OglethorpePower

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An Electric Membership Cooperative

October 14, 2009

Mr. Eric Cornwell
Acting Permit Program Manager
Georgia Environmental Protection Division
Air Protection Branch
4244 International Parkway, Suite 120
Atlanta, Georgia 30354

Dear Mr. Cornwell:

Subject Oglethorpe Power Corporation, Warren County Biomass Energy Facility
Revised Volume I
Initial Volume II (modelling)

Oglethorpe Power Corporation (Oglethorpe) is planning to construct a new nominal 100 megawatt (MW) biomass-fueled electric generating facility in Warren County, Georgia. The proposed facility consists of a biomass-fired boiler and ancillary equipment to produce steam for the generation of electricity. The proposed project is a major source with respect to the Prevention of Significant Deterioration (PSD) permitting program, as potential emissions of carbon monoxide (CO), oxides of nitrogen (NO_X), sulfur dioxide (SO_2), and particulate matter less than 10 microns in diameter (PM_{10}) are expected to exceed the major source thresholds and/or significant emission rates.

Oglethorpe submitted a PSD construction permit application, Application #19121, to the Georgia Environmental Protection Division (EPD) on August 7, 2009 with all portions except the dispersion modeling (i.e., Volume I was submitted). Since submittal of the original application, Oglethorpe has made a number of minor revisions to the proposed ancillary sources; no changes were made to the proposed biomass boiler. Highlights of these revisions include:

- Removal of biomass chip covered storage area, conveyors, and associated baghouse.
- Reduction in capacities of several material transfer conveyors due to the removal of the covered storage area.
- Replacement of the permanent chip grinding building with a mobile grinder and associated baghouse.
- Addition of a biomass transfer tower and baghouse.
- Renumbering of all proposed conveyors and baghouses to be consecutive.
- Revision of compression-ignition emergency fire pump engines to include two engines, nominally rated at 330 and 175 hp.
- Addition of a second 60,000-gallon ultra low sulfur diesel (ULSD) or a biodiesel blend storage tank.
- Addition of a second 500-gallon ULSD storage tank for ULSD for the additional fire pump engine.
- Revision of the cooling water total dissolved solids rate to the maximum design rate specified for the equipment.

ENV-B1-09-074

While these changes are minor, they propagate throughout the original Volume I of the PSD permit application. As such, instead of submitting only replacement pages, Oglethorpe is enclosing four (4) complete revisions of the Volume I application. These application copies are intended to replace, not supplement, the August 2009 applications.
This submittal also includes four copies of Volume II of the application, which contains all dispersion modeling information. Oglethorpe also has complete PDF copies of both Volume I and Volume II available if that would be helpful to Georgia EPD.

In addition to the enclosed permit applications, Oglethorpe is also providing a list of local government and legal organ contacts for the proposed project as requested by Georgia EPD.

Oglethorpe appreciates Georgia EPD's prompt processing of the enclosed application. Please feel free to contact me at 770-270-7166 or Mr. Mike Bilello at 770-270-7196 with any questions that you have.

Sincerely,

OGLETHORPE POWER CORPORATION

Douglas J. Fulle
Vice President, Environmental Affairs

DJF:dmc

Enclosures

c: Mr. Furqan Shaikh (Georgia EPD)
Mr. Alaa Afifi (Georgia EPD)
Mr. Peter Courtney (Georgia EPD)
Ms. Wende Martin (Oglethorpe)
Mr. Mike Bilello (Oglethorpe)
Mr. Russell Bailey (Trinity Consultants)

Warren County Legal Organ and Local Government Contacts

County legal organ name and address and phone number.	Warrenton Clipper Karl Haywood 407 Norwood Street Warrenton, GA 30828 Phone: (706) 465-3395
City mayor name and address	Tony Mimbs, Mayor 103 Academy Street Warrenton, GA 30828 Phone: (706) 465-3282
County clerk name and address, or other location, where the draft will be sent for public review.	Warren County Courthouse Shirley Cheeley, Clerk of Courts P.O. Box 46 Warrenton, Ga. 30828 Phone: (706) 465-2171 www.warrencountyga.com
County Board of Commissioners Chairman name and address.	John Graham, Chairman Warren County Courthouse P. O. Box 46 Warrenton, GA 30828 Phone: (706) 465-2171

OGLETHORPE POWER CORPORATION

Warrenton, Georgia

Warren County Biomass Electric Generation Facility Construction Permit Application

Volume I (Revised)

October 2009

Project 081101.0100

OGLETHORPE POWER CORPORATION

Warrenton, Georgia

Warren County Biomass Electric Generation Facility Construction Permit Application - Volume I (Revised)

October 2009

Warren County Biomass Electric Generation Facility
Construction Permit Application
Volume I (Revised)

Oglethorpe Power Corporation ▪ Warrenton, Georgia

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Project 081101.0100

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October 2009

LIST OF TABLES

1. EXECUTIVE SUMMARY

Oglethorpe Power Corporation (Oglethorpe) plans to construct a nominal net 100 megawatt (MW) biomass-fueled electric generating facility in Warren County, Georgia (Warren facility). The plant will consist of a biomass-fueled boiler and ancillary equipment to produce steam for the generation of electricity. The proposed project will be subject to Prevention of Significant Deterioration (PSD) air permitting.

1.1 PROJECT DESCRIPTION

The proposed Warren facility will consist of a nominal net 100 MW biomass fueled facility. Construction of the facility is anticipated to begin in early 2011 with the facility becoming operational by April 2014.

The proposed plant will consist of the following air emission units:

- Bubbling Fluidized Bed Boiler
- Emergency Fire Water Pumps (2)
- Raw Material Handling and Storage Area
- Sorbent Silo
- Sand Silo and Day Hopper
- Fly Ash Silo and Bottom Ash Storage Area
- Storage Tanks
- Cooling Tower
- Paved Roads

1.2 REGULATORY APPLICABILITY

The new facility will be a major source under the PSD permitting program since potential emissions of carbon monoxide (CO) and oxides of nitrogen (NO_X) will exceed the major source threshold of 250 tons per year (tpy). Further, as the facility will be a PSD major source, PSD permitting is also required for pollutants whose potential emissions exceed the Significant Emission Rate (SER), which adds particulate matter (PM, also called total suspended particulate [TSP]), particulate matter less than 10 or 2.5 microns in aerodynamic diameter (PM_{10} and $PM_{2.5}$), and sulfur dioxide (SO_2). All other PSD-regulated pollutants will be below the PSD permitting thresholds; these include volatile organic compounds (VOC), sulfuric acid mist (H_2SO_4), fluorides, and lead (Pb). For each pollutant exceeding the PSD SER, Best Available Control Technology (BACT) analyses and air quality modeling analyses are required.

Once operational, the Warren facility will be a Title V major source. Oglethorpe is submitting this state construction and operating permit application in accordance with all federal and state requirements. Oglethorpe will submit a permit application for a Title V operating permit within one year after commencement of facility operation.

The facility will be subject to New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAP), and several Georgia regulations. Note that the facility will not be a major source of hazardous air pollutants (HAP) and will only be subject to HAP requirements applicable to area sources. As an area source for HAP, construction permitting for HAP (termed Section 112[g]) is not applicable to the proposed project.

Facility-wide potential emissions are presented in Table 1-1.

TABLE 1-1. PROPOSED FACILITY-WIDE POTENTIAL TO EMIT

Pollutant	Potential Emissions (tpy)	PSD/112(g) Thresholds (tpy)	PSD/112(g) Permitting Triggered?
CO	625.7	100	Yes
NO_X	648.7	40	Yes
PM[1]	143.8	25	Yes
PM_{10}[1]	144.4	15	Yes
$PM_{2.5}$[2]	144.4	10	Yes
SO_2	56.2	40	Yes
VOC	39.1	40	No
H_2SO_4	6.9	7	No
Fluorides	-	3	No
Pb	8.13E-04	0.6	No
Total HAP	19.9	25	No
Maximum Single HAP	9.9	10	No

1. PM emissions are filterable particulate only. PM_{10} emissions are estimated as total particulate emissions (filterable + condensable). PM_{10} filterable emissions are based on the speciation of the PM. Due to the differences in the material handling particulate speciations, filterable PM emissions are very similar to total PM_{10} emissions.
2. $PM_{2.5}$ emissions assumed to be equal to PM_{10} emissions for PSD applicability purposes.

1.3 BACT DETERMINATION

Oglethorpe performed BACT analyses for the PSD-regulated pollutants that exceed the PSD SER, generally following the “top-down” approach suggested by U.S. EPA. The top-down process begins by ranking all potentially relevant control technologies in descending order of control effectiveness. The most stringent or “top” control option is BACT unless the applicant demonstrates, and the permitting authority in its informed opinion agrees, that energy, environmental, and/or economic impacts justify the conclusion that the most stringent control option does not meet the definition of BACT. Where the top option is not determined to be BACT, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is determined.

Based on the BACT review, Oglethorpe has determined that the technology and limits presented in Table 1-2 are BACT for the various emission units at the proposed Warren facility during periods of normal operation. Separate BACT secondary limits will be established for the proposed biomass boiler to address startup and/or shutdown events; refer to Section 5.15 for a discussion of the secondary BACT limits. Separate from BACT, the potential for different modeling-based short-term limits to protect the ambient air is discussed in Volume II.

TABLE 1-2. PROPOSED BACT PRIMARY LIMITS SUMMARY

Unit	Pollutant[1]	Limit	Units	Averaging Period	Proposed BACT
BFB Boiler	NO_X	0.11	lb/MMBtu	30-day	Selective Non-Catalytic Reduction
	SO_2	0.010	lb/MMBtu	30-day	Duct Sorbent Injection
	$PM/PM_{10}/PM_{2.5}$ (Filterable)	0.010	lb/MMBtu	3-hour	Baghouse
	$PM_{10}/PM_{2.5}$ (Total)	0.018	lb/MMBtu	3-hour	Baghouse
	CO	0.08	lb/MMBtu	30-day	Good Design and Operating Practices
Fire Pump Engines (each)[2]	NO_X + NMHC	3.0	g/Hp-hr	3-hour	Good Design and Operating Practices
	SO_2	15	ppmw	N/A	Fuel Sulfur Content
	$PM/PM_{10}/PM_{2.5}$	0.15	g/Hp-hr	3-hour	Good Design and Operating Practices
	CO	-		N/A	Good Design and Operating Practices
Biomass Unloading Operations	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Baghouse
Biomass Processing Building	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Baghouse
Biomass Transfer Tower	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Baghouse
Boiler Building Biomass Transfer	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Baghouse
Mobile Longwood Chipping	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Baghouse
Sorbent Storage Silo	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Bin Vent Filter[4]
Sand Storage Silo	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Bin Vent Filter[4]
Sand Day Silo	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Bin Vent Filter[4]
Fly Ash Storage Silo	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Bin Vent Filter[4]
Bottom Ash Storage Area	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Bin Vent Filter[4]
Cooling Tower	$PM/PM_{10}/PM_{2.5}$	0.0005%	drift	N/A	Drift Eliminators
Fugitive Dust Emissions[3]	$PM/PM_{10}/PM_{2.5}$	Varies with Emission Unit			Water Spray and/or Dust Reduction Devices

1. Compliance with $PM_{2.5}$ limits is assumed inherent with compliance with PM_{10} limits as vendors did not provide $PM_{2.5}$ estimates.
2. Fire pumps will operate for a maximum of 500 hours per year, total, and only 100 hours per year of non-emergency operation.
3. Refer to Sections 2 and 5 of the application for detail on the fugitive dust emission sources.
4. The bin vent filter is a type of fabric filter.

1.4 AIR QUALITY ANALYSIS

The air dispersion modeling and other air quality analyses required as part of this permit application are provided in Volume II. The modeling analyses were conducted in accordance with the approved modeling protocol[1], U.S. EPA's *Guideline on Air Quality Models,* 40 CFR Part 51, Appendix W (Revised, November 9, 2005), the U.S. EPA's *AERMOD Implementation Guide*[2]*,* and the Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions* (June 21, 1998).[3]

The modeling analyses demonstrate that the project will not cause or contribute to an exceedance of any National Ambient Air Quality Standards (NAAQS) or Class II PSD Increment requirements. An additional impacts analysis is also included in Volume II of this application.

1.5 APPLICATION ORGANIZATION

The following information is included as part of this application submittal:

- Section 1 includes the application summary;
- Section 2 provides a description of the proposed project;
- Section 3 discusses the emissions calculation methodologies and presents the facility-wide potential emissions;
- Section 4 details the regulatory applicability analysis;
- Section 5 presents the BACT analysis;
- Appendix A includes an area map, site layout, and process flow diagrams;
- Appendix B contains the construction permit application forms;
- Appendix C presents the detailed emission calculations; and
- Appendix D contains BACT supporting information.

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[1] Letter from Mr. Doug Fulle (Oglethorpe) to Mr. Peter Courtney (Georgia EPD), April 28, 2009. Approval of protocol provided in letter from Mr. Peter Courtney (Georgia EPD) to Mr. Doug Fulle (Oglethorpe), July 2, 2009. Copies of these documents are provided in Volume II.

[2] www.epa.gov/scram001/7thconf/aermod/aermod_implmtn_guide_19March2009.pdf

[3] www.georgiaair.org/airpermit/downloads/otherforms/infodocs/toxguide.pdf

This section describes the proposed biomass generation facility. An area map, a facility layout, and process flow diagrams are provided in Appendix A.

2.1 SITE DESCRIPTION

Oglethorpe plans to construct a nominal net 100 MW biomass fueled electric generating facility in Warren County, Georgia, approximately 40 miles west of Augusta. Warren County has been designated by the United States Environmental Protection Agency (U.S. EPA) as “attainment” or “unclassifiable” for all criteria pollutants.

The Warren facility site contains approximately 365 acres that are a mixture of managed forest and pastureland. Approximately two-thirds of the property is used as a pasture for cattle or for hay production; the remaining land is forested and covered with pine or pine and hardwood mixed forest. Some of the forested land has recently been harvested. There is a rail line along the western border of the site. An electrical transmission line right-of-way with one 230-kV line and one 115-kV line crosses the southern portion of the property and a 115-kV line crosses the northwestern portion of the property. An electrical distribution line runs along East Warrenton Road on the northern portion of the property. Several small ponds are located on the property; in addition, there are several intermittent streams.

The site is in fairly close proximity to the City of Warrenton. North and west of the property is a new industrial park being developed by Warren County. The amount of light industry increases west of the property towards Warrenton.

A site plot plan illustrating the facility layout is included as Figure A-2 in Appendix A. Additionally, a United States Geological Survey (USGS) map showing the location of the facility is also found in Appendix A (Figure A-1).

2.2 PROPOSED OPERATIONS

Oglethorpe plans to construct a renewable energy facility to produce electricity for sale to the power transmission grid. The facility, scheduled to commence construction in early 2011 and commence operation in 2014, will combust a woody biomass fuel blend. The facility will be designed to accept 100% chipped biomass (predominantly chipped wood) or up to 10% long wood processed on-site. The biomass to be utilized at the facility will meet the following definition:

> *organic matter, excluding fossil fuels, including agricultural crops, plants, trees, wood, wood residues, sawmill residue, sawdust, wood chips, bark chips, and forest thinning, harvesting, or clearing residues; wood residue from pallets or other wood demolition debris; peanut shells; pecan shells; cotton plants; corn stalks; and plant matter, including aquatic plants, grasses, stalks, vegetation, and residues, including hulls, shells, or cellulose containing fibers.*

The proposed facility's air emissions units will be:

- Bubbling Fluidized Bed Boiler
- Emergency Fire Water Pumps (2)
- Raw Material Handling and Storage
- Sorbent Silo
- Sand Silo and Day Hopper
- Fly Ash Silo and Bottom Ash Storage Area
- Storage Tanks
- Cooling Tower
- Paved Roads

Process flow diagrams for the proposed facility operations are included in Appendix A, and each of the air emission units are discussed in the following subsections.

2.2.1 BUBBLING FLUIDIZED BED BOILER

The bubbling fluidized bed boiler will fire woody biomass as the primary fuel and have a short-term (approximately daily) heat input of 1,399 MMBtu/hr (valves wide open [VWO], >100%) and a long-term heat input of 1,282 MMBtu/hr (100%), potentially operating 8,760 hours per year. Due to concerns with the technical feasibility of using the preferred startup fuel (pure biodiesel [B100]), Oglethorpe is proposing two possible startup fuels, with three potential startup scenarios.[4]

- Preferred scenario – B100 at 396 MMBtu/hr
- Alternate scenario No. 1 – Ultra Low Sulfur Diesel (ULSD) at 249 MMBtu/hr
- Alternate scenario No. 2 – blend of B100 and ULSD (Bxx blend), with a blend percentage and heat input set such that the maximum fossil heat input cannot exceed 249 MMBtu/hr[5]

The boiler will employ multiple pollution control devices, as shown in Table 1-2. Filterable particulate matter will be controlled by a baghouse (also known as a fabric filter). NO_X will be reduced by a selective non-catalytic reduction (SNCR) system in addition to the overfire air system (OFA) inherent in fluidized bed combustor design. SO_2 and acid gas emissions will be controlled by duct sorbent injection (using an alkaline sorbent) into the flue gas stream. Good combustion practices will be employed to minimize CO and organic emissions.

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[4] Several concerns have been expressed by boiler vendors contacted to discuss the feasibility of using solely B100 for startup. Some concerns appear addressable via maintenance or operating practices, such as the potential need to remove and clean the burners after each start or potential difficulties with long-term storage stability. Other concerns may not have technical solutions. Perhaps most concerning is potential light-off and flame stability as measured by Cetane number (self-ignition quality of the fuel). Oglethorpe is attempting to identify or develop solutions to these various concerns to allow sole usage of B100 as the startup fuel.

[55] The heat input to meet this condition can be calculated as [(249 MMBtu/hr) / (1 – xx/100)]. For example, with B30, a total heat input of (249 MMBtu/hr) / (1-30/100) = 355 MMBtu/hr would satisfy the requirement of keeping fossil heat input less than 249 MMBtu/hr.

Cold startup of the boiler will be accomplished via a series of phases.[6] Phase I is the initial firing period and will employ only the startup auxiliary fuel (B100, ULSD, or Bxx blend) and is estimated to last approximately six hours at 396 MMBtu/hr or ten hours at 249 MMBtu/hr.[7] During this phase, air is introduced through the bubble caps to agitate the bed, and the auxiliary burners are firing down toward the bed. The SNCR cannot be operated as the boiler temperatures are too low for ammonia injection. The fabric filter is also bypassed during this time to avoid condensation on the fabric filter bags. Because of the fabric filter bypass, and because of insufficient flue gas temperature, the duct injection system is also not in operation. Phase I commences when boiler load reaches approximately 26% based on steaming rate.

Phase II of startup is the transition phase where biomass feed begins and auxiliary fuel decreases. This phase is estimated to consist of Hours 7-10 (B100) or Hours 11- 16 (ULSD). A boiler bed temperature of at least 900 ºF is required to start this phase. Phase II includes both biomass and auxiliary fuel firing. The biomass fuel feed rate is slowly increased as the auxiliary fuel feed rate is decreased, maintaining stable combustion conditions. It is estimated that approximately halfway through Phase II (Hour 8 at 396 MMBtu/hr or Hour 14 at 249 MMBtu/hr), the temperature of flue gas exiting the air heater will be above the acid dew point and the fabric filter can be used. Since the duct sorbent injection system depends on the fabric filter for collection of the sorbent, the duct sorbent injection system can also be used at this point.

Phase III is the end of the startup period, and would be Hours 11-12 (B100) or Hours 17-18 (ULSD). During Phase III, only biomass is fired in the boiler, and the load is increased from approximately 50% to 65% load. The SNCR can be used for NO_X control at approximately 65% load (during Hour 12 or Hour 18, depending on startup heat input rate). At this point, the flue gas temperature inside the boiler (at the ammonia injection lances) is above the required minimum ammonia injection temperature. The baghouse and duct sorbent injection systems are utilized throughout Phase III. Note that while 65% load is required to initiate SNCR usage, once the SNCR is active its usage can be maintained down to 40% load.

2.2.2 FIRE WATER PUMPS

Three 2,500 gallon per minute pumps will be used for the emergency fire suppression system. One pump will be electric, and the other two pumps will be nominal 330 and 175 hp compression ignition fire pump engines. Pure biodiesel (B100) or ultra low sulfur diesel (ULSD) with a maximum sulfur content of 0.0015 weight percent will be used in the engines. Oglethorpe is proposing to limit the total operation of each fire pump engine to 500 hours per year.

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[6] Note that these startup details represent the best available estimates for startup on this unit from potential boiler vendors. There are no operating units like the proposed unit in a 100 MW size from which actual details could be obtained.

[7] Total oil fired during the startup, under any of the three startup options, is estimated to be approximately the same, since the same total heat must be transferred from the oil to the bed, with only the time period of the heat transfer differing. The preferred option (B100) is specifically used to calculate fuel usage. Emission tonnage from startup is also expected to be indistinguishable between the three options.

2.2.3 Raw Material Handling and Storage

The raw material handling and storage equipment will provide the necessary functions to receive, process, store, and convey biomass fuel (received as either chips or longwood) to the boiler. The biomass fuel handling system will be provided with baghouses for dust control at multiple locations; water sprays and/or other design features are utilized where the nature of the process prohibits the use of baghouses or enclosures for dust control.

Note that these descriptions are based on the planned layout details. When the final construction drawings are completed, minor changes may be necessary. Oglethorpe requests that Georgia EPD include a provision in the issued PSD permit authorizing such minor changes.

2.2.3.1 Biomass Receiving Operations

Chips will be received via truck. Each of the loads will average 25 tons of chips and will discharge into one of six underground truck dumper hoppers (HPR1 – HPR6) with a capacity of 37.5 tons, each. Each truck dumper (DMP1 – DMP6) will be capable of handling an average of four trucks per hour, and the hoppers will each have a live bottom-receiving feeder/drag chain conveyor with a capacity of 125 tons (FDR1 – FDR6). The truck dumping operations and all six truck hoppers will be equipped with dust suppression systems, which will fog the receiving area with a water mist to aid in PM control. Two collecting belt conveyor systems (CV01, CV02) will be designed to receive 400 tons per hour (tph), each, from all of the live bottom feeders and will be equipped with a baghouse (BM01) to provide PM control. The collecting belt conveyors then transfer the material to the enclosed biomass processing building for final processing.

As part of the longwood delivery system, the logs will be delivered via open logging trailers and unloaded using mobile equipment that will also both stack and reclaim the logs from the storage pile (SP03). Oglethorpe will use a diesel-powered, 125 tph mobile chipper (GRN3) for size reduction to 2 inch square (or smaller) chips. Chips will leave the chipper via an enclosed chute and discharge from the chute into an enclosed structure using a dust suppression system (BM10) to control PM emissions; the chute system is expected to capture 95% of the discharged particulate with the remaining 5% being emitted as fugitives. The chips in the enclosure are conveyed to the biomass receiving area's live bottom feeders. Chipper operation is expected to be used for limited periods of time throughout the year.

2.2.3.2 Biomass Processing

The enclosed biomass processing building will receive chips via two collecting belt conveyors (CV01 and CV02). The two collection belt conveyors will transfer the wood chips to the two 400 tph, each, receiving belt conveyors (CV03 and CV04), which transport the chips to one of the two 400 tph, each, diverter gates (GAT1 and GAT2). The diverter gates then distribute the wood chips to one of two 400 tph, each, disk scalping screens (SCN1 and SCN2), which will separate oversized materials from the acceptable material stream. Oversized materials will be routed to two electric-powered 200 tph, each, wood hogs (GRN1 and GRN2), which will discharge chips at a nominal 2-1/2 inch size. Two 400 tph, each, collecting belt feeders (FDR7 and FDR8) will transfer the chipped biomass from the fuel processing building to the two 400 tph, each, fuel transfer belt conveyors (CV05 and CV06) and then to the two 400 tph, each, radial stacking belt conveyors (CV07 and CV08). The fuel processing building will be completely enclosed and equipped with a dust collector (BM02) to provide PM control. The transfer belt conveyors and stacking belt conveyors will be equipped with dust suppression systems which will spray water mist to provide PM control.

2.2.3.3 BIOMASS STORAGE AND CONVEYING

The two radial stacking belt conveyors (CV07 and CV08) will transport up to 800 tph of biomass to the two radial stockpiles (SP01 and SP02), and a telescopic chute will be used to minimize PM generation from these drops. The biomass storage capacity of the piles will be 15.25 days of boiler fuel. The biomass fuel will be reclaimed from the two radial stockpiles by two 200 tph, each, radial reclaim chain conveyors (CV09, CV10), which transport the reclaimed biomass chips to the reclaim tower that discharges the material to the two 200 tph, each, reclaim belt conveyors (CV11, CV12). Then the biomass will be received by the 200 tph covered stackout belt conveyor (CV13) and transferred via the transfer tower (TWR1) to the 200 tph boiler reclaim belt conveyor (CV14). After passing through a diverter gate (GAT3), the biomass then goes to two 200 tph, each, distribution drag chain conveyors (CV15, CV16) that will keep the four boiler live bottom feed bins full by continuously overfilling the bins. Any excess biomass will be discharged to the 200 tph overfill return belt conveyor (CV17) and transported back to a location on the boiler reclaim belt conveyor (CV14). This overfill loop ensures that the four boiler live bottom feed bins are always full by continuously overfilling the bins.

Baghouse BM03 is used to control emissions from the transfer tower drop points while Baghouse BM04 is used to control emissions from CV14, CV15, and CV16.

2.2.4 SORBENT STORAGE SILO

A sorbent storage silo equipped with fabric filtration system (BM05) will store the alkaline sorbent (such as sodium bicarbonate, Trona, lime, or similar sorbent) that will be injected into the boiler flue gas stream for SO_2 and acid gas control as part of the duct sorbent injection system. The sorbent will be delivered to the site by trucks and pneumatically conveyed to a storage silo. The sorbent will be pneumatically conveyed from the storage silo to an on-line milling process and then to the injection system where it will be fed to the injection lances in the flue gas ductwork upstream of the fabric filter. The injection system (including the on-line milling process) is completely enclosed. The solid reaction products that result from the sorbent injection will be collected (along with fly ash) into hoppers located below the filter bags and will be transferred to the ash storage silo.

2.2.5 SAND SILO AND DAY HOPPER

A sand storage silo equipped with fabric filtration system (BM06) will store sand that will be used in the bubbling fluidized bed boiler as bed material. Sand will be delivered by truck and pneumatically unloaded into the silo. Sand from the silo will be pneumatically conveyed to the sand day storage hopper located near the boiler building. The sand day storage hopper will be equipped with a dust collector (BM07) to vent the conveying air to the atmosphere. Sand removed from the vented air will be discharged back to the sand day storage hopper.

2.2.6 ASH HANDLING

Ash from the steam generator ash coolers, the steam generator air heater ash hoppers, and the fabric filter ash hoppers will be collected and transported to the fly ash silo for loading into trucks and offsite reuse or disposal in a permitted landfill. A mechanical conveyor will be utilized to continuously transport ash from the steam generator ash cooler outlets. Ash will be removed through a pneumatic transport piping system (equipped with BM09) and delivered to the ash silo for storage prior to final disposal. The ash storage silo will be situated directly over a truck access road. An access bay will be provided beneath the silo, and the unloading will occur through a telescoping discharge chute. The discharge chute will include a vacuum annulus area to minimize dust.

Additionally, bottom ash will be transported in an enclosed belt conveyor from the discharge at the bottom of the boiler to a covered concrete storage. This storage will have three walls with one open side for access with wheeled mobile equipment. The transfer points in the bottom ash conveyance and storage will utilize a dust control system to minimize PM emissions (baghouse BM08).

2.2.7 STORAGE TANKS

Six storage tanks with the potential to emit VOC will be built at the facility. Biodiesel (B100), ULSD or a blend for boiler startup will be stored on site in two 60,000-gallon tanks (TK01, TK05); two 500-gallon day tanks for biodiesel (B100) or ULSD for the fire pump engines will be used (TK02, TK06). A 4,100-gallon turbine lube oil reservoir (TK03) and a 400-gallon turbine lube oil dump tank (TK04) will also be located on site. Numerous other storage tanks will be built but will not contain liquids with the potential to emit VOC or HAP.

2.2.8 COOLING TOWERS

Steam exiting the steam turbine will be condensed via indirect heat transfer using a mechanical draft, four cell, back-to-back counterflow wet cooling tower. Cooling tower drift will be minimized to 0.0005% of the design recirculation rate.

2.2.9 ROADS

Roadways throughout the plant site will be asphalt and all areas not paved or landscaped will be covered with gravel. Access to the site will be exclusively by roadway. The following materials will be delivered to the plant by truck on paved roadways:

- ▲ Woody biomass (chipped and longwood)
- ▲ Biodiesel/diesel
- ▲ Sand
- ▲ Aqueous Ammonia
- ▲ Alkaline sorbent
- ▲ Miscellaneous materials and chemicals

Additionally ash generated by the boiler will be removed from the plant by trucks for offsite reuse or disposal in a permitted landfill.

This section addresses the methodologies used to quantify the emissions increases associated with the proposed facility. Detailed calculations of both criteria and non-criteria pollutants are located in Appendix C.

3.1 PSD-REGULATED POLLUTANT EMISSIONS

Sources of criteria pollutant emissions include fuel combustion, material handling and storage, cooling towers, and fugitive dust.[8] The sources and calculation methodologies are discussed in the following sections. Note that annual emissions are based on 8,760 hours per year of operation unless otherwise noted.

3.1.1 BOILER

Combustion in the bubbling fluidized bed boiler will result in emissions of CO, NO_X, PM (and variants), SO_2, VOC, and H_2SO_4.[9] The PSD-regulated emissions are based on proposed limits and/or vendor emission factors. Table 3-1 lists the expected blends of biomass fuels that were used to develop flow rates and uncontrolled emissions. Copies of the fuel analyses performed in designing this project are included in Appendix C. Note that Oglethorpe initially had testing completed by Consol, with additional testing of the same samples later by Nablabs. Oglethorpe has determined that the Nablabs test data are more appropriate to use in permitting and all boiler combustion parameters have been based on the Nablabs data.

Two nominal fuel blends were identified from the fuel data. The design case is the expected average operating blend of material, while the worst-case blend is the blend that results in maximum required heat input to reach a VWO operating condition. Small quantities of other biomass materials, as described in Section 2.2, may also be included in either blend.

TABLE 3-1. NOMINAL WOODY BIOMASS FUEL BLENDS

Fuel Type	Design (%)	Worst-Case (%)
Whole Tree Chips	80	60
Forest Residues, Tops & Limbs	10	20
Mill Residues, Sawdust & Shavings	5	0
Mill Residues, Bark	5	20

[8] Although the mobile chipper engine is a source of combustion emissions, this engine is a nonroad engine rather than a stationary source and emissions from the engine are not considered for stationary source permitting. Emissions from the chipping process have been included in this permit application.

[9] No emissions of fluorides (other than HF) are expected; refer to additional discussion in Section 4 in the NSR evaluation.

Expected short-term (lb/hr) emissions from maximum operation of the boiler (VWO) were estimated using the boiler's short-term (approximately daily) heat input of 1,399 MMBtu/hr (worst-case fuel blend) and lb/MMBtu proposed BACT limits (discussed in Section 5 of this report) and/or expected vendor guarantees. However, these values do not account for variability at the shorter averaging periods used for modeling. Volume II (modeling) discusses short-term emissions potentially suitable for permit limits that consider the variability at shorter averaging periods than the 30-day average used for BACT.

Expected short-term emissions from startup scenarios were also considered. Startup will require usage of an auxiliary fuel to heat the boiler bed while shutdown will not require any auxiliary fuel. As previously noted, Oglethorpe is evaluating three different startup scenarios due to technical concerns if only biodiesel is combusted:

- ▲ Preferred scenario – B100 at 396 MMBtu/hr
- ▲ Alternate scenario No. 1 – Ultra Low Sulfur Diesel (ULSD) at 249 MMBtu/hr
- ▲ Alternate scenario No. 2 – blend of B100 and ULSD (Bxx blend), with a blend percentage and heat input set such that the maximum fossil heat input cannot exceed 249 MMBtu/hr

Expected short-term emissions from startup operations are based on worst-case vendor data (lb/hr basis) for all phases of start-up (biodiesel only, biodiesel/biomass mix, biomass only); however, the worst-case emission rates may only occur for a single hour within a startup phase. Table 3-2 illustrates the anticipated maximum start-up emissions based on vendor data for the maximum auxiliary heat input case (B100). Shutdown emissions will not exceed the emissions shown for startup. Based on all available data, there is no quantifiable difference on a lb/MMBtu basis in startup emissions when firing B100, ULSD, or any blend of the two.

TABLE 3-2. STARTUP EMISSIONS
(BASED ON 396 MMBTU/HR OF B100)

Pollutant	Phase I Startup Hours 0-6, 0-25% Load, Aux. Fuel Only (lb/hr)	Phase II Mid-Point Startup Hours 6-7, 25-37.5% Load, Biomass & Aux. Fuel (lb/hr)	Phase II End Point Startup Hours 7-10, 37.5-50% Load, Biomass & Aux. Fuel (lb/hr)	Phase III Startup Hours 10-12 50-65% Load, Biomass Only (lb/hr)
CO	653	387	119	68
NO_X	156	220	236	153
PM*	44	57	6	8
SO_2†	1	11	6	8
VOC	7	7	6	7

Note that all of the values provided in this table are estimates only and are not guaranteed by the vendor.
* Filterable only emissions. CPM data from startup were not provided by boiler vendors.
† Emissions based on auxiliary fuel maximum sulfur content of 0.0015% sulfur.
** Emissions shown are the maximum within a phase (not the average) and may not occur for all hours within that phase.

For annual emissions, normal operations were calculated using the same lb/MMBtu proposed BACT limits or vendor data as the short-term emissions but with the long-term heat input of 1,282 MMBtu/hr (100%, design fuel) and 8,760 operating hours per year for all pollutants except VOC and H_2SO_4. For VOC, Oglethorpe is proposing a 39 tpy limit for total boiler VOC emissions, and for H_2SO_4, Oglethorpe is proposing a 6.9 tpy limit for total boiler H_2SO_4 emissions.[10]

Annual emissions from startup and shutdown events were also considered based on the worst-case emissions from startup and up to 40 startup/shutdown events per year (16 hours per total event based on the preferred B100 startup scenario) after commissioning.[11] In actuality, the number of startup and shutdown events is expected to be less than 10 once boiler commissioning is completed.

The maximum expected short-term emissions represented in the permit application forms were selected as the maximum of the normal and startup/shutdown operations. Annual emissions were based on the maximum of 1) worst-case of normal operation for the entire year, or 2) startup/shutdown operation for 640 hours per year (40 events at 16 hours per total event) and normal operation for the remainder of the year. These annual emission rates are suitable for permit limits; however, the lb/hr values are only suitable as BACT limits for those pollutants with short-term compliance demonstration methods.

Detailed calculations are presented in Appendix C. Note $PM_{2.5}$ is assumed to be equal to PM_{10} as the boiler vendors did not provide separate $PM_{2.5}$ emissions data.

3.1.2 FIRE PUMP ENGINES

Biodiesel (B100) or ULSD combustion in the two fire pumps results in emissions of CO, NO_X, PM, SO_2, and VOC. The nominal 330 and 175 hp fire pumps' criteria emissions are based on vendor specifications (g/hp-hr factors), a maximum fuel sulfur content of 15 ppm by weight (as required by NSPS Subpart IIII), and a maximum operating schedule of 500 hours per year per engine that includes non-emergency service (readiness testing and maintenance as recommended by the manufacturer) and emergency usage. Fire pump calculations are presented in Appendix C. Note PM_{10} and $PM_{2.5}$ are assumed to be equal to PM.

Oglethorpe will utilize a non-resettable hour meter to monitor the annual hours of operation of each fire pump engine to ensure the requested 500 hours per year operating limit is met.

3.1.3 BIOMASS FUEL PREPARATION AND HANDLING

The biomass handling and preparation system is a source of particulate emissions. To minimize these emissions, the wood fuel handling system will be provided with dust control at the truck dump hoppers, transfer points in the fuel preparation building, and transfer and discharge locations in the fuel storage building. Partial or complete enclosures of emissions sources (where practicable) will also be utilized to minimize fugitive PM emissions.

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[10] For PSD applicability, other sources of VOC and H_2SO_4 emissions at the facility are negligible.

[11] For conservatism, the maximum emission rate from startup was presumed to occur throughout the duration of the startup/shutdown event. One event was assumed to be 16 total hours: 12 hours for startup and 4 hours for shutdown.

3.1.3.1 BIOMASS STORAGE PILES

Fugitive particulate emissions from the two uncovered radial storage piles (SP01 and SP02), and the longwood storage piles (SP03) were quantified. Emission factors were developed based on surface area of the piles in accordance with U.S. EPA guidance for storage pile fugitive emissions.[12] These factors provide estimates of PM emissions due to wind erosion at the surface of each storage pile based on the annual frequency of high wind speeds (> 12 mph). Detailed calculations are also included in Appendix C.

Note that PM_{10} is assumed to equal 50% of PM[13], while $PM_{2.5}$ is assumed to be 7.5% of PM.[14]

3.1.3.2 BIOMASS MATERIAL DROP/TRANSFER SOURCES

Fugitive particulate emissions from drop and transfer operations that are not confined in an enclosure and are not equipped with a dust control system (i.e., baghouse) were estimated based on maximum throughputs, and the methodology outlined in AP-42, Section 13.2.4.[15] A list of those sources and the associated emission calculations are included in Appendix C.

Note that PM_{10} is assumed to equal 48% of PM, and $PM_{2.5}$ is assumed to equal 7% of PM based on AP-42 Section 13.2.4 particle size multipliers.[16]

3.1.3.3 BIOMASS PROCESSING AND HANDLING ENCLOSED OPERATIONS

The enclosed and/or controlled biomass processing/handling operations are non-fugitive sources of filterable PM emissions. Particulate emissions from the biomass receiving area, biomass processing building, transfer tower, transfer operations inside the boiler building, and longwood mobile chipping dust collection are based on the baghouse air flow rate (displacement) and a baghouse outlet particulate matter grain loading factor of 0.005 gr/ft^3 (the proposed BACT limit). It was conservatively assumed that these sources will operate 8,760 hours per year unless a

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[12] U.S. EPA *Control of Open Fugitive Dust Sources*, Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988.

[13] U.S. EPA *Control of Open Fugitive Dust Sources*, Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988.

[14] U.S. EPA *Background Document for Revisions to Fine Fraction Ratios Used for AP-42 Fugitive Dust Emission Factors*. November 2006. http://www.epa.gov/ttn/chief/ap42/ch13/bgdocs/b13s02.pdf.

[15] U.S. EPA AP-42, Section 13.2.4, *Aggregate Handling and Storage Piles*. November 2006. http://www.epa.gov/ttn/chief/ap42/ch13/final/c13s0204.pdf.

[16] Estimates based on particle size multiplier values of 0.74, 0.35 and 0.053 for PM_{30}, PM_{10}, and $PM_{2.5}$ respectively. U.S. EPA AP-42, Section 13.2.4, *Aggregate Handling and Storage Piles*. November 2006. http://www.epa.gov/ttn/chief/ap42/ch13/final/c13s0204.pdf.

source is specifically limited to operating only 16 hours per day. Biomass enclosed operations calculations are presented in Appendix C.

Note that for conservatism, $PM_{2.5}$ and PM_{10} emissions were assumed to be equal to PM.

3.1.3.4 LONGWOOD CHIPPING FUGITIVE EMISSIONS OPERATIONS

95% of the longwood mobile chipping discharge chipping emissions are expected to be captured by the enclosed chute system and routed to BM10 for control (emissions for BM10 are based on the exit grain loading as discussed in Section 3.1.3.3). The remaining 5% of the emissions were calculated using a historical AP-42 Section 10.3-1 log debarking factor as recommended by the Bay Area Air Quality Management District's (BAAQMD) permit handbook for biomass tub grinding operations.[17] Annual emissions were based on 16 hr/day of operation for 365 days per year; in actuality, the mobile chipper will be utilized for a limited number of weeks per year.

Per the BAAQMD permit handbook, PM_{10} emissions were assumed to be 60% of PM emissions. $PM_{2.5}$ emissions were conservatively assumed to be equal to PM_{10} emissions.

3.1.4 MATERIAL STORAGE SILOS

The material storage silos are sources of PM emissions. Particulate emissions from the sorbent, sand, and fly ash silos as well as the sand day hopper and bottom ash storage area are based on air flow rate (displacement) and a baghouse outlet particulate matter grain loading factor of 0.005 gr/ft^3 (the proposed BACT limit). It was conservatively assumed that these sources will operate 8,760 hours per year. Storage silo emission calculations are presented in Appendix C.

Note that for conservatism, $PM_{2.5}$ and PM_{10} emissions were assumed to be equal to PM.

3.1.5 STORAGE TANKS

AP-42 Section 7.1, *Organic Liquid Storage Tanks*, recommends usage of U.S. EPA's TANKS 4.0 program to calculate the VOC and HAP emissions associated with fixed-roof or floating-roof organic liquid storage tanks. The program is based on the emission estimation procedures outlined in AP-42 Section 7.1 and uses chemical, meteorological, and tank-specific information (e.g., diameter, height, volume, color, throughput) to estimate the emissions from both standing and working losses.

The TANKS 4.0 program (version 4.09d) was utilized to estimate the emissions for several tanks at the Warren facility, including the following:

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[17] www.baaqmd.gov/pmt/handbook/rev02/PH_00_05_11_13.pdf

- ▲ TK01, TK05: Main Fuel Storage Tanks (B100, ULSD, or Bxx blend)
- ▲ TK02, TK06: Fire Pump Biodiesel/ULSD Day Tanks
- ▲ TK03: Turbine Lube Oil Reservoir
- ▲ TK04: Turbine Lube Oil Dump Tank

Emissions for the main fuel storage tanks were calculated based on tank annual throughput. The annual throughput was determined based on biodiesel/ULSD needs for boiler start-up events for up to 40 events per year.

Emissions from the fire pump biodiesel/ULSD day tanks were calculated based on annual throughput, determined based on hourly fuel consumption data and 500 operating hours for each engine.

Emissions for the turbine lube oil reservoir and the turbine lube oil dump tank were calculated based on an annual throughput that was conservatively estimated based on lube oil usage conservatively assuming 3 turnovers per year for the reservoir and the same throughput for the dump tank.

Copies of the TANKS reports are included in Appendix C.

3.1.6 COOLING TOWERS

Cooling towers produce a small amount of PM emissions when water droplets evaporate, leaving the dissolved solids in the water as PM. Emissions from the cooling towers are based on 0.0005% drift loss (the proposed BACT limit), the design circulation rate, and total dissolved solids (TDS) design for the cooling tower.[18] Cooling tower calculations are included in Appendix C.

3.1.7 ROAD FUGITIVE DUST

Fugitive PM emissions from roadways were estimated based on vehicle miles travelled (VMT) by trucks that transport materials to and from the facility. Vehicle miles traveled on site were estimated based on a total daily truck volume of 340 trucks for all trucks combined. The longest traveled distance was assumed for all of the trucks. Emission calculations for fugitive paved road dust emissions were developed based on AP-42, Section 13.2.1; detailed calculations are included in Appendix C. Based on discussion with the Region 4 modeler for U.S. EPA, the current paved road dust emission factors are currently being revised and preliminary data suggest that the current road emission factors overestimate emissions by more than 50% in some cases. Depending on when the revised factors are finalized, Oglethorpe may revise the PM fugitive modeling (including roads) included in this permit application.

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[18] U.S. EPA AP-42, Section 13.4, *Wet Cooling Towers* and *Effects of Pathogenic and Toxic Material Transport Via Cooling Device Drift - Vol. 1 Technical Report* EPA 600 7-79-251a, November 1979.

3.2 HAP/TAP EMISSIONS

HAP emissions are regulated by U.S. EPA under Title III of the Clean Air Act Amendments of 1990 and comprise 187 compounds. A Toxic Air Pollutant (TAP) is defined by Georgia EPD as any substance that may have an adverse affect on public health, excluding pollutants covered by a State or Federal ambient air quality standard. Thus, HAP is a subset of TAP. TAP emissions are not regulated by the state of Georgia. However, Georgia EPD does provide guidelines on modeling TAP emissions through a program approved under the provisions of Georgia Air Quality Control Rule (GRAQC) 391-3-1-.02(2)(a)(3)(ii). The procedures governing Georgia EPD's review of project TAP emissions are contained in the agency's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised June 21, 1998).* Thus, both HAP and TAP emissions are estimated for the proposed facility.

The only HAP emissions from the facility are due to the combustion sources.[19]

3.2.1 BOILER COMBUSTION

The facility will utilize a single modern, fluidized bed boiler combusting biomass. The boiler will be equipped with a fabric filter and will utilize duct sorbent injection to minimize particulate (filterable and condensable) and acid gas emissions. Using these control techniques coupled with the fluidized bed design, the organic, particulate, and acid gas emissions will be minimized.

Acid gas (HCl, HF) emission factors were provided by the boiler and sorbent injection vendors; Oglethorpe based the acid gas emissions on the vendor data for HF and a requested 9.9 tpy permit limit for HCl based on a conservative control efficiency from the duct sorbent injection. For particulate HAP and TAP, Oglethorpe utilized the AP-42 Section 1.6 default metal emission factors and applied 99% control efficiency to account for the presence of the baghouse.

For the organic HAP and TAP biomass factors, Oglethorpe developed custom fluidized bed boiler emission factors. Given the age of the AP-42 biomass combustion factors and the heavy influence of stoker boiler data in the AP-42 factors[20], custom HAP and TAP emission factors were developed based on fluidized bed boiler emission data available in the AP-42 Section 1.6 background database[21] and/or the U.S. EPA original Boiler MACT database.[22] If fluidized bed

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[19] Although the mobile chipper engine is a source of combustion emissions, this engine is not a stationary source and thus emissions from this engine are not considered for stationary source permit applications.

[20] As noted in AP-42 Section 1.6: *Wood fuel is pyrolyzed faster in a fluidized bed than on a grate due to its immediate contact with hot bed material. As a result, combustion is rapid and results in nearly complete combustion of the organic matter, thereby minimizing the emissions of unburned organic compounds.* A review of the background data used for AP-42 Section 1.6 development indicates that less than 10% of the test reports and less than 13% of the emission data evaluated were identified as fluidized bed boiler data while nearly 60% of the test reports and emission data evaluated were from stoker boilers.

[21] Emission factor file available on-line at: http://www.epa.gov/ttn/chief/ap42/ch01/related/c01s06.html

boiler emission data were not available for an organic HAP or TAP listed in AP-42 Section 1.6, default AP-42 Section 1.6 factors were used instead. More information on the development of the HAP and TAP fluidized bed biomass boiler emissions is included in Appendix C. Short-term biomass emissions were calculated based on the short-term heat input of 1,399 MMBtu/hr.

Combustion of auxiliary fuel during boiler startup events will also result in emissions of HAP and TAP. The biodiesel/ULSD HAP and TAP emissions factors were based on emission factors for No. 2 fuel oil combustion from AP-42 Section 1.3. Short-term startup emissions were considered for two scenarios:

- ▲ Based on a heat input of 396 MMBtu/hr and usage of pure biodiesel; and
- ▲ Based on a heat input of 249 MMBtu/hr using ULSD.

Since the TAP emission factors for ULSD and B100 are the same, and given the higher heat input rate of B100, the B100 case is the maximum lb/hr emission case and is used for the TAP/HAP short term startup emissions. For annual biomass emissions, normal biomass potential emissions were calculated using the same short-term emission factors and the annual heat input of 1,282 MMBtu/hr and 8,760 hours per year. The annual auxiliary fuel emissions were based on the calculated short-term emissions from the startup scenarios and 400 operating hours per year for the 396 MMBtu/hr startup scenario.[23]

The short-term emissions included in the permit application forms were the maximum of either the normal or startup (auxiliary fuel) emissions. For the annual emissions, the values utilized were the maximum of 1) normal operations for all 8,760 hour per year, or 2) startup emissions for 400 hours per year plus normal operating emissions from the remaining hours of the year.

Detailed emissions calculations are included in Appendix C.

3.2.2 FIRE PUMPS COMBUSTION

Biodiesel or ULSD combustion in the fire pumps results in emissions of HAP and TAP. The emissions for the nominal 330 and 175 hp fire pumps are based on AP-42, Section 3.3 emission factors for diesel combustion. A maximum operating schedule of 500 hours per year per engine for emergency and non-emergency service (readiness testing and maintenance as recommended by the manufacturer), which is being requested as an operating limit, was used to estimate annual emissions. Calculations are included in Appendix C.

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[22] Access 1997 database available on-line at: http://www.epa.gov/ttn/atw/combust/boiler/etdbas.mdb

[23] For the 396 MMBtu/hr startup scenario, auxiliary fuel is only utilized in hours 1-10 of the 12 hour startup event and not used at all in shutdown events; thus annual emissions scenario is based on 40 startup events per year: 10 hours/event * 40 events/year = 400 hours/year.

The proposed facility will be subject to certain federal and state air quality regulations. This section of the application summarizes the air permitting requirements and the key air quality regulations that will apply to the proposed facility. Specifically, applicability to New Source Review (NSR), New Source Performance Standards (NSPS), pollutant- and category-specific National Emission Standards for Hazardous Air Pollutants (NESHAP), Compliance Assurance Monitoring (CAM), Risk Management Plan (RMP) regulations, Title V operating permit regulations, Acid Rain Program (ARP), Clean Air Interstate Rule (CAIR), stratospheric ozone protection, and Georgia State Implementation Plan (SIP) regulations are addressed.

4.1 STATIONARY SOURCE DEFINITION

Air quality permitting for NSR (and Title V) is only applicable to stationary sources. *Stationary source* is defined in Title III of the Clean Air Act (General Provisions) as:

> *The term ''stationary source'' means generally any source of an air pollutant except those emissions resulting directly from an internal combustion engine for transportation purposes or from a nonroad engine or nonroad vehicle as defined in section 216.*
> [Clean Air Act, Section 302(z)]

Thus, nonroad engines as defined under Title II of the Clean Air Act (Section 216) are not stationary sources and their emissions are not considered under either NSR or Title V.

Most of the sources at the proposed Warren Facility are stationary sources (i.e., the BFB boiler, material handling systems, cooling towers). Diesel engines in the biomass delivery trucks are for transportation purposes and are excluded from the definition of a stationary source. Similarly, stationary fire pump engines are clearly stationary sources. For the mobile chipper engine, the definition of a nonroad engine must be considered further.

4.1.1 NONROAD ENGINE DEFINITION

The regulations implementing Section 216 manifest themselves in multiple sections of the CFR. However, the relevant definition of nonroad engine is found in two locations, with the exact same definition in each: 40 CFR 89.2 and 40 CFR 1068.30.[24]

[24] 40 CFR 89 is the original nonroad rule (published June 17, 1994). 40 CFR 1068 was added in 2004 revisions to the nonroad rules (published June 29, 2004).

Nonroad engine *means:*

(1) Except as discussed in paragraph (2) of this definition, a nonroad engine is any internal combustion engine:

(i) In or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function (such as garden tractors, off-highway mobile cranes and bulldozers); or

(ii) In or on a piece of equipment that is intended to be propelled while performing its function (such as lawnmowers and string trimmers); or

(iii) <u>That, by itself or in or on a piece of equipment, is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Indicia of transportability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform.</u>

(2) An internal combustion engine is not a nonroad engine if:

(i) the engine is used to propel a motor vehicle or a vehicle used solely for competition, or is subject to standards promulgated under section 202 of the Act; or

(ii) <u>the engine is regulated by a federal New Source Performance Standard promulgated under section 111 of the Act</u>; or

(iii) <u>the engine otherwise included in paragraph (1)(iii) of this definition remains or will remain at a location for more than 12 consecutive months</u> or a shorter period of time for an engine located at a seasonal source. <u>A location is any single site at a building, structure, facility, or installation</u>. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine replaced will be included in calculating the consecutive time period. An engine located at a seasonal source is an engine that remains at a seasonal source during the full annual operating period of the seasonal source. A seasonal source is a stationary source that remains in a single location on a permanent basis (i.e., at least two years) and that operates at that single location approximately three months (or more) each year. This paragraph does not apply to an engine after the engine is removed from the location.

[40 CFR 89.2 <u>or</u> 40 CFR 1068.30 – emphasis added]

The key portions of the definition applicable to proposed internal combustion engines for the Warren Facility include:

- Portable or transportable
- Does not remain at a location for more than 12 consecutive months
- Not regulated under NSPS

4.1.1.1 PORTABLE OR TRANSPORTABLE

The proposed Morbark mobile chipper engine easily meets this requirement. The entire unit is designed for portability and is legal for highway travel without any special permits. The unit would typically be rented when needed and delivered to the site as a trailer pulled by a semi-trailer truck.

4.1.1.2 NOT AT LOCATION MORE THAN 12 CONSECUTIVE MONTHS

The mobile chipper will not be operated for 12 consecutive months at a single location, and Oglethorpe requests that a permit condition prohibiting a portable chipper from being at a location more than 12 consecutive months be included in the issued permit.

4.1.1.3 NSPS NON-APPLICABILITY

U.S. EPA has promulgated an NSPS that applies to diesel-fired engines under 40 CFR 60 Subpart IIII (discussed in Section 4.3.10). However, in recognition of the applicability of NSPS to only stationary sources, NSPS IIII specifically exempts “nonroad engines” as defined in 40 CFR 1068.30.

4.1.2 SUMMARY

The proposed Morbark chipper is portable as it would not be a specific location at the site for more than 12 consecutive months and is not subject to an NSPS. Thus, combustion emissions from the engine are excluded from permitting under both NSR and Title V.

While the engine emissions are exempt from regulation under stationary source regulations, the PM emissions from the mobile chipper’s biomass transfer and chipping operations do meet the definition of a stationary source. Thus, mobile longwood chipping PM emissions are included in this permit application.

4.2 NSR APPLICABILITY

The NSR permitting program generally requires a stationary source obtain a permit and undertake other obligations prior to construction of any project at an industrial facility if the proposed project results in the potential to emit air pollution in excess of certain threshold levels. The NSR program is comprised of two elements: nonattainment NSR (NNSR) and Prevention of Significant Deterioration (PSD). The NNSR program potentially applies to new construction or modifications that result in emission increases of a particular pollutant for which the area in which the facility is located is classified as “nonattainment” for that pollutant. The PSD program applies to project increases of those pollutants for which the area the facility is located in is classified as “attainment” or “unclassifiable”. The Warren facility is located in Warren County, which has been designated by the U.S. EPA as “attainment” or “unclassifiable” for all criteria pollutants. Therefore, the facility is potentially subject to PSD permitting requirements for all pollutants covered under this program.

The PSD program only regulates emissions from “major” stationary sources of regulated air pollutants. A stationary source is considered PSD major if potential emissions of any regulated pollutant exceed the major source thresholds. The PSD major source emission threshold is 250 tpy of a PSD-regulated pollutant unless the source belongs to one of 28 specifically defined industrial source categories for which the major source threshold is 100 tpy.[25] Biomass-fired, non-fossil fuel-fired electric generating facilities are not on the list of 28 source categories. Further, fossil fuel-fired electric generating facilities with a fossil fuel heat input of less than 250 MMBtu/hr are not on the list of 28 sources categories. Therefore, the PSD major source threshold for the Warren facility is 250 tpy of any PSD-regulated pollutant. Note that since the facility is not on the List of 28 and does not have a source subject to a New Source Performance Standard (NSPS) or National Emission Standard for Hazardous Air Pollutants (NESHAP) promulgated before August 7, 1980, only non-fugitive (point source) emissions are assessed against the 250 tpy major source threshold; fugitive emissions are excluded from the major source applicability determination and are only calculated for pollutants for which PSD permitting is triggered.[26]

The PSD-regulated pollutants evaluated for this proposed project include: CO, NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, VOC, lead, fluorides, and H_2SO_4. Notably absent from the list are four compounds previously included under PSD that are regulated under Section 112, and thus are no longer regulated under the NSR program: asbestos, beryllium, mercury, vinyl chloride. Fluorides are discussed in further detail in the following paragraphs.

Fluorides in general are regulated under PSD. However, since hydrogen fluoride (HF) is on the CAA Section 112(b)(1) HAP list, emissions of HF are not regulated via PSD. Thus, the PSD-regulated pollutant related to fluorine is fluorides except HF.[27]

For combustion sources, most or all of the fluorine compounds emitted are expected to be in the form of HF, which is not regulated under PSD. The boiler vendor data provides HF emission factors but no factors for any other fluoride compound, presumably since HF is the only non-negligible form of fluoride released during the biomass combustion. For the purposes of PSD applicability and emissions estimates, Oglethorpe is assuming all fluorine compounds emitted are as HF.[28]

Table 4-1 illustrates that potential emissions of CO and NO_X will be greater than 250 tpy; each of these are non-fugitive since they are emitted from combustion exhausts. Therefore, since at least one PSD-regulated pollutant has non-fugitive emissions exceeding 250 tpy, the Warren facility will be a new PSD major stationary source, and PSD review will be required for the proposed project. As a

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[25] 40 CFR 52.21(b)(1)(i)(a)

[26] 40 CFR 52.21(a)(2)(iv)(b), 40 CFR 52.21(b)(1)(i)(c)(iii)

[27] The basis for the fluoride SER of 3 tpy is explained in the preamble to the 1980 PSD regulations (45 FR 52709). The rate is based on the NSPS for aluminum plants, adjusted to limit the potential for effects on vegetation near an aluminum plant. The NSPS for aluminum plants is 40 CFR 60, Subpart S, and 40 CFR 60.191 defines the fluorine compounds regulated.

> *Total fluorides means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.195 …*

Per 40 CFR 60.195, for stacks, either EPA Method 13A or 13B are used to measure fluoride compounds. However, to be able to differentiate HF from total fluorides, a combination of Method 26A first (to remove HF) followed by Method 13 could potentially be used to determine the non-HF fluorides emitted.

[28] Regardless, potential HF emissions, as shown in Table C-2, are less than the PSD SER of 3 tpy.

new site that will be a major PSD source, emissions increases from the project must then be assessed against the PSD Significant Emission Rates. Thus, in addition to CO and NO_X, PM, PM_{10}, $PM_{2.5}$, and SO_2 will also be subject to PSD review.[29]

TABLE 4-1. FACILITY-WIDE EMISSIONS AND PSD APPLICABILITY

Pollutant	Potential Emissions (tpy)	PSD Significant Emission Rates (tpy)	PSD Permitting Required? (Yes/No)
CO	625.7	100	Yes
NO_x	648.7	40	Yes
PM[1]	143.8	25	Yes
PM_{10}[1]	144.4	15	Yes
$PM_{2.5}$[2]	144.4	10	Yes
SO_2	56.2	40	Yes
VOC	39.1	40	No
H_2SO_4	6.9	7	No
Fluorides	-	3	No
Pb	8.13E-04	0.6	No

1. PM emissions are filterable particulate only. PM_{10} emissions are estimated as total particulate emissions (filterable + condensable). PM_{10} filterable emissions are based on the speciation of the PM. Due to the differences in the material handling particulate speciations, filterable PM emissions are very similar to total PM_{10} emissions.
2. $PM_{2.5}$ emissions assumed to be equal to PM_{10} emissions for PSD applicability purposes.

Greenhouse gases (GHG), including carbon dioxide (CO_2), are currently not evaluated for PSD permitting purposes, and therefore are not quantified or discussed further in this application.[30] However, it should be noted that this facility will be utilizing biomass as the primary fuel for the boiler. Minimal, if any, amounts of ULSD will be used for startup of the boiler only. Under EPA's final GHG reporting rule, emissions of CO_2 from biomass or biodiesel are considered carbon-neutral. Oglethorpe is pursuing sole biomass/biodiesel usage for Warren in an effort to rely entirely on renewable fuels.

[29] Fine particulate matter ($PM_{2.5}$) has not yet been incorporated into the Georgia State implementation plan (SIP). Per US EPA's May 8, 2008 implementation rule, Georgia has three years to update the SIP. Until that time, PM_{10} is used as a surrogate using both annual and 24-hr ambient standards. In addition, a recent Georgia Court of Appeals ruling confirmed that addressing $PM_{2.5}$ PSD requirements via the PM_{10} surrogate approach is allowable and appropriate. State of Georgia Court of Appeals Cases A09A0387 and A09A0388, *Longleaf Energy Associates, LLC v. Friends of the Chattahoochee, Inc. et al*, and *Couch v. Friends of the Chattahoochee, Inc. et al*, decided July 7, 2009.

[30] A recent Georgia Court of Appeals ruling confirmed that GHG need not be evaluated for PSD permitting in Georgia. State of Georgia Court of Appeals Cases A09A0387 and A09A0388, *Longleaf Energy Associates, LLC v. Friends of the Chattahoochee, Inc. et al*, and *Couch v. Friends of the Chattahoochee, Inc. et al*, decided July 7, 2009.

4.3 NEW SOURCE PERFORMANCE STANDARDS

NSPS require new, modified, or reconstructed sources to control emissions to the level achievable by the best-demonstrated technology as specified in the applicable provisions. Moreover, any source subject to an NSPS is also subject to the general provisions of NSPS Subpart A, unless specifically excluded.

4.3.1 40 CFR 60 SUBPART A, GENERAL PROVISIONS

All affected sources are subject to the general provisions of NSPS Subpart A unless specifically excluded by the source-specific NSPS. Subpart A requires initial notification and performance testing, recordkeeping, monitoring, provides reference methods, and mandates general control device requirements for all other subparts as applicable.

