANNAH ELECTRIC & POWER CO.	Combustion Turbine 6	GA269	1480.860	-717.713	19.2	10	4.6	36.6	609	5.50E-02	2	B
SAVANNAH ELECTRIC & POWER CO.	Combustion Turbine 5	GA270	1480.873	-717.685	19.2	8	4.6	36.6	609	0.00E+00	2	B
SAVANNAH ELECTRIC & POWER CO.	Combustion Turbine 4	GA271	1480.886	-717.658	19.2	10	4.6	36.6	609	0.00E+00	2	B
SAVANNAH ELECTRIC & POWER CO.	Combustion Turbine 3	GA272	1480.900	-717.630	19.2	10	4.6	36.6	609	0.00E+00	2	B
SAVANNAH ELECTRIC & POWER CO.	Combustion Turbine 2	GA273	1480.913	-717.602	19.2	12	4.6	36.6	609	4.90E-02	2	B
SAVANNAH ELECTRIC & POWER CO.	Combustion Turbine 1	GA274	1480.927	-717.575	19.2	14	4.6	36.6	609	6.90E-02	2	B
PCS NITROGEN FERTILIZER	New Boiler	GA275	1485.457	-742.124	42.7	3	2.1	10.2	478	1.55E+01	1	B
SAVANNAH ELECTRIC & POWER CO.	Coal-fired Boiler (Unit 1)	GA276	1481.197	-717.641	95.4	15	3.5	25.9	419	1.54E+02	2	B
HERCULES	Boiler SB10	GA277	1486.525	-747.590	11.8	2	0.8	7.6	505	0.00E+00	1	B
APAC-GEORGIA	Dryer	GA278	1488.203	-750.467	9.4	7	1.2	26.2	394	6.44E+00	1	B
GEORGIA-PACIFIC RESINS	Boiler production increase	GA279	1486.335	-739.865	1.0	4	1.0	0.0	478	1.15E+00	1	B
WILLAMETTE INDUSTRIES	Bark Boiler	GA280	1486.773	-740.002	76.2	5	4.3	7.3	477	-7.94E-01	1	F
WILLAMETTE INDUSTRIES	No. 1 Power Boiler	GA281	1486.773	-740.002	30.2	5	1.5	14.0	477	-2.52E-02	1	F
WILLAMETTE INDUSTRIES	No. 2 Lime Kiln	GA282	1486.773	-740.002	30.5	5	1.6	13.5	347	6.26E+00	1	B
WILLAMETTE INDUSTRIES	No. 3 Power Boiler	GA283	1486.773	-740.002	76.2	5	4.3	7.3	477	5.01E+01	1	B
WILLAMETTE INDUSTRIES	No. 3 Recovery Boiler	GA284	1486.773	-740.002	96.5	5	3.0	16.9	472	6.85E+00	2	B
WILLAMETTE INDUSTRIES	No. 3 Smelt Tank	GA285	1486.773	-740.002	96.5	5	1.0	10.9	355	1.60E+00	1	B
WILLAMETTE INDUSTRIES	No. 4 Power Boiler	GA286	1486.773	-740.002	96.5	5	3.6	16.8	472	4.21E+01	1	B
SAVANNAH SUGAR REFINERY	Coal-Fired Boiler (D)	GA287	1487.323	-740.812	45.7	2	1.9	23.8	344	5.12E+01	1	B
FUJI VEGETABLE OIL INC.	Boiler #1	GA288	1488.565	-744.215	6.7	1	0.5	0.001	0.001	8.06E-01	1	B
FUJI VEGETABLE OIL INC.	Boiler #3	GA289	1488.565	-744.215	8.2	1	0.6	0.001	0.001	2.13E+00	1	B
FUJI VEGETABLE OIL INC.	Boiler #4	GA290	1488.565	-744.215	29.0	1	0.5	0.001	0.001	3.40E-01	1	B
CITERCO	Heater #1	GA291	1489.748	-744.132	12.2	4	0.9	2.0	649	9.58E-01	1	B
INTERNATIONAL PAPER COMPANY	DV5	GA292	1490.045	-745.788	16.8	4	0.9	4.3	644	1.01E+00	1	B
INTERNATIONAL PAPER COMPANY	Incinerator (3 hr/day)	GA293	1490.055	-745.786	30.5	4	0.8	4.3	1033	8.00E+00	1	B
INTERNATIONAL PAPER COMPANY	Recovery Furnace #15	GA294	1490.016	-744.892	106.7	3	4.3	18.3	453	4.02E+01	1	B
INTERNATIONAL PAPER COMPANY	DV4	GA295	1490.186	-745.610	54.9	4	1.4	5.1	477	1.58E+01	1	B
INTERNATIONAL PAPER COMPANY	Smelt Tank #15	GA296	1490.076	-744.890	83.5	3	3.0	18.3	345	1.44E+00	1	B
INTERNATIONAL PAPER COMPANY	TRS Incineration (PB13)	GA297	1490.075	-744.813	106.7	3	3.0	23.9	447	4.60E-01	2	B
INTERNATIONAL PAPER COMPANY	Lime Kiln #7	GA298	1490.285	-744.578	82.3	4	1.8	15.5	505	4.16E-01	1	B
INTERNATIONAL PAPER COMPANY	Recovery Furnace #12	GA299	1490.337	-744.573	71.3	4	1.8	21.6	437	-3.03E+01	1	F
INTERNATIONAL PAPER COMPANY	Smelt Tank #12	GA300	1490.337	-744.573	70.2	4	1.5	6.1	341	-8.69E-01	1	F
INTERNATIONAL PAPER COMPANY	Lime Kilns #4, 5, & 6	GA301	1490.357	-744.549	41.5	4	1.4	17.5	339	-2.77E-01	1	F
INTERNATIONAL PAPER COMPANY	Recovery Furnace #13	GA302	1490.451	-744.532	71.3	4	1.8	20.2	420	-2.90E+01	1	F
INTERNATIONAL PAPER COMPANY	Smelt Tank #13	GA303	1490.451	-744.532	70.3	4	1.5	5.8	342	-8.32E-01	1	F
ENGELHARD CORPORATION	Boilers ST3	GA304	1494.880	-746.963	5.5	1	0.5	34.0	477	1.26E-01	1	B
ENGELHARD CORPORATION	Calciner ST2	GA305	1494.880	-746.963	20.4	1	1.6	11.1	344	1.01E-01	1	B
ENGELHARD CORPORATION	Secondary Dryers ST4	GA306	1494.880	-746.963	15.9	1	1.5	16.6	408	1.73E+00	1	B
ENGELHARD CORPORATION	Spray Dryer ST1	GA307	1494.880	-746.963	19.8	1	1.5	19.1	366	1.23E+00	1	B
CPV TERRAPIN	Combustion Turbine #3	GA308	1496.084	-747.064	60.4	3	5.5	12.3	342	5.73E+00	1	B

Table C-3 Georgia Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
CPV TERRAPIN	Combustion Turbine #2	GA309	1496.117	-747.066	60.4	3	5.5	12.3	342	5.73E+00	1	B
CPV TERRAPIN	Combustion Turbine #1	GA310	1496.187	-747.069	60.4	3	5.5	12.3	342	5.73E+00	1	B
CPV TERRAPIN	Heater	GA311	1496.221	-746.941	21.3	3	0.4	18.3	422	1.26E-02	1	B
G-P GYPSUM CORP.	Gas Turbines T1 & T2	GA312	1497.284	-747.009	11.0	8	0.6	45.7	733	8.19E-01	1	B
SAVANNAH ENERGY SYSTEM CO.	Unit 1	GA313	1499.596	-746.386	45.7	2	1.4	30.3	408	3.91E+00	1	B
SAVANNAH ENERGY SYSTEM CO.	Unit 2	GA314	1499.596	-746.386	45.7	2	1.4	30.3	408	3.91E+00	1	B
KERR-McGEE PIGMENTS	Boiler #5	GA315	1499.870	-745.230	13.0	1	1.9	6.4	450	-1.74E+00	1	F
KERR-McGEE PIGMENTS	Boiler B-1	GA316	1499.870	-745.230	22.7	1	1.5	13.7	436	1.06E+01	1	B
KERR-McGEE PIGMENTS	Boilers 1-4	GA317	1499.870	-745.230	12.5	1	1.5	7.9	533	-1.97E+00	1	F
KERR-McGEE PIGMENTS	Chloride Scrubber	GA318	1499.870	-745.230	61.0	1	0.6	5.8	300	7.56E-01	1	B
KERR-McGEE PIGMENTS	Incenerator	GA319	1499.870	-745.230	27.4	1	1.4	10.4	1139	7.94E+00	1	B
KERR-McGEE PIGMENTS	Ore Dryers 1A & 12A	GA320	1499.870	-745.230	18.3	1	0.6	10.7	408	7.56E-01	1	B
KERR-McGEE PIGMENTS	Rotary Dryer	GA321	1499.870	-745.230	12.2	1	0.7	22.0	372	7.56E-01	1	B
KERR-McGEE PIGMENTS	Spray Dryer 4A	GA322	1499.870	-745.230	25.9	1	1.4	11.2	383	1.76E+00	1	B
SOUTHERN LNG	Gas Heater (HS02)	GA323	1502.367	-744.180	5.3	3	0.4	1.7	505	1.26E-04	1	B
SOUTHERN LNG	Boiler (BS01)	GA324	1502.370	-744.192	6.1	3	0.6	5.9	505	5.54E-02	1	B
SOUTHERN LNG	Gas Heater (HS01)	GA325	1502.370	-744.185	5.3	3	0.4	1.7	505	1.26E-04	1	B
SOUTHERN LNG	LNG Vaporizer (VS08)	GA326	1502.375	-744.108	23.5	3	1.3	8.2	290	8.82E-03	1	B
SOUTHERN LNG	LNG Vaporizer (VS07)	GA327	1502.382	-744.117	23.5	3	1.3	8.2	290	8.82E-03	1	B
SOUTHERN LNG	LNG Vaporizer (VS06)	GA328	1502.390	-744.127	23.5	3	1.3	8.2	290	8.82E-03	1	B
SOUTHERN LNG	LNG Vaporizer (VS03)	GA329	1502.398	-744.140	23.5	3	1.5	4.1	290	6.55E-03	1	B
SOUTHERN LNG	LNG Vaporizer (VS02)	GA330	1502.405	-744.149	23.5	4	1.5	8.2	290	1.26E-02	1	B
SOUTHERN LNG	LNG Vaporizer (VS01)	GA331	1502.412	-744.161	23.5	3	1.5	8.2	290	1.26E-02	1	B
SOUTHERN LNG	Comp. Engine (CS01)	GA332	1502.439	-744.111	5.7	5	0.3	41.1	735	6.30E-04	1	B
SOUTHERN LNG	Gen. Engine (GS01)	GA333	1502.534	-744.166	9.4	5	0.6	41.8	761	2.02E-03	1	B
SOUTHERN LNG	Gen. Engine (GS02)	GA334	1502.538	-744.171	9.4	5	0.6	41.8	761	2.02E-03	1	B
SOUTHERN LNG	Gen. Turbine (GS03)	GA335	1502.541	-744.175	8.4	5	1.0	10.2	715	1.76E-02	1	B
SOUTHERN LNG	Gen. Turbine (GS04)	GA336	1502.543	-744.179	8.4	5	1.0	10.2	715	1.76E-02	1	B
GREAT SOUTHERN PAPER CO. (GEORGIA-PACIFIC)	Recovery Boilers 1&2	GA337	1133.459	-904.756	61.0	46	3.7	27.6	463	5.44E+01	1	B
GREAT SOUTHERN PAPER CO. (GEORGIA-PACIFIC)	Smelt Tank 3	GA338	1133.459	-904.756	75.6	45	1.8	7.0	336	1.76E+00	1	B
GREAT SOUTHERN PAPER CO. (GEORGIA-PACIFIC)	Smelt Tank 1 - Baseline	GA339	1133.474	-904.758	49.1	44	1.2	7.8	341	-6.30E-01	1	F
GREAT SOUTHERN PAPER CO. (GEORGIA-PACIFIC)	Smelt Tank 1 - Future	GA340	1133.474	-904.758	58.2	44	1.5	7.8	341	6.93E-01	1	B
GREAT SOUTHERN PAPER CO. (GEORGIA-PACIFIC)	Smelt Tank 2 - Baseline	GA341	1133.475	-904.747	49.1	44	1.5	7.9	343	-6.30E-01	1	F
GREAT SOUTHERN PAPER CO. (GEORGIA-PACIFIC)	Smelt Tank 2 - Future	GA342	1133.475	-904.747	58.2	44	1.5	7.9	343	6.93E-01	1	B
GREAT SOUTHERN PAPER CO. (GEORGIA-PACIFIC)	Lime Kiln 2	GA343	1133.534	-904.480	25.0	34	1.8	9.7	355	2.32E+00	1	B
GREAT SOUTHERN PAPER CO. (GEORGIA-PACIFIC)	Lime Kiln 1	GA344	1133.550	-904.488	25.0	34	1.8	9.7	355	2.32E+00	1	B
LONGLEAF ENERGY ASOCIATES	Auxiliary Boiler	GA345	1134.514	-897.086	68.6	61	1.5	18.1	628	1.15E+00	1	B
LONGLEAF ENERGY ASOCIATES	Unit 2 Boiler	GA346	1134.648	-897.074	140.2	65	7.3	18.2	347	9.29E+01	1	B
LONGLEAF ENERGY ASOCIATES	Unit 1 Boiler	GA347	1134.648	-897.066	140.2	65	7.3	18.2	347	9.29E+01	1	B
BIBB COMPANY	Boilers 7 & 8	GA348	1123.850	-756.880	10.7	104	0.6	12.8	505	3.21E+00	1	B
U. S. ARMY INFANTRY CENTER	Boiler B2	GA349	1127.357	-773.348	11.0	103	0.9	5.5	541	1.13E+00	1	B
U. S. ARMY INFANTRY CENTER	Boiler KH3	GA350	1127.357	-773.348	13.4	103	0.9	2.2	450	1.12E+00	1	B
U. S. ARMY INFANTRY CENTER	Boilers MH1 & MH2	GA351	1127.357	-773.348	19.5	103	0.9	2.5	450	2.51E+00	1	B
CATAULA GENERATING COMPANY	Turbines T1-T4	GA352	1128.689	-743.235	25.9	157	5.5	45.5	767	5.32E+01	1	B

Table C-3 Georgia Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
PEACE VALLEY GENERATION CO.	Auxiliary Boiler	GA353	1129.825	-744.091	33.5	182	0.9	19.9	439	1.39E-01	1	B
PEACE VALLEY GENERATION CO.	Comb-Cycle Turbines (4)	GA354	1129.825	-744.091	51.8	182	5.5	12.8	355	7.56E+00	1	B
PEACE VALLEY GENERATION CO.	Simple-Cycle Tur. (2)	GA355	1129.825	-744.091	33.5	182	5.8	26.8	793	2.82E+00	1	B
OGLETHORPE POWER CORPORATION	CT1	GA356	1150.352	-743.081	27.4	164	5.5	24.4	766	1.44E-02	1	B
OGLETHORPE POWER CORPORATION	CT2	GA357	1150.348	-743.052	27.4	163	5.5	24.4	766	1.44E-02	1	B
OGLETHORPE POWER CORPORATION	CT3	GA358	1150.345	-743.023	27.4	162	5.5	24.4	766	1.44E-02	1	B
OGLETHORPE POWER CORPORATION	CT4	GA359	1150.342	-742.994	27.4	161	5.5	24.4	766	1.44E-02	1	B
OGLETHORPE POWER CORPORATION	CT5	GA360	1150.338	-742.965	27.4	160	5.5	24.4	766	9.14E+00	1	B
OGLETHORPE POWER CORPORATION	CT6	GA361	1150.335	-742.936	27.4	160	5.5	24.4	766	9.14E+00	1	B
OGLETHORPE POWER CORPORATION	Heater 1	GA362	1150.407	-743.053	5.8	165	0.5	26.0	811	4.28E-03	1	B
OGLETHORPE POWER CORPORATION	Heater 2	GA363	1150.400	-742.995	5.8	161	0.5	26.0	811	4.28E-03	1	B
OGLETHORPE POWER CORPORATION	Heater 3	GA364	1150.393	-742.937	5.8	162	0.5	26.0	811	4.28E-03	1	B
ENGELHARD CORPORATION	Flash Dryer #3	GA365	1196.970	-945.247	36.6	54	0.9	11.3	422	3.53E+00	1	B
ENGELHARD CORPORATION	Flash Dryers #4 & #5	GA366	1196.970	-945.247	39.6	54	0.8	15.2	403	9.32E+00	1	B
ENGELHARD CORPORATION	No. 6 Boiler	GA367	1196.970	-945.247	30.5	54	1.8	1.7	533	1.81E+01	1	B
DUKE ENERGY BAKER	Combution Turbine No. 1	GA368	1198.259	-875.297	28.4	54	4.6	39.7	784	7.56E+00	1	B
DUKE ENERGY BAKER	Combution Turbine No. 2	GA369	1198.254	-875.250	28.4	54	4.6	39.7	784	7.56E+00	1	B
DUKE ENERGY BAKER	Combution Turbine No. 3	GA370	1198.252	-875.230	28.4	54	4.6	39.7	784	7.56E+00	1	B
DUKE ENERGY BAKER	Combution Turbine No. 4	GA371	1198.246	-875.183	28.4	55	4.6	39.7	784	7.56E+00	1	B
DUKE ENERGY BAKER	Combution Turbine No. 5	GA372	1198.244	-875.163	28.4	55	4.6	39.7	784	7.56E+00	1	B
DUKE ENERGY BAKER	Combution Turbine No. 6	GA373	1198.239	-875.116	28.4	55	4.6	39.7	784	7.56E+00	1	B
DUKE ENERGY BAKER	Combution Turbine No. 7	GA374	1198.236	-875.096	28.4	55	4.6	39.7	784	7.56E+00	1	B
DUKE ENERGY BAKER	Combution Turbine No. 8	GA375	1198.231	-875.049	28.4	54	4.6	39.7	784	7.56E+00	1	B
DAVIDSON EXTERIOR TRIM	Boilers	GA376	1203.678	-796.203	14.0	115	0.5	7.6	478	8.09E+00	1	B
REEVES CONSTRUCTION COMPANY	New Drum Mixer	GA377	1212.485	-843.317	9.8	67	1.1	30.8	405	1.46E+01	1	B
M&M/MARS	Boiler (B2)	GA378	1214.022	-851.138	8.8	59	0.9	12.5	505	1.15E+01	1	B
GEORGIA-PACIFIC CORPORATION	Wood-waste Boiler	GA379	1215.414	-845.184	9.1	62	0.6	27.4	505	2.90E-01	1	B
COATS & CLARK	Coal-fired Boiler	GA380	1217.776	-847.118	18.3	65	1.8	5.2	450	3.64E+00	1	B
PECAN GROVE GENERATING	Auxiliary Boiler No. 1	GA381	1223.293	-870.423	22.9	61	0.6	24.3	450	2.84E-02	1	B
PECAN GROVE GENERATING	HRSG Stack No. 2	GA382	1223.307	-870.462	45.7	61	4.6	33.3	411	1.26E+01	1	B
PECAN GROVE GENERATING	HRSG Stack No. 1	GA383	1222.953	-867.418	45.7	61	4.6	33.3	411	1.26E+01	1	B

1. SO_2 Emission rate based on PSD Increment Spreadsheet downloaded from Georgia EPD website and Major.xls and minor.xls spreadsheets provided by Georgia EPD
2. Actual SO_2 Emission rates taken from Georgia 2005 NEI database as provided by Georgia EPD.
3. The Gilman Paper Company has been shut down, therefore its emissions are included in the negative source emissions modelling bin (Bin F)

Note: The Calpuff Model is limited to 200 Sources. The bin group letter references the bin group in which the souces were modeled.

