Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

October 2010

Facility Name: Warren County Biomass Energy Facility
City: Warrenton
County: Warren
AIRS Number: 04-13-301-00016
Application Number: 19121
Date Application Received: August 7, 2009

Review Conducted by:
State of Georgia - Department of Natural Resources
Environmental Protection Division - Air Protection Branch
Stationary Source Permitting Program

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SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Warren County Biomass Energy Facility for a permit to construct and operate a 100-megawatt (MW) biomass-fueled electric generating facility. The proposed project will include: a bubbling fluidized bed boiler with a maximum total heat input capacity of 1,399 million British Thermal Unit per hour (MMBtu/hr), two fire water pump emergency engines; a raw material handling and storage area; a sorbent storage silo; a boiler bed sand silo, a sand day hopper; a fly ash silo, a bottom ash silo; storage tanks; and a four-cell mechanical draft wet cooling tower.

The proposed project will result in emissions to atmosphere. The sources of these emissions include the bubbling fluidized bed boiler (Source Code: B001), two fire water pump emergency engines (Source Codes: FP01 and FP02), and Potential Onsite Wood Chipper (Source Code: GRN3).

The construction of the Warren County Biomass Energy Facility will result in emissions of CO, NOx, PM/PM_{10}, $PM_{2.5}$, VOC, H_2SO_4, fluorides, lead, and SO_2. A Prevention of Significant Deterioration (PSD) analysis was performed for the facility for all pollutants to determine if any emissions were above the "significance" level. The CO, NOx, PM/PM_{10}, $PM_{2.5}$, and SO_2 emissions were above the PSD significant level threshold.

The Warren County Biomass Energy Facility is located in Warren County, which is classified as "attainment" or "unclassifiable" for SO_2, $PM_{2.5}$ and PM_{10}, NO_X, CO, and ozone (VOC).

The EPD review of the data submitted by Warren County Biomass Energy Facility related to the proposed modifications indicates that the project will be in compliance with all applicable state and federal air quality regulations.

It is the preliminary determination of the EPD that the proposal provides for the application of Best Available Control Technology (BACT) for the control of CO, NOx, PM/PM_{10}, $PM_{2.5}$, and SO_2, as required by federal PSD regulation 40 CFR 52.21(j).

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment in the area surrounding the facility or in Class I areas located within 200 km of the facility. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Warren County Biomass Energy Facility for the construction and operation of a 100-megawatt (MW) biomass-fueled electric generating facility. Various conditions have been incorporated into the draft permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit is included in Appendix A.

1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

On October 14, 2009, Warren County Biomass Energy Facility submitted an application for an air quality permit to construct and operate a 100-megawatt (MW) biomass-fueled electric generating facility. The facility is located at 612 East Warrenton Road in Warrenton, Warren County.

The application that was submitted on October 14, 2009 replaces the application that was submitted on August 6, 2009. This preliminary determination is based on the application that was submitted on October 14, 2009 and the subsequent submittals.

Based on the proposed project description and data provided in the permit application, the estimated emissions of regulated pollutants from the facility are listed in Table 1-1 below:

Table 1-1: Emissions from the Project

Pollutant	Potential Emissions (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM	144.4	25	Yes
PM_{10}	144.4	15	Yes
$PM_{2.5}$	134.6	10	Yes
VOC	39.1	40	No
NO_X	648.9	40	Yes
CO	625.7	100	Yes
SO_2	56.2	40	Yes
H_2SO_4	6.90	7	No
Fluorides	0	3	No
Pb	8.13E-04	0.6	No
Total HAP	19.9	25	No
Max. Single HAP	9.9	10	No

The emissions calculations for Table 1-1 can be found in detail in the facility's PSD application (see Section 1 and Appendix C of Application No. 19121). Emissions for $PM_{2.5}$ and NOx are updated based on the replacement of the 330 hp fire pump with a 420 hp fire pump (See NO_2 modeling letter dated June 2010) and refinement of some $PM_{2.5}$ emission factors (See $PM_{2.5}$ modeling letter dated June 2010).

Through its new source review procedure, EPD has evaluated Warren County Biomass Energy Facility's proposal for compliance with State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination.

2.0 PROCESS DESCRIPTION

According to Application No. 19121, Warren County Biomass Energy Facility has proposed to construct and operate a 100-megawatt (MW) biomass-fired power plant to generate electricity for sale.

The proposed project will include:

- A fluidized bed boiler with a maximum heat input capacity of 1,399 MMBtu/hr.

- One 220-foot exhaust stack that will exhaust the products of combustion from the fluidized bed boiler.

- Air pollution controls on the fluidized bed boiler that include:
  - Selective Non-Catalytic Reduction
  - Duct sorbent injection system
  - Baghouse (fabric filter)
  - Good combustion practices

- Fire Water Pumps that include:
  - One electric pump
  - One fire water pump emergency engine (Source Code: FP01) with nominal 420-horse power (hp) that will fire ultra low sulfur diesel (ULSD) with maximum sulfur content of 0.0015 weight percent.
  - One fire water pump emergency engine (Source Code: FP02) with nominal 175-hp that will fire ULSD with maximum sulfur content of 0.0015 weight percent.

- Raw material handling and storage that include:

  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 (Source Codes: FDR1 through FDR6) through one of six truck dumpers (Source Codes: DMP1 through DMP6), and the hoppers will each have a live bottom-receiving feeder/drag chain conveyor (Source Codes: CV01 and CV02). The truck dumping operations and all six truck hoppers will be equipped with dust suppression system, which will fog the receiving area with a water mist to provide PM control. Two collecting belt conveyor systems will be designed to receive 400 tons per hour (tph) from all of the live bottom feeders and will be equipped with baghouse (Source Code: BM01) to provide PM control. The collecting belt conveyors (Source Codes: CV01 and CV02) will then transfer the material to the enclosed biomass processing building (Source Code: BM02) 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 stack and reclaim the logs from the storage pile (Source Code: SP03). The facility will use a diesel-powered 125 tons per hour mobile chipper (Source Code: GRN3) for size reduction to 2-inch square chips. Chips will leave the chipper via an enclosed chute and discharge from the chute into an enclosed structure using a dust suppression system (Source Code: 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. The chipper operation is expected to be used for limited periods of time throughout the year.

Biomass Processing

The enclosed biomass processing building will receive chips via two collecting belt conveyors (Source Codes: CV01 and CV02), which will transfer the wood chips to the two receiving belt conveyors (Source Codes: CV03 and CV04), which will transport the chips to one of the two diverter gates (Source Codes: GAT1 and GAT2). The diverter gates then distribute the wood chips to one of the two disk scalping screens (Source Codes: SCN1 and SCN2), which will separate oversized materials from the acceptable stream.

Oversized materials will be routed to two electric-powered 200 tph each wood hogs (Source Codes: GRN1 and GRN2) which will discharge chips at a nominal 2-1/2 inch size. Two collecting belt feeders (Source Codes: FDR7 and FDR8) will transfer the chipped biomass from the fuel processing building (Source Code: BM02) to two fuel transfer belt conveyors (Source Codes: CV05 and CV06) and then to the two radial stacking belt conveyors (Source Codes: CV07 and CV08). The fuel processing building (Source Code: BM02) will be completely enclosed and equipped with a dust collector to provide PM control. The transfer belt conveyors (Source Codes: CV05 and CV06) and the stacking belt conveyors (Source Codes: CV07 and CV08) will be equipped with dust suppression systems which will spray water mist to provide PM control.

Biomass Storage and Conveying

The two radial stacking belt conveyors (Source Codes: CV07 and CV08) will transport up to 800 tph of biomass to the two radial stockpiles (Source Codes: SP01 and SP02) and a telescopic chute will be used to minimize PM generating from these drops. The biomass storage capacity of the piles will be 20 days of boiler fuel. The biomass fuel will be reclaimed from the two radial stockpiles by two radial reclaim chain conveyors (Source Codes: CV09 and CV10), which will transport the reclaimed biomass chips to reclaim tower that discharges the material to the two reclaim belt conveyors (Source Codes: CV11 and CV12). Then the biomass will be received by the covered stackout belt conveyor (Source Code: CV13) and transferred via the transfer tower (Source Code: TWR1) to boiler reclaim belt conveyor (Source Code: CV14). After passing through a diverter gate (Source Code: GAT3) the biomass then goes to two distribution drag chain conveyors (Source Codes: CV15 and CV16) that will keep the four boiler live bottom feed bins full by continuously overfilling the bins. Any excess biomass will be discharged to overfill return belt conveyor (Source Code: CV17) and transport back to a location on the boiler reclaim belt conveyor (Source Code: CV14). This overfill loop ensures that the four boiler live bottom feed bins are always fill by continuously overfilling the bins.

Baghouse (Source Code: BM03) is used to control emissions from the transfer tower (Source Code: TWR1) drop point, while baghouse (Source Code: BM04) is used to control emissions from conveyors (Source Codes: CV15, CV16, and CV17).

- Sorbent storage silo. A sorbent storage silo (Source Code: SSS) equipped with fabric filtration system (Source Code: 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.

- Boiler bed sand storage silo and sand day storage hopper. A boiler bed sand storage silo (Source Code: BBSSS) equipped with fabric filtration system (Source Code: BM06) will store sand that will be used in the Bubbling Fluidized Bed Boiler (Source Code: B001) 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 (Source Code: SDSH) located near the boiler building. The sand day storage hopper will be equipped with a dust collector (Source Code: 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.

- Ash handling. Ashes from the steam generator ash coolers, the steam generator air heater ash hoppers, and the fabric filter ash hoppers will be collected. Then it will be 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 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.

- Storage tanks. There will be six storage tanks with the potential to emit VOC or HAP built in the facility. Two 60,000 gallon (gal) capacity tanks of biodiesel (B100) (Source Codes: TK01 and TK05) for boiler startup, two 500 gal capacity day tanks of ultra low sulfur diesel (ULSD) for the fire water pump emergency engines (Source Codes: TK02 and TK06), one 4,100 gal capacity turbine lube oil reservoir (Source Code: TK03), and one 400 gal capacity turbine lube oil dump tank (Source Code: TK04).

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

- Roads. Roadways throughout the plant site will be asphalt and all areas not paved or landscaped will be covered with gravel.

The Warren County Biomass Energy Facility permit application and supporting documentation are included in Appendix A of this Preliminary Determination and can be found online at www.georgiaair.org/airpermit.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

State Rules

Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1) requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Georgia Rule 391-3-1-.03(8)(b) continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

Georgia Rule 391-3-1-.02(2)(b) Standards for Visible Emission:

Visible Emissions limits opacity to less than forty (40) percent, except as may be provided in other more restrictive or specific rules or subdivisions of *Georgia Rule 391-3-1-.02(2).* This limitation applies to direct sources of emissions such as stationary structures, equipment, machinery, stacks, flues, pipes, exhausts, vents, tubes, chimneys or similar structures. This regulation is applicable to the storage silos, the compression ignition fire pump engines, the cooling towers, the sample testing laboratory, the fuel processing buildings, the material handling and processing equipment, and other supporting equipment with the capability of emitting particulates.

Georgia Rule 391-3-1-.02(2)(d) Standards for Fuel Burning Equipment:

This regulation limits particulate matter emissions from fuel burning equipment.

The biomass fluidized bed boiler is subject to rule 391-3-1-.02(2)(d)(2)(iii) as the boiler will be constructed after January 1, 1972 and the heat input capacity is greater than 250 million BTUs per hour (MMBtu/hr). This rule limits the allowable weight of emissions of fly ash and/or particulate matter from the boiler to 0.10 lb/MMBtu heat input.

This regulation also limits the opacity of which is equal to or greater than twenty (20) percent except for one six minute period per hour of not more than twenty-seven (27) percent opacity. This opacity limit is applicable to the biomass fluidized bed boiler.

This regulation has a NOx limit of 0.3 lb/MMBtu for boilers greater than 250 MMBtu/hr heat input capacity when combusting fuel oil. The biomass fluidized bed boiler will not fire any fossil fuel derived fuel oil. The facility plans to fire biodiesel fuel in the biomass fluidized bed boiler during startup operations. This boiler will primarily fire biomass during normal operation although some biodiesel fuel maybe fired during normal operation. Thus, this NOx limitation will not apply to this boiler.

Georgia Rule 391-3-1-.02(2)(e) Emission Limitations and Standards for Particulate Emission from Manufacturing Processes:

$E = 4.1\ P^{0.67}$; for process input weight rate up to and including 30 tons per hour.

$E = 55\ P^{0.11} - 40$; for process input weight rate above 30 tons per hour.

This regulation is applicable to the storage silos, the cooling towers, and the fuel processing buildings, the material handling and processing equipment, and other supporting equipment with the capability of emitting particulate matter.

Georgia Rule 391-3-1-.02(2)(g) Standard for Sulfur Dioxide:

This regulation requires that new fuel-burning sources capable of firing fossil fuel(s) at a rate exceeding 250 MMBTU/hr heat input not emit sulfur dioxide equal to or exceeding 0.8 pounds of sulfur dioxide per million BTUs (lb/MMBtu) of heat input derived from liquid fossil fuel or derived from liquid fossil fuel and wood residue. This limitation is not applicable to the biomass fluidized bed boiler.

All fuel burning sources below 100 million BTUs of heat input per hour shall not burn fuel containing more than 2.5 percent sulfur, by weight. This limit is applicable to the fire water pump emergency engines.

All fuel burning sources having a heat input of 100 million BTUs of heat input per hour or greater shall not burn fuel containing more than 3 percent sulfur, by weight. This limitation is applicable to the biomass fluidized bed boiler.

Georgia Rule 391-3-1-.02(2)(n) Standard for Fugitive Dust:

This regulation requires Warren County Biomass Energy Facility to take all reasonable precautions to prevent such dust from becoming airborne for any operation, process, handling, transportation or storage facility which may result in fugitive dust. This regulation also limits opacity from such sources to less than 20 percent.

This limit applies to paved and unpaved plant roads and parking areas, storage systems, and material handing and processing equipment.

Georgia Rule 391-3-1-.02(2)(3) Standard for Sampling:

This regulation specifies testing requirements and operating conditions during such testing. This regulation is applicable to all required testing of applicable equipment.

Georgia Rule 391-3-1-.02(2)(5) Standard for 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 percent. This regulation is applicable to all open burning activities performed by the facility.

Georgia Rule 391-3-1-.02(2)(6)(b) Standard for General Monitoring and Reporting Requirements:

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 indicates in their permit application that it will comply with the rule.