4.3.2 40 CFR 60 SUBPART D, FOSSIL FUEL-FIRED STEAM GENERATING UNITS > 250 MMBTU/HR

NSPS Subpart D, *Standards of Performance for Fossil Fuel Fired Steam Generators for which Construction is Commenced after August 17, 1971*, provides standards of performance for fossil fuel-fired and wood-fired steam generating units for which construction commenced after August 17, 1971.[31] This subpart applies to steam generating units having a maximum fossil fuel rated heat input capacity in excess of 250 MMBtu/hr. The maximum fossil fuel heat input will not exceed 250 MMBtu/hr, and NSPS D is not applicable.

Additionally, the proposed biomass boiler is not subject to NSPS Subpart D since NSPS Subpart Db will apply. NSPS Subpart Db states in 40 CFR 60.40b(j) that any unit subject to Subpart Db that was constructed, modified, or reconstructed after June 19, 1986, is not subject to Subpart D.

4.3.3 40 CFR 60 SUBPART DA, ELECTRIC UTILITY STEAM GENERATING UNITS

NSPS Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced After September 18, 1978*, applies to electric utility steam generating units with fossil fuel capacities greater than 250 MMBtu/hr (alone or in combination with any other fuel) for which construction, modification, or reconstruction commenced after September 18, 1978.[32] The proposed biomass boiler at Warren facility will not fire more than 250 MMBtu/hr of fossil fuel and hence, will not be subject to Subpart Da. Further, the firing of fossil fuels will only be part of two of the three potential startup scenarios for the boiler (to be limited to 249 MMBtu/hr) and is not the preferred option.

4.3.4 40 CFR 60 SUBPART DB, STEAM GENERATING UNITS > 100 MMBTU/HR

NSPS Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, provides standards of performance for steam generating units with capacities

[31] 40 CFR 60.40(a)

[32] 40 CFR 60.40a(a)

greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984.[33] The proposed biomass boiler will be constructed after 1984, will have a maximum heat input capacity greater than 100 MMBtu/hr, and will generate steam. NSPS Subpart Db will apply to the proposed biomass boiler. The unit will also be subject to the more stringent requirements of the standard as it is being constructed post-February 2005.

Under NSPS Subpart Db, the particulate matter standard for a unit that combusts wood is 0.030 lb/MMBTU, and the opacity limit is 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.[34] The PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.[35] The NO_X emissions are not to exceed 0.20 lb/MMBtu while firing fossil fuel; the NSPS Subpart Db NO_X limit will not apply if pure biodiesel is used as a startup fuel.[36] The SO_2 standard of this subpart will not apply to the proposed boiler because it will be firing fuels with a potential SO_2 emission rate of less than 0.32 lb/MMBtu (140 ng/J) via the usage of biomass and biodiesel/USLD.[37]

Initial performance tests will be required for the boiler using Method 5 for particulate matter and Method 9 for opacity.[38] Further, in accordance with 40 CFR 60.48b(a), the affected facility must install, calibrate, maintain, and operate a continuous opacity monitor (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. A NO_X continuous emissions monitoring system (CEMS) will be required if the NSPS Subpart Db NO_X limit applies (i.e., only if ULSD is used as a startup fuel).[39] Regardless of NSPS Db applicability, Oglethorpe is proposing to include CEMS for both NO_X and SO_2.

Other record keeping and reporting requirements outlined in 40 CFR 60.49b will also apply to the boiler. Specifically, 40 CFR 60.49b(a) sets forth the initial reporting requirements of 40 CFR 60.7 for the notification of commencement of construction, notification of initial start-up, and the performance testing notifications and reports. The proposed facility will be required to record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for wood and ULSD (if used) for the reporting period.[40]

[33] 40 CFR 60.40b(a)

[34] 40 CFR 60.43b(f) and (h)(1)

[35] 40 CFR 60.43b(g)

[36] 40 CFR 60.44b(l)(1)

[37] 40 CFR 60.42b(k)(2)

[38] 40 CFR 60.46b(d)

[39] 40 CFR 60.46b(f)

[40] 40 CFR 60.49b(d)

Oglethorpe requests that no requirement to record the amount of fuel used each day be included in the permit if only B100 is used as the startup auxiliary fuel. The amount of wood and/or biodiesel burned in the boiler daily does not change the applicability of Subpart Db since Oglethorpe is not relying on an annual capacity factor restriction. In an October 2005 applicability determination, U.S. EPA determined that for a facility that combusts only wood the requirement to record the amount of wood combusted each day is not needed for the purposes of calculating the annual capacity factor.[41] Additionally, biodiesel is not one of the fuels listed in the requirement to calculate the annual capacity factor.

4.3.5 40 CFR 60 Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels

NSPS Subpart Kb, *Standards of Performance for Volatile Organic Liquid Storage Vessels*, regulates storage vessels with a capacity greater than 75 cubic meters (m^3) (19,813 gallons) that are used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984.[42]

NSPS Subpart Kb has provisions to exempt tanks based on size and the maximum true vapor pressure of the material stored. Specifically, NSPS Subpart Kb "does not apply to storage vessels with a capacity greater than or equal to 151 m [39,890 gallons] storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m [19,813 gallons] but less than 151 m [39,890 gallons] storing a liquid with a maximum true vapor pressure less than 15.0 kPa."[43]

Only two volatile organic liquid storage tanks proposed for the facility will be greater than 19,813 gallons in size, the two 60,000 biodiesel/ULSD storage tanks. These tanks will have a maximum true vapor pressure of less than 3.5 kPa [0.5 psi] (less than 0.02 psi per TANKS4.0), exempting them from NSPS Subpart Kb.

4.3.6 40 CFR 60 Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants

NSPS Subpart OOO, *Standards of Performance for Nonmetallic Mineral Processing Plants*, establishes requirements for affected facilities being constructed on or after August 31, 1983 (note separate requirements apply to sources constructed, reconstructed or modified after April 22, 2008; these new requirements are included in the following paragraphs).[44] An affected facility in this subpart is defined as a facility that uses any combination of equipment to crush or grind any nonmetallic material. The sorbent injection system will utilize an on-line

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[41] Letter from Mr. Jeff Ken Knight (U.S. EPA) to Mr. Michael Scott Atkinson (Bennett Forest Industries), dated October 4, 2005. Applicability Determination Control Number: 0700014. http://cfpub.epa.gov/adi/

[42] 40 CFR 60.110b(a)

[43] 40 CFR 60.110b(b)

[44] The final rule incorporating updates to NSPS Subpart OOO was published on April 28, 2009 (74 FR 19294).

milling process between the storage silo and injection system. This process will be completely enclosed and will therefore not produce any emissions to be vented to the atmosphere.

The building enclosing the sorbent milling and transfer operations must meet a 7% opacity standard for fugitive emissions from building openings for building vents.[45] An initial Method 9 performance test is required, and additional compliance testing must be conducted every 5 years since water sprays will not be used.

The sorbent storage silo is equipped with a baghouse (for pneumatic transfer) and while exempt from any PM limits, it is subject to a 7% opacity limit.[46] An initial Method 9 performance test is required. Additionally, quarterly 30-minute visible emissions inspections must be conducted while the baghouse is operating or a bag leak detection system must be used.[47]

Truck dumping of nonmetallic minerals into any screening operation, feed hopper, or crusher is exempt from the requirements of Subpart OOO per 40 CFR 60.672(d).

4.3.7 40 CFR 60 SUBPART AAAA, SMALL MUNICIPAL WASTE COMBUSTION UNITS

NSPS Subpart AAAA, *Standards of Performance for Small Municipal Waste Combustion Units for which Construction is Commenced After August 30, 1999 or for which Modification or Reconstruction is Commenced After June 6, 2001*, establishes requirements for planning, constructing, and operating a small municipal waste combustion unit. Units are subject if they have the capacity to combust at least 35 but no more than 250 tons per day of municipal solid waste (MSW) and meet the definition of a new municipal waste combustion unit.
NSPS Subpart AAAA defines MSW and municipal-type solid waste as follows:

> *household, commercial/retail, or institutional waste. Household waste includes material discarded by residential dwellings, hotels, motels, and other similar permanent or temporary housing. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, nonmanufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes materials discarded by schools, by hospitals (nonmedical), by nonmanufacturing activities at prisons and government facilities, and other similar establishments or facilities. Household, commercial/retail, and institutional waste does include yard waste and refuse-derived fuel.* ***Household, commercial/retail, and institutional waste does not include*** *used oil; sewage sludge;* ***wood pallets; construction, renovation, and demolition wastes (which include railroad ties and telephone poles)****;* ***clean wood****; industrial process or manufacturing wastes; medical waste; or motor vehicles (including motor vehicle parts or vehicle fluff).*[48] [Emphasis added]

[45] 40 CFR 60.672(e)

[46] 40 CFR 60.672(f)

[47] 40 CFR 60.673(c), (d)

[48] 40 CFR 60.1465

The proposed biomass boiler will not combust any fuel meeting the definition of MSW. Therefore, this subpart will not be applicable.

4.3.8 40 CFR 60 Subpart CCCC, Commercial and Industrial Solid Waste Incinerators

NSPS Subpart CCCC, *Standards of Performance for Commercial and Industrial Solid Waste Incineration [CISWI] Units for which Construction is Commenced After November 30, 1999 or for which Modification or Reconstruction is Commenced on or After June 1, 2001*, establishes requirements for planning, constructing, and operating a CISWI unit. This rule defines solid waste in 40 CFR 60.2265 as:

> *any garbage, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, commercial, mining, agricultural operations, and from community activities …*

Further, the original definition of commercial and industrial waste as included in the rule states:

> *solid waste that is combusted in any commercial or industrial facility using controlled flame combustion in an enclosed, distinct operating unit whose design does not provide for energy recovery…*

Although the definitions of this Subpart were vacated by the U.S. Court of Appeals for the District of Columbia Circuit, it is clear that boilers firing unadulterated biomass for the purposes of energy recovery were not intended to be regulated under this Subpart.[49] All indications from U.S. EPA are that any future proposed new CISWI definition will exclude biomass, and that biomass boilers such as the one proposed for the Oglethorpe facility will be regulated as boilers. Therefore, Oglethorpe believes that Subpart CCCC will not be applicable to the proposed boiler and has prepared this permit application as such, but will monitor EPA's ongoing response to the court vacatur to confirm this approach.

4.3.9 40 CFR 60 Subpart EEEE, Other Solid Waste Incineration Units

NSPS Subpart EEEE, *Standards of Performance for Other Solid Waste Incineration Units [OSWI] for which Construction is Commenced After December 9, 2004, or for which Modification or Reconstruction is Commenced on or After June 16, 2006*, establishes requirements for planning, constructing, and operating an OSWI.

The OSWI definition simply notes "a very small municipal waste combustion unit [any setting or equipment that combusts MSW] or an institutional waste incineration unit [any combustion unit that combusts institutional waste]". Definitions of MSW and institutional waste are included in 40 CFR 60.2977:

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[49] *Natural Resources Defense Council, Sierra Club, Environmental Integrity Project v. U. S. EPA*, U.S. Court of Appeals for the District of Columbia Circuit, No. 04-1385, decided June 8, 2007.

> *Municipal solid waste means refuse (and refuse-derived fuel) collected from the general public and from residential, commercial, institutional, and industrial sources consisting of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials and non-combustible materials such as metal, glass and rock, provided that: (1)* ***the term does not include industrial process wastes*** *or medical wastes that are* ***segregated from such other wastes****; and (2) an incineration unit shall not be considered to be combusting municipal solid waste for purposes of this subpart if it combusts a fuel feed stream, 30 percent or less of the weight of which is comprised, in aggregate, of municipal solid waste, as determined by §60.2887(b)*
>
> *Institutional waste means solid waste (as defined in this subpart) that is combusted at any institutional facility using controlled flame combustion in an enclosed, distinct operating unit:* ***whose design does not provide for energy recovery*** *(as defined in this subpart); operated without energy recovery (as defined in this subpart); or operated with only waste heat recovery (as defined in this subpart). Institutional waste also means solid waste (as defined in this subpart) combusted on site in an air curtain incinerator that is a distinct operating unit of any institutional facility* [Emphasis added]

The proposed biomass boiler will not combust any fuel meeting the definition of MSW or institutional waste for OSWI. Therefore, this subpart will not be applicable.

4.3.10 40 CFR 60 SUBPART IIII, STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

NSPS Subpart IIII, *Standards of Performance for Stationary Compressions Ignition Internal Combustion Engines*, applies to owners or operators of stationary compression ignition (CI) internal combustion engines (ICE) manufactured after April 1, 2006 that are not fire pump engines, and fire pump engines manufactured after July 1, 2006. The Warren facility will have nominal 330 and 175 hp certified National Fire Protection Association (NFPA) fire pump engines that will combust biodiesel or ULSD. The fire pumps will have been manufactured after the date specified above. Therefore, the fire pumps are subject to the provisions of Subpart IIII.

In accordance with 40 CFR 60.4205(c), owners and operators of NFPA certified fire pump engines manufactured after July 1, 2006 must comply with the emission limits in Table 4 of NSPS Subpart IIII, which are organized based on the size of the unit. The applicable limits for the proposed nominal 175 and 330 hp, model year 2010 or later engines are as follows:

- ▲ NO_X + nonmethane hydrocarbons (NMHC): 3.0 g/hp-hr
- ▲ PM: 0.15 g/hp-hr

Oglethorpe will comply with these emission limits by operating the fire pumps as instructed in the manufacturer's operating manual in accordance with 40 CFR 60.4211(a) and purchasing engines certified to meet the referenced emission limits. The engines will be equipped with non-resettable hour meters in accordance with 40 CFR 60.4209(a). Maintenance checks and readiness testing of the units will be limited to 100 hours per year; however, Oglethorpe is requesting that total operation (emergency and non-emergency) be limited to 500 hours per year per engine. No recordkeeping or reporting will be required for the emergency engines; additionally, no initial notification under 40 CFR 60.7(a)(1) is required.[50]

The fire pumps will be required to comply with the fuel requirements in 40 CFR 60.4207, which limit sulfur to a maximum 15 ppmw beginning October 1, 2010. Biodiesel or ULSD with a sulfur content of 15 ppmw or less will be utilized in the proposed fire pump engines.

Note that the mobile chipper engine will not be subject to NSPS Subpart IIII as it does not meet the definition of a stationary engine. Per 40 CFR 60.4219, a stationary internal combustion engine is:

> *any internal combustion engine [ICE], except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition.*

The 40 CFR 1068.30 definition of a nonroad engine was previously included in Section 4.1.1, and as previously discussed, the mobile chipper engine meets the paragraph (1)(iii) nonroad engine requirement and does not meet any of the exemptions in paragraph (2) as a rental chipper unit will only be on site on an as-needed basis (anticipated to be only a few months per year, if at all). Therefore, the mobile chipper engine meets the definition of a nonroad engine and is not considered a stationary engine under NSPS Subpart IIII.

Note that for conservatism, Oglethorpe has assumed 16 hr/day and 365 day/yr longwood chipping operation for emissions calculations and dispersion modeling purposes.

4.4 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

NESHAP, federal regulations found in Title 40 Parts 61 and 63 of the CFR, are emission standards for HAP and are primarily applicable to major sources of HAP (facilities that exceed the major source thresholds of 10 tpy of a single HAP and 25 tpy of any combination of HAP from stationary sources) or specifically designated area sources. NESHAP apply to sources in specifically regulated industrial source classifications (Clean Air Act Section 112(d)) or on a case-by-case basis (Clean Air Act Section 112(g)) for facilities not regulated as a specific industrial source type. Pollutant specific NESHAP may also be applicable.

To be classified as a non-major source for HAP, Oglethorpe requests a permit limit for HCl of 9.9 tpy, or a requirement that emissions of HCl shall be less than 10 tpy. All other individual HAP have potential emissions of 5 tpy or less using conservative estimates of emissions, with most below

[50] 40 CFR 60.4214(b)

0.1 tpy.[51] To provide ongoing verification of meeting the HCl annual limit, Oglethorpe proposes to perform an initial stack test for HCl during startup testing of the unit. Based on the result of that stack test, if actual emissions are above 8.0 tpy, Oglethorpe will commence stack testing for HCl on a quarterly basis, while stack tests will occur annually if actual emissions are less than 8.0 tpy. If two successive quarterly stack tests show that actual emission remain below 8.0 tpy, Oglethorpe will then again stack test on an annual basis. If the results of three successive annual stack tests show that Oglethorpe has remained below 8.0 tpy actual emissions, the stack testing frequency would decrease to every five years (or once during each Title V permit term).

4.4.1 40 CFR 63 Subpart A, General Provisions

All affected sources are subject to the general provisions of Part 63 NESHAP Subpart A unless specifically excluded by the source-specific NESHAP. Subpart A requires initial notification and performance testing, recordkeeping, monitoring, provides reference methods, and mandates general control device requirements for all other subparts as applicable.

4.4.2 40 CFR 63 Subpart B, 112(g) Case-by-Case MACT

Section 112(g) of the 1990 Clean Air Act Amendments (codified at 40 CFR 63 Subpart B, *Requirements for Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections*), is known as the case-by-case MACT. The NESHAP regulating boilers (Subpart DDDDD) has been vacated and the NESHAP regulating electric utility steam generating units (Subpart UUUUU) has not been promulgated. Thus, case-by-case MACT is potentially applicable to new boilers based on Georgia EPD guidance.[52]

Case-by-case MACT is applicable to newly constructed major sources of HAP emissions. As discussed previously in this application, the Warren facility will be a minor (area) source for HAP emissions. Therefore, case-by-case MACT does not apply to the proposed boiler.

4.4.3 40 CFR 63 Subpart Q, Cooling Towers

40 CFR 63 Subpart Q, *NESHAP for Industrial Process Cooling Towers*, applies to cooling towers operating with chromium-based water treatment chemicals that are located at facilities that are major sources of HAP. The only requirement for affected sources is to utilize water treatment chemicals that are not chromium based. The new cooling tower water treatment chemicals will not be chromium based, so this regulation will not apply to the proposed cooling tower.

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[51] The next highest HAP is chlorine (Cl_2) at 4.4 tpy, but this emission rate is based on AP-42 factors and is believed to substantially overestimate actual chlorine emissions. Boiler vendors contacted for specific Cl_2 emission factors and control efficiencies stated that to their knowledge all chlorine in the fuel is emitted as HCl with none as Cl_2. After Cl_2, the HAPs with the next highest emission rates are HF (2.25 tpy, AP-42 factor), formaldehyde (1.0 tpy), 1-2-dichloroethane (0.65 tpy), propionaldehyde (0.34 tpy), acetaldehyde (0.24 tpy), chlorobenzene (0.19 tpy), 1,2-dichloropropane (0.19 tpy), and methyl chloride (0.13 tpy). All remaining HAP are below 0.1 tpy. See Table 5 in Appendix C for a listing of all HAP potential emissions.

[52] Georgia EPD, *Boiler MACT Vacatur Q&A*, January 8, 2008 update. Available at: http://www.georgiaair.org/airpermit/html/sscp/sscp_boiler_mact_faq.htm

4.4.4 40 CFR Part 63 Subpart ZZZZ, Reciprocating Internal Combustion Engines

40 CFR 63 Subpart ZZZZ, *NESHAP for Stationary Reciprocating Internal Combustion Engines*, applies to reciprocating internal combustion engines (RICE) located at a major or area source of HAP emissions. The affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions. Thus, the fire pump engines are new affected sources under Subpart ZZZZ.

Emergency stationary RICE are defined in 40 CFR 63.6675 as any stationary RICE that operates in an emergency situation. These situations include engines used to pump water in the case of fire or flood. Thus, the fire pump engines are considered emergency RICE under Subpart ZZZZ.

As the proposed fire pumps will be subject to NSPS Subpart IIII and are emergency stationary RICE with a rating of less than or equal to 500 hp, compliance with NESHAP Subpart ZZZZ is met by complying with the NSPS Subpart IIII requirements. No other requirements will apply to the proposed fire pump engines under NESHAP Subpart ZZZZ.[53]

40 CFR 63.6675 provides a definition of a stationary reciprocating internal combustion engine. The specified definition is the same as the definition of a stationary internal combustion engine per 40 CFR 60 Subpart IIII. As discussed in Sections 4.1.2 and 4.3.10, the mobile chipper engine meets the definition of a nonroad engine and therefore does not meet the definition of a stationary internal combustion engine. NESHAP Subpart ZZZZ does not apply to the mobile chipper engine.

Note that for conservatism, Oglethorpe has assumed 16 hr/day and 365 day/yr longwood chipping operation for emissions calculations and dispersion modeling purposes.

4.4.5 40 CFR Part 63 Subpart DDDDD, Industrial Boilers and Process Heaters

As originally promulgated, NESHAP Subpart DDDDD, *NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters*, regulated HAP emissions from solid, liquid, and gaseous-fired steam generating units at major HAP sources. The proposed biomass boiler would have been regulated under Subpart DDDDD if the original rule had included requirements for minor HAP sources (the original rule only applied to HAP major sources), as it would be classified under the industrial boiler category.

However, in June 2007, the U.S. Court of Appeals for the District of Columbia Circuit ruled to vacate the NESHAP Subpart DDDDD in its entirety, and the mandate was issued July 30, 2007.[54] Upon promulgation of the revised rule (anticipated by December 2010), the

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[53] 40 CFR 63.6590(c)

[54] *Natural Resources Defense Council, Sierra Club, Environmental Integrity Project v. U. S. EPA*, U.S. Court of Appeals for the District of Columbia Circuit, No. 04-1385, decided June 8, 2007. http://pacer.cadc.uscourts.gov/docs/common/opinions/200706/04-1385a.pdf

applicability of the rule to the proposed biomass boiler will be reassessed. It is anticipated that the revised rule will regulate boilers at both HAP major and non-major facilities. Based on initial indications by U.S. EPA, the proposed biomass boiler will be subject to the Subpart DDDDD requirements for boilers located at non-major HAP sources.

4.4.6 40 CFR PART 63 SUBPART UUUUU, ELECTRIC UTILITY STEAM GENERATING UNITS

40 CFR 63 Subpart UUUUU, *NESHAP for Electric Utility Steam Generating Units*, was proposed on January 30, 2004 but never finalized.[55] U.S. EPA will be proposing a new rule (anticipated in 2010). Based on indications from U.S. EPA, however, the new rule is expected to apply only to coal and/or oil-fired boilers firing more than 250 MMBtu/hr of fossil fuel and generating electricity for sale to the grid. Thus, the proposed biomass boiler would not be subject to Subpart UUUUU since it will not be firing any fossil fuels at a heat input of greater than 250 MMBtu/hr. Further, as previously noted, the proposed biomass boiler is expected to be regulated under minor source rules under Subpart DDDDD.

4.5 COMPLIANCE ASSURANCE MONITORING

Under 40 CFR 64, Compliance Assurance Monitoring (CAM), facilities are required to prepare and submit monitoring plans for certain emission units with the initial or renewal Title V operating permit application. The CAM Plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation only applies to emission units that use a control device to achieve compliance with an emission limit and whose pre-controlled emission levels exceed the major source thresholds under the Title V permitting program unless such units meet a specified exemption.

For an emission unit whose post-controlled emissions are greater than the major source thresholds (referred to as large pollutant-specific emission units [PSEU] in the rule), a CAM plan is required to be submitted with the initial Title V operating permit application. For emission units whose post-controlled emissions are less than the major source emission thresholds, a CAM plan is not required to be submitted until the first Title V permit renewal application.[56]

The proposed biomass boiler has pre-controlled emissions greater than 100 tpy for CO, NO_X, $PM/PM_{10}/PM_{2.5}$, and SO_2 and will be subject to BACT limits for these pollutants. SNCR will be used to control NO_X emissions, a baghouse will be used to control filterable $PM/PM_{10}/PM_{2.5}$ emissions, and duct sorbent injection will be used to minimize SO_2 emissions and condensable $PM_{10}/PM_{2.5}$ emissions. As such, the boiler will require CAM Plans specific to NO_X, $PM/PM_{10}/PM_{2.5}$, and SO_2. None of the other PSD-regulated pollutants utilize a control device to meet an emission limit. Appropriate CAM Plans will be submitted as part of the initial and/or renewal Title V operating permit application, as required by 40 CFR 64 for large and small PSEU. Note that the CEMS for NO_X and SO_2 could be used in lieu of a CAM plan if elected by Oglethorpe, leaving only $PM/PM_{10}/PM_{2.5}$ requiring a CAM plan.

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[55] 69 Federal Register 4652 (January 30, 2004).

[56] 40 CFR 64.5

The proposed biomass boiler also has pre-controlled emissions of HCl greater than the 10 tpy. These emissions are controlled via the duct sorbent injection, and thus would also require submittal of a CAM plan as part of the initial Title V operating permit application.

All other units at the facility emit post-controlled emissions less than the major source threshold and/or do not use a control device as defined by the CAM regulations (note devices used for pneumatic transfer are considered inherent to the operation of the emission unit, not control devices, per the CAM definition of a control device). It is possible some of the biomass material handling baghouses will have pre-controlled PM emissions of greater than the major source threshold. However, final designs of the baghouses have not been completed. Upon design completion and installation of the baghouses, Oglethorpe will evaluate CAM applicability for these sources as part of the initial Title V operating permit application.

4.6 RISK MANAGEMENT PROGRAM

Subpart B of 40 CFR Part 68 outlines requirements for risk management prevention plans pursuant to Section 112(r) of the Clean Air Act. Applicability of the subpart is determined based on the type and quantity of chemicals stored at the facility. Oglethorpe has evaluated the amount of Section 112(r) substances proposed to be stored at the facility and has determined that no substance is stored in a quantity above the triggering threshold (the 19% aqueous ammonia planned to be utilized by the facility is below the % ammonia RMP threshold). Thus, the facility is not subject to the RMP requirements. However, the facility is subject to the provisions of the CAAA General Duty Clause, Section 112, as it pertains to accidental releases of hazardous materials.

4.7 TITLE V OPERATING PERMIT PROGRAM

40 CFR 70 establishes the federal Title V operating permit program. Georgia has incorporated the provisions of the federal program in GRAQC 391-3-1-.03(10) *Title V Operating Permits*. The major source thresholds with respect to the Georgia Title V operating permit program for sources in attainment areas are 10 tons per year of a single HAP, 25 tpy of any combination of HAP, or 100 tpy of a criteria pollutant.

As shown previously, the potential emissions of CO, NO_X, and $PM/PM_{10}/PM_{2.5}$ at the Warren facility exceed 100 tpy. Thus, a Title V operating permit will be required for Warren facility. In accordance with the Title V operating permit program, a Title V operating permit application will be submitted no later than 12 months after the Warren facility commences operation.

4.8 ACID RAIN PROGRAM

In order to reduce acid rain in the United States and Canada, Title IV (40 CFR 72 *et seq.*) of the Clean Air Act Amendments of 1990 established the Acid Rain Program to substantially reduce SO_2 and NO_X emissions from electric utility plants. Affected units are specifically listed in Tables 1 and 2 of 40 CFR 73.10 under Phase I of the program. Under Phase II implementation, the Acid Rain Program applies to fossil fuel-fired combustion sources that drive generators for the purposes of generating electricity for sale.

Under either of the two startup scenarios that employ ULSD as the auxiliary fuel, the proposed biomass boiler at Warren facility will fire some fossil fuel and thus will meet the definition of affected source under the Acid Rain regulations. If this is the case, Oglethorpe will comply with all subparts of the Acid Rain Program.

If the preferred startup scenario is feasible and only B100 is used as the startup auxiliary fuel, the proposed boiler will not be firing any fossil fuel and will not meet the definition of an affected source under the Acid Rain regulations. In this scenario, the Acid Rain Program would not apply.

4.9 STRATOSPHERIC OZONE PROTECTION REGULATIONS

The requirements originating from Title VI of the Clean Air Act, entitled *Protection of Stratospheric Ozone*, are contained in 40 CFR 82. Subparts A through E and Subparts G and H are not expected to be applicable to the Warren facility. 40 CFR 82 Subpart F, *Recycling and Emissions Reduction*, potentially applies if the facility maintains, services, or disposes of appliances that utilize Class I or Class II ozone depleting substances. Subpart F generally requires persons completing the repairs, service, or disposal to be properly certified. All repairs, service, and disposal of ozone depleting substances from any chillers and air conditioners at the proposed facility will be completed by a certified technician.

4.10 CLEAN AIR INTERSTATE RULE

In May 2005, U.S. EPA promulgated CAIR to reduce the impact of upwind sources on out-of-state downwind $PM_{2.5}$ and ozone nonattainment areas. CAIR required upwind states, including Georgia, to revise their state rules to include measures to reduce NO_X and SO_2. CAIR was added to the Georgia state rules effective March 1, 2007. Georgia incorporated most of the federal rule (40 CFR Part 96) via reference. CAIR in Georgia is designed to rectify $PM_{2.5}$ nonattainment and thus regulates SO_2 and NO_X via annual emission caps for each pollutant. Note that unlike many states, Georgia's CAIR rule does not include an ozone season NO_X cap, since CAIR for Georgia is focused on $PM_{2.5}$ and not ozone. In addition to the emissions caps, CAIR includes emissions trading provisions like the ARP. However, there are important differences. Allocations of emission allowances for SO_2 are identical to allocations under the ARP, but the value of an ARP allowance is less for CAIR (e.g., two ARP allowances for one CAIR allowance initially for SO_2).

As promulgated, CAIR defined NO_X and SO_2 affected sources in 40 CFR 96.104(a) and 40 CFR 96.204(a), respectively, as "any stationary, fossil-fuel-fired boiler…serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale."

If only B100 is used as the auxiliary fuel during startup, the proposed biomass boiler would not fire fossil fuel and therefore would not meet the definition of affected sources under CAIR. If, however, ULSD is used as an auxiliary fuel during startup, then the proposed boiler will utilize fossil fuels and will therefore be regulated by CAIR. If this is the case, then Oglethorpe will comply by retiring the necessary credits and conducting monitoring, recordkeeping, and reporting as required by CAIR.

4.11 STATE REGULATORY REQUIREMENTS

In addition to federal air regulations, GRAQC 391-3-1 establishes regulations applicable at the emission unit level (source specific) and at the facility level for stationary sources.[57] The rules also contain requirements related to the need for construction and/or operating permits.

4.11.1 GRAQC 391-3-1-.02(2)(B), VISIBLE EMISSIONS

This regulation limits the opacity from all sources to 40%, provided that the source is not subject to some other emission limitation under GRAQC 391-3-1-.02(2).[58] This regulation will be applicable to the storage silos, the compression ignition fire pump engines, the cooling tower, and the biomass handling and processing operations. The proposed biomass boiler, however, will be subject to another opacity limit under GRAQC 391-3-1-.02(2)(d).

4.11.2 GRAQC 391-3-1-.02(2)(D), FUEL-BURNING EQUIPMENT

This regulation limits PM emissions from all fuel-burning equipment. It also limits opacity and NO_X emissions from equipment constructed or modified after January 1, 1972. Georgia defines fuel-burning equipment as:

> *…equipment the primary purpose of which is the production of thermal energy from the combustion of any fuel. Such equipment is generally that used for, but not limited to, heating water, generating or superheating steam, heating air as in warm air furnaces, furnishing process heat indirectly, through transfer by fluids or transmissions through process vessel walls.*[59]

The main usage of the proposed biomass boiler will be the generation of steam, thus subjecting the boiler to this regulation; no other equipment at the Warren facility is primarily used for the production of thermal energy.

For the proposed biomass boiler, which will be constructed after January 1, 1972 and will be greater than 250 MMBtu/hr, this rule establishes a PM limit of 0.10 lb/MMBtu and a 20% opacity limit (except one 6-minute period per hour of up to 27%).

Rule (d) also has a NO_X limit of 0.3 lb/MMBtu for boilers greater than 250 MMBtu/hr when combusting fuel oil. As the rule does not specify that the heat input from the fossil fuel itself must be greater than 250 MMBtu/hr, the Rule (d) NO_X limit would likely apply during startup operations if ULSD is used. Regardless, the proposed NO_X BACT limit should subsume the Rule (d) NO_X limit.

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[57] The mobile chipper engine does not meet the definition of a stationary source per GRAQC 391-3-1-.01(aaaa).

[58] GRAQC 391-3-1-.02(2)(b)1

[59] GRAQC 391-3-1-.01(cc)

4.11.3 GRAQC 391-3-1-.02(2)(E), PM EMISSIONS FROM MANUFACTURING PROCESSES

This regulation, commonly known as the process weight rule (PWR), establishes PM limits for all sources if not specified elsewhere. The PM emissions are limited based on the following equations (for equipment constructed or modified after July 2, 1968), where equation (a) applies to sources with a process input rate of less than or equal to 30 ton/hr, while equation (b) applies to sources with a process input rate of more than 30 ton/hr:[60]

(a) $E = 4.10 \times P^{0.67}$ (b) $E = 55.0 \times P^{0.11} - 40$

where: E = allowable PM emission rate [lb/hr]
P = process input weight rate [tons/hr]

This regulation is expected to apply to the storage silos and biomass handling systems. Since the proposed biomass boiler will be subject to a PM limit under Rule (d), this rule will not apply to the boiler.[61]

4.11.4 GRAQC 391-3-1-.02(2)(G), SO_2

This regulation establishes SO_2 emission limits for fuel-burning sources, not "equipment". The proposed boiler, with a heat input capacity above 100 MMBtu/hr, is limited to 3% sulfur for any fuel fired.[62] The proposed fire pump engines, with a maximum heat input capacity below 100 MMBtu/hr, are subject to a fuel sulfur content limit of 2.5%. Compliance with the fuel sulfur limits will be inherent via the usage of biomass and/or biodiesel/ULSD with a sulfur content of 15 ppmw or less.

Note Rule (g) also imposes SO_2 lb/MMBtu limits if fossil fuel firing capabilities exceed 250 MMBtu/hr. Although ULSD may be used as a startup fuel for the proposed boiler, usage of this fuel would be restricted to less than 250 MMBtu/hr; thus, the Rule (g) lb/MMBtu SO_2 limits would not apply.

4.11.5 GRAQC 391-3-1-.02(2)(N), FUGITIVE DUST

This regulation requires facilities to take reasonable precautions to prevent fugitive dust from becoming airborne. Operations at the proposed facility, including the biomass handling and storage systems, are covered by this generally applicable rule. The appropriate precautions will be taken to prevent fugitive dust from becoming airborne and ensure that opacity from fugitive dust sources is less than 20% as required by this rule.

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[60] GRAQC 391-3-1-.02(2)(e)(1)(i)

[61] GRAQC 391-3-1-.02(2)(d)

[62] GRAQC 391-3-1-.02(2)(g)2

4.11.6 GRAQC 391-3-1-.02(2)(FF), SOLVENT METAL CLEANING

This regulation provides requirements for design and usage of various types of degreasers. All degreasers to be used at the proposed Warren facility will be operated under the requirements of this regulation.

4.11.7 GRAQC 391-3-1-.02(2)(UU), VISIBILITY PROTECTION

This regulation requires Georgia EPD to provide an analysis of a source's anticipated impact on visibility in any federal Class I area to the appropriate Federal Land Manager (FLM). Based on the June 2008 draft guidance from the FLMs, detailed Air Quality Related Values (AQRV) modeling for visibility and deposition is not required for facilities located more than 50 km from the nearest Class I area and have a Q/d value of less than 10 [where Q is the sum of the short-term NO_X, PM_{10}, SO_2, and H_2SO_4 project emission increases (expressed in tpy) and d is the distance to the Class I area (expressed in kilometers)].[63] This Q/d screening threshold was proposed since it is consistent with what was utilized by U.S. EPA in their 2005 Best Available Retrofit Technology (BART) guidelines.[64]

Based on a distance to the nearest Class I area (Shining Rock Wilderness area) of 216 km, the Q/d value would be approximately four.[65] Thus, it is unlikely the FLM would specifically require visibility impact modeling. However, both the FLM and Georgia EPD have the discretion to request that such modeling be conducted prior to issuance of a construction permit. Notifications have been sent to the FLMs and copied to Georgia EPD; copies of these notification letters are provided in Volume II.

4.11.8 GRAQC 391-3-1-.02(2)(JJJ), NO_X FROM ELECTRIC UTILITY STEAM GENERATING UNITS

This regulation limits NO_X emissions from electric utility steam generating units located in or near the original Atlanta 1-hour ozone nonattainment area. Warren facility is not located within the geographic area covered by this rule.

4.11.9 GRAQC 391-3-1-.02(2)(LLL), NO_X FROM FUEL-BURNING EQUIPMENT

This regulation limits NO_X emissions from fuel-burning equipment with capacities between 10 and 250 MMBtu/hr that are located in or near the original Atlanta 1-hour ozone nonattainment area. Warren facility is not located within the geographic area covered by this rule.

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[63] Federal Land Managers' Air Quality Related Values Work Group (FLAG), FLAG Phase I Report – Revised, June 27, 2008.

[64] Federal Register Vol. 70, No. 128, July 6, 2005, pages 39104-39172.

[65] Q value of 855.6 per Table 1-1 (Calculated using the formula, Q = 143.8 tpy PM_{10} + 648.7 tpy NO_X + 56.2 tpy SO_2 + 6.9 tpy H_2SO_4); D value of 216, the minimum distance to Shining Rock.

4.11.10 GRAQC 391-3-1-.02(2)(rrr), NO_X from Small Fuel-Burning Equipment

This regulation specifies requirements for fuel-burning equipment with capacities of less than 10 MMBtu/hr located in or near the original Atlanta 1-hour ozone nonattainment area. Warren facility is not located within the geographic area covered by this rule.

4.11.11 GRAQC 391-3-1-.02(2)(sss), Multipollutant Control for Electric Utility Steam Generating Units

This regulation limits the operation of specific electric utility steam generating units. As the proposed Oglethorpe facility will not contain any of the units specified by this regulation, Rule (sss) will not apply.

4.11.12 GRAQC 391-3-1-.02(2)(ttt), Mercury Emissions from New Electric Generating Units

This regulation limits the emission of mercury from affected units installed on or after January 1, 2007. For the purposes of this subsection, an "affected unit" refers to a "stationary coal-fired boiler or a stationary coal-fired combustion turbine." The boiler at the proposed Oglethorpe facility will solely fire biomass and biodiesel/ULSD fuels and therefore will not be considered a "coal-fired" unit. Hence, Rule (ttt) will not apply.

4.11.13 GRAQC 391-3-1-.02(3), Sampling

This regulation requires any sampling, computation, and analysis to determine compliance with any emission limits or standards established by the Georgia SIP be completed in accordance with Georgia EPD's *Procedures for Testing and Monitoring Sources of Air Pollutants*. The proposed facility will comply with the applicable portions of this rule as required.

4.11.14 GRAQC 391-3-1-.02(5), Open Burning

This regulation imposes restrictions on open burning activities. The regulation specifies what type of burning is permitted, when, and limits opacity to 40%. The facility shall comply with the requirements of this regulation in the event of performing open burning.

4.11.15 GRAQC 391-3-1-.02(6)(b), Source monitoring

This regulation allows Georgia EPD to require a facility to install, maintain, and use monitoring devices necessary to determine compliance with any emission limits or standards established by the Georgia SIP. Such devices shall be installed, operated, calibrated, maintained, and information reported in accordance with the Georgia EPD's *Procedures for Testing and Monitoring Sources of Air Pollutants*. The proposed facility will comply with the applicable portions of this rule as required.

4.11.16 GRAQC 391-3-1-.02(7), PSD of Air Quality

This regulation incorporates the federal PSD program in 40 CFR 52.21, with certain revisions. PSD permitting requirements were discussed previously in this report.

4.11.17 GRAQC 391-3-1-.03(1), CONSTRUCTION (SIP) PERMIT

This regulation requires any facility which may result in air pollution to acquire a construction permit. The application for such a permit must be submitted on the forms provided by the Director well in advance of any critical date involved in the construction of the facility. In compliance with this regulation, the SIP forms have been prepared for the construction of the proposed Oglethorpe facility and are included as Appendix B to this application.

4.11.18 GRAQC 391-3-1-.03(10), TITLE V OPERATING PERMITS

This regulation incorporates the federal Title V operating permit program of 40 CFR 70. Applicability of this program was discussed previously in this report.

4.11.19 INCORPORATION OF FEDERAL REGULATIONS BY REFERENCE

The following federal regulations are incorporated in the GRAQC by reference and were addressed previously in this application:

- GRAQC 391-3-1-.02(8) – NSPS
- GRAQC 391-3-1-.02(9) – NESHAP
- GRAQC 391-3-1-.02(10) – RMP
- GRAQC 391-3-1-.02(11) – CAM
- GRAQC 391-3-1-.02(12)-(13) – CAIR
- GRAQC 391-3-1-.13 – ARP

4.11.20 NON-APPLICABILITY OF OTHER SIP RULES

A thorough examination of the Georgia SIP rule applicability to the proposed facility reveals many SIP regulations that do not apply or impose no additional requirements on operations. Such SIP rules include those specific to a particular type of industrial operation and/or those specific to sources located within the metro Atlanta ozone nonattainment area.

This section discusses the regulatory basis for BACT, approach used in completing the BACT analyses, and the BACT analyses for the proposed facility. Supporting documentation is included in Appendix D.

5.1 BACT DEFINITION

The requirement to conduct a BACT analysis is set forth in the PSD regulations [40 CFR 52.21(j)(2)]:

(j) Control Technology Review.

(2) A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.

BACT is defined in the PSD regulations [40 CFR 52.21(b)(12)] as:

> *...an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, 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 such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.*
> [primary BACT definition]
>
> *If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*
> [allowance for secondary BACT standard under certain conditions]

The primary BACT definition can be best understood by breaking it apart into its separate components.

5.1.1 EMISSION LIMITATION

an emissions limitation

First and foremost, BACT is an emission limit. While BACT is prefaced upon the application of technologies to achieve that limit, the final result of BACT is a limit. In general, this limit would be an emission rate limit of a pollutant (i.e., lb/MMBtu).[66]

5.1.2 CASE-BY-CASE BASIS

a case-by-case basis, taking into account energy, environmental and economic impacts and other costs

Unlike many of the Clean Air Act programs, the PSD program's BACT evaluation is case-by-case. As noted by U.S. EPA,

> *The case-by-case analysis is far more complex than merely pointing to a lower emissions limit or higher control efficiency elsewhere in a permit or a permit application. The BACT determination must take into account all of the factors affecting the facility, such as the choice of [fuel]… The BACT analysis, therefore, involves judgment and balancing.* [67]

To assist applicants and regulators with the case-by-case process, in 1987 U.S. EPA issued a memorandum that implemented certain program initiatives to improve the effectiveness of the PSD program within the confines of existing regulations and state implementation plans.[68] Among the initiatives was a "top-down" approach for determining BACT. In brief, the top-down process suggests that all available control technologies be ranked in descending order of control effectiveness. The most stringent or "top" control option is the default BACT emission limit unless the applicant demonstrates, and the permitting authority in its informed opinion agrees, that energy, environmental, and/or economic impacts justify the conclusion that the most stringent control option is not achievable in that case. Upon elimination of the most stringent control option based upon energy, environmental, and/or economic considerations, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is selected.

The five steps in a top-down BACT evaluation can be summarized as follows:

Step 1. Identify all possible control technologies;

Step 2. Eliminate technically infeasible options;

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[66] Emission limits can be broadly differentiated as "rate-based" or "mass-based." For a boiler, a rate-based limit would typically be in units of lb/MMBtu (mass emissions per heat input). In contrast, a typical mass-based limit would be in units of lb/hr (mass emissions per time).

[67] U.S. EPA Responses to Public Comments on the Proposed PSD Permit for the Desert Rock Energy Facility, July 31, 2008, p.41-42.

[68] Memo dated December 1, 1987, from J. Craig Potter (EPA Headquarters) to EPA Regional Administrators, titled "Improving New Source Review Implementation."

Step 3. Rank the technically feasible control technologies based upon emission reduction potential;

Step 4. Evaluate ranked controls based on energy, environmental, and/or economic considerations; and

Step 5. Select BACT.

While the top-down BACT analysis is a procedural approach suggested by U.S. EPA policy, this approach is not specifically mandated as a statutory requirement of the BACT determination. As discussed in Section 5.1.1, the BACT limit is an emissions limitation and does not require the installation of any specific control device.

5.1.3 ACHIEVABLE

based on the maximum degree of reduction …[that Georgia EPD] … *determines is achievable … through application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques*

BACT is to be set at the lowest value that is achievable. However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life. As discussed by the DC Circuit Court of Appeals

> *In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."*[69]

U.S EPA has reached similar conclusions in prior determinations for PSD permits.

> *Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.* [70]

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[69] As quoted in Sierra Club v. EPA (97-1686).

[70] EPA Environmental Appeals Board decision, *In re: Newmont Nevada Energy Investment L.L.C.* PSD Appeal No. 05-04, decided December 21, 2005. Environmental Administrative Decisions, Volume 12, Page 442.

Thus, BACT must be set at the lowest feasible emission rate recognizing that the facility must be in compliance with that limit for the lifetime of the facility on a continuous basis. Thus, while viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life. While statistical variability of actual performance can be used to infer what is "achievable," such testing requires a detailed test plan akin to what teams in U.S. EPA use to develop MACT standards over a several year period, and is far beyond what is reasonable to expect of an individual source. In contrast to limited snapshots of actual performance data, emission limits from similar sources can reasonably be used to infer what is "achievable."[71]

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source (see Section 5.2)

5.1.4 FLOOR

Emissions [shall not] *exceed …40 CFR Parts 60 and 61*

The least stringent emission rate allowable for BACT is any applicable limit under either New Source Performance Standards (NSPS – Part 60) or National Emission Standards for Hazardous Air Pollutants (NESHAP – Parts 61 and 63). State SIP limitations must also be considered when determining the floor.

5.2 REDEFINING THE SOURCE

Historical practice, as well as recent court rulings, have been clear that a key foundation of the BACT process is that BACT applies to the type of source proposed by the applicant, and that redefining the source is not appropriate in a BACT determination.

Though BACT is based on the type of source as proposed by the applicant, the scope of the applicant's ability to define the source is not absolute. As U.S. EPA notes, a key task for the reviewing agency is to determine which parts of the proposed process are inherent to the applicant's purpose and which parts may be changed without changing that purpose. As discussed by U.S. EPA in an opinion on the Prairie State project,

> *We find it significant that all parties here, including Petitioners, agree that Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through application of BACT.*[72]

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[71] Emission limits must be used with care in assessing what is "achievable." Limits established for facilities which were never built must be viewed with care, as they have never been demonstrated and that company never took a significant liability in having to meet that limit. Likewise, permitted units which have not yet commenced construction must also be viewed with special care for similar reasons.

[72] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 26.

…

When the Administrator first developed [U.S. EPA's policy against redefining the source] *in* Pennsauken*, the Administrator concluded that permit conditions defining the emissions control systems "are imposed on the source as the applicant has defined it" and that "the source itself is not a condition of the permit.*[73]

Given that some parts of the project are not open for review under BACT, U.S. EPA then discusses that it is the permit reviewer's burden to define the boundary. Based on precedent set in multiple prior U.S. EPA rulings (e.g., Pennsauken County Resource Recovery [1988], Old Dominion Electric Coop [1992], Spokane Regional Waste to Energy [1989], U.S. EPA states the following in Prairie State.

For these reasons, we conclude that the permit issuer appropriately looks to how the applicant, in proposing the facility, defines the goals, objectives, purpose, or basic design for the proposed facility. Thus, the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility. [74]

U.S. EPA's opinion in Prairie State was upheld on appeal to the Seventh Circuit Court of Appeals, where the court affirmed the substantial deference due the permitting authority on defining the demarcation point.[75]

Taken as a whole, the permitting agency is tasked with determining which controls are appropriate, but the discretion of the agency does not extend to a point requiring the applicant to redefine the source.

Oglethorpe defines the proposed source as a nominal net 100 MW biomass boiler using bubbling fluidized bed combustion technology, which meets the project objective of the most efficient and flexible energy generation from biomass. Oglethorpe completed a detailed technical review of potential source types to meet the need for renewable power generation expressed by its member electrical cooperatives. In addition, the size of the unit was based on a detailed review of the potential "woodbasket" available to supply fuel for the project. Based on that review, for dedicated

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[73] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 29.

[74] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 30. See also EPA Environmental Appeals Board decision, *In re: Desert Rock Energy Company LLC*. PSD Appeal Nos. 08-03, 08-04, 08-05 & 08-06, decided Sept. 24, 2009, page 64 ("The Board articulated the proper test to be used to [assess whether a technology redefines the source] in *Prairie State*.").

[75] *Sierra Club v. EPA and Prairie State Generating Company LLC*, Seventh Circuit Court of Appeals, No. 06-3907, August 24, 2007. Rehearing denied October 11, 2007.

biomass combustion at this size, a bubbling fluidized bed (BFB) boiler is the clear combustion technology choice.

While circulating fluidized bed (CFB) boilers are also sometimes used for biomass combustion, they are primarily used for either coal combustion or when a wide mix of fuel types are intended. Given the difference in design of a CFB, the additional circulating loop in the boiler results in additional station load, reducing the overall project efficiency. For biomass, a CFB and a BFB provide essentially equivalent combustion, but the CFB requires additional equipment (for the circulating loop) with no gain in combustion quality. Thus, CFB technology is inconsistent with the purpose of generating renewable energy in the most efficient and practical way.

In comparison to a stoker boiler, a BFB provides much better combustion, as the HAP emission factor discussion in Appendix C documents. While a stoker can achieve generally similar controlled emissions of PSD-regulated pollutants, it cannot achieve the same low emissions of HAP. In addition, a stoker boiler provides less flexibility to adapt to normal variations in the biomass composition. Therefore, stoker technology is inconsistent with the goal of maximizing the capability of the facility to accommodate a wide range of biomass composition.

As for integrated gasification combined cycle (IGCC) boilers, the primary purpose of the project is to produce electricity using biomass. IGCC cannot satisfy this purpose as IGCC technology cannot be applied to biomass combustion.

5.3 BACT REQUIREMENT

The BACT requirement applies to each new or modified emission unit from which there are emissions increases of pollutants subject to PSD review. The proposed facility is subject to PSD permitting for NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, and CO and thus, subject to BACT for these pollutants. The biomass boiler and auxiliary equipment are subject to BACT for each pollutant requiring PSD permitting that is emitted by the particular piece of equipment. The following emission units and pollutants were considered in the BACT analysis; refer to Section 2 of this report for a detailed discussion of each emission unit:

- BFB Biomass Boiler: NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, CO
- Emergency Fire Water Pump Engines: NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, CO
- Biomass Handling and Storage: PM, PM_{10}, $PM_{2.5}$
- Sorbent, Ash, and Sand Handling and Storage: PM, PM_{10}, $PM_{2.5}$
- Cooling Tower: PM, PM_{10}, $PM_{2.5}$
- Fugitive Road Emissions: PM, PM_{10}, $PM_{2.5}$

Note the same control techniques that reduce PM also reduce filterable PM_{10} and $PM_{2.5}$. The PM_{10} BACT analyses will satisfy BACT for PM and $PM_{2.5}$. In the prepared BACT analyses, references to PM_{10} are also relevant for PM and $PM_{2.5}$, and neither PM nor $PM_{2.5}$ are explicitly addressed separately.

5.4 BACT ASSESSMENT METHODOLOGY

The following sections provide detail on the BACT assessment methodology utilized in preparing the BACT analysis for the proposed facility. As previously noted, the minimum control efficiency to be considered in a BACT assessment must result in an emission rate less than or equal to any applicable NSPS or NESHAP emission rate for the source. The following NSPS or NESHAP emission limits will apply to proposed equipment and effectively set the floor for BACT for these units for certain pollutants:

- ▲ Biomass Boiler
  - PM limit of 0.030 lb/MMBtu (NSPS Subpart Db)
  - If firing USLD, NO_X limit of 0.20 lb/MMBtu (NSPS Subpart Db)
- ▲ Emergency Fire Water Pump Engines
  - PM limit of 0.15 g/hp-hr NO_X (NSPS Subpart IIII)
  - NMHC limit of 3 g/hp-hr (NSPS Subpart IIII)
- ▲ Sorbent Injection System
  - covered under NSPS OOO but no limits on PSD-regulated pollutants

5.4.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNOLOGIES

Potentially applicable emission control technologies were identified by researching the U.S. EPA control technology database, technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. The Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC), a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These technologies are grouped into categories by industry and can be referenced in determining what emissions levels were proposed for similar types of emissions units.

Trinity performed searches of the RBLC database in September 2009 to start identifying the emission control technologies and emission levels that were determined by permitting authorities as BACT within the past ten years for emission sources comparable to the proposed biomass boiler. The following categories were searched:

- ▲ Biomass (Wood) Boilers > 250 MMBtu/hr (RBLC Code 11.120)
- ▲ Other Fuel Combination Boilers > 250 MMBtu/hr (RBLC Code 11.900)
- ▲ Solid Fuel Boilers > 100 MMBtu/hr and < 250 MMBtu/hr (RBLC Code 12.120)
- ▲ Other Fuel Combination Boilers > 100 MMBtu/hr and < 250 MMBtu/hr (RBLC Code 12.900)
- ▲ Miscellaneous Boilers, Furnaces, and Process Heaters (RBLC Code 19.600)

Upon completion of the RBLC search, Trinity then reviewed relevant vendor information, pending permit applications, and issued permits not included in the RBLC. Appendix D presents a summary table of relevant BACT determinations for biomass or mixed fuels boilers predominately firing biomass.

Additional RBLC searches were performed in September 2009 to identify control options for the auxiliary equipment as permitted within the past ten years. The following categories were searched:

- ▲ Diesel Internal Combustion Engines ≤ 500 hp (RBLC Code 17.210)
- ▲ Biomass Storage and Handling (RBLC Codes 30.290, 30.390, 30.490, 30.510, 30.999)
- ▲ Lime Handling and Storage (RBLC Code 90.019), as a surrogate for the duct injection reagent storage
- ▲ Industrial Process Cooling Tower (RBLC Code 99.009)
- ▲ Ash Storage and Handling (RBLC Code 99.120)
- ▲ Paved Roads (RBLC Code 99.140)
- ▲ Miscellaneous Fugitive Dust Sources (RBLC Code 99.190), included biomass piles and road emissions
- ▲ Miscellaneous Sources (RBLC Code 99.999), included roads, engines, cooling towers, and lime storage

5.4.2 ECONOMIC FEASIBILITY CALCULATION PROCESS

Economic analyses were preformed to compare total costs (capital and annual) for potential control technologies. Capital costs include the initial cost of the components intrinsic to the complete control system. Annual operating costs include the financial requirements to operate the control system on annual basis and include overhead, maintenance, outages, raw materials, and utilities.

The capital cost estimating technique used is based on a factored method of determining direct and indirect installation costs. That is, installation costs are expressed as a function of known equipment costs. This method is consistent with the latest U.S. EPA OAQPS guidance manual on estimating control technology costs.[76]

Total Purchased Equipment Cost represents the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all the structural, mechanical, and electrical components required for the efficient operation of the device. Auxiliary equipment costs are estimated as a straight percentage of the equipment cost. Direct installation costs consist of the direct expenditures for materials and labor for site preparation, foundations, structural steel, erection, piping, electrical, painting and facilities. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Other indirect costs include equipment startup, performance testing, working capital, and interest during construction.

[76] U.S. EPA, *OAQPS Control Cost Manual*, 6th edition, EPA 452/B-02-001, July 2002. http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf

Annual costs are comprised of direct and indirect operating costs. Direct annual costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include plant overhead, taxes, insurance, general administration, and capital charges. Replacement part costs, such as the cost of replacement bags for the baghouse, were included where applicable, while raw material costs were estimated based upon the unit cost and annual consumption. With the exception of overhead, indirect operating costs were calculated as a percentage of the total capital costs. The indirect capital costs were based on the capital recovery factor (CRF) defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where *i* is the annual interest rate and *n* is the equipment life in years. The equipment life is based on the normal life of the control equipment and varies on an equipment type basis. The same interest applies to all control equipment cost calculations. For this analysis, an interest rate of 7% was used based on information provided in the most recent OAQPS Control Cost Manual.[77]

Note that all economic calculations are based on 2009 dollars. Detailed cost analyses calculations are presented in Appendix D.

5.5 BIOMASS BOILER – NO_X BACT

5.5.1 BACKGROUND ON POLLUTANT FORMATION

In industrial boiler and furnace combustion processes, NO_X is formed by two fundamentally different mechanisms: fuel NO_X and thermal NO_X. Technical literature suggests that NO_X formation from wood combustion is primarily fuel NO_X.[78]

"Fuel NO_X" forms when the fuel bound nitrogen compounds are converted into nitrogen oxides. The amount of fuel bound nitrogen converted to fuel NO_X depends largely upon the fuel type, nitrogen content of the fuel, air supply, and boiler design (including combustion temperature). The reaction between elemental nitrogen and oxygen to form nitrogen oxides happens very rapidly. Therefore, the primary mechanisms for reducing fuel NO_X involve creating a minimum amount of excess oxygen available to react with the fuel bound nitrogen throughout the combustion process.[79]

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[77] U.S. EPA, *OAQPS Control Cost Manual*, 6th edition, Section 2, Chapter 1, page 1-52. http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf

[78] Webster, T.S. and S. Drennan. *Low NO_X Combustion of Biomass Fuels.* Coen Company, Inc. http://www.coen.com/i_html/white_lownoxbiom.html.

[79] Kraft, D.L. *Bubbling Fluid Bed Boiler Emissions Firing Bark & Sludge.* Barberton, OH: Babcock & Wilcox. September 1998. http://www.babcock.com/library/pdf/BR-1661.pdf.

NO_X formed in the high-temperature, post-flame region of the combustion equipment is "thermal NO_X." Temperature is the most important factor, and at flame temperatures above 2,200°F, thermal NO_X formation increases exponentially.[80]

NO formation is inherent in all high temperature combustion processes. Nitrogen dioxide (NO_2) can then be formed in a reaction between the NO and oxygen in the combustion gases. In stationary source combustion, little of the NO is converted to NO_2 before being emitted. However, the NO continues to oxidize in the atmosphere. For this reason, all NO_X emissions from the boiler stack are usually reported as NO_2.

5.5.2 Identification of Potential Control Techniques (Step 1)

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable NO_X control technologies for biomass, non-fossil fuel-fired boilers were identified based on the principles of control technology and engineering experience for general combustion units (e.g., industrial boilers).[81]

Pollution prevention options include:

- ▲ Flue Gas Recirculation (FGR)
- ▲ Fuel Staging (Reburning)
- ▲ Good Design and Operating Practices, including Overfire Air (Baseline)

Pollution reduction options include:

- ▲ Selective Non-Catalytic Reduction (SNCR)
- ▲ Selective Catalytic Reduction (SCR)
- ▲ Regenerative Selective Catalytic Reduction (RSCR)

These control technologies are briefly discussed in the following sections.

5.5.2.1 Flue Gas Recirculation

FGR reduces peak flame temperature, minimizing thermal NO_X, by recirculating a portion of the flue gas back into the combustion zone as a replacement for combustion air. The recirculated combustion products provide inert gases that lower the adiabatic flame temperature and overall oxygen concentration in the combustion zone.[82] As a result, FGR limits NO_X emissions by reduction of thermal NO_X only, making it ineffective for a fluidized bed combustion unit.

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[80] Kraft, D.L. *Bubbling Fluid Bed Boiler Emissions Firing Bark & Sludge.* Barberton, OH: Babcock & Wilcox. September 1998. http://www.babcock.com/library/pdf/BR-1661.pdf.

[81] Note control options were not considered if they were designed only for fossil fuel-fired boilers or other combustion sources (i.e., combustion turbines, engines): Xonon, $SCONO_X/EM_X$, $THERMALONO_X$, Rotating Opposed Fire Air, Pahlman Process.

[82] Prasad, Arbind, "Air Pollution Control Technologies for Nitrogen Oxides," *The National Environmental Journal*, May/June 1995.

5.5.2.2 FUEL STAGING (REBURNING)

Also known as "reburning" or "off-stoichiometric combustion," fuel staging is a technique where ten to twenty percent of the total fuel input is diverted to a second combustion zone downstream of the primary zone. The fuel in the secondary zone serves as a reducing agent; NO formed in the primary combustion zone is reduced to N_2.[83] This technique usually employs natural gas or distillate oil for the fuel in the secondary combustion zone.

5.5.2.3 GOOD DESIGN AND OPERATING PRACTICES

NO_X formation can be most cost-effectively minimized by proper boiler operation and design practices. Operators can control the localized peak combustion temperature and combustion stoichiometry to minimize NO_X formation while achieving efficient fuel combustion. One of the most beneficial design characteristics of a fluidized bed boiler is that it utilizes air staging technology in the combustion process to reduce NO_X. This is accomplished by introducing the primary air through a distributer plate, to fluidize the bed, in quantities to keep the combustion in a fuel rich environment. This limits the amount of oxygen available to react with fuel bound nitrogen to form fuel NO_X. The secondary air is then introduced in one or more layers to raise the combustion zone and ensure complete combustion of the fuel. Good combustion practices at this stage play a pivotal role to ensure optimal operating conditions. NO_X emissions are reduced by limiting the amount of excess air, but other emissions are limited by complete combustion. Incomplete combustion in this stage would contribute to excess amounts of CO emissions.

Fluidized bed boiler operation also assists in prevention of NO_X formation by regulating the operating temperature of the boiler at a comparatively low temperature for combustion as compared to stoker boilers,[84] with typical BFB bed temperatures between 1,500 and 1,600 ºF.[85] Due to the nature of NO_X formation, thermal NO_X formation would be negligible.

Overfire air (OFA), a staged combustion technique, is a fundamental part of a BFB boiler and reduces NO_X emissions by creating a "fuel-rich" zone via air staging (diverting a portion of the total amount of air required through separate ports). Conditions in such a zone result in lower peak temperatures and thus, lower NO_X emissions.

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[83] Ibid.