Table C-4 South Carolina Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
US Marines-MCRD Parris Island	CPP4 Boiler 4	SC001	1527.280	-710.030	19.8	8	1.0	12.0	491	-4.62E-01	1	F
US Marines-MCRD Parris Island	WPP5 Boiler 5	SC002	1524.647	-712.795	10.7	10	0.5	11.8	491	-4.77E+00	1	F
US Marines-MCRD Parris Island	WPP6 Boiler 6	SC003	1524.649	-712.792	10.7	10	0.7	7.8	491	7.47E+00	1	B
US Marines-MCRD Parris Island	WPP7 Boiler 7	SC004	1524.654	-712.786	10.7	10	0.7	7.8	496	7.47E+00	1	B
US Marines Corps Air Station	FC1/2 - boilers 1&2	SC005	1520.585	-698.555	22.3	12	1.2	0.010	405	1.12E-02	1	B
US Marines Corps Air Station	FC3 - boiler 3	SC006	1522.331	-697.562	7.6	4	0.3	0.010	422	2.16E-01	1	B
US Marines Corps Air Station	Microturbines	SC007	1520.579	-698.572	2.1	12	0.3	15.6	350	1.04E-01	1	B
US Marines Corps Air Station	TS5 - T10 Test Cell Stack 1	SC008	1519.152	-697.344	12.2	35	4.2	4.6	368	6.04E-01	1	B
US Marines Corps Air Station	TS5 - T10 Test Cell Stack 2	SC009	1519.152	-697.344	12.2	35	4.2	29.9	637	6.04E-01	1	B
Santee Cooper - Hilton Head	Unit 3	SC010	1527.479	-726.021	9.8	10	4.6	36.6	805	4.45E+01	1	B
PHB/Parker Die Castings	aluminum remelt	SC011	1515.828	-697.084	6.1	40	2.4	0.5	339	-5.04E-04	1	F
ArrMaz Custom Chemicals	HOHST	SC012	1517.848	-688.410	4.4	19	0.4	0.010	422	1.50E-01	1	B
ArrMaz Custom Chemicals	Main Scrubber	SC013	1517.793	-688.658	25.3	20	0.6	14.6	300	1.33E-02	1	B
Ulmer Brothers Inc.	incinerator	SC014	1512.589	-726.029	2.4	20	5.6	0.009	811	1.13E+00	1	B
Malphrus Construction Co.	Diesel Engine	SC015	1513.697	-724.730	2.7	20	0.1	45.3	789	1.01E-02	1	B
Malphrus Construction Co.	incinerator	SC016	1513.697	-724.730	3.0	20	6.0	0.9	811	5.51E-02	1	B
Hilton Head No. 1 Public Service District	Generator 1	SC017	1527.413	-725.674	4.2	12	13.8	0.010	711	6.84E-02	1	B
Hilton Head No. 1 Public Service District	Generator 2	SC018	1527.413	-725.674	3.7	12	12.0	0.010	794	7.98E-02	1	B
Resort Services, Inc.	boiler 3	SC019	1510.225	-725.223	10.7	20	0.5	15.2	478	1.60E+00	1	B
Beaufort Memorial Hospital	Boiler 01A	SC020	1524.573	-703.066	15.0	6	0.6	0.010	450	-3.15E-01	1	F
Beaufort-Jasper Water & Sewage	CB#1	SC021	1508.654	-711.494	4.9	15	0.2	89.3	672	4.73E-01	1	B
Beaufort-Jasper Water & Sewage	CB#2	SC022	1508.668	-711.511	6.1	14	0.2	150.6	821	8.01E-01	1	B
Beaufort-Jasper Water & Sewage	Generator	SC023	1508.677	-711.488	5.0	15	0.2	0.009	672	4.73E-01	1	B
SIPSD (Reclaimed Water Plant)	Generator #1	SC024	1521.780	-735.715	5.6	4	0.4	43.9	753	9.36E-02	1	B
Hilton Head #1 - Leg-O-Mutton Road Well	Diesel Generator	SC025	1526.141	-726.282	2.2	13	0.1	0.010	794	5.90E-02	1	B
Hilton Head #1 - Royal James Drive Facility	Diesel Generator	SC026	1523.693	-723.047	2.7	15	0.1	77.9	700	1.39E-01	1	B
SIPSD Reverse Osmosis Plant	Generator #1 1100 KW	SC027	1523.554	-733.602	6.6	10	0.4	53.9	0	7.52E-02	1	B
Daufuskie Island P&H Inc.	Air Curtain Incinerator	SC028	1512.613	-739.657	2.3	10	3.1	1.5	607	8.82E-02	1	B
Target Store 1298	Diesel Generator	SC029	1514.228	-723.619	7.2	11	0.3	52.1	726	4.03E-02	1	B
Plusa, Inc. (Prouvost USA)	Boiler 2 Stack	SC030	1598.761	-590.401	19.8	22	0.9	4.6	478	5.33E-01	1	B
Prouvost USA	Boiler 3	SC031	1598.761	-590.401	19.8	22	1.2	4.6	464	4.89E-01	1	B
SCE&G Williams	Boiler	SC032	1582.267	-624.139	122.0	10	7.0	27.6	403	9.08E+01	1	B
Lanxess	EXITBOIL	SC033	1582.602	-627.797	45.7	14	1.5	31.6	450	5.90E+01	1	B
Albany Int'l-Press Fabrics	Boiler #2	SC034	1574.078	-580.718	9.1	65	0.6	6.0	505	-3.67E+00	1	F
Albany Int'l-Press Fabrics	Boiler #3	SC035	1574.101	-580.757	23.7	61	0.3	34.1	489	4.32E+00	1	B
Albany Int'l-Press Fabrics	Boiler #4	SC036	1574.148	-580.753	9.8	58	0.6	5.2	589	-2.75E+00	1	F
Albany Int'l-Press Fabrics	Boiler #5	SC037	1574.096	-580.751	23.1	62	0.6	6.6	350	1.15E+00	1	B
Naval Weapons Station	Bldg 3107 Boiler #1	SC038	1580.017	-637.070	7.3	36	11.8	0.010	450	7.42E-01	1	B
Naval Weapons Station	Bldg 3107 Boiler #2	SC039	1580.014	-637.074	7.3	36	11.8	0.010	450	7.42E-01	1	B
Naval Weapons Station	Paint Booth Bldg 1659	SC040	1582.500	-631.789	9.3	26	1.1	13.2	294	8.57E-04	1	B
Alcoa - Mt. Holly	Anode Former Coke Scrub	SC041	1570.190	-622.795	48.5	32	1.1	19.5	322	1.60E-01	1	B
Alcoa - Mt. Holly	Baked Carbon Plant	SC042	1570.247	-622.665	61.3	29	1.4	26.5	353	8.49E+00	1	B
Alcoa - Mt. Holly	Cast House #50	SC043	1569.643	-622.988	18.3	38	1.2	12.3	295	1.13E-03	1	B
Alcoa - Mt. Holly	Cast House #51	SC044	1569.659	-623.013	20.4	39	0.9	12.2	533	1.02E-02	1	B
Alcoa - Mt. Holly	Cast House #52	SC045	1569.689	-623.045	17.4	40	0.6	0.010	366	5.42E-03	1	B
Alcoa - Mt. Holly	Cast House #64	SC046	1569.590	-623.039	17.7	37	1.0	0.3	0	1.64E-03	1	B
Alcoa - Mt. Holly	Diesel Fire Pump	SC047	1569.906	-623.048	6.1	41	0.1	27.2	422	6.55E-02	1	B

Table C-4 South Carolina Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
Alcoa - Mt. Holly	Scrubber Lines	SC048	1569.810	-622.780	61.0	29	3.2	23.5	353	1.07E+02	1	B
The Gates Rubber Company	Boiler #3	SC049	1571.931	-605.538	15.2	58	0.6	11.1	478	1.34E+00	1	B
The Gates Rubber Company	Coaters/Oxidize	SC050	1572.018	-605.373	19.2	55	0.7	9.5	543	2.02E-02	1	B
The Gates Rubber Company	Evaporator	SC051	1571.915	-605.453	7.6	56	0.5	0.010	295	2.86E-01	1	B
BP-Amoco Cooper River	#1 Ox Compressors	SC052	1587.254	-628.126	3.0	32	0.2	104.5	686	4.23E+00	1	B
BP-Amoco Cooper River	Emergency Generator #3	SC053	1587.169	-628.389	1.8	28	0.1	59.1	803	1.79E-01	1	B
BP-Amoco Cooper River	Boilers #1&2	SC054	1587.594	-628.190	30.5	33	2.1	11.9	416	-1.40E+02	1	F
BP-Amoco Cooper River	Boilers #3&4	SC055	1587.605	-628.250	30.5	29	1.9	12.2	405	1.20E+01	1	B
BP-Amoco Cooper River	ITEGEN	SC056	1587.515	-628.678	2.7	7	0.2	66.3	915	2.02E-01	1	B
BP-Amoco Cooper River	UT Compressor #2	SC057	1587.510	-628.215	3.0	32	0.3	64.9	683	2.94E-01	1	B
BP-Amoco Cooper River	WWT Compressors	SC058	1586.315	-628.600	3.0	14	0.1	104.5	686	7.56E-01	1	B
Santee Cooper - Cross	Unit 1	SC059	1558.065	-589.165	182.9	77	6.7	25.9	339	2.23E+02	1	B
Santee Cooper - Cross	Unit 2	SC060	1558.065	-589.165	182.9	77	6.7	21.3	339	3.93E+02	1	B
JW ALUMINUM	ANNEALING #11	SC061	1570.804	-624.951	14.9	39	0.7	3.1	408	1.26E-03	1	B
JW ALUMINUM	ANNEALING #1-10	SC062	1570.661	-624.977	13.7	40	0.5	5.1	408	1.26E-02	1	B
JW ALUMINUM	Coating Line #1	SC063	1570.887	-625.014	13.7	39	0.9	12.8	323	8.40E-05	1	B
JW ALUMINUM	HOLD FURNACE #1-5	SC064	1570.622	-625.029	21.3	41	0.6	9.8	515	3.78E-03	1	B
JW ALUMINUM	MELT FURNACE #1-4	SC065	1570.624	-625.036	25.9	41	1.4	15.9	1156	3.20E+00	1	B
Santee Cooper	Incinerator	SC066	1573.764	-605.265	6.1	50	0.3	0.010	783	-8.69E-02	1	F
SC Pipeline Corp.	Backup	SC067	1581.505	-623.865	7.6	9	0.6	0.010	344	1.26E-03	1	B
Berkeley Co. Water & Sanitatio	emergency generator	SC068	1580.125	-631.876	4.9	13	0.4	53.7	840	1.03E+00	1	B
Berkeley Co. Water & Sanitation Authority	CF-13 (Flare #13)	SC069	1568.794	-614.347	6.1	52	1.0	0.001	0.001	1.50E-01	1	C
Berkeley Co. Water & Sanitation Authority	Trommel Screen Engine	SC070	1568.794	-614.347	5.2	52	0.1	62.2	783	4.54E-03	1	C
Berkeley Co. Water & Sanitation Authority	Tub Grinder Loader Engine	SC071	1568.794	-614.347	3.4	52	0.1	46.6	758	2.77E-02	1	C
Berkeley Co. Water & Sanitation Authority	Tub Grinder Main Engine	SC072	1568.794	-614.347	1.7	52	0.2	93.0	755	5.04E-02	1	C
Nucor Steel	Annealing Furnaces	SC073	1586.816	-625.213	26.1	29	1.0	0.001	0.001	9.10E-03	1	C
Nucor Steel	Baghouse	SC074	1586.218	-624.883	45.7	25	5.2	20.8	339	4.10E+00	1	C
Nucor Steel	Baghouse	SC075	1586.102	-624.783	53.4	30	6.4	29.1	408	1.23E+01	1	C
Nucor Steel	Beam Mill Roof Monitor	SC076	1586.345	-625.026	38.6	30	1.0	0.001	0.001	7.56E-03	1	C
Nucor Steel	Galvanizing Furnace Stack	SC077	1586.752	-625.288	39.6	27	2.1	7.5	644	6.30E-03	1	C
Nucor Steel	Melt Shop Roof Monitor	SC078	1586.412	-624.921	38.6	30	1.0	0.001	0.001	1.20E-02	1	C
Nucor Steel	Pickle Line #1 Boiler	SC079	1586.809	-625.132	22.8	30	0.6	10.7	561	2.27E-03	1	C
Nucor Steel	Pickle Line No. 2 Boilers	SC080	1586.952	-625.113	22.9	30	0.6	10.7	561	2.31E-03	1	C
Nucor Steel	Reheat Furnace	SC081	1586.406	-625.131	45.7	32	2.3	12.5	811	1.40E-02	1	C
Nucor Steel	Tundish Dryer Monitor	SC082	1586.432	-624.982	38.6	31	1.0	0.001	0.001	1.20E-03	1	C
Nucor Steel	Tunnel Furnace 1 Stack 1	SC083	1586.487	-624.902	34.3	31	2.3	8.2	839	6.05E-03	1	C
Nucor Steel	Tunnel Furnace 1 Stack 2	SC084	1586.578	-624.913	34.3	31	2.3	8.2	839	3.81E-03	1	C
Nucor Steel	Tunnel Furnace 2	SC085	1586.482	-624.967	34.3	31	2.3	8.2	839	6.05E-03	1	C
Nucor Steel	Tunnel Furnace No. 1	SC086	1586.536	-624.929	16.8	31	1.0	0.001	0.001	1.51E-03	1	C
Nucor Steel	Tunnel Furnace No. 2	SC087	1586.534	-624.949	16.8	31	1.0	0.001	0.001	1.51E-03	1	C
Nucor Steel	Vacuum Tank Boiler	SC088	1586.446	-624.907	43.1	30	0.9	12.1	505	3.78E-03	1	C
Air Liquide Large	Vaporization Boiler #1	SC089	1587.197	-624.541	3.8	31	1.1	0.010	478	1.51E-03	1	C
Air Liquide Large	Vaporization Boiler #2	SC090	1587.164	-624.528	10.7	31	0.3	0.009	530	3.78E-03	1	C
Fortifiber Coporation	Air Dryer	SC091	1593.195	-633.034	9.1	10	0.4	27.1	517	7.56E-04	1	C
Santee River Rubber Co.	Air Dryer	SC092	1593.195	-633.034	21.3	10	1.1	0.009	351	1.26E-04	1	C
Santee River Rubber Co.	Primary Dryer	SC093	1593.195	-633.034	21.3	10	1.4	0.009	330	1.26E-04	1	C
Santee River Rubber Co.	Secondary Dryer	SC094	1593.195	-633.034	18.3	10	1.1	0.009	324	1.26E-04	1	C