Georgia Rule 391-3-1-.02(2)(jjj) Standard for NO_x Emissions from Electric Utility Steam Generating Units:

This regulation **does not apply** because the steam-generating unit is not coal-fired and the facility is not located in one of the counties subject to this standard.

Georgia Rule 391-3-1-.02(2)(lll) Standard for NO_x Emissions from Fuel-Burning Equipment:

This regulation **does not apply** because the biomass boiler heat input rated capacity is greater than 250 MMBtu/hr and the facility is not located in one of the counties subject to this standard.

Georgia Rule 391-3-1-.02(2)(rrr) Standard for NO_x Emissions from Small Fuel-Burning Equipment:

This regulation **does not apply** because the biomass boiler heat input rated capacity is greater than 10 MMBtu/hr and the facility is not located in one of the counties subject to this standard.

Georgia Rule 391-3-1-.02(2)(ttt) Standard for Mercury Emissions from New Electric Generating Units:

This regulation limits the emission of mercury from a stationary coal-fired boiler or a stationary coal-fired combustion turbine. The proposed facility will solely fire biomass and biodiesel fuels. Therefore, this regulation **does not apply** to the proposed facility.

Federal Rule - PSD

The regulations for PSD in 40 CFR 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply to any new or modified source, which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or to all other sources having potential emissions of 250 tons per year or more of any regulated pollutant. They also apply to any modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

Georgia has adopted a regulatory program for PSD permits, which the United States Environmental Protection Agency (EPA) has approved as part of Georgia's State Implementation Plan (SIP). This regulatory program is located in the Georgia Rules at 391-3-1-.02(7). This means that Georgia EPD issues PSD permits for new major sources pursuant to the requirements of Georgia's regulations. It also means that Georgia EPD considers, but is not legally bound to accept, EPA comments or guidance. A commonly used source of EPA guidance on PSD permitting is EPA's Draft October 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting (NSR Workshop Manual). The NSR Workshop Manual is a comprehensive guidance document on the entire PSD permitting process.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements:

- Application of BACT for each regulated pollutant that would be emitted in significant amounts;
- Analysis of the ambient air impact;
- Analysis of the impact on soils, vegetation, and visibility;
- Analysis of the impact on Class I areas; and
- Public notification of the proposed plant in a newspaper of general circulation

Definition of BACT

The PSD regulation requires that BACT be applied to all regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case, EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS).

In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose and enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

EPA's NSR Workshop Manual includes guidance on the 5-step top-down process for determining BACT. In general, Georgia EPD requires PSD permit applicants to use the top-down process in the BACT analysis, which EPA reviews. The five steps of a top-down BACT review procedure identified by EPA per BACT guidelines are listed below:

Step 1: Identification of all control technologies;
Step 2: Elimination of technically infeasible options;
Step 3: Ranking of remaining control technologies by control effectiveness;
Step 4: Evaluation of the most effective controls and documentation of results; and
Step 5: Selection of BACT.

The following is a discussion of the applicable federal rules and regulations pertaining to the equipment that is the subject of this preliminary determination, which is then followed by the top-down BACT analysis.

New Source Performance Standards (NSPS)

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 60) New Source Performance Standards (NSPS) Subpart A – General Provisions:

Except as provided in Subparts B and C of 40 CFR 60, the provisions of this regulation apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility [40 CFR 60.1(a)]. Warren County Biomass Energy Facility is a new facility with several pieces of equipment and/or processes subject to this regulation. Any new or revised standard of performance promulgated pursuant to Section 111(b) of the Clean Air Act apply to Warren County Biomass Energy Facility's applicable equipment and/or processes and any applicable source/equipment for which the construction or modification of is commenced after the date of publication in 40 CFR 60 of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that equipment and/or processes [40 CFR 60.1(b)].

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 60) New Source Performance Standards (NSPS) Subpart Da – Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978.

The regulation is applicable to each electric utility steam-generating unit that is capable of combusting more than 73 megawatts (MW) [250 million British thermal units per hour (MMBtu/hr)] heat input of fossil fuel (either alone or in combination with any other fuel), was constructed, modified, or reconstructed after September 18, 1978 [40 CFR 60.40Da(a)]. Warren County Biomass Energy Facility proposes to burn biodiesel for startup only. The proposed fluidized bed boiler (Source Code: B001) will not combust any fossil fuel and will not be subject to this regulation.

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 60) New Source Performance Standards (NSPS) Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units:

This regulation applies to each steam-generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam-generating unit of greater than 29 megawatts (MW) [100 million British thermal units per hour (MMBtu/hr)] [40 CFR 60.40b(a)]. Therefore, Warren County Biomass Energy Facility's proposed biomass fluidized bed boiler is subject to 40 CFR 60 Subpart Db.

This regulation limits SO_2 emissions from an affected facility. Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of 40 CFR 60.42b, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2 emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input [40 CFR 60.42b(k)(1)]. Except as provided in paragraph (f) of 40 CFR 60.42b, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis [40 CFR 60.42(e)]. Except as provided in paragraph (i) of 40 CFR 60.42b and §60.45b(a), the SO_2 emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction [40 CFR 60.42(g)]. The SO_2 standard of this subpart will not apply to the proposed biomass fluidized bed boiler (Source Code: B001) because the facility will be firing only biomass and biodiesel (B100).

This regulation also limits opacity to no greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity from the biomass fluidized bed boiler on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, since it combusts coal, oil, wood, or mixtures of these fuels with any other fuels [40 CFR 60.43b(f)].

Except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5) of 40 CFR 60.43b, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input [40 CFR 60.43b(h)(1)].
Warren County Biomass Energy Facility's proposed biomass fluidized bed boiler (Source Code: B001) does not meet the provisions provided in 40 CFR 60.43b(h)(2), (h)(3), (h)(4), or (h)(5), and therefore it is subject to this PM limit. The PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction [40 CFR 60.43b(g)].

On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility under this regulation that commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO_2) in excess a limit of 86 ng/J (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas if the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels [40 CFR 60.44b(k)(1)].

According to §60.41b, annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year. The NOx standard of this subpart will not apply to the proposed biomass fluidized bed boiler (Source Code: B001) because the facility will be firing only biomass and biodiesel (B100) during startup.

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 60) New Source Performance Standards (NSPS) Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.

This regulation applies to each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) (19,813 gallons) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984 [40 CFR 60.110b(a)] except as follow:

This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 (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^3 (19,813 gallons) but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa [40 CFR 60.110b(b)].

The two 60,000 gallon biodiesel storage tanks (TK01 and TK05) will not be subject to this subpart as the vapor pressure is less than 3.5 kPa (0.5 psi).

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 60) New Source Performance Standards (NSPS) Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants:

The duct sorbent injection system (DSI) will utilize an on-line sorbent milling process between the sorbent storage silo and injection system. The sorbent milling process will be done in an enclosed building and it does not transport material to a control device. Therefore, the PM emission limit of 0.032 g/dscm (0.014 gr/dscf) [40 CFR 60.672(a)] will not be applicable to the sorbent milling process and associated conveying system at Warren County Biomass Energy Facility.

The sorbent milling process will be done in an enclosed building and it does not transport material to a control device. Therefore, the fugitive emissions limits of 7 percent opacity [40 CFR 60.672(b)] will not be applicable to the sorbent milling process and associated conveying system at Warren County Biomass Energy Facility.

If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in paragraphs (a) and (b) of section 40

CFR 60.672, **or** the building enclosing the affected facility or facilities must comply with the following emission limits:
[40 CFR 60.672(e)]

(1) Fugitive emissions from the building openings (except for vents as defined in 60.671) must not exceed 7 percent opacity; and

(2) Vents in the building must meet a PM emissions limit of 0.032 g/dscm (0.014 gr/dscf).

The sorbent milling process building is enclosed in a building. Therefore, it is subject to the opacity limits of 40 CFR 60.672(e)(1). Method 9 shall be used to determine compliance.

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 60) New Source Performance Standards (NSPS) Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

This regulation is applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of § 60.4200.

The two compression ignition fire water pump emergency engines (Source Codes: FP01 and FP02) will commence construction after July 11, 2005 and will be manufactured as a certified National Fire Protection Association (NFPA) after July 1, 2006; hence they will be subject to the requirements of NSPS Subpart IIII. These fire pumps shall only use diesel fuel that has a maximum sulfur content of 15 parts per million (ppm) (0.0015% by weight) [40 CFR 80.510(b)]. The accumulated non-emergency service (maintenance check and readiness testing) time for the emergency fire water pumps shall not exceed 100 hours per year for each unit [40 CFR 60.4211(e)].

National Emissions Standards For Hazardous Air Pollutants

40 CFR 63 Subpart A - General provisions

This regulation contains national emission standards for hazardous air pollutants (NESHAP) established pursuant to section 112 of the Act as amended November 15, 1990. These standards regulate specific categories of stationary sources that emit (or have the potential to emit) one or more hazardous air pollutants listed in this part pursuant to section 112(b) of the Act. The standards in this part are independent of NESHAP contained in 40 CFR 61. The NESHAP in Part 61 promulgated by signature of the Administrator before November 15, 1990 (i.e., the date of enactment of the Clean Air Act Amendments of 1990) remain in effect until they are amended, if appropriate, and added to 40 CFR 63 [40 CFR 63.1(a)(1) and (2)]. No emission standard or other requirement established under 40 CFR 63 shall be interpreted, construed, or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established by the Administrator pursuant to other authority of the Act (section 111, part C or D or any other authority of this Act), or a standard issued under State authority.
The Administrator may specify in a specific standard under this part that facilities subject to other provisions under the Act need only comply with the provisions of that standard [40 CFR 63.1(a)(3)].

Warren County Biomass Energy Facility will be a minor source of HAPS. The facility has requested to limit facility wide single HAP emissions to less than 10 tpy and facility wide combined HAPS emissions to less than 25 tpy.

<u>40 CFR 63 Subpart B</u> - Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j)

The requirements of §63.40 through 63.44 of 40 CFR 63, Subpart B carry out section 112(g)(2)(B) of the 1990 Amendments [40 CFR 63.40(a)]. The requirements of §63.40 through 63.44 of 40 CFR 63, Subpart B apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants after the effective date of section 112(g)(2)(B) (as defined in §63.41) and the effective date of a title V permit program in the State or local jurisdiction in which the major source is (or would be) located unless the major source in question has been specifically regulated or exempted from regulation under a standard issued pursuant to section 112(d), section 112(h), or section 112(j) and incorporated in another subpart of Part 63, or the owner or operator of such major source has received all necessary air quality permits for such construction or reconstruction project before the effective date of section 112(g)(2)(B) [40 CFR 63.40(b)].

40 CFR 63 Subpart B is referred to as "Case-by-Case MACT," or as a 112(g) determination. Section 112 of the Clean Air Act as amended in 1990 requires that EPA issue emission standards for all major sources of 188 listed HAPs. Section 112(g) is intended to ensure that HAP emissions do not increase excessively if a facility is constructed or reconstructed before EPA issues a MACT standard for that particular category of sources or facilities. When 112(g) is triggered by a construction or modification project, EPD is required to make case-by-case MACT determination. Section 112(g) became effective in Georgia on June 30, 1998.

As discussed above, the Warren County Biomass Energy Facility will be a minor (area) source for HAPS emissions. Therefore, case-by-case MACT **does not apply** to the proposed biomass boiler.

<u>40 CFR 63 Subpart ZZZZ</u> - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

This regulation is applicable to Stationary Reciprocating Internal Combustion Engines (RICE) at a major or area source of HAP emissions as specified in paragraphs (a) through (e) of § 63.6585 and (a) through (c) of § 63.6590.

The proposed Diesel Fired Fire water Pump Emergency Engines (Source Codes: FP01 and FP02) are new emergency stationary RICE (compression ignition) with a rating of less than or equal to 500 HP. Each engine must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60 Subpart IIII [40 CFR 63.6590(c)].

<u>State and Federal – Startup and Shutdown and Excess Emissions</u>

Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7 (NSPS emission standards are not covered by these provisions. Instead, startup and shutdown emissions are addressed within the NSPS standards themselves). Excess emissions from the Bubbling Fluidized Bed Boiler B001 are most likely to occur during periods of startup and/or shutdown because during these periods of operation, operating conditions such as temperature and flow rates of the unit exhaust from the boiler may not be conducive to proper operation of the applicable control systems (Fabric filter, SNCR, and DSI system), resulting in emissions of applicable pollutants above usual levels.

In NSPS 40 CFR 60.8(c), it states "Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test, nor shall emission in excess of the level of the applicable emission limits during periods of startup, shutdown and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard". The NSPS Subpart Db NOx limit does not apply, the facility will only fire biodiesel for the startup of the proposed biomass boiler per 40 CFR 60.44b(l)(1). The SO_2 standard of this subpart will not apply to the proposed biomass boiler because it will be firing fuels with potential SO_2 emissions rate of less than 0.32 lbs/MMBtu via the usage of biomass and biodiesel per 40 CFR 60.42b(k)(2). Excess emissions of the short term (ppm or lb/MMBtu) PSD BACT limits during startup and shutdown are subject to the provisions in Georgia Rule 391-3-1-.02(2)(a)7.

Although the facility is expected to be a high capacity intermediate load power generation facility, there will be occasions when the facility will be out of service for planned and unplanned maintenance and reserve shutdown. In such cases, the facility will need to undergo a startup process to return to service. The unit cold startup for the biomass-fired boiler B001 will include a 18-hours startup cycle, which include three phases, beginning with phase I the biomass fired boiler will employ B100 as auxiliary fuel to agitate the bed and the auxiliary burners. This step is estimated to last about ten hours. During this phase the SNCR cannot be operated as the boiler temperatures are too low for ammonia injection and the fabric filter is also bypassed to avoid condensation on the fabric filter bags. Phase II of the startup is the transition phase where biomass feed begins and auxiliary fuel decreases. This step is estimated to last about six hours. It is estimated that approximately halfway through phase II the fabric filter and duct sorbent injection system can be used. Phase III is the end of the startup period, and it is estimated to last about two hours. During this phase only biomass is fired in the boiler. It is estimated that approximately at the end of this phase, the SNCR can be used for NOx control. The startup procedure will end at hour 18, with the boiler experiencing full biomass-based operation.

Table 3-2 of the permit application provides the firing and emission rates for the biomass-fired boiler during the startup period.

The facility has proposed a secondary BACT limits to address periods of startup, shutdown, and malfunction. This BACT limits are mass-based limits on an annual (tpy) basis, with compliance determined via CEMS.