[84] Babcock & Wilcox, *Bubbling Fluidized-Bed Boilers Burning Biomass and Low-Cost Fuels*, 2008. Available at: www.babcock.com/library/pdf/e1013161.pdf

[85] Woodruff, Everett B., Herbert B. Lammers, and Thomas F. Lammers, *Steam Plant Operation*, 2004, page 106.

5.5.2.4 SELECTIVE NON-CATALYTIC REDUCTION

SNCR is an exhaust gas treatment process in which urea or ammonia is injected into the exhaust gas. The effectiveness of SNCR systems depends on several factors, including CO and SO_2 flue gas concentrations, flue gas temperature, residence time, and reagent and flue gas mixing. If high CO concentrations are present, then the reagent efficiency is decreased, and if high SO_2 concentrations are present, then the temperature for optimal performance is increased. Per the SNCR vendor, high temperatures, normally between 1,550 and 2,000°F, are necessary to promote the reaction between urea or ammonia (NH_3) and NO_X to form N_2 and water.

Outside of the design temperature window, the emissions are adversely affected. If the temperatures are too high, then the reagent may be oxidized, causing additional NO_X emissions. If the temperatures are too low, then the reaction between the reagent and NO_X is slowed, and emissions of the reagent will be present. A sufficient residence time and reagent mixing time are also necessary to ensure maximum NO_X reductions are achieved and no excess emissions of the reagent are present.[86]

5.5.2.5 SELECTIVE CATALYTIC REDUCTION

SCR is an exhaust gas treatment process in which ammonia or urea is injected into the exhaust gas upstream of a catalyst. The ammonia or urea reacts to form nitrogen (N_2) and water on the surface of the catalyst, which typically has a temperature between 450 and 850° F. The installation of a SCR system on a fluidized bed boiler could be either on the "high dust" or "hot side," between the economizer and air heater, or on the "tail end" or "cold side," downstream of the particulate control and air heater.

In the SCR process, urea or ammonia, stored either as an anhydrous ammonia or aqueous solution, is injected into the exhaust upstream of the catalyst. The exhaust/ammonia (or urea) mixture passes over the catalyst, which lowers the activation energy of the NO decomposition reaction, therefore, lowering the temperature necessary to carry out the reaction.

As previously mentioned, a SCR control device is typically installed on either the hot side, high dust or the cold end. For a hot side, high dust SCR setup, the SCR is placed after the economizer and before the air heater and particulate control units. This situation allows for the placement of the system to be within the necessary temperature window for successful SCR operation; however, the high level of particulates present in the flue gas at this location can damage the catalyst, either by

[86] Kitto, J.B. *Air Pollution Control For Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996. http://www.babcock.com/library/pdf/BR-1624.pdf

physical damage or chemical contamination, resulting in significant downtime associated with cleaning or replacing the catalysts.

Another SCR placement option is on the cold side, after the air heaters and particulate control device. However, as the name implies, the temperature in this location is low, typically around 300 to 350° F, significantly below the required temperature rage for an SCR. At this lower temperature, ammonia does not readily react with NO_X, and both would be emitted to the atmosphere. Thus, heaters must be used to heat the flue gas back up to at least 470°F or higher.[87] When considering a cold side catalyst, the technology discussed in the following section is most appropriate as it minimizes the fuel penalty for the exhaust gas reheat.

5.5.2.6 Regenerative Selective Catalytic Reduction (RSCR)

Babcock Power's patented RSCR systems are "tail-end" SCR systems on the cold side, after the particulate control device. Such a system setup has a relatively limited amount of particulates and chemicals present in the flue gas, which limits the damage and degradation of the catalysts used in the system. However, the flue gas temperature is much less than the necessary temperature range for the successful reaction between the ammonia or urea injections with the NO_X of the flue gas. For this reason, the flue gas is temporarily reheated to a temperature in which NO_X successfully reacts with the ammonia or urea injections.

To minimize fuel consumption, the heating of the flue gas is accomplished using the "regenerative" heating technology, in a system analogous to a regenerative thermal oxidizer (RTO) as might be used to control an organics stream.[88] In the RSCR configuration, the reagent is first introduced upstream of the RSCR unit. The flue gas/reagent mixture (previously cleaned of particulate matter) then enters one end of the system, where the flue gas mixture travels up through the (hot) ceramic heat retention canister to be reheated. The flue gas mixture then flows through the catalyst section, where the ammonia reacts with the NO_X to form nitrogen and water. After the catalyst, the flue gas flows through a "retention" chamber, where a burner reheats the flue gas slightly. From this chamber, the flue gas then flows through the (cold) second canister and is used to heat this canister's ceramic heat retention block. Once this cycle is complete, the air flow is diverted, so that the second canister is the inlet for the "cold" flue gas, and the first canister is the outlet for the cleaned flue gas.[89] The RSCR approach minimizes the supplemental fuel required to reheat the cold exhaust gas.

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[87] Per Babcock Power Environmental proposal prepared for the proposed Oglethorpe boiler.

[88] In contrast, a traditional cold-side SCR would use a Ljungstrom-style air heater to reheat the flue gas at a much greater energy penalty.

[89] Abrams, Richard F. (Babcock Power Environmental, Inc.) and Kevin Toupin (Riley Power, Inc.). *Efficient and Low Emission Stoker Fired Biomass Boiler Technology in Today's Marketplace.* Worcester, MA: Babcock Power Environmental, Inc. March 2007. http://www.babcockpower.com/pdf/t-200.pdf

5.5.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

All control technologies and techniques identified in this section are technically infeasible for application to the proposed biomass boiler. Reasons for eliminating each option are identified below.

5.5.3.1 Flue Gas Recirculation

FGR requires considerable equipment for carrying the recirculated flue gas. For recirculation rates greater than 15 percent, an additional fan is needed. The recirculation fan is a specialty fan that must be able to withstand the high temperature and high particulate loading in the flue gas stream. High particulate loading in the flue gas stream is of particular concern since the boiler's fuel is wood.

Further, FGR does not significantly reduce NO_X emissions when firing biomass in a boiler since the majority of NO_X emissions from biomass-fired fluidized bed boilers arise from fuel bound nitrogen. Therefore, FGR (which controls thermal NO_X) does not effectively reduce the NO_X emissions from biomass fluidized bed boilers. Furthermore, the RBLC indicates FGR has not been successfully demonstrated on fluidized bed boilers combusting primarily biomass.[90]

Were FGR not eliminated at this step, its control effectiveness would fall below SNCR.

5.5.3.2 Fuel Staging (Reburning)

Fuel staging requires usage of natural gas or distillate oil in a secondary combustion zone downstream of the primary zone. The biomass boiler will only utilize biomass during normal operations (biodiesel as a backup and starter fuel only) and therefore, will be unable to utilize this technique. Further, this technique employs FGR, which is considered infeasible for biomass-fired boilers due to its inability to minimize fuel NO_X, the primary component of NO_X from biomass combustion.

[90] Note that FGR is listed as a potential technology for the No. 2 Power Boiler at the Weyerhaeuser Valliant, OK, facility. This boiler was permitted to burn "mixed fuels", which at a pulp and paper mill typically includes wood, oil, gas, and potentially coal. As such, this boiler is not comparable to a boiler designed to fire only biomass. Further, the Weyerhaeuser boiler was never constructed per permitting documents available on Oklahoma Department of Environmental Quality (ODEQ) website (for example: www.deq.state.ok.us/AQDnew/permitting/permitissue/97057-cp4.doc).

Were FGR not eliminated at this step, its control effectiveness would fall below SNCR.

5.5.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies, ranked by effectiveness, are presented in Table 5-1. Note that while RSCR and hot-side SCR use similar technology, the cleaner exhaust gas in an RSCR would lead to a lower attainable emission rate than a hot-side SCR.

TABLE 5-1. REMAINING NO_X CONTROL TECHNOLOGIES

Rank	Control Technology	Expected Emissions
1	Tail End SCR/RSCR	0.06 lb/MMBtu
2	Hot End, High Dust SCR	0.07 lb/MMBtu
3	SNCR	0.11 lb/MMBtu
4	Good Design and Operating Practices (including OFA)	0.18 lb/MMBtu

5.5.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for each remaining control technology on the basis of economic, energy, and environmental considerations, and is described in the following sections.

5.5.5.1 TAIL END SCR/RSCR

Tail end SCR or Babcock Power's RSCR works by reheating the flue gas to the necessary temperatures for the ammonia and NO_X to react to form nitrogen and water. While the regenerative heating reduces the required heat input, this reheating of the flue gas still represents a significant amount of auxiliary fuel that would be necessary for successful operation. Further, recent determinations and comments made by Georgia EPD confirm that it would not be economically feasible to re-heat the flue gas for the tail end application of a SCR on a biomass-fired fluidized bed boiler.[91]

Tail end SCR control technology has been demonstrated on smaller wood-fired stoker boilers. The efficiency of this system on wood fired stoker boilers has successfully been determined at up to 80% NO_X; however, the uncontrolled NO_X emissions of a stoker boiler is higher than that of a fluidized bed boiler. Therefore, it is not known whether this same efficiency would coincide with a fluidized bed

[91] In comments to Yellow Pine Energy Company on June 17, 2008, Georgia EPD states that, "EPD agrees that reheating flue gases with additional fuel would make the cost of control excessive and we believe that the impacts from the additional energy usage and emissions (from the additional fuel combustion) would be adverse impacts in this case." http://www.georgiaair.org/airpermit/downloads/permits/psd/dockets/yellowpine/epddocs/061708epdrequest.pdf

boiler with initial NO_X emissions that are less than those of modern stoker boilers.[92] Based on site-specific vendor data, the uncontrolled NO_X emissions of 0.18 lb/MMBtu would be expected to be reduced to 0.06 lb/MMBtu using a tail end SCR

Oglethorpe evaluated the environmental, energy, and economic impacts of using a tail end SCR. No significant environmental impacts are expected from operation of a tail end SCR. Energy impacts include combustion of 302,400 gallons per year of biodiesel to reheat the flue gas as well as 1.4 MW of lost capacity split between direct electrical load and increased pressure drop across the system. Next, Oglethorpe evaluated the economic impacts of a tail end SCR. Based on a vendor quote for total capital costs and OAQPS Manual equations, the annualized costs for a tail end SCR were estimated to be $12,760 per ton of NO_X removed. Refer to detailed calculations included in Appendix D for more information on the energy and economic impacts.

Oglethorpe has determined that a tail end SCR system is not BACT based on the environmental, energy, and economic analyses. Beyond the consumption of significant additional fuel and worse heat rate, the annualized cost for the SCR is well beyond the range of cost effectiveness for BACT, and even moreso when considering the very high incremental costs relative to other control devices as discussed later in this section ($26,090 per additional ton of NO_X removed as compared to a SNCR). Therefore, the next most efficient control technology listed in Table 5-1, hot end SCR, was evaluated.

5.5.5.2 HOT END/HIGH DUST SCR

Hot end, high dust SCR systems have been permitted and installed on boilers firing biomass or combined fuels; however, they have been primarily used on boilers firing natural gas, fuel oil, and coal. The primary issue associated with a hot end SCR involves the presence of other alkali metals and trace elements in the particulate matter of the flue gas that can chemically damage the catalyst, gradually neutralizing its ability to reduce NO_X. This chemical damage not only cuts the lifespan of the catalyst, but also increases the amount of ammonia slip. These alkali metals and trace elements include arsenic, sodium, potassium, and zinc. Sodium and potassium, both of which are present in fairly high concentrations in wood, are of particular concern for catalyst reactivity.

Oglethorpe is not aware of any CFB or BFB biomass boilers in the United States that are equipped with a high dust SCR. Oglethorpe is aware of four biomass-fired CFB or BFB boilers operating outside the United States that employ a SNCR/SCR

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[92] Abrams, Richard F. (Babcock Power Environmental, Inc.) and Kevin Toupin (Riley Power, Inc.). *Efficient and Low Emission Stoker Fired Biomass Boiler Technology in Today's Marketplace.* Worcester, MA: Babcock Power Environmental, Inc. March 2007. http://www.babcockpower.com/pdf/t-200.pdf

hybrid technology.[93] One of the CFB boilers is located at Wien Energy's Simmering plant, in Vienna, Austria. Although this facility has been able to meet its permit limits, the SCR vendor, CERAM, is uncertain if the NO_X reduction is due to the SNCR portion or catalyst portion of the SCR. A second CFB boiler had been operated with a high dust SCR for NO_X control at Norrkopping Energi AB in Sweden. However, the high dust SCR had many issues; the primary problem was the high operating costs stemming from the need to have the catalyst washed off-line frequently due to chemical damage and plugging from the biomass/TDF fuels. The plant eventually elected to decommission the SCR and instead utilize an SNCR system for NO_X control. Since this change, the SNCR system has produced similar NO_X reductions as the SCR system, without the high maintenance costs and boiler downtime.[94]

The two biomass-fired BFB boilers employing the hybrid SNCR/high dust SCR systems are located at the Cuijk Essent (Netherlands) and Stora Enso (Sweden) facilities. Both units have been successfully operated; however, the SCR reductions (beyond the SNCR reductions) have only been 5% and 22%, respectively. System outlet emissions have been equivalent to approximately 0.10 lb/MMBtu, much less than theoretically expected and very similar to the expected NO_X emissions achieved by the proposed Oglethorpe boiler via usage of only an SNCR.

Despite real questions about the technical feasibility of a high dust SCR for this application, Oglethorpe has nonetheless assumed for the purposes of this economic analysis that a high dust SCR system is technically feasible and could achieve NO_X outlet emissions of 0.07 lb/MMBtu.

Oglethorpe evaluated the environmental, energy, and economic impacts of using a high dust SCR. No significant environmental impacts are expected from operation of a high dust SCR (although catalyst must be replaced and/or regenerated more frequently than a tail end SCR). Energy impacts are attributed to only the additional 0.7MW of capacity associated with pressure drop across the SCR itself. Next, Oglethorpe evaluated the economic impacts of a high dust SCR. Based on cost calculations, as included in Appendix D, such a system is expected to have an annualized cost of \$10,880 per ton of NO_X removed. Refer to detailed calculations included in Appendix D for more information on the energy and economic impacts.

Oglethorpe has determined that a high dust SCR is not BACT based on the environmental, energy, and economic analyses. While the loss of heat rate is only

[93] The ammonia is injected sufficiently early in the unit such that SNCR reactions first occur, with unreacted ammonia continuing downstream to the catalyst and potentially further decreasing the NO_X levels. Thus, the hot SCR system is effectively an SNCR system followed by an SCR.

[94] The Metso data are from an email sent by Bob Denault (Metso Power) to Mark Sajer (Summit Energy Partners, LLC) on March 28, 2008. This document was contained in a response to EPD's comments, dated 6/17/2008, regarding Yellow Pine Energy Company's PSD permit application #17700. http://www.georgiaair.org/airpermit/downloads/permits/psd/dockets/yellowpine/facilitydocs/080108ypresp-a4a7.pdf

half that of the RSCR, the annualized cost for the SCR is well beyond the accepted range of cost effectiveness for BACT, particularly when considering the incremental costs relative to other control devices as discussed later in this section: \$24,230 per additional ton of NO_X removed as compared to a SNCR. In addition, there are real concerns regarding whether this technology is truly technically feasible. Therefore, the next most efficient control technology listed in Table 5-1, SNCR, is evaluated.

5.5.5.3 SNCR

SNCR has been successfully utilized and considered BACT on a number of fluidized bed biomass-fired boilers, according to RBLC entries. SNCR systems are generally thought to have a NO_X reduction efficiency of 20 to 60%; however, the fluidized bed design results in inherently lower uncontrolled NO_X emissions than other boiler designs. The SNCR vendor is expected to guarantee a NO_X outlet emission rate of 0.11 lb/MMBtu.

Oglethorpe evaluated the environmental, energy, and economic impacts of using a SNCR. No significant environmental impacts are expected from operation of a SNCR. Energy impacts are attributed to only the electrical capacity associated with operation of the SNCR itself and are only 0.05 MW of capacity, 15 times lower than hot SCR and 30 times lower than tail-end SCR. Next, Oglethorpe evaluated the economic impacts of a SNCR. The SNCR cost calculations indicate a cost per ton of NO_X removed of less than \$3,250 per ton of pollutant removed. Refer to detailed calculations included in Appendix D for more information on the energy and economic impacts

Oglethorpe believes that a SNCR is BACT since it will have minimal environmental and energy impacts and is within the range of costs generally considered to be cost-effective.

5.5.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, Oglethorpe has determined that SNCR is BACT for the proposed biomass BFB boiler. The environmental and energy impacts of the two SCR systems and the SNCR system are similar. However, the economic impacts of the two SCR systems are significantly higher than that of the SNCR for both annualized and incremental costs.
Table 5-2 presents a summary of the economic impacts.

TABLE 5-2. ANNUAL AND INCREMENTAL COSTS FOR SCRS AND SNCR

Control Device	Average Cost ($/ton)	Additional Emissions Removed[1] (tpy)	Additional Annual Cost[2] ($/yr)	Incremental Cost[3] ($/ton)
Tail End SCR	12,760	280.8	7,325,020	26,090
High Dust SCR	10,880	224.6	5,442,680	24,230
SNCR	3,250	-	-	-

1. Additional NO_X removed by the SCR as compared to using a SNCR to achieve 0.11 lb/MMBtu outlet emissions.
2. Additional annual operating cost for the SCR being evaluated as compared to the SCNR.
3. Annual operating cost for the SCR divided by the additional emissions removed.

Between the negative energy impacts of the SCR technologies, the average cost effectiveness beyond the accepted range for BACT, and the very high incremental cost effectiveness of either SCR technology, Oglethorpe has determined that neither the tail end SCR or high dust SCR are BACT. Thus, SNCR coupled with proper boiler design (i.e., bubbling fluidized bed) and combustion control has been selected as BACT for the proposed biomass boiler. The validity of this determination is also evidenced by the lack of biomass fluidized bed units using either type of SCR system.

The emission levels determined to constitute BACT for biomass boilers with heat input capacities exceeding 250 MMBtu/hr within the last 10 years vary greatly (refer to the RBLC Search/Permit Review table in Appendix D). The most stringent limits are shown in Table 5-3 and were considered by Oglethorpe in determining the appropriate emission rate to propose as BACT for the fluidized bed biomass boiler. Limits for boilers employing SCR or RSCR were not considered further since a SCR was determined to be economically infeasible for the proposed Oglethorpe biomass boiler.

As seen from Table 5-3, NO_X emission rates for biomass boilers with SNCR have some inherent variation in the amount of NO_X formation in the combustion process (due to variations in nitrogen content of the fuels). The Archer Daniels Midland and Schiller Station boilers are both permitted to also combust non-biomass fuels (coal) and are CFB boilers. The Plainview Renewable Energy boiler is a FB Gasification boiler and therefore fundamentally different than Oglethorpe's proposed BFB boiler; it is also subject to a LAER limit. The Bridgewater Power Company boiler has a quarterly NO_X emission limit, which allows for a lower limit because it is able to average out fluctuations in the emissions. The next several boilers have limits of 0.1 or 0.10 lb/MMBtu on a 30-day averaging period, however most of which have fuel flexibility that allows for the combustion of fuels such as TDF, Propane, Coal, or Natural Gas. These fuels have different compositions that result in the formation of NO_X and other pollutants in different levels. The Dominion stoker boiler also has a 0.10 lb/MMBtu NO_X limit; however, due to the nature of NO_X and CO formation, with this low NO_X limit comes a much higher CO emission limit (0.35 lb/MMBtu, whereas Oglethorpe is proposing a much lower limit for CO). Similarly, the Nacogdoches boiler has a slightly lower NO_X limit but a higher CO limit (0.15 lb/MMBtu on a 30-day average). Based on the vendor quotations, Oglethorpe has determined BACT is a limit of 0.11 lb/MMBtu, as measured using a CEMS, on a 30-day averaging period for normal operation of the proposed BFB boiler (i.e., not including startup).

TABLE 5-3. MOST STRINGENT RBLC ENTRIES FOR NO_X CONTROL

ID	State	Company/Facility	Boiler Type	Capacity (MMBtu/hr)	Permitted Fuels	Permit Date	Limit (lb/MMBtu)	Avg. Period	Control Type	Compliance Method	Note(s)
MA-02a	MA	RUSSELL BIOMASS	BFB	740	Clean Wood	12/30/2008	0.060	Unknown	SCR	CEMS	1
MA-02b	MA	RUSSELL BIOMASS	Stoker	740	Clean Wood	12/30/2008	0.060	Unknown	RSCR	CEMS	1
MA-03	MA	PIONEER RENEWABLE ENERGY	Stoker	663	Wood	Application	0.060	Unknown	SCR	CEMS	1
MA-05	MA	PALMER RENEWABLE ENERGY	Stoker	38 MW	Biomass	Application	0.060	Unknown	RSCR	CEMS	1
NH-05	NH	CONCORD STEAM CORPORATION	Stoker	305	Biomass, Natural Gas (startup)	2/27/2009	0.065	30-day	SCR	CEMS	1
NE-04	NE	ARCHER DANIELS MIDLAND, COLUMBUS	CFB	768	Coal, Biomass, Petcoke, TDF	Draft, 2008	0.07	30-day	SNCR	CEMS	2
CT-03	CT	WATERTOWN RENEWABLE POWER	FB Gasification	436	Biomass, Natural Gas (startup)	Draft 2009	0.075	24-hour	SCR	CEMS	1
CT-02	CT	PLAINFIELD RENEWABLE ENERGY	FB Gasification	523	Biomass, biodiesel	2008	0.075	30-day	SNCR	CEMS	1
ME-01	ME	BORALAX STRATTON ENERGY, INC.	FB	672	Wood, Oil	1/4/2005	0.075	Quarterly	Ecotube, RSCR	CEMS	3
NH-0013	NH	SCHILLER STATION, PUBLIC SERVICE OF NH	CFB	720	Wood, Coal	10/25/2004	0.075	24-hour	SNCR	CEMS	3
NH-02	NH	BRIDGEWATER POWER COMPANY	Stoker	250	Wood, Oil	9/12/2007	0.075	Quarterly	SNCR, RSCR	CEMS	3
NH-03	NH	WHITEFIELD POWER	Stoker	220	Wood	2004	0.075	Quarterly	RSCR	CEMS	3
VT-01	VT	BURLINGTON ELECTRIC DEPT, MCNEIL STATION	Stoker	750	Wood, Natural Gas, Oil	4/21/2008	0.075	Quarterly	RSCR	CEMS	3
OH-0307	OH	SOUTH POINT BIOMASS GENERATION	Stoker	318	Wood	4/4/2006	0.088	30-day	SCR	CEMS	4
GA-02	GA	YELLOW PINE ENERGY COMPANY	BFB	1,529	Biomass, TDF, Propane, Fuel Oil	5/15/2009	0.10	30-day	SNCR	CEMS	
MI-0386	MI	RIPLEY HEATING PLANT	CFB	205	Wood, Coal, Gas	5/12/2008	0.10	30-day	SNCR	CEMS	
TX-31	TX	NACOGDOCHES POWER PLANT, AMERICAN RENEWABLES	BFB	1,374	Biomass, Gas	3/1/2007	0.10	30-day	SNCR	CEMS	
VA-11	VA	MULTITRADE OF PITTSYLVANIA COUNTY (DOMINION)	Stoker	373	Biomass	1/1/2003	0.10	30-day	SNCR	CEMS	5
NM-03	NM	WESTERN WATER & POWER - ESTANCIA BASIN BIOMASS	BFB	483	Biomass	Draft, 2007	0.11	30-day	SNCR	CEMS	4
WA-0327	WA	SKAGIT COUNTY LUMBER MILL	Stoker	430	Biomass	12/12/2005	0.13	24-hour	SNCR	CEMS	
FL-0257	FL	CLEWISTON SUGAR MILL AND REFINERY	Unknown	936	Bagasse, Diesel	11/18/2003	0.14	30-day	SNCR	Unknown	

1. LAER limit.
2. Limit excludes startup periods.
3. Voluntary limit, not a BACT limit.
4. Based on lb/hr limit and maximum permitted capacity.
5. Minimum of 50% control required.

5.6 BIOMASS BOILER - SO_2 BACT

5.6.1 BACKGROUND ON POLLUTANT FORMATION

SO_2 emissions result from the oxidation of sulfur in the fuel during the combustion process. Uncontrolled SO_2 emissions almost entirely depend upon the sulfur content of the fuel and are not dependent upon boiler properties such as size, burner design, or fuel grade. Almost all of the fuel sulfur released is in the form of SO_2. Based on fuel analysis data for various biomass samples, the maximum tested sulfur content of the biomass was 0.018 percent sulfur; however, the variability inherent in a natural fuel makes the maximum sulfur content uncertain. However, since Oglethorpe is demonstration compliance via a CEMS, the emission rate is capped regardless of biomass sulfur variation.[95]

5.6.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search (refer to discussion in Section 5.4.1), permit review, and literature review included those classified as both pollution prevention and pollution reduction techniques. SO_2 pollution prevention and reduction options include:

▲ Limestone Injection
▲ Wet Flue Gas Desulfurization (WFGD)/Wet Scrubber
▲ Dry FGD (DFGD)/Spray Dryer with Baghouse
▲ Duct Sorbent Injection (DSI)
▲ Good Design and Operating Practices

These control technologies are briefly discussed in the following sections.

5.6.2.1 LIMESTONE INJECTION

Fluidized bed boilers typically use sand or similar materials for the bed material. Limestone can be added to the bed material as an "in-situ" SO_2 control. This form of control works on the basis of a several chemical reactions that work in series. First, the limestone calcines ($CaCO_3 \rightarrow CaO + CO_2$), allowing for the lime, or calcium oxide (CaO), to react with SO_2 and O_2 to form calcium sulfate, $CaSO_4$. The calcium sulfate is a solid that is captured by the particulate control, resulting in a reduction of SO_2 emissions.

5.6.2.2 WFGD/WET SCRUBBER

In a WFGD or wet scrubber system, a liquid alkaline sorbent is sprayed into the flue gas in a vessel to adsorb SO_2 from the flue gas. The SO_2 reacts with the alkaline liquid and is removed in solution as a liquid waste. Additional sorbent

[95] Based on fuel sampling data conducted by Nablabs (on behalf of potential boiler vendor Metso) using samples obtained from various potential biomass suppliers in Georgia. Refer to copy of sampling results in Appendix C.

solution is added to the recirculating sorbent solution to compensate for the quantity that reacts with SO_2.[96] Typically, large quantities of liquid waste are disposed of by wastewater treatment holding ponds.

5.6.2.3 DFGD/Spray Dryer with Baghouse

This technique, also known as "dry scrubbing," requires installation of a spray dryer and a baghouse. An alkaline slurry is injected by a spray dryer into the flue gas in the form of fine droplets under well controlled conditions such that the droplets will absorb SO_2 from the flue gas and then become dry particles because of the evaporation of water. The dry particles are captured by the baghouse downstream of the dryer. The captured particles are then removed from the system and disposed. The advantages of this system include a dry waste product and simpler process control.[97]

5.6.2.4 Duct Sorbent Injection (DSI)

DSI systems are typically placed in between the air heater outlet and particulate control inlet, where the sorbent is injected into the flue gas either dry or damp. A humidifier can then be used to cool the flue gas through evaporation to approach the adiabatic saturation temperature of the flue gas. This creates an atmosphere that allows for this technology to be most effective. Additionally, a fabric filter is instrumental in achieving SO_2 removal due to the intimate contact between the flue gases and sorbent in the filter cake.[98]

5.6.2.5 Good Design and Operating Practices

Good design and operating practices imply that the boiler is operated within parameters that, without significant control technology, allow the equipment to operate as efficiently as possible. In addition to minimizing SO_2 emissions through good operating practices, this control option includes combustion of biomass fuel which has inherently low sulfur content.

5.6.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. The following control technologies have been considered technically infeasible for the proposed biomass-fired boiler.

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[96] U.S. EPA, CATC Fact Sheet for FGD, EPA-452/F-03-034. http://www.epa.gov/ttn/catc/dir1/ffdg.pdf

[97] Kitto, J.B. *Air Pollution Control For Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996. http://www.babcock.com/library/pdf/BR-1624.pdf

[98] Ibid.

5.6.3.1 LIMESTONE INJECTION

Limestone is frequently added to the bed of CFB boilers, where the limestone reacts with the sulfur to create calcium sulfate. BFB boilers, however, cannot utilize limestone injection based on the boiler design and unsuitable residence times. Combustion in BFB boilers occurs primarily in the bed itself due to the lower air velocity in the bed and larger fuel size; combustion in CFB boilers, however, occurs above the bed as particulates are blown from the bed, collected by a hot particle separator, and recirculated.[99] This turbulent environment in the CFB boiler is what allows for limestone to react with the SO_2. This environment is not present in a BFB boiler. Therefore, limestone injection is considered technically infeasible for a BFB boiler.

5.6.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies, ranked by their control effectiveness, are presented in Table 5-4.

TABLE 5-4. REMAINING SO_2 CONTROL TECHNOLOGIES

Rank	Control Technology	Expected Emissions
1	WFGD/Wet Scrubber	0.005 lb/MMBtu
2	Spray Dryer with Baghouse	0.010 lb/MMBtu
3	Duct Sorbent Injection	0.010 lb/MMBtu
4	Good Design and Operating Practices	0.066 lb/MMBtu

5.6.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for each remaining control technology on the basis of economic, energy, and environmental considerations, and is described below.

5.6.5.1 WFGD/WET SCRUBBER

New wet scrubber systems are anticipated to reduce SO_2 outlet emissions from the proposed biomass boiler from 0.066 lb/MMBtu (worst-case fuel) to approximately 0.005 lb/MMBtu. The capital and overall costs of a wet scrubber on a fluidized bed boiler are expected to be quite high relative to other sulfur control options. Additionally, biomass-fired boilers have inherently low SO_2 emissions due to the low sulfur content of the fuel. For this reason, a wet scrubber system will not be able to provide as high a reduction efficiency as those that are achieved for high-

[99] Woodruff, Everett B., Herbert B. Lammers, and Thomas F. Lammers, *Steam Plant Operation*, 2004, page 103.

sulfur, coal-fired boilers since firing the biomass fuel results in low uncontrolled SO_2 emissions of 0.066 lb/MMBtu.

Oglethorpe evaluated the environmental, energy, and economic impacts of a wet scrubber system. The environmental impacts associated with the wet scrubber include needing over 68.3 million gallons per year of water for the alkaline liquid, treating of the wastewater, and increased solid waste disposal of 945 tpy from the waste generated from the caustic and SO_2 reaction. Energy impacts associated with operation of the scrubber system itself will require 2 MW of capacity. To evaluate the economic impacts, Oglethorpe calculated the annualized cost of operating a wet scrubber system. Based on cost calculations included in Appendix D (which do not include costs associated with treatment of the waste scrubbant liquid), a wet scrubber system would be expected to have annual costs of more than $45,270 per ton of SO_2 removed, far beyond an acceptable cost effectiveness.

Based on the environmental, energy, and economic analyses, Oglethorpe determined that a wet scrubber is not BACT for reducing SO_2 emissions from the proposed biomass boiler. Thus, Oglethorpe proceeded with evaluating the next most efficient control option presented in Table 5-4, a spray dryer system.

5.6.5.2 DFGD/Spray Dryer with Baghouse

A spray dryer using alkaline slurry in combination with a baghouse is expected to achieve outlet SO_2 emissions of 0.01 lb/MMBtu for the proposed biomass boiler. Note that this system is not expected to achieve a noticeably lower outlet emission rate than DSI due to the low uncontrolled SO_2 levels in the flue gas.

Oglethorpe evaluated the environmental, energy, and economic impacts of a spray dryer system. The environmental impacts associated with the spray dryer system include needing over 62.6 million gallons per year of water for the solvent, and increased solid waste disposal of 1,507 tpy from the waste generated from the lime and SO_2 reaction. Energy impacts associated with operation of the spray dryer system itself will require 0.7 MW capacity. To evaluate the economic impacts, Oglethorpe calculated the annualized cost of operating a spray dryer system. Based on economic calculations included in Appendix D, a spray dryer system is expected to have an annual cost of more than $22,340 per ton of SO_2 removed, far beyond an acceptable cost effectiveness.

Based on the environmental, energy, and economic analyses, Oglethorpe determined that a spray dryer system is not BACT for reducing SO_2 emissions from the proposed biomass boiler. Thus, Oglethorpe proceeded with evaluating the next most efficient control option presented in Table 5-4, DSI.

5.6.5.3 Duct Sorbent Injection

A DSI system, using dry or slightly damp alkaline sorbent in conjunction with a baghouse, has significant economic benefits when compared with the WFGD and

DFGD systems, along with offering outlet SO_2 emissions of 0.01 lb/MMBtu, equivalent to DFGD and in the same range as WFGD, due to the low uncontrolled SO_2 levels in the flue gas.

Environmental impacts for DSI are not expected to be significant. While an additional 3,900 tpy of solid waste is generated, no additional water is used nor wastewater generated. The energy impacts associated with DSI are only 0.3 MW of capacity needed to operate the DSI system. Economic impacts are at the upper end of the reasonable range for cost effectiveness for SO_2, with an annual cost of less than \$6,200 per ton of SO_2 removed. Refer to Appendix D for calculation details.

Based on the environmental, energy, and economic analyses, Oglethorpe determined that DSI is BACT for the proposed biomass boiler. This technology represents a high SO_2 removal while remaining cost effective and minimizing environmental and energy impacts.

5.6.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, Oglethorpe has determined that DSI is BACT for the proposed biomass BFB boiler. While energy impacts are similar, the environmental and economic impacts of the wet scrubber and spray dryer systems are significantly higher than those of the DSI system. Table 5-5 presents a summary of the economic impacts.

TABLE 5-5. ANNUAL COSTS FOR SO_2 CONTROL DEVICES

Control Device	Average Cost (\$/ton)
Wet Scrubber	45,280
Spray Dryer	22,340
DSI	6,200

Usage of DSI is determined as BACT for the proposed biomass boiler.

The emission levels determined to constitute BACT for biomass fluidized bed boilers with heat input capacities exceeding 250 MMBtu/hr within the last 10 years vary greatly (refer to the RBLC Search/Permit Review table in Appendix D). The most stringent limits are shown in Table 5-6 and were considered by Oglethorpe in determining the appropriate emission rate as BACT for the fluidized bed biomass boiler.

TABLE 5-6. MOST STRINGENT RBLC ENTRIES FOR SO_2 CONTROL

ID	State	Company/Facility	Boiler Type	Capacity (MMBtu/hr)	Permitted Fuels	Permit Date	Limit (lb/MMBtu)	Avg. Period	Control Type	Compliance Method	Note(s)
VT-01	VT	BURLINGTON ELECTRIC DEPT, MCNEIL STATION	Stoker	750	Wood, Natural Gas, Oil	4/21/2008	0.0083	Annual	Good Combustion Practices	Fuel Records	
GA-02	GA	YELLOW PINE ENERGY COMPANY	BFB	1529	Biomass, TDF, Propane, Fuel Oil	5/15/2009	0.014	30-day	Dry Scrubber	CEMS	
LA-0201	LA	WEYERHAEUSER - RED RIVER MILL	Unknown	940	Wood, Sludge, Recycle Fiber, Gas	5/24/2006	0.015	3-hour	Good Combustion Practices	Stack Test	
VA-11	VA	MULTITRADE OF PITTSYLVANIA COUNTY	Stoker	373.3	Biomass	1/1/2003	0.016	30-day	Good Combustion Practices	CEMS	
NM-03	NM	WESTERN WATER & POWER - ESTANCIA BASIN BIOMASS	BFB	483	Biomass	Draft, 2007	0.019	30-day	Good Combustion Practices	Stack Test	1
NH-0013	NH	SCHILLER STATION, PUBLIC SERVICE OF NH	CFB	720	Wood, Coal	10/25/2004	0.02	24-hour	Lime Injection	CEMS	2
MA-05	MA	PALMER RENEWABLE ENERGY	Stoker	38 MW	Biomass	Application	0.02	Unknown	Scrubber	Unknown	2
NC-0092	NC	RIEGELWOOD MILL, INTERNATIONAL PAPER CO.	Unknown	600	Coal, Wood, Sludge, Fuel Oil	5/10/2001	0.024	3-hour	Venturi scrubber	Stack Test	3
MA-02a	MA	RUSSELL BIOMASS	BFB	740	Clean Wood	12/30/2008	0.025	Unknown	Fuel selection	CEMS	
MA-02b	MA	RUSSELL BIOMASS	Stoker	740	Clean Wood	12/30/2008	0.025	Unknown	Fuel selection	CEMS	
MA-03	MA	PIONEER RENEWABLE ENERGY	Stoker	663	Wood	Application	0.025	Unknown	Wood ash alkalinity	Unknown	
WA-0327	WA	SKAGIT COUNTY LUMBER MILL	Stoker	430	Biomass	12/12/2005	0.025	3-hour	Good Combustion Practices	Stack Tests	
CT-03	CT	WATERTOWN RENEWABLE POWER	FB Gasification	436	Biomass, Natural Gas (startup)	Draft 2009	0.025	3-hour	DSI	CEMS	

1. Based on lb/hr limit and maximum permitted capacity.
2. Not a BACT limit.
3. Limit is for biomass combustion.

As shown in Table 5-6, SO_2 emission rates for biomass boilers vary due to fuel sulfur content, control methodology employed, and averaging period. Oglethorpe has determined that a BACT limit of 0.01 lb/MMBtu on a 30-day averaging period is appropriate given the range of sulfur contents in the biomass fuels proposed for this boiler and based on expected vendor guarantees. The BACT limit for SO_2 is for normal operation (i.e., not including startup). This limit is more stringent than any other recent SO_2 BACT determination based on the proposed averaging period, since the McNeil Station has both a longer averaging period (annual vs. 30-day) and a less stringent compliance method (fuel recordkeeping). Compliance with this limit will be achieved via usage of DSI and low sulfur fuels (biomass and biodiesel/ULSD); compliance will be evaluated via a CEMS.

5.7 BIOMASS BOILER – PM/PM_{10}/$PM_{2.5}$ BACT

This section identifies control options for the reduction of filterable PM. Although PSD permitting is also required for PM_{10} and $PM_{2.5}$, those options used to reduce PM are will also reduce PM_{10} and $PM_{2.5}$. Additionally, a total PM (filterable plus condensable) limit is discussed; the proposed filterable PM_{10} limits will serve as surrogates for filterable PM and filterable $PM_{2.5}$ emission limits.[100]

5.7.1 BACKGROUND ON POLLUTANT FORMATION

Filterable PM emissions from biomass boiler combustion include the ash from the fuel combustion, byproducts of sorbent injection, as well as any unburned carbon resulting from incomplete combustion. In contrast to filterable particulate, condensable particulate is less understood, and the quantities are less certain. A portion of condensable particulate results from sulfur and chlorine in the fuel and their resultant acid gases. Other condensable particulate can form from a portion of NO_X being oxidized to NO_3 (acidic) as well as from high molecular weight organics. The compounds that form condensable particulate are controlled via other pollutant BACT – SO_2 BACT for acid gases and CO BACT for high molecular weight organics. Thus, control options for condensable particulate are not discussed in this section, though a BACT emission rate for condensable PM is included.

5.7.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options for reducing filterable PM were identified from the RBLC search (refer to discussion in Section 5.4.1) and the literature review. Filterable PM reduction options, which may be utilized in series, include:

- ▲ Electrostatic Precipitator (ESP)
- ▲ Baghouse (Fabric Filter)
- ▲ Cyclone/Multiclone
- ▲ Venturi Scrubber

[100] Oglethorpe recognizes that U.S. EPA recently suggested that the appropriateness of using PM_{10} as a surrogate for $PM_{2.5}$ must be judged on a case-by-case basis. Oglethorpe is confident that PM_{10} is an appropriate surrogate for $PM_{2.5}$ for this project and would be happy to discuss with Georgia EPD what, if any, additional information might be needed to support this approach.

▲ Good Design and Operating Practices

These control technologies are briefly discussed in the following sections.

5.7.2.1 ELECTROSTATIC PRECIPITATOR (ESP)

An ESP removes particles from an air stream by electrically charging the particles then passing them through a force field that causes them to migrate to an oppositely charged collector plate. After the particles are collected, the plates are knocked ("rapped"), and the accumulated particles fall into a collection hopper at the bottom of the ESP. The collection efficiency of an ESP depends on particle diameter, electrical field strength, gas flow rate, and plate dimensions. An ESP can be designed for either dry or wet applications.[101]

5.7.2.2 BAGHOUSE (FABRIC FILTER)

A baghouse consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Dirty gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the baghouse. The air cleaning process stops once the pressure drop across the filter reaches an economically unacceptable level. Typically, the trade-off to frequent cleaning and maintaining lower pressure drops is the wear and tear on the bags produced in the cleaning process.[102]

5.7.2.3 CYCLONE SEPARATORS

Cyclone separators, which can be arranged in series as a multiclone, remove solids from the air stream by application of centrifugal force. Typically, the particle-laden gas enters the top of the cyclone tangentially to the barrel and spins inside the device. Because of the shape of the device, the gas turns and forms a vortex in the center of the device as it moves upward to the exit duct. The particles are removed by centrifugal force, which drives them to the wall of the collector where they fall to the bottom due to gravity. Cyclones are efficient in removing larger, denser particles but are not as effective for fine particle removal (less than 10 μm diameter).[103]

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[101] Kitto, J.B. *Air Pollution Control for Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996. http://www.babcock.com/library/pdf/BR-1624.pdf

[102] Ibid.

[103] Ibid.

5.7.2.4 Venturi Scrubber

Venturi scrubbers intercept dust particles using droplets of liquid (usually water). The larger, particle-enclosing water droplets are separated from the remaining droplets by gravity. The solid particulates are then separated from the water. The waste water must be properly treated.[104]

5.7.2.5 Good Design and Operating Practices

Good design and operating practices imply that the boiler is operated within parameters that, without significant control technology, allow the equipment to operate as efficiently as possible.

5.7.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

All potential control technologies identified in Section 5.7.2 are considered feasible for removing filterable PM and will be evaluated for BACT.

5.7.4 Rank of Remaining Control Technologies (Step 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-7.

Table 5-7. Remaining PM_{10} Control Technologies

Rank	Control Technology	Expected Emissions
1	Fabric Filter	0.010 lb/MMBtu, filterable
2	ESP	0.015 lb/MMBtu, filterable
3	Venturi Scrubber	0.040 lb/MMBtu, filterable
4	Cyclone/Multicyclone	0.10 lb/MMBtu, filterable
5	Good Design and Operating Practices	2.9 lb/MMBtu, filterable

5.7.5 Evaluation of Most Stringent Controls (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for each remaining

[104] U.S. EPA, CATC Fact Sheet for Venturi Scrubbers, EPA-452/F-03-017. http://www.epa.gov/ttn/catc/dir1/fventuri.pdf

control technology on the basis of economic, energy, and environmental considerations, and is described below.

Oglethorpe has proposed to install a baghouse (fabric filter) to reduce filterable PM emissions from the boiler. As this device is ranked as the most efficient control option in Table 5-7, Oglethorpe has determined that the proposed baghouse is BACT for the biomass boiler.

5.7.6 SELECTION OF BACT (STEP 5)

Based on the analysis described above, a baghouse is proposed as the BACT control for the biomass-fired boiler for filterable particulate. In addition, the baghouse is an integral part of the DSI system used for acid gas/condensable particulate control.

The emission levels determined to constitute BACT for biomass fluidized bed boilers with heat input capacities exceeding 250 MMBtu/hr within the last 10 years vary greatly (refer to the RBLC Search/Permit Review table in Appendix D). The most stringent limits are shown in Table 5-8 and were considered by Oglethorpe in determining the appropriate emission rate to propose as BACT for the fluidized bed biomass boiler.

Oglethorpe does not believe the Tate & Lyle Boiler is representative of the proposed BFB boiler as it combusts a very specific biomass (corn fibers) as well as several gaseous fuels. Gaseous fuels inherently have lower PM emissions than solid fuels such as the biomass proposed for the Oglethorpe boiler. It is also unclear if this unit is a gasifier or a fluidized bed boiler.

The Schiller Station total PM limit is for a CFB boiler combusting coal and biomass; this limit is on a 24-hour average basis. Determination of compliance with the 24-hour limit is based on calculations and cannot readily be measured. Further, it is unclear if the 0.010 lb/MMBtu limit is truly total PM_{10}. While PM_{10} testing using both Methods 201 and 202 is required by the permit, it is noted to be used to determine annual emissions. A Method 5 test (filterable PM only) is noted to be used to assess 24-hour average emissions; as the 0.010 lb/MMBtu permit limit is based on a 24-hour average, the limit may only be filterable PM.

Oglethorpe has determined BACT limits for this unit are 3-hour average PM BACT emission limits of 0.010 lb/MMBtu filterable PM and 0.018 lb/MMBtu total PM (filterable plus condensable) identical to those recently determined as BACT by Georgia EPD for the Yellow Pine BFB boiler.

Compliance with these limits will be ensured through proper usage of the baghouse (filterable) and the DSI (condensable). Continuous monitoring of opacity, coupled with stack testing and control device parameter monitoring, will be used to demonstrate compliance.

TABLE 5-8. MOST STRINGENT RBLC ENTRIES FOR PM, PM_{10}, AND $PM_{2.5}$ CONTROL

ID	State	Company/Facility	Boiler Type	Capacity (MMBtu/hr)	Permitted Fuels	Permit Date	Filterable Limit (lb/MMBtu)	Total Limit (lb/MMBtu)	Avg. Period	Control Type	Compliance Method	Note(s)
IA-0095	IA	TATE & LYLE INGREDIENTS AMERICAS, INC.	Unknown	200	Corn Fibers, Gas, Biogas, Process Gas	9/19/2008	0.008	0.012	3-hour	Baghouse	Stack Test	1
NH-0013	NH	SCHILLER STATION, PUBLIC SERVICE OF NH	CFB	720	Wood, Coal	10/25/2004	N/A	0.010	24-hour	Baghouse	Stack Test, Calculations	
GA-02	GA	YELLOW PINE ENERGY COMPANY	BFB	1529	Biomass, TDF, Propane, Fuel Oil	5/15/2009	0.010	0.018	3-hour	Baghouse	Stack Test	
MA-03	MA	PIONEER RENEWABLE ENERGY	Stoker	663	Wood	Application	0.012	0.019	3-hour	ESP	Stack Test	
WA-0329	WA	DARRINGTON ENERGY COGENERATION POWER	Stoker	403	Wood	2/11/2005	N/A	0.020	24-hour	ESP	Stack Test, Calculations	
WA-0298	WA	ABERDEEN DIVISION - SIERRA PACIFIC	Stoker	310	Wood, Natural Gas (Startup only)	10/17/2002	N/A	0.020	24-hour	ESP	Stack Test	
WA-0327	WA	SKAGIT COUNTY LUMBER MILL	Stoker	430	Biomass	12/12/2005	N/A	0.020	24-hour	ESP	6-hr Stack Test, Calculations	
MN-0057	MN	FIBROMINN BIOMASS POWER PLANT	Stoker	792	Manure, Biomass, Natural Gas, Propane	10/23/2002	N/A	0.020	3-hour	Baghouse	Stack Test	
OH-0307	OH	SOUTH POINT BIOMASS GENERATION	Stoker	318	Wood	4/4/2006	0.012	N/A	3-hour	Baghouse	Stack Test	2
MA-02a	MA	RUSSELL BIOMASS	BFB	740	Clean Wood	12/30/2008	0.012	0.026	3-hour	Baghouse	Stack Test	1
MA-02b	MA	RUSSELL BIOMASS	Stoker	740	Clean Wood	12/30/2008	0.012	0.026	3-hour	ESP	Stack Test	1
VT-01	VT	BURLINGTON ELECTRIC DEPT, MCNEIL STATION	Stoker	750	Wood, Natural Gas, Oil	4/21/2008	0.013	N/A	3-hour	ESP	Stack Test	
NE-04	NE	ARCHER DANIELS MIDLAND, COLUMBUS	CFB	768	Coal, Biomass, Petcoke, TDF	Draft, 2008	0.015	0.025	3-hour	Baghouse	Stack Test	
TX-31	TX	NACOGDOCHES POWER PLANT, AMERICAN	BFB	1374	Biomass, Gas	3/1/2007	0.015	0.032	30-day	Baghouse	Stack Test	
CT-03	CT	WATERTOWN RENEWABLE POWER	FB Gasification	436	Biomass, Natural Gas (startup)	Draft 2009	0.020	0.030	24-hour	Baghouse	CEMS	
VA-11	VA	MULTITRADE OF PITTSYLVANIA COUNTY	Stoker	373.3	Biomass	1/1/2003	0.020	N/A	3-hour	ESP	Stack Test	3
MA-05	MA	PALMER RENEWABLE ENERGY	Stoker	38 MW	Biomass	Application	0.020	N/A	3-hour	Baghouse	Stack Test	3
WA-0335	WA	SIMPSON TACOMA KRAFT COMPANY, LLC	Unknown	595	Wood, OCC, Sludge, No. 6 Fuel Oil	5/22/2007	0.020	N/A	24-hour	ESP	6-hr Stack Test, Calculations	

1. Filterable limit is case-by-case MACT limit.
2. Based on lb/hr limit and maximum permitted capacity.
3. Minimum of 99.7% control required.

5.8 BIOMASS BOILER - CO BACT

5.8.1 BACKGROUND ON POLLUTANT FORMATION

CO from biomass boilers is a by-product of incomplete combustion. Conditions leading to incomplete combustion include the following: insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction. In addition, combustion modifications taken to reduce NO_X emissions may result in increased CO emissions.

5.8.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. CO reduction options include:

- ▲ RSCR/Oxidation Catalyst
- ▲ Good Design and Operating Practices

These control technologies are briefly discussed in the following sections.

5.8.2.1 RSCR/OXIDATION CATALYST

As described in Section 5.5.2, a RSCR system utilizes the technology of a SCR system that can be paired with an oxidation catalyst. RSCR systems are placed on the "tail end" of the boiler setup, downstream of the air heaters and particulate control. If no RSCR is present, an oxidation catalyst can still be used but would require its own flue gas reheating system.

A catalytic oxidation system is designed such that the combustion gas passes over a catalyst bed (usually a noble metal such as palladium or platinum) where CO is converted into carbon dioxide (CO_2). This process requires temperatures above 500°F to achieve conversion of CO.[105]

5.8.2.2 GOOD DESIGN AND OPERATING PRACTICES

A properly designed and operated power boiler acts as an oxidizer. Ensuring that the temperature and oxygen availability are adequate for complete combustion minimizes CO formation. This technique includes continued operation of the boiler at the appropriate oxygen range and furnace bed temperature.

5.8.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if

[105] U.S. EPA, CATC Fact Sheet for Catalytic Incineration, EPA-452/F-03-018. Available at: www.epa.gov/ttn/catc/dir1/fcataly.pdf

there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. Both previously identified control technologies are feasible.

5.8.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-9.

TABLE 5-9. REMAINING CO CONTROL TECHNOLOGIES

Rank	Control Technology	Expected Emissions
1	RSCR/Oxidation Catalyst	0.01 lb/MMBtu
2	Good Design and Operating Practices	0.08 lb/MMBtu

5.8.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for the remaining control technology on the basis of economic, energy, and environmental considerations, and is described below.

5.8.5.1 RSCR/OXIDATION CATALYST

The oxidation catalyst must be installed downstream of the particulate control device to ensure that the catalyst is not chemically damaged. However, significant auxiliary fuel input will be required to raise the temperature of the flue gas. Note that if an oxidation catalyst is paired with a Babcock Power RSCR system in which reheating is already occurring, no additional reheating of the flue gas would be required. Both situations, an oxidation catalyst coupled with a RSCR system (no reheat scenario) and a stand-alone oxidation catalyst (reheat required scenario), were considered. Either RSCR or stand-alone oxidation catalyst system would be expected to reduce CO emissions from the proposed biomass boiler to 0.01 lb/MMBtu.

Oglethorpe evaluated the environmental, energy, and economic impacts of the no reheat and reheat required oxidation catalyst scenarios. Environmental impacts are greater for the reheat scenario as additional fuel must be combusted; no other significant environmental impacts are anticipated. Energy impacts include combustion of 3.03 million gallons per year of biodiesel to reheat the flue gas (stand-alone scenario only) as well as 0.9 MW of capacity associated with pressure drop operation from the oxidation catalyst itself or 0.1 MW when used in concert with RSCR.

Next, Oglethorpe evaluated the economic impacts of both the no-reheat and stand alone oxidation catalysts. Based on vendor quotes for total capital costs and OAQPS Manual equations, the annualized costs for a stand-alone oxidation catalyst system would be expected to be more than $43,560 per ton of CO removed. Costs exceed $3,840 per ton of CO removed if an oxidation catalyst is coupled with a tail-end SCR such that reheating costs are not included in the annual operating costs for the oxidation catalyst (no reheat scenario). However, such a scenario is inappropriate since RSCR has already been determined not to be BACT for NO_X control. Even when used with RSCR, the average cost effectiveness of $3,840/ton is very high for CO, which has far lower environmental impact than SO_2, NO_X, or PM/PM_{10}. Thus, even the $3,840/ton value is beyond the accepted range of cost effectiveness, while the non-RSCR CO catalyst is far beyond the range.

Oglethorpe has determined that an oxidation catalyst is not BACT based on the environmental, energy, and economic analyses. In particular, the annualized cost for the stand-alone oxidation catalyst is well beyond the range of cost effectiveness. While the cost for the no-reheat oxidation catalyst scenario appears to be reasonable at face value, the cost infeasibility threshold for CO is much lower than for other pollutants such as NO_X and SO_2. Further, such low costs are only possible if the oxidation catalyst is installed in concert with a RSCR system. However, as previously discussed, a RSCR system was determined not to be BACT. Thus, neither oxidation catalyst scenario is BACT, and Oglethorpe proceeded with evaluating the next most efficient control option presented in Table 5-9.

5.8.5.2 GOOD DESIGN AND OPERATING PRACTICES

The only remaining technology is good design and operating practices, a logical option since a properly designed and operated fluidized bed boiler minimizes CO formation. This is done by ensuring that the boiler temperature and oxygen availability are adequate for complete combustion. Good design and operating practices is considered BACT for CO for the proposed boiler.

5.8.6 SELECTION OF BACT (STEP 5)

Good design and operating practices to achieve minimum emissions of CO is determined as the BACT control for the proposed boiler. The emission levels determined to constitute BACT for biomass fluidized bed boilers with heat input capacities exceeding 250 MMBtu/hr within the last 10 years vary greatly (refer to the RBLC Search/Permit Review table in Appendix D). The most stringent limits are shown in Table 5-10 and were considered by Oglethorpe in determining the appropriate emission rates to propose as BACT for the fluidized bed biomass boiler.

TABLE 5-10. MOST STRINGENT RBLC ENTRIES FOR CO CONTROL

ID	State	Company/Facility	Boiler Type	Capacity (MMBtu/hr)	Permitted Fuels	Permit Date	Limit (lb/MMBtu)	Avg. Period	Control Type	Compliance Method	Note(s)
MA-02a	MA	RUSSELL BIOMASS	BFB	740	Clean Wood	12/30/2008	0.075	Unknown	Good Combustion Practices	CEMS	
MA-02b	MA	RUSSELL BIOMASS	Stoker	740	Clean Wood	12/30/2008	0.075	Unknown	Oxidation Catalyst	CEMS	1
MA-03	MA	PIONEER RENEWABLE ENERGY	Stoker	663	Wood	Application	0.075	Unknown	Oxidation Catalyst	CEMS	1
MA-05	MA	PALMER RENEWABLE ENERGY	Stoker	38 MW	Biomass	Application	0.075	Unknown	Oxidation Catalyst	CEMS	1
CT-03	CT	WATERTOWN RENEWABLE POWER	FB Gasification	436	Biomass, Natural Gas (startup)	Draft 2009	0.10	8-hour	Good Combustion Practices	CEMS	
NE-04	NE	ARCHER DANIELS MIDLAND, COLUMBUS	CFB	768	Coal, Biomass, Petcoke, TDF	Draft, 2008	0.10	30-day	Good Combustion Practices	CEMS	
NH-0013	NH	SCHILLER STATION, PUBLIC SERVICE OF NH	CFB	720	Wood, Coal	10/25/2004	0.10	24-hour	CFB Design	CEMS	
OH-0286	OH	AKRON THERMAL ENERGY CORPORATION	Grate	180	Wood, Tires, Gas	8/12/2008	0.10	annual	Good Combustion Practices	Fuel Records	2, 3
OH-0307	OH	SOUTH POINT BIOMASS GENERATION	Stoker	318	Wood	4/4/2006	0.10	30-day	Oxidation Catalyst	CEMS	
NM-03	NM	WESTERN WATER & POWER - ESTANCIA BASIN BIOMASS	BFB	483	Biomass	Draft, 2007	0.10	30-day	Good Combustion Practices	CEMS	3
CT-02	CT	PLAINFIELD RENEWABLE ENERGY	FB Gasification	523.1	Biomass, biodiesel	2008	0.105	30-day	Good Combustion Practices	CEMS	
GA-02	GA	YELLOW PINE ENERGY COMPANY	BFB	1529	Biomass, TDF, Propane, Fuel Oil	5/15/2009	0.149	30-day	Good Combustion Practices	CEMS	4
GA-09	GA	PLANT CARL, GREEN ENERGY PARTNERS	BFB	400	Biomass, Oil/Grease/Fat, Biodiesel, Chicken Litter	7/29/2008	0.149	30-day	Oxidation Catalyst	CEMS	4
TX-31	TX	NACOGDOCHES POWER PLANT, AMERICAN	BFB	1374	Biomass, Gas	3/1/2007	0.15	30-day	Good Combustion Practices	CEMS	
IA-0083	IA	ROQUETTE AMERICA, INC.	CFB	996	Coal, Petcoke, Biomass, TDF	8/16/2006	0.154	24-hour	Good Combustion Practices	CEMS	
IA-0095	IA	TATE & LYLE INGREDIENTS AMERICAS, INC.	Unknown	200	Corn Fibers, Gas, Biogas, Process Gas	9/19/2008	0.17	30-day	Good Combustion Practices	CEMS	4
MI-0386	MI	RIPLEY HEATING PLANT	CFB	205	Wood, Coal, Gas	5/12/2008	0.17	3-hour	Good Combustion Practices	Stack Test	

1. Part of an RSCR system.
2. Not a BACT limit.
3. Based on lb/hr limit and maximum permitted capacity.
4. Case-by-case MACT limit

As seen from Table 5-10 and Table D-1, CO emission rates for biomass boilers vary based on a few major factors. Primarily, the amount of CO emissions is inversely related to the amount of NO_X emissions. This is due to the basic principles of NO_X and CO formation in combustion. In general, incomplete combustion leads to increased CO formation, while any amount of excess oxygen, which is needed for complete combustion, allows for the fuel-bound nitrogen to react with the oxygen to form fuel NO_X. Oglethorpe has determined that a limit of 0.08 lb/MMBtu on a 30-day average for CO (as measured by a CEMS) is BACT for the proposed boiler. This limit is amongst the lowest limits shown in Table 5-10 and will be achieved without an oxidation catalyst. The BACT limit for CO is for normal operation (i.e., not including startup).

5.9 FIRE PUMP ENGINES - NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, CO BACT

Two fire pump engines will be used in the proposed facility's emergency fire suppression system. These engines will be NFPA certified nominal 330 and 175 hp compression ignition fire pump engines and will be run on either B100 or ULSD, with a maximum sulfur content of 0.0015 weight percent (15 ppmw). Combustion of the biodiesel or ULSD will yield emissions of NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, and CO.

As discussed in Section 4, the engines will be subject to NSPS Subpart IIII. In accordance with this regulation, the engines will each be limited to 100 hours per year of non-emergency maintenance checks and readiness testing, will use fuel with a sulfur content of 15 ppmw or less, and will comply with the 3.0 g/hp-hr emission limit for NO_X + NMHC and 0.15 g/hp-hr emission limit for PM (to serve as a surrogate for PM_{10} and $PM_{2.5}$). Although a specific limit for CO is not established, CO emissions are minimized via the same mechanisms used to minimize NMHC emissions. Oglethorpe is proposing to limit total engine operation, emergency and non-emergency, to 500 hours per year per engine and will use non-resettable hour meters to measure the monthly engine operation to ensure actual operation does not exceed 500 hours for each rolling 12-month period.

A search of the RBLC was conducted for biodiesel- and/or diesel-fired reciprocating internal combustion engines. All data entries for permits issued in 2005 and later for engines less than 500 hp were reviewed. The results can be seen in Table 5-11. As this table illustrates, the only potential control technologies deemed as BACT for emergency engines less than 500 hp are good combustion practices and usage of low-sulfur fuels. In keeping with these results, Oglethorpe proposes BACT for the biodiesel-fired fire pump engines to be good combustion practices (i.e., operate under manufacturer's guidance), ensure compliance with all applicable requirements of NSPS Subpart IIII, including the use of low sulfur fuel, and limit annual operation to 500 hours per year per engine. No specific emission limits beyond those required by NSPS Subpart IIII are proposed.