Table C-4 South Carolina Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
Corning, Inc.	Annealing Furnaces & Heaters	SC095	1567.693	-626.550	13.7	38	1.0	17.8	450	1.64E-03	1	C
Corning, Inc.	Boiler 1 (EP-8)	SC096	1567.693	-626.550	15.2	38	0.7	6.7	505	1.44E-03	1	C
Corning, Inc.	Boiler 2 (EP-9)	SC097	1567.693	-626.550	15.2	38	0.7	6.7	505	1.44E-03	1	C
Corning, Inc.	Emergency Generator (EP-7)	SC098	1567.693	-626.550	13.1	38	0.2	46.4	755	1.20E-01	1	C
Corning, Inc.	Furnace 3 (EP-1)	SC099	1567.693	-626.550	22.9	38	1.0	30.1	380	6.80E-04	1	C
Corning, Inc.	Furnaces 1 and 2 (EP-2)	SC100	1567.693	-626.550	22.9	38	1.5	30.0	380	1.36E-03	1	C
Detyens Shipyard	3 mobile hydroblasting units	SC101	1593.143	-632.686	5.8	5	1.0	0.001	0.001	6.80E-02	1	C
DAK Americas LLC	Boiler 1	SC102	1580.083	-620.125	45.7	20	1.5	10.7	433	1.77E-01	1	C
DAK Americas LLC	Boiler 2	SC103	1580.074	-620.110	45.7	21	1.5	13.0	433	1.77E-01	1	C
DAK Americas LLC	Vaporizors 1-4	SC104	1580.102	-620.131	45.7	20	1.3	4.6	605	8.13E+00	1	C
Williams Technology	Dyno1 - Engine Testing	SC105	1562.630	-626.491	4.6	77	0.1	0.010	325	1.26E-03	1	C
Williams Technology	Dyno2 - Engine Testing	SC106	1562.634	-626.493	4.6	77	0.1	0.010	325	1.26E-03	1	C
Williams Technology	PRW-1 Pressure Washer	SC107	1562.581	-626.464	9.5	77	0.3	0.010	322	3.78E-05	1	C
Williams Technology	PW-1 Parts Washer	SC108	1562.590	-626.460	9.6	77	0.2	0.010	339	2.52E-05	1	C
Williams Technology	PW-2 Parts Washer	SC109	1562.590	-626.460	9.6	77	0.2	0.010	339	1.26E-05	1	C
Williams Technology	SH1-8 Space Heaters	SC110	1562.575	-626.442	1.0	76	1.0	0.001	0.001	5.04E-05	1	C
Kemira	600.000	SC111	1582.695	-627.922	15.2	15	1.1	15.9	323	2.10E-02	1	C
American-LaFrance	Paint Booths (P1-P9)	SC112	1544.857	-622.094	17.6	69	1.2	13.7	297	2.52E-03	1	C
Collum's Lumber Mill	Woodwaste Boiler	SC113	1499.884	-578.591	18.3	173	0.5	22.0	505	1.68E-02	1	C
Devro-Teepak	Gas Boiler	SC114	1476.157	-554.321	15.2	195	0.9	0.010	421	3.99E-03	1	C
Worthington Custom Plastics	Air Make-up Units	SC115	1492.956	-566.089	13.7	242	0.2	9.1	450	6.68E-04	1	C
Worthington Custom Plastics	Plant Heater #1&2	SC116	1492.948	-566.101	15.2	242	0.3	6.7	450	5.17E-04	1	C
Worthington Custom Plastics	Washer Heater #1,2&3	SC117	1492.952	-566.095	13.7	242	0.2	10.7	478	8.06E-04	1	C
Trinity Industries, Inc.	Stack 1-Kettle Furnace	SC118	1494.038	-565.487	11.0	230	0.7	5.8	866	5.17E-04	1	C
Columbia Energy Center	Auxiliary Boiler 1&2	SC119	1465.660	-549.568	45.7	150	1.7	21.3	450	5.29E+00	1	C
Columbia Energy Center	Auxiliary Boiler 3	SC120	1465.683	-549.592	45.7	151	2.1	20.2	426	3.99E+00	1	C
Columbia Energy Center	Combustion Turbine 1&2	SC121	1465.622	-549.606	61.0	155	5.8	19.7	393	2.49E+01	1	C
MeadWestvaco	KREC004 Recovery Boiler #1	SC122	1581.085	-638.076	125.3	11	3.5	20.9	437	6.03E+01	1	C
MeadWestvaco	KREC005 East SDTV #1	SC123	1581.097	-638.068	78.7	11	1.2	9.0	350	9.30E-01	1	C
MeadWestvaco	KREC006 West SDTV #1	SC124	1581.085	-638.063	78.7	11	1.2	9.0	350	9.30E-01	1	C
MeadWestvaco	Temp Mobile Chip Screen	SC125	1580.772	-637.938	2.3	9	0.1	0.010	450	1.10E-02	1	C
MeadWestvaco	Temp Mobile Bark Screen	SC126	1580.586	-638.105	2.3	5	0.1	0.010	450	1.10E-02	1	C
MeadWestvaco	No. 4 Lime Kiln	SC127	1580.961	-637.957	34.8	10	1.8	8.0	340	4.65E-01	1	C
MeadWestvaco	No. 5 Lime Kiln	SC128	1580.882	-637.946	64.9	10	1.8	17.8	449	2.72E+00	1	C
MeadWestvaco	PB5 Power Boiler 5	SC129	1581.245	-638.049	47.9	7	2.3	26.8	350	-8.79E-01	1	F
MeadWestvaco	TALLSTK	SC130	1581.217	-638.066	91.8	8	3.4	31.7	441	-1.18E+02	1	F
Rhodia	Boiler #1	SC131	1582.432	-645.040	12.2	11	0.6	14.1	450	1.60E-01	1	C
Rhodia	Boiler #2	SC132	1582.436	-645.048	19.8	11	1.4	3.7	450	8.92E+00	1	C
Rhodia	old Boiler #1&2	SC133	1582.436	-645.048	19.8	11	1.4	6.4	450	-1.61E+01	1	F
Rhodia	Thermal Oxidizer Unit	SC134	1582.615	-645.108	19.2	10	0.9	7.6	331	4.28E-01	1	C
Allied Terminal	Daniels Heater	SC135	1584.031	-645.762	15.2	15	0.8	10.1	672	1.65E+00	1	C
Allied Terminal	Superior Boiler	SC136	1584.028	-645.797	17.8	15	0.5	8.0	522	2.75E+00	1	C
RM Engineered Products	Boiler 2	SC137	1580.522	-639.911	21.3	27	1.2	4.6	533	-9.27E+00	1	F
Charleston AFB	545 Engine Test Cell	SC138	1572.907	-639.224	14.6	36	9.3	16.8	360	5.04E-01	1	C
Charleston AFB	Air Handler 1 Boiler	SC139	1574.788	-638.953	28.7	40	0.5	0.010	328	1.13E-03	1	C
Charleston AFB	Air Handler 2 Boiler	SC140	1573.519	-639.224	28.7	35	0.5	0.010	328	1.13E-03	1	C
Charleston AFB	Boiler #4	SC141	1572.907	-639.224	12.8	36	0.4	0.010	422	1.50E-01	1	C

Table C-4 South Carolina Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
Charleston AFB	Boiler #6	SC142	1572.907	-639.224	5.8	36	0.4	0.010	422	2.68E-01	1	C
Charleston AFB	Boiler #7	SC143	1572.907	-639.224	10.1	36	0.3	6.9	491	1.47E-01	1	C
Charleston AFB	Boiler #8	SC144	1572.907	-639.224	8.5	36	0.3	0.010	422	2.52E-04	1	C
Charleston AFB	hot water heater	SC145	1573.683	-639.156	8.5	38	0.5	10.4	505	1.01E-03	1	C
Medical University of South Carolina	BSB-2&3 Boiler	SC146	1585.187	-650.220	26.8	6	0.9	7.5	439	4.33E-01	1	C
Medical University of South Carolina	HCC-1&2 Boiler	SC147	1585.166	-650.214	31.1	6	0.5	0.010	450	1.47E+00	1	C
Medical University of South Carolina	Old S-1 Boilers	SC148	1585.071	-650.139	45.7	6	1.8	0.010	509	-2.80E+01	1	F
Medical University of South Carolina	S-1 Boilers	SC149	1585.095	-650.160	19.8	6	1.1	0.009	519	6.42E+00	1	C
Medical University of South Carolina	S-13, S-14, S-15 Boilers	SC150	1585.231	-650.325	29.8	5	0.3	13.0	394	3.26E-01	1	C
Medical University of South Carolina	Superior Boiler B770-2	SC151	1585.119	-650.182	55.5	6	0.6	0.010	505	1.71E+00	1	C
Medical University of South Carolina	SAC-1 Boiler	SC152	1585.089	-650.238	29.0	6	0.3	11.2	450	4.03E-01	1	C
City of Chas. Plum Island Sludge Inciner	Incineration scrubber Exhaust	SC153	1583.952	-653.315	13.7	8	1.2	12.7	341	1.39E-01	1	C
GS Roofing Products	RTO	SC154	1578.591	-644.818	22.9	16	0.8	13.1	530	2.39E-03	1	C
Kinder Morgan Bulk Terminals	Boiler	SC155	1585.180	-645.158	12.2	5	0.9	3.0	500	5.32E-01	1	C
SCE&G - Hagood	Combustion Turbine	SC156	1582.872	-645.925	38.1	5	4.9	45.7	798	7.94E+01	1	C
SCE&G - Hagood	Reduction: Boiler 1	SC157	1582.866	-645.896	38.1	8	3.4	15.0	450	-9.07E+01	1	F
SCE&G - Hagood	Reduction: Boiler 2	SC158	1582.866	-645.896	38.1	8	3.4	15.0	450	-9.07E+01	1	F
SCE&G - Hagood	Reduction: Boiler 3	SC159	1582.866	-645.896	38.1	8	3.4	13.2	444	-1.86E+02	1	F
Siebe North, Inc.	boiler 1	SC160	1578.915	-644.542	8.7	26	0.5	0.010	478	9.45E-02	1	C
Charleston Steel & Metal Co.	EP01	SC161	1584.821	-647.302	9.1	7	0.6	4.2	1311	8.06E-01	1	C
Kinder Morgan Bulk Terminals	Dryer/Baghouse	SC162	1580.582	-639.303	12.2	27	1.6	12.7	355	3.78E-04	1	C
Lockheed Martin Aeronautical	1966.000	SC163	1578.472	-644.704	10.4	26	2.1	0.009	666	-5.04E-04	1	F
Lockheed Martin Aeronautical	1950&1951	SC164	1578.393	-644.630	11.3	25	0.2	0.009	494	-4.28E-01	1	F
Lockheed Martin Aeronautical	1964 & 1965	SC165	1578.453	-644.651	10.4	26	2.1	0.009	444	-2.52E-03	1	F
Roper Hospital	S-01&2 Boiler 1&2	SC166	1584.959	-650.251	21.3	5	0.6	9.0	464	4.03E-01	1	C
Roper Hospital	S-03 Generator 9&10	SC167	1584.939	-650.306	10.1	5	0.2	0.010	821	1.85E-01	1	C
R.H. Johnson VA Medical Center	Boiler 1,2,3	SC168	1584.622	-650.288	21.3	5	0.7	13.7	491	7.56E-01	1	C
R.H. Johnson VA Medical Center	Incinerator	SC169	1584.640	-650.387	24.4	5	0.6	10.3	988	1.73E-01	1	C
Moore Drums	Fuel Oil Boiler	SC170	1578.548	-644.437	7.9	24	0.3	11.6	464	-2.10E-01	1	F
Moore Drums	Naturlgas boilr	SC171	1578.554	-644.434	9.2	24	0.6	2.1	475	1.26E-03	1	C
Moore Drums	Reclam Furnace	SC172	1578.408	-644.391	15.7	11	0.7	18.5	533	1.02E-01	1	C
Tarmac America	Steam Generator	SC173	1586.492	-653.871	6.7	9	0.1	0.009	422	1.26E-01	1	C
South Carolina Farm Bureau	Cambell Dryer	SC174	1581.702	-636.990	21.3	5	2.1	0.009	344	-1.89E-03	1	F
Trident Medical Center	Boiler 1&2	SC175	1569.704	-631.583	12.2	45	0.6	12.3	489	2.65E-01	1	C
Broyhill Furniture	14MMBut/hr Boiler	SC176	1561.094	-628.959	17.4	80	1.1	6.7	533	8.82E-03	1	C
MeadWestvaco Chemical Division	Boiler #9	SC177	1580.795	-638.322	10.7	5	0.6	0.010	616	6.90E-01	1	C
MeadWestvaco Chemical Division	Kettle Thermal Oxidizer	SC178	1580.905	-638.399	30.5	5	0.9	19.8	361	1.57E-01	1	C
MeadWestvaco Chemical Division	Poly Process Tank	SC179	1580.794	-638.273	9.8	5	0.1	0.010	304	-2.20E+00	1	F
MeadWestvaco Chemical Division	Process Tank Point Sources	SC180	1580.763	-638.237	14.0	5	0.4	0.2	304	-9.95E-03	1	F
MeadWestvaco Chemical Division	Spray Dryer	SC181	1580.818	-638.272	25.9	5	1.8	12.4	333	2.90E-01	1	C
Siebe-North, Inc.-Butyl 2	Boiler 1&2	SC182	1577.232	-642.929	11.7	34	0.4	9.1	478	1.07E+00	1	C
SC Department of Natural Resources	two 5.5 MMBtu/hr boiler	SC183	1590.077	-652.983	7.6	6	10.4	0.010	444	6.92E-01	1	C
North Charleston Sewer Dist.	incinerator	SC184	1584.432	-645.359	16.8	15	0.6	8.7	310	9.32E-01	1	C
Foster Wheeler	Boiler SG-201A	SC185	1583.321	-644.124	75.9	11	1.6	15.9	422	1.01E+01	1	C
The Scotts Company	Thermal Oxidizer 1	SC186	1572.041	-637.232	14.3	41	0.9	12.1	590	2.68E-01	1	C
The Scotts Company	Thermal Oxidizer 2	SC187	1572.044	-637.273	15.2	40	1.0	13.8	450	1.28E+00	1	C
Englehard Corp - Mearl LLC	Heat Treating Furnace (EP01)	SC188	1571.812	-637.032	11.6	35	0.9	2.4	978	5.67E-04	1	C

Table C-4 South Carolina Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
Englehard Corp - Mearl LLC	Steam Boiler No. 1 (EP05)	SC189	1571.812	-637.032	11.6	35	0.9	12.2	533	9.45E-04	1	C
ExxonMobil	Boiler	SC190	1584.640	-646.130	16.8	6	0.5	10.0	505	7.99E-01	1	C
Deytens Shipyards	Boiler #1	SC191	1581.801	-641.875	7.6	9	0.6	2.4	572	6.96E-02	1	C
Deytens Shipyards	Boiler #2	SC192	1581.735	-641.785	7.6	9	0.6	2.7	594	1.10E-01	1	C
Deytens Shipyards	Boiler #3	SC193	1581.787	-641.677	3.7	8	0.3	6.5	578	4.81E-02	1	C
Deytens Shipyards	Boiler #4	SC194	1582.112	-641.820	6.1	9	0.3	10.4	589	6.02E-02	1	C
Deytens Shipyards	Boiler #5	SC195	1582.086	-641.876	3.7	9	0.3	9.7	578	4.81E-02	1	C
Deytens Shipyards	H1-H6	SC196	1581.664	-641.753	3.7	9	0.6	0.003	366	1.53E+00	1	C
Deytens Shipyards	H7-H10	SC197	1581.742	-641.901	2.4	10	0.6	0.003	366	4.61E-01	1	C
Bon Secours St. Francis Xavier	Boiler 1&2	SC198	1576.078	-648.901	13.6	9	0.6	9.3	503	2.22E-01	1	C
Bon Secours St. Fancis Xavier	Generator 1&2	SC199	1576.157	-649.906	15.2	8	0.3	69.3	825	1.13E-01	1	C
Bon Secours St. Francis Xavier	Generator 3	SC200	1576.277	-648.956	16.8	10	0.2	107.3	825	6.21E-02	1	C
City of Charleston-Hanahan	diesel generator 1&2	SC201	1575.124	-636.365	7.3	21	0.2	129.3	839	1.06E-01	1	C
City of Charleston-Hanahan	diesel generator 6&7	SC202	1575.124	-636.365	10.0	21	0.2	97.1	786	3.00E-01	1	C
Cogen South LLC	Aux Boilers	SC203	1580.958	-638.352	74.1	5	3.0	20.8	461	3.91E+01	1	C
Cogen South LLC	Main Boiler	SC204	1581.038	-638.415	122.9	5	3.4	17.2	345	5.06E+01	1	C
Palmetto Lime LLC	Kiln stack	SC205	1585.114	-645.693	90.1	5	2.1	18.6	453	4.64E-01	1	C
Charleston Technical Center	CTC Boiler	SC206	1580.484	-638.504	19.4	5	0.5	12.6	422	4.62E-01	1	C
Green Oasis Environmental	EE1	SC207	1584.890	-646.085	12.2	9	0.5	6.6	632	6.35E-01	1	C
Mount Pleasant Waterworks	600 kW Generator	SC208	1595.886	-645.445	5.5	5	30.9	0.010	775	4.10E-01	1	C
Mount Pleasant Waterworks	900 kW Generator	SC209	1595.886	-645.445	6.1	5	24.2	0.010	754	6.15E-01	1	C
Avebe (SC)	Air Heater	SC210	1571.421	-635.323	9.1	30	0.7	10.1	578	1.26E-03	1	C
Avebe (SC)	Boiler	SC211	1571.421	-635.323	9.1	30	0.5	6.5	478	1.26E-03	1	C
College of Charleston	Boiler 1	SC212	1586.643	-649.660	13.1	10	0.9	11.2	494	9.50E-01	1	C
College of Charleston	Boiler 2	SC213	1586.647	-649.652	13.1	10	0.9	11.2	494	9.50E-01	1	C
Mt. Pleasant Waterworks	WG-7 peak generator	SC214	1594.834	-644.230	4.3	15	0.2	0.010	775	1.42E-01	1	C
American Tank Fabrication Co.	TF-F1	SC215	1581.760	-641.752	16.5	9	1.0	0.010	478	1.26E-03	1	C
Heritage Synfuel Binders	Hot Oil Heater	SC216	1584.420	-646.025	10.7	12	0.4	4.0	478	3.09E-01	1	C
Cummins MerCruiser Diesel, LLC	ETC1015	SC217	1576.661	-645.099	14.3	7	0.1	6.8	533	2.03E-01	1	C
Cummins MerCruiser Diesel, LLC	ETC1618	SC218	1576.645	-645.110	14.3	7	0.3	6.8	533	1.69E-01	1	C
Mt. Pleasant Waterworks Plant #4	Generator	SC219	1599.969	-636.831	5.3	23	0.3	25.6	775	1.58E-01	1	C
Vought Aircraft Industries, Inc.	AC - AutoClave	SC220	1575.393	-641.652	21.0	16	1.2	20.1	505	3.41E-03	1	C
Vought Aircraft Industries, Inc.	Paint Boilers	SC221	1575.255	-641.280	21.0	7	0.7	11.5	450	1.49E-03	1	C
Holset Engineering	Test Cell 1	SC222	1565.544	-633.152	13.7	27	0.2	53.7	533	1.23E-02	1	C
Holset Engineering	Test Cell 2	SC223	1565.544	-633.152	13.7	27	0.2	53.7	533	1.23E-02	1	C
Holset Engineering	Test Cell 3	SC224	1565.544	-633.152	13.7	27	0.2	53.7	533	1.23E-02	1	C
Holset Engineering	Test Cell 4	SC225	1565.544	-633.152	13.7	27	0.2	53.7	533	1.23E-02	1	C
Holset Engineering	Test Cell 5	SC226	1565.544	-633.152	13.7	27	0.2	53.7	533	1.23E-02	1	C
Holset Engineering	Test Cell 6	SC227	1565.544	-633.152	13.7	27	0.2	71.6	533	5.22E-02	1	C
Southwoods Lumber & Millwork	Woodwaste Boil.	SC228	1543.638	-555.401	15.2	95	0.5	2.3	455	1.64E-02	1	C
Aircap Industries	boilers	SC229	1545.685	-555.544	12.8	90	0.6	14.5	469	-2.16E+01	1	F
Grant Clarendon, Inc	Thermal Oil Heater	SC230	1538.475	-544.396	22.9	138	1.2	22.2	578	5.42E-03	1	C
Grant Clarendon, Inc	H1 Common Stack 1	SC231	1538.406	-544.425	38.1	138	3.0	20.4	385	1.13E+00	1	C
Grant Clarendon, Inc	H2 Common Stack 2	SC232	1538.384	-544.401	38.1	139	3.0	20.4	385	1.13E+00	1	C
Grant Clarendon, Inc	Press Fugitives	SC233	1538.493	-544.401	24.4	138	2.4	0.010	305	1.37E-02	1	C
Giant Cement	Kilns #2 & 3	SC234	1530.363	-608.253	49.7	85	3.0	18.0	411	-8.60E+01	1	F
Giant Cement	Kilns #4 & 5	SC235	1530.642	-608.447	53.3	84	3.0	18.0	400	-1.12E+02	1	F