Federal Rule – 40 CFR 64 – Compliance Assurance Monitoring

Part 64, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 64) Compliance Assurance Monitoring [CAM]

Except for backup utility units that are exempt under paragraph (b)(2) of 40 CFR 64.2, the requirements of 40 CFR 64 apply to a pollutant-specific emissions unit at a major source that is required to obtain a Part 70 or 71 permit if the unit satisfies all of the following criteria: (1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under paragraph (b)(1) of 40 CFR 64.2; (2) The unit uses a control device to achieve compliance with any such emission limitation or standard; and (3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. Where "potential pre-control device emissions" has the same meaning as "potential to emit," as defined in §64.1, except that emission reductions achieved by the applicable control device are not taken into account [40 CFR 64.2(a)].

Warren County Biomass Energy Facility is required to address CAM applicability in their initial Title V Operating Permit application, which will be due within 12 months after the facility commences operation.

Federal Rule – 40 CFR 70 – Title V Operating Permit

Part 70, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 70) State Operating Permit Programs [Title V]

The regulations in 40 CFR 70 provide for the establishment of comprehensive State air quality permitting systems consistent with the requirements of title V of the Clean Air Act (Act) (42 U.S.C. 7401, *et seq.*). These regulations define the minimum elements required by the Clean Air Act for State operating permit programs and the corresponding standards and procedures by which the Administrator will approve, oversee, and withdraw approval of State operating permit programs. Georgia has an established such a program. Warren County Biomass Energy Facility, because it can potentially emit applicable pollutants above the applicable major source thresholds, is subject to 40 CFR 70. All sources subject to these regulations must have a permit to operate that assures compliance by the source with all applicable requirements [40 CFR 70.1(b)].

Warren County Biomass Energy Facility must prepare and submit an initial Title V Operating Permit Application for the operation of the Warren County Biomass Energy Facility in accordance with 40 CFR 70.5. The initial Title V application must be submitted within 12 months after Warren County Biomass Energy Facility becomes subject to the permit program or on or before such earlier date as the Division may establish [40 CFR 70.5(a)(i)].

Federal Rule – 40 CFR 72, 73, 75, 76, and 77 – Acid Rain

Part 72, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 72) Permits Regulation [Acid Rain]

Warren County Biomass Energy Facility will install one fluidized bed boiler with a maximum heat input capacity of 1,399 MMBtu/hr.

The proposed fluidized boiler is not subject to the requirements of the Acid Rain Program [40 CFR 72.6(a)(3)(i)], because the facility will not burn any fossil fuel in the proposed fluidized boiler. Therefore, Warren County Biomass Energy Facility is not required to meet applicable permit requirements, monitoring requirements, sulfur dioxide (SO_2) requirements, nitrogen oxides (NOx) requirements, excess emissions requirements, and liability specifications as specified in 40 CFR 72.9.
The regulations also set forth requirements for obtaining three types of Acid Rain permits, during Phases I and II, for which an affected source may apply: Acid Rain permits issued by the United States Environmental Protection Agency during Phase I; the Acid Rain portion of an operating permit issued by a State permitting authority during Phase II; and the Acid Rain portion of an operating permit issued by EPA when it is the permitting authority during Phase II.

According to this regulation, fossil fuel-fired means the combustion of fossil fuel or any derivative of fossil fuel, alone or in combination with any other fuel, independent of the percentage of fossil fuel consumed in any calendar year (expressed in MMBtu) [40 CFR 72.2]. Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material [40 CFR 72.2]. Based on these definitions and the proposed fuel usage of the boiler as indicated in Application 19121 and associated additional submittals, the fluidized boiler will not be classified as fossil fuel-fired.

Part 73, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 73) Permits Regulation [Sulfur Dioxide Allowance System]

The regulation requires owners, operators, and designated representatives of affected sources and affected units pursuant to §72.6 and as specified in 40 CFR 73. This regulation establishes the requirements and procedures for the following: (1) The allocation of sulfur dioxide emissions allowances; (2) The tracking, holding, and transfer of allowances; (3) The deduction of allowances for purposes of compliance and for purposes of offsetting excess emissions pursuant to parts 72 and 77 of Chapter I; (4) The sale of allowances through EPA-sponsored auctions and a direct sale, including the independent power producers written guarantee program; and (5) The application for, and distribution of, allowances from the Conservation and Renewable Energy Reserve; and (6) The application for, and distribution of, allowances for desulfurization of fuel by small diesel refineries [40 CFR 73.1]. Warren County Biomass Energy Facility's proposed fluidized bed boiler will not be subject to 40 CFR 73.

Part 75, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 75) Permits Regulation [Continuous Emissions Monitoring]

The purpose of this regulation is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO_2), nitrogen oxides (NOx), and carbon dioxide (CO_2) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to sections 412 and 821 of the CAA, 42 U.S.C. 7401–7671q as amended by Public Law 101–549 (November 15, 1990) [the Act]. In addition, this regulation sets forth provisions for the monitoring, recordkeeping, and reporting of NOx mass emissions with which EPA, individual States, or groups of States may require sources to comply in order to demonstrate compliance with a NOx mass emission reduction program, to the extent these provisions are adopted as requirements under such a program. Warren County Biomass Energy Facility's proposed fluidized bed boiler will not be subject to 40 CFR 75.

Part 76, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 76) Permits Regulation [Acid Rain Nitrogen Oxides Emissions Reduction Program]

Except as provided in paragraphs (b) through (d) of § 76.1, the provisions apply to each coal-fired utility unit that is subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II pursuant to sections 404, 405, or 409 of the Clean Air Act [40 CFR 76.1(a)]. A coal-fired utility unit means a utility unit in which the combustion of coal (or any coal-derived fuel) on a Btu basis exceeds 50.0 percent of its annual heat input during the following calendar year: for Phase I units, in calendar year 1990; and, for Phase II units, in calendar year 1995 or, for a Phase II unit that did not combust any fuel that resulted in the generation of electricity in calendar year 1995, in any calendar year during the period 1990–1995. For the purposes of this part, this definition shall apply notwithstanding the definition in §72.2 [40 CFR 76.2]. Based on this definition, the proposed bubbling fluidized bed boiler will not be subject to the emission limits in 40 CFR 76.

Part 77, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR 77) Permits Regulation [Excess Emissions]

This regulation sets forth the excess emissions offset planning and offset penalty requirements under section 411 of the Clean Air Act, 42 U.S.C. 7401, et seq., as amended by Public Law 101–549 (November 15, 1990). These requirements shall apply to the owners and operators and, to the extent applicable, the designated representative of each affected unit and affected source under the Acid Rain Program. Nothing in 40 CFR 77 will limit or otherwise affect the application of sections 112(r)(9), 113, 114, 120, 303, 304, or 306 of the Clean Air Act, as amended. Any allowance deduction, excess emission penalty, or interest required under 40 CFR 77 will not affect the liability of the affected unit's and affected source's owners and operators for any additional fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the Clean Air Act.

Warren County Biomass Energy Facility's proposed fluidized bed boiler will not be subject to the acid rain regulations as it burns only biomass and biodiesel (B100).

Federal Rule – Clean Air Interstate Rule (CAIR)

40 CFR 96 Subpart AA - CAIR NOx Annual Trading Program General Provisions, Subpart BB – CAIR Designated Representative for CAIR NOx Sources, Subpart CC – Permits, Subpart EE – CAIR NOx Allowance Allocations, Subpart FF – CAIR NOx Allowance Tracking System, Subpart GG – CAIR NOx Allowance Transfers, Subpart HH – Monitoring and Reporting

These regulations established the model rule comprising general provisions and the designated representative, permitting, allowance, and monitoring provisions for the State Clean Air Interstate Rule (CAIR) NOx Annual Trading Program, under section 110 of the Clean Air Act and §51.123 of Chapter I, as a means of mitigating interstate transport of fine particulates and nitrogen oxides. The owner or operator of a unit or a source was to comply with the requirements of these regulations as a matter of federal law only if the State with jurisdiction over the unit and the source incorporated by reference such subparts or otherwise adopted the requirements of such subparts in accordance with §51.123(o)(1) or (2) of Chapter I, the State submitted to the Administrator one or more revisions of the State implementation plan that included such adoption, and the Administrator approved such revisions.

40 CFR 96 Subpart AAA - Clean Air Interstate Rule [CAIR] SO_2 Trading Program General Provisions, Subpart BBB – CAIR Designated Representative for CAIR SO_2 Sources, Subpart CCC – Permits, Subpart FFF – CAIR SO_2 Allowance Tracking System, Subpart GGG – CAIR SO_2 Allowance Transfers, Subpart HHH – Monitoring and Reporting

These regulations established the model rule comprising general provisions and the designated representative, permitting, allowance, and monitoring provisions for the State Clean Air Interstate Rule (CAIR) SO_2 Trading Program, under section 110 of the Clean Air Act and §51.124 of Chapter I, as a means of mitigating interstate transport of fine particulates and sulfur dioxide. The owner or operator of a unit or a source was to comply with the requirements of these regulations as a matter of federal law only if the State with jurisdiction over the unit and the source incorporated by reference such subparts or otherwise adopts the requirements of such subparts in accordance with §51.124(o)(1) or (2) of Chapter I, the State submitted to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approved such revisions.

On May 12, 2005, EPA issued CAIR to make reductions in emissions of NOx and SO_2 in the eastern United States. On July 11, 2008, the District of Columbia (D.C.) Circuit Court of Appeals vacated CAIR in its entirety. On November 17, 2008 the United States EPA filed a reply in support of its petition for rehearing in the Clean Air Interstate Rule case. On December 28, 2008, the District of Columbia (D.C.) Circuit Court of Appeals has remanded the CAIR rule without vacatur. Therefore, this rule will remain in place until EPA issues a new rule to replace CAIR in accordance with the July 11, 2008 decision. In July 2010, EPA has proposed the new Transport CAIR Rule. However, this new rule is not promulgated yet.

The Biomass Boiler B001 is not subject to this regulation as it does not burn any fossil fuel and has capacity greater than 25 MW producing electricity for sale. CAIR permit application for new unit is due 18 months before the unit commences operation [40 CFR 96.121]. Warren County Biomass Energy Facility will not need to apply for CAIR permit.

4.0 CONTROL TECHNOLOGY REVIEW

The proposed project will result in emissions that are significant enough to trigger PSD review for the following pollutants: CO, NOx, PM, PM_{10}, $PM_{2.5}$, and SO_2.

Fluidized Bed Boiler- Background

The bubbling fluidized bed boiler (Source Code: B001) is proposed to commence construction in 2012 and to begin operation by 2015. According to Application 19121, the boiler will be designed to be 100% chipped biomass-fired (predominantly chipped wood) or up to 10% long wood processed on-site. The Biomass shall consist of 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 stalk and plant matter including aquatic plants, grasses, stalks, vegetation, and residues including hulls, shells, or cellulose containing fibers.

Startup of the fluidized bed boiler involves heating the boiler using auxiliary fuel (B100). During startup phase, the facility plans to fire biodiesel fuel (B100). Startup of the boiler will be accomplished via a series of phases.

Phase I is the initial firing period and will employ only the startup auxiliary fuel and is estimated to last approximately ten hours. During this phase, air is introduced through the bubble caps to agitate the bed and auxiliary burners are firing down toward the bed, phase I ends when boiler load reaches approximately 26% based on steaming rate. Phase II includes both biomass and auxiliary fuel firing, and is estimated to last approximately six hours. Phase III is the end of startup period, only biomass is fired in the boiler and the load is increased from approximately 50% to 65%. Phase III is estimated to last approximately two hours.

Fluidized Bed Boiler – Nitrogen Oxides (NO_x) Emissions

Applicant's Proposal

Nitrogen Oxides (NOx) are formed in industrial boiler and furnace combustion processes by two fundamentally different mechanisms: fuel NOx and thermal NOx. Fuel NOx forms when the fuel bound nitrogen compounds are converted into nitrogen oxides. The amount of fuel bound nitrogen converted to fuel NOx depends largely upon the fuel type, nitrogen content of the fuel, air supply, and boiler design. The reaction between elemental nitrogen and oxygen to form nitrogen oxides happens very rapidly. Therefore the primary mechanisms for reducing fuel NOx involve creating a minimum amount of excess oxygen available to react with fuel bound nitrogen through the combustion process. Thermal NOx results when atmospheric nitrogen is oxidized at high temperatures to yield nitric oxide (NO), nitrogen dioxide (NO_2), and other oxides of nitrogen. Thermal NOx is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce a peak temperature.

Care must be taken when incorporating design changes to reduce both NOx and carbon monoxide emissions. Carbon monoxide emission combustion modifications can possibly increase NOx emissions and vice versa. A balance between these air pollutants must be achieved in order for combustion modification to be useful.

In the facility application 19121, the applicant performed the 5-step BACT analysis for the NOx emissions from the fluidized bed boiler. The brief summary of the applicant's BACT analysis is as follows:

Applicant's Proposal

Step 1: Identify all control technologies

The applicant identified and performed detailed discussion of the following NOx control technologies for the biomass Fluidized Bed Boiler:

Pollution prevention options include:

- Flue Gas Recirculation (FGR)
- Fuel Staging
- Good Design and Operating Practices, include Overfire Air

Pollution reduction options include:

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

Please refer to pages 5-10 through 5-13 of the facility permit application for details on the NOx control technologies.

Step 2: Eliminate technically infeasible option

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 and determined that the following control technologies were not technically feasible:
(Please refer to pages 5-14 through 5-15 of the facility permit application)

- Flue Gas Recirculation (FGR)
- Fuel Staging

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The applicant has provided a ranking of the NOx control technologies that are technically feasible for this project, as listed in the following table 4-1:

Table 4-1: Remaining NOx Control Technology Ranking

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

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant discussed control effectiveness, energy impacts, environmental impacts and economic impacts for the top control technology.

The facility has indicated that the Tail End SCR/RSCR works by reheating the flue gas to the necessary temperatures for the ammonia and NOx to react to form nitrogen and water, this reheating process of the flue gas still represents a significant amount of auxiliary fuel that would be necessary for successful operation. In addition, this technology has been demonstrated on small wood-fired stroke boilers. The facility has indicated that 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.

Finally, the facility indicated that the annualized costs for a tail end SCR are estimated to be $12,764 per ton of NOx removed (refer to Appendix D of facility application for more information on the energy and economic impacts).

The facility has indicated that the Hot End/High Dust SCR systems have been permitted and installed 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 NOx. The facility has indicated that energy impacts include 0.7 MW of lost capacity. Finally, the facility indicated that the annualized costs for a hot end SCR are estimated to be $10,877 per ton of NOx removed (refer to Appendix D of facility application for more information on the energy and economic impacts).