TABLE 5-11. MOST STRINGENT RBLC ENTRIES FOR FIRE PUMP ENGINE CONTROL

ID	State	Company/Facility[1]	Engine Type	Rating (Hp)	Permitted Fuel(s)	Permit Date	NO_X Limit (g/Hp-hr)	CO Limit (g/Hp-hr)	SO_2 Limit (g/Hp-hr)	PM/PM_{10} Limit (g/Hp-hr)	Control Type(s)	Note(s)
LA-0204	LA	PLAQUEMINE PVC PLANT	EMERGENCY ENGINES	180-450	DIESEL	2/27/2009	14.0	3.0	-	1.0	2	
OH-0317	OH	OHIO RIVER CLEAN FUELS, LLC	FIRE PUMP ENGINES	300	DIESEL	11/20/2008	7.8	2.6	-	0.4	2	3
MD-0040	MD	CPV ST CHARLES	FIRE PUMP ENGINE	300	DIESEL	11/12/2008	3	2.6	-	0.15	2, 4	3, 5
LA-0224	LA	ARSENAL HILL POWER PLANT	FIRE PUMP ENGINE	310	DIESEL	3/20/2008	14.1	3.0	0.9	1.0	2	6
MN-0070	MN	MINNESOTA STEEL INDUSTRIES, LLC	FIRE PUMP ENGINE	<500	DIESEL	9/7/2007	-	-	-	-	2, 4	
CA-1144	CA	BLYTHE ENERGY PROJECT II	FIRE PUMP ENGINE	303	DIESEL	4/25/2007	11.2	1.0	-	0.15	2, 4	6
IA-0084	IA	ADM POLYMERS	FIRE PUMP ENGINE	460	DIESEL	11/30/2006	-	2.6	-	-	2	
OK-0110	OK	MUSKOGEE PORCELAIN FLOOR TILE PLT	EMERGENCY GENERATORS	<500	DIESEL	10/21/2005	-	3.0	-	1.0	2	
NC-0101	NC	FORSYTH ENERGY PLANT	EMERGENCY GENERATOR	<500	DIESEL	9/29/2005	7.7	2.05	-	-	2	
LA-0192	LA	CRESCENT CITY POWER	FIRE PUMP ENGINE	425	DIESEL	6/6/2005	9.5	2.01	0.65	0.15	2	7

1. Only entries from 2005 and on for facilities with diesel engines < 500 hp are shown.
2. Good Combustion Practices.
3. Limit shown is for NO_X + NMOC.
4. Use of Low-Sulfur fuels.
5. NO_X limit is a LAER limit.
6. Limits shown are based on lb/hr limit and rated engine capacity.
7. Limits are based on an annual averaging period.

5.10 BIOMASS FUEL PREPARATION AND HANDLING – PM, PM_{10}, $PM_{2.5}$ BACT

The following section identifies and selects the control technologies to be considered BACT for the various biomass fuel preparation and handling processes. Processes include biomass (chip and log) delivery, biomass processing and chipping, biomass transfer, and storage. All particulate emissions from these processes are filterable particulate.

The PM/PM_{10}/$PM_{2.5}$ emissions from these processes will come from both fugitive and non-fugitive sources. Non-fugitive sources are those that vent through a stack, vent, or other functionally equivalent opening. Fugitive emission sources are converted to non-fugitive sources by enclosing the area and exhausting through a stack or functionally equivalent opening.

Emissions from the biomass fuel preparation and handling areas result from the breakdown of solids into fine particulates that become airborne. This process, also known as "dusting," potentially could result from the wood processing/chipping operation, biomass handling, and wind erosion from the biomass storage piles. Due to the nature of the emissions from the various sources related to biomass fuel preparation and handling, multiple emission control techniques and technologies could be incorporated, varying with the specific sources. These technologies include enclosures, water sprays, and/or surface sealants.

Enclosures could potentially be used on any process, transfer point, or storage pile where structural or operational considerations do not preclude their use. Generally speaking, the technical feasibility of an enclosure depends on a number of factors, including functionality, safety, and practicality of the enclosure for the specific application. When used in conjunction with a baghouse or vent filter, the enclosure could capture as much as 99% of the PM/PM_{10}/$PM_{2.5}$ emissions from a source. Cyclones could also be used in conjunction with an enclosure, however this setup would not offer the degree of control that an enclosure with a baghouse would, and a cyclone is typically associated with pneumatic transfer in similar biomass storage and handling operations. Where feasible, enclosures represent the most stringent control option for minimizing fugitive biomass handling and storage PM/PM_{10}/$PM_{2.5}$ emissions.

Where usage of an enclosure is not feasible, water spray could be used to suppress PM/PM_{10}/$PM_{2.5}$ emissions. Water sprays reduce the PM/PM_{10}/$PM_{2.5}$ emissions either by direct contact between the particles within the air and spray droplets or by binding the smaller particles to the surface of the material. Similarly, surface sealants could be used on many of the same sources as water sprays and they work similarly except that the surface sealant is a chemical treatment that creates a protective layer on the surface of the material that will bind and contain the PM/PM_{10}/$PM_{2.5}$ particles.

Enclosure or usage of water sprays is technically feasible for some of the biomass preparation and handling sources. However, there are instances in which each of the control options would not be effective or would possibly be detrimental to facility operation. Examples include, constructing an enclosure which would limit the functionality of the process, spraying water to the extent that the moisture content of the fuel piles would be significantly increased, or spraying surface sealants on material that is frequently disturbed or manipulated.

Oglethorpe conducted a review of the RBLC to determine what control techniques have been employed to reduce $PM/PM_{10}/PM_{2.5}$ emissions from the various biomass handling and storage operations. Tables 5-12 through 5-14 present a summary of the RBLC review for Biomass Storage, Biomass Handling, and Fuel Preparation, respectively.

Processes in which enclosures and dust control systems have been deemed feasible and are considered BACT include the following:

▲ **Biomass unloading operations**: the six feeder conveyors (FDR1 – FDR6) and two collecting belt conveyors (CV01, CV02) will be enclosed and will utilize a baghouse (BM01).

▲ **Biomass processing building**: the entire biomass processing building, which includes two receiving belts (CV03, CV04), two diverter gates (GAT1, GAT2), two scalping screens (SCN1, SCN2), two wood hogs (GRN1, GRN2), and two collecting feeders (FDR7, FDR8), will be enclosed and employ a dust collection system and baghouse (BM02).

▲ **Biomass transfer tower**: the transfer from the stockout belt conveyor (CV13) to the boiler reclaim belt conveyor (CV14) is enclosed and the building will utilize a baghouse to collect dust (BM03).

▲ **Boiler building fuel transfer operations**: the boiler reclaim belt conveyor (CV14), distribution drag chain conveyor (CV15) and overfill return belt conveyor (CV16) are enclosed, and a baghouse (BM04) will capture any dust from these conveyors.

▲ **Longwood grinding**: the mobile chipper (GRN3) will discharge to an enclosed chute into an enclosed structure equipped with a dust suppression system (BM10). The enclosed chute is expected to capture 95% of the emissions.

These areas will use the enclosures and dust control systems to achieve $PM/PM_{10}/PM_{2.5}$ control. Baghouse outlet $PM/PM_{10}/PM_{2.5}$ emissions will be limited to 0.005 gr/cf.

Surface sealants provide the second highest degree of control but are only suitable for essentially stationary piles, of which there are none at the proposed Warren facility. Water sprays provide the next highest degree of control. Areas in which water sprays will be used include:

▲ **Biomass unloading operations**: the six truck dumpers (DMP1 – DMP6) and associated six collection hoppers (HPR1 – HPR6) will utilize a water mist.

▲ **Biomass storage area**: the two fuel transfer belt conveyors (CV05, CV06) are enclosed and the discharge point will utilize a water mist. The two radial stacking belt conveyors (CV07, CV08) and two radial reclaim chain conveyors (CV09, CV10) will also utilize a water mist, with CV07 and CV08 using a telescopic chute to minimize dust generation from the drop to the pile. Although a specific dust suppression system or spray is not proposed for the two reclaim belt conveyors (CV11, CV12) or stackout conveyor (CV13), these belts are covered and the material traveling on these belts will remain wetted from the previous water sprays used for the reclaim chain conveyors.

TABLE 5-12. RBLC ENTRIES FOR BIOMASS STORAGE

ID	State	Company/Facility	Process	Process Type	Throughput (tons/hr)	Permit Date	PM (lb/hr)	PM_{10} (lb/hr)	PM (lb/ton)	PM_{10} (lb/ton)	Control Type
MS-0054	MS	WEYERHAEUSER COMPANY	Fuel Silo	Bin Storage	N/A	12/28/2000	-	-			Pneumatic Transport
TX-0292k	TX	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	Sawdust Truck Bin	Bin Storage	N/A	8/6/2000	0.32	0.15			Good Operating Practices
WI-0234	WI	STORA ENSO - BIRON MILL	Bark Silo	Bin Storage	N/A	3/31/2006	-	0.30			Baghouse
TX-0403a	TX	LOUISIANA-PACIFIC CORPORATION	Raw Fuel Bin	Bin Storage	N/A	7/6/1999	-	0.58			Baghouse
TX-0403b	TX	LOUISIANA-PACIFIC CORPORATION	Finish Fuel Bin	Bin Storage	N/A	7/6/1999	-	0.71			Baghouse
WI-0205a	WI	WHITING MILL	Wood Room Storage	Bin Storage	30	12/19/2003	0.90	-	0.03		Enclosure
TX-0292a	TX	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	Fuel House	Covered Storage	N/A	8/6/2000	0.08	0.04			Enclosure
TX-0292b	TX	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	Chip Truck Bin	Covered Storage	N/A	8/6/2000	0.36	0.17			Good Operating Practices
TX-0263	TX	DONAHUE INDUSTRIES, INC. PAPER MILL	Woodyard	Storage Pile	N/A	10/17/2000	-	-			Good Operating Practices
WI-0205b	WI	WHITING MILL	Chip and Bark Piles	Storage Pile	30	12/19/2003	-	-			Enclosure
OH-0317	OH	OHIO RIVER CLEAN FUELS, LLC	Biomass Storage Piles	Storage Pile	5,500	11/20/2008	-	-			Partial Enclosure, Water, Dust Suppressants
LA-0174c	LA	GP - PORT HUDSON OPERATIONS	Bark Pile	Storage Pile	320	1/25/2002	0.03	0.03	0.00009	0.00009	Good Operating Practices
TX-0446b	TX	LP - JASPER ORIENTED STRANDBOARD MILL	Fuel Piles	Storage Pile	N/A	2/9/2004	0.04	-			Good Operating Practices
LA-0174b	LA	GP - PORT HUDSON OPERATIONS	Softwood Chip Pile	Storage Pile	1,130	1/25/2002	0.12	0.12	0.00011	0.00011	Good Operating Practices
LA-0174a	LA	GP - PORT HUDSON OPERATIONS	Hardwood Chip Pile	Storage Pile	2,443	1/25/2002	0.25	0.25	0.00010	0.00010	Good Operating Practices
LA-0139c	LA	LP - URANIA PLANT	Chips and Shaving Pile	Storage Pile	21	12/7/2000	-	0.42		0.02	Enclosure

TABLE 5-13. RBLC ENTRIES FOR BIOMASS HANDLING

ID	State	Company/Facility	Process	Process Type	Throughput (tons/hr)	Permit Date	PM (lb/hr)	PM_{10} (lb/hr)	PM (lb/ton)	PM_{10} (lb/ton)	PM (gr/cf)	PM_{10} (gr/cf)	Control Type
AR-0039	AR	DEL TIN FIBER LLC	Material Handling	Handling	N/A	5/9/2001	-	-					Baghouse
LA-0201a	LA	WEYERHAEUSER - RED RIVER MILL	Chip Handling	Handling	N/A	5/24/2006	-	-					Covered Conveyors
LA-0201b	LA	WEYERHAEUSER - RED RIVER MILL	Chip Unloading	Handling	N/A	5/24/2006	-	-					Good Operating Practices
SC-0074	SC	KRONOTEX, USA, INC. - BARNWELL	Wood Dust System	Handling	N/A	4/8/2002	-	-				0.05	Bin Vent Filter
WI-0187	WI	STORA-ENSO NORTH AMERICA - WI RAPIDS PULP	Bark and Wood Handling	Handling	N/A	8/30/2001	-	-					Enclosure
TX-0292c	TX	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	Chip Loading	Handling	N/A	8/6/2000	0.05	0.03					Good Operating Practices
AR-0029	AR	TEMPLE INLAND FOREST PRODUCTS CORP.	Material Handling	Handling	N/A	11/19/1999	0.10	-					Baghouse
TX-0446a	TX	LP - JASPER ORIENTED STRANDBOARD MILL	Bark Handling	Handling	N/A	2/9/2004	0.47	0.16					Good Operating Practices
LA-0122a	LA	INTERNATIONAL PAPER - MANSFIELD MILL	Bark Handling	Handling	1,701	8/14/2001	-	0.49		0.0003			Good Operating Practices
VA-0298d	VA	INTERNATIONAL BIOFUELS, INC	Peanut Hull Handling	Handling	3	12/13/2005	0.60	0.60	0.20	0.20			Good Operating Practices
LA-0139b	LA	LP - URANIA PLANT	Chips and Shavings Loading	Handling	33	12/7/2000	-	1.08		0.032			Enclosure
OH-0249	OH	SAUDER WOODWORKING COMPANY	Wood Residue Handling	Handling	N/A	6/3/2004	2.59	1.85			0.0042	0.003	Baghouse
OH-0307	OH	SOUTH POINT BIOMASS GENERATION	Wood Residue Handling	Handling	202.79	4/4/2006	-	6.71	0.033	0.033		0.0064	Baghouse
VA-0298c	VA	INTERNATIONAL BIOFUELS, INC	Wood Residue Handling	Handling	121	12/13/2005	12.10	12.10	0.10	0.10			Good Operating Practices
LA-0122b	LA	INTERNATIONAL PAPER - MANSFIELD MILL	Woodyard	Handling	N/A	8/14/2001	-	24.60					Covered Conveyors

TABLE 5-14. RBLC ENTRIES FOR FUEL PREPARATION

ID	State	Company/Facility	Process	Process Type	Throughput (tons/hr)	Permit Date	PM (lb/hr)	PM_{10} (lb/hr)	PM (lb/ton)	PM_{10} (lb/ton)	Control Type
OK-0094	OK	WEYERHAEUSER-VALLIANT	Chipper	Chipping	N/A	8/27/2003	-	-			Good Operating Practices
VA-0298b	VA	INTERNATIONAL BIOFUELS, INC	Hammermill	Chipping	52	12/13/2005	1.00	1.00	0.02	0.02	Baghouse
TX-0345	TX	DIBOLL PARTICLEBOARD OPERATION	Hammermill	Chipping	N/A	9/28/2001	5.20	5.20			Baghouse
VA-0298a	VA	INTERNATIONAL BIOFUELS, INC	Hammermill	Chipping	121	12/13/2005	14.50	14.50	0.12	0.12	Cyclones
TX-0292g	TX	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	Bark Hog and Screen	Hog	N/A	8/6/2000	0.02	0.01			Good Operating Practices
TX-0292f	TX	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	Bark Hog	Hog	N/A	8/6/2000	0.04	0.02			Good Operating Practices
TX-0292e	TX	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	Bark Hog and Screen	Hog	N/A	8/6/2000	0.10	0.05			Good Operating Practices
LA-0139a	LA	LP - URANIA PLANT	Classifier and Separator	Screen	25	12/7/2000	-	2.17		0.09	Baghouse
TX-0292j	TX	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	Chip Screen	Screen	N/A	8/6/2000	0.03	0.02			Good Operating Practices
TX-0292h	TX	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	Chip Screen	Screen	N/A	8/6/2000	0.04	0.02			Good Operating Practices
TX-0292i	TX	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	Chip Screen	Screen	N/A	8/6/2000	0.06	0.03			Good Operating Practices

5.11 MATERIAL STORAGE SILOS – PM, PM_{10}, $PM_{2.5}$ BACT

This section identifies control options for the reduction of $PM/PM_{10}/PM_{2.5}$ from the Sorbent Storage Silo, Sand Storage Silo, Sand Day Hopper, Fly Ash Storage Silo, and Bottom Ash Storage Area. $PM/PM_{10}/PM_{2.5}$ emissions from these sources form in various ways, most notably from the breakdown of solids into fine particulates that become airborne. This effect is exacerbated by the amount of shifting that comes with the throughput of the materials. Emissions can be minimized through the usage of fabric filtration systems (baghouses, bin vent filters) and/or good operating practices.

Fabric filtration systems typically operate by having dirty gas enter from one side and pass through the filter media, which forms a particulate cake. The air cleaning process stops once the pressure drop across the filter reaches an economically unacceptable level. Typically, the trade-off to frequent cleaning and maintaining lower pressure drops is the wear and tear on the bags produced in the cleaning process. Where a fabric filtration system is not feasible, good operating practices are used to minimize $PM/PM_{10}/PM_{2.5}$ emissions from the transfer of materials into and out of the silos.

Oglethorpe conducted a review of the RBLC to determine what control techniques have been employed to reduce filterable PM_{10} emissions from the storage silos. Table 5-15 show the most stringent emission limits and control techniques for ash and lime silos. Control for sand silos is expected to be similar to the techniques and grain loadings considered BACT for the ash and lime silos.

For the Sorbent Storage Silo, Sand Storage Silo, Sand Day Hopper, Fly Ash Storage Silo, and Bottom Ash Storage Area, Oglethorpe proposes to utilize fabric filtration systems to reduce outlet $PM/PM_{10}/PM_{2.5}$ emissions to 0.005 gr/cf. Additionally, water suppression will be used in the fly ash storage silo for $PM/PM_{10}/PM_{2.5}$ control during the loading process. In all instances, good operating procedures will be used to minimize the formation of $PM/PM_{10}/PM_{2.5}$ from these areas.

TABLE 5-15. MOST STRINGENT RBLC ENTRIES FOR SILO CONTROL

ID	State	Company/Facility[1]	Process	Throughput (tons/hr)	Permit Date	PM (gr/cf)	PM_{10} (gr/cf)	Control Type
*LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	SAND/BOTTOM ASH SILOS AND DAY BINS	N/A	6/22/2009	0.005	-	Baghouse
OH-0317	OH	OHIO RIVER CLEAN FUELS, LLC	FLYASH HANDLING SYSTEM	95.4	11/20/2008	0.005	-	Baghouse
OH-0321b	OH	MARTIN MARIETTA MATERIALS	LIME LOAD-OUT, TRANSFER, STORAGE	300	11/13/2008	0.005	0.005	Baghouse
*IA-0095	IA	TATE & LYLE INDGREDIENTS AMERICAS, INC.	ASH STORAGE BIN/ LOADOUT	N/A	9/19/2008	0.005	0.005	Dust Collector
*IA-0095	IA	TATE & LYLE INDGREDIENTS AMERICAS, INC.	LIME SILO	150	9/19/2008	0.005	0.005	Dust Collector
ND-0024	ND	SPIRITWOOD STATION	MATERIALS HANDLING	60	9/14/2007	0.005	-	Baghouse
IA-0089	IA	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	ASH STORAGE AND HANDLING	250	8/8/2007	0.005	0.005	Baghouse
*IA-0086	IA	UNIVERSITY OF NORTHERN IOWA	LIMESTONE SILO	10	5/3/2007	0.005	0.005	Baghouse
ND-0021	ND	GASCOYNE GENERATING STATION	MATERIAL HANDLING	N/A	6/3/2005	0.005	-	Baghouse
AL-0220a	AL	CHEMICAL LIME COMPANY - O"NEAL PLANT	LIME HANDLING & STORAGE	N/A	3/23/2005	0.005	-	Unknown
OH-0321c	OH	MARTIN MARIETTA MATERIALS	DUST LOAD-OUT SYSTEM	100	11/13/2008	0.01	0.01	Baghouse
WV-0024	WV	WESTERN GREENBRIER CO-GENERATION, LLC	ASH HANDLING	105	4/26/2006	0.01	-	Fabric Filters
WV-0024	WV	WESTERN GREENBRIER CO-GENERATION, LLC	LIMESTONE HANDLING	100	4/26/2006	0.01	0.01	Fabric Filters
CO-0057c	CO	COMANCHE STATION	RECYCLE ASH HANDLING	N/A	7/5/2005	0.01	-	Baghouse
CO-0057	CO	COMANCHE STATION	LIME HANDLING	N/A	7/5/2005	0.01	0.01	Baghouse

1. Only entires from 2005 and on with gr/cf limit of 0.01 or less are listed.

5.12 COOLING TOWER – PM, PM_{10}, $PM_{2.5}$ BACT

The multi-cell Cooling Tower will operate as part of the heat rejection process by circulating water through the surface condenser and using a mechanically induced draft to reject the heat from the cooling water to the environment, primarily through evaporation of a portion of the cooling water. In this process, a very small portion of the cooling water may be carried to the ambient air in liquid form. This is referred to as drift and can contain a small amount of mineral material, which is present in the cooling water. This will represent a very small source of $PM/PM_{10}/PM_{2.5}$ at the Oglethorpe facility.

A search of the RBLC was done for potential control technologies for Cooling Towers. As shown in Table 5-16, the only control technology identified for the reduction of $PM/PM_{10}/PM_{2.5}$ from Cooling Towers are drift eliminators. Drift eliminators are designed to capture as many of the droplets at the exit of the Cooling Tower as possible. By capturing these droplets, the amount of mineral material (in the form of $PM/PM_{10}/PM_{2.5}$) carried out into the ambient environment is reduced. This is accomplished by placing objects of various geometric configurations at the exit of the cooling towers. By forcing the exhaust to quickly change directions, the inertia of the droplets causes them to collide with the drift eliminators, in which the surface tension acts to keep the droplets on the surface of the drift eliminators. Gravity then pulls the droplets back down to the cooling tower basin.

Drift eliminators are the most stringent control technology for wet cooling towers. They are a well established and proven way of decreasing drift from the Cooling Tower, which will reduce the amount of $PM/PM_{10}/PM_{2.5}$ emissions. Therefore, drift eliminators will be considered BACT for the Cooling Tower and will minimize the $PM/PM_{10}/PM_{2.5}$ drift to 0.0005% or less.

TABLE 5-16. MOST STRINGENT RBLC ENTRIES FOR COOLING TOWERS

ID	State	Company/Facility[1]	Unit	Throughput (gpm)	Permit Date	PM Limit (% drift)	PM_{10} Limit (% drift)	Control Type	Note(s)
MT-0030	MT	BILLINGS REFINERY	COOLING TOWER	10,000	11/19/2008	-	0.0005	Drift Eliminator	
MD-0040	MD	CPV ST CHARLES	COOLING TOWER	N/A	11/12/2008	0.0005	0.0005	Drift Eliminator	2
AR-0094	AR	JOHN W. TURK JR. POWER PLANT	COOLING TOWER	N/A	11/5/2008	-	0.0005	Drift Eliminator	3
*IA-0095	IA	TATE & LYLE INDGREDIENTS AMERICAS, INC.	COOLING TOWER (4 CELLS)	30,000	9/19/2008	0.0005	0.0005	Drift Eliminator	
*FL-0304	FL	CANE ISLAND POWER PARK	COOLING TOWER (8 CELLS)	N/A	9/8/2008	0.0005	-	Drift Eliminator	
*FL-0303	FL	FPL WEST COUNTY ENERGY CENTER UNIT 3	COOLING TOWER (26 CELLS)	304,000	7/30/2008	0.0005	-	Drift Eliminator	
FL-0299	FL	CRYSTAL RIVER POWER PLANT	COOLING TOWER	342,306	10/12/2007	0.0005	-	Drift Eliminator	
ND-0024	ND	SPIRITWOOD STATION	COOLING TOWER	80,000	9/14/2007	0.0005	-	Drift Eliminator	
IA-0089	IA	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	COOLING TOWER	50,000	8/8/2007	0.0005	0.0005	Drift Eliminator	
IA-0088	IA	ADM CORN PROCESSING - CEDAR RAPIDS	COOLING TOWER	150,000	6/29/2007	0.0005	0.0005	Drift Eliminator	
*FL-0286	FL	FPL WEST COUNTY ENERGY CENTER	COOLING TOWER (26 CELLS)	306,000	1/10/2007	0.0005	-	Drift Eliminator	
FL-0294	FL	ANCLOTE POWER PLANT	COOLING TOWER	660,000	12/22/2006	0.0005	-	Drift Eliminator	
CO-0057	CO	COMANCHE STATION	COOLING TOWER	140,650	7/5/2005	0.0005	0.0005	Drift Eliminator	
NV-0036	NV	TS POWER PLANT	COOLING TOWER	N/A	5/5/2005	-	0.0005	Drift Eliminator	
NY-0093	NY	TRIGEN-NASSAU ENERGY CORPORATION	COOLING TOWER	N/A	3/31/2005	-	0.0005	Drift Eliminator	
WA-0329	WA	DARRINGTON ENERGY COGENERATION POWER	COOLING TOWER	N/A	2/11/2005	0.001	-	Drift Eliminator	
*WA-0328	WA	BP CHERRY POINT COGENERATION PROJECT	COOLING TOWER	N/A	1/11/2005	0.001	-	Drift Eliminator	

1. Only RBLC entries with % drift limits of 0.001% and smaller are listed.
2. LAER limit for PM2.5, not a BACT limit.
3. Also includes a lb/hr emission limit.

5.13 ROADS – PM, PM_{10}, $PM_{2.5}$ BACT

Throughout the proposed Oglethorpe facility, there will be a number of roadways. Trucks will be traveling along these roads daily for the delivery of biomass fuels, delivery of sand and sorbent, removal of fly ash from the boiler, and various other day-to-day tasks associated with the operation of the proposed facility. The high amount of traffic on these roads has the potential to cause fugitive particulate matter emissions.

A search of the RBLC reveals a few methods of controlling or reducing fugitive road emissions, including paving of the roads, limiting vehicle access, vacuuming, water suppressant sprays, and reduced vehicle speeds. These results can be seen below in Table 5-17. Suppressant sprays work by binding with the particulates on the surface of the unpaved roadways, preventing them from emitting to the immediate atmosphere. Paving of the roads, sweeping, limiting vehicle access, and reducing vehicle speeds are all effective and relatively easily implemented measures that have a significant effect on the amount of PM/PM_{10}/$PM_{2.5}$ generated by travel along the proposed facility's roadways. As BACT, Oglethorpe plans on paving all the facility's roads, restricting vehicle access to authorized vehicles, reducing vehicle speeds, and watering the roads as a means of minimizing the amount of fugitive PM/PM_{10}/$PM_{2.5}$ emissions created via road travel at the proposed facility.

OPC has proposed a limit of 340 trucks per day, paved roads, and road watering to minimize dust from the roads for the proposed project.

TABLE 5-17. RBLC ENTRIES FOR ROADS

ID	State	Company/Facility[1]	Unit	Road Type	Permit Date	Control Type	Note(s)
*LA-0204	LA	PLAQUEMINE PVC PLANT	ROADS	Paved	7/27/2005	Pave Roads	
OH-0317	OH	OHIO RIVER CLEAN FUELS, LLC	ROADS, PARKING LOT	Paved	11/20/2008	Minimize Speed, Sweeping, Watering for 90% Reduction	
*IA-0095	IA	TATE & LYLE INDGREDIENTS AMERICAS, INC.	ROADS	Paved	9/19/2008	Daily Water, Sweeping for 80% Reduction	
*OH-0315	OH	NEW STEEL INTERNATIONAL, INC., HAVERHILL	ROADS	Paved	5/6/2008	Watering/Dust Suppression Sprays, Minimize Speed	
LA-0223	LA	BIG CAJUN I POWER PLANT	ROADS	Paved	1/8/2008	Pave Roads	2
*LA-0221	LA	LITTLE GYPSY GENERATING PLANT	ROADS	Paved	11/30/2007	Pave Roads	2
IA-0089	IA	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	ROADS	Paved	8/8/2007	Sweeping, Dust Suppression	
IA-0088	IA	ADM CORN PROCESSING - CEDAR RAPIDS	ROADS	Paved	6/29/2007	Daily Water, Sweeping for 80% Reduction	
IA-0092	IA	SOUTHWEST IOWA RENEWABLE ENERGY	ROADS	Paved	4/19/2007	Daily Water, Sweeping	
WV-0024	WV	WESTERN GREENBRIER CO-GENERATION, LLC	ROADS	Paved	4/26/2006	Watering/Dust Suppression Sprays, Minimize Speed	
CO-0055	CO	LAMAR LIGHT & POWER POWER PLANT	ROADS	Paved	2/3/2006	Watering; Daily Cleaning, Covering, and Inspection of Trucks	
IL-0102	IL	AVENTINE RENEWABLE ENERGY, INC.	ROADS	Paved	11/1/2005	Pave Roads	
LA-0204	LA	PLAQUEMINE PVC PLANT	ROADS	Paved	7/27/2005	Pave Roads	2
CO-0057	CO	COMANCHE STATION	ROADS	Both	7/5/2005	Chemical Stabilizers for Unpaved Roads; Sweep and Water Paved Roads	3
LA-0203	LA	OAKDALE OSB PLANT	ROADS	Paved	6/13/2005	Limit Access	2

1. Only entries from 2005 and on for facilities with paved roads are shown.
2. Permit also includes a numeric emission limit.
3. RACT requirement.

5.14 SUMMARY OF PROPOSED BACT PRIMARY LIMITS

Table 5-18 presents a summary of the proposed primary BACT determinations and limits for the biomass boiler and other emission units at the facility. Note the BFB boiler primary limits only apply during periods of normal operation; secondary limits, as discussed in the following section, will apply during periods that encompass startup and shutdown events.

TABLE 5-18. SUMMARY OF PROPOSED PRIMARY BACT DETERMINATIONS

Unit	Pollutant[1]	Limit	Units	Averaging Period	Proposed BACT
BFB Boiler	NO_X	0.11	lb/MMBtu	30-day	Selective Non-Catalytic Reduction
	SO_2	0.010	lb/MMBtu	30-day	Duct Sorbent Injection
	$PM/PM_{10}/PM_{2.5}$ (Filterable)	0.010	lb/MMBtu	3-hour	Baghouse
	$PM_{10}/PM_{2.5}$ (Total)	0.018	lb/MMBtu	3-hour	Baghouse
	CO	0.08	lb/MMBtu	30-day	Good Design and Operating Practices
Fire Pump Engines (each)[2]	NO_X + NMHC	3.0	g/Hp-hr	3-hour	Good Design and Operating Practices
	SO_2	15	ppmw	N/A	Fuel Sulfur Content
	$PM/PM_{10}/PM_{2.5}$	0.15	g/Hp-hr	3-hour	Good Design and Operating Practices
	CO	-		N/A	Good Design and Operating Practices
Biomass Unloading Operations	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Baghouse
Biomass Processing Building	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Baghouse
Biomass Transfer Tower	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Baghouse
Boiler Building Biomass Transfer	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Baghouse
Mobile Longwood Chipping	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Baghouse
Sorbent Storage Silo	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Bin Vent Filter[4]
Sand Storage Silo	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Bin Vent Filter[4]
Sand Day Silo	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Bin Vent Filter[4]
Fly Ash Storage Silo	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Bin Vent Filter[4]
Bottom Ash Storage Area	$PM/PM_{10}/PM_{2.5}$	0.005	gr/cf	3-hour	Bin Vent Filter[4]
Cooling Tower	$PM/PM_{10}/PM_{2.5}$	0.0005%	drift	N/A	Drift Eliminators
Fugitive Dust Emissions[3]	$PM/PM_{10}/PM_{2.5}$	Varies with Emission Unit			Water Spray and/or Dust Reduction Devices

1. Compliance with $PM_{2.5}$ limits is assumed inherent with compliance with PM_{10} limits as vendors did not provide $PM_{2.5}$ estimates.
2. Fire pumps will operate for a maximum of 500 hours per year, total, and only 100 hours per year of non-emergency operation.
3. Refer to Sections 2 and 5 of the application for detail on the fugitive dust emission sources.
4. The bin vent filter is a type of fabric filter.

Oglethorpe is proposing to demonstrate compliance with $PM_{2.5}$ limits via complying with the identical PM_{10} limits as vendors have not provided nor guaranteed $PM_{2.5}$ emission factors.

5.15 BIOMASS BOILER SECONDARY BACT EMISSION LIMITS

The primary BACT emission limits discussed in earlier sections are rate-based limits based on the boiler heat input (lb/MMBtu), which means that for every unit of heat consumed by the boiler, there will be no more than "X" amount of emissions. These limits reflect what are expected to be the achievable emission rates using the respective control technology during periods of normal boiler operation. However, emission limits that directly correspond to the instantaneous heat input of the boiler may not be appropriate during periods of startup and shutdown. In these situations, the amount of fuel, and thus heat input, is lower than during typical operation, which therefore linearly decreases the emission limits. To keep in compliance with the lb/MMBtu limits during times of startup or shutdown, the boiler would have to sustain the expected control efficiency of normal operation, where the boiler and control devices are designed to operate, at much lower temperatures and flow rates. For many of the control devices, this is simply not possible, due to the nature of the control device. For example, an SNCR relies on various chemical reactions that do not take place under certain temperature thresholds. This makes it difficult, if not impossible for the boiler to comply with stringent BACT limits that are based on a heat input rate during startup and shutdown periods.

In the definition of BACT, it clearly states that a BACT limit is one that, "on a case-by-case basis is determined to be achievable."[106] Therefore, in order for Oglethorpe to propose limits that are both "achievable" and keep the boiler under a high degree of control during normal operation, Oglethorpe is proposing secondary BACT limits to address periods of startup and shutdown. Permitting of separate secondary limits is consistent with what has been proposed and accepted by other power generating facilities. Prairie State Generating Company (Peabody), outside of Marissa, IL, was permitted using secondary BACT limits. This permit, issued April 24, 2005 by the Illinois Environmental Protection Agency (IEPA), was petitioned and taken to the U.S. EPA Environmental Appeals Board (EAB) for review.[107] The EAB sided with the IEPA's issuing of the "secondary" BACT limits, stating that:

> *… adoption of an alternative method during these periods [startup and shutdown] "reflects Illinois EPA's experience with industrial boilers, which found that the rate-based compliance methodology of the NSPS*[108] *is problematic when applied to stringent BACT limits."… IEPA stated further that, "[w]ithout this provision for an alternative compliance methodology, the BACT limits for* SO_2 *and* NO_X *could not be extended with the necessary confidence that compliance is reasonably achievable with the BACT limits."*[109]

[106] 40 CFR 52.21(b)(12)

[107] PSD Appeals No. 05-05, decided August 24, 2006.

[108] Reference from quoted material states: "The Permit uses the NSPS's methodology as the primary method for determining compliance with the BACT limits at issue during periods that do not include startup or shutdown."

[109] Section II.C.2 of PSD Appeals No. 05-05 (pages 118-119), decided August 24, 2006.

Although this statement just refers to SO_2 and NO_X limits, the EAB concurred with IEPA's ruling on lb/hr startup/shutdown BACT limits for CO.[110]

It is Oglethorpe's determination that not only are secondary BACT limits justified, but that they are required to ensure with a necessary degree of confidence that the stringent primary BACT limits proposed in the previous sections are achievable for those pollutants with continuous compliance demonstration methods. Oglethorpe is proposing secondary NO_X, SO_2, and CO limits that are mass-based limits on an annual (tpy) basis, with compliance determined via CEMS. The mass limits are based on the summation of: 1) 40 startup/shutdown events per year (640 hours total) at the maximum startup/shutdown hourly emissions, and 2) normal operation at the annual heat input capacity of 1,282 MMBtu/hr and at the primary BACT limit for the remainder of the year (8,760 – 640 hours).[111] Table 5-19 presents a summary of the proposed secondary BACT limits for the biomass boiler.

TABLE 5-19. SUMMARY OF PROPOSED SECONDARY BACT LIMITS

Unit	Pollutant	Limit	Units	Averaging Period
BFB Boiler	NO_X	648.1	tons	annual
	SO_2	56.2	tons	annual
	CO	625.4	tons	annual

In determining compliance with the primary BACT limits for CO, NO_X, and SO_2, Oglethorpe would exclude any hours from the average where the steam load was less than 40% as well as any hours when the steam load was below 65% during startup. Compliance with BACT during these periods would instead be met by the limits listed in Table 5-19.

A specific quantitative $PM/PM_{10}/PM_{2.5}$ secondary BACT limit has not been proposed for the biomass boiler because emissions during periods of startup and shutdown cannot be measured. As explained earlier, the boiler baghouse cannot be operated during the entire period of startup. Thus, Oglethorpe is proposing a secondary BACT work practice that would consist of good operating practices coupled with bringing the baghouse on-line as quickly as possible after the exhaust temperature has risen above the acid dew point. No specific monitoring is required to demonstrate compliance with the proposed $PM/PM_{10}/PM_{2.5}$ secondary BACT limit. Because there is a technical infeasibility in measuring PM during startup, a work practice standard is allowable as secondary BACT.

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[110] PSD Appeals No. 05-05, Section II.C.3 refers to the EAB determination on startup and shutdown BACT limits for CO.

[111] Example: NO_X = [(640 hr/yr)* (236 lb/hr) + (8,760 – 640 hr/yr)*(1,282 MMBtu/hr)*(0.11 lb/MMBtu)] = (151,040 lb/yr + 1,145,082 lb/yr) = 1,296,122 lb/yr = 648.1 tpy.

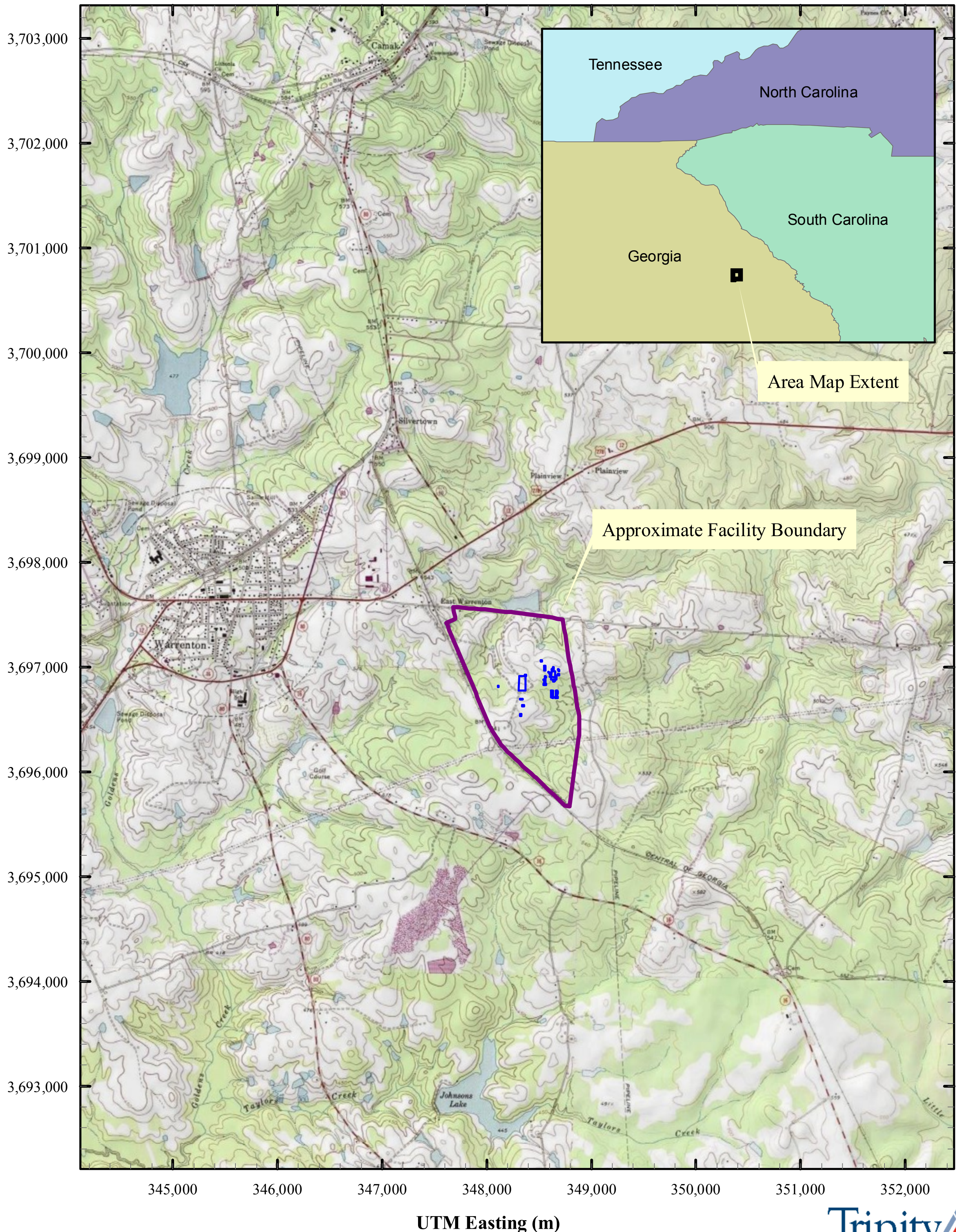
APPENDIX A

FACILITY INFORMATION

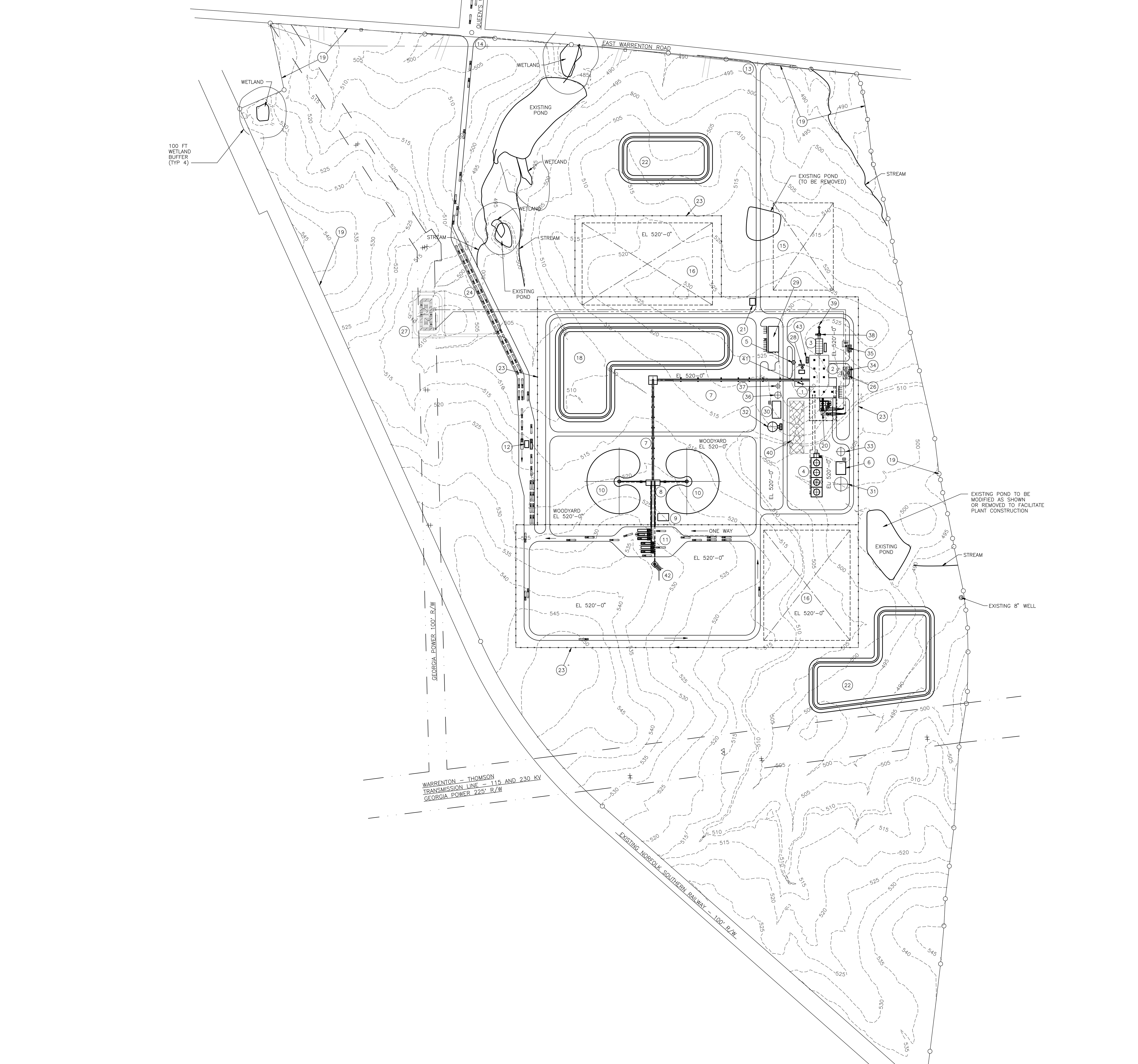
Area Map
Site Layout
Process Flow Diagrams

Figure A-1. Facility Area Map

Oglethorpe Power Corporation Warren County Facility
Warrenton, Warren County, Georgia



Coordinates reflect UTM projection Zone 17, NAD83.



SITE FEATURES

ITEM NO.	EQUIP. NO.	DESCRIPTION	TIE DOWN EL*
1	-----	TURBINE ROOM	–
2	-----	BOILER ROOM	–
3	-----	FABRIC FILTER	–
4	-----	COOLING TOWER	–
5	-----	ASH SILO	–
6	-----	WASTEWATER TREATMENT BUILDING	–
7	-----	PROCESSED FUEL CONVEYOR	–
8	-----	FUEL PROCESSING BUILDING	–
9	-----	TRUCK DUMPER HYDRAULIC BUILDING	–
10	-----	FUEL STOCK-OUT PILE	–
11	-----	FUEL TRUCK DUMPING AREA	–
12	-----	TRUCK SCALE AND WEIGH MASTER BUILDING	–
13	-----	PLANT ENTRANCE ROAD	–
14	-----	FUEL TRUCK ENTRANCE ROAD	–
15	-----	CONTRACTOR PARKING LOT	–
16	-----	CONSTRUCTION LAYDOWN AREA	–
17	-----	NOT USED	–
18	-----	WOOD YARD RUN-OFF POND	–
19	-----	PROPERTY OUTLINE	–
20	-----	TRANSFORMERS	–
21	-----	SECURITY BUILDING	–
22	-----	STORM WATER POND	–
23	-----	PERIMETER FENCE	–
24	-----	FUEL TRUCK STAGING AREA	–
25	-----	NOT USED	–
26	-----	DIESEL STORAGE TANK	–
27	-----	SUBSTATION (BY OTHERS)	–
28	-----	SORBENT UNLOADING, STORAGE AND INJECTION EQUIPMENT	–
29	-----	ADMINISTRATION/MAINTENANCE/WAREHOUSE BUILDING	–
30	-----	WATER TREATMENT BUILDING	–
31	-----	GRAYWATER/SURFACE WATER STORAGE TANK	–
32	-----	SERVICE/FIRE WATER STORAGE TANK & PUMP BUILDING	–
33	-----	POWER PLANT WASTEWATER STORAGE TANK	–
34	-----	BIODIESEL STORAGE TANK	–
35	-----	AMMONIA STORAGE TANK	–
36	-----	CONDENSATE STORAGE TANK	–
37	-----	DEMINERALIZED WATER STORAGE TANK	–
38	-----	INDUCED DRAFT FAN	–
39	-----	STACK	–
40	-----		–
41	-----	BOILER SAND SILO	–
42	-----	MOBILE CHIPPER	–
43	-----	FIRE BOOSTER PUMP HOUSE	–

NOTES:

1. THIS DRAWING IS CONCEPTUAL DESIGN AND INTENDED TO SHOW TYPICAL ARRANGEMENTS FOR EQUIPMENT OF THIS TYPE AND CAPACITY. THE ARRANGEMENTS ARE SUBJECT TO CHANGE AS A RESULT OF THE SUPSEQUENT DETAILED DESIGN.

2. SURVEY IS BASED ON DRAWINGS GENERATED BY:
   CSRA LAND SUVEYORS, LLC
   34 ALLEN ST
   WARRENTON, GA 30828
   THOMAS L. MAY, GA. RLS#2925
   AND DATED JANUARY 26, 2009.

PRELIMINARY
NOT TO BE USED
FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FILE FORMAT OF THIS DRAWING OUTSIDE OF BLACK & VEATCH IS UNCONTROLLED AND SHALL BE USED FOR REFERENCE PURPOSES ONLY.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
2	23/SEP/09	ADDED FIRE BOOSTER PUMP HOUSE	ANG	ANG		SPW	JJB
1	14/SEP/09	ADDED MOBILE CHIPPING EQUIPMENT	ANG	ANG		SPW	JJB
0	21/AUG/09	ISSUED WITH FINAL CE REPORT	ANG	ANG		SPW	JJB

N

200' 100' 0 200' 400'
1"=200'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF GEORGIA.
SIGNED ______
DATE ______ REG NO. ______

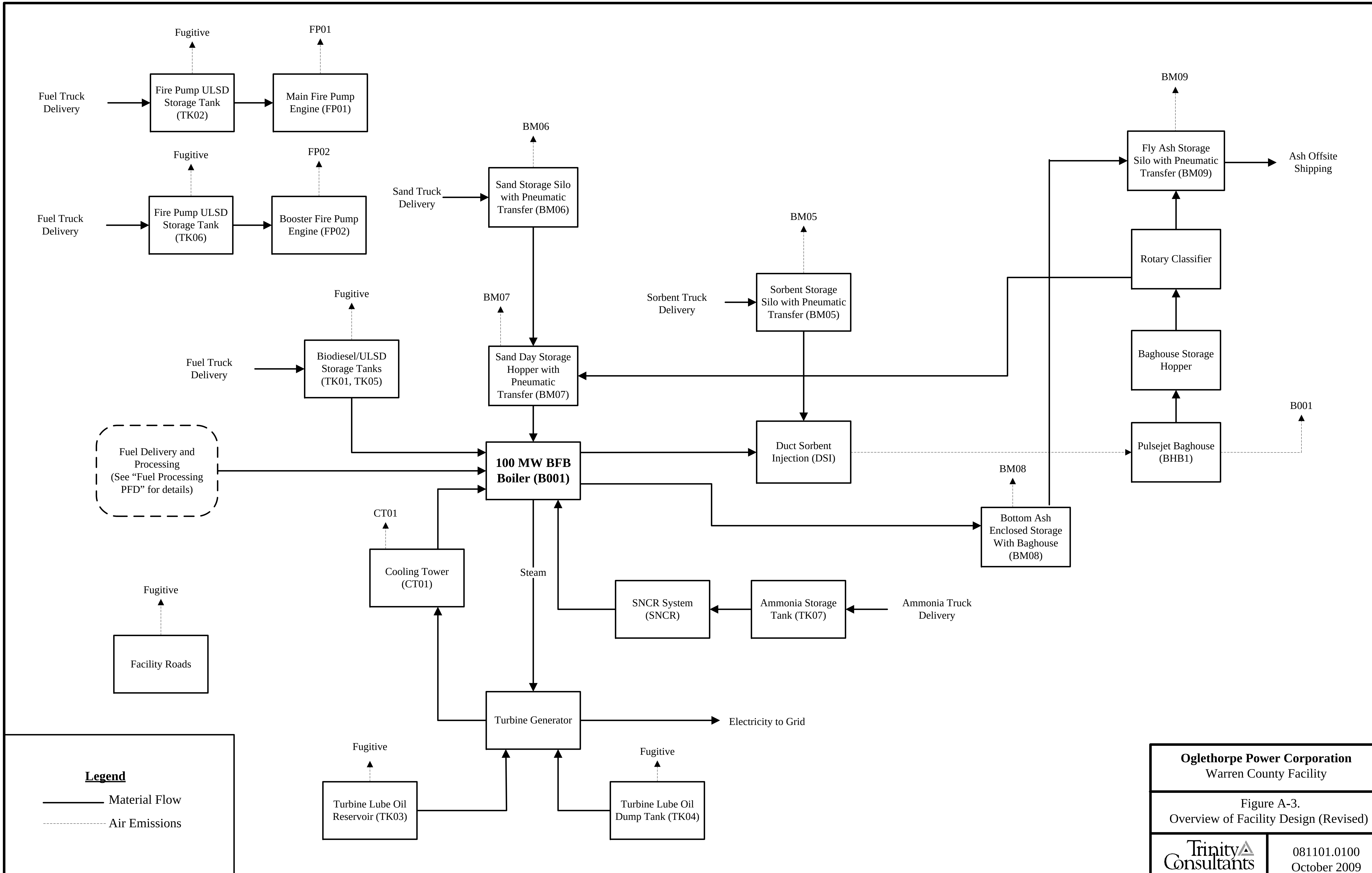
BLACK & VEATCH CORPORATION
ENGINEER SPW | DRAWN ANG
CHECKED | DATE

OGLETHORPE POWER CORP.
WARREN COUNTY 100 MW BIOMASS FACILITY

GENERAL ARRANGEMENT - WARREN COUNTY
SITE ARRANGEMENT

PROJECT | DRAWING NUMBER 163899-SM-1001 | REV 2
CODE
AREA

GU10130 A1ASL017 09/23/09
E1 14:41:12
ACAD 16.1s (LMS Tech) 1=1

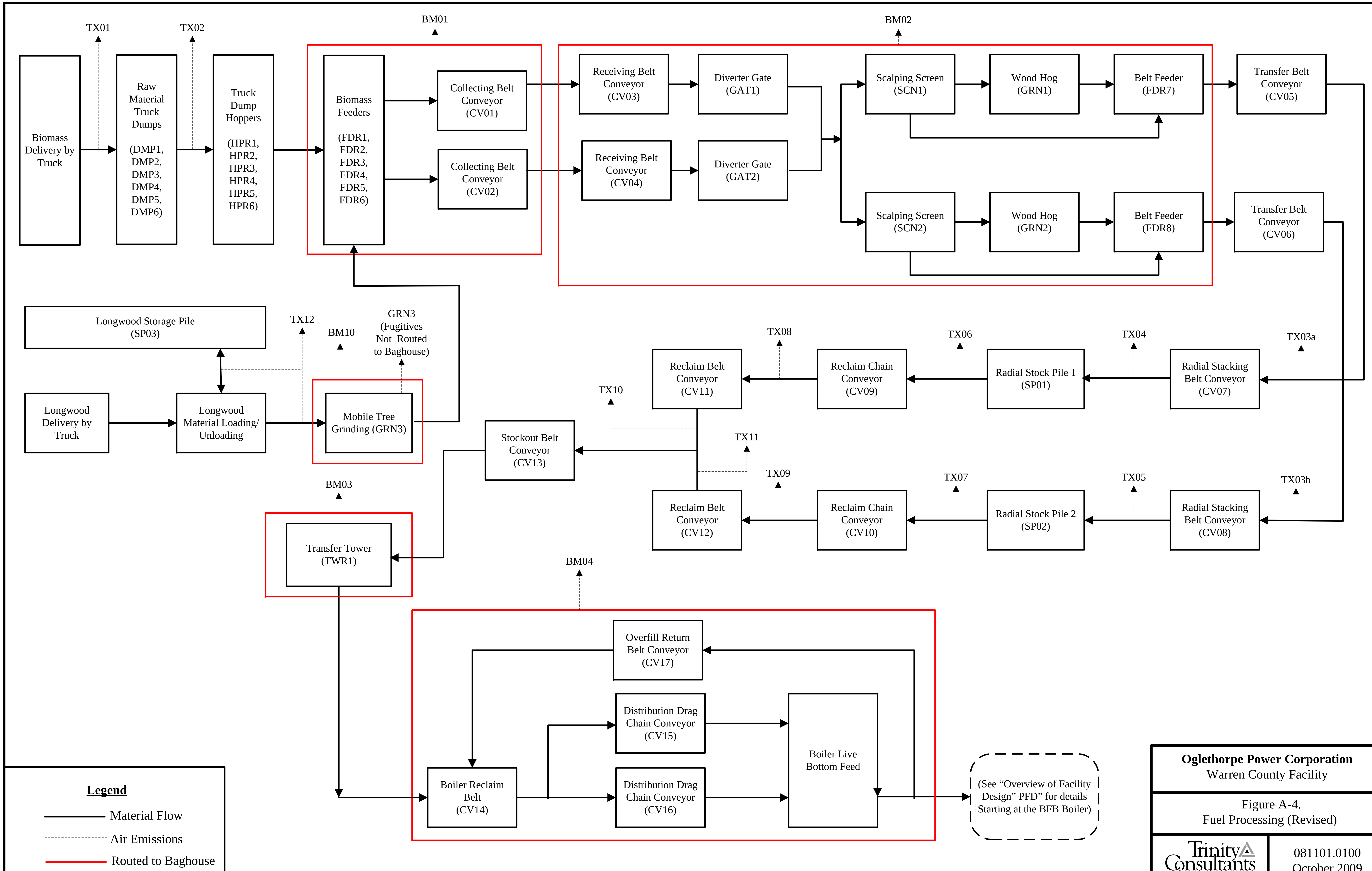


Oglethorpe Power Corporation
Warren County Facility

Figure A-3.
Overview of Facility Design (Revised)

Trinity Consultants

081101.0100
October 2009



Oglethorpe Power Corporation
Warren County Facility

Figure A-4.
Fuel Processing (Revised)

Trinity Consultants

081101.0100
October 2009

APPENDIX B

CONSTRUCTION PERMIT APPLICATION 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: Warren County Biomass Energy Facility

AIRS No. (if known): 04-13- -

Facility Location: Street: 612 East Warrenton Road

City: Warrenton Georgia Zip: 30828 County: Warren

2. Facility Coordinates

Latitude: 33° 23' 59" **NORTH** Longitude: 82° 37' 45" **WEST**

UTM Coordinates: 348,500 m **EAST** 3,696,800 m **NORTH** **ZONE** 17

3. Facility Owner

Name of Owner: Oglethorpe Power Corporation

Owner Address Street: 2100 East Exchange Place

City: Tucker State: GA Zip: 30084-5336

4. Permitting Contact and Mailing Address

Contact Person: Douglas J. Fulle Title: Vice President , Environmental Affairs

Telephone No.: 770-270-7166 Ext. ____ Fax No.: 770-270-7920

Email Address: doug.fulle@opc.com

Mailing Address: Same as: Facility Location: ☐ Owner Address: ☒ Other: ☐

If Other: Street Address: 2100 East Exchange Place

City: Tucker State: GA Zip: 30084-5336

5. Authorized Official

Name: Keith Russell Title: Senior Vice President, Construction

Address of Official Street: 2100 East Exchange Place

City: Tucker State: GA Zip: 30084-5336

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: Keith D Russell Date: 10/14/2009

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.: 19121

Date of Original Submittal: August 7, 2009

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: Trinity Consultants

Name of Contact: Russell Bailey

Telephone No.: 540-342-5945 Fax No.: 540-301-4922

Email Address: rbailey@trinityconsultants.com

Mailing Address: Street: 53 Perimeter Center East, Suite 230

City: Atlanta State: GA Zip: 30346

Describe the Consultant's Involvement:

Preparation of permit application

9. Submitted Application Forms: Select only the necessary forms for the facility application that will be submitted.

No. of Forms	Form
1	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)
0	3.01 Scrubbers
1	3.02 Baghouses & Other Filter Collectors
0	3.03 Electrostatic Precipitators
1	4.00 Emissions Data
1	5.00 Monitoring Information
1	6.00 Fugitive Emission Sources
1	7.00 Air Modeling Information

10. Construction or Modification Date

Estimated Start Date: Construction to commence in January 2011; operation to commence in April 2014

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

12. New Facility Emissions Summary

Criteria Pollutant	New Facility	
	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)	625.7	
Nitrogen oxides (NOx)	648.7	
Particulate Matter (PM)	143.8	
PM <10 microns (PM10)	144.4	
PM <2.5 microns (PM2.5)	134.6	
Sulfur dioxide (SO_2)	56.2	
Volatile Organic Compounds (VOC)	39.1	
Total Hazardous Air Pollutants (HAPs)	19.9	
Individual HAPs Listed Below:		
Chlorine	4.4	
1,2-Dichloroethane	0.7	
Formaldehyde	1.0	
HCl	9.9	
HF	2.3	
*HAP <0.5 are in Appendix C Table		

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
NAICS Code:	221119	NAICS Description:	Other 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.

Oglethorpe plans to construct a 100 megawatt (MW) biomass-fueled electric generating facility in Warren County, Georgia. The plant will consist of a biomass-fueled boiler and ancillary equipment to produce steam for the generation of electricity.

16. Additional information provided in attachments as listed below:

Attachment A - Permit Application Narrative, Figures, Calculations
Attachment B - Air Dispersion Modeling Analyses and Report
Attachment C -
Attachment D -
Attachment E -
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 Appendix A of Permit Application Narrative
- ☒ Flow Diagram or date of previous submittal: See Appendix A of Permit Application Narrative

Facility Name: Warren County Biomass Energy Facility **Date of Application:** October 2009

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
B001	BFB Boiler	TBD	1,399 MMBtu/hr (short-term) BFB Boiler
FP01	Fire Pump Engine	TBD	Nominal 330 Hp compression ignition fire pump engine
FP02	Fire Pump Engine	TBD	Nominal 175 Hp compression ignition fire pump engine
TK01	Biodiesel/ULSD Storage Tank	TBD	60,000 gallon Biodiesel/ULSD storage tank
TK03	Turbine Lube Oil Reservoir	Custom Fabrication	4,100 gallon Turbine Lube Oil Reservoir
TK05	Biodiesel/ULSD Storage Tank	TBD	60,000 gallon Biodiesel/ULSD storage tank
TK07	Aqueous Ammonia Storage Tank	Custom Fabrication	20,000 Gallon Aqueous Ammonia Tank
BM01	Biomass Unloading Operations	TBD	6 Feeders and 2 Collecting Belt Conveyors with Baghouse
BM02	Fuel Processing Building	TBD	Screens, Hogs, and Transfer Points in Fuel Processing Building with Baghouse
BM03	Biomass Transfer Tower	TBD	Biomass Transfer Tower with Baghouse
BM04	Boiler Fuel Feed	TBD	Boiler Fuel Feed Transfer with Baghouse
BM05	Sorbent Silo	TBD	5,000 ft3 sorbent storage silo with pneumatic transfer
BM06	Boiler Bed Sand Silo	TBD	1,700 ft3 sand storage silo with pneumatic transfer
BM07	Sand Day Silo	TBD	240 ft3 sand storage silo with pneumatic transfer
BM08	Bottom Ash Storage	TBD	Covered bottom ash storage area with baghouse
BM09	Flyash Silo	TBD	15,000 ft3 ash storage silo with pneumatic transfer
GRN3	Longwood Mobile Chipping	TBD	Longwood Mobile Chipping with Baghouse and fugitives

Facility Name: Warren County Biomass Energy Facility **Date of Application:** October 2009

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	
B001	Fluidized bed boiler	Fluidized bed	1,399 (short-term)	6%	2011	2014	N/A
B001	Fluidized bed boiler	Fluidized bed	1,282 (long-term)	6%	2011	2014	N/A
FP01	Biodiesel/ULSD IC Engine	IC Engine	Nominal 330 hp	N/A	2011	2014	N/A
FP02	Biodiesel/ULSD IC Engine	IC Engine	Nominal 175 hp	N/A	2011	2014	N/A

[1] This column does not have to be completed for natural gas only fired equipment.