Table C-4 South Carolina Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
Giant Cement	Main Baghouse/Bypass Vent	SC236	1530.638	-608.503	89.9	95	4.3	15.3	383	6.80E+01	1	C
Giant Cement	Marl Dryer Scrubber	SC237	1530.413	-608.375	15.2	88	1.1	21.1	344	-4.10E+00	1	F
Blue Circle Cement	Stack #1	SC238	1529.866	-610.608	30.5	84	3.0	21.3	378	1.34E+01	1	C
Blue Circle Cement	Stack #36	SC239	1529.893	-610.666	35.1	82	1.8	3.6	355	6.71E+00	1	C
Westvaco Lumber Mill	Kiln 3-Stack 3C	SC240	1557.513	-627.435	7.9	81	0.2	0.010	389	4.66E-02	1	C
Westvaco Lumber Mill	Kiln 4-Stack 5	SC241	1557.506	-627.447	9.1	81	15.7	0.010	389	7.60E-02	1	C
Robert Bosch Corporation	Boiler 5	SC242	1568.483	-639.388	10.1	26	0.6	5.2	425	3.23E-01	1	C
Robert Bosch Corporation	Boiler 6	SC243	1568.487	-639.390	10.1	26	0.6	5.2	425	3.23E-01	1	C
Showa Denko Carbon	furn. Incinerator (S7)	SC244	1542.544	-623.574	24.4	68	2.4	61.0	1061	3.84E+00	1	C
Showa Denko Carbon	Graphitizing (S22)	SC245	1542.489	-623.582	57.9	66	2.3	23.0	361	1.67E+01	1	C
Showa Denko Carbon	roof moniters (VS1-6)	SC246	1542.444	-623.599	23.2	66	1.0	0.001	0.001	5.59E+00	1	C
Summerville Medical Center	boiler 1	SC247	1562.474	-634.074	8.0	20	0.3	7.3	475	1.51E-01	1	C
Summerville Medical Center	boiler 2	SC248	1562.474	-634.074	8.0	20	0.3	7.3	475	1.51E-01	1	C
Lauscha Fiber International-Summerville	Flame Attenuation Stack 01	SC249	1555.430	-626.101	15.9	67	1.2	30.6	378	1.52E-03	1	C
Lauscha Fiber International-Summerville	Flame AttenuationStack 02	SC250	1555.422	-626.115	15.9	67	1.2	30.6	378	1.52E-03	1	C
Lauscha Fiber International-Summerville	Flame AttenuationStack 03	SC251	1555.416	-626.130	15.9	67	1.2	30.6	378	1.52E-03	1	C
Chamber Oakridge Landfill	flare	SC252	1539.064	-618.912	6.7	93	0.2	12.2	1033	1.89E-02	1	C
Dausey	boiler	SC253	1519.404	-617.051	5.5	109	0.4	0.010	505	1.71E-01	1	C
Raisio Staest US Inc	Hot Oil System	SC254	1554.883	-625.789	9.1	67	0.5	6.7	605	1.26E-03	1	C
Raisio Staest US Inc	Steam Boiler	SC255	1554.883	-625.789	9.1	67	0.6	12.2	561	3.78E-03	1	C
Cemplank Inc.	0021 (Boiler)	SC256	1554.697	-625.539	13.4	65	0.7	11.2	516	1.50E+00	1	C
DBW Inc (formerly Lauscha Fiber International)	Process Stack 01	SC257	1555.720	-626.007	12.2	68	0.6	20.0	343	5.04E-05	1	C
Trebol USA, Inc.	Spray Dryer	SC258	1606.638	-572.027	9.3	20	0.3	6.6	411	5.67E-04	1	C
International Paper - Pulp & Paper Mill	7&8 power boilers	SC259	1632.215	-575.701	61.0	18	4.4	18.3	516	-1.20E+02	1	F
International Paper - Pulp & Paper Mill	Black Liquor Oxidation Stage 2	SC260	1631.886	-575.455	30.5	18	1.4	13.5	343	1.15E+00	1	C
International Paper - Pulp & Paper Mill	common stack	SC261	1632.174	-575.647	61.0	18	4.4	18.3	516	-4.10E+02	1	F
International Paper - Pulp & Paper Mill	Container Division Sources	SC262	1631.886	-575.455	8.2	18	0.7	0.010	483	4.08E-03	1	C
International Paper - Pulp & Paper Mill	lime kiln	SC263	1632.085	-575.714	30.5	18	1.8	10.0	350	-5.25E+00	1	F
International Paper - Pulp & Paper Mill	lime kiln	SC264	1632.074	-575.706	30.5	18	1.8	10.0	350	-5.24E+00	1	F
International Paper - Pulp & Paper Mill	lime kiln 2	SC265	1632.132	-575.663	29.0	18	1.8	7.0	343	1.41E-01	1	C
International Paper - Pulp & Paper Mill	NCG incinerator	SC266	1632.132	-575.534	20.7	19	1.1	8.0	356	-1.15E+00	1	F
International Paper - Pulp & Paper Mill	power boiler	SC267	1632.241	-575.737	21.3	18	2.4	12.2	561	-6.14E+01	1	F
International Paper - Pulp & Paper Mill	power boiler 1&2	SC268	1632.245	-575.648	85.4	18	5.2	12.2	462	1.32E+02	1	C
International Paper - Pulp & Paper Mill	recovery boiler 1	SC269	1632.301	-575.644	71.6	18	2.4	17.3	436	2.90E+00	1	C
International Paper - Pulp & Paper Mill	recovery boiler 2	SC270	1632.236	-575.614	76.2	18	3.7	12.1	344	4.29E+01	1	C
Georgetown Steel, Inc.	5.000	SC271	1632.863	-574.658	31.4	19	10.2	4.5	332	-1.20E+00	1	F
Georgetown Steel, Inc.	8A	SC272	1632.863	-574.658	24.1	19	2.9	11.2	515	-1.85E+01	1	F
Georgetown Steel, Inc.	DRI Reduction Furnace	SC273	1632.863	-574.658	9.1	19	0.5	10.1	293	2.52E-03	1	C
Georgetown Steel, Inc.	Melt Shop Baghouse	SC274	1632.863	-574.658	24.4	19	232.8	0.010	356	4.49E+00	1	C
Georgetown Steel, Inc.	PS	SC275	1632.863	-574.658	28.3	19	3.6	13.7	417	3.53E-02	1	C
Santee Cooper - Winyah	Unit 1 Old Stack	SC276	1627.689	-580.274	123.2	20	5.5	18.3	422	-2.19E+02	1	F
Santee Cooper - Winyah	Unit 3	SC277	1627.574	-580.321	123.2	20	4.9	22.9	345	2.12E+02	1	C
Santee Cooper - Winyah	Unit 4	SC278	1627.517	-580.336	123.2	20	4.9	22.9	345	2.12E+02	1	C
International Paper - Sampit Lumber	Gasification Boiler	SC279	1617.423	-571.851	15.9	40	0.9	12.9	491	9.95E-02	1	C
Oneita Industries	Boilers	SC280	1606.276	-570.110	19.2	20	0.8	0.010	505	-1.54E+01	1	F
3V, Inc.	Boiler #1 (01S01)	SC281	1625.055	-577.443	19.5	19	0.8	10.0	514	7.80E-01	1	C
3V, Inc.	Boiler #2 (01S02)	SC282	1625.053	-577.432	19.5	19	0.8	16.7	514	1.31E+00	1	C

Table C-4 South Carolina Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
3V, Inc.	Oil Heater #1 (01S03)	SC283	1624.910	-577.388	15.9	19	0.8	4.9	477	4.67E-01	1	C
Georgetown Memorial Hospital	BOILER #1 & #2	SC284	1633.196	-573.560	13.7	19	0.5	10.5	461	7.07E+00	1	C
Georgetown Memorial Hospital	removed two boilers	SC285	1633.196	-573.555	9.1	19	0.5	4.0	461	-6.80E-01	1	F
Holnam - Georgetown Terminal	Diesel Engine	SC286	1633.254	-575.777	4.2	19	0.2	36.2	722	1.76E-02	1	C
Holnam - Georgetown Terminal	Diesel Engine #1	SC287	1633.273	-575.765	4.1	19	0.2	43.4	708	8.82E-03	1	C
Holnam - Georgetown Terminal	Diesel Engine #2	SC288	1633.265	-575.769	4.1	19	0.2	43.4	708	8.82E-03	1	C
Holnam - Georgetown Terminal	Diesel Engine #3	SC289	1633.268	-575.773	4.1	19	0.2	43.4	708	8.82E-03	1	C
Holnam - Georgetown Terminal	Diesel Engine #4	SC290	1633.274	-575.769	4.1	19	0.2	43.4	708	8.82E-03	1	C
International Paper - Container Facility	Steam Boiler	SC291	1632.297	-576.196	8.2	19	0.7	0.010	483	4.72E-02	1	C
Praxair, Inc	Product Vaporizers	SC292	1632.648	-575.217	10.0	19	0.2	0.010	478	1.26E-03	1	C
AGSC	EP18	SC293	1627.989	-579.785	20.0	20	2.1	21.1	347	1.30E-02	1	C
AGSC	EP5	SC294	1627.906	-579.906	45.3	20	1.7	20.1	361	6.15E-03	1	C
AGSC	EP8	SC295	1627.896	-579.920	45.3	20	1.3	22.4	436	3.41E-03	1	C
AGSC	EP9	SC296	1627.901	-579.913	45.3	20	1.3	22.4	436	3.41E-03	1	C
SCE&G-Jasper Co. Generating Facility	Turbines 1-3	SC297	1485.228	-716.635	57.9	21	5.5	22.1	410	4.03E+01	1	C
Coastal Debris	ACI	SC298	1573.237	-4655.334	3.0	10	4.0	1.3	922	7.56E-02	1	C
Wasteco	ACI	SC299	1504.543	-705.224	9.1	15	6.2	0.4	811	7.94E-02	1	D
Voridian	13L04-6 A-F, H-K, O, Q, R	SC300	1465.832	-549.703	4.9	160	0.2	0.001	303	-1.66E-01	1	F
Voridian	16M08 ID#6	SC301	1466.258	-550.039	22.8	145	0.9	5.6	672	-5.05E+00	1	F
Voridian	16M08 ID#7	SC302	1466.258	-550.039	22.8	145	0.9	3.5	478	-5.05E+00	1	F
Voridian	HEAT1011	SC303	1466.326	-550.050	36.6	141	1.2	7.5	478	7.46E+00	1	D
Foster-Dixiana Corp	Dryer	SC304	1458.431	-547.074	13.1	307	1.0	39.9	325	-8.46E-01	1	F
Michelin Tire Corp	124_44	SC305	1439.864	-546.556	36.6	445	0.4	14.3	411	9.50E+00	1	D
Diamond Pet Food	EP-10 Boiler	SC306	1459.026	-557.741	10.1	462	0.5	10.4	464	1.39E-03	1	D
Diamond Pet Food	EP-6 Dryer Exhaust	SC307	1459.026	-557.741	12.8	462	0.9	15.3	344	2.52E-03	1	D
Diamond Pet Food	EP-9 Boiler	SC308	1459.026	-557.741	10.1	462	0.5	2.0	450	1.39E-03	1	D
Lexington Medical Center	Boiler No. 5 (removed)	SC309	1454.288	-536.256	7.3	336	0.2	8.6	422	-2.80E-01	1	F
Lexington Medical Center	Boiler No. 6	SC310	1454.288	-536.256	11.6	336	0.4	8.3	476	3.54E-01	1	D
Lexington Medical Center	Boiler No. 7 or Boiler No. 8	SC311	1454.288	-536.256	11.6	336	0.4	10.1	463	5.91E-01	1	D
Lexington Medical Center	Boiler No. 9 or Boiler No. 10	SC312	1454.288	-536.256	11.6	336	0.5	11.5	440	7.04E-01	1	D
Corley & Sons Sawmill	gas-fired Boiler	SC313	1448.605	-536.397	7.6	245	0.5	0.010	394	-2.95E-01	1	F
SMI Steel SC	Baghouse #1 East Section	SC314	1460.727	-540.009	25.9	141	9.1	2.9	383	1.36E+00	1	D
SMI Steel SC	Baghouse #2 West Section	SC315	1460.707	-540.022	25.9	145	9.1	2.9	383	1.36E+00	1	D
SMI Steel SC	Melt Shop	SC316	1460.782	-539.935	14.8	144	1.0	0.001	0.001	2.75E-02	1	D
SMI Steel SC	Roll Mill Reheat Furnace	SC317	1460.950	-540.003	27.7	142	1.5	21.4	306	4.33E+00	1	D
J.B.Martin Co.	Tenter Process	SC318	1422.173	-551.434	7.9	608	0.6	0.010	450	6.80E-04	1	D
Union Underwear Co.	Boiler #1	SC319	1443.472	-543.221	9.8	386	0.6	2.3	422	-3.75E-01	1	F
Union Underwear Co.	Boiler #2	SC320	1443.472	-543.221	9.8	386	0.5	14.5	444	-1.27E+00	1	F
Inland Container Corp	Boiler #2 (backup boiler)	SC321	1443.335	-543.218	14.4	383	0.6	10.9	488	1.36E+00	1	D
Columbia Farms/OSI LP	Boilers #1&2	SC322	1458.516	-543.144	15.2	139	0.4	6.1	478	9.10E-01	1	D
Pallet Removal and Repair	Incinerator	SC323	1437.042	-560.889	6.1	338	2.6	1.5	1478	7.56E-03	1	D
PBR Automotive	Fugitive Emissions	SC324	1452.887	-542.102	11.0	301	1.4	14.5	294	2.19E-03	1	D
PBR Automotive	Tower Melt Furnace	SC325	1452.877	-542.058	16.2	302	0.8	9.5	623	1.62E-02	1	D
Lion Ribbon	Boiler #1	SC326	1417.473	-550.521	10.2	524	0.5	8.7	500	6.68E-01	1	D
United Parcel Service - Air Hub	Generator	SC327	1456.199	-544.148	4.2	191	0.2	346.3	768	4.41E-03	1	D
SEFA Group, Inc.	FAB Unit	SC328	1443.856	-532.200	15.2	230	109.4	0.001	422	2.63E+01	1	D
Albemarle Corp	701 HE-950-1	SC329	1486.107	-591.442	7.9	173	0.3	0.010	541	9.05E-02	1	D