The facility has indicated that the SNCR has no significant environmental impacts and the energy impacts are attributed to only 0.05 MW of lost capacity. Finally, the facility indicated that the annualized costs for a SNCR are estimated to be $3,246 per ton of NOx removed (refer to Appendix D of facility application for more information on the energy and economic impacts).

The facility has concluded that the use of SNCR in combination with OFA as the BACT control technology for NOx emissions from the wood biomass fired boiler. Please refer to pages 5-15 through 5-18 of the facility permit application for more detail.

Step 5: Selection of BACT

According to the facility application 19121, the proposed BACT for the fluidized bed boiler(s) includes combustion controls and SNCR capable of achieving NOx emissions of 0.11 lb/MMBtu on a 30-day rolling average. The applicant has proposed to use NOx Continuous Emission Monitor (CEMS) to demonstrate compliance with this limit.

In addition, the facility has proposed a secondary NOx BACT limit of 648 tons per year to address periods of startup and shutdown of the wood biomass fired boiler.

<u>EPD Review – NOx Control</u>

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the NOx BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LEAR/Clearinghouse[1]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- Final permit, Preliminary and Final Determination, and Permit Application for Yellow Pine Energy Company, LLC, Georgia[2]
- EPA's Air Pollution Control technology Fact Sheet SCR[3]
- EPA's Air Pollution Control technology Fact Sheet SNCR[4]
- Website of Babcock Power for NOx control technology information[5]

[1] http://cfpub.epa.gov/rblc/index.cfm?action=Results.PermitSearchResults

[2] http://www.georgiaair.org/airpermit/html/permits/psd/dockets/yellowpine/index.htm

[3] http://www.epa.gov/ttn/catc/dir1/fscr.pdf

[4] http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[5] http://www.babcockpower.com/

The Division has prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix D. Based on the research performed by the Division and review of the applicant's proposal, the use of SNCR in combination with good design and operating practices is the BACT control technology for NOx emissions. The Division's review shows that biomass bubbling fluidized bed boiler (BFB) with SNCR NOx control can achieve a limit of 0.10 lbs/MMBtu on a 30-day averaging period. Therefore, the Division has chosen emission limits of 0.010 lb/MMBtu on a 30-day rolling average as the BACT NOx emissions limit. To ensure compliance with the limit, the facility will be required to install a NOx CEMS at the stack outlet.

EPA finalized a 1-hour NO_2 National Ambient Air Quality Standard (NAAQS) and has issued guidance indicating that a 1-hour NO_2 NAAQS analysis is required after April 12, 2010 for any project triggering PSD review for NOx without a final permit. Based on EPD's request the facility has submitted supplemental 1-hour NO_2 Class II Area Modeling on June 25, 2010. In order to demonstrate compliance with this 1-hour NO_2 standard, EPD has decided to add a NOx BACT limit of 0.28 lb/MMBtu for the bubbling fluidized bed boiler (Source Code: B001) based on a 1-hour average.

<u>Conclusion – NOx Control</u>

The BACT selection for the fluidized bed boiler is summarized below in Table 4-2:

Table 4-2: NOx BACT Summary for the Fluidized Bed Boiler

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NOx	SNCR and Good design and operating practices	0.28 lbs/MMBtu	1-hour average	CEMS
NOx	SNCR and Good design and operating practices	0.10 lbs/MMBtu	30 day rolling average	CEMS
NOx	SNCR and Good design and operating practices	648 tons*	12 month rolling total	CEMS

*This limit includes emissions during startup, shutdown, and malfunctions.

<u>Fluidized Bed Boiler – Sulfur Dioxide (SO_2) Emissions</u>

Sulfur dioxide (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. The facility indicated that, 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. Therefore, the facility is demonstrating compliance via a CEMS and the emission rate is capped regardless of biomass sulfur variation.

In the facility application 19121, the applicant performed the 5-step BACT analysis for the SO_2 emissions from the fluidized bed boiler. The brief summary of the applicant's BACT analysis is as follows:

<u>Applicant's Proposal</u>

Step 1: Identify all control technologies

The applicant identified and performed detailed discussion of the following SO_2 control technologies for the biomass Fluidized Bed Boiler:

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

Please refer to pages 5-21 through 5-22 of the facility permit application for details on the SO_2 control technologies.

Step 2: Eliminate technically infeasible option

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 and determined that the following control technologies were not technically feasible:

Please refer to pages 5-22 through 5-23 of the facility permit application.

- Limestone Injection

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The applicant has provided a ranking of the SO_2 control technologies that are technically feasible for this project, as listed in the following table 4-3:

Table 4-3: Remaining SO_2 Control Technology Ranking

Rank	Control Technology	Expected Emissions	Control Efficiency
1	WFGD/Wet Scrubber	0.005 lb/MMBtu	92%
2	Spray Dryer with Baghouse	0.010 lb/MMBtu	85%
3	Duct Sorbent Injection	0.010 lb/MMBtu	85%
4	Good Design and Operation Practices	0.066 lb/MMBtu	Baseline

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant discussed control effectiveness, energy impacts, environmental impacts and economic impacts for the top control technology.

The facility has indicated that the WFGD/Wet Scrubber will reduce SO_2 outlet emissions from the proposed biomass boiler from 0.066 lbs/MMBtu to approximately 0.005 lbs/MMBtu. In addition, the facility indicated that biomass fired-boilers have inherent low SO_2 emissions due to the low sulfur content of the fuel. The facility has indicated that energy impacts include 2 MW of lost capacity and the need of 68 million gallons per year of water for treating the wastewater. Finally, the facility indicated that the annualized costs for a WFGD/Wet Scrubber are estimated to be \$45,275 per ton of SO_2 removed (refer to Appendix D of facility application for more information on the energy and economic impacts).

The facility has indicated that the Spray Dryer with Baghouse will reduce SO_2 outlet emissions from the proposed biomass boiler from 0.066 lbs/MMBtu to approximately 0.01 lbs/MMBtu. The facility has indicated that energy impacts include 0.7 MW of lost capacity and the need of 63 million gallons per year of water for treating the wastewater. Finally, the facility indicated that the annualized costs for a Spray Dryer with Baghouse are estimated to be \$22,344 per ton of SO_2 removed (refer to Appendix D of facility application for more information on the energy and economic impacts).

The facility has indicated that the Duct Sorbent Injection system will reduce SO_2 outlet emissions from the proposed biomass boiler from 0.066 lbs/MMBtu to approximately 0.01 lbs/MMBtu. The facility has indicated that energy impacts include 0.3 MW of lost capacity and there is no wastewater generated.

Finally, the facility indicated that the annualized costs for a Duct Sorbent Injection system are estimated to be $6,196 per ton of SO_2 removed (refer to Appendix D of facility application for more information on the energy and economic impacts).

The facility has concluded that the use of duct sorbent injection in conjunction with baghouse as the BACT control technology for SO_2 emissions from the wood biomass fired boiler. Please refer to pages 5-23 through 5-25 of the facility permit application.

Step 5: Selection of BACT

According to the facility application 19121, the proposed BACT for the fluidized bed boiler(s) includes duct sorbent injection system capable of achieving SO_2 emissions of 0.010 lb/MMBtu on a 30-day rolling average. The applicant has proposed to use SO_2 Continuous Emission Monitor (CEMS) to demonstrate compliance with this limit.

In addition, the facility has proposed a secondary SO_2 BACT limit of 56 tons per year to address periods of startup and shutdown of the wood biomass fired boiler.

<u>EPD Review – SO_2 Control</u>

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the SO_2 BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LEAR/Clearinghouse[6]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- Final permit, Preliminary and Final Determination, and Permit Application for Yellow Pine Energy Company, LLC, Georgia[7]
- EPA's Air Pollution Control technology Fact Sheet Spray-Chamber/Wet Scrubber[8]
- EPA's Air Pollution Control technology Fact Sheet WFGD/Wet Scrubber[9]
- Website of Babcock Power for SO_2 control technology information[10]

The Division has prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix D. Based on the research performed by the Division and review of the applicant's proposal, the use of Duct Sorbent Injection system is the BACT control technology for SO_2 emissions and 0.010 lb/MMBtu on a 30-day rolling average is the BACT SO_2 emissions limit. To ensure compliance with the limit, the facility will be required to install a SO_2 CEMS at the stack outlet.

EPA finalized a 1-hour SO_2 National Ambient Air Quality Standard (NAAQS) on June 22, 2010 with an effective date of August 23, 2010, and all PSD permits issued after that date should demonstrate compliance with the new standard. Based on EPD's request the facility has submitted supplemental 1-hour SO_2 Class II Area Modeling on June 25, 2010. In order to demonstrate compliance with this 1-hour SO_2 standard, EPD has decided to add a SO_2 BACT limit of 0.095 lb/MMBtu for the bubbling fluidized bed boiler (Source Code: B001) based on a 1-hour average.

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[6] http://cfpub.epa.gov/rblc/index.cfm?action=Results.PermitSearchResults

[7] http://www.georgiaair.org/airpermit/html/permits/psd/dockets/yellowpine/index.htm

[8] http://www.epa.gov/ttn/catc/dir1/fsprytwr.pdf

[9] http://www.epa.gov/ttn/catc/dir1/ffdg.pdf

[10] http://www.babcockpower.com/

Conclusion – Sulfur Dioxide (SO_2) Control

The BACT selection for the fluidized bed boiler is summarized below in Table 4-4:

Table 4-4: SO_2 BACT Summary for the Fluidized Bed Boiler

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
SO_2	Duct Sorbent Injection System (DSI)	0.095 lbs/MMBtu	1-hour average	CEMS
SO_2	Duct Sorbent Injection System (DSI)	0.010 lbs/MMBtu	30 day rolling average	CEMS
SO_2	None	56 tons*	12 month rolling total	CEMS

*This limit includes emissions during startup, shutdown, and malfunctions.

Fluidized Bed Boiler – Particulate matter PM/PM_{10} BACT Emissions

Filterable PM emissions from biomass boiler combustion include the ash (incombustible inert matter) 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 (it is not captured on a filter at stack conditions but could condense in the atmosphere to form an aerosol) 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.

In the facility application 19121, the applicant performed the 5-step BACT analysis for the PM/PM_{10} emissions from the fluidized bed boiler. The brief summary of the applicant's BACT analysis is as follows:

Applicant's Proposal

Step 1: Identify all control technologies

The applicant identified and performed detailed discussion of the following PM/PM_{10} control technologies for the biomass Fluidized Bed Boiler:

- Electrostatic Precipitator (ESP)
- Baghouse (Fabric Filter)
- Cyclone/Multiclone
- Venturi Scrubber
- Good Design and Operating Practices

Please refer to pages 5-27 through 5-29 of the facility permit application for details on the PM/PM_{10} control technologies.

Step 2: Eliminate technically infeasible option

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 and determined that all control technologies were technically feasible:

Please refer to page 5-29 of the facility permit application.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The applicant has provided a ranking of the PM/PM_{10} control technologies that are technically feasible for this project, as listed in the following table 4-5:

Table 4-5: Remaining PM/PM_{10} Control Technology Ranking

Rank	Control Technology	Expected Emissions	Control Efficiency
1	Baghouse (Fabric Filter)	0.010 lb/MMBtu filterable	99% to 99.9%
2	Electrostatic Precipitator (ESP)	0.015 lb/MMBtu filterable	99%
3	Venturi Scrubber	0.040 lb/MMBtu filterable	99%
4	Cyclone/Multiclone	0.10 lb/MMBtu filterable	95%
5	Good Design and Operation Practices	2.9 lb/MMBtu filterable	Baseline

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant discussed control effectiveness, energy impacts, environmental impacts and economic impacts for the top control technology and concluded that the use of baghouse (Fabric Filter) as the BACT control technology for $PM/PM_{10}/PM_{2.5}$ emissions from the wood biomass fired boiler. Please refer to page 5-30 of the facility permit application.

Step 5: Selection of BACT

According to the facility application 19121, the proposed BACT for the fluidized bed boiler(s) includes baghouse for control of filterable particulate matter emissions capable of achieving PM emission of 0.010 lb/MMBtu filterable PM and 0.018 lb/MMBtu total PM (filterable plus condensable) on 3-hour average. These emissions are identical to those recently determined as BACT by Georgia EPD for the Yellow Pine bubbling fluidizing bed boiler.

Compliance with these limits will be ensured through proper operation 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.

<u>EPD Review – PM/PM_{10} Control</u>

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the PM/PM_{10} BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LEAR/Clearinghouse[11]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- Final permit, Preliminary and Final Determination, and Permit Application for Yellow Pine Energy Company, LLC, Georgia[12]
- EPA's Air Pollution Control technology Fact Sheet Cyclones[13]
- EPA's Air Pollution Control technology Fact Sheet Venturi Scrubber[14]

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[11] http://cfpub.epa.gov/rblc/index.cfm?action=Results.PermitSearchResults

[12] http://www.georgiaair.org/airpermit/html/permits/psd/dockets/yellowpine/index.htm

[13] http://www.epa.gov/ttn/catc/dir1/fcyclon.pdf

[14] http://www.epa.gov/ttn/catc/dir1/fventuri.pdf

- EPA's Air Pollution Control technology Fact Sheet Fabric Filter[15]
- EPA's Air Pollution Control technology Fact Sheet Electrostatic Precipitator[16]

The Division has prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix D. Based on the research performed by the Division and review of the applicant's proposal, the use of baghouse is the BACT control technology for filterable particulate in combination with duct sorbent injection system for condensable particulate emissions and 0.010 lb/MMBtu filterable PM and 0.018 lb/MMBtu total PM (filterable and condensable) on a 3-hours average is the BACT PM/PM_{10}/$PM_{2.5}$ emissions limit. The facility will be required to install a COMS at the stack outlet and conduct annual performance tests for filterable PM_{10} and total PM_{10} to determine compliance with the PM_{10} emissions limits.

The baghouse must be installed in stack for the fluidized bed boiler, and must be operated at all times the fluidized bed boiler is in normal operation, regardless of the fuel type being combusted.