Facility Name: Warren County Biomass Energy Facility **Date of Application:** October 2009

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.
B001	**Biomass**	**1,235,651**	**tons**	**42%**	**58%**	**165***	**141***	**4,234 Btu/lb**	**4,544 Btu/lb**	**0.015**	**0.012**	**1%**	**0.55%**
B001	**Ultra Low Sulfur Diesel**	**1,138,286**	**gal**	**42%**	**58%**	**1,779***	**1,779***	**140,000 Btu/gal**	**140,000 Btu/gal**	**0.0015**	**0.0015**	**N/A**	**N/A**
B001	**B100 Biodiesel**	**1,246,832**	**gal**	**42%**	**58%**	**3,117***	**3,117***	**127,042 Btu/gal**	**127,042 Btu/gal**	**0.0015**	**0.0015**	**N/A**	**N/A**
FP01	**Biodiesel or ULSD**	**8,200**	**gal**	**42%**	**58%**	**16.4**	**16.4**	**127,042 Btu/gal**	**127,042 Btu/gal**	**0.0015**	**0.0015**	**N/A**	**N/A**
FP02	**Biodiesel or ULSD**	**4,400**	**gal**	**42%**	**58%**	**8.8**	**8.8**	**127,042 Btu/gal**	**127,042 Btu/gal**	**0.0015**	**0.0015**	**N/A**	**N/A**

Fuel Supplier Information

Fuel Type	Name of Supplier	Phone Number	Supplier Location			
			Address	City	State	Zip
Biomass	**Southeastern Georgia (various)**					
Biodiesel	**TBD - ASTM Standard for Biodiesel**					
Diesel	**TBD - AP-42 value for No. 2 Fuel Oil**					

* Value based on approximate daily maximum firing rate (1,399 MMBtu/hr) or expected startup operation.

Facility Name: Warren County Biomass Energy Facility **Date of Application:** October 2009

FORM 2.02 – ORGANIC COMPOUND STORAGE TANK

Emission Unit ID	Emission Unit Name	Capacity (gal)	Material Stored	Maximum True Vapor Pressure (psi @ ºF)	Storage Temp. (ºF)	Filling Method	Construction/ Modification Date	Roof Type	Seal Type
TK01	Biodiesel, ULSD Storage Tank	60,000	Biodiesel or Ultra Low Sulfur Diesel or Blend	<0.01 psi @ ambient	Ambient	Submerged	**C: 2014**	Fixed Roof	Atmospheric Vent
TK03	Turbine Lube Oil Reservoir	4,100	Lube Oil	<0.01 psi @ ambient	Ambient	Submerged	C: 2014	Horizontal Tank	Atmospheric Vent
TK05	Biodiesel, ULSD Storage Tank	60,000	Biodiesel or Ultra Low Sulfur Diesel or Blend	<0.01 psi @ ambient	Ambient	Submerged	C: 2014	Fixed Roof	Atmospheric Vent
TK07	Aqueous Ammonia Storage Tank	20,000	19% Ammonia	9.1 psi @ 60 deg F	Ambient	Submerged	C: 2014	Fixed Rood	Atmospheric Vent

Facility Name: Warren County Biomass Energy Facility **Date of Application:** October 2009

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: N/A

PRODUCTION INPUT FACTORS

Emission Unit ID	Emission Unit Name	Const. Date	Input Raw Material(s)	Annual Input	Hourly Process Input Rate		
					Design	Normal	Maximum
BM01	Biomass Unloading Operations	2014	Wood chips	4,672,000 tons*	800 tons	800 tons	800 tons
BM02	Fuel Processing Building	2014	Wood chips	4,672,000 tons*	800 tons	800 tons	800 tons
BM03	Biomass Transfer Tower	2014	Wood chips	1,752,000 tons	200 tons	200 tons	200 tons
BM04	Boiler Fuel Feed	2014	Wood chips	1,752,000 tons	200 tons	200 tons	600 tons
BM05	Sorbent Silo	2014	Sorbent	3,815 tons	22.5 tons	0.44 tons	22.5 tons
BM06	Boiler Bed Sand Silo	2014	Sand	4,432 tons	22.5 tons	0.51 tons	22.5 tons
BM07	Sand Day Silo	2014	Sand	4,380 tons	14.4 tons	0.50 tons	14.4 tons
BM08	Bottom Ash Storage	2014	Bottom ash	9,531 tons	14.04 tons	1.09 tons	14.04 tons
BM09	Fly Ash Silo	2014	Fly ash	32,346 tons	28.04 tons	3.69 tons	28.04 tons
GRN3	Longwood Mobile Chipper	2014	Longwood	730,000 tons*	125 tons	125 tons	125 tons
	* Based on 16 hr/day						

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

Facility Name: Warren County Biomass Energy Facility **Date of Application:** October 2009

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	
BHB1	B001	Baghouse	2014	TBD	N/A	335	335	587,570
SNCR	B001	SNCR	2014	TBD	N/A	1,550 - 2000	1,550 - 2000	UNK
DSI	B001	Duct Sorbent Injection	2014	TBD	N/A	UNK	UNK	UNK
BM01	BM01	Baghouse	2014	TBD	N/A	Ambient	Ambien t	45,342
BM02	BM02	Baghouse	2014	TBD	N/A	Ambient	Ambien t	46,165
BM03	BM03	Baghouse	2014	TBD	N/A	Ambient	Ambien t	25,312
BM04	BM04	Baghouse	2014	TBD	N/A	Ambient	Ambien t	19,885
BM05	BM05	Bin Vent Fabric Filter	2014	TBD	N/A	Ambient	Ambien t	987
BM06	BM06	Bin Vent Fabric Filter	2014	TBD	N/A	Ambient	Ambien t	987
BM07	BM07	Bin Vent Fabric Filter	2014	TBD	N/A	Ambient	Ambien t	987
BM08	BM08	Baghouse	2014	TBD	N/A	Ambient	Ambien t	1,481
BM09	BM09	Bin Vent Fabric Filter	2014	TBD	N/A	Ambient	Ambien t	1,481
BM10	GRN3	Baghouse	2014	TBD	N/A	Ambient	Ambien t	6,229

Facility Name: Warren County Biomass Energy Facility **Date of Application:** October 2009

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	
BHB1	PM (filterable)	100%	99%	4,491	Vendor Data	14.0	Vendor Data	TBD
SNCR	NOX	39%	39%	252	Vendor Data	153.9	Vendor Data	TBD
DSI	SO2	85%	85%	92	Vendor Data	14.0	Vendor Data	TBD
DSI	HCl	90%	90%	19.6	Vendor Data	2.0	Vendor Data	TBD
BM01	PM	0.005 gr/cf		UNK		1.94	Vendor Data	TBD
BM02	PM	0.005 gr/cf		UNK		1.98	Vendor Data	TBD
BM03	PM	0.005 gr/cf		UNK		1.08	Vendor Data	TBD
BM04	PM	0.005 gr/cf		UNK		0.85	Vendor Data	TBD
BM05	PM	0.005 gr/cf		UNK		0.042	Vendor Data	TBD
BM06	PM	0.005 gr/cf		UNK		0.042	Vendor Data	TBD
BM07	PM	0.005 gr/cf		UNK		0.042	Vendor Data	TBD
BM08	PM	0.005 gr/cf		UNK		0.064	Vendor Data	TBD
BM09	PM	0.005 gr/cf		UNK		0.064	Vendor Data	TBD
BM10	PM	0.005 gr/cf		UNK		0.27	Vendor Data	TBD

Facility Name: Warren County Biomass Energy Facility **Date of Application:** October 2009

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
BHB1	TBD	TBD	N/A	335	TBD	TBD	Pulsejet baghouse	N/A	N/A
BM01	TBD	TBD	N/A	Ambient	TBD	TBD	TBD	N/A	N/A
BM02	TBD	TBD	N/A	Ambient	TBD	TBD	TBD	N/A	N/A
BM03	TBD	TBD	N/A	Ambient	TBD	TBD	TBD	N/A	N/A
BM04	TBD	TBD	N/A	Ambient	TBD	TBD	TBD	N/A	N/A
BM05	TBD	TBD	N/A	Ambient	TBD	TBD	TBD	N/A	N/A
BM06	TBD	TBD	N/A	Ambient	TBD	TBD	TBD	N/A	N/A
BM07	TBD	TBD	N/A	Ambient	TBD	TBD	TBD	N/A	N/A
BM08	TBD	TBD	N/A	Ambient	TBD	TBD	TBD	N/A	N/A
BM09	TBD	TBD	N/A	Ambient	TBD	TBD	TBD	N/A	N/A
BM10	TBD	TBD	N/A	Ambient	TBD	TBD	TBD	N/A	N/A

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: Warren County Biomass Energy Facility **Date of Application:** October 2009

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
B001	N/A	B001	CO	653.0*	653.0*	625.4	625.4	Vendor Data
B001	SNCR	B001	NOX	236.0*	236.0*	648.1	648.1	Vendor Data
B001	BHB1	B001	PM	51.7*	51.7*	68.6	68.6	Vendor Data
B001	BHB1	B001	Total PM10, PM2.5	51.7*	51.7*	110.2	110.2	Vendor Data
B001	DSI	B001	SO2	14.0*	14.0*	56.2	56.2	Vendor Data
B001	N/A	B001	VOC	9.7*	9.7*	39.0	39.0	Vendor/Proposed Limit
B001	N/A	B001	Total HAP	5.0	5.0	19.9	19.9	Vendor/AP-42
B001	N/A	B001	Chlorine	1.1	1.1	4.4	4.4	Vendor Data
B001	N/A	B001	1,2-Dichloroethane	0.16	0.16	0.66	0.66	Custom FBC Boiler data
B001	N/A	B001	Formaldehyde	0.25	0.25	1.0	1.0	Custom FBC Boiler data
B001	DSI	B001	HCl	2.5	2.5	9.9	9.9	Proposed Limit
B001	N/A	B001	HF	0.6	0.6	2.3	2.3	Vendor Data
B001	DSI	B001	H2SO4	1.7	1.7	6.9	6.9	Proposed Limit
FP01	N/A	FP01	CO	1.03	1.03	0.26	0.26	Vendor Data
FP01	N/A	FP01	NOX	1.70	1.70	0.43	0.43	Vendor Data
FP01	N/A	FP01	PMPM10/PM2.5	0.086	0.086	0.022	0.022	Vendor Data
FP01	N/A	FP01	SO2	3.6E-03	3.6E-03	9.0E-04	9.0E-04	Vendor Data
FP01	N/A	FP01	VOC	0.090	0.090	0.022	0.022	Vendor Data
FP01	N/A	FP01	Total HAP	9.0E-03	9.0E-03	2.2E-03	2.2E-03	AP-42

*Emissions are based on the higher of BACT emissions rate at approximate daily maximum firing rate (1399 MMBtu/hr) or expected startup emissions.

Emissions used for modeling are higher for some pollutants. These lb/hr values do not represent proposed permit limits.

Facility Name: Warren County Biomass Energy Facility **Date of Application:** October 2009

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
FP02	N/A	FP02	CO	0.55	0.55	0.14	0.14	Vendor Data
FP02	N/A	FP02	NOX	0.90	0.90	0.23	0.23	Vendor Data
FP02	N/A	FP02	PM/PM10	0.046	0.046	0.011	0.011	Vendor Data
FP02	N/A	FP02	SO2	1.9E-03	1.9E-03	4.8E-04	4.8E-04	Vendor Data
FP02	N/A	FP02	VOC	0.048	0.048	0.012	0.012	Vendor Data
FP02	N/A	FP02	Total HAP	4.8E-03	4.8E-03	1.2E-03	1.2E-03	AP-42
TK01	N/A	N/A	VOC	6.5E-03	6.5E-03	0.029	0.029	TANKS4.0
TK03	N/A	N/A	VOC	2.5E-04	2.5E-04	1.1E-03	1.1E-03	TANKS4.0
TK05	N/A	N/A	VOC	6.5E-03	6.5E-03	0.029	0.029	TANKS4.0
BM01	BM01	BM01	PM/PM10	1.94	1.94	5.67	5.67	Vendor Data
BM02	BM02	BM02	PM/PM10	1.98	1.98	5.78	5.78	Vendor Data
BM03	BM03	BM03	PM/PM10	1.08	1.08	4.75	4.75	Vendor Data
BM04	BM04	BM04	PM/PM10	0.85	0.85	3.73	3.73	Vendor Data
BM05	BM05	BM05	PM/PM10	0.042	0.042	0.19	0.19	Vendor Data
BM06	BM06	BM06	PM/PM10	0.042	0.042	0.19	0.19	Vendor Data
BM07	BM07	BM07	PM/PM10	0.042	0.042	0.19	0.19	Vendor Data
BM08	BM08	BM08	PM/PM10	0.064	0.064	0.28	0.28	Vendor Data
BM09	BM09	BM09	PM/PM10	0.064	0.064	0.28	0.28	Vendor Data
GRN3	BM10	BM10	PM/PM10	0.27	0.27	0.78	0.78	Vendor Data

Facility Name: Warren County Biomass Energy Facility **Date of Application:** October 2009

FORM 5.00 MONITORING INFORMATION

Emission Unit ID/ APCD ID	Emission Unit/APCD Name	Monitored Parameter		Monitoring Frequency
		Parameter	Units	
B001	Boiler Baghouse	Opacity	%	Continuous
B001	Boiler Stack	NOX, CO, SO2	ppm, lb/hr	Continuous
B001	Boiler DSI	Sorbent Injection Rate	lb/hr	Continuous
BM01	Biomass Unloading Baghouse	Visibile Emissions	% opacity	Quarterly
BM02	Fuel Processing Building Baghouse	Visibile Emissions	% opacity	Quarterly
BM03	Biomass Transfer Tower Baghouse	Visibile Emissions	% opacity	Quarterly
BM04	Biomass Fuel Delivery Baghouse	Visibile Emissions	% opacity	Quarterly
BM05	Sorbent Silo Filter	Visibile Emissions	% opacity	Quarterly
BM06	Sand Silo Filter	Visibile Emissions	% opacity	Quarterly
BM07	Sand Day Silo Filter	Visibile Emissions	% opacity	Quarterly
BM08	Bottom Ash Storage Baghouse	Visibile Emissions	% opacity	Quarterly
BM09	Flyash Silo Filter	Visibile Emissions	% opacity	Quarterly
BM10	Longwood Mobile Chipping Baghouse	Visibile Emissions	% opacity	Quarterly
FP01	Emergency Fire Pump Engine	Operating Hours	Hours	As Necessary
FP02	Emergency Fire Pump Engine	Operating Hours	Hours	As Necessary

Comments:

Facility Name: Warren County Biomass Energy Facility **Date of Application:** October 2009

FORM 6.00 – FUGITIVE EMISSION SOURCES

Fugitive Emission Source ID	Description of Source	Emission Reduction Precautions	Pot. Fugitive Emissions	
			Amount (tpy)	Pollutant
CT01	Counterflow Mechanical Draft Cooling Tower	Drift eliminators to keep drift below 0.0005%	1.05	PM10
SP01	Processed Wood Pile 1	Water sprayed on material prior to storage	0.52	PM10
SP02	Processed Wood Pile 2	Water sprayed on material prior to storage	0.52	PM10
SP03	Longwood Storage	N/A	0.46	PM10
ROAD	Fugitive Road Dust	Pave roads, minimize speed, watering	9.50	PM10
TX01	Raw Material Unloading/Truck Dump (DMP1-6)	Water sprays	1.29E-02	PM10
TX02	Dump (DMP1-6) to Hopper (HPR 1-6)	Dust suppression	4.30E-03	PM10
TX03	Transfer Belt Conveyors (CV05, CV06) to Radial Stacking Belt Conveyors (CV07, CV08)	Water sprays	1.56E-03	PM10
TX04	Radial Stacking Belt Conveyor (CV07) to Radial Stock Pile (SP01)	Water sprays, telescoping chute	2.29E-03	PM10
TX05	Radial Stacking Belt Conveyor (CV08) to Radial Stock Pile (SP02)	Water sprays, telescoping chute	2.29E-03	PM10
TX06	Radial Stock Pile (SP01) to Reclaim Chain Conveyor (CV09)	Water sprays	1.72E-03	PM10
TX07	Radial Stock Pile (SP02) to Reclaim Chain Conveyor (CV10)	Water sprays	1.72E-03	PM10
TX08	Reclaim Chain Conveyor (CV09) to Reclaim Belt Conveyor (CV11)	Water sprays	5.85E-04	PM10
TX09	Reclaim Chain Conveyor (CV10) to Reclaim Belt Conveyor (CV12)	Water sprays	5.85E-04	PM10
TX10	Reclaim Belt Conveyor (CV11) to Stockout Belt Conveyor (CV13)	Previously wetted, assumed equivalent to dust suppression by wetting	5.85E-04	PM10
TX11	Reclaim Belt Conveyor (CV12) to Stockout Belt Conveyor (CV13)	Previously wetted, assumed equivalent to dust suppression by wetting	5.85E-04	PM10
TX12	Longwood Material Unloading	Water sprays	7.17E-03	PM10
GRN3	Longwood Mobile Chipping	Dust Collection System with 95% Capture	0.26	PM10

Facility Name: Warren County Biomass Energy Facility **Date of Application:** October 2009

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
B001	B001	220	12.00	Vertical	190	180	76.51	330	519,191	519,191
CT01-CT04	CT01-CT04	46	27.9	Vertical	N/A	N/A	38.25 9 (each)	94.3	1,401,618 (each)	1,401,618 (each)
BM01	BM01	50	3.50	Vertical	N/A	N/A	78.55	Ambient	45,342	45,342
BM02	BM02	85	3.50	Vertical	N/A	N/A	79.97	Ambient	46,165	46,165
BM03	BM03	40	2.50	Vertical	N/A	N/A	85.94	Ambient	25,312	25,312
BM04	BM04	190	2.17	Vertical	190	180	89.89	Ambient	19,885	19,885
BM05	BM05	75	0.33	Vertical	N/A	N/A	188.50	Ambient	987	987
BM06	BM06	55	0.33	Vertical	N/A	N/A	188.50	Ambient	987	987
BM07	BM07	75	0.33	Vertical	N/A	N/A	188.50	Ambient	987	987
BM08	BM08	15	0.33	Vertical	N/A	N/A	282.85	Ambient	1,481	1,481
BM09	BM09	75	0.33	Vertical	N/A	N/A	282.85	Ambient	1,481	1,481
BM10	GRN3	25	1.25	Vertical	N/A	N/A	84.60	Ambient	6,229	6,229

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.

Refer to attachment describing volume sources.

Facility Name: Warren County Biomass Energy Facility **Date of Application:** October 2009

FORM 7.00 AIR MODELING INFORMATION: Chemicals Data

Chemical	Potential Emission Rate (lb/hr)	Toxicity	Reference	MSDS Attached
Refer to Toxics Modeling SCREEN3 Analysis in Volume II Report				☐
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Oglethorpe Power Corporation - Warren County Biomass Energy Facility

Modeled Volume Sources

Description[1]	Source ID	Release Height (ft)	Release Height (m)	Length of side (ft)	Length of side (m)
Biomass Material Handling					
Raw Material Unloading/Truck Dump (DMP1-6)	TX01	5.00	1.52	8.50	2.59
Dump (DMP 1-6) to Hopper (HPR1-6)	TX02	5.00	1.52	5.00	1.52
Transfer Belt Conveyors (CV05, CV06) to Radial Stacking Belt Conveyors (CV07, CV08)	TX03	25.00	7.62	4.50	1.37
Radial Stacking Belt Conveyor (CV07) to Radial Stock Pile (SP01)	TX04	50.00	15.24	4.50	1.37
Radial Stacking Belt Conveyor (CV08) to Radial Stock Pile (SP02)	TX05	50.00	15.24	4.50	1.37
Radial Stock Pile (S0P1) to Reclaim Chain Conveyor (CV09)	TX06	50.00	15.24	5.00	1.52
Radial Stock Pile (SP02) to Reclaim Chain Conveyor (CV10)	TX07	50.00	15.24	5.00	1.52
Reclaim Chain Conveyor (CV09) to Reclaim Belt Conveyor (CV11)	TX08	50.00	15.24	5.00	1.52
Reclaim Chain Conveyor (CV10) to Reclaim Belt Conveyor (CV12)	TX09	50.00	15.24	5.00	1.52
Reclaim Belt Conveyor (CV11) to Covered Stockpile Belt Conveyor (CV13)	TX10	10.00	3.05	5.00	1.52
Reclaim Belt Conveyor (CV12) to Covered Stockpile Belt Conveyor (CV13)	TX11	10.00	3.05	5.00	1.52
Longwood Material Unloading	TX12	5.00	1.52	48.75	14.86
Longwood Mobile Chipping	GRN3	20.00	6.10	1.00	0.3
Biomass Storage Piles					
Processed Wood Pile 1	SP01	25.00	7.62	420.0	128.0
Processed Wood Pile 2	SP02	25.00	7.62	420.0	128.0
Longwood Storage	SP03	25.00	7.62	520.0	158.5
Road Segment[3]	RMH01-RMH71	8.00	2.44	-	-

1. All not stack emissions are modeled as volume sources per *Georgia Guideline for Assuring Acceptable Ambient Concentrations of PM_{10} in areas impacted by Quarry Operations Producing Crushed Stone* , October 2004.

2. Vertical dimensions were estimated base on source characteristics and site specific information provided by OPC.

3. Paved roads are represented as 71 volume sources, with an initial lateral dimensions of 14.70 feet.

APPENDIX C

EMISSIONS SUPPORTING INFORMATION

Calculation Tables
Boiler HAP/TAP Biomass Emission Factor Development

Table C-1. BFB Biomass Boiler Potential NSR-Regulated Pollutant Emissions

Biomass Boiler	**B001**	
Short Term (Daily) Heat Input	1,399	MMBtu/hr
Annual Sustainable Heat Input	1,282	MMBtu/hr
Startup Maximum Heat Input for Biodiesel	396	MMBtu/hr
Startup Maximum Heat Input for Diesel	249	MMBtu/hr
Fuel Heat Content	8.47	MMBtu/ton bark (green)
Potential Operation	8,760	hr/yr
Startup/Shutdown Operation	640	hr/yr

	Scenario A (100% Biomass)[1]			**Scenario B (Startup/Shutdown)[2,3]**		**Worst-case Potential Emissions[4]**	
	Factor	Potential Emissions		Vendor Emissions			
Pollutant	(lb/MMBtu)	(lbs/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CO	0.080	111.92	449.21	653.00	208.96	653.00	625.35
NO_X	0.110	153.89	617.67	236.00	75.52	236.00	648.06
TSP	0.010	13.99	56.15	51.70	16.54	51.70	68.59
Total PM_{10}	0.018	25.18	101.07	51.70	16.54	51.70	110.23
Total $PM_{2.5}$	0.018	25.18	101.07	51.70	16.54	51.70	110.23
SO_2	0.010	13.99	56.15	11.00	3.52	13.99	56.15
VOC	0.007	9.72	39.00	7.00	2.24	9.72	39.00
H_2SO_4	0.0012	1.72	6.90	-	-	1.72	6.90
Fluorides[5]	-	-	-	-	-	-	-
Lead[6]	4.80E-07	6.72E-06	2.70E-05	3.93E-03	7.86E-04	3.93E-03	8.13E-04

1. Emissions for Scenario A (100% Load: Biomass) are estimated for both short term (daily) maximum heat input and long term (annual) sustainable heat input multiplied by either the proposed BACT limits, vendor data emission factors, or AP-42 factors.

2. Factors are worst-case vendor data for all phases of startup (biodiesel only, biodiesel/biomass mix, biomass only). Emissions from combustion of diesel during startup will be smaller as the burner heat inputs are smaller and boiler vendor data uses the same lb/MMBtu factor for both biodiesel and diesel combustion.

3. PM emissions from the boiler when combusting biodiesel are filterable only, no condensable particulate included due to lack of data.

4. Short-term worst-case emissions are the maximum of Scenario A or Scenario B hourly emissions. Annual worst-case emissions evaluated as the maximum of Scenario A or [Scenario B, tpy + (Scenario A, tpy *(potential - startup/shutdown, hr/yr)/(potential, hr/yr)].

5. Fluorides emissions (other than HF) are assumed to be negligible.

Table C-2. BFB Biomass Boiler Potential HAP/TAP Emissions

Biomass Boiler	**B001**				
Short Term Heat Input	1,399	MMBtu/hr	Maximum Biodiesel Heat Input[1]	396	MMBtu/hr
Annual Sustainable Heat Input	1,282	MMBtu/hr	Biodiesel Heating Value	127,042	Btu/gal
Hours of Operation per Year	8,760	hr/yr	Biodiesel Heating Value	127.04	MMBtu/Mgal
Organic HAP Control	0.0%		Potential Startup Operation[2]	400	hr/yr
PM HAP Control	99.0%				

			Scenario A (100% Biomass)						Scenario B (Biodiesel or Diesel for Startup)					
	VOC	HAP	Biomass Factor[3]		Uncontrolled Emissions[4]		Controlled Emissions[5]		Biodiesel/Diesel Factor[6]		Biodiesel Emissions[7]		Worst-Case Emissions[8]	
Pollutant	**(Yes/No)**	**(Yes/No)**	**(lb/MMBtu)**	**Source**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/Mgal)**	**Source**	**(lb/hr)**	**(tpy)**	**(lbs/hr)**	**(tpy)**
1,1,1-Trichloroethane	No	Yes	6.70E-06	Custom FBC Boiler	9.37E-03	3.76E-02	9.37E-03	3.76E-02	2.36E-04	AP-42, Table 1.3-9	7.36E-04	1.47E-04	9.37E-03	3.76E-02
1,2-Dibromoethene	Yes	Yes	8.08E-06	Custom FBC Boiler	1.13E-02	4.53E-02	1.13E-02	4.53E-02					1.13E-02	4.53E-02
2-Butanone (MEK)	Yes	No	5.39E-06	Custom FBC Boiler	7.54E-03	3.03E-02	7.54E-03	3.03E-02					7.54E-03	3.03E-02
2-Chloronaphthalene	Yes	Yes	2.40E-09	AP-42, Table 1.6-3	3.36E-06	1.35E-05	3.36E-06	1.35E-05					3.36E-06	1.35E-05
2-Chlorophenol	Yes	No	2.40E-08	AP-42, Table 1.6-3	3.36E-05	1.35E-04	3.36E-05	1.35E-04					3.36E-05	1.35E-04
Acenaphthene	Yes	Yes	1.18E-07	Custom FBC Boiler	1.64E-04	6.60E-04	1.64E-04	6.60E-04	2.11E-05	AP-42, Table 1.3-9	6.58E-05	1.32E-05	1.64E-04	6.60E-04
Acenaphthylene	Yes	Yes	2.61E-07	Custom FBC Boiler	3.65E-04	1.46E-03	3.65E-04	1.46E-03	2.53E-07	AP-42, Table 1.3-9	7.89E-07	1.58E-07	3.65E-04	1.46E-03
Acetaldehyde	Yes	Yes	4.34E-05	Custom FBC Boiler	6.08E-02	2.44E-01	6.08E-02	2.44E-01					6.08E-02	2.44E-01
Acetone	No	No	2.15E-04	Custom FBC Boiler	3.01E-01	1.21E+00	3.01E-01	1.21E+00					3.01E-01	1.21E+00
Acetophenone	Yes	Yes	3.20E-09	AP-42, Table 1.6-3	4.48E-06	1.80E-05	4.48E-06	1.80E-05					4.48E-06	1.80E-05
Acrolein	Yes	Yes	9.78E-06	Custom FBC Boiler	1.37E-02	5.49E-02	1.37E-02	5.49E-02					1.37E-02	5.49E-02
Ammonia	No	No	2.46E-02	Custom FBC Boiler	3.45E+01	1.38E+02	3.45E+01	1.38E+02					3.45E+01	1.38E+02
Anthracene	Yes	Yes	1.07E-07	Custom FBC Boiler	1.49E-04	6.00E-04	1.49E-04	6.00E-04	1.22E-06	AP-42, Table 1.3-9	3.80E-06	7.61E-07	1.49E-04	6.00E-04
Antimony	No	Yes	7.90E-08	AP-42, Table 1.6-4	1.11E-04	4.44E-04	1.11E-06	4.44E-06					1.11E-06	4.44E-06
Arsenic	No	Yes	2.20E-07	AP-42, Table 1.6-4	3.08E-04	1.24E-03	3.08E-06	1.24E-05	5.60E-04	AP-42, Table 1.3-10	1.75E-03	3.49E-04	1.75E-03	3.61E-04
Barium	No	No	1.70E-06	AP-42, Table 1.6-4	2.38E-03	9.55E-03	2.38E-05	9.55E-05					2.38E-05	9.55E-05
Benzaldehyde	Yes	No	8.50E-07	AP-42, Table 1.6-3	1.19E-03	4.77E-03	1.19E-03	4.77E-03					1.19E-03	4.77E-03
Benzene	Yes	Yes	1.39E-05	Custom FBC Boiler	1.95E-02	7.81E-02	1.95E-02	7.81E-02	2.14E-04	AP-42, Table 1.3-9	6.67E-04	1.33E-04	1.95E-02	7.81E-02
Benzo(a)anthracene	Yes	Yes	7.53E-08	Custom FBC Boiler	1.05E-04	4.23E-04	1.05E-04	4.23E-04	4.01E-06	AP-42, Table 1.3-9	1.25E-05	2.50E-06	1.05E-04	4.23E-04
Benzo(a)pyrene	Yes	Yes	4.39E-07	Custom FBC Boiler	6.14E-04	2.46E-03	6.14E-04	2.46E-03					6.14E-04	2.46E-03
Benzo(b)fluoranthene	Yes	Yes	7.53E-08	Custom FBC Boiler	1.05E-04	4.23E-04	1.05E-04	4.23E-04					1.05E-04	4.23E-04
Benzo(e)pyrene	Yes	Yes	2.10E-09	Custom FBC Boiler	2.94E-06	1.18E-05	2.94E-06	1.18E-05					2.94E-06	1.18E-05
Benzo(g,h,i)perylene	Yes	Yes	7.46E-08	Custom FBC Boiler	1.04E-04	4.19E-04	1.04E-04	4.19E-04	2.26E-06	AP-42, Table 1.3-9	7.04E-06	1.41E-06	1.04E-04	4.19E-04
Benzo(b,k)fluoranthene	Yes	Yes	-	N/A	-	-	-	-	1.48E-06	AP-42, Table 1.3-9	4.61E-06	9.23E-07	4.61E-06	9.23E-07
Benzo(j,k)fluoranthene	Yes	Yes	1.60E-07	AP-42, Table 1.6-3	2.24E-04	8.98E-04	2.24E-04	8.98E-04					2.24E-04	8.98E-04
Benzo(k)fluoranthene	Yes	Yes	7.44E-08	Custom FBC Boiler	1.04E-04	4.18E-04	1.04E-04	4.18E-04					1.04E-04	4.18E-04
Benzoic acid	Yes	No	4.70E-08	AP-42, Table 1.6-3	6.58E-05	2.64E-04	6.58E-05	2.64E-04					6.58E-05	2.64E-04
Beryllium	No	Yes	1.10E-08	AP-42, Table 1.6-4	1.54E-05	6.18E-05	1.54E-07	6.18E-07	4.20E-04	AP-42, Table 1.3-10	1.31E-03	2.62E-04	1.31E-03	2.62E-04
Bis(2-ethylhexyl)phthalate	Yes	Yes	4.70E-08	AP-42, Table 1.6-3	6.58E-05	2.64E-04	6.58E-05	2.64E-04					6.58E-05	2.64E-04
Bromomethane	Yes	Yes	2.38E-06	Custom FBC Boiler	3.33E-03	1.34E-02	3.33E-03	1.34E-02					3.33E-03	1.34E-02
Cadmium	No	Yes	4.10E-08	AP-42, Table 1.6-4	5.74E-05	2.30E-04	5.74E-07	2.30E-06	4.20E-04	AP-42, Table 1.3-10	1.31E-03	2.62E-04	1.31E-03	2.64E-04
Carbazole	Yes	Yes	1.80E-06	AP-42, Table 1.6-3	2.52E-03	1.01E-02	2.52E-03	1.01E-02					2.52E-03	1.01E-02
Carbon tetrachloride	Yes	Yes	4.95E-06	Custom FBC Boiler	6.92E-03	2.78E-02	6.92E-03	2.78E-02					6.92E-03	2.78E-02
Chlorine	No	Yes	7.90E-04	AP-42, Table 1.6-3	1.11E+00	4.44E+00	1.11E+00	4.44E+00					1.11E+00	4.44E+00
Chlorobenzene	Yes	Yes	3.30E-05	AP-42, Table 1.6-3	4.62E-02	1.85E-01	4.62E-02	1.85E-01					4.62E-02	1.85E-01
Chloroform	Yes	Yes	6.01E-06	Custom FBC Boiler	8.40E-03	3.37E-02	8.40E-03	3.37E-02					8.40E-03	3.37E-02
Chromium	No	Yes	2.10E-07	AP-42, Table 1.6-4	2.94E-04	1.18E-03	2.94E-06	1.18E-05	4.20E-04	AP-42, Table 1.3-10	1.31E-03	2.62E-04	1.31E-03	2.73E-04
Chromium VI	No	Yes	3.50E-08	AP-42, Table 1.6-4	4.90E-05	1.97E-04	4.90E-07	1.97E-06	4.20E-04	AP-42, Table 1.3-10	1.31E-03	2.62E-04	1.31E-03	2.64E-04
Chrysene	Yes	Yes	7.61E-08	Custom FBC Boiler	1.07E-04	4.27E-04	1.07E-04	4.27E-04	2.38E-06	AP-42, Table 1.3-9	7.42E-06	1.48E-06	1.07E-04	4.27E-04
Cobalt	No	Yes	6.50E-08	AP-42, Table 1.6-4	9.09E-05	3.65E-04	9.09E-07	3.65E-06					9.09E-07	3.65E-06
Copper	No	No	4.90E-07	AP-42, Table 1.6-4	6.86E-04	2.75E-03	6.86E-06	2.75E-05	4.20E-04	AP-42, Table 1.3-10	1.31E-03	2.62E-04	1.31E-03	2.88E-04
o-Cresol	Yes	Yes	3.20E-06	Custom FBC Boiler	4.48E-03	1.80E-02	4.48E-03	1.80E-02					4.48E-03	1.80E-02
m-Cresol, p-Cresol	Yes	Yes	1.65E-06	Custom FBC Boiler	2.31E-03	9.27E-03	2.31E-03	9.27E-03					2.31E-03	9.27E-03
Crotonaldehyde	Yes	No	9.90E-06	AP-42, Table 1.6-3	1.39E-02	5.56E-02	1.39E-02	5.56E-02					1.39E-02	5.56E-02
Decachlorobiphenyl	Yes	Yes	4.34E-09	Custom FBC Boiler	6.08E-06	2.44E-05	6.08E-06	2.44E-05					6.08E-06	2.44E-05
Dibenzo(a,h)anthracene	Yes	Yes	8.66E-08	Custom FBC Boiler	1.21E-04	4.86E-04	1.21E-04	4.86E-04	1.67E-06	AP-42, Table 1.3-9	5.21E-06	1.04E-06	1.21E-04	4.86E-04
Dichlorobenzene	Yes	Yes	4.59E-07	Custom FBC Boiler	6.42E-04	2.58E-03	6.42E-04	2.58E-03					6.42E-04	2.58E-03
Dichlorobiphenyl	Yes	Yes	1.57E-08	Custom FBC Boiler	2.19E-05	8.79E-05	2.19E-05	8.79E-05					2.19E-05	8.79E-05
1,2-Dichloroethane	Yes	Yes	1.17E-04	Custom FBC Boiler	1.63E-01	6.55E-01	1.63E-01	6.55E-01					1.63E-01	6.55E-01
Dichlorophenol	Yes	No	2.16E-07	Custom FBC Boiler	3.02E-04	1.21E-03	3.02E-04	1.21E-03					3.02E-04	1.21E-03

Table C-2. BFB Biomass Boiler Potential HAP/TAP Emissions

Biomass Boiler	**B001**				
Short Term Heat Input	1,399	MMBtu/hr	Maximum Biodiesel Heat Input[1]	396	MMBtu/hr
Annual Sustainable Heat Input	1,282	MMBtu/hr	Biodiesel Heating Value	127,042	Btu/gal
Hours of Operation per Year	8,760	hr/yr	Biodiesel Heating Value	127.04	MMBtu/Mgal
Organic HAP Control	0.0%		Potential Startup Operation[2]	400	hr/yr
PM HAP Control	99.0%				

			Scenario A (100% Biomass)						Scenario B (Biodiesel or Diesel for Startup)					
	VOC	HAP	Biomass Factor[3]		Uncontrolled Emissions[4]		Controlled Emissions[5]		Biodiesel/Diesel Factor[6]		Biodiesel Emissions[7]		Worst-Case Emissions[8]	
Pollutant	(Yes/No)	(Yes/No)	(lb/MMBtu)	Source	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/Mgal)	Source	(lb/hr)	(tpy)	(lbs/hr)	(tpy)
1,2-Dichloropropane	Yes	Yes	3.30E-05	AP-42, Table 1.6-3	4.62E-02	1.85E-01	4.62E-02	1.85E-01					4.62E-02	1.85E-01
2,4-Dinitrophenol	Yes	Yes	1.80E-07	AP-42, Table 1.6-3	2.52E-04	1.01E-03	2.52E-04	1.01E-03					2.52E-04	1.01E-03
Ethanol	Yes	No	6.23E-06	Custom FBC Boiler	8.72E-03	3.50E-02	8.72E-03	3.50E-02					8.72E-03	3.50E-02
Ethylbenzene	Yes	Yes	5.73E-07	Custom FBC Boiler	8.02E-04	3.22E-03	8.02E-04	3.22E-03	6.36E-05	AP-42, Table 1.3-9	1.98E-04	3.96E-05	8.02E-04	3.22E-03
Fluoranthene	Yes	Yes	1.70E-07	Custom FBC Boiler	2.38E-04	9.56E-04	2.38E-04	9.56E-04	4.84E-06	AP-42, Table 1.3-9	1.51E-05	3.02E-06	2.38E-04	9.56E-04
Fluorene	Yes	Yes	1.29E-07	Custom FBC Boiler	1.81E-04	7.26E-04	1.81E-04	7.26E-04	4.47E-06	AP-42, Table 1.3-9	1.39E-05	2.79E-06	1.81E-04	7.26E-04
Formaldehyde	Yes	Yes	1.78E-04	Custom FBC Boiler	2.49E-01	1.00E+00	2.49E-01	1.00E+00	4.80E-02	AP-42, Table 1.3-5	1.50E-01	2.99E-02	2.49E-01	1.00E+00
HCl	No	Yes	1.76E-03	Proposed Annual Limit	2.47E+00	9.90E+00	2.47E+00	9.90E+00					2.47E+00	9.90E+00
HF	No	Yes	4.00E-04	Vendor Data	5.60E-01	2.25E+00	5.60E-01	2.25E+00					5.60E-01	2.25E+00
Heptachlorobiphenyl	Yes	Yes	2.60E-09	Custom FBC Boiler	3.63E-06	1.46E-05	3.63E-06	1.46E-05					3.63E-06	1.46E-05
Hexachlorobenzene	Yes	Yes	2.35E-07	Custom FBC Boiler	3.29E-04	1.32E-03	3.29E-04	1.32E-03					3.29E-04	1.32E-03
Hexachlorobiphenyl	Yes	Yes	2.91E-09	Custom FBC Boiler	4.07E-06	1.63E-05	4.07E-06	1.63E-05					4.07E-06	1.63E-05
Hexanal (hexaldehyde)	Yes	No	4.52E-05	Custom FBC Boiler	6.32E-02	2.54E-01	6.32E-02	2.54E-01					6.32E-02	2.54E-01
Heptachlorodibenzo-p-dioxins	Yes	Yes	1.29E-08	Custom FBC Boiler	1.80E-05	7.24E-05	1.80E-05	7.24E-05					1.80E-05	7.24E-05
Heptachlorodibenzo-p-furans	Yes	Yes	1.60E-09	Custom FBC Boiler	2.24E-06	8.98E-06	2.24E-06	8.98E-06					2.24E-06	8.98E-06
Hexachlorodibenzo-p-dioxins	Yes	Yes	3.47E-09	Custom FBC Boiler	4.85E-06	1.95E-05	4.85E-06	1.95E-05					4.85E-06	1.95E-05
Hexachlorodibenzo-p-furans	Yes	Yes	3.18E-09	Custom FBC Boiler	4.45E-06	1.78E-05	4.45E-06	1.78E-05					4.45E-06	1.78E-05
Indeno(1,2,3,c,d)pyrene	Yes	Yes	7.43E-08	Custom FBC Boiler	1.04E-04	4.17E-04	1.04E-04	4.17E-04	2.14E-06	AP-42, Table 1.3-9	6.67E-06	1.33E-06	1.04E-04	4.17E-04
Iron	No	No	9.90E-06	AP-42, Table 1.6-4	1.39E-02	5.56E-02	1.39E-04	5.56E-04					1.39E-04	5.56E-04
Isobutyraldehyde	Yes	No	1.20E-05	AP-42, Table 1.6-3	1.68E-02	6.74E-02	1.68E-02	6.74E-02					1.68E-02	6.74E-02
Isobutyl alcohol	Yes	No	1.00E-05	Custom FBC Boiler	1.40E-02	5.62E-02	1.40E-02	5.62E-02					1.40E-02	5.62E-02
Lead	No	Yes	4.80E-07	AP-42, Table 1.6-4	6.72E-04	2.70E-03	6.72E-06	2.70E-05	1.26E-03	AP-42, Table 1.3-10	3.93E-03	7.86E-04	3.93E-03	8.11E-04
Manganese	No	Yes	1.60E-05	AP-42, Table 1.6-4	2.24E-02	8.98E-02	2.24E-04	8.98E-04	8.40E-04	AP-42, Table 1.3-10	2.62E-03	5.24E-04	2.62E-03	1.38E-03
Mercury	No	Yes	1.00E-06	Vendor Data	1.40E-03	5.62E-03	1.40E-03	5.62E-03	4.20E-04	AP-42, Table 1.3-10	1.31E-03	2.62E-04	1.40E-03	5.62E-03
Methane	No	No	2.10E-02	AP-42, Table 1.6-3	2.94E+01	1.18E+02	2.94E+01	1.18E+02					2.94E+01	1.18E+02
Methyl chloride (chloromethane)	Yes	Yes	2.31E-05	Custom FBC Boiler	3.23E-02	1.30E-01	3.23E-02	1.30E-01					3.23E-02	1.30E-01
2-Methylnaphthalene	Yes	Yes	4.05E-08	Custom FBC Boiler	5.66E-05	2.27E-04	5.66E-05	2.27E-04					5.66E-05	2.27E-04
Methylene chloride (dichloromethane)	No	Yes	1.68E-06	Custom FBC Boiler	2.35E-03	9.43E-03	2.35E-03	9.43E-03					2.35E-03	9.43E-03
Molybdenum	No	No	2.10E-08	AP-42, Table 1.6-4	2.94E-05	1.18E-04	2.94E-07	1.18E-06					2.94E-07	1.18E-06
Monochlorobiphenyl	Yes	Yes	6.02E-09	Custom FBC Boiler	8.42E-06	3.38E-05	8.42E-06	3.38E-05					8.42E-06	3.38E-05
Monochlorophenol	Yes	No	2.35E-07	Custom FBC Boiler	3.29E-04	1.32E-03	3.29E-04	1.32E-03					3.29E-04	1.32E-03
Naphthalene	Yes	Yes	4.27E-06	Custom FBC Boiler	5.98E-03	2.40E-02	5.98E-03	2.40E-02	1.13E-03	AP-42, Table 1.3-9	3.52E-03	7.04E-04	5.98E-03	2.40E-02
Nickel	No	Yes	3.30E-07	AP-42, Table 1.6-4	4.62E-04	1.85E-03	4.62E-06	1.85E-05	4.20E-04	AP-42, Table 1.3-10	1.31E-03	2.62E-04	1.31E-03	2.80E-04
2-Nitrophenol	Yes	No	2.40E-07	AP-42, Table 1.6-3	3.36E-04	1.35E-03	3.36E-04	1.35E-03					3.36E-04	1.35E-03
4-Nitrophenol	Yes	Yes	1.10E-07	AP-42, Table 1.6-3	1.54E-04	6.18E-04	1.54E-04	6.18E-04					1.54E-04	6.18E-04
Nonachlorobiphenyl	Yes	Yes	2.88E-09	Custom FBC Boiler	4.03E-06	1.62E-05	4.03E-06	1.62E-05					4.03E-06	1.62E-05
Octachlorobiphenyl	Yes	Yes	2.04E-09	Custom FBC Boiler	2.86E-06	1.15E-05	2.86E-06	1.15E-05					2.86E-06	1.15E-05
Octachlorodibenzo-p-dioxins	Yes	Yes	5.45E-09	Custom FBC Boiler	7.63E-06	3.06E-05	7.63E-06	3.06E-05	3.10E-09	AP-42, Table 1.3-9	9.66E-09	1.93E-09	7.63E-06	3.06E-05
Octachlorodibenzo-p-furans	Yes	Yes	3.85E-10	Custom FBC Boiler	5.39E-07	2.16E-06	5.39E-07	2.16E-06					5.39E-07	2.16E-06
Pentachlorodibenzo-p-dioxins	Yes	Yes	7.08E-10	Custom FBC Boiler	9.90E-07	3.98E-06	9.90E-07	3.98E-06					9.90E-07	3.98E-06
Pentachlorodibenzo-p-furans	Yes	Yes	2.32E-09	Custom FBC Boiler	3.25E-06	1.31E-05	3.25E-06	1.31E-05					3.25E-06	1.31E-05
Pentachlorobenzene	Yes	No	2.35E-07	Custom FBC Boiler	3.29E-04	1.32E-03	3.29E-04	1.32E-03					3.29E-04	1.32E-03
Pentachlorobiphenyl	Yes	Yes	3.31E-09	Custom FBC Boiler	4.64E-06	1.86E-05	4.64E-06	1.86E-05					4.64E-06	1.86E-05
Pentachlorophenol	Yes	Yes	2.35E-07	Custom FBC Boiler	3.29E-04	1.32E-03	3.29E-04	1.32E-03					3.29E-04	1.32E-03
2-Pentanone	Yes	No	1.16E-05	Custom FBC Boiler	1.62E-02	6.51E-02	1.62E-02	6.51E-02					1.62E-02	6.51E-02
Perylene	Yes	Yes	2.27E-10	Custom FBC Boiler	3.17E-07	1.27E-06	3.17E-07	1.27E-06					3.17E-07	1.27E-06
Phenanthrene	Yes	Yes	3.39E-07	Custom FBC Boiler	4.75E-04	1.91E-03	4.75E-04	1.91E-03	1.05E-05	AP-42, Table 1.3-9	3.27E-05	6.55E-06	4.75E-04	1.91E-03
Phenol	Yes	Yes	3.30E-06	Custom FBC Boiler	4.62E-03	1.85E-02	4.62E-03	1.85E-02					4.62E-03	1.85E-02
Propanol	Yes	No	8.10E-06	Custom FBC Boiler	1.13E-02	4.55E-02	1.13E-02	4.55E-02					1.13E-02	4.55E-02
Phosphorus	No	Yes	2.70E-07	AP-42, Table 1.6-4	3.78E-04	1.52E-03	3.78E-06	1.52E-05					3.78E-06	1.52E-05

Table C-2. BFB Biomass Boiler Potential HAP/TAP Emissions

Biomass Boiler	**B001**				
Short Term Heat Input	1,399	MMBtu/hr	Maximum Biodiesel Heat Input[1]	396	MMBtu/hr
Annual Sustainable Heat Input	1,282	MMBtu/hr	Biodiesel Heating Value	127,042	Btu/gal
Hours of Operation per Year	8,760	hr/yr	Biodiesel Heating Value	127.04	MMBtu/Mgal
Organic HAP Control	0.0%		Potential Startup Operation[2]	400	hr/yr
PM HAP Control	99.0%				

			Scenario A (100% Biomass)						Scenario B (Biodiesel or Diesel for Startup)					
	VOC	HAP	Biomass Factor[3]		Uncontrolled Emissions[4]		Controlled Emissions[5]		Biodiesel/Diesel Factor[6]		Biodiesel Emissions[7]		Worst-Case Emissions[8]	
Pollutant	(Yes/No)	(Yes/No)	(lb/MMBtu)	Source	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/Mgal)	Source	(lb/hr)	(tpy)	(lbs/hr)	(tpy)
Potassium	No	No	3.90E-04	AP-42, Table 1.6-4	5.46E-01	2.19E+00	5.46E-03	2.19E-02					5.46E-03	2.19E-02
Propionaldehyde	Yes	Yes	6.11E-05	Custom FBC Boiler	8.55E-02	3.43E-01	8.55E-02	3.43E-01					8.55E-02	3.43E-01
Pyrene	Yes	Yes	1.46E-07	Custom FBC Boiler	2.04E-04	8.20E-04	2.04E-04	8.20E-04	4.25E-06	AP-42, Table 1.3-9	1.32E-05	2.65E-06	2.04E-04	8.20E-04
Pyridine	Yes	No	3.20E-06	Custom FBC Boiler	4.48E-03	1.80E-02	4.48E-03	1.80E-02					4.48E-03	1.80E-02
Selenium	No	Yes	2.80E-08	AP-42, Table 1.6-4	3.92E-05	1.57E-04	3.92E-07	1.57E-06	2.10E-03	AP-42, Table 1.3-10	6.55E-03	1.31E-03	6.55E-03	1.31E-03
Silver	No	No	1.70E-05	AP-42, Table 1.6-4	2.38E-02	9.55E-02	2.38E-04	9.55E-04					2.38E-04	9.55E-04
Sodium	No	No	3.60E-06	AP-42, Table 1.6-4	5.04E-03	2.02E-02	5.04E-05	2.02E-04					5.04E-05	2.02E-04
Strontium	No	No	1.00E-07	AP-42, Table 1.6-4	1.40E-04	5.62E-04	1.40E-06	5.62E-06					1.40E-06	5.62E-06
Styrene	Yes	Yes	5.60E-07	Custom FBC Boiler	7.83E-04	3.14E-03	7.83E-04	3.14E-03					7.83E-04	3.14E-03
2,3,7,8-Tetrachlorodibenzo-p-dioxins	Yes	Yes	5.38E-12	Custom FBC Boiler	7.52E-09	3.02E-08	7.52E-09	3.02E-08					7.52E-09	3.02E-08
Tetrachlorodibenzo-p-dioxins	Yes	Yes	1.10E-10	Custom FBC Boiler	1.53E-07	6.16E-07	1.53E-07	6.16E-07					1.53E-07	6.16E-07
2,3,7,8-Tetrachlorodibenzo-p-furans	Yes	Yes	6.84E-11	Custom FBC Boiler	9.57E-08	3.84E-07	9.57E-08	3.84E-07					9.57E-08	3.84E-07
Tetrachlorodibenzo-p-furans	Yes	Yes	6.69E-10	Custom FBC Boiler	9.35E-07	3.75E-06	9.35E-07	3.75E-06					9.35E-07	3.75E-06
Tetrachlorobenzene	Yes	No	2.35E-07	Custom FBC Boiler	3.29E-04	1.32E-03	3.29E-04	1.32E-03					3.29E-04	1.32E-03
Tetrachlorobiphenyl	Yes	Yes	5.90E-09	Custom FBC Boiler	8.26E-06	3.31E-05	8.26E-06	3.31E-05					8.26E-06	3.31E-05
Tetrachloroethene	No	Yes	6.33E-06	Custom FBC Boiler	8.85E-03	3.55E-02	8.85E-03	3.55E-02					8.85E-03	3.55E-02
Tetrachlorophenol	Yes	No	2.35E-07	Custom FBC Boiler	3.29E-04	1.32E-03	3.29E-04	1.32E-03					3.29E-04	1.32E-03
Thallium	No	No	1.26E-08	Custom FBC Boiler	1.76E-05	7.05E-05	1.76E-05	7.05E-05					1.76E-05	7.05E-05
Tin	No	No	2.30E-07	AP-42, Table 1.6-4	3.22E-04	1.29E-03	3.22E-06	1.29E-05					3.22E-06	1.29E-05
Titanium	No	No	2.00E-07	AP-42, Table 1.6-4	2.80E-04	1.12E-03	2.80E-06	1.12E-05					2.80E-06	1.12E-05
o-Tolualdehyde	Yes	No	7.20E-06	AP-42, Table 1.6-3	1.01E-02	4.04E-02	1.01E-02	4.04E-02					1.01E-02	4.04E-02
p-Tolualdehyde	Yes	No	1.10E-05	AP-42, Table 1.6-3	1.54E-02	6.18E-02	1.54E-02	6.18E-02					1.54E-02	6.18E-02
Toluene	Yes	Yes	4.60E-06	Custom FBC Boiler	6.43E-03	2.58E-02	6.43E-03	2.58E-02	6.20E-03	AP-42, Table 1.3-9	1.93E-02	3.87E-03	1.93E-02	2.85E-02
Trichlorobiphenyl	Yes	Yes	3.44E-08	Custom FBC Boiler	4.82E-05	1.93E-04	4.82E-05	1.93E-04					4.82E-05	1.93E-04
Trichlorobenzene	Yes	Yes	2.35E-07	Custom FBC Boiler	3.29E-04	1.32E-03	3.29E-04	1.32E-03					3.29E-04	1.32E-03
Trichloroethylene (trichloroethene)	Yes	Yes	6.61E-06	Custom FBC Boiler	9.25E-03	3.71E-02	9.25E-03	3.71E-02					9.25E-03	3.71E-02
Trichlorofluoromethane	No	No	5.40E-06	Custom FBC Boiler	7.55E-03	3.03E-02	7.55E-03	3.03E-02					7.55E-03	3.03E-02
2,4,6-Trichlorophenol	Yes	Yes	2.20E-08	AP-42, Table 1.6-3	3.08E-05	1.24E-04	3.08E-05	1.24E-04					3.08E-05	1.24E-04
Vanadium	No	No	9.80E-09	AP-42, Table 1.6-4	1.37E-05	5.50E-05	1.37E-07	5.50E-07					1.37E-07	5.50E-07
Vinyl chloride	Yes	Yes	3.51E-06	Custom FBC Boiler	4.91E-03	1.97E-02	4.91E-03	1.97E-02					4.91E-03	1.97E-02
o-Xylene	Yes	Yes	3.47E-06	Custom FBC Boiler	4.85E-03	1.95E-02	4.85E-03	1.95E-02	1.09E-04	AP-42, Table 1.3-9	3.40E-04	6.80E-05	4.85E-03	1.95E-02
m/p-Xylenes	Yes	Yes	4.42E-06	Custom FBC Boiler	6.18E-03	2.48E-02	6.18E-03	2.48E-02					6.18E-03	2.48E-02
Yttrium	No	No	3.00E-09	AP-42, Table 1.6-4	4.20E-06	1.68E-05	4.20E-08	1.68E-07					4.20E-08	1.68E-07
Zinc	No	No	4.20E-06	AP-42, Table 1.6-4	5.88E-03	2.36E-02	5.88E-05	2.36E-04	5.60E-04	AP-42, Table 1.3-10	1.75E-03	3.49E-04	1.75E-03	5.74E-04
Total VOC							**0.99**	**3.97**			**0.17**	**0.035**	**1.00**	**3.98**
Total HAP							**4.96**	**19.90**			**0.20**	**0.039**	**4.99**	**19.91**
MAX Single HAP							**2.47**	**9.90**			**0.15**	**0.03**	**2.47**	**9.90**

1. Either biodiesel or diesel will be used for startup operations. However, if diesel is used, the heat input will be smaller than for biodiesel.
2. Biodiesel or ULSD will only be used for aportion of each startup event. For B100, biodiesel consumption is expected to cease by Hour 10. For ULSD, the startup will take longer (with lower lb/hr emissions), but total oil consumed is expected to be the same as the B100 case (equivalent tpy emissions). To determine the hours emissions, the B100 case is used.
3. Where data were available for FBC boilers in the AP-42 Section 1.6 background database and/or the U.S. EPA original Boiler MACT database, custom factors were developed. Otherwise, vendor data or AP-42 Section 1.6 factors were used.
4. Emissions for Scenario A (100% Load: Biomass) are estimated for both short term (daily) heat input and long term (annual) sustainable heat input. Emissions for HCl, Cl, and Hg are based on controlled vendor factors.
5. Control efficiency applied to the uncontrolled emissions.
6. Emission factors based on factors for No. 2 fuel oil from AP-42 Section 1.3; lb/Mgal factors were converted to biodiesel based on the biodiesel heat input while lb/MMBtu factors were converted to biodiesel using the ratio of diesel to biodiesel heating values.
7. Emissions for Scenario B (Biodiesel or diesel) are estimated using the maximum biodiesel or biodiesel/diesel blend heat input and hours of operation for biodiesel. Control devices will not be utilized or just starting up during biodiesel or diesel combustion; control has not been assumed.
8. Short-term worst-case emissions are the maximum of Scenario A or Scenario B hourly emissions. Annual worst-case emissions evaluated as the maximum of Scenario A or [Scenario B, tpy + (Scenario A, tpy *(potential - biodiesel operation, hr/yr)/(potential, hr/yr)].

Table C-3. Emergency Fire Water Pump Engine Potential NSR-Regulated and HAP Emissions

Biodiesel Fire Water Pump	**FP01**	**FP02**	
Engine Power	330	175	hp, output
Hours of Operation[1]	500	500	hr/yr
Heating Value of Biodiesel	19,300	19,300	Btu/lb
Power Conversion[2]	7,000	7,000	Btu/hp-hr
Heat Input	2.31	1.23	MMBtu/hr, input

Criteria Pollutant Emissions

Pollutant	Emission Factor[3,4]	Units	FP01 Potential Emissions (lb/hr)	FP01 Potential Emissions (tpy)	FP02 Potential Emissions (lb/hr)	FP02 Potential Emissions (tpy)	Total Fire Pump Potential Emissions (lb/hr)	Total Fire Pump Potential Emissions (tpy)
CO	3.12E-03	lb/hp-hr	1.03E+00	2.58E-01	5.47E-01	1.37E-01	1.58E+00	3.94E-01
NO_X	5.15E-03	lb/hp-hr	1.70E+00	4.25E-01	9.02E-01	2.26E-01	2.60E+00	6.51E-01
TSP	2.60E-04	lb/hp-hr	8.58E-02	2.15E-02	4.55E-02	1.14E-02	1.31E-01	3.28E-02
PM_{10}	2.60E-04	lb/hp-hr	8.58E-02	2.15E-02	4.55E-02	1.14E-02	1.31E-01	3.28E-02
SO_2	15	ppmw	3.59E-03	8.98E-04	1.90E-03	4.76E-04	5.49E-03	1.37E-03
VOC (NMHC)	2.71E-04	lb/hp-hr	8.95E-02	2.24E-02	4.75E-02	1.19E-02	1.37E-01	3.42E-02

Toxic/Hazardous Air Pollutant Emissions

Pollutant	HAP (Yes/No)	Emission Factor (lb/MMBtu)	FP01 Potential Emissions (lb/hr)	FP01 Potential Emissions (tpy)	FP02 Potential Emissions (lb/hr)	FP02 Potential Emissions (tpy)	Total Fire Pump Potential Emissions (lb/hr)	Total Fire Pump Potential Emissions (tpy)
1,3-Butadiene	Yes	3.91E-05	9.03E-05	2.26E-05	4.79E-05	1.20E-05	1.38E-04	3.46E-05
Acenaphthene	Yes	1.42E-06	3.28E-06	8.20E-07	1.74E-06	4.35E-07	5.02E-06	1.25E-06
Acenaphthylene	Yes	5.06E-06	1.17E-05	2.92E-06	6.20E-06	1.55E-06	1.79E-05	4.47E-06
Acetaldehyde	Yes	7.67E-04	1.77E-03	4.43E-04	9.40E-04	2.35E-04	2.71E-03	6.78E-04
Acrolein	Yes	9.25E-05	2.14E-04	5.34E-05	1.13E-04	2.83E-05	3.27E-04	8.17E-05
Anthracene	Yes	1.87E-06	4.32E-06	1.08E-06	2.29E-06	5.73E-07	6.61E-06	1.65E-06
Benzene	Yes	9.33E-04	2.16E-03	5.39E-04	1.14E-03	2.86E-04	3.30E-03	8.25E-04
Benzo(a)anthracene	Yes	1.68E-06	3.88E-06	9.70E-07	2.06E-06	5.15E-07	5.94E-06	1.48E-06
Benzo(a)pyrene	Yes	1.88E-07	4.34E-07	1.09E-07	2.30E-07	5.76E-08	6.65E-07	1.66E-07
Benzo(b)fluoranthene	Yes	9.91E-08	2.29E-07	5.72E-08	1.21E-07	3.03E-08	3.50E-07	8.76E-08
Benzo(g,h,i)perylene	Yes	4.89E-07	1.13E-06	2.82E-07	5.99E-07	1.50E-07	1.73E-06	4.32E-07
Benzo(k)fluoranthene	Yes	1.55E-07	3.58E-07	8.95E-08	1.90E-07	4.75E-08	5.48E-07	1.37E-07
Chrysene	Yes	3.53E-07	8.15E-07	2.04E-07	4.32E-07	1.08E-07	1.25E-06	3.12E-07
Dibenzo(a,h)anthracene	Yes	5.83E-07	1.35E-06	3.37E-07	7.14E-07	1.79E-07	2.06E-06	5.15E-07
Fluoranthene	Yes	7.61E-06	1.76E-05	4.39E-06	9.32E-06	2.33E-06	2.69E-05	6.73E-06
Fluorene	Yes	2.92E-05	6.75E-05	1.69E-05	3.58E-05	8.94E-06	1.03E-04	2.58E-05
Formaldehyde	Yes	1.18E-03	2.73E-03	6.81E-04	1.45E-03	3.61E-04	4.17E-03	1.04E-03
Indeno(1,2,3-cd)pyrene	Yes	3.75E-07	8.66E-07	2.17E-07	4.59E-07	1.15E-07	1.33E-06	3.31E-07
Naphthalene	Yes	8.48E-05	1.96E-04	4.90E-05	1.04E-04	2.60E-05	3.00E-04	7.49E-05
Phenanthrene	Yes	2.94E-05	6.79E-05	1.70E-05	3.60E-05	9.00E-06	1.04E-04	2.60E-05
Propylene	No	2.58E-03	5.96E-03	1.49E-03	3.16E-03	7.90E-04	9.12E-03	2.28E-03
Pyrene	Yes	4.78E-06	1.10E-05	2.76E-06	5.86E-06	1.46E-06	1.69E-05	4.22E-06
Toluene	Yes	4.09E-04	9.45E-04	2.36E-04	5.01E-04	1.25E-04	1.45E-03	3.61E-04
Xylene (Total)	Yes	2.85E-04	6.58E-04	1.65E-04	3.49E-04	8.73E-05	1.01E-03	2.52E-04
Total HAP			**8.95E-03**	**2.24E-03**	**4.75E-03**	**1.19E-03**	**1.37E-02**	**3.42E-03**

1. NSPS Subpart IIII allows for only 100 hrs/yr of non-emergency operation of these engines. Emergency situations are included.
2. Conversion factor for diesel as noted in AP-42, Section 3.3, Table 3.3-1 footnote.
3. Criteria emissions factors provided via engine vendor (based on Tier III engines).
4. Sulfur content in accordance with Year 2010 standards of 40 CFR 80.510(a) as required by NSPS Subpart IIII.