Table C-4 South Carolina Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
Albemarle Corp	701 HE-950-2	SC330	1486.098	-591.444	8.2	174	0.5	0.010	505	8.92E-02	1	D
Albemarle Corp	DR-3 Diesel Engine 11	SC331	1486.003	-591.715	3.4	176	0.2	41.8	816	3.28E-02	1	D
Albemarle Corp	HCN Diesel Engine 12	SC332	1486.078	-591.794	3.7	167	0.2	54.3	777	1.58E-02	1	D
Albemarle Corp	HCN Flare	SC333	1486.170	-591.767	30.5	161	0.6	3.2	811	5.29E-04	1	D
Holnam, Inc.	(81) #1 Kiln ESP	SC334	1530.731	-604.254	45.7	73	3.4	9.2	426	-6.03E+01	1	F
Holnam, Inc.	(82) #2 Kiln ESP	SC335	1530.730	-604.174	48.8	75	3.7	15.2	452	-1.88E+02	1	F
Holnam, Inc.	(94) Preheater Kiln	SC336	1531.018	-604.545	109.5	51	6.1	15.8	391	1.08E+02	1	D
Holnam, Inc.	(95) Coal Mill Vent	SC337	1530.977	-604.522	42.0	52	1.3	23.6	358	7.80E+00	1	D
Stone Forest Products	Pine Bark Boiler	SC338	1483.788	-593.954	12.2	256	1.2	17.4	440	1.93E-01	1	D
Carolina Lumber	Temporary Boiler	SC339	1483.788	-593.954	5.8	256	0.6	11.9	436	1.66E+00	1	D
Stone Forest Products	Wood Waste Boiler	SC340	1483.813	-593.944	15.9	255	0.6	14.3	500	1.05E-01	1	D
Elloree Veneer Co.	Wood Waste Boiler	SC341	1512.375	-580.003	18.3	167	0.9	16.2	478	2.92E-02	1	D
Frigidaire Home Products	Boilers	SC342	1492.189	-585.916	12.2	198	0.6	0.010	478	1.76E-02	1	D
Frigidaire Home Products	Diesel Fire Pump	SC343	1492.189	-585.916	9.1	198	0.2	36.6	366	2.52E-02	1	D
Frigidaire Home Products	Dryoff, Bake & Burnoff Ovens	SC344	1492.189	-585.916	7.5	198	0.6	0.010	325	8.78E-04	1	D
Frigidaire Home Products	Engine Testing	SC345	1492.189	-585.916	7.6	198	1.0	0.010	294	8.82E-03	1	D
SCE&G-Cope	Unit 1 Boiler	SC346	1474.371	-605.128	160.0	174	7.0	14.9	339	1.26E+02	1	D
American Koyo	S17 Peacemaker Burnoff 1-3	SC347	1488.408	-584.809	10.1	276	0.4	0.010	394	5.04E-05	1	D
Carolina Pole, Inc	Kiln Boiler	SC348	1535.296	-592.871	15.5	104	0.6	15.9	478	6.58E+00	1	D
Hughes Aircraft	Boiler	SC349	1489.444	-591.342	14.0	190	1.5	9.1	293	1.26E-03	1	D
Orangeburg Dept. of Public Utilities	Generator 1&2	SC350	1481.499	-583.290	6.7	268	1.1	27.2	700	6.80E+00	1	D
North American Container	AC Incinerator	SC351	1491.914	-593.835	6.1	180	4.0	2.4	1366	1.45E-01	1	D
North American Container	Boiler	SC352	1491.914	-593.835	15.2	180	0.6	6.6	422	4.16E-03	1	D
Gulbrandsen Manufacturing	125 HP Boiler	SC353	1489.357	-596.207	12.5	177	0.5	0.7	512	3.34E-01	1	D
Gulbrandsen Manufacturing	250 HP Boiler	SC354	1489.357	-596.207	12.5	177	0.5	8.7	464	6.14E-01	1	D
Okonite Company	Boiler No. 1	SC355	1489.352	-592.449	11.9	189	14.9	0.010	497	8.82E-04	1	D
Okonite Company	Boiler No. 2	SC356	1489.350	-592.443	11.9	189	14.9	0.010	497	8.82E-04	1	D
Okonite Company	Hot Water Boiler 1	SC357	1489.350	-592.434	11.9	189	10.9	0.010	380	6.30E-04	1	D
City of Orangeburg	350 kW Generator	SC358	1488.783	-593.739	5.8	186	0.2	144.9	933	1.22E-01	1	D
City of Orangeburg	500 kW Generator	SC359	1488.783	-593.739	5.8	186	0.2	144.9	933	3.40E-02	1	D
City of Orangeburg	900 kW Generator	SC360	1488.783	-593.739	5.5	186	0.2	280.5	736	6.17E-02	1	D
City of Orangeburg	Hot Oil Burner Exhaust	SC361	1488.783	-593.739	10.2	186	0.6	4.6	616	1.01E-03	1	D
SC Pipeline Corporation	Boiler #1	SC362	1450.914	-585.602	10.4	367	0.9	0.010	400	3.53E-03	1	D
SC Pipeline Corporation	Boiler #2	SC363	1450.914	-585.602	10.4	367	0.9	0.010	400	3.53E-03	1	D
Doane Products Company	Boiler&Heater	SC364	1489.034	-592.344	11.0	188	0.5	4.3	478	1.30E-03	1	D
Doane Products Company	Dryers Combustion Exhaust	SC365	1489.024	-592.376	11.6	188	1.2	4.6	422	1.93E-03	1	D
Federal Mogul Corp	Air Handler	SC366	1489.127	-591.454	10.7	190	0.1	23.8	311	1.51E-03	1	D
Pennington Crossarm Co.	Boiler	SC367	1529.125	-598.101	9.1	105	0.4	0.010	508	5.37E-01	1	D
Trinity Industries, Inc.	Stack 1-Kettle Furnace	SC368	1489.981	-592.875	11.0	187	0.7	5.8	866	5.17E-04	1	D
City of Orangeburg Dept of Public Utilities	Generator 1	SC369	1486.503	-588.412	5.4	212	0.5	40.4	751	4.15E-02	1	D
Hanson Brick	P4SCRB - Plant 4 Scrubber	SC370	1457.680	-530.282	26.2	185	1.5	10.8	502	1.55E-01	1	D
Vulcan Construction Materials - Columbia Quarry	Plant Engine	SC371	1462.101	-537.757	1.5	38	0.1	11.0	803	1.02E-02	1	D
Owens Electric Steel Co.	Melt Shop	SC372	1460.737	-539.995	25.9	142	10.9	3.0	394	2.39E-01	1	D
Fort Jackson	CEP#3 Boilers #1,2&3	SC373	1470.071	-534.724	16.8	206	0.9	0.010	503	3.34E+00	1	D
Fort Jackson	CEP#3 Old Boilers #1,2,&3	SC374	1470.071	-534.724	16.8	206	0.9	0.010	503	-2.27E+01	1	F
Fort Jackson	Boiler & Diesel Engine	SC375	1470.237	-534.453	4.6	190	0.3	0.010	450	9.53E-03	1	D
Fort Jackson	B2100 - Boiler	SC376	1468.480	-534.246	13.4	176	0.4	0.010	366	7.56E-04	1	D

Table C-4 South Carolina Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
Fort Jackson	CEP#1 Boilers #1,2,&3	SC377	1468.971	-533.765	16.8	253	1.1	0.010	450	6.33E-01	1	D
Fort Jackson	CEP#1 Old Boilers #1,2&3	SC378	1468.971	-533.765	16.8	253	1.1	0.010	450	-3.41E+01	1	F
Fort Jackson	CEP#2 Boilers #1-#5	SC379	1469.603	-532.493	16.8	253	1.1	0.010	422	8.28E+00	1	D
Fort Jackson	CEP#2 Old Boilers #1-#5	SC380	1469.603	-532.493	16.8	253	1.1	0.010	450	-4.94E+01	1	F
Fort Jackson	CEP3CHL - CEP #3 Chiller	SC381	1470.071	-534.724	6.1	206	2.9	0.010	422	1.26E-04	1	D
Fort Jackson	H032E - Boiler	SC382	1471.158	-531.690	14.2	352	0.9	0.010	450	4.16E-03	1	D
Vulcan Construction Materials - Columbia Quarry	Screen1	SC383	1462.101	-537.757	12.2	183	1.0	0.001	0.001	1.26E-04	1	D
City of Columbia WWTP	Exchanger No. 3, No. 4, No. 5	SC384	1464.419	-542.003	7.6	134	7.3	0.010	422	5.67E-04	1	D
WJBD VA Hospital	Medical Waste Incinerator	SC385	1468.597	-536.960	11.3	255	0.5	12.2	1257	3.11E-01	1	D
Anchor Continental	B4-Latex Bldg Boiler	SC386	1467.419	-539.493	7.9	118	0.4	8.2	533	6.30E-04	1	D
Anchor Continental	LA1-Latex Saturator	SC387	1467.420	-539.473	8.5	118	0.7	0.010	447	6.30E-04	1	D
Anchor Continental	RA1-Thermal Oxidizer	SC388	1467.242	-539.287	4.6	123	1.0	11.6	533	1.51E-03	1	D
Cardinal Stabilizers	Boiler 1 800hp	SC389	1467.072	-539.214	9.1	138	0.6	12.7	554	2.13E+00	1	D
Cardinal Stabilizers	Boiler 2 300hp	SC390	1467.072	-539.214	7.6	138	0.5	6.3	436	6.35E-01	1	D
Cardinal Stabilizers	Boiler 3 400hp	SC391	1467.072	-539.214	7.6	138	0.5	6.3	436	-8.56E-01	1	F
Cardinal Stabilizers	Boiler 4 800hp	SC392	1467.072	-539.214	9.1	138	0.6	12.7	554	2.13E+00	1	D
Shakespeare Monofilament	Boilers	SC393	1465.796	-528.165	11.0	374	0.5	9.9	422	1.51E-03	1	D
Square D Company	Boiler#1&2	SC394	1476.411	-539.710	7.9	189	0.6	0.010	422	1.26E-03	1	D
Consolidated Systems Inc	SB01-Dryer #3, Spray Booth 1	SC395	1462.720	-538.830	16.8	169	0.6	12.9	311	2.52E-04	1	D
Consolidated Systems Inc	EP01A RTO Exhaust	SC396	1462.642	-538.832	27.7	175	1.4	12.6	559	1.64E-04	1	D
Consolidated Systems Inc	EP01B Heat Exchanger	SC397	1462.673	-538.698	10.1	183	1.2	9.1	422	7.56E-05	1	D
Consolidated Systems Inc	EP01C Heat Exchanger	SC398	1462.664	-538.709	10.4	183	1.2	7.1	354	8.82E-05	1	D
Palmetto Baptist Medical Center	Boiler #1	SC399	1461.564	-534.658	30.3	309	2.7	1.0	478	9.50E-01	1	D
Palmetto Baptist Medical Center	Boiler #3	SC400	1461.564	-534.658	30.3	309	2.7	1.0	478	9.50E-01	1	D
Palmetto Baptist Medical Center	Boiler #4	SC401	1461.564	-534.658	38.7	309	0.5	0.010	478	1.13E-03	1	D
Palmetto Baptist Medical Center	Old Boiler #1	SC402	1461.564	-534.658	42.7	309	1.1	3.7	519	-1.34E+00	1	F
Palmetto Baptist Medical Center	Old Boiler #3	SC403	1461.564	-534.658	42.7	309	1.1	3.7	519	-1.34E+00	1	F
International Paper - Eastover	No. 1 Lime Kiln	SC404	1499.744	-541.279	54.0	213	1.8	10.7	330	1.16E+00	1	D
International Paper - Eastover	No. 1 RecFurn/No. 1 Boiler	SC405	1499.610	-541.511	86.1	210	4.1	17.2	459	1.73E+02	1	D
International Paper - Eastover	No. 1 Smelt Dissolving Tank	SC406	1499.687	-541.574	75.9	212	1.4	6.5	349	4.41E-01	1	D
International Paper - Eastover	No. 2 Lime Kiln	SC407	1499.735	-541.220	54.0	211	1.8	21.3	518	1.65E+00	1	D
International Paper - Eastover	No. 2 RecFurn	SC408	1499.658	-541.485	141.2	213	4.3	15.5	461	1.41E+02	1	D
International Paper - Eastover	No. 2 Power Boiler	SC409	1499.562	-541.536	141.2	204	2.9	20.8	465	1.21E+02	1	D
International Paper - Eastover	No. 2 Smelt Dissolving Tank	SC410	1499.699	-541.537	75.9	212	1.8	8.4	351	9.83E-01	1	D
FN Manufacturing, Inc.	Stack#90&91	SC411	1477.220	-536.355	3.2	337	0.8	11.2	294	4.79E-03	1	D
Richland Memorial Hospital	Boiler 2-600HP	SC412	1461.245	-532.464	9.1	238	1.2	0.010	475	1.61E+00	1	D
Richland Memorial Hospital	Boiler 3-800HP	SC413	1461.245	-532.464	10.8	238	0.6	6.0	475	2.14E+00	1	D
Richland Memorial Hospital	Removed boiler-1250HP	SC414	1461.245	-532.464	11.0	238	1.2	2.4	483	-1.73E+01	1	F
Masterfoods USA	Boiler #1 (8.4 MM BTU/hr)	SC415	1469.968	-541.642	11.0	141	0.4	4.9	503	2.14E-01	1	D
Masterfoods USA	Boiler #2 (12.6 MM BTU/hr)	SC416	1469.968	-541.642	10.1	141	0.3	10.1	506	3.23E-01	1	D
Masterfoods USA	Dryers 1-3	SC417	1469.968	-541.642	10.7	141	0.6	0.010	312	1.76E-03	1	D
SC State Farmers Market	Air Curtain Incinerator	SC418	1461.773	-544.665	2.4	130	1.7	0.9	811	4.54E-02	1	D
SC Dept of Corrections	Boiler #1&2	SC419	1453.119	-531.018	6.1	231	0.7	10.8	505	-1.50E+01	1	F
SC Dept of Corrections	Boiler #1&2	SC420	1452.752	-528.928	7.6	258	0.5	0.010	450	8.14E-01	1	D
SC Dept of Corrections	Boiler #1	SC421	1463.692	-526.239	6.7	306	0.5	0.010	439	1.26E-04	1	D
Springs Industries - Olympia	Boiler #1&2	SC422	1461.205	-537.680	53.4	160	2.4	0.6	455	5.82E+00	1	D
American-Italian Pasta	Boiler #1	SC423	1471.317	-540.115	13.5	165	0.6	11.6	416	6.44E-01	1	D

Table C-4 South Carolina Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
American-Italian Pasta	Boiler #2	SC424	1471.317	-540.115	13.5	165	0.6	11.6	416	6.44E-01	1	D
Pepsi-Cola South, Inc.	Boiler #1&2	SC425	1462.905	-527.210	10.2	292	0.5	4.1	505	1.58E-03	1	D
USC Central Energy Facilities	(old) South Boiler #1	SC426	1462.693	-536.673	14.6	217	1.8	1.2	511	-1.94E+00	1	F
USC Central Energy Facilities	Biomass Gasifier	SC427	1462.516	-536.512	28.4	212	1.2	18.3	430	3.40E-01	1	D
USC Central Energy Facilities	Colonial Center	SC428	1461.372	-536.023	30.5	212	0.9	0.010	422	1.01E-03	1	D
USC Central Energy Facilities	Carolina Gardens, Bldg #1	SC429	1462.927	-536.466	11.0	288	0.4	0.009	422	1.76E-04	1	D
USC Central Energy Facilities	East Boiler #1	SC430	1462.604	-535.412	15.2	281	1.2	4.3	463	2.09E-01	1	D
USC Central Energy Facilities	East Boiler #2	SC431	1462.595	-535.417	15.2	279	1.2	4.3	463	2.05E-01	1	D
USC Central Energy Facilities	East Boiler #3	SC432	1462.586	-535.423	15.2	278	1.2	4.3	463	2.09E-01	1	D
USC Central Energy Facilities	Field House Heater	SC433	1462.797	-536.502	4.9	262	0.9	0.010	422	1.64E-04	1	D
USC Central Energy Facilities	MacMaster Boiler #1	SC434	1462.294	-534.992	15.9	313	0.6	0.009	294	1.26E-04	1	D
USC Central Energy Facilities	Old East Boiler #1	SC435	1462.585	-535.628	15.2	240	1.2	4.3	463	-2.71E+00	1	F
USC Central Energy Facilities	Old East Boiler #2	SC436	1462.585	-535.628	15.2	240	1.2	4.3	463	-2.71E+00	1	F
USC Central Energy Facilities	Old East Boiler #3	SC437	1462.585	-535.628	15.2	240	0.8	10.9	463	-3.48E+00	1	F
USC Central Energy Facilities	Old West Boiler #1	SC438	1462.159	-536.298	13.4	240	0.8	11.5	519	-3.48E+00	1	F
USC Central Energy Facilities	South Boiler #2	SC439	1462.684	-536.469	14.6	254	1.8	1.2	511	1.94E+00	1	D
USC Central Energy Facilities	West Boiler #1	SC440	1462.190	-536.107	13.4	272	0.8	11.5	519	2.09E-01	1	D
USC Central Energy Facilities	West Boiler #2	SC441	1462.182	-536.111	14.0	272	1.2	4.5	519	3.48E-01	1	D
IBP Carolina Cooled Meats	Boiler #1&2	SC442	1466.130	-539.788	14.0	131	0.5	7.4	466	6.77E-01	1	D
Specialty Minerals, Inc.	Carbonators 1-3	SC443	1499.692	-541.295	16.8	216	0.6	12.5	344	3.14E-01	1	D
Office of General Services Cola. Bldg.	boiler 1	SC444	1459.537	-534.979	12.5	196	0.7	9.1	422	1.07E+00	1	D
Office of General Services Cola. Bldg.	boiler 2	SC445	1459.537	-534.979	12.5	196	0.7	9.1	422	1.07E+00	1	D
Office of General Services energy fac.	New Boiler No. 1	SC446	1459.536	-534.977	13.7	196	0.6	16.9	472	2.14E+00	1	D
Office of General Services energy fac.	Old Boiler No. 1	SC447	1459.537	-534.979	13.9	196	0.9	0.010	436	-9.46E-01	1	F
Office of General Services energy fac.	Old Boiler No. 2	SC448	1459.537	-534.979	13.9	196	0.9	0.010	436	-9.46E-01	1	F
FinnChem USA, Inc.	Boiler A & B	SC449	1501.688	-547.329	10.7	146	1.1	10.7	587	6.27E-01	1	D
Boozer Lumber Company	Air Curtain	SC450	1451.830	-537.343	6.1	319	4.0	1.3	922	6.55E-03	1	D
Office of General Services	Boiler #1	SC451	1466.378	-523.993	12.2	354	0.4	0.010	450	2.14E-01	1	D
Office of General Services	Boiler #2	SC452	1466.376	-523.999	12.2	354	0.4	0.010	450	2.14E-01	1	D
Providence Northeast	Boiler 1	SC453	1466.850	-523.001	7.6	326	0.4	0.010	492	2.87E-01	1	D
Sea Hunt Boats	DF-2	SC454	1466.739	-538.770	9.1	162	1.1	10.5	294	1.05E-03	1	D
Whitaker Container Service, Inc.	Air Curtain Incinerator	SC455	1460.455	-524.801	9.1	374	6.2	0.4	811	7.94E-02	1	D
ALSCO	Boiler	SC456	1461.335	-536.779	12.2	171	0.5	18.3	505	8.05E-01	1	D
Santee Print Works	Stack 106 Finish A	SC457	1528.434	-532.378	13.7	139	0.6	4.6	450	1.21E-03	1	D
Santee Print Works	Stack 108 Finish B	SC458	1528.434	-532.378	11.2	139	9.4	0.009	450	1.61E-03	1	D
Santee Print Works	Stack 130 Bleach Range	SC459	1528.434	-532.378	7.1	139	13.3	0.010	450	1.76E-03	1	D
Santee Print Works	Stack 44 Boiler 4	SC460	1528.434	-532.378	27.4	139	1.5	9.1	505	4.37E+01	1	D
Santee Print Works	Stack 53 SCR PRT	SC461	1528.434	-532.378	10.6	139	19.5	0.010	450	2.52E-03	1	D
Santee Print Works	Stack 69 Space Heater	SC462	1528.434	-532.378	11.0	139	8.5	0.009	450	6.30E-04	1	D
Santee Print Works	Stack 74 ASD	SC463	1528.434	-532.378	11.3	139	15.4	0.009	450	7.56E-04	1	D
Santee Print Works	Stack 79 Tint/Dye	SC464	1528.434	-532.378	10.8	139	13.2	0.010	450	8.82E-04	1	D
Shaw Air Force Base	Boiler 14007	SC465	1511.767	-530.087	10.7	270	0.3	0.010	561	5.42E-01	1	D
Shaw Air Force Base	Boiler 14008	SC466	1511.767	-530.087	10.7	270	0.5	0.010	533	4.36E-01	1	D
Shaw Air Force Base	Boiler 14013	SC467	1512.187	-529.098	7.6	269	0.4	0.010	422	2.17E-01	1	D
Shaw Air Force Base	Boiler 14014	SC468	1512.187	-529.098	7.6	269	0.3	0.010	422	1.63E-01	1	D
Shaw Air Force Base	Boiler 14015	SC469	1512.455	-529.114	7.6	254	0.4	0.010	450	2.45E-01	1	D
Shaw Air Force Base	Boiler 14017	SC470	1512.905	-528.499	9.1	253	0.4	0.010	450	2.17E-01	1	D