Conclusion – Particulate Matter (PM/PM_{10}) Control

The BACT selection for the fluidized bed boiler is summarized below in Table 4-6:

Table 4-6: BACT Summary for the Fluidized Bed Boilers

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM_{10} (filterable)	Fabric Filter Baghouse	0.010 lbs/MMBtu	3 hours	COMS and Performance Testing
PM_{10} (total)	Fabric Filter Baghouse and Duct Sorbent Injection system	0.018 lbs/MMBtu	3 hours	COMS and Performance Testing

Fluidized Bed Boiler – Particulate matter $PM_{2.5}$ BACT Emissions

$PM_{2.5}$ BACT background

On May 16, 2008 EPA finalized regulations to implement the New Source Review (NSR) program for $PM_{2.5}$. The rule finalized several NSR program requirements for sources that emit $PM_{2.5}$ and other pollutants that contribute to $PM_{2.5}$. $PM_{2.5}$ can be emitted directly from a facility or formed secondarily in the atmosphere from emissions of other compounds referred to as precursors. This rule requires NSR permits to address directly emitted $PM_{2.5}$ as well as pollutants responsible for secondary formation of $PM_{2.5}$ as follows:

- Sulfur dioxide (SO_2) – regulated
- Nitrogen oxides (NOx) – regulated unless state demonstrates that NOx emissions are not a significant contributor to the formation of $PM_{2.5}$ for an area(s) in the state
- Volatile organic compounds (VOC) – not regulated unless state demonstrates that VOC emissions are a significant contributor to the formation of $PM_{2.5}$for an area(s) in the state
- Ammonia – not regulated unless state demonstrates that ammonia emissions are a significant contributor to the formation of $PM_{2.5}$ for an area(s) in the state

[15] http://www.epa.gov/ttn/catc/dir1/ff-shaker.pdf

[16] http://www.epa.gov/ttn/catc/dir1/fdespwpi.pdf

Direct $PM_{2.5}$ are emitted directly into the air in either solid particle form (filterable) or vapors that can condense in the atmosphere (condensable). This rule defines major source threshold for $PM_{2.5}$ and significant emission rates for direct $PM_{2.5}$ and indirect $PM_{2.5}$ or precursors.

As per EPA's initial guidance, SIP approved states (Georgia) had up to 3 years to revise SIP to include implementation of $PM_{2.5}$ NSR program. Until then, states were allowed to use implementation of PM_{10} program as a surrogate for meeting $PM_{2.5}$ NSR requirements. As per the current guidance, EPA is planning to repeal the PM_{10} Surrogate Policy for SIP-approved states in the immediate future. Therefore, Warren County Biomass Energy Facility indicated in their permit application that the use of PM_{10} BACT limits to serve as surrogates for filterable $PM_{2.5}$ BACT emissions limits. In Georgia, SO_2 is the only pollutant that is responsible for secondary formation of $PM_{2.5}$. However, Georgia EPD requested from the facility to submit $PM_{2.5}$ BACT analysis on December 10, 2009. The facility has submitted supplemental $PM_{2.5}$ BACT on June 29, 2010.

<u>Applicant's Proposal</u>

Step 1: Identify all control technologies

The applicant identified and performed detailed discussion of the following $PM/PM_{10}/PM_{2.5}$ control technologies for the biomass Fluidized Bed Boiler:

- Electrostatic Precipitator (ESP)
- Baghouse (Fabric Filter)
- Cyclone/Multiclone
- Venturi Scrubber
- Good Design and Operating Practices
- Wet Electrostatic Precipitator (WESP)

Please refer to pages 5-27 through 5-29 of the facility permit application and the facility supplemental of $PM_{2.5}$ BACT pages 7 through 9 submitted on June 29, 2010, for details on the $PM/PM_{10}/PM_{2.5}$ control technologies.

Step 2: Eliminate technically infeasible option

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 and determined that all control technologies were technically feasible:

Please refer to page 5-29 of the facility permit application.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The applicant has provided a ranking of the $PM/PM_{10}/PM_{2.5}$ control technologies that are technically feasible for this project, as listed in the following table 4-7:

Table 4-7: Remaining $PM_{2.5}$ Control Technology Ranking

Rank	Control Technology	Expected Emissions
1	Baghouse (Fabric Filter)	0.010 lb/MMBtu filterable
2	Electrostatic Precipitator (ESP)	0.015 lb/MMBtu filterable
3	Venturi Scrubber	0.040 lb/MMBtu filterable
4	Cyclone/Multiclone	0.10 lb/MMBtu filterable
5	Good Design and Operation Practices	2.9 lb/MMBtu filterable

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant discussed control effectiveness, energy impacts, environmental impacts and economic impacts for the top control technology and concluded that the use of baghouse (Fabric Filter) as the BACT control technology for $PM/PM_{10}/PM_{2.5}$ emissions from the wood biomass fired boiler. Please refer to page 5-30 of the facility permit application and the facility supplemental of $PM_{2.5}$ BACT pages 7 through 9 submitted on June 29, 2010.

Step 5: Selection of BACT

According to the facility application 19121, the proposed BACT for the fluidized bed boiler(s) includes baghouse for control of filterable particulate matter emissions capable of achieving PM emission of 0.010 lb/MMBtu filterable PM and 0.018 lb/MMBtu total PM (filterable plus condensable) on 3-hour average.

Compliance with these limits will be ensured through proper operation 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.

EPD Review – $PM_{2.5}$ Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the $PM_{2.5}$ BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LEAR/Clearinghouse[17]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources
- Final permit, Preliminary and Final Determination, and Permit Application for Yellow Pine Energy Company, LLC, Georgia[18]
- EPA's Air Pollution Control technology Fact Sheet Cyclones[19]
- EPA's Air Pollution Control technology Fact Sheet Venturi Scrubber[20]
- EPA's Air Pollution Control technology Fact Sheet Fabric Filter[21]
- EPA's Air Pollution Control technology Fact Sheet Electrostatic Precipitator[22]

The Division has prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix D. Based on the research performed by the Division and review of the applicant's proposal, the use of baghouse is the BACT control technology for filterable particulate in combination with duct sorbent injection system for condensable particulate emissions and 0.010 lb/MMBtu filterable PM and 0.018 lb/MMBtu total PM (filterable and condensable) on a 3-hours average is the BACT $PM_{2.5}$ emissions limit. The facility will conduct annual performance tests for $PM_{2.5}$ to demonstrate compliance with the filterable $PM_{2.5}$ and total $PM_{2.5}$ limits.

The baghouse must be installed in stack for the fluidized bed boiler, and must be operated at all times the fluidized bed boiler is in normal operation, regardless of the fuel type being combusted.

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[17] http://cfpub.epa.gov/rblc/index.cfm?action=Results.PermitSearchResults

[18] http://www.georgiaair.org/airpermit/html/permits/psd/dockets/yellowpine/index.htm

[19] http://www.epa.gov/ttn/catc/dir1/fcyclon.pdf

[20]http://www.epa.gov/ttn/catc/dir1/fventuri.pdf

[21] http://www.epa.gov/ttn/catc/dir1/ff-shaker.pdf

[22] http://www.epa.gov/ttn/catc/dir1/fdespwpi.pdf

Conclusion – Particulate Matter ($PM_{2.5}$) Control

The BACT selection for the fluidized bed boiler is summarized below in Table 4-8:

Table 4-8: BACT Summary for the Fluidized Bed Boilers

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
$PM_{2.5}$ (total)	Fabric Filter Baghouse and Duct Sorbent Injection system	0.018 lbs/MMBtu	3 hours	COMS and Performance Testing

Fluidized Bed Boiler – Carbon Monoxide CO BACT Emissions

Carbon Monoxide (CO) from the biomass boilers is a by-product of incomplete combustion of carbon in the fuel source. Conditions leading to incomplete combustion include insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction. Control of CO is usually accomplished by providing proper fuel residence time and proper combustion conditions (excess air). However, factors to reduce CO emissions, such as addition of excess air to improve combustion, can lead to an increase in NOx emissions.

Therefore, an evaluation of the reduction of CO emissions must consider the potential secondary impacts on NOx emissions. CO can be accurately measured in stack gases and be continuously monitored and recorded. Complete combustion of carbon results in carbon dioxide, so the presence of CO indicates incomplete combustion. As such, it would be an effective indicator of incomplete combustion of any type.

In the facility application 19121, the applicant performed the 5-step BACT analysis for the CO emissions from the fluidized bed boiler. The brief summary of the applicant's BACT analysis is as follows:

Applicant's Proposal

Step 1: Identify all control technologies

The applicant identified and performed detailed discussion of the following CO control technologies for the biomass Fluidized Bed Boiler:

- Regenerative Selective Catalytic Reduction (RSCR)/Oxidation Catalyst
- Good Design and Operating Practices

Please refer to page 5-32 of the facility permit application for details on the CO control technologies.

Step 2: Eliminate technically infeasible option

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 and determined that all control technologies were technically feasible:
(Please refer to pages 5-32 through 5-33 of the facility permit application)

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The applicant has provided a ranking of the CO control technologies that are technically feasible for this project, as listed in the following table 4-9:

Table 4-9: Remaining CO Control Technology Ranking

Rank	Control Technology	Expected Emissions	Control Efficiency
1	RSCR/Oxidation Catalyst	0.01 lb/MMBtu	67%
2	Good Design and Operation Practices	0.08 lb/MMBtu	Baseline

Step 4: Evaluating the Most Effective Controls and Documentation

In this section, the applicant discussed control effectiveness, energy impacts, environmental impacts and economic impacts for the top control technology.

The facility has indicated that Oxidation Catalyst must be installed downstream of the particulate control device to ensure the catalyst is not chemically damaged. However, significant amount of auxiliary fuel will be required to reheat the flue gas. The facility has indicated that energy impacts include combustion of 3 million gallons per year of biodiesel to reheat the flue gas and 0.9 MW of lost capacity. Finally, the facility indicated that the annualized costs for an Oxidation Catalyst are estimated to be $43,566 per ton of CO removed (refer to Appendix D of facility application for more information on the energy and economic impacts).

The facility has also indicated that if Oxidation Catalyst is paired with a Babcock Power RSCR system, there will be no additional reheating of the flue gas required. The facility has indicated that energy impacts include 0.1 MW of lost capacity. Finally, the facility indicated that the annualized costs for an Oxidation Catalyst paired with a Babcock Power RSCR are estimated to be $3,842 per ton of CO removed (refer to Appendix D of facility application for more information on the energy and economic impacts). However, the facility has indicated that the RSCR system has not been selected as NOx BACT.

The facility has concluded that the use of good design and operation practices as the BACT control technology for CO emissions from the wood biomass fired boiler. Please refer to page 5-34 of the facility permit application.

Step 5: Selection of BACT

According to the facility application 19121, the proposed BACT for the fluidized bed boiler(s) includes good design and operation practices. In addition, the applicant has proposed BACT limits of 0.08 lb/MMBtu on a 30 day average for CO emissions. The applicant has proposed to use CO Continuous Emission Monitor System (CEMS) to demonstrate compliance with this limit.

In addition, the facility has proposed a secondary CO BACT limit of 625 tons per year to address periods of startup and shutdown of the wood biomass fired boiler.

EPD Review – CO Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the CO BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LEAR/Clearinghouse.[23]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources.
- Final permit, Preliminary and Final Determination, and Permit Application for Yellow Pine Energy Company, LLC, Georgia[24]

The Division has prepared a BACT comparison spreadsheet for the similar units using the above-mentioned resources and it is attached in Appendix D. The RSCR has been eliminated as potential NO_x control. Although catalytic oxidation would provide the highest level of CO emissions reduction, the Division has considered that achieving the relatively conservative NO_x BACT limit will have an effect on the amount that CO emissions can be controlled due to the inverse relationship of NO_x and CO. In addition, based on the research performed by the Division and review of the applicant's proposal, the use of good design and operating practices is the BACT control technology for CO emissions and 0.08 lb/MMBtu on a 30-day rolling average is the BACT CO emissions limit. To ensure compliance with the limit, the facility will be required to install a CO CEMS at the stack outlet.

Conclusion – Carbon Monoxide (CO) Control

The BACT selection for the fluidized bed boiler is summarized below in Table 4-10:

Table 4-10: CO BACT Summary for the Fluidized Bed Boiler

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	Good design and operating practices	0.08 lbs/MMBtu	30 day rolling average	CEMS
CO	Good design and operating practices	625 tons*	12 month rolling total	CEMS

*This limit includes emissions during startup, shutdown, and malfunctions.

Fire Water Pump Engines - Background

There are two fire pump engines that will be used in the proposed facility's emergency fire suppression system. These engines will be NFPA certified nominal 420 and 175 hp compression ignition fire water pump emergency engines and will be run on ULSD, with a maximum sulfur content of 0.0015 weight percent (15 ppmw). Combustion of the ULSD will yield emissions of NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, and CO. The facility 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.

[23] http://cfpub.epa.gov/rblc/index.cfm?action=Results.PermitSearchResults

[24] Final permit, Preliminary and Final Determination, and Permit Application for Yellow Pine Energy Company, LLC, Georgia

Fire Water Pump Engines – NOx, SO_2, PM/PM_{10}/$PM_{2.5}$, and CO BACT Emissions

Applicant's Proposal

In the facility application 19121, the applicant has proposed BACT for the 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.

EPD Review

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LEAR/Clearinghouse[25]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources.

The Division agrees with applicant's proposal to use good combustion controls and ultra low sulfur fuel, and to comply with the emission limitations contained in 40 CFR 60 Subpart IIII as BACT. The facility shall only use fuel that has a maximum sulfur content of 15 ppm (0.0015% by weight). To ensure compliance, the facility needs to install and configure the engine according to the manufacturer's specifications and keep records of fuel oil certification and hours of operation.

Conclusion

The BACT selection for the fire water pump engines are summarized below in table 4-11:

Table 4-11: NOx, SO_2, PM/$PM_{10,}$ $PM_{2.5}$, and CO BACT Summary for Fire Water Pump Engines

Pollutant	Control Technology	Proposed BACT Limit	Compliance Determination Method
NOx	Combustion Controls	40 CFR 60 Subpart IIII	Manufacturer's specification, fuel oil certification and records of hours of operation
CO	Combustion Controls	40 CFR 60 Subpart IIII	
PM/PM_{10}	Ultra low sulfur fuel oil	40 CFR 60 Subpart IIII	
$PM_{2.5}$	Ultra low sulfur fuel oil		
SO2	Ultra low sulfur fuel oil		

Biomass Fuel Preparation and Handling (BFPH Group) – PM/PM_{10}/$PM_{2.5}$ BACT Emissions

These 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 (Source Codes: FDR1-FDR8, CV01-CV04, GAT1, GAT2, GAT3, SCN1, SCN2, CV13-CV16, and GRN1-GRN3) and non-fugitive (Source Codes: SP01-SP03, TX01-TX12, Roads, and GRN3) sources.