Table C-4. Baghouse/Bin Vent Filter Flowrate-Based PM Emissions

Emission Unit/Area	Baghouse or Bin Vent Filter	Flowrate (acfm)	Grain Loading (gr/cfm)	Annual Operation (hours)	% PM that is PM_{10}	% PM that is $PM_{2.5}$	Potential Emissions PM (lb/hr)	PM (tpy)	PM_{10} (lb/hr)	PM_{10} (tpy)	$PM_{2.5}$ (lb/hr)	$PM_{2.5}$ (tpy)
Biomass Unloading Area[1]	BM01	45,342	0.005	5,840	100%	100%	1.94	5.67	1.94	5.67	1.94	5.67
Fuel Processing Building[2]	BM02	46,165	0.005	5,840	100%	100%	1.98	5.78	1.98	5.78	1.98	5.78
Transfer Tower[3]	BM03	25,312	0.005	8,760	100%	100%	1.08	4.75	1.08	4.75	1.08	4.75
Boiler Fuel Feed System[4]	BM04	19,885	0.005	8,760	100%	100%	0.85	3.73	0.85	3.73	0.85	3.73
Sorbent Silo[5]	BM05	987	0.005	8,760	100%	100%	4.23E-02	1.85E-01	4.23E-02	1.85E-01	4.23E-02	1.85E-01
Boiler Bed Sand Silo[5]	BM06	987	0.005	8,760	100%	100%	4.23E-02	1.85E-01	4.23E-02	1.85E-01	4.23E-02	1.85E-01
Sand Day Silo[5]	BM07	987	0.005	8,760	100%	100%	4.23E-02	1.85E-01	4.23E-02	1.85E-01	4.23E-02	1.85E-01
Bottom Ash Covered Storage Area[6]	BM08	1,481	0.005	8,760	100%	100%	6.35E-02	2.78E-01	6.35E-02	2.78E-01	6.35E-02	2.78E-01
Flyash Silo[5]	BM09	1,481	0.005	8,760	100%	100%	6.35E-02	2.78E-01	6.35E-02	2.78E-01	6.35E-02	2.78E-01
Mobile Longwood Chipping[7]	BM10	6,229	0.005	5,840	100%	100%	0.27	0.78	0.27	0.78	0.27	0.78

1. Emissions from the six feeders and two collecting belt conveyors located in the non-longwood biomass unloading area are controlled by this baghouse. Operation is limited to 6 am - 10 pm.
2. Emissions from the two scalping screens, two wood hogs, and all transfer points inside the fuel processing building are controlled by this baghouse. Operation is limited to 6 am - 10 pm.
3. Emissions from all transfer points inside the transfer tower are controlled by this baghouse.
4. Emissions from the boiler reclaimer, distribution chain, and overfill return belt sources inside the boiler building are controlled by this baghouse.
5. Emissions from pneumatic conveyance.
6. Emissions from the outdoor ash storage area will be controlled by this baghouse. Note that the storage area is contained by concrete walls on three sides and covered with a roof.
7. Longwood chipping was conservatively assumed to operate 365 days/year at 16 hrs/day. However, actual chipper operation is anticipated to be much smaller as the chipper will not be onsite for the duration of the entire year.

Table C-5. Raw Material Handling Potential Fugitive PM Emissions

Emission Unit ID	Emission Source Description	Maximum Throughput (ton/hr)	Operating Hours (hr/yr)	Control	Control Efficiency[1] (%)	Potential Uncontrolled Emissions for PM[2] (lb/hr)	Potential Uncontrolled Emissions for PM[2] (tpy)	Potential Uncontrolled Emissions for PM_{10}[2] (lb/hr)	Potential Uncontrolled Emissions for PM_{10}[2] (tpy)	Potential Uncontrolled Emissions for $PM_{2.5}$[2] (lb/hr)	Potential Uncontrolled Emissions for $PM_{2.5}$[2] (tpy)	Potential Controlled Emissions for PM[2] (lb/hr)	Potential Controlled Emissions for PM[2] (tpy)	Potential Controlled Emissions for PM_{10}[2] (lb/hr)	Potential Controlled Emissions for PM_{10}[2] (tpy)	Potential Controlled Emissions for $PM_{2.5}$[2] (lb/hr)	Potential Controlled Emissions for $PM_{2.5}$[2] (tpy)
TX01	Raw Material Unloading/Truck Dump (DMP 1-6)	750	5,840	Dust suppression by wetting	70%	3.11E-02	9.09E-02	1.47E-02	4.30E-02	2.23E-03	6.51E-03	9.34E-03	2.73E-02	4.42E-03	1.29E-02	6.69E-04	1.95E-03
TX02	Dump (DMP 1-6) to Hopper (HPR 1-6)	750	5,840	Dust suppression by wetting	90%	3.11E-02	9.09E-02	1.47E-02	4.30E-02	2.23E-03	6.51E-03	3.11E-03	9.09E-03	1.47E-03	4.30E-03	2.23E-04	6.51E-04
TX03	Transfer Belt Conveyors (CV05, CV06) to Radial Stacking Belt Conveyors (CV07, CV08)	800	5,840	Dust suppression by wetting	97%	3.32E-02	9.70E-02	1.57E-02	4.59E-02	2.38E-03	6.95E-03	1.13E-03	3.30E-03	5.34E-04	1.56E-03	8.09E-05	2.36E-04
TX04	Radial Stacking Belt Conveyor (CV07) to Radial Stock Pile (SP01)	400	5,840	Dust suppression by wetting, telescoping chute	90%	1.66E-02	4.85E-02	7.86E-03	2.29E-02	1.19E-03	3.47E-03	1.66E-03	4.85E-03	7.86E-04	2.29E-03	1.19E-04	3.47E-04
TX05	Radial Stacking Belt Conveyor (CV08) to Radial Stock Pile (SP02)	400	5,840	Dust suppression by wetting, telescoping chute	90%	1.66E-02	4.85E-02	7.86E-03	2.29E-02	1.19E-03	3.47E-03	1.66E-03	4.85E-03	7.86E-04	2.29E-03	1.19E-04	3.47E-04
TX06	Radial Stock Pile (SP01) to Reclaim Chain Conveyor (CV09)	200	8,760	Dust suppression by wetting	90%	8.31E-03	3.64E-02	3.93E-03	1.72E-02	5.95E-04	2.61E-03	8.31E-04	3.64E-03	3.93E-04	1.72E-03	5.95E-05	2.61E-04
TX07	Radial Stock Pile (SP02) to Reclaim Chain Conveyor (CV10)	200	8,760	Dust suppression by wetting	90%	8.31E-03	3.64E-02	3.93E-03	1.72E-02	5.95E-04	2.61E-03	8.31E-04	3.64E-03	3.93E-04	1.72E-03	5.95E-05	2.61E-04
TX08	Reclaim Chain Conveyor (CV09) to Reclaim Belt Conveyor (CV11)	200	8,760	Dust suppression by wetting	97%	8.31E-03	3.64E-02	3.93E-03	1.72E-02	5.95E-04	2.61E-03	2.82E-04	1.24E-03	1.34E-04	5.85E-04	2.02E-05	8.86E-05
TX09	Reclaim Chain Conveyor (CV10) to Reclaim Belt Conveyor (CV12)	200	8,760	Dust suppression by wetting	97%	8.31E-03	3.64E-02	3.93E-03	1.72E-02	5.95E-04	2.61E-03	2.82E-04	1.24E-03	1.34E-04	5.85E-04	2.02E-05	8.86E-05
TX10	Reclaim Belt Conveyor (CV11) to Stockout Belt Conveyor (CV13)	200	8,760	Material fully wet, assumed equivalent to dust suppression by wetting	97%	8.31E-03	3.64E-02	3.93E-03	1.72E-02	5.95E-04	2.61E-03	2.82E-04	1.24E-03	1.34E-04	5.85E-04	2.02E-05	8.86E-05
TX11	Reclaim Belt Conveyor (CV12) to Stockout Belt Conveyor (CV13)	200	8,760	Material fully wet, assumed equivalent to dust suppression by wetting	97%	8.31E-03	3.64E-02	3.93E-03	1.72E-02	5.95E-04	2.61E-03	2.82E-04	1.24E-03	1.34E-04	5.85E-04	2.02E-05	8.86E-05
TX12	Longwood Material Unloading[3]	125	5,840	None	0%	5.19E-03	1.52E-02	2.46E-03	7.17E-03	3.72E-04	1.09E-03	5.19E-03	1.52E-02	2.46E-03	7.17E-03	3.72E-04	1.09E-03
Total Emissions						**1.84E-01**	**6.09E-01**	**8.69E-02**	**2.88E-01**	**1.32E-02**	**4.36E-02**	**2.49E-02**	**7.68E-02**	**1.18E-02**	**3.63E-02**	**1.78E-03**	**5.50E-03**

1. Control efficiencies as follows:

Truck unloading	70%	Based on dust suppression by "wetting", per Georgia Guideline for Assuring Acceptable Ambient Concentrations of PM_{10} in areas impacted by Quarry Operations Producing Crushed Stone, October 2004.
Drop Point	90%	Engineering assumption for dust suppression by "wetting"
Indexing/reclaiming Point	90%	Engineering assumption for dust suppression by "wetting"
Conveyor Transfer	97%	Based on dust suppression by "wetting", per Georgia Guideline for Assuring Acceptable Ambient Concentrations of PM_{10} in areas impacted by Quarry Operations Producing Crushed Stone, October 2004.

2. Based emission factors calculated per AP-42 Section 13.2.4, September 2006.

$$E = k\ (0.0032)\ \frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}\quad \text{(lb/ton)}$$

where:

	E = emission factor (lb/ton)		
	k = particle size multiplier (dimensionless) for PM	0.74	
	k = particle size multiplier (dimensionless) for PM_{10}	0.35	
	k = particle size multiplier (dimensionless) for $PM_{2.5}$	0.053	
	U = mean wind speed (mph)	7.14	Based on meteorological data averaged for 1989-1993, provided by Georgia EPD for Athens, GA.
	M = material moisture content (%)	50	

E for PM (lb/ton) =	4.2E-05
E for PM_{10} (lb/ton) =	2.0E-05
E for $PM_{2.5}$ (lb/ton) =	3.0E-06

3. Longwood biomass operation schedule was conservatively calculated based on 365 days/year, 16 hrs/day. However actual onsite longwood transfer and chipping will not occur for the duration of the entire year.

Oglethorpe Power Corporation - Warren County Biomass Energy Facility

Table C-6. Biomass Chipping Operations - Fugitive PM Transfer of Chips from Chipper to Truck

Emission Unit ID	Description	Exhaust Location	Baghouse Capture Efficiency (%)	TSP Emission Factor[1] (lb/ton)	Annual Operation (hours)[2]	Maximum Biomass Processed[3] (ton/hr)	Maximum Biomass Processed[3] (ton/yr)	TSP Emission Rate (lb/hr)	TSP Emission Rate (tpy)	PM_{10} Emission Rate[4] (lb/hr)	PM_{10} Emission Rate[4] (tpy)	$PM_{2.5}$ Emission Rate[5] (lb/hr)	$PM_{2.5}$ Emission Rate[5] (tpy)
GRN3	Longwood Mobile Chipping	Atmosphere	95%	2.4E-02	5,840	125	730,000	0.15	0.44	0.09	0.26	0.09	0.26

1. TSP emission factor for "log debarking" based on U.S. EPA AP-42, Section 10.3-1, *Wood Products Industry*, Table 10.3-1. September 1985. www.epa.gov/ttn/chief/old/ap42/4th_edition/ap42_4thed_withsuppsa_f.pdf. Also recommended by Bay Area Air Quality Management District (BAAQMD) Permit Handbook for biomass tub grinding operations. www.baaqmd.gov/pmt/handbook/rev02/PH_00_05_11_13.pdf. The mobile chipper is equipped with a baghouse/chute system that captures 95% of the emissions.

2. Longwood chipping was conservatively assumed to operate 365 days/year at 16 hrs/day. However, actual chipper operation is anticipated to be much smaller as the chipper will not be onsite for the duration of the entire year.

3. Short-term equipment capacity for ton/hr.

4. PM_{10} emissions assumed equal to 60% of TSP, based on Bay Area Air Quality Management District (BAAQMD) *Permit Handbook*. www.baaqmd.gov/pmt/handbook/rev02/PH_00_05_11_13.pdf.

5. $PM_{2.5}$ emissions conservatively assumed to be equal toPM_{10} emissions.

Table C-7. Biomass Storage Pile Potential Fugitive PM Emissions

Emission Unit ID	Description	TSP Emission Factor [1] (lb/day/acre)	TSP Emission Factor [1] ($lb/hr/ft^2$)	Pile Shape	Width of the Pile, W (ft)	Length of the Pile, L (ft)	Height, H (ft)	Cone 1 Inside Radius, r_1 (ft)	Cone 1 Outside Radius, r_2 (ft)	Cone 2 Inside Radius, r_1 (ft)	Cone 2 Outside Radius, r_2 (ft)	Outer Surface Area of Storage Pile (ft^2)	PM Emissions (lb/hr)	PM Emissions (tpy)	PM_{10} Emissions (lb/hr)	PM_{10} Emissions (tpy)	$PM_{2.5}$ Emissions (lb/hr)	$PM_{2.5}$ Emissions (tpy)
SP01	Processed wood pile 1[2]	1.59	1.52E-06	Cone	N/A	N/A	50	70	130	150	210	154,928	0.24	1.03	0.12	0.52	0.02	0.08
SP02	Processed wood pile 2[2]	1.59	1.52E-06	Cone	N/A	N/A	50	70	130	150	210	154,928	0.24	1.03	0.12	0.52	0.02	0.08
SP03	Longwood storage[3,4]	1.59	1.52E-06	Sloping	100	520	50	N/A	N/A	N/A	N/A	136,800	0.21	0.91	0.10	0.46	0.02	0.07
Total													**0.68**	**2.97**	**0.34**	**1.49**	**0.05**	**0.22**

1. TSP emission factor based on U.S. EPA *Control of Open Fugitive Dust Sources* . Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988, Page 4-17.

$$E = 1.7\left(\frac{s}{1.5}\right)\left(\frac{(365-p)}{235}\right)\left(\frac{f}{15}\right)(lb/day/acre)$$

where:

s, silt content of wood chips (%):	2	Georgia Power Plant Mitchell Application #18663 submitted December 12, 2008.
p, number of days with rainfall greater than 0.01 inch:	120	Based on AP-42, Section 13.2.2, Figure 13.2.1-2.
f (time that wind exceeds 5.36 m/s - 12 mph) (%):	10.1	Based on meteorological data averaged for 1989-1993, provided by Georgia EPD for Athens, GA.
PM_{10}/TSP ratio:	50%	PM_{10} is assumed to equal 50% of TSP based on U.S. EPA *Control of Open Fugitive Dust Sources* , Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988.
$PM_{2.5}$/TSP ratio:	7.5%	$PM_{2.5}$ is assumed to equal 7.5 % of TSP U.S. EPA Background Document for Revisions to Fine Fraction Ratios Used for AP-42 Fugitive Dust Emission Factors. November 2006.

2. The surface area is calculated based on the assumption that the pile geometry is accurately characterized by two truncated cones added to account for all of the pile's surface area.
3. The surface area is calculated as [2*H*L+2*W*H+L*W] + 20% to consider the sloping pile edges.
4. The storage pile dimensions are approximated using the proposed site layout.

Table C-8. Cooling Tower Potential NSR-Regulated Pollutant Emissions

Cooling Tower CT01

The facility is equipped with one (1) re-circulating counterflow wet linear mechanical draft cooling tower that is comprised of four (4) cells.[1]

Cooling Tower Capacity[1] (gpm)	Total Dissolved Solids[1] (mg/L)	Drift Loss[1] (%)	Drift Mass Governed by Atmospheric Dispersion[2] (%)	Drift Mass Flow Rate[3] (lb/hr)	Total PM/PM_{10} Emission Rate[4,5] (lb/hr)	Total PM/PM_{10} Emission Rate[4,5] (tpy)	Total $PM_{2.5}$ Emission Rate[5,6] (lb/hr)	Total $PM_{2.5}$ Emission Rate[5,6] (tpy)
76,210	4,000	0.0005%	31.3%	190.79	0.239	1.05	0.14	0.63

[1] Cooling tower makeup water is a blend of water from four different sources. Value is maximum design value for the tower itself.

[2] Based on *Effects of Pathogenic and Toxic Material Transport Via Cooling Device Drift - Vol. 1* Technical Report EPA 600 7-79-251a, November 1979.

[3] Drift mass flow rate (lb/hr) = Cooling tower capacity (gpm) x Density of water (8.34 lb/gal) x 60 (min/hour) x Drift loss (%) .

[4] Hourly PM/PM_{10} emission rate (lb/hr) = Drift mass flow rate (lb/hr) x Dispersion Factor (%) x TDS (mg/L)/(1,000,000).

[5] Annual PM/PM_{10}/$PM_{2.5}$ emission rate (ton/yr) = Hourly emission rate (lb/hr) x 8,760 (hours/yr)/(2000 lb/ton).

[6] Hourly $PM_{2.5}$ emission rate (lb/hr) = 60% * PM_{10} emission rate (lb/hr). $PM_{2.5}$ fraction of PM_{10} in cooling tower exhaust was obtained from California Emissions Inventory Development and Reporting System (CEIDARS).

Table C-9. Paved Road Potential Fugitive PM Emissions

Source	Distance Traveled per Round Trip[1] (ft)	Trips Per Day	Miles Traveled per Day (VMT/day)	Events Per Year (Days)	Truck Weight (Empty) tons	Truck Weight (Loaded) tons	Average Weight (W) (tons)	Vehicle Miles Traveled (VMT/yr)	Emission Factor[2] (lb/VMT) PM	Emission Factor[2] (lb/VMT) PM_{10}	Emission Factor[2] (lb/VMT) $PM_{2.5}$	Potential Uncontrolled Emissions[3] PM (lb/hr)	Potential Uncontrolled Emissions[3] PM (tpy)	Potential Uncontrolled Emissions[3] PM_{10} (lb/hr)	Potential Uncontrolled Emissions[3] PM_{10} (tpy)	Potential Uncontrolled Emissions[3] $PM_{2.5}$ (lb/hr)	Potential Uncontrolled Emissions[3] $PM_{2.5}$ (tpy)	Control Efficiency (%)	Potential Controlled Emissions[4] PM (lb/hr)	Potential Controlled Emissions[4] PM (tpy)	Potential Controlled Emissions[4] PM_{10} (lb/hr)	Potential Controlled Emissions[4] PM_{10} (tpy)	Potential Uncontrolled Emissions[4] $PM_{2.5}$ (lb/hr)	Potential Uncontrolled Emissions[4] $PM_{2.5}$ (tpy)
Biomass Delivery	9,900				15	40	27.5		0.73	0.14	0.021													
Sand Delivery	6,300				15	40	27.5		0.73	0.14	0.021													
Reagent Delivery (Duct Injection)	6,300				15	40	27.5		0.73	0.14	0.021													
Reagent Delivery (Ammonia)	6,300				15	40	27.5		0.73	0.14	0.021													
Flyash Removal	6,300				15	40	27.5		0.73	0.14	0.021													
Biodiesel/ULSD/Misc. Chemical Delivery	6,300				15	40	27.5		0.73	0.14	0.021													
Total Road Emissions[5]	**9,900**	**340**	**637.5**	**365**				**232,688**	**0.73**	**0.14**	**0.021**	**19.48**	**85.32**	**3.79**	**16.61**	**0.56**	**2.46**	**42.82%**	**11.14**	**48.78**	**2.17**	**9.50**	**0.32**	**1.41**

1. Distance traveled per round trip was estimated based on truck route and site layout.
2. Emission Factor $=[k\ (sL/2)^{0.65}\ (W/3)^{1.5}-C]*(1-P/4N)$, per AP-42, Section 13.2.1 - Paved Roads, Equation 2 (11/06), with variables defined below.

k (lb/mile)	0.0024	Particle size multiplier for $PM_{2.5}$ per AP-42, Table 13.2.1-1
k (lb/mile)	0.016	Particle size multiplier for PM_{10} per AP-42, Table 13.2.1-1
k (lb/mile)	0.082	Particle size multiplier for PM per AP-42, Table 13.2.1-1
sL (g/m^2)	0.4	Based on AWMA Air Pollution Engineering Manual second edition, page 126.
P	120	No. days with rainfall greater than 0.01 inch, Per AP-42, Section 13.2.1 - Paved Roads, Figure 13.2.1-2
N	365	Days in averaging period
C	0.00036	lb/VMT for $PM_{2.5}$ per AP-42, Table 13.2.1-2
C	0.00047	lb/VMT for PM_{10} and PM per AP-42, Table 13.2.1-2

3. Potential emissions calculated from appropriate emission factor times vehicle miles traveled.
4. Control efficiency by "water flushing" C= 69-0.231*V, U.S. EPA Control of Open Fugitive Dust Sources, Table 2-4, Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988, Page 2-7.

V	113	Number of vehicles traveling on the roadway since the last application of water. It is assumed that water will be applied three times per day.

5. Based on maximum distance, emission factors, and 340 (total) 40-ton delivery trucks per day.

Table C-10. Storage Tank Potential Fugitive VOC Emissions

Tank ID	Tank	Volume[1] (gal)	Throughput (gal/yr)	Turnovers	TANKS 4.0 VOC Emissions (tpy)
TK01	Biodiesel/ULSD Storage Tank[2]	60,000	1,246,832	20.78	2.85E-02
TK02	Fire Pump ULSD Day Tank[3]	500	8,200	16.40	2.20E-04
TK03	Turbine Lube Oil Reservoir[4]	4,100	12,300	3.00	1.10E-03
TK04	Turbine Lube Oil Dump Tank[5]	400	12,300	30.75	2.65E-04
TK05	Biodiesel/ULSD Storage Tank[6]	60,000	1,246,832	20.78	2.85E-02
TK06	Fire Pump ULSD Day Tank[3]	500	4,400	8.80	1.65E-04
Total					**5.88E-02**

1. Design specifications.
2. Throughput based on start-up biodiesel heat input of 396 MMBtu/hr, biodiesel heating value, and anticipated startup hours of operation per year. Emissions based on diesel profile in TANKS4.0.
3. Throughput based on fuel consumption and 500 hours of operation per year. Fuel consumption data provided by pump engine vendors.
4. Throughput estimated based on lube oil usage of 3 turnovers.
5. Throughput conservatively estimated based on lube oil usage.
6. Conservatively assumed identical to TK05.

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	TK01
City:	Warrenton
State:	Georgia
Company:	Oglethorpe Power Corporation
Type of Tank:	Vertical Fixed Roof Tank
Description:	Biodiesel Storage Tank
Tank Dimensions	
Shell Height (ft):	18.50
Diameter (ft):	23.50
Liquid Height (ft) :	18.50
Avg. Liquid Height (ft):	9.00
Volume (gallons):	60,000.00
Turnovers:	20.78
Net Throughput(gal/yr):	1,246,832.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	Gray/Light
Shell Condition	Good
Roof Color/Shade:	Gray/Light
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft)	0.00
Radius (ft) (Dome Roof)	23.50
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Athens, Georgia (Avg Atmospheric Pressure = 14.34 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

TK01 - Vertical Fixed Roof Tank
Warrenton, 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	69.02	59.75	78.30	63.87	0.0088	0.0065	0.0115	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK01 - Vertical Fixed Roof Tank
Warrenton, Georgia

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	33.79	23.28	57.08

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	TK02
City:	Warrenton
State:	Georgia
Company:	Oglethorpe Power Corporation
Type of Tank:	Horizontal Tank
Description:	Main Fire Pump ULSD Day Tank

Tank Dimensions

Shell Length (ft):		5.50
Diameter (ft):		4.00
Volume (gallons):		500.00
Turnovers:		16.40
Net Throughput(gal/yr):		8,200.00
Is Tank Heated (y/n):	N	
Is Tank Underground (y/n):	N	

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Athens, Georgia (Avg Atmospheric Pressure = 14.34 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

TK02 - Horizontal Tank
Warrenton, 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	69.02	59.75	78.30	63.87	0.0088	0.0065	0.0115	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK02 - Horizontal Tank
Warrenton, Georgia

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	0.22	0.21	0.44

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification		
User Identification:	TK03	
City:	Warrenton	
State:	Georgia	
Company:	Oglethorpe Power Corporation	
Type of Tank:	Horizontal Tank	
Description:	Turbine Lube Oil Reservoir	
Tank Dimensions		
Shell Length (ft):		12.00
Diameter (ft):		8.00
Volume (gallons):		4,100.00
Turnovers:		3.00
Net Throughput(gal/yr):		12,300.00
Is Tank Heated (y/n):	N	
Is Tank Underground (y/n):	N	
Paint Characteristics		
Shell Color/Shade:	Gray/Light	
Shell Condition	Good	
Breather Vent Settings		
Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Athens, Georgia (Avg Atmospheric Pressure = 14.34 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

TK03 - Horizontal Tank
Warrenton, 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	69.02	59.75	78.30	63.87	0.0088	0.0065	0.0115	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK03 - Horizontal Tank
Warrenton, Georgia

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	0.33	1.86	2.20

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	TK04
City:	Warrenton
State:	Georgia
Company:	Oglethorpe Power Corporation
Type of Tank:	Horizontal Tank
Description:	Turbine Lube Oil Dump Tank

Tank Dimensions

Shell Length (ft):	5.00
Diameter (ft):	4.00
Volume (gallons):	400.00
Turnovers:	30.75
Net Throughput(gal/yr):	12,300.00
Is Tank Heated (y/n):	N
Is Tank Underground (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Athens, Georgia (Avg Atmospheric Pressure = 14.34 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

TK04 - Horizontal Tank
Warrenton, 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	69.02	59.75	78.30	63.87	0.0088	0.0065	0.0115	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK04 - Horizontal Tank
Warrenton, Georgia

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	0.33	0.19	0.53

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	TK06
City:	Warrenton
State:	Georgia
Company:	Oglethorpe Power Corporation
Type of Tank:	Horizontal Tank
Description:	Booster Fire Pump ULSD Day Tank

Tank Dimensions

Shell Length (ft):		5.50
Diameter (ft):		4.00
Volume (gallons):		500.00
Turnovers:		8.80
Net Throughput(gal/yr):		4,400.00
Is Tank Heated (y/n):	N	
Is Tank Underground (y/n):	N	

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Athens, Georgia (Avg Atmospheric Pressure = 14.34 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

TK06 - Horizontal Tank
Warrenton, 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	69.02	59.75	78.30	63.87	0.0088	0.0065	0.0115	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK06 - Horizontal Tank
Warrenton, Georgia

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	0.12	0.21	0.33

TANKS 4.0.9d
Emissions Report - Summary Format
Total Emissions Summaries - All Tanks in Report

Emissions Report for: Annual

Tank Identification				Losses (lbs)
TK01	Oglethorpe Power Corporation	Vertical Fixed Roof Tank	Warrenton, Georgia	57.08
TK02	Oglethorpe Power Corporation	Horizontal Tank	Warrenton, Georgia	0.44
TK03	Oglethorpe Power Corporation	Horizontal Tank	Warrenton, Georgia	2.20
TK04	Oglethorpe Power Corporation	Horizontal Tank	Warrenton, Georgia	0.53
TK06	Oglethorpe Power Corporation	Horizontal Tank	Warrenton, Georgia	0.33
Total Emissions for all Tanks:				60.57

Comparison Data: Ogelthorpe Power Fuel Sampling

FUEL TYPE		Sawdust, Hardwood		Shavings, Pine		Bark, Hardwood		Sawdust, Pine		Bark, Pine	
ORIGIN		Warren, Georgia		Warren, Georgia		Warren, Georgia		Appling, Georgia		Appling, Georgia	
PROJECT		Oglethorpe		Oglethorpe		Oglethorpe		Oglethorpe		Oglethorpe	
DATE		8/26/2008		8/26/2008		9/2/2009		9/2/2009		8/26/2008	
DESCRIPTION		Green sawdust collected during sawmill operation on site; Oak, Hickory, Poplar, Gum		Dry shavings collected during planar mill operation on site; Loblolly		Green hardwood bark collected during sawmill operation on site; Oak, Hickory, Poplar, Gum		Green sawdust collected from coveyor during operation on site; Slash and Longleaf		Unhogged softwood bark collected during operation on site; Slash and Longleaf	
HANDLED BY:		E. Smith		E. Smith		E. Smith		E. Smith		E. Smith	
ANALYZED BY:		Consol Energy	Nablabs	Consol Energy	Nablabs	Consol Energy	Nablabs	Consol Energy	Nablabs	Consol Energy	Nablabs
REMARK:		Sample ID: W1HM1, Supplier: Timberman.		Sample ID: W1SM2, Supplier:Timberman.		Sample ID: W1HM3, Supplier: Timberman.		Sample ID: A1SM3, Supplier: Rayonier.		Sample ID: A1SM1, Supplier: Rayonier.	
Proximate analysis											
moisture	wt-%	48.7	49	12.2	14.5	36	38.2	26.57	51.9	53.04	25.4
volatiles	wt-% (d.s.)	83.1	80.5	82.2	79.2	73.5	71.3	83.5	79.8	69.6	66.3
fixed carbon	wt-% (d.s.)	12.5	19.1	15.3	20.5	17.4	24.3	13.6	20.0	25.6	32.3
ash (ashing temp 815 °C for Nablabs, 600 °C for Consol)	wt-% (d.s.)	0.6	0.4	0.4	0.3	6.9	4.4	0.4	0.2	3.1	1.4
Ultimate analysis (dry solids)											
C	wt-% (d.s.)	49.2	49.4	50.4	50.9	49.3	49.3	51.5	51.7	53.4	55.1
H	wt-% (d.s.)	6.0	5.9	6.0	6.0	5.1	5.4	6.0	6.1	4.9	5.5
S	wt-% (d.s.)	0.01	0.02	0.01	0.02	0.04	0.03	0.01	0.02	0.02	0.02
O (diff.)	wt-% (d.s.)	44.0	44.2	43.0	42.7	38.4	40.7	42.0	41.9	38.4	37.8
N	wt-% (d.s.)	0.25	0.10	0.12	0.10	0.29	0.21	0.18	0.10	0.29	0.18
Cl	wt-% (d.s.)	0.001	0.003	0.002	0.003	0.002	0.002	0.002	0.002	0.005	0.009
	wt-% (d.s.)	0.6	0.4	0.4	0.3	6.9	4.4	0.4	0.2	3.1	1.4
SUM		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Heating values											
HHV, dry	MJ/kg	18.71	19.90	19.37	20.50	18.88	19.40	21.24	21.20	19.38	21.70
HHV, wet	MJ/kg	9.60	10.15	17.01	17.53	12.08	11.99	15.60	10.20	9.10	16.19
LHV, dry	MJ/kg	1.62	1.98	3.03	3.65	3.21	3.44	2.57	2.06	2.77	5.46
LHV, wet	MJ/kg	1.42	1.60	2.57	2.90	2.65	2.60	2.22	1.65	2.06	3.69
LHV, ash free, dry	MJ/kg	1.41	1.59	2.56	2.89	2.47	2.49	2.21	1.64	2.00	3.64
LHV, ash free, wet	MJ/kg	1.41	1.59	2.56	2.89	2.47	2.49	2.21	1.64	2.00	3.64

FUEL TYPE		Tops & Limbs chips		Whole tree chips, Hardwood		Whole tree chips, Pine		Whole tree chips, Hardwood		Whole tree chips, Pine	
ORIGIN		Liberty, Georgia		Echols, Georgia		Echols, Georgia		Wilkes, Georgia		Wilkes, Georgia	
PROJECT		Oglethorpe		Oglethorpe		Oglethorpe		Oglethorpe		Oglethorpe	
DATE		8/28/2008		9/3/2008		9/3/2008		9/4/2008		9/4/2008	
DESCRIPTION		Collected on site during chipping operation		Collected on site during chipping operation; Live oak		Collected on site during chipping operation; Loblolly		Obtained from 2 weeks old residual trees chipped the day of sampling; Chips dried out; Oak, Gum, Hickory			
HANDLED BY:		D. Davis		D. Davis		D. Davis		E. Smith		E. Smith	
ANALYZED BY:		Consol Energy	Nablabs	Consol Energy	Nablabs	Consol Energy	Nablabs	Consol Energy	Nablabs	Consol Energy	Nablabs
REMARK:		Sample ID: A1HT, Supplier: Plum Creek.		Sample ID: E1HW, Supplier: Langdale.		Sample ID: E1SW, Supplier: Langdale.		Sample ID: W1HW, Supplier: McWhorter.		Sample ID: W1SW, Supplier McWhorter.	
Proximate analysis											
moisture	wt-%	42.81	48	28.82	41.4	38.35	46.8	20.85	37.2	48.12	54.3
volatiles	wt-% (d.s.)	82.2	77.1	82.3	78.1	83.4	78.1	83.5	77.5	83.0	78.8
fixed carbon	wt-% (d.s.)	14.0	21.4	14.4	21.0	13.4	21.6	12.8	21.2	14.6	20.8
ash (ashing temp 815 °C for Nablabs, 600 °C for Consol)	wt-% (d.s.)	1.4	1.5	0.9	0.9	0.4	0.3	0.8	1.3	0.2	0.4
Ultimate analysis (dry solids)											
C	wt-% (d.s.)	50.1	50.4	49.1	49.5	50.8	51.1	49.0	49.2	51.0	51.5
H	wt-% (d.s.)	5.9	5.9	5.9	5.9	6.0	6.0	5.9	5.8	6.0	6.1
S	wt-% (d.s.)	0.02	0.02	0.01	0.02	0.01	0.02	0.02	0.02	0.01	0.02
O (diff.)	wt-% (d.s.)	42.2	42.0	43.8	43.5	42.6	42.5	44.0	43.5	42.6	41.9
N	wt-% (d.s.)	0.34	0.15	0.30	0.21	0.24	0.10	0.27	0.18	0.17	0.10
Cl	wt-% (d.s.)	0.005	0.005	0.002	0.003	0.005	0.002	0.002	0.003	0.003	0.003
	wt-% (d.s.)	1.4	1.5	0.9	0.9	0.4	0.3	0.8	1.3	0.2	0.4
SUM		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Heating values											
HHV, dry	MJ/kg	21.09	20.30	19.25	19.80	19.51	20.60	19.59	19.70	19.85	21.00
HHV, wet	MJ/kg	12.06	10.56	13.70	11.60	12.03	10.96	15.51	12.37	10.30	9.60
LHV, dry	MJ/kg	2.15	2.42	2.42	2.54	2.00	2.40	2.56	2.78	1.75	2.03
LHV, wet	MJ/kg	1.85	1.90	2.08	2.01	1.73	1.88	2.23	2.19	1.50	1.61
LHV, ash free, dry	MJ/kg	1.82	1.87	2.06	1.99	1.72	1.88	2.21	2.16	1.50	1.60
LHV, ash free, wet	MJ/kg	1.82	1.87	2.06	1.99	1.72	1.88	2.21	2.16	1.50	1.60

FUEL TYPE		Sawdust, Pine		Bark, Pine		Whole tree chips, Hardwood		Whole tree chips, Pine		Tops & Limbs chips, pine	
ORIGIN		Columbia, Georgia		Columbia, Georgia		Emanuel, Georgia		Emanuel, Georgia		Long, Georgia	
PROJECT		Oglethorpe		Oglethorpe		Oglethorpe		Oglethorpe		Oglethorpe	
DATE		8/28/2008		8/28/2008		9/5/2008		9/8/2008		9/4/2008	
DESCRIPTION		Green sawdust collected from conveyor during operation on site; Loblolly saw timber		Dry bark collected from bark pile stored on mill site; Loblolly saw timber		Sample collected on site during chipping operation; Live Oak and Water oak, Sandy soil		Sample collected from chip van on site during chipping operation; 18 year Slash pine plantation; Sandy soil		Collected on site during chipping operation; Loblolly	
HANDLED BY:		E. Smith		E. Smith		E. Smith		E. Smith		D. Davis	
ANALYZED BY:		Consol Energy	Nablabs	Consol Energy	Nablabs	Consol Energy	Nablabs	Consol Energy	Nablabs	Consol Energy	Nablabs
REMARK:		Sample ID: W2SM1, Supplier: Pollard.		Sample ID: W2SM3, Supplier: Pollard.		Sample ID: A1HW, Supplier: Collins.		Sample ID: A1SW, Supplier: Collins.		Sample ID: A2ST, Supplier: Collins.	
Proximate analysis											
moisture	wt-%	29.37	28.8	42.26	44	33.01	38.1	34.79	40.8	44.25	48
volatiles	wt-% (d.s.)	83.4	78.6	69.6	67.0	77.2	77.8	79.9	77.3	81.8	75.8
fixed carbon	wt-% (d.s.)	14.1	21.1	26.4	31.4	15.8	20.7	17.8	22.3	14.5	19.8
ash (ashing temp 815 °C for Nablabs, 600 °C for Consol)	wt-% (d.s.)	0.3	0.3	1.7	1.6	5.3	1.5	0.5	0.5	1.0	4.4
Ultimate analysis (dry solids)											
C	wt-% (d.s.)	51.6	51.1	54.2	54.2	47.2	49.3	51.0	52.1	50.0	49.0
H	wt-% (d.s.)	6.1	6.0	5.3	5.4	5.4	5.9	5.8	6.1	5.7	5.7
S	wt-% (d.s.)	0.01	0.02	0.03	0.03	0.02	0.02	0.01	0.02	0.01	0.02
O (diff.)	wt-% (d.s.)	41.8	42.5	38.5	38.5	41.7	43.1	42.5	41.2	43.1	40.8
N	wt-% (d.s.)	0.14	0.10	0.30	0.22	0.29	0.18	0.26	0.12	0.20	0.10
Cl	wt-% (d.s.)	0.002	0.002	0.007	0.007	0.005	0.003	0.001	0.004	0.003	0.004
	wt-% (d.s.)	0.3	0.3	1.7	1.6	5.3	1.5	0.5	0.5	1.0	4.4
SUM		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Heating values											
HHV, dry	MJ/kg	20.06	20.70	21.14	21.30	20.36	19.60	21.26	21.40	19.46	19.70
HHV, wet	MJ/kg	14.17	14.74	12.21	11.93	13.64	12.13	13.86	12.67	10.85	10.24
LHV, dry	MJ/kg	2.35	3.15	3.71	3.94	3.11	2.69	2.78	2.88	1.98	2.48
LHV, wet	MJ/kg	2.02	2.49	2.73	2.70	2.62	2.14	2.29	2.24	1.69	1.99
LHV, ash free, dry	MJ/kg	2.02	2.48	2.69	2.66	2.48	2.10	2.28	2.23	1.67	1.90
LHV, ash free, wet	MJ/kg	2.02	2.48	2.69	2.66	2.48	2.10	2.28	2.23	1.67	1.90

FUEL TYPE		Whole tree chips, Hardwood		Clean chips/ Bark, Pine		Whole tree chips, Pine		Clean chips/ Bark	
ORIGIN		Tatanall, Georgia		Tatanall, Georgia		Echols, Georgia		Washington, Georgia	
PROJECT		Oglethorpe		Oglethorpe		Oglethorpe		Oglethorpe	
DATE		9/10/2008		9/9/2008		9/10/2008		9/9/2008	
DESCRIPTION		Collected during operation on site; Low wet flat; Black gum		Collected during chip mill operation on site; Slash		Collected on site during chipping operation; Loblolly		Clean chips from pulpwood collected during operation on sit; Bark unhogged, Loblolly	
HANDLED BY:		E. Smith		E. Smith		R. Clealand		E. Smith	
ANALYZED BY:		Consol Energy	Nablabs	Consol Energy	Nablabs	Consol Energy	Nablabs	Consol Energy	Nablabs
REMARK:		Sample ID: A2HW, Supplier: Collins.		Sample ID: A2SW, Supplier: Fullghum.		Sample ID: E2SW, Supplier:Fulghum		Sample ID: W2SW, Supplier: Fulghum	
Proximate analysis									
moisture	wt-%	31.79	43.7	43.52	48.8	44.93	50	39.98	44.2
volatiles	wt-% (d.s.)	83.0	78.9	82.0	78.1	78.9	76.8	75.9	71.9
fixed carbon	wt-% (d.s.)	13.8	20.3	16.9	21.4	18.4	21.7	16.7	20.7
ash (ashing temp 815 °C for Nablabs, 600 °C for Consol)	wt-% (d.s.)	1.0	0.8	0.7	0.5	1.4	1.5	5.7	7.4
Ultimate analysis (dry solids)									
C	wt-% (d.s.)	48.4	49.4	50.2	51.8	50.3	50.0	48.2	48.0
H	wt-% (d.s.)	5.7	5.9	5.8	6.1	5.8	5.8	5.4	5.6
S	wt-% (d.s.)	0.02	0.02	0.01	0.02	0.02	0.03	0.01	0.02
O (diff.)	wt-% (d.s.)	44.5	43.6	43.1	41.5	42.1	42.4	40.4	38.9
N	wt-% (d.s.)	0.35	0.22	0.25	0.12	0.36	0.27	0.20	0.10
Cl	wt-% (d.s.)	0.006	0.007	0.002	0.004	0.006	0.006	0.001	0.002
	wt-% (d.s.)	1.0	0.8	0.7	0.5	1.4	1.5	5.7	7.4
SUM		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Heating values									
HHV, dry	MJ/kg	18.82	19.90	19.66	21.20	19.59	20.20	18.90	19.40
HHV, wet	MJ/kg	12.84	11.20	11.10	10.85	10.79	10.10	11.34	10.83
LHV, dry	MJ/kg	2.19	2.36	2.00	2.38	2.28	2.34	2.73	3.04
LHV, wet	MJ/kg	1.88	1.89	1.66	1.87	1.86	1.83	2.27	2.41
LHV, ash free, dry	MJ/kg	1.87	1.87	1.65	1.86	1.83	1.81	2.14	2.23
LHV, ash free, wet	MJ/kg	1.87	1.87	1.65	1.86	1.83	1.81	2.14	2.23

CONSOL ENERGY

Customer: K. Faulkner
Company: Oglethorpe Power
Date: 9/19/2008

					Concentration (Wt %, Dry Basis)								Concentration (ppm, Dry Basis)		Wt %, Dry Basis	BTU/lb, Dry Basis	lbs/mmBTU
Lab Number	**Date Received**	**Customer Sample Number**	**Customer Sample Designation**	**Sample Description**	**Total Moisture at 103 C**	**Moisture at 103 C**	**Volatile Matter**	**Ash at 600 C**	**Fixed Carbon (by difference)**	**Carbon**	**Hydrogen**	**Nitrogen**	**Sulfur**	**Chlorine**	**Oxygen (by difference)**	**Heating Value**	**SO2**
20084240	9/2/2008	21	W1HM1	Warren, Sawdust, Hwd, Timberman (Not Resized)	48.70	3.81	83.11	0.57	12.52	49.16	6.04	0.25	122	10	43.97	8045	0.0303
20084241	9/2/2008	22	W1SM2	Warren, Shavings, Pine, Timberman (Sample taken due to availability)	12.20	2.11	82.17	0.43	15.30	50.38	6.04	0.12	90	19	43.03	8328	0.0216
20084242	9/2/2008	23	W1HM3	Warren, Bark, Hwd, Timberman	36.00	2.27	73.47	6.91	17.36	49.25	5.13	0.29	362	15	38.42	8117	0.0892
20084306	9/4/2008	16	A1SM1	Appling, Sawdust, Pine, Rayonier (Not Resized)	26.57	2.43	83.54	0.44	13.59	51.48	5.95	0.18	118	24	41.95	9133	0.0258
20084307	9/4/2008	18	A1SM3	Appling, Bark, Pine, Rayonier	53.04	1.77	69.59	3.07	25.57	53.37	4.87	0.29	220	48	38.39	8330	0.0528
20084328	9/8/2008	2	A1HT	Sample taken from Liberty County, (near coast, < 5mi.)	42.81	2.40	82.19	1.40	14.02	50.10	5.93	0.34	211	54	42.22	9065	0.0466
20084329	9/8/2008	7	E1HW	Echols, Whole Tree, Hwd, Langdale (Additional Testing Added)	28.82	2.37	82.31	0.94	14.38	49.10	5.86	0.30	136	18	43.80	8274	0.0329
20084330	9/8/2008	8	E1SW	Echols, Whole Tree, Pine, Langdale	38.35	2.85	83.38	0.35	13.42	50.80	5.97	0.24	69	54	42.63	8387	0.0165
20084331	9/8/2008	11	W1HW	Wilkes Co., WT, McWhorter Logging, Dried out (Additional Testing Added)	20.85	2.83	83.51	0.82	12.84	49.00	5.87	0.27	201	23	44.04	8422	0.0477
20084332	9/8/2008	12	W1SW	Wilkes Co., Whole Tree, Pine, McWhorter Logging Inc.	48.12	2.31	82.96	0.16	14.57	51.00	6.04	0.17	102	28	42.63	8533	0.0239
20084333	9/8/2008	19	W2SM1	Warren, Sawdust, Pine, Pollard (Not Resized)	29.37	2.23	83.39	0.32	14.06	51.60	6.10	0.14	91	15	41.84	8625	0.0211
20084334	9/8/2008	20	W2SM3	Warren, Bark, Pine, Pollard	42.26	2.36	69.60	1.66	26.38	54.22	5.28	0.30	280	74	38.53	9087	0.0616
20084392	9/11/2008	1	A1HW	Emanuel Co., Whole Tree, Hwd, Collins	33.01	1.67	77.23	5.33	15.78	47.20	5.42	0.29	155	49	41.74	8755	0.0354
20084392	9/11/2008	1	A1HW	Emanuel Co., Whole Tree, Hwd, Collins**RECHECK**				5.35									
20084393	9/11/2008	3	A1SW	Emanuel Co., Whole Tree, Swd, Collins	34.79	1.81	79.93	0.51	17.75	50.99	5.77	0.26	106	14	42.46	9140	0.0232
20084394	9/11/2008	5	A2ST	Long County, T&L, Pine, Mike Collins	44.25	2.64	81.79	1.03	14.54	50.02	5.68	0.20	91	31	43.06	8367	0.0218
20084401	9/12/2008	4	A2HW	Tattnall, WT, Hwd, Collins **(Omitted from C-ZMW, due to timing reasons)**	31.79	2.17	82.96	1.04	13.83	48.41	5.67	0.35	189	61	44.51	8091	0.0467
20084402	9/12/2008	6	A2SW	Tattnall County, mix of clean chips & bark, Fulghum mills **(Herty to blend)**	43.52	0.40	82.02	0.66	16.92	50.19	5.83	0.25	92	22	43.05	8453	0.0218
20084403	9/12/2008	10	E2SW	Echols Co., WT, Swd, Fulghum **(Omitted from C-ZMW, due to timing reasons)**	44.93	1.25	78.90	1.42	18.43	50.31	5.75	0.36	221	63	42.13	8424	0.0525
20084404	9/12/2008	14	W2SW	Washington County, mix of clean chips & bark, Fulghum mills **(Herty to blend)**	38.98	1.65	75.94	5.72	16.69	48.20	5.43	0.20	98	13	40.44	8127	0.0241
20084404	9/12/2008	14	W2SW	Washington County, mix of clean chips & bark, Fulghum mills**RECHECK**				5.52									
ASTM Coal Repeatability Limit where x = Average of Duplicate Concentrations.					**0.42**	**0.20+0.012x**	**0.29+0.014x**	**0.07+0.020x**		**0.64**	**0.16**	**0.11**		**1.92 +0.06x**	**2.89+0.09x**	**50**	

ASTM Repeatability Limit is the value below which the absolute difference between two test results of separate and consecutive test determinations , carried out on the same sample in the same laboratory by the same operator using the same apparatus on samples taken at random from a single quantity of homogeneous material, may be expected to occur with a probability of approximately 95%

Parameter	**Method of Analysis Utilized by CONSOL R&D**	**Method of Analysis Referenced by Black & Veatch**
Total Moisture	ASTM D3302	No Method Referenced
Proximate: Moisture, Volatile Matter, and Ash	ASTM D5142 with Temperatures Modified to Comply with ASTM E871 and ASTM E1102-84	Moisture: ASTM E871 Volatile Matter: ASTM E872 Ash: ASTM E830, ASTM D1102
Carbon, Hydrogen, and Nitrogen	ASTM D5373	Carbon: ASTM E777 Nitrogen: ASTM E778
Sulfur	ICP (caustic/peroxide/nitric acid digestion)	Sulfur: ASTM E775
Chlorine	ASTM D6721	Chlorine: ASTME776
Heating Value	ASTM D5865, Equivalent to ASTM E711	ASTM E711, ASTM D2015

All results meet laboratory quality control guidelines unless stated otherwise above. To the best of my knowledge all results are accurate. Services rendered by CONSOL Energy Inc, R&D are without warranty or liability of any kind beyond the cost of the analytical services.

Vince Conrad

Vincent B. Conrad Date: 9/19/08
Director of Technical Services

CONSOL ENERGY

Customer: K. Faulkner
Company: Oglethorpe Power
Date: 9/23/2008

Lab Number	Date Received	Customer Sample Number	Customer Sample Designation	Sample Description	(lb/ft^3, As Received Basis) Bulk Density	Size Distribution (Wt. %, As Received Basis) 1/2" x 1/4"	1/4" x 1/8"	1/8" x 8M	8M x 16M	16M x 60M	-60M
20084240	9/2/2008	21	W1HM1	Warren, Sawdust, Hwd, Timberman (Not Resized)	13.90	1.89	13.87	12.17	13.53	44.56	13.98
20084335	9/9/2008	33	C-YMMX	Blend of W1HM1, W1SM2, W2SM1, A1SM1 (Sample #s 16, 19, 21, & 22)	15.58	19.44	4.30	14.61	13.53	6.45	41.67
20084336	9/9/2008	34	C-YMM3	Blend of W1HM3, W2SM3, A1SM3 (Sample #s 18, 20 & 23)	17.80	21.56	13.48	7.57	17.11	8.27	32.01
20084395	9/11/2008	26	C-AMT	Blend of A1HT and A2ST (Sample #s 2 & 5)	19.16	5.71	27.32	47.55	9.35	3.47	6.60
20084396	9/11/2008	31	C-ZMW	Blend of A1SW, A1HW, E1SW, E1HW, W1SW, W1HW **(Real WT Chips)**	20.11	4.27	59.39	26.08	6.75	1.43	2.08
20084472	9/15/2008	32	C-ALL	Blend of all samples except E2HW, W2HW, X1MU, & A1SM2	20.34	6.48	37.72	21.86	9.46	4.37	20.11
ASTM Coal Repeatability Limit where x = Average of Duplicate Concentrations. Limit in Maroon Font is a CONSOL limit as no ASTM repeatability criteria have been established.					**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**

Lab Number	Date Received	Customer Sample Number	Customer Sample Designation	Sample Description	(lb/ft^3, As Received Basis) Bulk Density	Size Distribution (Wt. %, As Received Basis) +1"	1" x 1/2"	1/2" x 1/4"	1/4" x 1/8"	1/8" x 8M	-8M
20084397	9/12/2008	24	C-ASW	Blend of A1SW, A2SW (Sample #s 3 & 6)	12.67	<0.01	<0.01	2.84	37.72	51.50	7.94
20084398	9/12/2008	25	C-AHW	Blend of A1HW, A2HW (Sample #s 1 & 4)	9.59	<0.01	27.45	9.72	42.25	27.45	18.08
20084399	9/12/2008	27	C-ESW	Blend of E1SW, E2SW (Sample #s 8 & 10)	11.79	<0.01	<0.01	0.76	27.57	61.15	12.06
20084400	9/12/2008	29	C-WSW	Blend of W1SW, W2SW (Sample #s 12 & 14)	12.51	<0.01	<0.01	0.61	29.59	60.09	11.86
ASTM Coal Repeatability Limit where x = Average of Duplicate Concentrations. Limit in Maroon Font is a CONSOL limit as no ASTM repeatability criteria have been established.					**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**

Parameter	Method of Analysis Utilized by CONSOL R&D	Method of Analysis Referenced by Black & Veatch
Bulk Density	ASTM D6347	ASTM E873
Size Distribution	ASTM D4749	ASTM E323

CONSOL ENERGY

Customer: K. Faulkner
Company: Oglethorpe Power
Date: 9/23/2008

					Concentration (µg element/g of biomass leached, Dry Basis)			Ash Fusion Temperatures, Reducing Atmosphere (degrees Fahrenheit)				Ash Fusion Temperatures, Oxidizing Atmosphere (degrees Fahrenheit)			
Lab Number	**Date Received**	**Customer Sample Number**	**Customer Sample Designation**	**Sample Description**	**Soluble Na**	**Soluble K**	**Soluble Ca**	**IT**	**ST**	**HT**	**FT**	**IT**	**ST**	**HT**	**FT**
20084329	9/8/2008	7	E1HW	Echols, Whole Tree, Hwd, Langdale (Additional Testing Added)	47	849	207	2689	>2700	>2700	>2700	2358	2508	2563	2603
20084331	9/8/2008	11	W1HW	Wilkes Co., WT, McWhorter Logging, Dried out (Additional Testing Added)	15	1130	311	2445	>2700	>2700	>2700	>2700	>2700	>2700	>2700
20084335	9/9/2008	33	C-YMMX	Blend of W1HM1, W1SM2, W2SM1, A1SM1 (Sample #s 16, 19, 21, & 22)	24	768	342	2229	2285	2295	2328	2230	2241	2253	2267
20084336	9/9/2008	34	C-YMM3	Blend of W1HM3, W2SM3, A1SM3 (Sample #s 18, 20 & 23)	27	473	237	2488	2645	2688	>2700	2430	2530	2610	2673
20084395	9/11/2008	26	C-AMT	Blend of A1HT and A2ST (Sample #s 2 & 5)	42	650	226	2219	2275	2327	2536	2240	2270	2340	2580
20084396	9/11/2008	31	C-ZMW	Blend of A1SW, A1HW, E1SW, E1HW, W1SW, W1HW (Real WT Chips)	25	807	192	2130	2151	2194	2277	2130	2170	2220	2260
20084397	9/12/2008	24	C-ASW	Blend of A1SW, A2SW (Sample #s 3 & 6)	14	543	175	2091	2220	2239	2251	2140	2196	2210	2230
20084398	9/12/2008	25	C-AHW	Blend of A1HW, A2HW (Sample #s 1 & 4)	36	1310	188	2488	2645	2688	2731	2652	>2700	>2700	>2700
20084398	9/12/2008	25	C-AHW	Blend of A1HW, A2HW (Sample #s 1 & 4)-**RECHECK**		1290									
20084399	9/12/2008	27	C-ESW	Blend of E1SW, E2SW (Sample #s 8 & 10)	24	636	171	2088	2128	2150	2164	2127	2155	2177	2196
20084400	9/12/2008	29	C-WSW	Blend of W1SW, W2SW (Sample #s 12 & 14)	<10	434	149	2267	2470	2515	2608	2270	2567	2624	2672
20084472	9/15/2008	32	C-ALL	Blend of all samples except E2HW, W2HW, X1MU, & A1SM2	29	795	211	2251	2294	2313	2345	2248	2273	2291	2309
ASTM Coal Repeatability Limit where x = Average of Duplicate Concentrations. Limit in Maroon Font is a CONSOL limit as no ASTM repeatability criteria have been established.								**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**

Parameter	**Method of Analysis Utilized by CONSOL R&D**	**Method of Analysis Referenced by Black & Veatch**
Water Soluble Alkalinity	30 minute leach with stirring in water at ~95 C. Analyze by ICP-AES	Leach overnight in water at 90 C. Analyze by ICPAES
Ash Fusion	ASTM D1857	ASTM D1857

CONSOL ENERGY

Customer: K. Faulkner
Company: Oglethorpe Power
Date: 9/23/2008

				Major Ash Elements, Concentration in 600C Ash (Wt %)											Wt% on the Ash, Dry Basis					
Lab Number	Date Received	Customer Sample Number	Customer Sample Designation	SiO_2	Al_2O_3	TiO_2	Fe_2O_3	CaO	MgO	Na_2O	K_2O	P_2O_5	SO_3	MnO_2	Mass Balance (assuming all elements as oxides)	CO_3	Ca as $CaCO_3$ (Based on CO_3)	Calcium as Ca	Ca (in excess of CO_3) as CaO	New Mass Balance (assuming all elements as oxides and Ca as CaO and $CaCO_3$)
20084335	9/9/2008	33	C-YMMX	25.20	5.30	0.20	1.85	33.53	3.24	0.27	4.82	1.55	1.50	1.15	78.61	28.20	47.04	23.97	7.24	99.36
20084336	9/9/2008	34	C-YMM3	50.51	4.82	0.18	2.59	16.81	3.44	0.57	5.79	1.98	1.38	0.92	88.99	---	---	12.02		---
20084395	9/11/2008	26	C-AMT	59.03	2.63	0.38	2.13	16.56	2.90	0.35	4.45	1.26	0.94	0.26	90.89	12.30	20.52	11.84	5.09	99.94
20084396	9/11/2008	31	C-ZMW	38.62	7.12	0.39	3.85	19.90	4.33	0.40	8.95	3.71	1.74	3.07	92.08	---	---	14.22		---
20084397	9/12/2008	24	C-ASW	28.94	4.17	0.25	3.19	24.34	7.33	0.37	12.01	4.28	3.25	2.99	91.12	---	---	17.40		---
20084398	9/12/2008	25	C-AHW	71.86	0.71	0.12	1.29	7.59	1.26	0.12	3.71	1.03	0.71	1.06	89.45	5.26	8.77	5.42	2.68	93.32
20084472	9/15/2008	32	C-ALL	45.68	3.27	0.26	3.49	19.96	3.03	0.28	5.23	2.16	1.17	1.31	85.84	17.50	29.19	14.27	3.64	98.71
Duplicate Concentrations. Limit in **Maroon Font** is a CONSOL limit as no ASTM repeatability criteria have been				-0.13+0.09x	0.17+0.06x	0.02+0.07x	0.13x	0.11x	0.02+0.08x	0.06+0.09x	0.06+0.11x	0.01+0.18x	**0.12x**	0.16x						

				ppm, Dry Basis		
Lab Number	Date Received	Customer Sample Number	Customer Sample Designation	Mercury in 500C Ash	Fluorine	Selenium
20084335	9/9/2008	33	C-YMMX	<0.005	4.62	0.062
20084336	9/9/2008	34	C-YMM3	<0.005	10.0	0.042
20084395	9/11/2008	26	C-AMT	<0.005	4.10	<0.040
20084396	9/11/2008	31	C-ZMW	<0.005	2.44	<0.040
20084397	9/12/2008	24	C-ASW	<0.005	2.66	<0.040
20084398	9/12/2008	25	C-AHW	<0.005	2.44	<0.040
20084472	9/15/2008	32	C-ALL	<0.005	1.78	<0.040
Duplicate Concentrations. Limit in **Maroon Font** is a CONSOL limit as no ASTM repeatability criteria have been				0.008+0.06x	10	**0.10x**

Parameter	Method of Analysis Utilized by CONSOL R&	Method of Analysis Referenced by Black & Veatch
Major Ash Elementals	ASTM D6349	ASTM D3682, D2795
Carbonate	ASTM D6316	No Method Referenced
Mercury	ASTM D6722	No Method Referenced
Fluorine	ASTM D5987	No Method Referenced
Selenium	ASTM D5987 Digestion; ASTMD6357	No Method Referenced

Explanation of Mass Balance Calculations:

1. Column R: Mass Balance:
This mass balance assumes that all of the major elements are present in the sample as the major oxides reported in Columns G through Q.