Table C-4 South Carolina Off-Site Sources Used in Class I Area Modeling

Company Name	Emission Source	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
Shaw Air Force Base	Boiler 14018	SC471	1512.905	-528.499	9.1	253	0.4	0.010	450	2.17E-01	1	D
Shaw Air Force Base	Boiler 14040	SC472	1511.578	-530.678	7.6	268	0.2	0.010	450	1.64E-01	1	D
Shaw Air Force Base	Boiler 14043	SC473	1512.825	-528.916	7.9	248	0.4	0.010	436	1.52E-01	1	D
Shaw Air Force Base	Boiler 14044	SC474	1511.438	-530.383	9.1	296	0.2	0.010	450	1.52E-01	1	D
Shaw Air Force Base	Jet Engine Testing	SC475	1513.306	-527.890	6.1	242	8.5	45.7	589	1.21E-01	1	D
Shaw Air Force Base	Jet Engine Testing	SC476	1513.306	-527.890	6.1	242	8.5	45.7	589	1.81E-01	1	D
Carolina Golden Products	Anaerobic Flare	SC477	1524.975	-540.634	6.1	169	0.5	54.6	978	1.34E+00	1	D
Yuasa	C22 - Boiler #1	SC478	1522.462	-540.973	9.8	184	0.7	4.0	439	-3.65E-02	1	F
Yuasa	C23 - Boiler #2	SC479	1522.460	-540.970	9.8	184	0.7	4.0	439	-3.65E-02	1	F
Yuasa	C24 - Boiler #3	SC480	1522.457	-540.966	9.8	184	0.7	4.0	439	-3.65E-02	1	F
CAROLINA FURNITURE WORKS, INC	200 HP BOILER	SC481	1526.810	-533.457	8.1	155	0.6	13.1	297	2.77E-02	1	D
Sumter Casket Co.	Wood Boiler	SC482	1526.408	-533.380	25.9	166	0.8	4.7	492	-2.90E-03	1	F
Phibro-Tech, Inc.	Backup boiler	SC483	1522.699	-540.622	6.9	179	0.4	10.9	536	2.52E-03	1	D
Phibro-Tech, Inc.	Main boiler	SC484	1522.699	-540.622	12.2	179	0.5	10.2	441	1.37E+00	1	D
Phibro-Tech, Inc.	Scrubber Exhaust (Stack17)	SC485	1522.699	-540.622	10.7	179	0.8	16.1	356	2.89E-03	1	D
Carolina Golden Products,Co.	500hp boiler	SC486	1520.416	-535.094	9.1	171	0.8	10.0	450	1.31E+00	1	D
Tuomey Regional Medical	Boiler 1	SC487	1525.720	-532.473	16.8	170	0.5	8.1	447	3.20E-01	1	D
Tuomey Regional Medical	Boiler 3	SC488	1525.720	-532.473	16.8	170	0.5	8.1	447	3.20E-01	1	D
Tuomey Regional Medical	Boiler 4	SC489	1525.720	-532.473	16.8	170	0.5	8.1	341	2.51E-01	1	D
Tuomey Regional Medical	Boiler 5	SC490	1525.720	-532.473	16.8	170	0.5	8.1	341	2.51E-01	1	D
Florence Concrete Products	6.7 MMBtu Boiler	SC491	1527.013	-534.397	7.4	163	0.5	3.3	450	4.28E-01	1	D
Florence Concrete Products	6.7 MMBtu Boiler	SC492	1527.013	-534.397	7.4	163	0.4	3.3	450	4.28E-02	1	D
MetoKote Corporation	Boiler No. 2	SC493	1524.265	-541.863	13.7	181	0.5	0.010	486	4.66E-04	1	D
Interlake Material Handling	HPL01	SC494	1523.210	-539.129	12.2	184	0.6	3.1	389	1.76E-02	1	D
Interlake Material Handling	VPL01	SC495	1523.250	-539.212	14.2	184	0.5	5.4	389	1.76E-02	1	D
Ace Textile America, Inc.	Stack 1,2,3	SC496	1527.716	-538.470	7.3	109	0.4	0.009	519	1.13E-02	1	D
Peace Textile America	Boiler 1	SC497	1528.475	-542.280	10.1	143	0.5	4.6	629	1.26E-03	1	D
Peace Textile America	Boiler 2	SC498	1528.475	-542.280	10.1	143	0.7	13.7	491	2.52E-03	1	D
City of Sumter	Stack 1	SC499	1529.683	-540.645	19.8	108	0.4	14.9	328	1.26E-03	1	D
C&C Recycling	Car Crusher	SC500	1519.566	-535.650	8.2	181	0.3	10.7	533	4.10E-02	1	D
Caterpillar Precision Pin Products	Boiler #1&2	SC501	1523.144	-527.278	13.7	179	0.4	12.7	561	9.58E-04	1	D
Caterpillar Precision Pin Products	Diesel Generator Set	SC502	1523.143	-527.274	13.7	179	0.2	21.8	672	1.29E-01	1	D
Biopure Corporation	Stack 1	SC503	1523.980	-529.127	12.2	169	0.6	0.009	469	1.21E-02	1	D
Biopure Corporation	Stack 2	SC504	1523.980	-529.127	12.2	169	0.6	0.009	469	1.21E-02	1	D
Souteastern Soil Recovery	Soil Treatment Unit	SC505	1555.463	-626.968	9.4	60	1.2	14.1	422	1.34E+00	1	D
Banks Construction Co.	Drum Mixer/Dryer	SC506	1553.738	-617.132	9.1	66	0.9	27.0	389	2.92E+00	1	D
Banks Construction Co.	Hot Oil Heater	SC507	1553.738	-617.132	4.3	66	0.3	3.3	589	1.32E-01	1	D

1. South Carolina Emission Data received via email from John Glass with the SC DHEC BAQ Modeling Section.

Table C-5 Florida Off-Site Sources Used in Class I Area PSD Modeling

Company Name	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
TALHOPK2	FL001	1210.076	-975.270	76.2	40	4.3	21.0	400	4.11E+02	1	E
GRUDH2	FL002	1414.411	-1023.116	106.7	54	5.6	15.2	408	3.67E+02	1	E
SRC1	FL003	1487.400	-1013.795	205.7	25	11.0	8.0	327	3.46E+02	2	E
CSEMELEC	FL004	1487.400	-1013.795	205.7	25	11.0	8.0	327	3.46E+02	2	E
CRIVER2	FL005	1482.017	-935.321	195.1	3	6.8	27.4	342	3.01E+02	2	E
CRIVER1	FL006	1481.998	-935.324	195.1	4	6.8	27.4	342	3.01E+02	2	E
CPB5	FL007	1483.664	-1020.407	70.7	5	2.7	18.5	503	1.97E+02	1	E
CBMILL1	FL008	1486.175	-906.382	78.4	2	3.4	15.2	454	1.91E+02	1	E
CFPLPUTM	FL009	1493.894	-1024.556	22.3	6	3.2	58.6	437	1.76E+02	1	E
CBMILL4	FL010	1486.175	-906.382	103.7	2	4.5	12.8	441	1.55E+02	1	E
BB3	FL011	1098.029	-1025.295	64.9	4	2.4	26.2	338	1.50E+02	1	E
CCB4	FL012	1483.664	-1020.407	72.2	5	2.4	21.9	500	1.45E+02	1	E
PCSSACEF	FL013	1364.208	-953.787	61.0	40	2.9	9.3	356	1.05E+02	1	E
BB4	FL014	1098.029	-1025.295	64.9	4	2.4	28.2	332	9.84E+01	1	E
PCSSACCD	FL015	1364.208	-953.787	45.7	40	1.6	28.7	356	9.66E+01	1	E
CPAPER2	FL016	1477.027	-900.731	45.7	4	3.1	7.8	326	8.88E+01	1	E
CPAPER1	FL017	1477.027	-900.731	83.8	4	4.3	2.8	450	8.74E+01	1	E
FCPPB9	FL018	1132.109	-1058.101	51.8	0	4.3	10.3	343	7.62E+01	1	E
CTRS	FL019	1483.664	-1020.407	76.2	5	0.9	32.0	533	7.56E+01	1	E
CJEAN2	FL020	1481.871	-936.975	151.0	3	4.6	19.2	331	6.97E+01	1	E
CJEAN1	FL021	1481.871	-936.975	151.0	3	4.6	19.2	331	6.97E+01	1	E
CRAY3	FL022	1485.044	-908.629	54.9	2	3.0	9.8	329	5.55E+01	1	E
CRAY1	FL023	1485.044	-908.629	54.9	2	3.0	9.8	336	5.32E+01	1	E
CRAY2	FL024	1485.044	-908.629	54.9	2	3.0	9.8	336	5.06E+01	1	E
CPB4	FL025	1483.664	-1020.407	61.0	5	1.2	21.8	475	4.52E+01	1	E
CBMILL3	FL026	1486.175	-906.382	88.1	2	3.9	18.9	484	4.51E+01	1	E
PCSAUXCD	FL027	1364.208	-953.787	31.7	40	2.0	15.2	468	4.19E+01	1	E
CBMILL2	FL028	1486.175	-906.382	80.8	2	3.5	18.6	493	4.05E+01	1	E
CMILL1	FL029	1476.191	-943.890	53.4	3	3.2	22.9	410	3.68E+01	1	E
CCBAY3	FL030	1476.787	-937.392	122.9	0	4.1	36.6	327	3.22E+01	1	E
CCBAY2	FL031	1476.787	-937.392	122.9	0	4.1	36.6	327	3.22E+01	1	E
CCBAY1	FL032	1476.787	-937.392	122.9	0	4.1	36.6	327	3.22E+01	1	E
UFCOGEN	FL033	1420.379	-1035.729	28.4	29	3.0	24.6	398	2.60E+01	1	E
CMILL2	FL034	1476.191	-943.890	61.0	3	3.0	10.7	335	2.57E+01	1	E
PCSAUXB	FL035	1364.208	-953.787	10.7	40	1.5	9.5	468	2.20E+01	1	E
PCSAUXE	FL036	1364.208	-953.787	15.3	40	1.6	15.9	428	2.15E+01	1	E
RB2	FL037	1098.029	-1025.295	71.0	4	2.0	27.5	428	1.64E+01	1	E
RB1	FL038	1098.029	-1025.295	71.0	4	2.0	26.5	421	1.64E+01	1	E
CPAPER4	FL039	1477.027	-900.731	76.2	4	2.6	12.2	411	1.58E+01	1	E
CPAPER3	FL040	1477.027	-900.731	54.9	4	2.1	16.8	425	1.52E+01	1	E
CRB4	FL041	1483.664	-1020.407	70.1	5	3.7	19.4	478	1.39E+01	1	E
S3	FL042	1446.190	-954.061	57.9	25	5.5	21.3	403	1.38E+01	1	E
S2FO	FL043	1446.251	-954.051	57.9	25	5.5	21.3	403	1.38E+01	1	E
BCEB12	FL044	1107.617	-1010.087	38.1	15	1.4	17.5	478	9.02E+00	1	E

Table C-5 Florida Off-Site Sources Used in Class I Area PSD Modeling

Company Name	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
BAYENERGY	FL045	1107.624	-1010.149	38.1	15	1.4	17.5	478	9.00E+00	1	E
TALPURD8	FL046	1234.020	-1004.764	60.9	0	5.0	15.4	353	7.82E+00	1	E
GRUDHCC	FL047	1414.213	-1023.151	15.9	53	4.3	51.2	867	6.68E+00	1	E
GRULKCC1	FL048	1422.806	-1034.372	31.1	43	4.7	19.0	390	6.50E+00	1	E
FRKILN2	FL049	1396.492	-1033.319	95.9	24	2.9	16.0	453	4.41E+00	1	E
SUWKILN2	FL050	1366.434	-1007.683	96.0	17	2.9	24.3	375	4.31E+00	1	E
CMCHEM	FL051	1472.864	-943.002	13.7	5	1.2	5.5	450	4.01E+00	1	E
FRKILN	FL052	1396.492	-1033.319	76.2	24	2.9	14.6	453	3.63E+00	1	E
SUWKILN	FL053	1366.515	-1007.566	96.0	17	2.9	14.1	369	3.58E+00	1	E
CBMILL5	FL054	1486.175	-906.382	22.9	2	1.7	16.8	436	3.37E+00	1	E
CPAPER5	FL055	1477.027	-900.731	30.5	4	1.5	11.6	350	2.13E+00	1	E
CPB6	FL056	1483.664	-1020.407	18.3	5	1.8	17.4	622	1.40E+00	1	E
CLK4	FL057	1483.664	-1020.407	39.9	5	1.4	18.5	339	1.37E+00	1	E
CMILL3	FL058	1476.191	-943.890	64.0	3	1.4	11.0	346	1.31E+00	1	E
LK4	FL059	1300.361	-1005.660	38.1	17	2.2	15.2	511	1.12E+00	1	E
CBUSCH2	FL060	1475.550	-936.330	6.1	6	0.6	126.1	811	1.07E+00	1	E
CBUSCH1	FL061	1475.550	-936.330	6.1	6	0.6	126.1	811	1.07E+00	1	E
CSDT4	FL062	1483.664	-1020.407	62.8	5	1.5	6.5	344	1.00E+00	1	E
GPHOS1	FL063	1174.559	-981.609	39.6	58	2.6	15.3	399	8.50E-01	1	E
CS3	FL064	1478.138	-937.307	61.0	4	2.4	5.2	439	7.20E-01	1	E
CS2	FL065	1478.138	-937.307	61.0	4	2.4	5.2	439	7.20E-01	1	E
CS1	FL066	1478.138	-937.307	61.0	4	2.4	5.2	439	7.20E-01	1	E
PCSDAPZ	FL067	1364.208	-953.787	42.7	40	2.4	13.1	325	6.90E-01	1	E
LK1	FL068	1098.029	-1025.295	18.6	4	2.4	11.8	348	5.90E-01	1	E
RB4	FL069	1300.039	-1005.828	68.6	16	2.9	25.8	500	2.30E-01	1	E
SDT2	FL070	1098.029	-1025.295	71.0	4	1.8	4.6	347	1.30E-01	1	E
SDT1	FL071	1098.029	-1025.295	71.0	4	1.8	5.3	347	1.30E-01	1	E
COMBO	FL072	1300.126	-1005.781	68.6	17	4.0	19.0	367	1.20E-01	1	E
CJEAN3	FL073	1481.911	-936.794	22.9	3	1.0	15.2	347	3.50E-02	1	E
CCBAY5	FL074	1476.787	-937.392	19.2	0	1.3	28.4	301	3.00E-02	1	E
CCBAY4	FL075	1476.787	-937.392	19.2	0	1.3	28.4	301	3.00E-02	1	E
SDT4	FL076	1300.052	-1005.819	49.4	16	1.2	12.9	342	1.00E-02	1	E
GPHOS10	FL077	1174.559	-981.609	42.0	58	1.7	6.4	644	5.00E-03	1	E
SFP	FL078	1446.368	-954.025	7.3	25	0.2	60.0	616	4.20E-03	1	E
GPHOS2	FL079	1174.559	-981.609	30.5	58	2.2	18.5	341	1.00E-03	1	E
CSJRPP12	FL080	1481.967	-935.143	195.1	3	6.8	27.4	342	0.00E+00	2	E
ESDT1	FL081	1483.664	-1020.407	30.5	5	0.8	7.5	366	-1.30E-01	1	F
ESDT3	FL082	1483.664	-1020.407	33.2	5	0.8	3.6	369	-1.80E-01	1	F
ESDT2	FL083	1483.664	-1020.407	30.5	5	0.9	9.5	375	-1.80E-01	1	F
EBMILL7	FL084	1486.175	-906.382	69.5	2	1.8	5.2	350	-2.00E-01	1	F
ELK2	FL085	1483.664	-1020.407	15.9	5	1.7	10.7	341	-2.40E-01	1	F
ELK1	FL086	1483.664	-1020.407	15.2	5	1.3	5.2	401	-2.40E-01	1	F
ES23	FL087	1478.138	-937.307	36.6	4	1.1	4.0	344	-3.50E-01	1	F
ES9	FL088	1478.138	-937.307	36.6	4	1.1	4.0	344	-3.70E-01	1	F