Applicant's Proposal

In Application 19121, Warren County Biomass Energy Facility evaluated pre and post combustion control technologies for the material storage and handling equipment listed above. The brief summary of the applicant's BACT analysis is as follows:

[25] http://cfpub.epa.gov/rblc/index.cfm?action=Results.PermitSearchResults

Step 1: Identify all control technologies

- Enclosures could potentially be used on any process, transfer point or storage pile where structural or operational considerations do not preclude their use. When used in conjunction with a baghouse or vent fabric filter, the enclosure could capture as much as 99% of the $PM/PM_{10}/PM_{2.5}$ emissions from a source.

- Water spray could be used to suppress $PM/PM_{10}/PM_{2.5}$ emissions. Water sprays reduce $PM/PM_{10}/PM_{2.5}$ 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 spray 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.

Please refer to pages 5-38 through 5-39 of the facility permit application for details on the $PM/PM_{10}/PM_{2.5}$ control technologies.

Step 2: Eliminate technically infeasible options

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 above and determined that all control technologies were technically feasible. Application 19121 indicates that fabric filters are technically feasible $PM/PM_{10}/PM_{2.5}$ emissions control technology only when the source of emissions can be enclosed and funneled through a vent.

Please refer to pages 5-38 through 5-39 of the facility permit application.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

Application 19121's ranking of remaining control technologies by control effectiveness is nonexistent.

Step 4: Evaluating the Most Effective Controls and Documentation

Application 19121's evaluation of the most effective controls and documentation is nonexistent.

Step 5: Selection of BACT

According to Application 19121, Warren County Biomass Energy Facility's proposal to use of fabric filter baghouse and enclosures with 0.005 grains per dry standard cubic feet (gr/dscf) as BACT limit for non-fugitive $PM/PM_{10}/PM_{2.5}$ emissions and water spray and/or dust reduction devices for fugitive $PM/PM_{10}/PM_{2.5}$ emissions.

<u>EPD Review – Particulate matter $PM/PM_{10}/PM_{2.5}$ Emissions Control</u>

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the $PM/PM_{10}/PM_{2.5}$ BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LEAR/Clearinghouse.[26]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources.

[26] http://cfpub.epa.gov/rblc/index.cfm?action=Results.PermitSearchResults

The Division agrees with the applicant's proposal to the use baghouse with efficiency of 99.9% as the BACT control technology for $PM/PM_{10}/PM_{2.5}$ non-fugitive emissions with 0.005 grains per dry standard cubic feet (gr/dscf) on a 3-hours average as the BACT $PM/PM_{10}/PM_{2.5}$ non-fugitive emissions limit and the use of water spray and/or dust reduction devices as the BACT control technology for $PM/PM_{10}/PM_{2.5}$ fugitive emissions. In addition, an opacity limit of five percent will be imposed to ensure that particulate emissions from these processes remain at a minimum (for non-fugitive sources).

Conclusion – Particulate Matter ($PM/PM_{10}/PM_{2.5}$) Control

The BACT selection for the biomass fuel preparation and handling is summarized below in Table 4-12:

Table 4-12: BACT Summary for the Biomass Fuel Preparation and Handling (BFPH Group)

Pollutant	Emissions Units	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM_{10}	Biomass Unloading Operation	Fabric Filter Baghouse and Enclosures	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
$PM_{2.5}$	Biomass Unloading Operation	Fabric Filter Baghouse and Enclosures	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
PM_{10}	Biomass Processing Building	Fabric Filter Baghouse and Enclosures	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
$PM_{2.5}$	Biomass Processing Building	Fabric Filter Baghouse and Enclosures	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
PM_{10}	Biomass Transfer Tower	Fabric Filter Baghouse and Enclosures	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
$PM_{2.5}$	Biomass Transfer Tower	Fabric Filter Baghouse and Enclosures	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
PM_{10}	Boiler Building Biomass Transfer	Fabric Filter Baghouse and Enclosures	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
$PM_{2.5}$	Boiler Building Biomass Transfer	Fabric Filter Baghouse and Enclosures	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
PM_{10}	Mobile Longwood Chipping	Fabric Filter Baghouse and Enclosures	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
$PM_{2.5}$	Mobile Longwood Chipping	Fabric Filter Baghouse and Enclosures	0.005 gr/dscf	3 hours	Performance Testing and Monitoring

Pollutant	Emissions Units	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
$PM_{10}/PM_{2.5}$	Fugitive Emission Sources [refer to Biomass Fuel Preparation and Handling (BFPH Group) table]	Water spray and/or dust reduction devices	None	None	Monitoring
Opacity	Biomass Fuel Preparation and Handling Processes	None	5 %		Performance Testing and Monitoring

Material Storage Silos (MSS Group) – $PM/PM_{10}/PM_{2.5}$ BACT Emissions

This section identifies control options for the reduction of $PM/PM_{10}/PM_{2.5}$ emissions from the Sorbent Storage Silo, Boiler Bed Sand Storage Silo, Sand Day Storage Silo, Fly Ash Storage Silo, and Bottom Ash Storage Silo (Source Codes: SSS, BBSSS, SDSS, FASS, and BASS). The $PM/PM_{10}/PM_{2.5}$ emissions from these sources form in various ways, most notably from the breakdown of the solids into fine particulates that become airborne.

Applicant's Proposal

In Application 19121, Warren County Biomass Energy Facility evaluated pre and post combustion control technologies for the material storage and handling equipment listed above. The brief summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

- Enclosures, could potentially be used on any process, transfer point or storage pile where structural or operational considerations do not preclude their use. When used in conjunction with a baghouse or vent fabric filter, the enclosure could capture as much as 99% of the $PM/PM_{10}/PM_{2.5}$ emissions from a source. Examples of types of enclosures include material transfer chutes, conveyor hooding, and storage pile covers

- Water spray, could be used to suppress $PM/PM_{10}/PM_{2.5}$ emissions. Water sprays reduce $PM/PM_{10}/PM_{2.5}$ 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 spray 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.

Please refer to pages 5-38 through 5-39 of the facility permit application for details on the $PM/PM_{10}/PM_{2.5}$ control technologies.

Step 2: Eliminate technically infeasible options

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 and determined that all control technologies were technically feasible. Application 19121 indicates that fabric filters are technically feasible $PM/PM_{10}/PM_{2.5}$ emissions control technology only when the source of emissions can be enclosed and funneled through a vent.

Please refer to page 5-43 of the facility permit application.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

Application 19121's ranking of remaining control technologies by control effectiveness is nonexistent.

Step 4: Evaluating the Most Effective Controls and Documentation

Application 19121's evaluation of the most effective controls and documentation is nonexistent.

Step 5: Selection of BACT

According to Application 19121, the facility proposes to utilize fabric filtration systems (baghouses, bin vent filters) and/or good operating practices to reduce $PM/PM_{10}/PM_{2.5}$ emissions to 0.005 grains per dry standard cubic feet (gr/dscf). In addition, the facility has indicated that the water suppression will be utilized in the Fly Ash Storage Silo during the loading process.

<u>EPD Review – Particulate Matter $PM/PM_{10}/PM_{2.5}$ Emissions Control</u>

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the $PM/PM_{10}/PM_{2.5}$ BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LEAR/Clearinghouse[27].
- Final/Draft Permits and Final/Preliminary Determinations for similar sources.

The Division agrees with the proposed most effective controls and documentation evaluation. However, Warren County Biomass Energy Facility must install high efficient bin vent filter (fabric filter) and use water sprays for the fly ash storage silo. In addition, an opacity limit of five percent will be imposed to ensure that particulate emissions from these processes remain at a minimum.

Step 5: Selection of BACT

The Division agrees with the applicant's proposal to use of bin vent filter (fabric filter) with efficiency of 99.9% in combination with the use of water spray for the Fly Ash Storage Silo as the BACT control technology for $PM/PM_{10}/PM_{2.5}$ emissions and 0.005 grains per dry standard cubic feet (gr/dscf) on a 3-hours average as the BACT $PM/PM_{10}/PM_{2.5}$ emissions limit. In addition, an opacity limit of five percent will be imposed to ensure that particulate emissions from these processes remain at a minimum.

<u>Conclusion – Particulate Matter ($PM/PM_{10}/PM_{2.5}$) Control</u>

The BACT selection for the material storage silos is summarized below in Table 4-13:

[27] http://cfpub.epa.gov/rblc/index.cfm?action=Results.PermitSearchResults

Table 4-13: BACT Summary for the Material Storage Silos (MSS Group)

Pollutant	Emissions Units	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM_{10}	Sorbent Storage Silo (SSS)	Bin Vent Filter (fabric filter), good operating practices.	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
$PM_{2.5}$	Sorbent Storage Silo (SSS)	Bin Vent Filter (fabric filter), good operating practices.	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
PM_{10}	Boiler Bed Sand Storage Silo (BBSSS)	Bin Vent Filter (fabric filter), good operating practices.	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
$PM_{2.5}$	Boiler Bed Sand Storage Silo (BBSSS)	Bin Vent Filter (fabric filter), good operating practices.	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
PM_{10}	Sand Day Storage Hopper (SDSH)	Bin Vent Filter (fabric filter), good operating practices.	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
$PM_{2.5}$	Sand Day Storage Hopper (SDSH)	Bin Vent Filter (fabric filter), good operating practices.	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
PM_{10}	Bottom Ash Storage Silo (BASS)	Bin Vent Filter (fabric filter), good operating practices.	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
$PM_{2.5}$	Bottom Ash Storage Silo (BASS)	Bin Vent Filter (fabric filter), good operating practices.	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
PM_{10}	Fly Ash Storage Silo (FASS)	Bin Vent Filter (fabric filter), good operating practices, and water sprays.	0.005 gr/dscf	3 hours	Performance Testing and Monitoring

Pollutant	Emissions Units	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
$PM_{2.5}$	Fly Ash Storage Silo (FASS)	Bin Vent Filter (fabric filter), good operating practices, and water sprays.	0.005 gr/dscf	3 hours	Performance Testing and Monitoring
Opacity	Material Storage Silos	None	5 %	As specified by 40 CFR 60, Subpart OOO as applicable	Performance Testing and Monitoring

Cooling Tower (CT) - Background

The multi-cell cooling water 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 tower 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 referred to as drift and can contain a small amount of mineral material, which is present in the cooling water. Primary emissions from this equipment are $PM/PM_{10}/PM_{2.5}$.

Cooling Tower – $PM/PM_{10}/PM_{2.5}$ BACT Emissions

Applicant's Proposal

In Application 19121, Warren County Biomass Energy Facility evaluated pre and post combustion control technologies for the cooling tower equipment listed above. The brief summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

Application 19121 indicates that drift eliminators are the most stringent control technology identified for limiting $PM/PM_{10}/PM_{2.5}$ emissions from cooling towers.

Step 2: Eliminate technically infeasible options

Application 19121's elimination of technically infeasible options is nonexistent.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

Application 19121's ranking of remaining control technologies by control effectiveness is nonexistent.

Step 4: Evaluating the Most Effective Controls and Documentation

Application 19121's evaluation of the most effective controls and documentation is nonexistent.

Step 5: Selection of BACT

According to Application 19121, the use of drift eliminators on the cooling tower represents BACT for the control of cooling tower fugitive $PM/PM_{10}/PM_{2.5}$ emissions. The proposed BACT emission limit is equal to the mass flow rate of drift that would correspond to a drift eliminator effectiveness of 0.0005%.

EPD Review – Particulate Matter ($PM/PM_{10}/PM_{2.5}$) Emissions Control

The Division has determined that Warren County Biomass Energy Facility's proposal to meet a drift eliminator effectiveness of 0.0005% to minimize the emissions of $PM/PM_{10}/PM_{2.5}$ does constitute BACT for the cooling tower.

Conclusion – Particulate Matter ($PM/PM_{10}/PM_{2.5}$) Emissions Control

The BACT selection for the Cooling Tower is summarized below in Table 4-14:

Table 4-14: BACT Summary for the Cooling Tower

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM_{10}	Drift eliminators	Drift eliminator effectiveness of 0.0005%	None	Vendor Certification and Specification
$PM_{2.5}$	Drift eliminators	Drift eliminator effectiveness of 0.0005%	None	Vendor Certification and Specification

Roads – $PM/PM_{10}/PM_{2.5}$ BACT Emissions

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.

Applicant's Proposal

In Application 19121, Warren County Biomass Energy Facility evaluated pre and post combustion control technologies for roads. The brief summary of the applicant's BACT analysis is as follows:

Step 1: Identify all control technologies

Application 19121 indicates that there are few methods of controlling or reducing fugitive road emissions, including paving of the roads, limiting vehicle access, vacuuming, water suppressant sprays, and reducing vehicle speeds.

Step 2: Eliminate technically infeasible options

Application 19121's indicated that all control technologies are considered feasible options.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

Application 19121's ranking of remaining control technologies by control effectiveness is nonexistent.

Step 4: Evaluating the Most Effective Controls and Documentation

Application 19121's evaluation of the most effective controls and documentation is nonexistent.

Step 5: Selection of BACT

According to the facility Application 19121, the proposed BACT for the roads include paving all the facility's roads, restricting vehicle access to authorized vehicles, reducing vehicle speeds, and watering the roads.

EPD Review – Particulate Matter ($PM/PM_{10}/PM_{2.5}$) Emissions Control

The Division has determined that Warren County Biomass Energy Facility's proposal for paving all the facility's roads, restricting vehicle access to authorized vehicles, reducing vehicle speeds, and watering the roads does constitute BACT.

5.0 TESTING AND MONITORING REQUIREMENTS

Biomass Fired Boiler B001

The Biomass Fired Boiler B001 is subject to BACT requirements for NOx, CO, Total PM/PM_{10}, $PM_{2.5}$, and SO_2 emissions. The facility has taken limits for any single HAP (i.e. HCl) and total HAPS to avoid classification as a major source for HAPS under 40 CFR 63. The Filterable PM BACT requirement subsume the PM requirements specified in Georgia Rule 391-3-1-.02(2)(d) and NSPS Subpart Db; the NOx BACT requirement subsumes the NOx requirements specified in Georgia Rule 391-3-1-.02(2)(d) and NSPS Subpart Db; the SO_2 BACT requirement subsumes the SO_2 requirements specified in Georgia Rule 391-3-1-.02(2)(g) and NSPS Subpart Db.

In addition, the general provisions of NSPS provides avenues to obtain permission to use alternative testing and monitoring protocols, and in some cases, to waive testing requirements, when justified.