For coal samples, this mass balance should be 100%. In order to meet typical quality control criteria for coal samples and allowing for analytical error, this balance should be between 97 and 103%.

Because the mass balances calculated in Column U are much lower than 100%, it was apparent that an additional chemical species was also present in the ash.

2. Column S: CO_3:
From our experience with other prior biomass samples, we expected that the low mass balance was probably due to the presence of carbonate (CO_3) in the sample. To verify our expectation, we analyzed the CO_3 content on four of the ash samples by ASTM D6316.

The concentrations reported in column S confirm the presence of CO_3.

3. Column T: Ca as $CaCO_3$ (Based on CO_3):
The carbonate present in each ash sample is present as Calcium Carbonate, $CaCO_3$. In other words, all of the Calcium present in the ash samples exists as both CaO and $CaCO_3$.

Using the molecular weights of Ca, $CaCO_3$, and the concentration of CO_3 reported in Column S, the concentration of $CaCO_3$ present in the ash is reported.

3. Column U: Calcium as Ca:
By convention, it is assumed that all Ca in the sample is present as CaO (reported in column K). The total Ca concentration is back-calculated from the molecular weight and reported concentration of CaO.

4. Column V: Ca (in excess of CO_3) as CaO:
To determine how much of the Calcium present is actually present as CaO, we subtract the Ca concentration from $CaCO_3$ from the total Ca. The deficit Ca is then calculated as CaO using molecular weight.

5. Column W: Mass Balance (assuming all elements as oxides and Ca as CaO and $CaCO_3$):
A final mass balance is calculated by summing the oxide concentrations of the typical major ash elements (other than CaO), the total Ca, the CO_3, and the calculated CaO concentration.

CONSOL ENERGY

Customer: K. Faulkner
Company: Oglethorpe Power
Date: 9/23/2008

Lab Number	Date Received	Customer Sample Number	Customer Sample Designation	Sample Description	ppm, Dry Basis Mercury in Biomass
20084306	9/4/2008	16	A1SM1	Appling, Sawdust, Pine, Rayonier (Not Resized)	<0.005
20084329	9/8/2008	7	E1HW	Echols, Whole Tree, Hwd, Langdale (Additional Testing Added)	<0.005
20084331	9/8/2008	11	W1HW	Wilkes Co., WT, McWhorter Logging, Dried out (Additional Testing Added)	<0.005
20084335	9/9/2008	33	C-YMMX	Blend of W1HM1, W1SM2, W2SM1, A1SM1 (Sample #s 16, 19, 21, & 22)	0.008
20084336	9/9/2008	34	C-YMM3	Blend of W1HM3, W2SM3, A1SM3 (Sample #s 18, 20 & 23)	<0.005
20084395	9/11/2008	26	C-AMT	Blend of A1HT and A2ST (Sample #s 2 & 5)	<0.005
20084396	9/11/2008	31	C-ZMW	Blend of A1SW, A1HW, E1SW, E1HW, W1SW, W1HW (Real WT Chips)	<0.005
20084397	9/12/2008	24	C-ASW	Blend of A1SW, A2SW (Sample #s 3 & 6)	<0.005
20084398	9/12/2008	25	C-AHW	Blend of A1HW, A2HW (Sample #s 1 & 4)	<0.005
20084399	9/12/2008	27	C-ESW	Blend of E1SW, E2SW (Sample #s 8 & 10)	<0.005
20084400	9/12/2008	29	C-WSW	Blend of W1SW, W2SW (Sample #s 12 & 14)	<0.005
20084472	9/15/2008	32	C-ALL	Blend of all samples except E2HW, W2HW, X1MU, & A1SM2	<0.005
ASTM Coal Repeatability Limit where x = Average of Duplicate Concentrations.					0.008+0.06x

Parameter	Method of Analysis Utilized by CONSOL R&D	Method of Analysis Referenced by Black & Veatch
Mercury	ASTM D6722	No Method Referenced

CONSOL ENERGY

Customer: K. Faulkner
Company: Oglethorpe Power
Date: 9/23/2008

Lab Number	Date Received	Customer Sample Number	Customer Sample Designation	Sample Description	ug/g Biomass, Dry Basis Ag	As	Ba	Cd	Cr	Ni	Pb
20084335	9/9/2008	33	C-YMMX	Blend of W1HM1, W1SM2, W2SM1, A1SM1 (Sample #s 16, 19, 21, & 22)	0.0137	0.141	78.7	0.0600	0.693	1.01	0.360
20084336	9/9/2008	34	C-YMM3	Blend of W1HM3, W2SM3, A1SM3 (Sample #s 18, 20 & 23)	0.0241	0.0483	14.6	0.0446	0.356	0.767	0.423
20084395	9/11/2008	26	C-AMT	Blend of A1HT and A2ST (Sample #s 2 & 5)	0.0148	0.0726	25.2	0.0135	0.753	0.917	0.470
20084396	9/11/2008	31	C-ZMW	Blend of A1SW, A1HW, E1SW, E1HW, W1SW, W1HW (Real WT Chips)	0.0167	0.0380	18.3	0.0487	0.457	0.625	0.277
20084472	9/15/2008	32	C-ALL	Blend of all samples except E2HW, W2HW, X1MU, & A1SM2	0.0141	0.0394	28.0	0.0490	0.423	0.625	0.334
ASTM Coal Repeatability Limit where x = Average of Duplicate Concentrations. Limit in Maroon Font is a CONSOL limit as no ASTM repeatability criteria have been established.						0.42+0.29x		0.03+0.16x	1.03+0.09x	0.35+0.13x	0.26+0.16x

Parameter	Method of Analysis Utilized by CONSOL R&D	Method of Analysis Referenced by Black & Veatch
Trace Elements	ASTM D6357	

Customer: K. Faulkner
Company: Oglethorpe Power
Date: 9/23/2008

Lab Number	Date Received	Customer Sample Number	Customer Sample Designation	Sample Description	mg/L in TCLP leachate solution								
					Ag	As	Ba	Cd	Cr	Hg	Ni	Pb	Se
20084472	9/15/2008	32	C-ALL	Blend of all samples except E2HW, W2HW, X1MU, & A1SM2	0.012	<0.05	9.2	<0.001	0.049	0.0024	<0.001	<0.01	0.028

Parameter	Method of Analysis Utilized by CONSOL R&D	Method of Analysis Referenced by Black & Veatch
TCLP Metals	EPA SW846, Methods 1311, 200.7, 245.7	

FACTOR DEVELOPMENT FOR BOILER HAP/TAP BIOMASS EMISSIONS

Based on AP-42 background data as well as engineering knowledge from boiler manufacturers, fluidized bed combustion (FBC) boilers have more complete combustion than other biomass boiler types and thus, lower organic compound emissions.[112] Emissions data for organic compounds from non-FBC boilers therefore are not expected be representative of the proposed Oglethorpe biomass boiler organic compound emissions and will likely overestimate such emissions.

In contrast to organic compounds, the variations in boiler combustion technologies are not expected to have much impact on filterable particulate compounds. Rather, the control technology employed will primarily impact the emissions of filterable particulate compounds. ESPs and baghouses (fabric filters) are commonly employed for new biomass boilers and are superior to venturi scrubbers and multiclones. As such, all biomass boilers with ESPs or baghouses would be expected to be representative of the Oglethorpe biomass boiler particulate emissions (though recognizing that the proposed boiler will have higher particulate removal efficiency than most or all existing units).

AP-42 SECTION 1.6 EMISSION FACTORS

U.S. EPA's AP-42 Section 1.6, dated September 2003, includes emission factors for the combustion of wood residue in industrial boilers.[113] Tables 1.6-3 and 1-6.4 include emission factors for a number of speciated organic and metal compounds, respectively. Although Section 1.6 is dated September 2003, the introductory text in this chapter notes that the emission factors were last updated in July 2001.

AP-42 Factor Development Methodology

As part of the background data for AP-42 Section 1.6, U.S. EPA makes available a background report as well as an emission factor spreadsheet containing the test data analyzed during the emission factor development process.[114] The report outlines the sources of the test data as well as how the data were analyzed. The background report specifies the following criteria were used in the development of the emission factors:

- ▲ Incomplete data were deleted and not considered further.
- ▲ Sources determined to be combusting non-representative wood residues were excluded (i.e., sources with large percentage of urban wood).
- ▲ F-factor of 9,240 dscf/MMBtu (from Method 19 of Appendix A of 40 CFR 60) was used to convert data to lb/MMBtu basis if site-specific F-factor was unavailable.

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[112] For example, refer to the Babcock & Wilcox BFB technical paper: DeFusco, J.P. et al. *BFB or Stoker – Which is the Right Choice for Your Renewable Energy Project?* May 2007. Available at: http://www.babcock.com/library/pdf/BR-1802.pdf

[113] U.S. EPA, *Wood Residue Combustion in Boilers,* September 2003. Available on-line at: http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s06.pdf

[114] Eastern Research Group, *Background Document Report on Revisions to 5th Edition AP-42 Section 1.6 Wood Residue Combustion in Boilers*. July 2001. Report available on-line at: http://www.epa.gov/ttn/chief/ap42/ch01/bgdocs/b01s06.pdf Emission factor file available on-line at: http://www.epa.gov/ttn/chief/ap42/ch01/related/c01s06.html

- Non-detect values were not used in the average factor development when they were greater than detect values.
- Non-detect values that were less than the cumulative average value were divided in half and used in the average factor development.
- For test runs with 3 non-detect values that yielded an average that was the maximum of all the data sets considered, the test was excluded.
- In general, separate factors for FBC and non-FBC boilers were not made. Only a separate CO emission factor is provided for FBC boilers.
- All factors for speciated organic compounds were grouped together, regardless of boiler type, since they were relatively small.

Emission factors were assigned ratings in accordance with U.S. EPA's *Procedures for Preparing Emission Factor Documents*.[115] The five emission factor ratings are A-E.

- A – Excellent
- B – Above average
- C – Average
- D – Below average
- E – Poor

Review of Data Sources

The PROCESS tab of the AP-42 Section 1.6 background data emission workbook lists the individual test reports (not emission factors) evaluated for the AP-42 factor development and assessment. Table 1 lists the breakdown of the boiler types associated with each of these test reports.

TABLE 1. AP-42 SECTION 1.6 TEST REPORTS EVALUATED

Boiler Type	Number of Tests	Percentage of Tests
Stoker	263	59.8%
Dutch Oven	33	7.5%
Gasifier	1	0.2%
FBC	34	7.7%
Not Reported	109	24.8%
Total	440	100%

[115] U.S. EPA OAQPS, *Procedures for Preparing Emission Factor Documents*. EPA-454/R-95-015 Revised, November 1997. Available on-line at: http://www.epa.gov/ttn/chief/efdocs/procedur.pdf

As Table 1 illustrates, the overwhelming majority of the test reports evaluated for inclusion in the September 2003 version of AP-42 Section 1.6 are from stoker boilers; FBC boilers comprised less than 8% of the test reports evaluated.

As the test reports include a number of emission factors, data from the Process and Emissions tabs were combined using VLOOKUP functions in a new worksheet tab to facilitate data evaluation. The breakdown of boiler types associated with the emission factors themselves is presented in Table 2. As with the test data, stoker boilers dominate the data set while FBC boilers are a small portion of the overall data set.

TABLE 2. AP-42 SECTION 1.6 EMISSION FACTORS EVALUATED

Boiler Type	Number of Factors	Percentage of Factors
Stoker	1,320	58.2%
Dutch Oven	209	9.2%
Gasifier	1	0.04%
FBC	293	12.9%
Not Reported	445	19.6%
Total	2,268	100%

Of the HAP and TAP factors included in Tables 1.6-3 and 1.6-4, more than 70% of the factors have C or lower emission factor ratings with almost half of the factors having a D rating (the lowest rating included). Table 3 summarizes the number of emission factors for each rating.

TABLE 3. AP-42 SECTION 1.6 EMISSION FACTOR RATINGS

Rating	Number of Factors	Percentage of Factors
A	19	16.8%
B	13	11.5%
C	28	24.8%
D	53	46.9%
E	0	0%
Total	113	100%

Given the dominance of non-FBC boiler test and emission factor data as well as the relatively poor ratings for most of the AP-42 emission factors, one may question whether the AP-42 factors (which lump the data) are representative of the proposed Oglethorpe boiler's anticipated emissions.

Lastly, the specific pollutants listed in AP-42 Tables 1.6-3 and 1.6-4 were examined relative to emissions data in the AP-42 background data set. For FBC boilers, it was noted that tested emission factors were available in the background data set for the following pollutants but that no factors were listed in Table 1.6-3 or Table 1.6-4:

- ▲ 1,4-Dichlorobenzene
- ▲ Monochlorophenol
- ▲ Pentachlorobenzene
- ▲ Tetrachlorobenzene
- ▲ Tetrachlorophenol
- ▲ Trichlorobenzene

Section 3.2 of the background report for AP-42 Section 1.6 notes that data sets including only non-detect values were not included in the U.S. EPA average emission factor if those non-detect values were greater than detected values for the same pollutant from another set of data (i.e., different boiler or different stack test).[116] For all of the pollutants listed, except 1,4-Dichlorobenzene, only three test results were available. Below detection limit (BDL) results occurred in two tests for FBC boilers, and the stoker boiler test yielded a detect value lower than the BDL level. As such, the two FBC tests would have been discarded. The stoker test also appears to have been discarded since the facility, Pacific Oroville Power, combusted 30% urban wood waste during the test. It is possible U.S. EPA also discarded the two FBC boiler tests since they combusted some agricultural waste in addition to wood. As such, following the U.S. EPA factor development method, all three tests would have been discarded; thus, these pollutants are not included in the AP-42 tables per the U.S. EPA factor development methodology.

For 1,4-Dichlorobenzene, the same three test sets were available. However, the FBC boiler test sets were not BDL. As noted previously, U.S. EPA may have discarded all tests as non-representative of "typical" wood residue boilers. However, as the Oglethorpe boiler will be permitted to burn biomass, it may not be appropriate to exclude the FBC boiler tests solely because they included some agricultural waste (which is not defined). This source was included by Oglethorpe for further consideration in the FBC boiler factor assessment.

OTHER DATA SOURCES REVIEWED

Original Boiler MACT Database[117]

During the development of the original 40 CFR 63 Subpart DDDDD, Boiler MACT, U.S. EPA prepared an emissions database that contains some of the same test data as the AP-42 Section 1.6 database plus additional test data.[118] The database was downloaded, and a query used to create a table containing the relevant emission factor, process, and facility information. The data were then copied

[116] For example, if the Boiler A average is based on only BDL value while Boilers B and C have detected values that are lower than the Boiler A detection level, Boiler A data were not included in the AP-42 factor. If, however, the Boiler A detection level was lower than the Boiler B and/or C detected emissions, it was included.

[117] Data evaluated are those associated with the Boiler MACT as originally promulgated in 2004. Since that time, the rule was vacated. In Fall 2008, U.S. EPA collected additional data as part of an effort to prepare a new version of the rule. The additional collected data have not been made available to the public and are still undergoing U.S. EPA review.

[118] Access 1997 database available on-line at: http://www.epa.gov/ttn/atw/combust/boiler/etdbas.mdb

into Excel and edited to remove all non-wood or non-biomass test results; results for combination firing of wood or biomass with other fuels (i.e., coal, sludge) were also removed.

Next, Oglethorpe evaluated the specific boiler type for each test data set, using the same classes as the AP-42 Section 1.6 background emission factor data sets. To make the assignments, information from the unit description entries were used as well as matching the test ID numbers and/or names with the process data tab from the AP-42 background data set.

TABLE 4. ORIGINAL BOILER MACT EMISSION FACTORS EVALUATED

Boiler Type	Number of Factors	Percentage of Factors
Stoker	2,386	60.2%
Dutch Oven	151	3.8%
Fuel Cell	94	2.4%
FBC	758	19.1%
Not Reported	573	14.5%
Total	3,962	100%

As Table 4 illustrates, the overwhelming majority of the test reports evaluated for development of the original Boiler MACT are from stoker boilers although FBC boilers comprise almost 20% of the emission factors in the dataset evaluated, more than double the percentage of FBC boiler data used in the AP-42 factor development.

Note that while the Boiler MACT data set appears to have included many more data than the AP-42 Section 1.6 emissions factor development data set, overlap between the two sets does exist. To identify data that overlapped, Oglethorpe looked at the ID numbers themselves between the two data sets as well as comparing the facility/location/tested unit name/similar results. For example, the test set with AP22 as the AP-42 ID and E266 as the Boiler MACT ID were determined to be the same even though the name was not reported in the AP-42 test set; however, the boiler sizes, fuel descriptions, steaming rates (capacity and actual during test run), and location all aligned.[119]

The Boiler MACT data set includes FBC test results from 5 facilities with multiple tests at the facilities. In considering these facilities, Oglethorpe did not exclude any as non-representative of the proposed Oglethorpe boiler even though some units may burn fuels such as urban wood waste or agricultural waste (hulls, pits) that may not be a permitted fuel for the Oglethorpe proposed boiler.

[119] Note that the emission rates between these sources did not perfectly align in the two databases. The AP-42 test values were slightly higher than the Boiler MACT factors, likely due to usage of different heat input factors or other data used to convert ppm or lb/ton factors to a lb/MMBtu basis. AP-42 factors were conservatively used since they were higher in magnitude.

Maine DEP Acrolein Emission Factor

Concern has been expressed by the Maine Department of Environmental Protection (Maine DEP) to U.S. EPA on the appropriateness of the AP-42 Section 1.6 acrolein factor:[120]

> *…the emission factor for the largest Maine acrolein source category, wood/biomass boilers, is 4.04E-03 lb/MMBtu in AP-42, compared to the Boiler MACT emission factor of 9.47E-06 lb/MMBtu. The consequences of using an emission factor that may be orders of magnitude different than actual emissions include inaccurate risk assessments, poor resource allocation, and improper regulatory oversight.*

In a response letter, U.S. EPA does not specifically comment on the acrolein factor but does note:[121]

> *My office is in the process of revamping the emissions factors program in order to address concerns such as those expressed by your Committee. … as mentioned in the Introduction to AP-42, Volume I, Fifth Edition, the use of emissions factors may not be appropriate in all situations, particularly for emissions limits, standards, source-specific permit limits, and/or in compliance determinations… users should be aware of the limitations in accurately representing a particular facility.*

The Maine Air Toxics Inventory (MATI) in fact uses two different acrolein factors for wood combustion emissions. For pulp and paper mill boilers, MATI uses a National Council on Air and Stream Improvements (NCASI) factor of 7.8E-05 lb/MMBtu of wood combustion and a factor of 0.036 lb/ton of wood based on the AP-42 factor and 9 MMBtu/ton wood.[122] The NCASI factor is a 50 times smaller than the AP-42 factor of 4.03E-03 lb/MMBtu. To help address these discrepancies, Maine DEP had facilities conduct acrolein testing in 2006 and 2007; these tests yielded emissions ranging from <2.46E-07 to <1.45E-04 lb/MMBtu with an average of <2.98E-05 lb/MMBtu and a median of <9.86E-07 lb/MMBtu.[123]

Maine DEP has recently revised their recommended acrolein factor for biomass combustion in the 2008 annual emissions inventory factor workbook to 7.40E-04 lb/ton of wood based on NCASI guidance.[124] Using the same AP-42 heat input factor of 9 MMBtu/ton of wood, this is equivalent to

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[120] Letter from Mr. David P. Littell (Maine DEP) to Mr. Steve Page (U.S. EPA OAQPS), dated April 19, 2006. Available on-line at: http://maine.gov/dep/air/toxics/SAS_Ltr_to_S_Page.doc

[121] Letter to Mr. David P. Littell (Maine DEP) from Mr. Steve Page (U.S. EPA OAQPS), dated October 2, 2006. Available on-line at: http://maine.gov/dep/air/toxics/mati_docs/EPA-EF-letter-10-12-06.pdf

[122] Refer to the Excel workbook of MATI emissions. Available on-line at: http://maine.gov/dep/air/toxics/MATI_Inventory_Tox_Weight_.001_v3b.zip

[123] Maine Air Toxics Advisory Committee, *Recommended Air Toxics Strategy*, September 17, 2007 Revision. Refer to Table 3 in Appendix I. Available on-line at: http://mainegov-images.informe.org/dep/air/toxics/mati_docs/ATAC_2DEP_2007-06-26_v7.pdf

[124] Maine DEP Default Emission Factors for the Reporting of HAP in the 2008 Annual Emissions Inventory, March 2009. Available on-line at: http://maine.gov/dep/air/emissions/docs/DEP_Default_HAP_EFs%20revised.xls

8.2E-05 lb/MMBtu, significantly smaller than the AP-42 factor. Note that none of the other pollutants listed in the Maine DEP 2008 annual inventory factor workbook utilize NCASI factors.

While the Maine DEP test data and factors can be used to help describe the apparent flaws with the AP-42 emission factor, these data are from boilers of unknown types. As such, the data were not included in Oglethorpe's assessments.

California ARB Emission Factor Database

The California Air Resources Board (CARB) has developed an air emission factor inventory based on source test data.[125] These data, however, are based on measurements from the early 1990s and have not been updated since the mid-1990s. As such, the datasets used to develop the emission inventory should already be included in the datasets utilized for the current AP-42 Section 1.6 emission factor and/or the original Boiler MACT emission limit development. Data from the CARB emission inventory were not included in any of Oglethorpe's assessments.

NCASI Emission Factors

NCASI is the technical association for the wood products industry, and membership is restricted to dues-paying companies within the wood products industry. NCASI conducts research and develops publications pertaining to a number of technical subjects, including emissions factor developments. A number of emission factors have been developed by NCASI for wood residue combustion in boilers.

NCASI data access is limited to NCASI members unless it has been made publically available in technical reports for government agencies and/or used in specific applications or inventories that are publicly available (i.e., permit applications). NCASI emission factors are developed based on a more comprehensive set of data than AP-42 emission factors and include test factors from member companies as well as tests conducted by NCASI. Such data sets, however, generally include wood boilers as a whole and distinctions in HAP/TAP factors are not made for the various boiler types (i.e., stoker vs. FBC boilers).

A number of NCASI factors have been located in publicly available documents:

▲ Piedmont Green Power, LLC (Barnesville, GA) facility, June 2008 SIP permit application, boiler emissions calculations using Technical Bulletin No. 858 factors

▲ Maine DEP Default Emission Factors for the Reporting of HAP in the 2008 Annual Emissions Inventory, March 2009, comments for biomass factor cells[126]

▲ U.S. EPA docket document EPA-HQ-OAR-2006-0859-0254.1, emissions calculations for Bowater Newsprint South (Grenada, MS) submitted by Steven Moore for revisions to the 2002 NEI data based on Technical Bulletin No. 701 factors[127]

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[125] Available on-line at: http://www.arb.ca.gov/ei/catef/catef.htm Accessed April 2009.

[126] Maine DEP Default Emission Factors for the Reporting of HAP in the 2008 Annual Emissions Inventory, March 2009. Available on-line at: http://maine.gov/dep/air/emissions/docs/DEP_Default_HAP_EFs%20revised.xls

The NCASI factors were not used to develop factors specific to FBC boilers since the NCASI HAP data set is expected to be dominated by stoker boilers.

DEVELOPMENT OF FBC-SPECIFIC EMISSION FACTORS

Using the AP-42 Section 1.6 and original Boiler MACT background datasets, custom fluidized bed combustion (FBC) boiler organic emission factors were derived based solely on FBC boiler data.

As discussed in the previous sections, FBC boiler data that are likely to be representative of the proposed Oglethorpe boiler were identified. Care was taken to ensure that overlap between data sets was identified and duplicate entries were not double-counted.

The AP-42 and original Boiler MACT FBC boiler test results were combined and sorted via pollutant name. For units with results that were BDL, half of the detection level was used for the factor, consistent with U.S. EPA's approach for AP-42. Factors were then averaged to determine a representative factor for FBC boilers.

In general, all FBC boiler test factors were used to calculate the average factor. However, the following data were excluded:

- ▲ For particulate species included in the background data but not in the AP-42 Section 1.6 Table 1.6-3, tests from boilers without ESP or baghouse controls were excluded as boilers without these devices (i.e., with only a multiclone) will have relatively high emissions as compared to the well-controlled boilers and are not comparable to the proposed Oglethorpe boiler.
- ▲ Acrolein test factor cited as an outlier in Maine DEP memo was excluded as it was more than 1,000 times higher than other FBC boiler test data.[128]

A total of 85 factors were developed for various pollutants. Note factors for hydrogen chloride, mercury, and other particulate components listed in AP-42 Section 1.6 Table 1.6-4 were not developed since either proposed permit limit, vendor data, or AP-42 data were utilized for these factors.

Note a number of pollutants have FBC boiler emission factors but no AP-42 emission factors listed in Section 1.6 Tables 1.6-3 or 1.6-4. Most of these pollutants have factors based on ½ the detection limit. However, several of these pollutants are also HAP, and AP-42 methodologies specify including results below detection levels. Thus, Oglethorpe included the pollutants in the emission inventory.

Table 5 presents a summary of the AP-42 and custom FBC boiler emission factors.

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[127] Available on-line at:
http://www.regulations.gov/fdmspublic/ContentViewer?objectId=090000648026eee1&disposition=attachment&contentType=pdf

[128] Memo to Maine DEP MATI Emissions Inventory Subcommittee from Mr. David Dixon, *Dealing with Uncertainty of Acrolein Emissions in MATI Inventory*, dated November 1, 2005. Available on-line at: http://www.dirigo-air.com/news_and_views.htm

Table 5. FBC Biomass Boiler HAP Factor and Emissions Evaluation

Pollutant	VOC	HAP	AP-42 Section 1.6 Controlled Factor[1] (lb/MMBtu)	Custom FBC Boiler Controlled Factor[2] (lb/MMBtu)	Potential Emissions (tpy)[3] AP-42 Section 1.6 Factors	Potential Emissions (tpy)[3] FBC Custom Factors
1,1,1-Trichloroethane	No	Yes	3.10E-05	6.70E-06	1.74E-01	3.76E-02
1,2-Dibromoethene	Yes	Yes	5.50E-05	8.08E-06	3.09E-01	4.53E-02
2-Butanone (MEK)	Yes	No	5.40E-06	5.39E-06	3.03E-02	3.03E-02
2-Chloronaphthalene	Yes	Yes	2.40E-09	2.40E-09	1.35E-05	1.35E-05
2-Chlorophenol	Yes	No	2.40E-08	2.40E-08	1.35E-04	1.35E-04
Acenaphthene	Yes	Yes	9.10E-07	1.18E-07	5.11E-03	6.60E-04
Acenaphthylene	Yes	Yes	5.00E-06	2.61E-07	2.81E-02	1.46E-03
Acetaldehyde	Yes	Yes	8.30E-04	4.34E-05	4.66E+00	2.44E-01
Acetone	No	No	1.90E-04	2.15E-04	1.07E+00	1.21E+00
Acetophenone	Yes	Yes	3.20E-09	3.20E-09	1.80E-05	1.80E-05
Acrolein	Yes	Yes	4.00E-03	9.78E-06	2.25E+01	5.49E-02
Ammonia	No	No	N/A	2.46E-02	N/A	1.38E+02
Anthracene	Yes	Yes	3.00E-06	1.07E-07	1.68E-02	6.00E-04
Antimony	No	Yes	7.90E-08	7.90E-08	4.44E-04	4.44E-04
Arsenic	No	Yes	2.20E-07	2.20E-07	1.24E-03	1.24E-03
Barium	No	No	1.70E-06	1.70E-06	9.55E-03	9.55E-03
Benzaldehyde	Yes	No	8.50E-07	8.50E-07	4.77E-03	4.77E-03
Benzene	Yes	Yes	4.20E-03	1.39E-05	2.36E+01	7.81E-02
Benzo(a)anthracene	Yes	Yes	6.50E-08	7.53E-08	3.65E-04	4.23E-04
Benzo(a)pyrene	Yes	Yes	2.60E-06	4.39E-07	1.46E-02	2.46E-03
Benzo(b)fluoranthene	Yes	Yes	1.00E-07	7.53E-08	5.62E-04	4.23E-04
Benzo(e)pyrene	Yes	Yes	2.60E-09	2.10E-09	1.46E-05	1.18E-05
Benzo(g,h,i)perylene	Yes	Yes	9.30E-08	7.46E-08	5.22E-04	4.19E-04
Benzo(j,k)fluoranthene	Yes	Yes	1.60E-07	1.60E-07	8.98E-04	8.98E-04
Benzo(k)fluoranthene	Yes	Yes	3.60E-08	7.44E-08	2.02E-04	4.18E-04
Benzoic acid	Yes	No	4.70E-08	4.70E-08	2.64E-04	2.64E-04
Beryllium	No	Yes	1.10E-08	1.10E-08	6.18E-05	6.18E-05
Bis(2-ethylhexyl)phthalate	Yes	Yes	4.70E-08	4.70E-08	2.64E-04	2.64E-04
Bromomethane	Yes	Yes	1.50E-05	2.38E-06	8.42E-02	1.34E-02
Cadmium	No	Yes	4.10E-08	4.10E-08	2.30E-04	2.30E-04
Carbazole	Yes	Yes	1.80E-06	1.80E-06	1.01E-02	1.01E-02
Carbon tetrachloride	Yes	Yes	4.50E-05	4.95E-06	2.53E-01	2.78E-02
Chlorine	No	Yes	7.90E-04	7.90E-04	4.44E+00	4.44E+00
Chlorobenzene	Yes	Yes	3.30E-05	3.30E-05	1.85E-01	1.85E-01
Chloroform	Yes	Yes	2.80E-05	6.01E-06	1.57E-01	3.37E-02
Chromium	No	Yes	2.10E-07	2.10E-07	1.18E-03	1.18E-03
Chromium VI	No	Yes	3.50E-08	3.50E-08	1.97E-04	1.97E-04
Chrysene	Yes	Yes	3.80E-08	7.61E-08	2.13E-04	4.27E-04
Cobalt	No	Yes	6.50E-08	6.50E-08	3.65E-04	3.65E-04
Copper	No	No	4.90E-07	4.90E-07	2.75E-03	2.75E-03
o-Cresol	Yes	Yes	N/A	3.20E-06	N/A	1.80E-02
m-Cresol, p-Cresol	Yes	Yes	N/A	1.65E-06	N/A	9.27E-03
Crotonaldehyde	Yes	No	9.90E-06	9.90E-06	5.56E-02	5.56E-02
Decachlorobiphenyl	Yes	Yes	2.70E-10	4.34E-09	1.52E-06	2.44E-05
Dibenzo(a,h)anthracene	Yes	Yes	9.10E-09	8.66E-08	5.11E-05	4.86E-04
Dichlorobenzene	Yes	Yes	N/A	4.59E-07	N/A	2.58E-03
Dichlorobiphenyl	Yes	Yes	7.40E-10	1.57E-08	4.16E-06	8.79E-05
1,2-Dichloroethane	Yes	Yes	2.90E-05	1.17E-04	1.63E-01	6.55E-01
Dichlorophenol	Yes	No	N/A	2.16E-07	N/A	1.21E-03
1,2-Dichloropropane	Yes	Yes	3.30E-05	3.30E-05	1.85E-01	1.85E-01
2,4-Dinitrophenol	Yes	Yes	1.80E-07	1.80E-07	1.01E-03	1.01E-03
Ethanol	Yes	No	N/A	6.23E-06	N/A	3.50E-02
Ethylbenzene	Yes	Yes	3.10E-05	5.73E-07	1.74E-01	3.22E-03
Fluoranthene	Yes	Yes	1.60E-06	1.70E-07	8.98E-03	9.56E-04
Fluorene	Yes	Yes	3.40E-06	1.29E-07	1.91E-02	7.26E-04
Formaldehyde	Yes	Yes	4.40E-03	1.78E-04	2.47E+01	1.00E+00
HCl	No	Yes	1.76E-03	1.76E-03	9.90E+00	9.90E+00
HF	No	Yes	4.00E-04	4.00E-04	2.25E+00	2.25E+00
Heptachlorobiphenyl	Yes	Yes	6.60E-11	2.60E-09	3.71E-07	1.46E-05
Hexachlorobenzene	Yes	Yes	N/A	2.35E-07	N/A	1.32E-03
Hexachlorobiphenyl	Yes	Yes	5.50E-10	2.91E-09	3.09E-06	1.63E-05
Hexanal (hexaldehyde)	Yes	No	7.00E-06	4.52E-05	3.93E-02	2.54E-01
Heptachlorodibenzo-p-dioxins	Yes	Yes	2.00E-09	1.29E-08	1.12E-05	7.24E-05
Heptachlorodibenzo-p-furans	Yes	Yes	2.40E-10	1.60E-09	1.35E-06	8.98E-06
Hexachlorodibenzo-p-dioxins	Yes	Yes	1.60E-06	3.47E-09	8.98E-03	1.95E-05
Hexachlorodibenzo-p-furans	Yes	Yes	2.80E-10	3.18E-09	1.57E-06	1.78E-05
Indeno(1,2,3-c,d)pyrene	Yes	Yes	8.70E-08	7.43E-08	4.89E-04	4.17E-04
Iron	No	No	9.90E-06	9.90E-06	5.56E-02	5.56E-02
Isobutyraldehyde	Yes	No	1.20E-05	1.20E-05	6.74E-02	6.74E-02
Isobutyl alcohol	Yes	No	N/A	1.00E-05	N/A	5.62E-02
Lead	No	Yes	4.80E-07	4.80E-07	2.70E-03	2.70E-03
Manganese	No	Yes	1.60E-05	1.60E-05	8.98E-02	8.98E-02
Mercury	No	Yes	1.00E-06	1.00E-06	5.62E-03	5.62E-03
Methane	No	No	2.10E-02	2.10E-02	1.18E+02	1.18E+02
Methyl chloride (chloromethane)	Yes	Yes	2.30E-05	2.31E-05	1.29E-01	1.30E-01
2-Methylnaphthalene	Yes	Yes	1.60E-07	4.05E-08	8.98E-04	2.27E-04
Methylene chloride (dichloromethane)	No	Yes	2.90E-04	1.68E-06	1.63E+00	9.43E-03
Molybdenum	No	No	2.10E-08	2.10E-08	1.18E-04	1.18E-04
Monochlorobiphenyl	Yes	Yes	2.20E-10	6.02E-09	1.24E-06	3.38E-05
Monochlorophenol	Yes	No	N/A	2.35E-07	N/A	1.32E-03

Table 5. FBC Biomass Boiler HAP Factor and Emissions Evaluation

Pollutant	VOC	HAP	AP-42 Section 1.6 Controlled Factor[1] (lb/MMBtu)	Custom FBC Boiler Controlled Factor[2] (lb/MMBtu)	Potential Emissions (tpy)[3] AP-42 Section 1.6 Factors	Potential Emissions (tpy)[3] FBC Custom Factors
Naphthalene	Yes	Yes	9.70E-05	4.27E-06	5.45E-01	2.40E-02
Nickel	No	Yes	3.30E-07	3.30E-07	1.85E-03	1.85E-03
2-Nitrophenol	Yes	No	2.40E-07	2.40E-07	1.35E-03	1.35E-03
4-Nitrophenol	Yes	Yes	1.10E-07	1.10E-07	6.18E-04	6.18E-04
Nonachlorobiphenyl	Yes	Yes	N/A	2.88E-09	N/A	1.62E-05
Octachlorobiphenyl	Yes	Yes	N/A	2.04E-09	N/A	1.15E-05
Octachlorodibenzo-p-dioxins	Yes	Yes	6.60E-08	5.45E-09	3.71E-04	3.06E-05
Octachlorodibenzo-p-furans	Yes	Yes	8.80E-11	3.85E-10	4.94E-07	2.16E-06
Pentachlorodibenzo-p-dioxins	Yes	Yes	1.50E-09	7.08E-10	8.42E-06	3.98E-06
Pentachlorodibenzo-p-furans	Yes	Yes	4.20E-10	2.32E-09	2.36E-06	1.31E-05
Pentachlorobenzene	Yes	No	N/A	2.35E-07	N/A	1.32E-03
Pentachlorobiphenyl	Yes	Yes	1.20E-09	3.31E-09	6.74E-06	1.86E-05
Pentachlorophenol	Yes	Yes	5.10E-08	2.35E-07	2.86E-04	1.32E-03
2-Pentanone	Yes	No	N/A	1.16E-05	N/A	6.51E-02
Perylene	Yes	Yes	5.20E-10	2.27E-10	2.92E-06	1.27E-06
Phenanthrene	Yes	Yes	7.00E-06	3.39E-07	3.93E-02	1.91E-03
Phenol	Yes	Yes	5.10E-05	3.30E-06	2.86E-01	1.85E-02
Propanol	Yes	No	3.20E-06	8.10E-06	1.80E-02	4.55E-02
Phosphorus	No	Yes	2.70E-07	2.70E-07	1.52E-03	1.52E-03
Potassium	No	No	3.90E-04	3.90E-04	2.19E+00	2.19E+00
Propionaldehyde	Yes	Yes	6.10E-05	6.11E-05	3.43E-01	3.43E-01
Pyrene	Yes	Yes	3.70E-06	1.46E-07	2.08E-02	8.20E-04
Pyridine	Yes	No	N/A	3.20E-06	N/A	1.80E-02
Selenium	No	Yes	2.80E-08	2.80E-08	1.57E-04	1.57E-04
Silver	No	No	1.70E-05	1.70E-05	9.55E-02	9.55E-02
Sodium	No	No	3.60E-06	3.60E-06	2.02E-02	2.02E-02
Strontium	No	No	1.00E-07	1.00E-07	5.62E-04	5.62E-04
Styrene	Yes	Yes	1.90E-03	5.60E-07	1.07E+01	3.14E-03
2,3,7,8-Tetrachlorodibenzo-p-dioxins	Yes	Yes	8.60E-12	5.38E-12	4.83E-08	3.02E-08
Tetrachlorodibenzo-p-dioxins	Yes	Yes	4.70E-10	1.10E-10	2.64E-06	6.16E-07
2,3,7,8-Tetrachlorodibenzo-p-furans	Yes	Yes	9.00E-11	6.84E-11	5.05E-07	3.84E-07
Tetrachlorodibenzo-p-furans	Yes	Yes	7.50E-10	6.69E-10	4.21E-06	3.75E-06
Tetrachlorobenzene	Yes	No	N/A	2.35E-07	N/A	1.32E-03
Tetrachlorobiphenyl	Yes	Yes	2.50E-09	5.90E-09	1.40E-05	3.31E-05
Tetrachloroethene	No	Yes	3.80E-05	6.33E-06	2.13E-01	3.55E-02
Tetrachlorophenol	Yes	No	N/A	2.35E-07	N/A	1.32E-03
Thallium	No	No	N/A	1.26E-08	N/A	7.05E-05
Tin	No	No	2.30E-07	2.30E-07	1.29E-03	1.29E-03
Titanium	No	No	2.00E-07	2.00E-07	1.12E-03	1.12E-03
o-Tolualdehyde	Yes	No	7.20E-06	7.20E-06	4.04E-02	4.04E-02
p-Tolualdehyde	Yes	No	1.10E-05	1.10E-05	6.18E-02	6.18E-02
Toluene	Yes	Yes	9.20E-04	4.60E-06	5.17E+00	2.58E-02
Trichlorobiphenyl	Yes	Yes	2.60E-09	3.44E-08	1.46E-05	1.93E-04
Trichlorobenzene	Yes	Yes	N/A	2.35E-07	N/A	1.32E-03
Trichloroethylene (trichloroethene)	Yes	Yes	3.00E-05	6.61E-06	1.68E-01	3.71E-02
Trichlorofluoromethane	No	No	4.10E-05	5.40E-06	2.30E-01	3.03E-02
2,4,6-Trichlorophenol	Yes	Yes	2.20E-08	2.20E-08	1.24E-04	1.24E-04
Vanadium	No	No	9.80E-09	9.80E-09	5.50E-05	5.50E-05
Vinyl chloride	Yes	Yes	1.80E-05	3.51E-06	1.01E-01	1.97E-02
o-Xylene	Yes	Yes	2.50E-05	3.47E-06	1.40E-01	1.95E-02
m,p-Xylene	Yes	Yes	N/A	4.42E-06	N/A	2.48E-02
Yttrium	No	No	3.00E-09	3.00E-09	1.68E-05	1.68E-05
Zinc	No	No	4.20E-06	4.20E-06	2.36E-02	2.36E-02
VOC			**1.69E-02**	**7.08E-04**	**95.0**	**4.0**
Total HAP			**2.02E-02**	**3.56E-03**	**113.4**	**20.0**
Maximum Single HAP			**4.40E-03**	**1.76E-03**	**24.7**	**9.9**

1. AP-42 particulate factors based on assumption for baghouse control of 99%
2. AP-42 controlled factors are used for particulate components except for Thallium, which is based on ESP and/or baghouse-controlled boiler test data.
3. Based on maximum sustainable annual boiler biomass heat input: 1,282 MMBtu/hr
4. Factor presented is the annual factor to keep HCl emissions to 9.9 tpy.

APPENDIX D

BACT SUPPORTING INFORMATION

Boiler RBLC Summary Table
Economic Feasibility Analysis Calculations

Table D-1. Biomass Boiler RBLC and Permit Review Summary

ID	State	Facility	Unit	Boiler Type	Heat Input Capacity (MMBtu/hr)	New or Modified?	Unit Operating?	Fuels Unit is Permitted to Combust	Permit Date	Primary RBLC Fuel	CO BACT Limit (lb/MMBtu)	CO BACT Limit (ppm)	CO Averaging Period	CO Control Option	CO Compliance Method	NO_X BACT Limit (lb/MMBtu)	NO_X Averaging Period	NO_X Control Option	NO_X Compliance Method
AL-0198	AL	SMURFIT-STONE-STEVENSON	BOILER, NO.2 WOOD RESIDUE		620			Wood, NCG, Fuel Oil	9/30/2002	WOOD WASTE									
AL-0223	AL	STEVENSON MILL	NO. 2 WOOD-FIRED BOILER		620			Biomass	7/14/2006	BIOMASS									
AR-0072	AR	DEL TIN FIBER LLC	HEAT ENERGY SYSTEM	Gassifier	291			Biomass	2/28/2003	WOOD WASTE	0.78			Good Combustion Practices		0.3		LNB, SNCR	Unknown
AR-0083	AR	POTLATCH CORPORATION - OZAN UNIT	WOOD FIRED BOILER		175			Wood	7/26/2005	WOOD CHIPS	1.35			Good Combustion Practices		0.25		Good Combustion Practices	
CT-02	CT	PLAINFIELD RENEWABLE ENERGY	BOILER	FB Gasification	523.1	New	Not Yet	Biomass, biodiesel	2008	WOOD	0.105	103.7	30-day	Good Combustion Practices	CEMS	0.075	30-day	SNCR	CEMS
CT-03	CT	WATERTOWN RENEWABLE POWER	BOILER	FB Gasification	436	New	Not Yet	Biomass, Natural Gas (startup)	Draft 2009	WOOD	0.1	107.15	8-hour	Good Combustion Practices	CEMS	0.075	24-hour	SCR	CEMS
FL-0034	FL	U.S. SUGAR CLEWISTON MILL AND REFINERY	BOILER, TRAVELING GRATE	Grate	633			Bagasse, No. 6 Fuel Oil	11/29/2000	BAGASSE	6.5			Good Combustion Practices		0.2		Good Combustion Practices	
FL-0248	FL	US SUGAR CORPORATION	BOILER, BAGASSE, NO. 4		633			Bagasse, No. 6 Fuel Oil	11/19/1999	BAGASSE	6.5			Good Combustion Practices		0.2		Good Combustion Practices	
FL-0257	FL	CLEWISTON SUGAR MILL AND REFINERY	BOILER	Unknown	936			Bagasse, Diesel	11/18/2003	BAGASSE	0.38		annual	Good Combustion Practices		0.14	30-day	SNCR	Unknown
FL-0301	FL	CLEWISTON SUGAR MILL AND REFINERY	BOILER 7		738			Wood, Bagasse	12/6/2007	BAGASSE						0.31	3-hour	OFA, Good Combustion	
GA-0097	GA	INTERSTATE PAPER	MULTIFUEL BOILER	BFB	300			Wood, Oil, Gas, TDF, Sludge, Peat, Turpentii	12/30/2002	COMBINED	0.3		30-day	Good Combustion Practices		0.25	30-day	Fluidized Bed Design	
GA-0114	GA	INLAND PAPERBOARD AND PACKAGING, INC. - ROME	BOILER, SOLID FUEL		856			Bark, Sludge, TDF, Fuel Oil, NCG	10/13/2004	BARK		368		Staged Combustion					
GA-0117	GA	TRI-GEN BIOPOWER	BOILER, MULTIFUEL	BFB	302.2			Wood, Sludge	5/24/2001	WOODWASTE AND PAPERMILL SLUDGE	0.3			Good Combustion Practices					
GA-02	GA	YELLOW PINE ENERGY COMPANY	BOILER	BFB	1,529	New	Not Yet	Biomass, TDF, Propane, Fuel Oil	5/15/2009	BIOMASS	0.149		30-day	Good Combustion Practices	CEMS	0.10	30-day	SNCR	CEMS
GA-09	GA	PLANT CARL, GREEN ENERGY PARTNERS	BOILER	BFB	400	New	Not Yet	Biomass, Oil/Grease/Fat, Biodiesel, Chicken I	7/29/2008	BIOMASS	0.149		30-day	Oxidation Catalyst	CEMS			SNCR	CEMS
GA-04	GA	GREENWAY RENEWABLE POWER, LLC	BOILER		719	New	Not Yet	Biomass, biodiesel	7/19/2008	BIOMASS			annual	Good Combustion Practices	CEMS		Annual	SNCR	CEMS
GA-05	GA	PIEDMONT GREEN POWER, LLC	BOILER		719	New	Not Yet	Biomass, biodiesel	9/17/2008	BIOMASS			annual	Good Combustion Practices	CEMS		Annual	SNCR	CEMS
GA-08	GA	BIOMASS GAS & ELECTRIC	Gasifier/Combustor w/HRSG	Gassifier	372	New	Not Yet	Biomass	5/20/2008	BIOMASS				Good Combustion Practices	Stack Test		Annual	SCR	CEMS
IA-0083	IA	ROQUETTE AMERICA, INC.	CFB BOILER	CFB	996	New?		Coal, Petcoke, Biomass, TDF	8/16/2006	COAL	0.154	400	24-hour	Good Combustion Practices	CEMS	0.15	30-day	SNCR	CEMS
IA-0095	IA	TATE & LYLE INGREDIENTS AMERICAS, INC.	FIBER FIRED BOILERS AND GERM	Unknown	200	New	Not Yet	Corn Fibers, Gas, Biogas, Process Gas	9/19/2008	CORN FIBER	0.17	100	30-day	Good Combustion Practices	CEMS	0.129	30-day	SCR	CEMS
KY-0085	KY	MEADWESTVACO KENTUCKY, INC/WICKLIFFE	BOILER, BARK		631			Wood, Sludge, Oil, Gas, NCG	2/27/2002	BARK						0.4		Good Combustion Practices	
LA-0122	LA	INTERNATIONAL PAPER - MANSFIELD MILL	POWER BOILERS 1 & 2		760			Wood Waste, Coal, Oil, Gas, Recycle Fiber	8/14/2001	COMBINED						0.7		Good Combustion Practices	
LA-0125	LA	WEYERHAEUSER COMPANY, DODSON SAWMILL	WOOD FIRED BOILER (#017)	Unknown	233			Wood/Bark	10/29/2007	WOOD	0.82			Good Combustion Practices		0.21		Good Combustion Practices	
LA-0126	LA	JOYCE MILL, WEST FRASER	KIPPER BOILERS NO. 1 AND NO. 2 (EAC		58.3			Biomass	4/24/2002	WOOD WASTE	1.81			Good Combustion Practices					
LA-0126	LA	JOYCE MILL, WEST FRASER	MCBURNEY BOILER NO.4		154.2			Biomass	4/24/2002	WOOD WASTE	1.81			Good Combustion Practices					
LA-0174	LA	GEORGIA-PACIFIC - PORT HUDSON	BOILER 1		459.5	Modified	Yes	Wood, Natural Gas	1/25/2002	COMBINED	2.45			Good Combustion Practices		0.3		Good Combustion Practices	
LA-0178	LA	DERIDDER PAPER MILL, BOISE CASCADE	WOOD-FIRED BOILER		454.29			Wood, Gas, NCG	11/14/2003	BARK	0.33		annual	Good Combustion Practices					
LA-0188	LA	BOGALUSA MILL, INLAND PAPERBOARD	NO. 12 HOGGED FUEL BOILER	Has Grate	787.5			Wood, OCC Rejects, Fuel Oil	11/23/2004	BARK	0.6		annual	OFA, Good Combustion Practices		0.45		OFA, LNB for gas-fired under grate air heater system	
LA-0190	LA	GEORGIA-PACIFIC - PORT HUDSON	BOILER 6	CFB	Unknown	Modified	Yes	Wood, Sludge, Petcoke, Coal, Gas, Paper, Ba	8/22/2005	COMBINED					None	0.7		Good Combustion Practices	CEMS
LA-0201	LA	WEYERHAEUSER - RED RIVER MILL	Hogged Fuel BOILER 2 (EQT 11)	Unknown	940	Modified	Yes	Wood, Sludge, Recycle Fiber, Gas	5/24/2006	HOGGED FUEL						0.15	30-day	SNCR	CEMS
LA-0218	LA	FLORIEN PLYWOOD PLANT, BOISE BUILDING SOLUTIONS	HOGGED FUEL FIRED BOILER (EQT 1)	Unknown	225	Modified	Yes	Wood, Natural Gas	7/18/2007	WOOD	0.6		1-hour	OFA, Good Combustion Practices	Stack Test	0.22		Good Combustion Practices	CEMS
MA-02a	MA	RUSSELL BIOMASS	BIOMASS BOILER	BFB	740	New	Not Yet	Clean Wood	12/30/2008	WOOD	0.075		Unknown	Good Combustion Practices	CEMS	0.06	Unknown	SCR	CEMS
MA-02b	MA	RUSSELL BIOMASS	BIOMASS BOILER	Stoker	740	New	Not Yet	Clean Wood	12/30/2008	WOOD	0.075		Unknown	Oxidation Catalyst	CEMS	0.06	Unknown	RSCR	CEMS
MA-03	MA	PIONEER RENEWABLE ENERGY	BIOMASS BOILER	Stoker	663	New	Not Yet	Wood	Application	WOOD	0.075		Unknown	Oxidation Catalyst	CEMS	0.06	Unknown	SCR	CEMS
MA-05	MA	PALMER RENEWABLE ENERGY	BIOMASS BOILER	Stoker	38 MW	New	Not Yet	Biomass	Application	WOOD	0.075		Unknown	Oxidation Catalyst	CEMS	0.06	Unknown	RSCR	CEMS
ME-0021	ME	S.D. WARREN CO. - SKOWHEGAN, ME	POWER BOILER, #2	Unknown	1,300	Modified	Yes	Wood, Sludge, Oil, TDF, Paper, NCG	11/27/2001	WOOD WASTE	0.40		30-day	Good Combustion Practices	CEMS	0.20	30-day	SNCR	CEMS
ME-0026	ME	WHEELABRATOR SHERMAN ENERGY COMPANY	BOILER # 1		315			Wood, Fuel Oil	4/9/1999	WOOD	0.45			Good Combustion Practices		0.25	30-day	Good Combustion Practices	
ME-01	ME	BORALAX STRATTON ENERGY, INC.	WOOD/OIL-FIRED BOILER	FB	672	Modified	Yes	Wood, Oil	1/4/2005	COMBINED	0.6		24-hour	Good Combustion Practices	CEMS	0.075	Quarterly	Ecotube, RSCR	CEMS
MI-0258	MI	TES FILER CITY STATION	BOILER, SPREADER STOKER, 2 EACH	Stoker	384	New?		Coal, Wood, TDF	4/5/2001	COAL/TIRES/WOOD	0.3		8-hour	Good Combustion Practices	CEMS	0.60	30-day	SCR	CEMS
MI-0285	MI	GRAYLING GENERATING STATION	BOILER, MIXED FUEL (WOOD & TIRES)	Stoker	523	Modified	Yes	Wood, TDF	9/18/2001	WOOD AND TIRES	0.40	464	24-hour	Good Combustion Practices	CEMS	0.15	30-day	SNCR	CEMS
MI-0382	MI	WYANDOTTE DEPARTMENT OF MUNICIPAL SERVICES	BOILER NO. 8	CFB	369			Coal, Wood, Gas, TDF	5/26/2005	TDF									
MI-0386	MI	RIPLEY HEATING PLANT	CFB BOILER	CFB	205	New	Not Yet	Wood, Coal, Gas	5/12/2008	WOOD & COAL	0.17		3-hour	Good Combustion Practices	Stack Test	0.10	30-day	SNCR	CEMS
MN-0046	MN	DISTRICT ENERGY ST. PAUL, INC	BOILER		550			Wood, Gas	11/15/2001	WOOD	0.3			Good Combustion Practices		0.15		SNCR	Unknown
MN-0057	MN	FIBROMINN BIOMASS POWER PLANT	BOILER, MULTIFUEL	Stoker	792	New	Yes	Manure, Biomass, Natural Gas, Propane	10/23/2002	MANURE	0.24		24-hour	Good Combustion Practices	CEMS	0.16	30-day	SNCR	CEMS
MN-0058	MN	VIRGINIA DEPARTMENT OF PUBLIC UTILITIES	BOILER, WOOD FIRED	Stoker	230			Wood	6/30/2005	WOOD	0.3		4-hour	Good Combustion Practices		0.15	30-day	SNCR	Unknown
MN-0059	MN	HIBBING PUBLIC UTILITIES	BOILER, WOOD FIRED	Stoker	230			Wood	6/30/2005	WOOD	0.3		4-hour	Good Combustion Practices		0.15	30-day	SNCR	Unknown
MN-0074	MN	KODA ENERGY	BIOMASS BOILER 1	Suspension	308			Natural Gas, Biomass	8/23/2007	BIOMASS	0.43		30-day	Good Combustion Practices		0.25	30-day	SNCR	Unknown
MS-0075	MS	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	COMBINATION BOILER	Stoker	917.4			Wood, Sludge, TDF, Fuel Oil	7/9/2003	SCRAP WOOD	1.38			Good Combustion Practices		0.31		LNB, OFA, Stoker Controls	
NC-0092	NC	RIEGELWOOD MILL, INTERNATIONAL PAPER CO.	BOILER, POWER #5	Unknown	600	Modified	Yes	Coal, Wood, Sludge, Fuel Oil	5/10/2001	WOODWASTE	0.5		3-hour	Good Combustion Practices	Stack test	0.35	3-hour	OFA	Stack Test
ND-0022	ND	NORTHERN SUN, ARCHER DANIELS MIDLAND	WOOD/HULL FIRED BOILER	Stoker				Wood, Hulls, RR Ties	5/1/2006	BIOMASS	0.63					0.2	30-day	Good Combustion Practices	
NE-04	NE	ARCHER DANIELS MIDLAND, COLUMBUS	COGEN BOILERS (2)	CFB	768	New		Coal, Biomass, Petcoke, TDF	Draft, 2008	COMBINED	0.1		30-day	Good Combustion Practices	CEMS	0.07	30-day	SNCR	CEMS
NH-0013	NH	SCHILLER STATION, PUBLIC SERVICE OF NH	BOILER, WOOD FIRED CFB, UNIT #5	CFB	720	New	Yes	Wood, Coal	10/25/2004	BIOMASS	0.10		24-hour	CFB Design	CEMS	0.075	24-hour	SNCR	CEMS
NH-02	NH	BRIDGEWATER POWER COMPANY	WOOD/OIL-FIRED BOILER	Stoker	250	Modified	Yes	Wood, Oil	9/12/2007	COMBINED	0.23		annual	Good Combustion Practices	CEMS	0.075	Quarterly	SNCR, RSCR	CEMS
NH-03	NH	WHITEFIELD POWER	BOILER	Stoker	220	Modified	Yes	Wood	2004	BIOMASS	0.26		annual	Good Combustion Practices	CEMS	0.075	Quarterly	RSCR	CEMS
NH-04	NH	LAIDLAW BERLIN BIOPOWER	BOILER	BFB		Modified	No	Biomass	Pre-Application	BIOMASS								SCR	
NH-05	NH	CONCORD STEAM CORPORATION	BOILER	Stoker	305	New	Not Yet	Biomass, Natural Gas (startup)	2/27/2009	BIOMASS	0.18		annual	Good Combustion Practices	CEMS	0.065	30-day	SCR	CEMS
NM-03	NM	WESTERN WATER & POWER - ESTANCIA BASIN BIOMASS	BOILER	BFB	483	New	No	Biomass	Draft, 2007	BIOMASS	0.1		30-day	Good Combustion Practices	CEMS	0.11	30-day	SNCR	CEMS
OH-0286	OH	AKRON THERMAL ENERGY CORPORATION	BOILERS (2)	Grate	180	Modified	Yes	Wood, Tires, Gas	8/12/2008	WOOD, TIRES, NATURAL GAS	0.1		annual	Good Combustion Practices	Fuel Records	0.24		Restriction on usage of natural gas	Fuel Records
OH-0307	OH	SOUTH POINT BIOMASS GENERATION	WOOD FIRED BOILERS (7), EACH	Stoker	318	Modified	Yes	Wood	4/4/2006	WOOD	0.1		30-day	Oxidation Catalyst	CEMS	0.088	30-day	SCR	CEMS
OK-0084	OK	WEYERHAEUSER - VALLIANT MILL	POWER BOILER 2		N/A			Mixed Fuels	6/8/1999	COMBINED		250		Good Combustion Practices		0.15		FGR	
TX-31	TX	NACOGDOCHES POWER PLANT, AMERICAN RENEWABLES	BOILER	BFB	1,374	New		Biomass, Gas	3/1/2007	BIOMASS	0.15		30-day	Good Combustion Practices	CEMS	0.10	30-day	SNCR	CEMS
TX-32	TX	ASPEN POWER LUFKIN BIOMASS	BOILER	Stoker	692.6	New	Not Yet	Biomass	5/2008 - Stayed	BIOMASS	0.31		30-day	Good Combustion Practices	CEMS	0.15	30-day	SNCR	CEMS
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 1-2: CASE 1					Bagasse	10/10/2003	BAGASSE								Good Combustion Practices	
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 3-4: CASE 1					Bagasse	10/10/2003	BAGASSE								Good Combustion Practices	
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 1-2: CASE 2					Bagasse	10/10/2003	BAGASSE								Good Combustion Practices	
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 3-4: CASE 2					Bagasse	10/10/2003	BAGASSE								Good Combustion Practices	
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 6					Bagasse	10/10/2003	BAGASSE								Good Combustion Practices	
TX-0485	TX	INLAND PAPERBOARD AND PACKAGING, INC. - ORANGE	BARK BOILER		471			Wood, OCC, Gas, NCG	10/5/2004	WOOD WASTES, OCC, BARK, GAS, NCG	0.4		30-day	Good Combustion Practices		0.22		SNCR	Unknown
VA-0268	VA	THERMAL VENTURES	BOILER, STEAM		120			Wood, Coal	2/15/2002	WOOD	0.44			Good Combustion Practices		0.4		Good Combustion Practices	
VA-0298	VA	INTERNATIONAL BIOFUELS, INC	HEAT ENERGY SYSTEMS FOR PELLET PROCESSING		77			Wood	12/13/2005	WOOD/WOODPASTE	0.19			Thermal Oxidizer		0.22		Good Combustion Practices	
VA-11	VA	MULTITRADE OF PITTSYLVANIA COUNTY (DOMINION)	BOILERS (3)	Stoker	373.3	New	Yes	Biomass	1/1/2003	BIOMASS	0.35		30-day	Good Combustion Practices	CEMS	0.10	30-day	SNCR	CEMS
VT-01	VT	BURLINGTON ELECTRIC DEPT, MCNEIL STATION	MULTIFUEL BOILER	Stoker	750	Modified	Yes	Wood, Natural Gas, Oil	4/21/2008	COMBINED		1500	1-hour	Good Combustion Practices	CO Monitor	0.075	Quarterly	RSCR	CEMS
VT-02	VT	NORTH SPRINGFIELD SUSTAINABLE ENERGY PROJECT	BOILER																
WA-0298	WA	ABERDEEN DIVISION - SIERRA PACIFIC	HOG FUEL BOILER	Stoker	310	New		Wood, Natural Gas (Startup only)	10/17/2002	WASTE WOOD	0.35	300	24-hour	Good Combustion Practices	CEMS	0.15	24-hour	SNCR	CEMS
WA-0327	WA	SKAGIT COUNTY LUMBER MILL	WOOD-FIRED COGENERATION UNIT	Stoker	430	New		Biomass	12/12/2005	BARK & WASTE WOOD	0.35		1-hour	Good Combustion Practices	CEMS	0.13	24-hour	SNCR	CEMS
WA-0329	WA	DARRINGTON ENERGY COGENERATION POWER PLANT	WOOD WASTE-FIRED BOILER	Stoker	403	New		Wood	2/11/2005	WOOD WASTE	0.35		24-hour	Good Combustion Practices	CEMS	0.12	24-hour	SNCR	CEMS
WA-0335	WA	SIMPSON TACOMA KRAFT COMPANY, LLC	POWER BOILER 7	Unknown	595	Modified	Yes	Wood, OCC, Sludge, No. 6 Fuel Oil	5/22/2007	WOOD WASTE	0.35		30-day	OFA	CEMS	0.20	30-day	OFA, Good Combustion	CEMS
WA-0336	WA	GRAYS HARBOR PAPER LP	RILEY BOILER	Riley VO	379			Wood, No. 6 Fuel Oil	11/17/2006	WOOD WASTE									
WA-0336	WA	GRAYS HARBOR PAPER LP	BOILER 6	Dutch Oven	227			Wood, No. 6 Fuel Oil	11/17/2006	WOOD WASTE									
WA-0337	WA	BOISE WHITE PAPER LLC	HOG FUEL BOILER		343			Wood Waste, Gas	2/1/2006	WOOD/BARK		500	annual	OFA, Good Combustion Practices		0.3	30-day	OFA, Good Combustion Practices	

* Note that entries with a six character ID are from the U.S EPA RBLC Database. Entries with a four character ID are from permit file reviews.