Table C-5 Florida Off-Site Sources Used in Class I Area PSD Modeling

Company Name	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
ES25	FL089	1478.138	-937.307	37.8	4	1.2	4.3	344	-4.50E-01	1	F
ES24	FL090	1478.138	-937.307	37.8	4	1.2	4.3	344	-4.50E-01	1	F
ES11	FL091	1478.138	-937.307	37.8	4	1.2	4.3	344	-4.70E-01	1	F
ES10	FL092	1478.138	-937.307	37.8	4	1.2	4.3	344	-4.70E-01	1	F
ELK3	FL093	1483.664	-1020.407	15.9	5	1.7	8.5	342	-4.80E-01	1	F
ES26	FL094	1478.138	-937.307	21.0	4	1.8	3.1	343	-5.60E-01	1	F
ES28	FL095	1478.138	-937.307	22.9	4	1.1	8.2	336	-6.60E-01	1	F
ES27	FL096	1478.138	-937.307	22.9	4	1.4	6.5	336	-6.70E-01	1	F
EBMILL8	FL097	1486.175	-906.382	33.2	2	0.6	5.8	360	-6.90E-01	1	F
ESDT4	FL098	1483.664	-1020.407	62.8	5	1.5	8.3	346	-7.10E-01	1	F
ES14	FL099	1478.138	-937.307	22.9	4	1.1	8.2	336	-8.20E-01	1	F
ES13	FL100	1478.138	-937.307	22.9	4	1.4	6.5	336	-8.20E-01	1	F
ES12	FL101	1478.138	-937.307	21.0	4	1.8	3.1	343	-8.20E-01	1	F
EMILL2	FL102	1476.191	-943.890	15.8	3	1.5	6.7	347	-9.80E-01	1	F
EBMILL6	FL103	1486.175	-906.382	13.4	2	1.4	17.6	360	-1.30E+00	1	F
EBMILL5	FL104	1486.175	-906.382	13.4	2	1.1	12.3	361	-1.30E+00	1	F
ELK4	FL105	1483.664	-1020.407	45.4	5	1.3	16.5	351	-1.40E+00	1	F
ERB1	FL106	1483.664	-1020.407	76.2	5	3.7	8.8	360	-6.21E+00	1	F
EPAPER4	FL107	1477.027	-900.731	53.3	4	1.6	25.2	394	-7.60E+00	1	F
EPAPER3	FL108	1477.027	-900.731	47.2	4	2.3	13.1	426	-7.60E+00	1	F
ES15	FL109	1478.138	-937.307	41.5	4	2.5	13.0	332	-7.85E+00	1	F
EMCHEM	FL110	1472.864	-943.002	12.2	5	1.1	10.1	658	-8.49E+00	1	F
ERB3	FL111	1483.664	-1020.407	40.5	5	3.4	7.3	372	-8.58E+00	1	F
ERB2	FL112	1483.664	-1020.407	76.2	5	3.7	8.8	372	-8.88E+00	1	F
ES16	FL113	1478.138	-937.307	41.5	4	2.5	13.0	332	-9.35E+00	1	F
EBMILL4	FL114	1486.175	-906.382	40.8	2	2.7	13.3	390	-1.05E+01	1	F
ES20	FL115	1478.138	-937.307	38.4	4	2.6	16.0	341	-1.23E+01	1	F
ES6	FL116	1478.138	-937.307	38.4	4	2.6	16.0	341	-1.29E+01	1	F
ES21	FL117	1478.138	-937.307	38.4	4	2.7	15.6	345	-1.57E+01	1	F
EPAPER5	FL118	1477.027	-900.731	76.2	4	2.6	22.1	427	-1.58E+01	1	F
ES22	FL119	1478.138	-937.307	38.4	4	2.7	14.6	344	-1.59E+01	1	F
ES8	FL120	1478.138	-937.307	38.4	4	2.7	14.6	344	-1.65E+01	1	F
ES7	FL121	1478.138	-937.307	38.4	4	2.7	15.6	345	-1.65E+01	1	F
EMILL1	FL122	1476.191	-943.890	53.4	3	3.2	22.9	410	-1.68E+01	1	F
ERB4	FL123	1483.664	-1020.407	70.1	5	3.7	16.9	474	-3.50E+01	1	F
EBMILL3	FL124	1486.175	-906.382	75.9	2	3.5	18.8	493	-3.51E+01	1	F
EMILL3	FL125	1476.191	-943.890	76.2	3	3.8	8.0	455	-3.65E+01	1	F
PCSSADE	FL126	1364.208	-953.787	45.7	40	1.6	28.7	356	-3.78E+01	1	F
PCSSACE	FL127	1364.208	-953.787	45.7	40	1.6	28.7	356	-3.78E+01	1	F
ERAY	FL128	1485.044	-908.629	54.9	2	3.0	9.8	329	-3.98E+01	1	F
ES17	FL129	1478.138	-937.307	32.3	4	1.8	14.0	455	-4.07E+01	1	F
ES3	FL130	1478.138	-937.307	32.3	4	1.8	14.0	455	-4.21E+01	1	F
EPB4	FL131	1483.664	-1020.407	37.2	5	1.2	14.5	477	-4.52E+01	1	F
JEASS2	FL132	1474.931	-949.635	40.7	2	2.4	15.5	446	-5.27E+01	1	F

Table C-5 Florida Off-Site Sources Used in Class I Area PSD Modeling

Company Name	Modeled Source ID	LCC East (km)	LCC North (km)	Stack Height (m)	Base Elev. (m)	Stack Diam. (m)	Exit Vel. (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	SO_2 rate Citation	Bin Group
JEASS1	FL133	1474.935	-949.655	40.7	2	2.4	15.5	446	-5.27E+01	1	F
ES2	FL134	1478.138	-937.307	41.5	4	2.5	13.0	332	-5.78E+01	1	F
ES1	FL135	1478.138	-937.307	41.5	4	2.5	13.0	332	-5.78E+01	1	F
ES19	FL136	1478.138	-937.307	32.3	4	2.1	14.5	439	-5.94E+01	1	F
ES18	FL137	1478.138	-937.307	32.3	4	2.1	14.5	439	-5.96E+01	1	F
EPAPER2	FL138	1477.027	-900.731	36.6	4	1.8	20.0	700	-5.99E+01	1	F
ES5	FL139	1478.138	-937.307	32.3	4	2.1	14.5	439	-6.12E+01	1	F
ES4	FL140	1478.138	-937.307	32.3	4	2.1	14.5	439	-6.16E+01	1	F
KNDY9	FL141	1476.389	-944.029	45.7	2	3.2	12.2	416	-7.50E+01	1	F
EKEN	FL142	1476.307	-943.972	45.7	2	3.2	10.4	394	-7.51E+01	1	F
JEASS3	FL143	1474.935	-949.611	40.7	2	3.1	13.4	424	-7.98E+01	1	F
KNDY10B	FL144	1476.409	-944.056	41.5	2	2.7	24.3	427	-9.25E+01	1	F
KNDY10A	FL145	1476.411	-944.066	41.5	2	2.7	24.3	427	-9.25E+01	1	F
JEASS5B	FL146	1474.955	-949.701	44.2	2	3.0	21.3	415	-1.04E+02	1	F
JEASS5A	FL147	1474.954	-949.693	44.2	2	3.0	21.3	415	-1.04E+02	1	F
GRUJK8	FL148	1422.806	-1034.372	61.0	43	3.2	11.9	406	-1.08E+02	1	F
JEASS4	FL149	1474.922	-949.583	43.7	2	3.3	18.5	408	-1.10E+02	1	F
ECB4	FL150	1483.664	-1020.407	72.9	5	3.1	10.5	477	-1.21E+02	1	F
EBMILL1	FL151	1486.175	-906.382	69.2	2	2.4	16.9	483	-1.45E+02	1	F
PCSSAB	FL152	1364.208	-953.787	61.0	40	1.8	15.5	350	-1.52E+02	1	F
PCSSAA	FL153	1364.208	-953.787	61.0	40	1.8	15.5	350	-1.52E+02	1	F
EPB5	FL154	1483.664	-1020.407	72.9	5	2.7	16.0	520	-1.61E+02	1	F
EBMILL2	FL155	1486.175	-906.382	69.2	2	3.4	16.3	480	-1.70E+02	1	F
EFPLPALA	FL156	1493.399	-1024.644	45.7	0	4.0	9.5	408	-2.57E+02	1	F
EPAPER1	FL157	1477.027	-900.731	83.8	4	4.3	7.3	450	-2.81E+02	1	F
EJEAN2	FL158	1482.082	-936.784	88.4	3	5.0	13.1	394	-5.85E+02	1	F
EJEAN1	FL159	1482.140	-936.764	76.2	3	4.9	23.1	403	-6.91E+02	1	F

1. Text file (NEPSDINVSO2.txt) received from Cleve Holiday
2. National Emission Inventory Database

Table C-6: Ambient Air Concentration Development

Pollutant	Air Unit Risk (m^3/mg)	Weight of Evidence	Cancer Risk	RBAC (mg/m^3)	RfDi (mg/kg-d)	Rfc (mg/m3)	PEL (mg/m^3)	PEL Adj (mg/m^3)	PEL-C (mg/m^3)	PEL-C Adj (mg/m^3)	TLV-TWA (mg/m^3)	TLV-TWA Adj (mg/m^3)	TLC-STEL (mg/m^3)	TLC-STEL adj (mg/m^3)	TLV-C (mg/m^3)	TLV-Adj (mg/m^3)	REL-TWA (mg/m^3)	REL-TWA Adj (mg/m^3)	REL-STEL (mg/m^3)	REL-STEL Adj (mg/m^3)	REL-C (mg/m^3)	REL-C Adj (mg/m^3)	LD 50[1] (mg/kg)	AAC - Annual (mg/m3)	AAC - Annual (mg/m^3)	AAC - 24-hr (mg/m^3)	Short Term Limit (mg/m^3)
Organics																											
Acenaphthene			-	-		-		-		-		-		-		-		-		-		-	600	-	-	4.1E-02	-
Acenaphthylene		D	-	-		-		-		-		-		-		-		-		-		-	1760	-	-	1.2E-01	-
Acetaldehyde	0.0022	B	1.00E-05	4.55E-03		9.00E-03		-		-		-		-	45.04	4.50		-		-		-		4.5E-03	4.5E-03	-	4.50
Acetophenone		D	-	-		-		-		-	49.14	0.12		-		-		-		-		-		-	-	1.2E-01	-
Acrolein			-	-		2.00E-05		-		-		-		-	0.2293	0.02		-		-		-		2.0E-05	2.0E-05	-	0.02
Ammonia			-	-		1.00E-01		-		-		-	24.38	2.44		-		-	24.38	2.44		-		1.0E-01	1.0E-01	-	2.44
Anthracene		D	-	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	4.8E-04	-
Benzene	0.0078	A	1.00E-06	1.28E-04		-		-	15	1.50		-		-		-		-		-		-		1.3E-04	1.3E-04	-	1.50
Benzo(a)anthracene		B	1.00E-05	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	4.8E-04	-
Benzo(a)pyrene		B	1.00E-05	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	4.8E-04	-
Benzo(a)fluranthene		B	1.00E-05	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	4.8E-04	-
Benzo(b)fluoranthene		B	1.00E-05	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	4.8E-04	-
Benzo(e)pyrene			-	-		-		-		-		-		-		-		-		-		-	9	-	-	6.2E-04	-
Benzo(g,h,i)perylene[2]		D	-	-		-		-		-		-		-		-		-		-		-	9	-	-	6.2E-04	-
Benzo(g,h,i)pyrene[2]			-	-		-		-		-		-		-		-		-		-		-	9	-	-	6.2E-04	-
Benzo(b,k)fluoranthene		B	1.00E-05	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	4.8E-04	-
Benzo(k)fluoranthene		B	1.00E-05	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	4.8E-04	-
Benzyl chloride		B	1.00E-05	-		-	5	0.01		-		-		-		-		-		-	5	0.50		-	-	1.2E-02	0.50
Biphenyl			-	-		-	1	2.38E-03		-		-		-		-		-		-		-		-	-	2.4E-03	-
bis(2-Ethylhexyl)phthalate			-	-		-	5	0.01		-		-		-		-		-	10	1.00		-		-	-	1.2E-02	1.00
Bromoform	1.10E-03	B	1.00E-05	9.09E-03		-		-		-		-		-		-		-		-		-		9.1E-03	9.1E-03	-	-
2-Butanone (MEK)			-	-		5.00		-		-		-	884.66	88.47		-		-		-		-		5.0E+00	5.0E+00	-	88.47
Carbon tetrachloride	0.015	B	1.00E-05	6.67E-04		-		-	157.25	15.73		-		-		-		-		-		-		6.7E-04	6.7E-04	-	15.73
Carbon disulfide			-	-		0.70		-	93.3	9.33		-		-		-		-		-		-		7.0E-01	7.0E-01	-	9.33
Chlorobenzene		D	-	-		-	350	0.83		-		-		-		-		-		-		-		-	-	8.3E-01	-
Chloroform	0.023	B	1.00E-05	4.35E-04		-		-	240	24.00		-		-		-		-		-		-		4.3E-04	4.3E-04	-	24.00
Chloromethane		D	-	-		0.09			414	41.40		-		-		-		-		-		-		9.0E-02	9.0E-02	-	41.40
2-Chloronaphthalene[3]		C	1.00E-04	-	0.00086	3.01E-03		-		-		-	78.64	7.86		-		-		-		-		3.0E-03	3.0E-03	-	7.86
2-Chloroacetophenone			-	-		3.00E-05		-		-		-		-		-		-		-		-		3.0E-05	3.0E-05	-	-
Chrysene		B	1.00E-05	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	4.8E-04	-
Cumene		D	-	-		4.00E-01		-		-		-		-		-		-		-		-		4.0E-01	4.0E-01	-	-
Cyanide		D	-	-		-	5	0.01		-		-		-		-		-		-		-		-	-	1.2E-02	-
Dibenzo(a,h)anthracene		B	1.00E-05	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	4.8E-04	-
Di-nbutylphthalate		D	-	-			5	0.01		-		-		-		-		-		-		-		-	-	1.2E-02	-
Dimethyl sulfate		B	1.00E-05	-		-	5	0.01		-		-		-		-		-		-		-		-	-	1.2E-02	-
7,12-Dimethylbenz(a)anthracene[3]		D	-	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	4.8E-04	-
2,4-Dinitrotoluene			-	-		-				-		-		-		-	1.5	3.57E-03		-		-		-	-	3.6E-03	-
Ethylbenzene		D	-	-		1.00		-		-		-	542.74	54.27		-		-		-		-		1.0E+00	1.0E+00	-	54.27
Ethyl Chloride			-	-		10.00		-		-		-		-		-		-		-		-		1.0E+01	1.0E+01	-	-
Ethylene dichloride	2.60E-02	B	1.00E-05	3.85E-04		-		-	404.8	40.48		-		-		-		-		-		-		3.8E-04	3.8E-04	-	40.48
Ethylene dibromide	6.00E-01	A	1.00E-06	1.67E-06		-		-	230.6	23.06		-		-		-		-		-		-		1.7E-06	1.7E-06	-	23.06
Fluoranthene		D	-	-		-		-		-		-		-		-		-		-		-	100	-	-	6.9E-03	-
Fluorene[3]		D	-	-		-	0.2	4.76E-04		-				-		-		-		-		-		-	-	4.8E-04	-
Formaldehyde	0.013	B	1.00E-05	7.69E-04		-		-	2.46	0.25		-		-		-		-		-		-		7.7E-04	7.7E-04	-	0.25
Hexane			-	-		0.70		-		-		-		-		-		-		-		-		7.0E-01	7.0E-01	-	-
Hydrogen chloride			-	-		0.02		-	7	0.70		-		-		-		-		-		-		2.0E-02	2.0E-02	-	0.70
Indeno(1,2,3,c,d)pyrene		B	1.00E-05	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	4.8E-04	-
Isophorone		C	1.00E-04	-		-	140	0.33		-		-		-	28.26	2.83		-		-		-		-	-	3.3E-01	2.83
Methyl Bromide		D	-	-		0.005			80	8.00				-		-								5.0E-03	5.0E-03	-	8.00
Methyl Chloroform			-	-			1900	4.52					2460	246.00		-								-	-	4.5E+00	246.00
Methyl hydrazine			-	-		-		-	0.35	0.04	0.019	4.52E-05		-		-		-		-		-		-	-	4.5E-05	0.04
MIBK			-	-		3.00		-		-		-	307.24	30.72		-		-		-		-		3.0E+00	3.0E+00	-	30.72
MMA		E	-	-		0.70		-		-		-	409.53	40.95		-		-		-		-		7.0E-01	7.0E-01	-	40.95
2-Methylnaphthalene			-	-		-		-		-	2.91	0.01		-		-		-		-		-		-	-	6.9E-03	-
3-Methylchloranthrene			-	-		-		-		-		-		-		-		-		-		-	100	-	-	6.9E-03	-