EPD proposes the following monitoring and testing requirements for the Biomass Boiler B001:

a. NOx CEMS to verify compliance with the NOx BACT emission standards.
b. SO_2 CEMS to verify compliance with the SO_2 BACT emission standards.
c. CO CEMS to verify compliance with the CO BACT emission standards.
d. Continuous Opacity Monitor to verify compliance with the opacity standard.
e. Initial performance tests and annually thereafter (Method 5 in conjunction with Method 202) to verify compliance with the total PM/PM_{10} BACT emission standards.
f. Initial performance tests and annually thereafter (Method 5 in conjunction with Method 202) to verify compliance with the filterable PM/PM_{10} BACT emission standards.
g. Initial performance tests and annually thereafter (Other Test Method 027 (OTM-027) in conjunction with Other Test Method 028 (OTM-028)) to verify compliance with the total $PM_{2.5}$ BACT emission standards.
h. Initial performance tests and annually thereafter (Method 26 or Method 26A) to establish and verify compliance with hydrogen chloride (HCl) emission rate standard.
i. Initial performance tests (Method 18) to establish emissions factor value for Benzene.
j. Initial performance tests (Method 320) to establish emissions factor value for Formaldehyde.
k. Initial performance tests (NCASI Method A105.01) to establish emissions factor value for Acrolein.
l. CO_2 or O_2 monitors at each location where emissions are monitored to measure the CO_2 or O_2 content of the flue gas to correct pollutant emission concentration.
m. Instrumentation to continuously measure the sorbent injection rate into the Duct Sorbent Injection System.
n. Instrumentation to measure the heat input to the Biomass Fired Boiler B001.

Biomass Fuel Preparation and Handling Particulate Sources

Biomass Fuel Preparation and Handling Particulate Sources (BFPH Group) are subject to BACT requirement limits for PM/PM_{10} and $PM_{2.5}$ EPD proposes initial performance testing for PM to verify compliance with PM_{10} and $PM_{2.5}$ standards.

Sorbent milling process and associated conveying system Particulate Sources

The duct sorbent injection system (DSI) will utilize an on-line sorbent milling process between the sorbent storage silo and injection system. The sorbent milling process will be done in an enclosed building and it does not transport material to a control device. Therefore, the PM emission limit of 0.032 g/dscm (0.014 gr/dscf) [40 CFR 60.672(a)] will not be applicable to the sorbent milling process and associated conveying system at Warren County Biomass Energy Facility.

The sorbent milling process will be done in an enclosed building and it does not transport material to a control device. Therefore, the fugitive emissions limits of 7 percent opacity [40 CFR 60.672(b)] will not be applicable to the sorbent milling process and associated conveying system at Warren County Biomass Energy Facility.

If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in paragraphs (a) and (b) of section 40 CFR 60.672, **or** the building enclosing the affected facility or facilities must comply with the following emission limits:
[40 CFR 60.672(e)]

(1) Fugitive emissions from the building openings (except for vents as defined in 60.671) must not exceed 7 percent opacity; and

(2) Vents in the building must meet a PM emissions limit of 0.032 g/dscm (0.014 gr/dscf).

The sorbent milling process building is enclosed in a building. Therefore, it is subject to the opacity limits of 40 CFR 60.672(e)(1). Method 9 shall be used to determine compliance.

Material Storage Silos (MSS Group) Particulate Sources

Material Storage Silos (MSS Group) Particulate Sources are subject to BACT requirement limits for PM/PM_{10} and $PM_{2.5}$. EPD proposes initial performance testing for PM to verify compliance with PM_{10} and $PM_{2.5}$ standards.

Fire Water Pumps

Fire Water Pumps (Source Codes: FP01 and FP02) are subject to NSPS Subpart IIII. EPD proposes to track the hours operated during emergency service and in non-emergency service (maintenance and/or testing), to record the reason the engine was in operation during those time, and to record the cumulative total hours of operation. Fuel sampling is required to verify compliance. The facility needs to comply with 40 CFR 60.4211(b) to demonstrate compliance with the NSPS Subpart IIII emission limits for the Fire Water Pumps (Source Codes: FP01 and FP02).

6.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required to determine the ambient impacts associated with the construction and operation of the proposed new major stationary source. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed new major stationary source, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class I or Class II area. NAAQS exist for NO_2, CO, $PM_{2.5}$,, PM_{10}, SO_2, Ozone (O_3), and lead. PSD increments exist for SO_2, NO_2, and PM_{10}.

The proposed project at the Warren County Biomass Energy Facility triggers PSD review for CO, NOx, PM/PM_{10}, $PM_{2.5}$, and SO_2. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for NO_2, CO, PM_{10}, $PM_{2.5}$, and SO_2. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application and in the additional information packages.

Modeling Requirements

The air quality modeling analysis was conducted in accordance with Appendix W of Title 40 of the Code of Federal Regulations (CFR) §51, *Guideline on Air Quality Models*, and Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised).*

The proposed project will cause net emission increases of CO, NOx, PM/PM_{10}, $PM_{2.5}$, and SO_2 that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment. Modeling is not required for VOC emissions; however, the project will likely have no impact on ozone attainment in the area based on data from the monitored levels of ozone in Columbia County and the level of emissions increases that will result from the proposed project. The southeast is generally NO_X limited with respect to ground level ozone formation.

Significance Analysis: Ambient Monitoring Requirements and Source Inventories

Initially, a Significance Analysis is conducted to determine if the CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2 emissions increases at the Warren County Biomass Energy Facility would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established Significant Impact Level (SIL). The SIL for the pollutants of concern are summarized in Table 6-1.

If a significant impact (i.e., an ambient impact above the SIL) does not result, no further modeling analyses would be conducted for that pollutant for NAAQS or PSD Increment. If a significant impact does result, further refined modeling would be completed to demonstrate that the proposed project would not cause or contribute to a violation of the NAAQS or consume more than the available Class II Increment.

Under current U.S. EPA policies, the maximum impacts due to the emissions increases from a project are also assessed against monitoring *de minimis* levels to determine whether pre-construction monitoring should be considered. These monitoring *de minimis* levels are also listed in Table 6-1. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. This evaluation is required for CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the SIL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the facility with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses.

Table 6-1: Summary of Modeling Significance Levels

Pollutant	Averaging Period	PSD Significant Impact Level (ug/m^3)	PSD Monitoring Deminimis Concentration (ug/m^3)
PM_{10}	Annual	1	--
	24-Hour	5	10
$PM_{2.5}$	Annual	0.3	--
	24-Hour	1.2	--
SO_2	Annual	1	--
	24-Hour	5	13
	3-Hour	25	--
	1-Hour	7.8	--
NO_2	Annual	1	14
	1-Hour	9.4	--
CO	8-Hour	500	575
	1-Hour	2000	--

NAAQS Analysis

The primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of pollutant in the atmosphere, which define the "levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health". Secondary NAAQS define the levels that "protect the public welfare from any known or anticipated adverse effects of a pollutant". The primary and secondary NAAQS are listed in Table 6-2 below.

Table 6-2: Summary of National Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary (ug/m^3)	Primary / Secondary (ppm)
PM_{10}	Annual	*Revoked 12/17/06	*Revoked 12/17/06
	24-Hour	150 / 150	--
$PM_{2.5}$	Annual	15 / 15	--
	24-Hour	35 / 35	--
SO_2	Annual	80 / None	0.03 / None
	24-Hour	365 / None	0.14 / None
	3-Hour	None / 1300	None / 0.5
	1-Hour	196 / None	0.075 / None
NO_2	Annual	100 / 100	0.053 / 0.053
	1-Hour	188.7 / None	0.10 / None
CO	8-Hour	10,000 / None	9 / None
	1-Hour	40,000 / None	35 / None
Pb	3-month	1.5 / None	--

If the maximum pollutant impact calculated in the Significance Analysis exceeds the SIL at an off-property receptor, a NAAQS analysis is required. The NAAQS analysis would include the potential emissions from all emission units at the Warren County Biomass Energy Facility, except for units that are generally exempt from permitting requirements and are normally operated only in emergency situations. The emissions modeled for this analysis would reflect the results of the BACT analysis for the modified emission unit. Facility emissions would then be combined with the allowable emissions of sources included in the regional source inventory.

The resulting impacts, added to appropriate background concentrations, would be assessed against the applicable NAAQS to demonstrate compliance. For an annual average NAAQS analysis, the highest modeled concentration among five consecutive years of meteorological data would be assessed, while the highest second-high impact would be assessed for the short-term averaging periods.

PSD Increment Analysis

The PSD Increments were established to "prevent deterioration" of air quality in certain areas of the country where air quality was better than the NAAQS. To achieve this goal, U.S. EPA established PSD Increments for certain pollutants. The sum of the PSD Increment concentration and a baseline concentration defines a "reduced" ambient standard, either lower than or equal to the NAAQS that must be met in an attainment area. Significant deterioration is said to have occurred if the change in emissions occurring since the baseline date results in an off-property impact greater than the PSD Increment (i.e., the increased emissions "consume" more that the available PSD Increment).

U.S. EPA has established PSD Increments for NO_2, SO_2, and PM_{10}; no increments have been established for CO or $PM_{2.5}$ (however, $PM_{2.5}$ increments are expected to be added soon). The PSD Increments are further broken into Class I, II, and III Increments. The Warren County Biomass Energy Facility is located in a Class II area. The PSD Increments are listed in Table 6-3.

Table 6-3: Summary of PSD Increments

Pollutant	Averaging Period	PSD Increment	
		Class I (ug/m^3)	Class II (ug/m^3)
PM_{10}	Annual	4	17
	24-Hour	8	30
SO_2	Annual	2	20
	24-Hour	5	91
	3-Hour	25	512
NO_2	Annual	2.5	25

To demonstrate compliance with the PSD Increments, the increment-affecting emissions (i.e., all emissions increases or decreases after the appropriate baseline date) from the facility and those sources in the regional inventory would be modeled to demonstrate compliance with the PSD Class II increment for any pollutant greater than the SIL in the Significance Analysis. For an annual average analysis, the highest incremental impact will be used. For a short-term average analysis, the highest second-high impact will be used.

The determination of whether an emissions change at a given source consumes or expands increment is based on the source classification (major or minor) and the time the change occurs in relation to baseline dates. The major source baseline date for NO_2 is February 8, 1988, and the major source baseline for SO_2 and PM_{10} is January 6, 1975. Emission changes at major sources that occur after the major source baseline dates affect Increment. In contrast, emission changes at minor sources only affect Increment after the minor source baseline date, which is set at the time when the first PSD application is completed in a given area, usually arranged on a county-by-county basis. The minor source baseline dates have been set for PM_{10} and SO_2 as January 30, 1980, and for NO_2 as April 12, 1991.

Modeling Methodology

Details on the dispersion model, including meteorological data, source data, and receptors can be found in EPD's PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix C of this Preliminary Determination and in Volume II of the permit application.

Modeling Results

Table 6-4 show that the proposed project will not cause ambient impacts of CO at 1-hour and 8-hour, NO_2 at annual, and SO_2 at 3-hour, 24-hour, and annual averaging periods above the appropriate SIL. Because the emissions increases from the proposed project result in ambient impacts less than the SIL, no further PSD analyses were conducted for these pollutants.

However, ambient impacts above the SILs were predicted for PM_{10} at 24-hour and annual, $PM_{2.5}$ at 24-hour and annual, NO_2 at 1-hour, and SO_2 at 1-hour averaging periods, requiring NAAQS and Increment analyses be performed for PM_{10}, $PM_{2.5}$, NO_2, and SO_2.

Table 6-4: Class II Significance Analysis Results – Comparison to SILs

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	SIL (ug/m^3)	Significant?
NO_2	Annual	1989	348.1	396.6	0.71	1	No
	1-hour	5-yr average	348.1	369.7	39.96	9.4	**Yes**
PM_{10}	24-hour	92040924	348	369.7	33.18	5	**Yes**
	Annual	1991	348	369.6	4.12	1	**Yes**
$PM_{2.5}$	24-hour	5-yr average	348	369.6	5.58	1.2	**Yes**
	Annual	5-yr average	348	369.6	1.16	0.3	**Yes**
SO_2	1-hour	5-yr average	348.4	369.7	15.69	7.8	**Yes**
	3-hour	90051215	348.5	369.7	10.96	25	No
	24-hour	90051224	348	369.8	2.13	5	No
	Annual	1991	348	369.7	0.05	1	No
CO	1-hour	90051216	349	369.8	725.32	2000	No
	8-hour	90081505	349	369.8	176.94	500	No

Data for worst year provided only.

As indicated in the tables above, maximum modeled impacts were below the corresponding SILs for CO at 1-hour and 8-hour, NO_2 at annual, and SO_2 at 3-hour, 24-hour, and annual averaging periods. However, maximum-modeled impacts were above the SILs for PM_{10} at 24-hour and annual, $PM_{2.5}$ at 24-hour and annual, NO_2 at 1-hour, and SO_2 at 1-hour averaging periods. Therefore, a Full Impact Analysis was conducted for PM_{10} at 24-hour and annual, $PM_{2.5}$ at 24-hour and annual, NO_2 at 1-hour, and SO_2 at 1-hour averaging periods.

Significant Impact Area

For any off-site pollutant impact calculated in the Significance Analysis that exceeds the SIL, a Significant Impact Area (SIA) must be determined. The SIA encompasses a circle centered on the facility being modeled with a radius extending out to the lesser of either: 1) the farthest location where the emissions increase of a pollutant from the proposed project causes a significant ambient impact, or 2) a distance of 50 kilometers. All sources of the pollutants in question within the SIA plus an additional 50 kilometers are assumed to potentially contribute to ground-level concentrations and must be evaluated for possible inclusion in the NAAQS and Increment Analysis.

Based on the results of the Significance Analysis, the distance between the facility and the furthest receptor from the facility that showed a modeled concentration exceeding the corresponding SIL was determined to be less than 3.7 kilometers for PM_{10}, 7.2 kilometers for SO_2, and 24.5 kilometers for NO_2. To be conservative, regional source inventories for all of these pollutants were prepared for sources located within 53.7 kilometers for PM_{10}, 57.2 kilometers for SO_2, and 74.5 kilometers for NO_2 of the facility.

NAAQS and Increment Modeling

The next step in completing the NAAQS and Increment analyses was the development of a regional source inventory. Nearby sources that have the potential to contribute significantly within the facility's SIA are ideally included in this regional inventory. Warren County Biomass Energy Facility requested and received an inventory of NAAQS and PSD Increment sources from Georgia EPD. Warren County Biomass Energy Facility reviewed the data received and calculated the distance from this facility to each facility in the inventory. All sources more than 53.7 km, 57.2 km, and 74.5 km for PM_{10}, SO_2, and NO_2 respectively outside the SIA were excluded.