Table D-1. Biomass Boiler RBLC and Permit Review Summary

ID	State	Facility	Unit	Boiler Type	Heat Input Capacity (MMBtu/hr)	New or Modified?	Unit Operating?	Fuels Unit is Permitted to Combust	Permit Date	Primary RBLC Fuel	PM BACT Limit (lb/MMBtu)	PM_{10} BACT Limit (lb/MMBtu)	CPM BACT Limit (lb/MMBtu)	Total PM BACT Limit (lb/MMBtu)	Total PM_{10} BACT Limit (lb/MMBtu)	Averaging Period	Control Option	Compliance Method	SO_2 BACT Limit (lb/MMBtu)	SO_2 Averaging Period	SO_2 Control Option	SO_2 Compliance Method
AL-0198	AL	SMURFIT-STONE-STEVENSON	BOILER, NO.2 WOOD RESIDUE		620			Wood, NCG, Fuel Oil	9/30/2002	WOOD WASTE									0.1		Limited NCG firing	
AL-0223	AL	STEVENSON MILL	NO. 2 WOOD-FIRED BOILER		620			Biomass	7/14/2006	BIOMASS									0.15	3-hour	Good Combustion Practices	
AR-0072	AR	DEL TIN FIBER LLC	HEAT ENERGY SYSTEM	Gassifier	291			Biomass	2/28/2003	WOOD WASTE												
AR-0083	AR	POTLATCH CORPORATION - OZAN UNIT	WOOD FIRED BOILER		175			Wood	7/26/2005	WOOD CHIPS	0.1						Multiclone, ESP					
CT-02	CT	PLAINFIELD RENEWABLE ENERGY	BOILER	FB Gasification	523.1	New	Not Yet	Biomass, biodiesel	2008	WOOD		0.021	0.017		0.037	3-hour	Baghouse	Stack Test	0.035	30-day	Spray Dryer	CEMS
CT-03	CT	WATERTOWN RENEWABLE POWER	BOILER	FB Gasification	436	New	Not Yet	Biomass, Natural Gas (startup)	Draft 2009	WOOD		0.02	0.017		0.03	24-hour	Baghouse	CEMS	0.025	3-hour	DSI	CEMS
FL-0034	FL	U.S. SUGAR CLEWISTON MILL AND REFINERY	BOILER, TRAVELING GRATE	Grate	633			Bagasse, No. 6 Fuel Oil	11/29/2000	BAGASSE	0.15						Scrubber		0.06		Low Sulfur fuels	
FL-0248	FL	US SUGAR CORPORATION	BOILER, BAGASSE, NO. 4		633			Bagasse, No. 6 Fuel Oil	11/19/1999	BAGASSE	0.15						Scrubber		0.06		Low Sulfur fuels	
FL-0257	FL	CLEWISTON SUGAR MILL AND REFINERY	BOILER	Unknown	936			Bagasse, Diesel	11/18/2003	BAGASSE	0.026						Wet cyclone and ESP		0.06		Low S fuels	
FL-0301	FL	CLEWISTON SUGAR MILL AND REFINERY	BOILER 7		738			Wood, Bagasse	12/6/2007	BAGASSE												
GA-0097	GA	INTERSTATE PAPER	MULTIFUEL BOILER	BFB	300			Wood, Oil, Gas, TDF, Sludge, Peat, Turpentir	12/30/2002	COMBINED	0.03						ESP		0.14	24-hour	Caustic wet scrubber	
GA-0114	GA	INLAND PAPERBOARD AND PACKAGING, INC. - ROME	BOILER, SOLID FUEL		856			Bark, Sludge, TDF, Fuel Oil, NCG	10/13/2004	BARK		0.025					ESP					
GA-0117	GA	TRI-GEN BIOPOWER	BOILER, MULTIFUEL	BFB	302.2			Wood, Sludge	5/24/2001	WOODWASTE AND PAPERMILL SLUDGE		0.026					ESP, Wet Scrubber					
GA-02	GA	YELLOW PINE ENERGY COMPANY	BOILER	BFB	1,529	New	Not Yet	Biomass, TDF, Propane, Fuel Oil	5/15/2009	BIOMASS		0.010			0.018	3-hour	Baghouse	Stack Test	0.014	30-day	Dry Scrubber	CEMS
GA-09	GA	PLANT CARL, GREEN ENERGY PARTNERS	BOILER	BFB	400	New	Not Yet	Biomass, Oil/Grease/Fat, Biodiesel, Chicken l	7/29/2008	BIOMASS	0.03					3-hour	ESP	Stack Test			Dry Scrubber	CEMS
GA-04	GA	GREENWAY RENEWABLE POWER, LLC	BOILER		719	New	Not Yet	Biomass, biodiesel	7/19/2008	BIOMASS	0.03					3-hour	Baghouse	Stack Test		Annual	Dry Scrubber	CPMS for Sorbject Injection
GA-05	GA	PIEDMONT GREEN POWER, LLC	BOILER		719	New	Not Yet	Biomass, biodiesel	9/17/2008	BIOMASS	0.03					3-hour	Baghouse	Stack Test		Annual	Dry Scrubber	CPMS for Sorbject Injection
GA-08	GA	BIOMASS GAS & ELECTRIC	Gasifier/Combustor w/HRSG	Gassifier	372	New	Not Yet	Biomass	5/20/2008	BIOMASS	0.03					3-hour	ESP	Stack Test				
IA-0083	IA	ROQUETTE AMERICA, INC.	CFB BOILER	CFB	996	New?		Coal, Petcoke, Biomass, TDF	8/16/2006	COAL					0.03	6-hour	Baghouse	Stack Test	0.09	30-day	Limestone Injection, dry scrubber	CEMS
IA-0095	IA	TATE & LYLE INGREDIENTS AMERICAS, INC.	FIBER FIRED BOILERS AND GERM	Unknown	200	New	Not Yet	Corn Fibers, Gas, Biogas, Process Gas	9/19/2008	CORN FIBER	0.008				0.012	3-hour	Baghouse	Stack Test	0.072	3-hour	Spray Dryer	CEMS
KY-0085	KY	MEADWESTVACO KENTUCKY, INC/WICKLIFFE	BOILER, BARK		631			Wood, Sludge, Oil, Gas, NCG	2/27/2002	BARK	0.1						ESP		0.8		Good Combustion Practices	
LA-0122	LA	INTERNATIONAL PAPER - MANSFIELD MILL	POWER BOILERS 1 & 2		760			Wood Waste, Coal, Oil, Gas, Recycle Fiber	8/14/2001	COMBINED	0.1						ESP					
LA-0125	LA	WEYERHAEUSER COMPANY, DODSON SAWMILL	WOOD FIRED BOILER (#017)	Unknown	233			Wood/Bark	10/29/2007	WOOD												
LA-0126	LA	JOYCE MILL, WEST FRASER	KIPPER BOILERS NO. 1 AND NO. 2 (EAC		58.3			Biomass	4/24/2002	WOOD WASTE												
LA-0126	LA	JOYCE MILL, WEST FRASER	MCBURNEY BOILER NO.4		154.2			Biomass	4/24/2002	WOOD WASTE												
LA-0174	LA	GEORGIA-PACIFIC - PORT HUDSON	BOILER 1		459.5	Modified	Yes	Wood, Natural Gas	1/25/2002	COMBINED	0.1	0.1					Wet scrubber		0.73		Wet Scrubber, low S fuels	
LA-0178	LA	DERIDDER PAPER MILL, BOISE CASCADE	WOOD-FIRED BOILER		454.29			Wood, Gas, NCG	11/14/2003	BARK												
LA-0188	LA	BOGALUSA MILL, INLAND PAPERBOARD	NO. 12 HOGGED FUEL BOILER	Has Grate	787.5			Wood, OCC Rejects, Fuel Oil	11/23/2004	BARK		0.15					Wet scrubber		1.54		10% annual limit on fuel oil capacity	
LA-0190	LA	GEORGIA-PACIFIC - PORT HUDSON	BOILER 6	CFB	Unknown	Modified	Yes	Wood, Sludge, Petcoke, Coal, Gas, Paper, Ba	8/22/2005	COMBINED		0.05							0.2	30-day	Limestone Injection	CEMS
LA-0201	LA	WEYERHAEUSER - RED RIVER MILL	Hogged Fuel BOILER 2 (EQT 11)	Unknown	940	Modified	Yes	Wood, Sludge, Recycle Fiber, Gas	5/24/2006	HOGGED FUEL		0.025				3-hour	ESP	Stack Test	0.015	3-hour	Good Combustion Practices	Stack Test
LA-0218	LA	FLORIEN PLYWOOD PLANT, BOISE BUILDING SOLUTIONS	HOGGED FUEL FIRED BOILER (EQT 1)	Unknown	225	Modified	Yes	Wood, Natural Gas	7/18/2007	WOOD		0.1				1-hour	Multiclone, venturi scrubber					
MA-02a	MA	RUSSELL BIOMASS	BIOMASS BOILER	BFB	740	New	Not Yet	Clean Wood	12/30/2008	WOOD	0.012			0.026		3-hour	Baghouse	Stack Test	0.025	Unknown	Fuel selection	CEMS
MA-02b	MA	RUSSELL BIOMASS	BIOMASS BOILER	Stoker	740	New	Not Yet	Clean Wood	12/30/2008	WOOD	0.012			0.026		3-hour	ESP	Stack Test	0.025	Unknown	Fuel selection	CEMS
MA-03	MA	PIONEER RENEWABLE ENERGY	BIOMASS BOILER	Stoker	663	New	Not Yet	Wood	Application	WOOD		0.012			0.019	3-hour	ESP	Stack Test	0.025	Unknown	Wood ash alkalinity	Unknown
MA-05	MA	PALMER RENEWABLE ENERGY	BIOMASS BOILER	Stoker	38 MW	New	Not Yet	Biomass	Application	WOOD	0.02					3-hour	Baghouse	Stack Test	0.020	Unknown	Scrubber	Unknown
ME-0021	ME	S.D. WARREN CO. - SKOWHEGAN, ME	POWER BOILER, #2	Unknown	1,300	Modified	Yes	Wood, Sludge, Oil, TDF, Paper, NCG	11/27/2001	WOOD WASTE	0.03	0.03				3-hour	Multiclone, ESP	Stack Test	0.27	30-day	Sodium-Based Wet Scrubber	CEMS
ME-0026	ME	WHEELABRATOR SHERMAN ENERGY COMPANY	BOILER # 1		315			Wood, Fuel Oil	4/9/1999	WOOD	0.036						Cyclone, ESP		0.12		Low Sulfur fuels	
ME-01	ME	BORALAX STRATTON ENERGY, INC.	WOOD/OIL-FIRED BOILER	FB	672	Modified	Yes	Wood, Oil	1/4/2005	COMBINED	0.03	0.03				1-hour	ESP	Stack Test	0.05	1-hour		Stack Test
MI-0258	MI	TES FILER CITY STATION	BOILER, SPREADER STOKER, 2 EACH	Stoker	384	New?		Coal, Wood, TDF	4/5/2001	COAL/TIRES/WOOD		0.03				3-hour	Baghouse	COMS	0.5	30-day	Lime Spray Dryer	CEMS
MI-0285	MI	GRAYLING GENERATING STATION	BOILER, MIXED FUEL (WOOD & TIRES)	Stoker	523	Modified	Yes	Wood, TDF	9/18/2001	WOOD AND TIRES	0.03					3-hour	Multiclone, ESP	Stack Test	0.07	24-hour	Limit on TDF used	CEMS
MI-0382	MI	WYANDOTTE DEPARTMENT OF MUNICIPAL SERVICES	BOILER NO. 8	CFB	369			Coal, Wood, Gas, TDF	5/26/2005	TDF	0.025	0.025				3-hour	Baghouse					
MI-0386	MI	RIPLEY HEATING PLANT	CFB BOILER	CFB	205	New	Not Yet	Wood, Coal, Gas	5/12/2008	WOOD & COAL	0.025					3-hour	Baghouse	Stack Test	0.15	30-day	Lime Injection	CEMS
MN-0046	MN	DISTRICT ENERGY ST. PAUL, INC	BOILER		550			Wood, Gas	11/15/2001	WOOD	0.03						Cyclone, ESP					
MN-0057	MN	FIBROMINN BIOMASS POWER PLANT	BOILER, MULTIFUEL	Stoker	792	New	Yes	Manure, Biomass, Natural Gas, Propane	10/23/2002	MANURE				0.02		3-hour	Baghouse	Stack Test	0.07	24-hour	Spray Dryer	CEMS
MN-0058	MN	VIRGINIA DEPARTMENT OF PUBLIC UTILITIES	BOILER, WOOD FIRED	Stoker	230			Wood	6/30/2005	WOOD	0.025	0.025				3-hour	ESP					
MN-0059	MN	HIBBING PUBLIC UTILITIES	BOILER, WOOD FIRED	Stoker	230			Wood	6/30/2005	WOOD	0.025	0.025				3-hour	ESP					
MN-0074	MN	KODA ENERGY	BIOMASS BOILER 1	Suspension	308			Natural Gas, Biomass	8/23/2007	BIOMASS	0.03				0.037	3-hour	Cyclone, ESP					
MS-0075	MS	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	COMBINATION BOILER	Stoker	917.4			Wood, Sludge, TDF, Fuel Oil	7/9/2003	SCRAP WOOD	0.1						Multiclone, ESP		0.26		1% S fuel oil	
NC-0092	NC	RIEGELWOOD MILL, INTERNATIONAL PAPER CO.	BOILER, POWER #5	Unknown	600	Modified	Yes	Coal, Wood, Sludge, Fuel Oil	5/10/2001	WOODWASTE	0.25					3-hour	Venturi scrubber	Stack Test	0.024	3-hour	Venturi scrubber	Stack Test
ND-0022	ND	NORTHERN SUN, ARCHER DANIELS MIDLAND	WOOD/HULL FIRED BOILER	Stoker				Wood, Hulls, RR Ties	5/1/2006	BIOMASS	0.08						ESP		0.47	24-hour	Good Combustion Practices	
NE-04	NE	ARCHER DANIELS MIDLAND, COLUMBUS	COGEN BOILERS (2)	CFB	768	New		Coal, Biomass, Petcoke, TDF	Draft, 2008	COMBINED	0.015				0.025	3-hour	Baghouse	Stack Test	0.11	30-day	Limestone Injection	CEMS
NH-0013	NH	SCHILLER STATION, PUBLIC SERVICE OF NH	BOILER, WOOD FIRED CFB, UNIT #5	CFB	720	New	Yes	Wood, Coal	10/25/2004	BIOMASS				0.01	0.01	24-hour	Baghouse	Stack Test, Calculations	0.02	24-hour	Lime Injection	CEMS
NH-02	NH	BRIDGEWATER POWER COMPANY	WOOD/OIL-FIRED BOILER	Stoker	250	Modified	Yes	Wood, Oil	9/12/2007	COMBINED	0.1					3-hour	Gravel Bed Filter, Baghouse	Stack Test				
NH-03	NH	WHITEFIELD POWER	BOILER	Stoker	220	Modified	Yes	Wood	2004	BIOMASS												
NH-04	NH	LAIDLAW BERLIN BIOPOWER	BOILER	BFB		Modified	No	Biomass	ʼre-Application	BIOMASS							Baghouse					
NH-05	NH	CONCORD STEAM CORPORATION	BOILER	Stoker	305	New	Not Yet	Biomass, Natural Gas (startup)	2/27/2009	BIOMASS	0.030					6-hour	ESP	Stack Test				
NM-03	NM	WESTERN WATER & POWER - ESTANCIA BASIN BIOMASS	BOILER	BFB	483	New	No	Biomass	Draft, 2007	BIOMASS				0.028	0.028	3-hour	ESP or Baghouse	Stack Test	0.019	30-day	Good Combustion Practices	Stack Test
OH-0286	OH	AKRON THERMAL ENERGY CORPORATION	BOILERS (2)	Grate	180	Modified	Yes	Wood, Tires, Gas	8/12/2008	WOOD, TIRES, NATURAL GAS	0.08					3-hour	ESP	Stack Test	0.28		Restriction on TDF used	Fuel Records
OH-0307	OH	SOUTH POINT BIOMASS GENERATION	WOOD FIRED BOILERS (7), EACH	Stoker	318	Modified	Yes	Wood	4/4/2006	WOOD		0.01				3-hour	Baghouse	Stack Test	0.087	30-day	Spray Dryer	CEMS
OK-0084	OK	WEYERHAEUSER - VALLIANT MILL	POWER BOILER 2		N/A			Mixed Fuels	6/8/1999	COMBINED	0.03								0.15		Good Combustion Practices	
TX-31	TX	NACOGDOCHES POWER PLANT, AMERICAN RENEWABLES	BOILER	BFB	1,374	New		Biomass, Gas	3/1/2007	BIOMASS	0.015	0.015		0.032	0.032	30-day	Baghouse	Stack Test	0.046	30-day	Good Combustion Practices	CEMS
TX-32	TX	ASPEN POWER LUFKIN BIOMASS	BOILER	Stoker	692.6	New	Not Yet	Biomass	5/2008 - Stayed	BIOMASS	0.025					3-hour	ESP	Stack Test	0.025		Good Combustion Practices	Stack Test
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 1-2: CASE 1					Bagasse	10/10/2003	BAGASSE							Multiclones, wet scrubbers					
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 3-4: CASE 1					Bagasse	10/10/2003	BAGASSE							Multiclones, wet scrubbers					
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 1-2: CASE 2					Bagasse	10/10/2003	BAGASSE							Multiclones, wet scrubbers					
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 3-4: CASE 2					Bagasse	10/10/2003	BAGASSE							Multiclones, wet scrubbers					
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 6					Bagasse	10/10/2003	BAGASSE							Multiclones, wet scrubbers					
TX-0485	TX	INLAND PAPERBOARD AND PACKAGING, INC. - ORANGE	BARK BOILER		471			Wood, OCC, Gas, NCG	10/5/2004	WOOD WASTES, OCC, BARK, GAS, NCG	0.07						Venturi scrubber		0.10		Scrubber	
VA-0268	VA	THERMAL VENTURES	BOILER, STEAM		120			Wood, Coal	2/15/2002	WOOD	0.15	0.14							0.47		Good Combustion Practices	
VA-0298	VA	INTERNATIONAL BIOFUELS, INC	HEAT ENERGY SYSTEMS FOR PELLET PROCESSING		77			Wood	12/13/2005	WOOD/WOODPASTE	0.09	0.08					Settling Chamber, Cyclones		0.05		Good Combustion Practices	
VA-11	VA	MULTITRADE OF PITTSYLVANIA COUNTY (DOMINION)	BOILERS (3)	Stoker	373.3	New	Yes	Biomass	1/1/2003	BIOMASS	0.02	0.02				3-hour	ESP	Stack Test	0.016	30-day	Good Combustion Practices	CEMS
VT-01	VT	BURLINGTON ELECTRIC DEPT, MCNEIL STATION	MULTIFUEL BOILER	Stoker	750	Modified	Yes	Wood, Natural Gas, Oil	4/21/2008	COMBINED	0.013					3-hour	ESP	Stack Test	0.0083	Annual	Good Combustion Practices	Fuel Records
VT-02	VT	NORTH SPRINGFIELD SUSTAINABLE ENERGY PROJECT	BOILER																			
WA-0298	WA	ABERDEEN DIVISION - SIERRA PACIFIC	HOG FUEL BOILER	Stoker	310	New		Wood, Natural Gas (Startup only)	10/17/2002	WASTE WOOD					0.02	24-hour	ESP	Stack Test				
WA-0327	WA	SKAGIT COUNTY LUMBER MILL	WOOD-FIRED COGENERATION UNIT	Stoker	430	New		Biomass	12/12/2005	BARK & WASTE WOOD					0.02	24-hour	ESP	6-hr Stack Test, Calculations	0.025	3-hour	Good Combustion Practices	Stack Tests
WA-0329	WA	DARRINGTON ENERGY COGENERATION POWER PLANT	WOOD WASTE-FIRED BOILER	Stoker	403	New		Wood	2/11/2005	WOOD WASTE				0.02	0.02	24-hour	ESP	Stack Test, Calculations				
WA-0335	WA	SIMPSON TACOMA KRAFT COMPANY, LLC	POWER BOILER 7	Unknown	595	Modified	Yes	Wood, OCC, Sludge, No. 6 Fuel Oil	5/22/2007	WOOD WASTE		0.02				24-hour	ESP	6-hr Stack Test, Calculations				
WA-0336	WA	GRAYS HARBOR PAPER LP	RILEY BOILER	Riley VO	379			Wood, No. 6 Fuel Oil	11/17/2006	WOOD WASTE		0.14				24-hour	Multiclone, 2 wet scrubbers					
WA-0336	WA	GRAYS HARBOR PAPER LP	BOILER 6	Dutch Oven	227			Wood, No. 6 Fuel Oil	11/17/2006	WOOD WASTE		0.35				24-hour	Multiclones, venturi scrubber					
WA-0337	WA	BOISE WHITE PAPER LLC	HOG FUEL BOILER		343			Wood Waste, Gas	2/1/2006	WOOD/BARK												

* Note that entries with a six character ID are from the U.S EPA RBLC Database. Entries with a four character ID are from permit file reviews.

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Table D-2. Cost Analysis Supporting Information for Tail-End SCR

Parameter	Boiler	Units	Note(s)
Maximum Boiler Capacity	1,282	MMBtu/hr	1
Uncontrolled Inlet Emissions	0.18	lb/MMBtu	1
Controlled Outlet Emissions	0.06	lb/MMBtu	2
Removal Efficiency	67	%	2
Pollutant Removed	674	tpy	3
SCR Inlet Airflow (before reheating)	551,894	acfm	4
SCR Inlet Temperature (before reheating)	335	° F	5
SCR Inlet Temperature (after reheating)	470	° F	4
SCR Inlet Airflow (after reheating)	645,612	acfm	6
Volume of Catalyst	6,622	ft^3	4
Catalyst Layers	4	layers	4
Ammonia Consumption (Pure)	73	lb/hr	4
Water Consumption for Reagent Solution	37.09	gal/hr	4
Reagent Solution Consumption	49	gal/hr	4
Reagent Storage Capacity	24,000	gal	4
Concentration of Stored Reagent Solution	19	% Reagent	7
Pressure Drop Across the SCR and Ductwork	15.0	inches of H_2O	4
Electricity Usage	1,404	kWhr	4
Catalyst Life	2.74	year	4
Reheating Needed	4.40	MMBtu/hr	4
Biodiesel Heat Capacity	127.04	MMBtu/Mgal	8
Biodiesel Consumption for Gas Reheating	34.63	gal/hr	9
Catalyst Cost, Initial	298.73	$\$/ft^3$	4
Catalyst Cost, Replacement	373.14	$\$/ft^3$	4
Ammonia Cost	0.53	$/lb	10
Water Cost	0.0015	$/gal	10
Electricity Cost	0.098	$/kW-hr	10
Biodiesel Cost	4.50	$/gal	11
SCR Equipment Life	20	years	12
Interest Rate	7.0	%	12

1. Potential inlet emissions based on maximum boiler capacity and emissions.
2. Based on vendor data. Efficiency calculated based on anticipated inlet emissions and outlet emissions.
3. Pollutant Removed (tpy) = (Uncontrolled Inlet Emissions - Controlled Outlet Emissions, lb/MMBtu) × (Maximum Boiler Capacity, MMBtu/hr) × (8,760 hr/yr) / (2000 lb/ton).
4. Value provided by vendor, Babcock Power Environmental.
5. Value for designed stack outlet (after baghouse, based on no SCR).
6. Calculated value determined using flowrate before reheating and temperatures before and after reheating.
7. Design basis.
8. Per ASTM D6751, HHV value of typical biodiesel as noted in Biodiesel Handling and Use Guide (Fourth Edition), Table 1.
9. Calculated based on reheating needed (MMBtu/hr) and biodiesel heat input capacity (MMBtu/Mgal).
10. Site-specific costs.
11. Engineering estimate.
12. Based on example problem in OAQPS Manual, Section 4.2, Chapter 2, page 2-50.

Table D-3. Cost Analysis for Tail-End SCR

Capital Cost	Boiler	OAQPS Notation[1]
Purchased Equipment Costs		
Total Equipment Cost[2]	12,755,026	A
Instrumentation[3]	1,275,503	0.10 × A
Sales Tax[3]	382,651	0.03 × A
Freight[3]	637,751	0.05 × A
Total Purchased Equipment Costs	*15,050,931*	*B = 1.18 × A*
Direct Installation Costs[4]		
Foundations and Supports	1,505,093	0.10 × B
Handling and Erection	6,020,372	0.40 × B
Electrical	602,037	0.04 × B
Piping	301,019	0.02 × B
Insulation	150,509	0.01 × B
Painting	150,509	0.01 × B
Site Preparation (Site Specific)	903,056	0.06 × B
Total Direct Installation Costs	*9,632,596*	*C = 0.64 × B*
Indirect Installation Costs		
General Facilities[5]	4,936,705	0.20 × (B + C)
Engineering and Home Office Fees	2,468,353	0.10 × (B + C)
Process Contingencies	1,234,176	0.05 × (B + C)
Construction Management[5]	3,702,529	0.15 × (B + C)
Owner's Cost[5]	1,234,176	0.05 × (B + C)
Total Indirect Installation Costs	*13,575,939*	*D = 0.55 × (B + C)*
Project Contingency[5]	7,651,893	E = 0.20 × (B + C + D)
Total Plant Cost	45,911,359	F = B + C + D + E
Allowance for Funds During Construction[5]	3,213,795	G = 0.07 × F
Royalty Allowance	0	H
Preproduction Costs	982,503	I = 0.02 × (F + G)
Inventory Capital[6]	18,531	J
Initial Catalyst and Chemicals	0	K
Total Capital Investment	**50,126,188**	**TCI = F + G + H + I + J + K**

Operating Cost	Boiler	OAQPS Notation
Direct Annual Costs		
Operating and Supervisory Labor	0	L
Maintenance	751,893	M = 0.015 × TCI
Reagent Consumption	334,385	N
Electricity	1,205,497	O
Catalyst Replacement[7]	212,334	P
Biodiesel for Gas Reheating[8]	1,365,281	Q
Total Direct Annual Costs	*3,869,390*	*DAC = L + M + N + O + P + Q*
Indirect Annual Costs		
Overhead, Taxes, Insurance, Administration	0	R
Capital Recovery[9]	4,731,558	S
Total Indirect Annual Costs	*4,731,558*	*IDAC = R + S*
Total Annual Cost	**8,600,947**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	674	
Cost per ton of NO_X Removed	**12,764**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 4.2, Chapter 2. Adjustments to lettering made as PEC and direct installation costs were broken out for this analysis.
2. Direct Capital Costs are based on a vendor quote from Babcock Power Environmental, April 20, 2009. This figure includes Tail End SCR, additional catalyst price for 10 ppm NH3 slip, additional ID fans requirements, and flue gas handling systems.
3. Based on general OAQPS costs as presented on page 2-27 of Section 1, Chapter 2 of OAQPS Manual.
4. Estimates based on engineering knowledge and evaluation of costs for other equipment as specified in OAQPS Manual.
5. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience. Costs have been included or adjusted.
6. Inventory capital is the cost to fill the reagent tank(s) for the first time, OAQPS Manual, Section 4.2, Chapter 2, page 2-44.
7. Catalyst replacement is calculated based on Future Worth Factor in Equations 2.51 and 2.52 of OAQPS Manual, Section 4.2, Chapter 2, page 2-47.
8. Based on fuel needed for reheating and fuel costs.
9. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.

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Table D-4. Cost Analysis Supporting Information for High-Dust, Hot-End SCR

Parameter	Boiler	Units	Note(s)
Maximum Boiler Capacity	1,282	MMBtu/hr	1
Potential Inlet Emissions	0.18	lb/MMBtu	1
Controlled Outlet Emissions	0.07	lb/MMBtu	2
Removal Efficiency	61	%	2
Pollutant Removed	618	tpy	3
SCR Inlet Airflow	740,471	acfm	4
SCR Inlet Temperature	700	° F	4
Volume of Catalyst	4,626	ft^3	4
Catalyst Layers	2	layers	4
Reagent Solution Consumption	44	gal/hr	4
Ammonia Consumption (Pure)	65	lb/hr	4
Water Consumption for Reagent Solution	33.20	gal/hr	4
Reagent Storage Capacity	16,400	gal	4
Concentration of Stored Reagent Solution	19	% Reagent	5
Pressure Drop Across the SCR and Ductwork	8.0	inches of H_2O	4
Electricity Usage	712	kWhr	4
Catalyst Life	0.91	year	4
Catalyst Cost, Initial	359.14	$\$/ft^3$	4
Catalyst Cost, Replacement	373.14	$\$/ft^3$	4
Catalyst Regeneration Cost	99.11	$\$/ft^3$	4
Ammonia Cost	0.53	$/lb	6
Water Cost	0.0015	$/gal	6
Electricity Cost	0.098	$/kW-hr	6
SCR Equipment Life	20	years	7
Interest Rate	7.0	%	7

1. Potential inlet emissions based on maximum boiler capacity and emissions.
2. Based on vendor data. Efficiency calculated based on anticipated inlet emissions and outlet emissions.
3. Pollutant Removed (tpy) = (Uncontrolled Inlet Emissions - Controlled Outlet Emissions, lb/MMBtu) × (Maximum Boiler Capacity, MMBtu/hr) × (8,760 hr/yr) / (2000 lb/ton).
4. Value provided by vendor, CERAM, or calculated based on design and vendor data.
5. Design basis.
6. Site-specific costs.
7. Based on example problem in OAQPS Manual, Section 4.2, Chapter 2, page 2-50.

Table D-5. Cost Analysis for High-Dust, Hot-End SCR

Capital Cost	Boiler	OAQPS Notation[1]
Purchased Equipment Costs		
Total Equipment Cost[2]	10,238,805	A
Instrumentation[3]	1,023,881	0.10 × A
Sales Tax[3]	307,164	0.03 × A
Freight[3]	511,940	0.05 × A
Total Purchased Equipment Costs	*12,081,790*	*B = 1.18 × A*
Direct Installation Costs[4]		
Foundations and Supports	1,208,179	0.10 × B
Handling and Erection	4,832,716	0.40 × B
Electrical	483,272	0.04 × B
Piping	241,636	0.02 × B
Insulation	120,818	0.01 × B
Painting	120,818	0.01 × B
Site Preparation (Site Specific)	724,907	0.06 × B
Total Direct Installation Costs	*7,732,346*	*C = 0.64 × B*
Indirect Installation Costs		
General Facilities[5]	3,962,827	0.20 × (B + C)
Engineering and Home Office Fees	1,981,414	0.10 × (B + C)
Process Contingencies	990,707	0.05 × (B + C)
Construction Management[5]	2,972,120	0.15 × (B + C)
Owner's Cost[5]	990,707	0.05 × (B + C)
Total Indirect Installation Costs	*10,897,774*	*D = 0.55 × (B + C)*
Project Contingency[5]	6,142,382	E = 0.20 × (B + C + D)
Total Plant Cost	36,854,292	F = B + C + D + E
Allowance for Funds During Construction[5]	2,579,800	G = 0.07 × F
Royalty Allowance	0	H
Preproduction Costs	788,682	I = 0.02 × (F + G)
Inventory Capital[6]	12,663	J
Initial Catalyst and Chemicals	0	K
Total Capital Investment	**40,235,437**	**TCI = F + G + H + I + J + K**

Operating Cost	Boiler	OAQPS Notation
Direct Annual Costs		
Operating and Supervisory Labor	0	L
Maintenance	603,532	M = 0.015 × TCI
Reagent Consumption	299,371	N
Electricity	611,340	O
Catalyst Replacement[7]	947,918	P
Catalyst Regeneration[5]	458,500	Q
Total Direct Annual Costs	*2,920,661*	*DAC = L + M + N + O + P + Q*
Indirect Annual Costs		
Overhead, Taxes, Insurance, Administration	0	R
Capital Recovery[8]	3,797,941	S
Total Indirect Annual Costs	*3,797,941*	*IDAC = R + S*
Total Annual Cost	**6,718,601**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	618	
Cost per ton of NO_X Removed	**10,877**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 4.2, Chapter 2. Adjustments to lettering made as PEC and direct installation costs were broken out for this analysis.
2. Direct Capital Costs are based on a vendor quote from Babcock & Wilcox, February 20, 2009. Quote includes High Dust SCR, Ammonia Unloading and Storage, ID Fans, Flue Gas Handling System, Ash Handling System, and Extra Charge of Catalyst.
3. Based on general OAQPS costs as presented on page 2-27 of Section 1, Chapter 2 of OAQPS Manual.
4. Estimates based on engineering knowledge and evaluation of costs for other equipment as specified in OAQPS Manual.
5. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience. Costs have been included or adjusted.
6. Inventory capital is the cost to fill the reagent tank(s) for the first time, OAQPS Manual, Section 4.2, Chapter 2, page 2-44.
7. Catalyst replacement is calculated based on Future Worth Factor in Equations 2.51 and 2.52 of OAQPS Manual, Section 4.2, Chapter 2, page 2-47.
8. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.

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Table D-6. Cost Analysis Supporting Information for SNCR

Parameter	Boiler	Units	Note(s)
Maximum Boiler Capacity	1,282	MMBtu/hr	1
Potential Inlet Emissions	0.18	lb/MMBtu	1
Controlled Outlet Emissions	0.11	lb/MMBtu	2
Removal Efficiency	39	%	2
Pollutant Removed	393	tpy	3
Reagent Solution Consumption (Ammonia)	126.65	gal/hr	4
Ammonia Consumption (Pure)	186	lb/hr	4
Water Consumption for Reagent Solution	95.02	gal/hr	4
Reagent Solution Storage Capacity (Ammonia)	42,600	gal	4
Concentration of Injected Reagent Solution	19	% Reagent	5
Electricity Usage	50	kW-hr	4
Ammonia Cost	0.53	$/lb	6
Water Cost	0.0015	$/gal	6
Electricity Cost	0.098	$/kW-hr	6
SNCR Equipment Life	20	years	8
Interest Rate	7.0	%	8

1. Inlet emissions based on maximum boiler capacity and emissions.
2. Based on vendor data. Efficiency calculated based on anticipated inlet emissions and outlet emissions.
3. Pollutant Removed (tpy) = (Uncontrolled Inlet Emissions - Controlled Outlet Emissions, lb/MMBtu) × (Maximum Boiler Capacity, MMBtu/hr) × (8,760 hr/yr) / (2000 lb/ton).
4. Value provided by vendor or calculated based on design and vendor data.
5. Design basis.
6. Site-specific costs.
7. Based on example problem in OAQPS Manual, Section 4.2, Chapter 1, page 1-39.

Table D-7. Cost Analysis for SNCR

Capital Cost	Boiler	OAQPS Notation[1]
Purchased Equipment Costs		
Total Equipment Cost[2]	1,188,354	A
Instrumentation[3]	118,835	0.10 × A
Sales Tax[3]	35,651	0.03 × A
Freight[3]	59,418	0.05 × A
Total Purchased Equipment Costs	*1,402,258*	*B = 1.18 × A*
Direct Installation Costs[4]		
Foundations and Supports	70,113	0.05 × B
Handling and Erection	280,452	0.20 × B
Electrical	56,090	0.04 × B
Piping	28,045	0.02 × B
Insulation	14,023	0.01 × B
Painting	14,023	0.01 × B
Total Direct Installation Costs	*462,745*	*C = 0.33 × B*
Indirect Installation Costs		
General Facilities[5]	186,500	0.10 × (B + C)
Engineering and Home Office Fees[5]	279,750	0.15 × (B + C)
Process Contingencies	93,250	0.05 × (B + C)
Construction Management[5]	186,500	0.10 × (B + C)
Owner's Cost[5]	93,250	0.05 × (B + C)
Total Indirect Installation Costs	*839,251*	*D = 0.45 × (B + C)*
Project Contingency[5]	540,851	E = 0.20 × (B + C + D)
Total Plant Cost	3,245,105	F = B + C + D + E
Allowance for Funds During Construction	0	G
Royalty Allowance	0	H
Preproduction Costs[5]	162,255	I = 0.05 × (F + G)
Inventory Capital[6]	32,893	J
Initial Catalyst and Chemicals[5]	0	K
Total Capital Investment	**3,440,253**	**TCI = F + G + H + I + J + K**

Operating Cost	Boiler	OAQPS Notation
Direct Annual Costs		
Operating and Supervisory Labor	0	L
Maintenance	51,604	M = 0.015 × TCI
Solution Consumption[7]	856,663	N
Electricity	42,924	O
Total Direct Annual Costs	*951,190*	*DAC = L + M + N + O*
Indirect Annual Costs		
Overhead, Taxes, Insurance, Administration[5]	0	P
Capital Recovery[8]	324,736	Q
Total Indirect Annual Costs	*324,736*	*IDAC = P + Q*
Total Annual Cost	**1,275,926**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	393	
Cost per ton of NO_X Removed	**3,246**	*\$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 4.2, Chapter 1. Adjustments to lettering made as PEC and direct installation costs were broken out for this analysis.
2. Direct Capital Costs are based on a vendor quote from Babcock & Wilcox, February 20, 2009.
3. Based on general OAQPS costs as presented on page 2-27 of Section 1, Chapter 2 of OAQPS Manual.
4. Estimates based on engineering knowledge and evaluation of costs for other equipment as specified in OAQPS Manual.
5. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience. Costs have been included or adjusted.
6. Inventory capital is the cost to fill the reagent tank(s) for the first time, OAQPS Manual, Section 4.2, Chapter 1, page 1-32.
7. Based on ammonia and water consumption.
8. Capital Recovery calculated based on Equations 1.33 and 1.34 of OAQPS Manual, Section 4.2, Chapter 1, pages 1-37 and 1-38.

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Table D-8. Cost Analysis Supporting Information for Wet Flue Gas Desulfurization (WFGD)

Parameter	Boiler	Units	Note(s)
Maximum Boiler Capacity	1,282	MMBtu/hr	1
Potential Inlet Emissions	0.066	lb/MMBtu	1
Controlled Outlet Emissions	0.005	lb/MMBtu	2
Removal Efficiency	92	%	2
Pollutant Removed	343	tpy	3
Solvent Consumption	7,800	gal/hr	4
Scrubber Inlet Temperature	335	° F	4
Scrubber Inlet Airflow	551,894	acfm	4
Pressure Drop Across Scrubber	12.00	inches of H_2O	4
Total Electricity Usage	2,000	kW-hr	4
Caustic Consumption	0.07	ton/hr	5
Caustic Consumption	1.8	ton/ton SO_2 removed	5
Solid Waste Generated	2.8	ton/ton SO_2 removed	5
Solvent Usage Cost (Water)	0.0015	$/gal	6
Operating Labor Cost	32.21	$/hr	6
Maintenance Labor Cost	36.64	$/hr	6
Electricity Cost	0.098	$/kW-hr	6
Caustic Cost	24.55	$/ton	6
Solid Waste Disposal Cost	6.00	$/ton	6
Scrubber Equipment Life	15	years	7
Interest Rate	7.0	%	7

1. Inlet emissions based on maximum boiler capacity and emissions.
2. Based on vendor data. Efficiency calculated based on anticipated inlet emissions and outlet emissions.
3. Pollutant Removed (tpy) = (Uncontrolled Inlet Emissions - Controlled Outlet Emissions, lb/MMBtu) × (Maximum Boiler Capacity, MMBtu/hr) × (8,760 hr/yr) / (2000 lb/ton).
4. Value provided by vendor or calculated based on design and vendor data.
5. Based on design pollutant loading and limestone usage rate.
6. Site-specific costs.
7. Per OAQPS Manual, Section 5.2, Chapter 1, page 1-30.

Table D-9. Cost Analysis for Wet Flue Gas Desulfurization (WFGD)

Capital Cost	Boiler	OAQPS Notation[1]
Purchased Equipment Costs		
Total Equipment Cost[2]	25,640,812	A
Instrumentation[3]	2,564,081	0.10 × A
Sales Tax[3]	769,224	0.03 × A
Freight[3]	1,282,041	0.05 × A
Total Purchased Equipment Costs	*30,256,158*	*B = 1.18 × A*
Direct Installation Costs		
Foundations and Supports	3,630,739	0.12 × B
Handling and Erection	12,102,463	0.40 × B
Electrical	302,562	0.01 × B
Piping	9,076,847	0.30 × B
Insulation	302,562	0.01 × B
Painting	302,562	0.01 × B
Site Preparation (Site-Specific)	907,685	0.03 × B
Building (Site-Specific)	1,512,808	0.05 × B
Total Direct Installation Costs	*28,138,227*	*C = 0.93 × B*
Indirect Installation Costs		
Engineering	3,025,616	0.10 × B
Construction and Field Expense	3,025,616	0.10 × B
Contractor Fees	3,025,616	0.10 × B
Start-up[3]	605,123	0.02 × B
Performance Test[3]	60,512	0.002 × B
Process Contingencies	907,685	0.03 × B
Owners Cost[3]	1,512,808	0.05 × B
Total Indirect Installation Costs	*12,162,976*	*D = 0.402 × B*
Project Contingency[3]	14,111,472	E = 0.20 × (B + C + D)
Total Plant Cost	84,668,833	F = B + C + D + E
Allowance for Funds During Construction[3]	5,926,818	G = 0.07 × F
Inventory Capital[3,4]	577	H
Total Capital Investment	**90,596,228**	**TCI = (F + G + H)**

Operating Cost	Boiler	OAQPS Notation
Direct Annual Costs		
Operating Labor (1/2 hr, per 8-hr shift)	17,635	I
Supervisory Labor	2,645	J = 0.15 × I
Maintenance Labor (1/2 hr, per 8-hr shift)	20,060	K
Maintenance Materials	20,060	L = K
Scrubbant[5]	102,492	M
Chemicals (Caustic)	15,304	N
Solid Waste Disposal	5,672	O
Electricity	1,716,960	P
Total Direct Annual Costs	*1,900,830*	*DAC = I + J + K + L + M + N + O + P*
Indirect Annual Costs		
Overhead	36,241	Q = 0.60 × (I + J + K + L)
Administrative Charges	1,811,925	R = 0.02 × TCI
Property Tax	905,962	S = 0.01 × TCI
Insurance	905,962	T = 0.01 × TCI
Capital Recovery[6]	9,946,979	U
Total Indirect Annual Costs	*13,607,069*	*IDAC = Q + R + S + T + U*
Total Annual Cost	**15,507,898**	*TAC = DAC + IDAC*
Pollutant/Additional Pollutant Removed (tpy)	343	
Cost per ton of SO_2 Removed	**45,275**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 5.2, Chapter 1. Values based on average requirements specified in OAQPS Manual, Section 5.2, Chapter 1, pages 1-27 and 1-28 unless otherwise noted. Adjustments to lettering made as PEC and direct installation costs were broken out for this analysis.
2. Direct Capital Costs are based on a vendor quote scaled to the current boiler size.
3. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience. Costs have been included or adjusted.
4. Inventory capital is the cost to store limestone for 14 days.
5. Cost is conservatively based on usage of water as a solvent.
6. Capital Recovery calculated based on Equations 1.33 and 1.34 of OAQPS Manual, Section 4.2, Chapter 1, pages 1-37 and 1-38.

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Table D-10. Cost Analysis Supporting Information for Dry FGD/Spray Dryer Absorber

Parameter	Boiler	Units	Note(s)
Maximum Boiler Capacity	1,282	MMBtu/hr	1
Potential Inlet Emissions	0.066	lb/MMBtu	1
Controlled Outlet Emissions	0.010	lb/MMBtu	2
Removal Efficiency	85	%	2
Pollutant Removed	314	tpy	3
Water Consumption	7,148	gal/hr	4
Dryer Inlet Temperature	325	° F	4
Dryer Inlet Airflow	560,267	acfm	4
Pressure Drop Across Dryer	5.00	inches of H_2O	4
Total Electricity Usage	667.1	kW-hr	4
Lime Consumption	0.097	ton/hr	5
Lime Consumption	2.71	ton/ton SO_2 removed	5
Solid Waste Generated	4.79	ton/ton SO2 removed	5
Water Usage Cost	0.00150	$/gal	6
Operating Labor Cost	32.21	$/hr	6
Maintenance Labor Cost	36.64	$/hr	6
Electricity Cost	0.098	$/kW-hr	6
Lime Cost	82.50	$/ton lime	6
Solid Waste Disposal Cost	6.00	$/ton material	6
Equipment Life	15	years	7
Interest Rate	7.0	%	7

1. Inlet emissions based on maximum boiler capacity and emissions.
2. Based on vendor data. Efficiency calculated based on anticipated inlet emissions and outlet emissions.
3. Pollutant Removed (tpy) = (Uncontrolled Inlet Emissions - Controlled Outlet Emissions, lb/MMBtu) × (Maximum Boiler Capacity, MMBtu/hr) × (8,760 hr/yr) / (2000 lb/ton).
4. Value provided by vendor or calculated based on design and vendor data.
5. Based on design pollutant loading and lime usage rate.
6. Site-specific costs.
7. Per OAQPS Manual, Section 5.2, Chapter 1, page 1-30.

Table D-11. Cost Analysis for Dry FGD/Spray Dryer Absorber

Capital Cost	Boiler	OAQPS Notation[1]
Purchased Equipment Costs		
Total Equipment Cost[2]	11,682,307	A
Instrumentation	1,168,231	0.10 × A
Sales Tax	350,469	0.03 × A
Freight	584,115	0.05 × A
Total Purchased Equipment Costs	*13,785,122*	*B = 1.18 × A*
Direct Installation Costs		
Foundations and Supports	1,654,215	0.12 × B
Handling and Erection	5,514,049	0.40 × B
Electrical	137,851	0.01 × B
Piping	4,135,537	0.30 × B
Insulation	137,851	0.01 × B
Painting	137,851	0.01 × B
Site Preparation (Site-Specific)	413,554	0.03 × B
Building (Site-Specific)	689,256	0.05 × B
Total Direct Installation Costs	*12,820,164*	*C = 0.93 × B*
Indirect Installation Costs		
Engineering	1,378,512	0.10 × B
Construction and Field Expense	1,378,512	0.10 × B
Contractor Fees	1,378,512	0.10 × B
Start-up[3]	275,702	0.02× B
Performance Test	27,570	0.002 × B
Process Contingencies	413,554	0.03 × B
Owners Cost[3]	689,256	0.05 × B
Total Indirect Installation Costs	*5,541,619*	*D = 0.402 × B*
Project Contingency[3]	6,429,381	E = 0.20 × (B + C + D)
Total Plant Cost	38,576,286	F = B + C + D + E
Allowance for Funds During Construction[3]	2,700,340	G = 0.07 × F
Inventory Capital[3,4]	2,697	H
Total Capital Investment	**41,279,323**	**TCI = (F + G + H)**

Operating Cost	Boiler	OAQPS Notation
Direct Annual Costs		
Operating Labor (0.5 hr, per 8-hr shift)	17,635	I
Supervisory Labor	2,645	J = 0.15 × I
Maintenance Labor (0.5 hr, per 8-hr shift)	20,060	K
Maintenance Materials	20,060	L = K
Water[5]	93,929	M
Lime	70,319	N
Solid Waste Disposal	9,040	O
Electricity	572,670	P
Total Direct Annual Costs	*806,358*	*DAC = I + J + K + L + M + N + O + P*
Indirect Annual Costs		
Overhead	36,241	Q = 0.60 × (I + J + K + L)
Administrative Charges	825,586	R = 0.02 × TCI
Property Tax	412,793	S = 0.01 × TCI
Insurance	412,793	T = 0.01 × TCI
Capital Recovery[6]	4,532,248	U
Total Indirect Annual Costs	*6,219,661*	*IDAC = Q + R + S + T + U*
Total Annual Cost	**7,026,020**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	314	
Cost per ton of SO_2 Removed	**22,344**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 5.2, Chapter 1. Values based on average requirements specified in OAQPS Manual, Section 5.2, Chapter 1, pages 1-27 and 1-28 unless otherwise noted. Adjustments to lettering made as PEC and direct installation costs were broken out for this analysis.
2. Direct Capital Costs are based on a vendor quote from SPE Amerex.
3. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience. Costs have been included or adjusted.
4. Inventory capital is the cost to store lime for 14 days.
5. Cost is conservatively based on usage of water as a solvent.
6. Capital Recovery calculated based on Equations 1.33 and 1.34 of OAQPS Manual, Section 4.2, Chapter 1, pages 1-37 and 1-38.

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Table D-12. Cost Analysis Supporting Information for Duct Sorbent Injection

Parameter	Boiler, SO2	Units	Note(s)
Maximum Boiler Capacity	1,282	MMBtu/hr	1
Potential Inlet Emissions	0.066	lb/MMBtu	1
Controlled Outlet Emissions	0.010	lb/MMBtu	2
Removal Efficiency	85	%	2
Pollutant Removed	314	tpy	3
Total Electricity Usage	312	kW-hr	4
Trona Consumption	0.41	ton/hr	5
Trona Consumption	12.1	ton/ton pollutant removed	5
Solid Waste Generated	12.5	ton/ton pollutant removed	5
Water Usage Cost	0.0015	$/gal	6
Operating Labor Cost	32.21	$/hr	6
Maintenance Labor Cost	36.64	$/hr	6
Electricity Cost	0.098	$/kW-hr	6
Trona Cost	150.00	$/ton reagent	6
Solid Waste Disposal Cost	6.00	$/ton material	6
Equipment Life	15	years	7
Interest Rate	7.0	%	7

1. Inlet emissions based on maximum boiler capacity and emissions.
2. Based on vendor data. Efficiency calculated based on anticipated inlet emissions and outlet emissions.
3. Pollutant Removed (tpy) = (Uncontrolled Inlet Emissions - Controlled Outlet Emissions, lb/MMBtu) × (Maximum Boiler Capacity, MMBtu/hr) × (8,760 hr/yr) / (2000 lb/ton).
4. Value provided by vendor or calculated based on design and vendor data.
5. Based on design pollutant loading and trona usage rate.
6. Site-specific costs.
7. Per OAQPS Manual, Section 5.2, Chapter 1, page 1-30.

Table D-13. Cost Analysis for Duct Sorbent Injection

Capital Cost	Boiler, SO2	OAQPS Notation
Purchased Equipment Costs [1]		
Total Equipment Cost[2]	2,231,201	A
Instrumentation	223,120	0.10 × A
Sales Tax	66,936	0.03 × A
Freight	111,560	0.05 × A
Total Purchased Equipment Costs	*2,632,817*	*B = 1.18 × A*
Direct Installation Costs [3]		
Foundations and Supports	263,282	0.10 × B
Handling and Erection	1,053,127	0.40 × B
Electrical	105,313	0.04 × B
Piping	131,641	0.05 × B
Insulation	26,328	0.01 × B
Painting	26,328	0.01 × B
Total Direct Installation Costs	*1,606,018*	*C = 0.61 × B*
Indirect Installation Costs [4]		
Engineering[5]	394,923	0.15 × B
Construction and Field Expense	263,282	0.10 × B
Contractor Fees	263,282	0.10 × B
Start-up[3]	263,282	0.10 × B
Performance Test	26,328	0.01 × B
Process Contingencies	78,985	0.03 × B
Owners Cost[3]	131,641	0.05 × B
Total Indirect Installation Costs	*1,421,721*	*D = 0.54 × B*
Project Contingency[5]	1,132,111	E = 0.20 × (B + C + D)
Total Plant Cost	6,792,668	F = B + C + D + E
Inventory Capital[5,6]	20,782	G
Total Capital Investment	**6,813,450**	**TCI = (F + G)**

Operating Cost	Boiler, SO2	OAQPS Notation
Direct Annual Costs		
Operating Labor (0 hr, per 8-hr shift)	0	H
Supervisory Labor	0	I = 0.15 × H
Maintenance Labor (0.5 hr, per 8-hr shift)[4]	20,060	J
Maintenance Materials[4]	20,060	K = J
Reagent	572,247	L
Solid Waste Disposal	23,559	M
Electricity	267,846	N
Total Direct Annual Costs	*903,773*	*DAC = H + I + J + K + L + M + N*
Indirect Annual Costs [4]		
Overhead	24,072	L = 0.60 × (H + I + J + K)
Administrative Charges	136,269	M = 0.02 × TCI
Property Tax	68,135	N = 0.01 × TCI
Insurance	68,135	O = 0.01 × TCI
Capital Recovery[7]	748,080	P
Total Indirect Annual Costs	*1,044,691*	*IDAC = L + M + N + O + P*
Total Annual Cost	**1,948,464**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	314	
Cost per ton of SO_2 Removed	**6,196**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 1, Chapter 2. Values based on average requirements specified on page 2-27 unless otherwise noted. Adjustments to lettering made as PEC and direct installation costs were broken out for this analysis.
2. Direct Capital Costs are based on a vendor quote from O'Brien & Gere, March 24, 2009.
3. Estimates based on engineering knowledge and evaluation of costs for other equipment as specified in OAQPS Manual.
4. Assumed the values listed in OAQPS Manual, Section 5.2, Chapter 1, are appropriate unless otherwise noted.
5. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience. Costs have been included or adjusted.
6. Inventory capital is the cost to store reagent for 14 days.
7. Capital Recovery calculated based on Equations 1.33 and 1.34 of OAQPS Manual, Section 4.2, Chapter 1, pages 1-37 and 1-38.

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Table D-14. Cost Analysis Supporting Information for Tail-End Oxidation Catalyst

Parameter	Boiler - CO	Units	Note(s)
Maximum Boiler Capacity	1,282	MMBtu/hr	1
Uncontrolled Inlet Emissions	0.08	lb/MMBtu	1
Controlled Outlet Emissions	0.01	lb/MMBtu	2
Removal Efficiency	67	%	2
Pollutant Removed	393	tpy	3
Inlet Airflow	614,000	acfm	4
Inlet Temperature	425	° F	4
Volume of Catalyst	800	ft^3	4
Pressure Drop Across the Oxidation Catalyst	10.0	inches of H_2O	4
Electricity Usage	890.1	kW-hr	4
Catalyst Life	3	year	4
Biodiesel Consumption for Gas Reheating	346	gal/hr	5
Catalyst Cost, Initial	387.50	$\$/ft^3$	4
Catalyst Cost, Replacement	401.50	$\$/ft^3$	4
Operating Labor Cost	32.21	$/hr	6
Maintenance Labor Cost	36.64	$/hr	6
Electricity Cost	0.098	$/kW-hr	6
Biodiesel Cost	4.50	$/gal	7
Oxidation Catalyst Equipment Life	10	years	8
Interest Rate	7.0	%	8

1. Potential inlet emissions based on maximum boiler capacity and emissions.
2. Based on vendor data. Efficiency calculated based on anticipated inlet emissions and outlet emissions.
3. Pollutant Removed (tpy) = (Uncontrolled Inlet Emissions - Controlled Outlet Emissions, lb/MMBtu) × (Maximum Boiler Capacity, MMBtu/hr) × (8,760 hr/yr) / (2000 lb/ton).
4. Value provided by vendor, BASF.
5. Calculated based on reheating needed (MMBtu/hr) and biodiesel heat input capacity (MMBtu/Mgal).
6. Site-specific costs.
7. Engineering estimate.
8. Based on example problem in OAQPS Manual, Section 3.2, Chapter 2, page 2-45.

Table D-15. Cost Analysis for Tail-End Oxidation Catalyst (Stand-Alone)

Capital Cost	CO + Reheat	OAQPS Notation[1]
Purchased Equipment Costs		
Total Equipment Cost[2]	7,149,961	A
Instrumentation	714,996	0.10 × A
Sales Tax	214,499	0.03 × A
Freight	357,498	0.05 × A
Total Purchased Equipment Costs	*8,436,954*	*B = 1.18 × A*
Direct Installation Costs		
Foundations and Supports	674,956	0.08 × B
Handling and Erection	1,181,174	0.14 × B
Electrical	337,478	0.04 × B
Piping	168,739	0.02 × B
Insulation	84,370	0.01 × B
Painting	84,370	0.01 × B
Total Direct Installation Costs	*2,531,086*	*C = 0.30 × B*
Indirect Installation Costs		
Engineering	843,695	0.10 × B
Construction and Field Expense	421,848	0.05 × B
Contractor Fees	843,695	0.10 × B
Start-up	168,739	0.02 × B
Performance Test	84,370	0.01 × B
Process Contingencies	253,109	0.03 × B
Owners Cost[3]	421,848	0.05 × B
Total Indirect Installation Costs	*3,037,303*	*D = 0.36 × B*
Project Contingency[3]	2,801,069	E = 0.20 × (B + C + D)
Total Plant Cost	16,806,412	F = B + C + D + E
Allowance for Funds During Construction[3]	1,176,449	G = 0.07 × F
Total Capital Investment	**17,982,861**	**TCI = (F + G)**

Operating Cost	CO + Reheat	OAQPS Notation
Direct Annual Costs		
Operating Labor (0.5 hr, per 8-hr shift)	17,635	H
Supervisory Labor	2,645	I = 0.15 × H
Maintenance Labor (0.5 hr, per 8-hr shift)	20,060	J
Maintenance Materials	20,060	K = J
Electricity	764,175	L
Catalyst Replacement[4]	99,910	M
Biodiesel for Gas Reheating	13,639,320	N
Total Direct Annual Costs	*14,563,806*	*DAC = H + I + J + K + L + M + N*
Indirect Annual Costs		
Overhead	36,241	O = 0.60 × (H + I + J + K)
Administrative Charges	359,657	P = 0.02 × TCI
Property Tax	179,829	Q = 0.01 × TCI
Insurance	179,829	R = 0.01 × TCI
Capital Recovery[5]	2,560,355	S
Total Indirect Annual Costs	*3,315,910*	*IDAC = O + P + Q + R + S*
Total Annual Cost	**17,124,161**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	393	
Cost per ton of Pollutant Removed	**43,566**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 3.2, Chapter 2.
2. Direct Capital Costs are based on a vendor quote scaled to the current boiler size.
3. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience. Costs have been included or adjusted.
4. Catalyst replacement is calculated based Future Worth Factor from Equations 2.51 and 2.52 of OAQPS Manual, Section 4.2, Chapter 2, page 2-47.
5. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.

Table D-16. Cost Analysis for Tail-End Oxidation Catalyst (No Additional Reheat Required)

Capital Cost	CO, No Reheat	OAQPS Notation[1]
Purchased Equipment Costs		
Total Equipment Cost[2]	1,274,374	A
Instrumentation	127,437	0.10 × A
Sales Tax	38,231	0.03 × A
Freight	63,719	0.05 × A
Total Purchased Equipment Costs	*1,503,761*	*B = 1.18 × A*
Direct Installation Costs		
Foundations and Supports	150,376	0.10 × B
Handling and Erection	601,505	0.40 × B
Electrical	60,150	0.04 × B
Piping	30,075	0.02 × B
Insulation	15,038	0.01 × B
Painting	15,038	0.01 × B
Total Direct Installation Costs	*872,182*	*C = 0.58 × B*
Indirect Installation Costs		
Engineering	150,376	0.10 × B
Construction and Field Expense	225,564	0.15 × B
Process Contingencies	75,188	0.05 × B
Owners Cost[3]	75,188	0.05 × B
General Facilities[3]	300,752	0.20 × B
Total Indirect Installation Costs	*827,069*	*D = 0.55 × B*
Project Contingency[3]	640,602	E = 0.20 × (B + C + D)
Total Plant Cost	3,843,614	F = B + C + D + E
Allowance for Funds During Construction[3]	269,053	G = 0.07 × F
Total Capital Investment	**4,112,667**	**TCI = (F + G)**

Operating Cost	CO, No Reheat	OAQPS Notation
Direct Annual Costs		
Operating Labor (0.5 hr, per 8-hr shift)	17,635	H
Supervisory Labor	2,645	I = 0.15 × H
Maintenance Labor (0.5 hr, per 8-hr shift)	20,060	J
Maintenance Materials	20,060	K = J
Electricity	764,175	L
Catalyst Replacement[4]	99,910	M
Biodiesel for Gas Reheating	-	N
Total Direct Annual Costs	*924,486*	*DAC = H + I + J + K + L + M + N*
Indirect Annual Costs		
Overhead	36,241	O = 0.60 × (H + I + J + K)
Administrative Charges	82,253	P = 0.02 × TCI
Property Tax	41,127	Q = 0.01 × TCI
Insurance	41,127	R = 0.01 × TCI
Capital Recovery[5]	585,551	S
Total Indirect Annual Costs	*786,299*	*IDAC = O + P + Q + R + S*
Total Annual Cost	**1,510,037**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	393	
Cost per ton of Pollutant Removed	**3,842**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 3.2, Chapter 2.
2. Direct Capital Costs are based on a vendor quote scaled to the current boiler size.
3. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience. Costs have been included or adjusted.
4. Catalyst replacement is calculated based Future Worth Factor from Equations 2.51 and 2.52 of OAQPS Manual, Section 4.2, Chapter 2, page 2-47.
5. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.