Completed by: PBS 11/26/08
Checked by: SAK 11/26/08

Table C-6: Ambient Air Concentration Development

Pollutant	Air Unit Risk (m^3/mg)	Weight of Evidence	Cancer Risk	RBAC (mg/m^3)	RfDi (mg/kg-d)	Rfc (mg/m3)	PEL (mg/m^3)	PEL Adj (mg/m^3)	PEL-C (mg/m^3)	PEL-C Adj (mg/m^3)	TLV-TWA (mg/m^3)	TLV-TWA Adj (mg/m^3)	TLC-STEL (mg/m^3)	TLC-STEL adj (mg/m^3)	TLV-C (mg/m^3)	TLV-Adj (mg/m^3)	REL-TWA (mg/m^3)	REL-TWA Adj (mg/m^3)	REL-STEL (mg/m^3)	REL-STEL Adj (mg/m^3)	REL-C (mg/m^3)	REL-C Adj (mg/m^3)	LD 50[1] (mg/kg)	AAC - Annual (mg/m3)	AAC - Annual (mg/m^3)	AAC - 24-hr (mg/m^3)	Short Term Limit (mg/m^3)
MTBE			-	-		3.00		-		-		-		-		-		-		-		-		**3.0E+00**	**3.0E+00**	-	-
Methylene chloride	4.70E-04	B	1.00E-05	2.13E-02		-		-	434.2	43.42		-		-		-		-		-		-		**2.1E-02**	**2.1E-02**	-	**43.42**
Naphthalene		C	1.00E-04	-		3.00E-03		-		-		-	78.64	7.86		-		-		-		-		**3.0E-03**	**3.0E-03**	-	**7.86**
5-Methyl chrysene[4]		B	1.00E-05	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	**4.8E-04**	-
OCDD			-	-										-		-							1000	-	-	**6.9E-02**	-
Phenanthrene		D	-	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	**4.8E-04**	-
Phenol		D	-	-		-	19	0.05		-		-		-		-		-			60	6.00		-	-	**4.5E-02**	**6.00**
Propionaldehyde			-	-		-		-		-	47.53	0.11		-		-		-		-		-		-	-	**1.1E-01**	-
Pyrene		D	-	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	**4.8E-04**	-
Styrene			-	-		1.00		-	852	85.20		-		-		-		-		-		-		**1.0E+00**	**1.0E+00**	-	**85.20**
Sulfuric Acid (H_2SO_4)			-	-		-	1	2.38E-03		-		-		-		-		-		-		-		-	-	**2.4E-03**	-
Tetrachloroethylene			-	-		-	678	1.61	1356	135.60		-		-		-		-		-		-		-	-	**1.6E+00**	**135.60**
Toluene			-	-		5.00		-	1130	113.00		-		-		-		-		-		-		**5.0E+00**	**5.0E+00**	-	**113.00**
1,1,1-Trichloroethane			-	-		-	1900	4.52		-		-	2460	246.00		-		-		-				-	-	**4.5E+00**	**246.00**
1,1,2-Trichloroethane	0.016	C	1.00E-04	6.25E-03		-		-		-		-		-		-		-		-		-		**6.3E-03**	**6.3E-03**	-	-
1,2,4-Trichlorobenzene		D	-	-		-		-		-		-		-	37	3.70		-		-		-		-	-	-	**3.70**
Trichloroethylene			-	-		-	537	1.28	1075	107.50		-		-		-		-		-		-		-	-	**1.3E+00**	**107.50**
Vinyl acetate			-	-		0.20		-		-		-	52.82	5.28		-		-		-		-		**2.0E-01**	**2.0E-01**	-	**5.28**
Xylene			-	-		0.10		-		-		-	651	65.10		-		-		-		-		**1.0E-01**	**1.0E-01**	-	**65.10**
m-Xylene			-	-		0.10		-		-		-	651	65.10		-		-		-		-		**1.0E-01**	**1.0E-01**	-	**65.10**
o-Xylene			-	-		0.10		-		-		-	651	65.10		-		-		-		-		**1.0E-01**	**1.0E-01**	-	**65.10**
p-Xylene			-	-		0.10		-		-		-	651	65.10		-		-		-		-		**1.0E-01**	**1.0E-01**	-	**65.10**
P-cresol		C	1.00E-04	-		-	22	0.05		-		-		-		-		-		-		-		-	-	**5.2E-02**	-
Pentachlorophenol		B	1.00E-05	-		-	0.5	1.19E-03		-		-		-		-		-		-		-		-	-	**1.2E-03**	-
Hexachlorobenzene	4.60E-01	B	1.00E-05	2.17E-05		-		-		-		-		-		-		-		-		-		**2.2E-05**	**2.2E-05**	-	-
Methyl iodide			-	-		-	28	0.07		-		-		-		-		-		-		-		-	-	**6.7E-02**	-
1,3-Butadiene	0.03	A	1.00E-06	3.33E-05		-		-	11	1.10		-		-		-		-		-		-		**3.3E-05**	**3.3E-05**	-	**1.10**
1,3-Dichloropropene	4.00E-03	B	1.00E-05	2.50E-03		-		-		-		-		-		-		-		-		-		**2.5E-03**	**2.5E-03**	-	-
1,4-Dichlorobenzene			-	-		8.00E-01		-		-		-		-		-		-		-		-		**8.0E-01**	**8.0E-01**	-	-
2,4,6-Trichlorophenol	3.10E-03	B	1.00E-05	3.23E-03		-		-		-		-		-		-		-		-		-		**3.2E-03**	**3.2E-03**	-	-
2,4-Dinitrophenol			-	-		-		-		-		-		-		-		-		-		-	13	-	-	**9.0E-04**	-
4-Nitrophenol			-	-		-		-		-		-		-		-		-		-		-	75	-	-	**5.2E-03**	-
Allyl Chloride		C	1.00E-04	-		1.00E-03		-		-		-	6	0.60		-		-		-		-		**1.0E-03**	**1.0E-03**	-	**0.60**
Arsenic Trioxide			-	-		-		-		-	0.01	2.38E-05		-		-		-		-		-		-	-	**2.4E-05**	-
Cadmium Oxide			-	-		-		-		-		-		-		-		-		-		-	72	-	-	**5.0E-03**	-
Calcium Cyanamide			-	-		-		-		-	0.5	1.19E-03		-		-		-		-		-		-	-	**1.2E-03**	-
Chromic Acid (VI)			-	-		-		-	0.1	0.01	0.05	1.19E-04		-		-		-		-		-		-	-	**1.2E-04**	**0.01**
Chromic Oxide			-	-		-	0.5	1.19E-03		-		-		-		-		-		-		-		-	-	**1.2E-03**	-
Dibenzo[a,j]Acridine			-	-		-		-		-		-		-		-		-		-		-	500	-	-	**3.5E-02**	-
Dibenzofuran		D	-	-		-		-		-		-		-		-		-		-		-		-	-	-	-
Diethyl Sulfate			-	-		-		-		-		-		-		-		-		-		-	647	-	-	**4.5E-02**	-
Dimethyl Phthalate		D	-	-		-		-		-	5	1.19E-02		-		-		-		-		-		-	-	**1.2E-02**	-
Manganese Dioxide			-	-		-		-		-		-		-		-		-		-		-	3478	-	-	**2.4E-01**	-
Polychlorinated Biphenyls		B	1.00E-05	-		-		-		-		-		-		-		-		-		-	1000	-	-	**6.9E-02**	-
Polycyclic Organic Matter			-	-		-		-		-		-		-		-		-		-		-		-	-	-	-
Propylene Dichloride			-	-		4.00E-03		-		-		-	508	50.80		-		-		-		-		**4.0E-03**	**4.0E-03**	-	**50.80**
Sodium Cyanide			-	-		-	5	1.19E-02		-		-		-	5	0.50		-		-		-		-	-	**1.2E-02**	**0.50**
Toluene-2,4-Diamine			-	-		-		-		-		-		-		-		-		-		-	80	-	-	**5.5E-03**	-
Vinyl Chloride	8.80E-03	A	1.00E-06	1.14E-04		-		-	12.781	1.28		-		-		-		-		-		-		**1.1E-04**	**1.1E-04**	-	**1.28**
Dioxins (Toal)				-		-												-					0	-	-	**1.5E-06**	-
Metals																											
Antimony			-	-		-	0.5	1.19E-03		-		-		-		-		-		-		-		-	-	**1.2E-03**	-
Arsenic	4.3	A	1.00E-06	2.33E-07		-		-		-		-		-		-		-		-	0.002	2.00E-04		**2.3E-07**	**2.3E-07**	-	**2.00E-04**
Beryllium	2.4	B	1.00E-05	4.17E-06		-		-	0.005	5.00E-04		-		-		-		-		-		-		**4.2E-06**	**4.2E-06**	-	**5.00E-04**

Completed by: PBS 11/26/08
Checked by: SAK 11/26/08

Table C-6: Ambient Air Concentration Development

Pollutant	Air Unit Risk (m^3/mg)	Weight of Evidence	Cancer Risk	RBAC (mg/m^3)	RfDi (mg/kg-d)	Rfc (mg/m3)	PEL (mg/m^3)	PEL Adj (mg/m^3)	PEL-C (mg/m^3)	PEL-C Adj (mg/m^3)	TLV-TWA (mg/m^3)	TLV-TWA Adj (mg/m^3)	TLC-STEL (mg/m^3)	TLC-STEL adj (mg/m^3)	TLV-C (mg/m^3)	TLV-Adj (mg/m^3)	REL-TWA (mg/m^3)	REL-TWA Adj (mg/m^3)	REL-STEL (mg/m^3)	REL-STEL Adj (mg/m^3)	REL-C (mg/m^3)	REL-C Adj (mg/m^3)	LD 50[1] (mg/kg)	AAC - Annual (mg/m3)	AAC - Annual (mg/m^3)	AAC - 24-hr (mg/m^3)	Short Term Limit (mg/m^3)
Cadmium	1.8	B	1.00E-05	5.56E-06		-		-	0.3	0.03		-		-		-		-		-		-		**5.6E-06**	**5.6E-06**	-	**3.00E-02**
Chromium, total			-	-		-	1	2.38E-03		-		-		-		-		-		-		-		-	-	**2.4E-03**	-
Chromium, hexavalent	12	A	1.00E-06	8.33E-08		-		-	0.1	0.01		-		-		-		-		-		-		**8.3E-08**	**8.3E-08**	-	**1.00E-02**
Cobalt			-	-		-	0.1	2.38E-04		-		-		-		-		-		-		-		-	-	**2.4E-04**	-
Copper		D	-	-		-	0.1	2.38E-04		-		-		-		-		-		-		-		-	-	**2.4E-04**	-
Lead		B	1.00E-05	-		-	0.05	1.19E-04		-		-		-		-		-		-		-		-	-	**1.2E-04**	-
Mercury		D	-	-		0.00030		-	0.1	0.01		-		-		-		-		-	0.1	0.01		**3.0E-04**	**3.0E-04**	-	**1.00E-02**
Magnesium			-	-		-		-		-	10	0.02		-		-		-		-		-		-	-	**2.4E-02**	-
Manganese		D	-	-		0.00005		-	5	0.50		-		-		-		-		-		-		**5.0E-05**	**5.0E-05**	-	**5.00E-01**
Nickel			-	-		-	1	2.38E-03		-		-		-		-		-		-		-		-	-	**2.4E-03**	-
Phosphorus			-	-		-	0.1	2.38E-04		-		-		-		-		-		-		-		-	-	**2.4E-04**	-
Selenium		D	-	-		-	0.2	4.76E-04		-		-		-		-		-		-		-		-	-	**4.8E-04**	-
Zinc [5]			-	-		-		-		-	2	4.76E-03	10	1.00		-		-		-		-		-	-	**4.8E-03**	**1.00E+00**
Additional Evaluations																											
Carbon Monoxide			-	-			55	0.13		-	29	0.07		-		-	40	0.10	229	22.90		-		-	-	**1.3E-01**	**2.29E+01**
Hydrogen Fluoride, as F			-	-			2.5	0.01		-					1.64	0.16	2.5	0.01	5	0.50		-		-	-	**5.95E-03**	**1.64E-01**

Completed by: PBS 11/26/08
Checked by: SAK 11/26/08

EXHIBIT D

AIR QUALITY MODELS

(INCLUDED ON CD)

EXHIBIT E

CASE-BY-CASE MACT ANALYSIS SUPPORTING DOCUMENTATION

Exhibit E – Reference Information

Item #	Documentation	Reference
1	Hunter Unit 4 – Pacific Corporation Case-By-Case MACT Analysis	See Attached CD
2	Midamerican Energy Company – Walter Scott Jr. Energy Center CBEC4 Boiler Case-By-Case MACT Analysis	See Attached CD
3	Roundup Power Project Case-By-Case MACT Analysis	See Attached CD
4	Santee Cooper Cross Generating Station Case-By-Case MACT Analysis	See Attached CD
5	Thoroughbred Generating Station Case-By-Case MACT Analysis	See Attached CD
6	Santee Cooper Pee Dee Generating Station Case-By-Case MACT Analysis	See Attached CD
7	Consumer's Energy Karn/Weadock Generating Station Case-By-Case MACT Analysis	See Attached CD
8	John W Turk Jr Case-By-Case MACT Analysis	See Attached CD
9	Cliffside Station Unit 6 Case-By-Case MACT Analysis	See Attached CD
10	USEPA AP-42 Section 1.1 and 1.3	www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf www.epa.gov/ttn/chief/ap42/ch01/final/c01s03.pdf See Attached CD
11	United States Court of Appeals For the District of Columbia Circuit CAMR Decision (2/8/08)	http://pacer.cadc.uscourts.gov/docs/common/opinions/200802/05-1097a.pdf See Attached CD
12	Code of Federal Regulations – 40 CFR Part 63 Subpart B	http://edocket.access.gpo.gov/cfr_2007/julqtr/pdf/40cfr63.43.pdf See Attached CD
13	Fabric Filter Technology Fact Sheet – USEPA	http://www.epa.gov/ttn/catc/dir1/ff-pulse.pdf See Attached CD
14	Wet Electrostatic Precipitator (WESP) Fact Sheet – USEPA	http://www.epa.gov/ttn/catc/dir1/fwespwpl.pdf See Attached CD
15	Flue Gas Desulfurization (FGD) Fact Sheet – USEPA	http://www.epa.gov/ttn/catc/dir1/ffdg.pdf See Attached CD
16	Dry Electrostatic Precipitator (ESP) Fact Sheet -- USEPA	http://www.epa.gov/ttn/catc/dir1/fdespwpl.pdf See Attached CD
17	Spray Chamber/Spray Tower Fact Sheet -- USEPA	http://www.epa.gov/ttn/catc/dir1/fsprytwr.pdf See Attached CD
18	Study of Hazardous Air Pollutant Emissions From Electric Utility Steam Generating Units – Final Report To Congress – USEPA (February 1998)	http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html See Attached CD
19	Guidelines For MACT Determinations Under Section 112(j) Requirements – USEPA (February 2002)	http://www.epa.gov/ttn/atw/112j/guidance.pdf See Attached CD
20	Mercury Study Report To Congress – USEPA (December 1997)	http://www.epa.gov/mercury/report.htm See Attached CD For Volume 1

Exhibit E – Reference Information Cont.

Item #	Documentation	Reference
21	Control of Mercury Emissions From Coal Fired Electric Utility Boilers: An Update – USEPA (February 2005)	http://www.epa.gov/ttn/atw/utility/ord_whtpaper_hgcontroltech_oar-2002-0056-6141.pdf See Attached CD
22	Control of Mercury Emissions From Coal Fired Electric Utility Boilers: Interim Report Including Errata Dated 3-21-02 – USEPA (April 2002)	http://www.epa.gov/nrmrl/pubs/600r01109/600r01109.htm See Attached CD
23	Effects of SCR Catalyst and Wet FGD Additive on the Speciation and Removal of Mercury within a Forced-Oxidized Limestone Scrubber – The Babcock & Wilcox Company, Dominion Generation, Cormtech, Inc. (2005)	See Attached CD
24	Reducing Acid Mist Emissions from Coal-fired Power Plants – Sargent & Lundy, LLC (2005)	See Attached CD
25	Evaluation of Sorbent Injection for Mercury Control – ADA-ES, Inc. (August 2005)	See Attached CD
26	Preliminary Cost Estimate of Activated Carbon Injection for Controlling Mercury Emissions from an Un-Scrubbed 500 MW Coal-Fired Power Plant – Science Applications International Corporation (November 2003)	See Attached CD
27	Mercury Control For PRB and PRB/Bituminous Blends – ADA-ES, Inc. (2005)	http://www.icac.com/files/public/POWER_GEN_2005_Durham.pdf See Attached CD
28	Fabric Filter Considerations for Hg Control on High Sulfur Coals – Sargent & Lundy, LLC (2006)	See Attached CD
29	Hydrogen Chloride Emissions From Maryland Utility Boilers – State of Maryland Department of Natural Resources (June 1999)	http://esm.versar.com/pprp/hcl/pprp-118pdf.pdf See Attached CD
30	Mercury Capture and Fate Using Wet FGD at Coal-Fired Power Plants – USDOE (August 2006)	See Attached CD
31	Performance and Cost of Mercury & Multipollutant Emission Control Technology Applications on Electric Utility Boilers – USEPA (2003)	http://www.epa.gov/appcdwww/aptb/EPA600R03110.pdf See Attached CD
32	Memo From Maxwell To Wayland – USEPA (May 2006)	http://www.epa.gov/ttn/atw/utility/NSPS-053106.pdf See Attached CD
33	EPA Regulatory Finding on Emissions of HAPs from Electric Utility Steam Generating Units – USEPA (2000)	http://www.epa.gov/ttn/oarpg/t3/fr_notices/utilfind.pdf See Attached CD
34	Proposed NESHAP, and in the Alternative, Proposed NSPS for New & Existing Electric Utility Steam Generating Units – USEPA (2004)	http://edocket.access.gpo.gov/2004/pdf/04-1539.pdf See Attached CD

Exhibit E – Reference Information Cont.

Item #	Documentation	Reference
35	Revision of December 2000 Regulatory Finding on the Emissions of HAP From Electric Utility Steam Generating Units & the Removal of Coal and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c) List – USEPA (2005)	http://edocket.access.gpo.gov/2005/pdf/05-6037.pdf See Attached CD
36	Standards of Performance For New and Existing Stationary Sources: Electric Utility Steam Generating Units – USEPA (2005)	http://edocket.access.gpo.gov/2005/pdf/05-8447.pdf See Attached CD
37	Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units: Reconsideration – USEPA (2005)	http://edocket.access.gpo.gov/2005/pdf/05-21457.pdf See Attached CD
38	Revision of December 2000 Clean Air Act Section 112(n) Finding Regarding Electric Utility Steam Generating Units; and Standards of Performance for New and Existing Electric Utility Steam Generating Units: Reconsideration – USEPA (2006)	http://edocket.access.gpo.gov/2006/pdf/06-5173.pdf See Attached CD
39	Cross 3 Initial Compliance Sampling HCl, HF, and Metals Source Test – Integrity Air Monitoring, Inc. (February 2007)	See Attached CD
40	National Emissions Standards For Hazardous Air Pollutants: Industrial, Commercial and Institutional Boilers and Process Heaters (40 CFR Part 63, Subpart DDDDD) Applicability Flow Chart – USEPA (2004)	http://www.epa.gov/ttn/atw/boiler/finalflowchart9_30_04.pdf See Attached CD
41	Control of Mercury Emissions From Coal-Fired Electric Utility Boilers – USEPA (2004)	http://www.epa.gov/ttnatw01/utility/hgwhitepaperfinal.pdf See Attached CD
42	Final Standards For Hazardous Air Pollutants for Hazardous Waste Combustors; Final Rule – USEPA (1999)	http://www.epa.gov/epaoswer/hazwaste/combust/pdfs/frhwc1.pdf See Attached CD
43	Wygen II Performance Test Reports – Black Hills Corporation (March, June 2008)	See Attached CD
44	Midamerican (Walter Scott Jr. Energy Center) Unit 4 Performance Test Report Summary (August 2007)	See Attached CD
45	DOE/NETL Phase II and Phase III Study Documentation	See Attached CD