The distance from the facility of each source listed in the regional inventories was calculated, and all sources located more than 53.7 kilometers, 57.2 kilometers, and 74.5 kilometers for PM_{10}, SO_2, and NO_2 respectively from the facility were excluded from the analysis. Additionally, pursuant to the "20D Rule," facilities outside the SIA were also excluded from the inventory if the entire facility's emissions (expressed in tons per year) were less than 20 times the distance (expressed in kilometers) from the facility to the edge of the SIA. In applying the 20D Rule, facilities in close proximity to each other (within approximately 5 kilometers of each other) were considered as one source. Then, any Increment consumers from the provided inventory were added to the permit application forms or other readily available permitting information.

The regional source inventory used in the analysis is included in the permit application (Volume II - Modeling) and the modeling report.

NAAQS Analysis

In the NAAQS analysis, impacts within the facility's SIA due to the potential emissions from all sources at the facility and those sources included in the regional inventory were calculated. Since the modeled ambient air concentrations only reflect impacts from industrial sources, a "background" concentration was added to the modeled concentrations prior to assessing compliance with the NAAQS.

The results of the NAAQS analysis are shown in Table 6-5. For the short-term averaging periods, the impacts are the highest second-high impacts. For the annual averaging period, the impacts are the highest impact. When the total impact at all significant receptors within the SIA are below the corresponding NAAQS, compliance is demonstrated.

Table 6-5: NAAQS Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	All Source Impact (ug/m^3)	Total* Impact (ug/m^3)	NAAQS (ug/m^3)	Exceed NAAQS?
SO_2	1-hour	5-yr average	353.6	370.2	51.78	124.78	196	No
PM_{10}	24-hour	92111824	347.1	369.4	465.75	503.75	150	**Yes**
	Annual	1992	347.2	369.4	139.35	159.35	50	**Yes**
$PM_{2.5}$	24-hour	5-yr average	348	369.6	5.58	33.48	35	No
	Annual	5-yr average	348	369.6	1.16	14.26	15	No
NO_2	1-hour	5-yr average	368.6	368.2	5863.83	5903.83	188.7	**Yes**

Data for worst year provided only.
* Total impact equals source impact, plus impact from offsite sources, plus background.

As indicated in Table 6-5 above, the total modeled impact for PM_{10} at 24-hour and annual periods and NO_2 at 1-hour exceed the corresponding NAAQS.

SO_2 at 1-hour and $PM_{2.5}$ at 24-hour and annual averaging periods have met their applicable NAAQS standard, while PM_{10} concentrations at 24-hour and annual and NO_2 at 1-hour averaging periods concentration show NAAQS exceedances. Figure 6 and 7 (in the modeling memo) illustrate the PM_{10} NAAQS exceedances for the annual period occurs inside the property of Martin Marietta Aggregates Warrenton Rock Quarry (MMQ), while for the 24-hour period, the exceedances also occurs at one ambient receptor very close to the northeastern boundary of MMQ. Additional analysis demonstrates that the Warren County Biomass Energy Facility is not significant at the NAAQS exceeding receptors.

In terms of NO_2 at 1-hour, Figure 8 (in the modeling memo) shows the significant impact receptors from the proposed project (blue cross) and the NAAQS exceeding receptors when including offsite sources (pink and red solid circle). At any NAAQS exceeding receptors, the facility is not significant. Therefore, the proposed project will not cause or contribute significantly to an exceeding impact in the ambient air.

All of the other total modeled impacts at all significant receptors within the SIA are below the corresponding NAAQS.

Increment Analysis

The modeled impacts from the NAAQS run were evaluated to determine whether compliance with the Increment was demonstrated. The results are presented in Table 6-6.

Table 6-6: Increment Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Increment (ug/m^3)	Exceed Increment?
PM_{10}	24-hour	89011824	347.1	369.4	333.49	30	**Yes**
	Annual	1992	347.1	369.4	61.61	17	**Yes**

Data for worst year provided only

Table 6-6 demonstrates that the impacts are above the corresponding increments for PM_{10} at 24-hour and annual periods with the conservative modeling assumption that all NAAQS sources were Increment sources.

PM_{10} 24-hour increment exceedances occurs at the properties of Martin Marietta Aggregates Warrenton Rock Quarry (MMQ), Georgia Pacific Chip-N-Saw (GP), TRW Warrenton Foundry (TRW), and northeastern ambient area of MMQ, while annual PM_{10} increment exceedances occurs only at the MMQ property. Additional analysis demonstrates that the Warren County Biomass Energy Facility is not significant at any of the PM_{10} 24-hour increment exceeding ambient receptors during an exceeding event. (See Figure Nos. 1 through 7 in the modeling memo, Appendix C). Therefore, the proposed project will not contribute significantly on any occurrences of the allowable increment exceedance.

Ambient Monitoring Requirements

Table 6-7: Significance Analysis Results – Comparison to Monitoring *De Minimis* Levels

Pollutant	Averaging Period	Year*	UTM East (km)	UTM North (km)	Monitoring De Minimis Level (ug/m^3)	Modeled Maximum Impact (ug/m^3)	Significant?
NO_2	Annual	1989	348.1	369.6	14	0.71	No
PM_{10}	24-hour	92040924	348	369.8	10	33.18	**Yes**
SO_2	24-hour	90051224	348.4	369.8	13	2.13	No
CO	8-hour	90051216	348.4	369.7	575	176.94	No
$PM_{2.5}$	24-hour	5-yr average	348	369.6	4	5.58	**Yes**

Data for worst year provided only

Monitoring De Minimus concentrations of CO, NO_2, and SO_2 are less than their respective, prescribing threshold concentration, so no pre-construction monitoring is required. No pre-construction monitoring is necessary for PM_{10} and $PM_{2.5}$ because Georgia EPD existing ambient air data from representative regional monitoring station is sufficient. This data for PM_{10} and $PM_{2.5}$ is contemporaneous representative and regularly quality assured.

In terms of ozone impact, no significant air quality concentration has been established. PSD permit applicants with net project emissions increases of 100 tons per year or more of VOC or NOx are required to perform an ambient ozone impact analysis that includes pre-application monitoring data to determine the current state of the ambient air conditions for this pollutant.

The proposed Warren County Biomass Energy Facility is expected to emit 648 tpy NOx. The Columbia County ozone monitor at Riverside Park, Evans, (maintained by Georgia EPD) is considered to be conservatively representative of the air quality at the project site and since this area is in attainment with the 8-hour ozone standard (75 ppbv), the facility would also be in attainment for ozone. The site (ID: 130730001) is about 48.5 km away from the facility, and the latest three-year design value (2007-2009 average of the annual 4th highest 8-hour ambient concentrations) is 71 ppbv.

Class I Area Analysis

Federal Class I areas are regions of special national or regional value from a natural, scenic, recreational, or historic perspective. Class I areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations. U.S. EPA has established policies and procedures that generally restrict consideration of impacts of a PSD source on Class I Increments to facilities that are located near a federal Class I area. Historically, a distance of 100 km has been used to define "near", but more recently, a distance of 300 kilometers has been used for all facilities.

The nearest Class I Area to the facility, Shining Rock Wilderness Area, is more than 216 kilometers away. The magnitude of the emissions from the proposed project do not warrant a review of impacts at this distance. Therefore, no Class I Increment consumption of Air Quality Related Values (AQRV) analyses were performed.

7.0 ADDITIONAL IMPACT ANALYSES

PSD requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of a modification to the facility and an analysis of the air quality impact projected for the area as a result of the general commercial, residential, and other growth associated with the proposed project.

Soils and Vegetation

The U.S. EPA has developed certain screening concentrations below which it can be reasonably assumed that the soils and vegetation in the vicinity of a proposed project will not experience any adverse effects due to air emissions associated with the project. These threshold concentrations are listed in Table V of the Model Request Form that is attached to the EPD's PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix C, and were compiled from EPA's Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA, 1980). Table V presents a comparison of the proposed facility's worst-case impacts to these screening concentrations. Review of that table indicates the highest predicted impacts are all well below the screening concentrations. In addition, the facility has been modeled to demonstrate compliance with all applicable NAAQS, which are, in part, based on acceptable levels of environmental impact.

Growth

The growth analysis is a projection of the commercial, industrial, residential and other growth that may be projected to occur in the area as a result of the construction and operation of the proposed source. The anticipated increase in industrial, commercial, or residential growth in the area as a direct result of the proposed project will be negligible. Construction of the new power generation unit will require a temporary construction work force that will fluctuate from approximately 100 to an estimated 500 people for approximately 24 months. Many construction workers will be hired locally. Operation of the facility is expected to create between 100-150 permanent jobs. No significant amount of related industrial growth is expected to accompany the operation of the plant. Since no significant associated commercial or industrial growth is projected as a result of the proposed action, negligible growth-related air pollution impacts are expected.

Visibility

Visibility impairment is any perceptible change in visibility (visual range, contrast, atmospheric color, etc.) from that which would have existed under natural conditions. Poor visibility is caused when fine solid or liquid particles, usually in the form of volatile organics, nitrogen oxides, or sulfur oxides, absorb or scatter light. This light scattering or absorption actually reduces the amount of light received from viewed objects and scatters ambient light in the line of sight. This scattered ambient light appears as haze.

Another form of visibility impairment in the form of plume blight occurs when particles and light-absorbing gases are confined to a single elevated haze layer or coherent plume. Plume blight, a white, gray, or brown plume clearly visible against a background sky or other dark object, usually can be traced to a single source such as a smoke stack.

Georgia's SIP and Georgia *Rules for Air Quality Control* provide no specific prohibitions against visibility impairment other than regulations limiting source opacity and protecting visibility at federally protected Class I areas. To otherwise demonstrate that visibility impairment will not result from operation of the proposed facility, the VISCREEN model was used to assess potential impacts on ambient visibility at so-called "sensitive receptors" within the SIA of the Warren County Biomass Energy Facility. The maximum PM_{10} and NOx significant impact distance is 3.7 km and 24.5 km, respectively. There are no potentially sensitive receptors (such as, scenic vistas) within 24.5 km radius area about the Warren County Biomass Energy Facility.

There is no ambient visibility protection standard for Class II area. For this reason, it was not necessary to conduct an analysis of Class II visible plume impacts.

Georgia Toxic Air Pollutant Modeling Analysis

Georgia EPD regulates the emissions of toxic air pollutant (TAP) emissions through a program covered by the provisions of *Georgia Rules for Air Quality Control*, 391-3-1-.02(2)(a)3.(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the Georgia EPD's review of TAP emissions as part of air permit reviews are contained in the agency's "*Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*."

Selection of Toxic Air Pollutants for Modeling

For projects with quantifiable increases in TAP emissions, an air dispersion modeling analysis is generally performed to demonstrate that off-property impacts are less than the established Acceptable Ambient Concentration (AAC) values. The TAP evaluated are restricted to those that may increase due to the proposed project. Thus, the TAP analysis would generally be an assessment of off-property impacts due to facility-wide emissions of any TAP emitted by a facility. To conduct a facility-wide TAP impact evaluation for any pollutant that could conceivably be emitted by the facility is impractical. A literature review would suggest that at least one molecule of hundreds of organic and inorganic chemical compounds could be emitted from the various combustion units. This is understandable given the nature of the biomass and biodiesel fuel fed to the combustion sources, and the fact that there are complex chemical reactions and combustion of fuel taking place in some. The vast majority of compounds potentially emitted however are emitted in only trace amounts that are not reasonably quantifiable.

Section 6 of Volume II Modeling of the permit application contains discussion of how toxic emissions were determined. For each TAP identified for further analysis, both the short-term and long-term AAC were calculated following the procedures given in Georgia EPD's *Guideline*. Figure 8-3 of Georgia EPD's *Guideline* contains a flow chart of the process for determining long-term and short-term ambient thresholds. Warren County Biomass Energy Facility referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AAC (i.e., 24-hour or 15-minute). The AACs were verified by the EPD.

Determination of Toxic Air Pollutant Impact

The Georgia EPD *Guideline* recommends a tiered approach to model TAP impacts, beginning with screening analyses using SCREEN3, followed by refined modeling, if necessary, with ISCST3 or ISCLT3. For the refined modeling completed, the infrastructure setup for the SIA analyses was relied upon with appropriate sources added for the TAP modeling. Note that per the Georgia EPD's *Guideline*, downwash was not considered in the TAP assessment.

Initial Screening Analysis Technique

Generally, an initial screening analysis is performed in which the total TAP emission rate is modeled from the stack with the lowest effective release height to obtain the maximum ground level concentration (MGLC). Note, the MGLC could occur within the facility boundary for this evaluation method. The individual MGLC is obtained and compared to the smallest AAC. Due to the likelihood that this screening would result in the need for further analysis for most TAP, the analyses were initiated with the secondary screening technique.

Acceptable Ambient Concentrations (AACs) were calculated for each contaminant and applicable time-averaging period according to the Georgia Air Toxics Guideline, as shown in the Table F-1 of Appendix F of the permit application Volume II - Modeling. SCREEN3 model was used to estimate the maximum ground level concentration (MGLC). A unit emission rate of 1 g/s was modeled from the boiler stack. The modeled impact was then multiplied by the emission rate of each TAP (total 134 TAPs) to obtain the maximum-modeled impact of each TAP for comparison to the applicable AACs. All air toxic concentrations assessed were found to be less than their respective AACs.

The Air Toxics analysis shows conformance with the Georgia Air Toxics Guideline Acceptable Ambient Concentrations.

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit No. 4911-301-0016-P-01-0.

Section 1.0: General Requirements

The following permit conditions were added to standard permit conditions:

Condition 1.6 – General applicability of 40 CFR 60, Subpart Db to Source B001.

Condition 1.7 – General applicability of 40 CFR 60, Subpart IIII to Source FP01 and FP02.

Condition 1.8 – General applicability of 40 CFR 63, Subpart ZZZZ to Source FP01 and FP02.

Section 2.0: Allowable Emissions

Condition 2.1 defines the requirements to construct and operate the facility in accordance with Georgia Rule 391-3-1-.02(7).

Condition 2.2 requires the commencement of construction of the Warren County Biomass Energy Facility within 18 months of the issuance of the permit.

Condition 2.3 requires the submittal of a Title V Permit application within 12 months of commencing operation as well as the review of potential applicability of 40 CFR 64 to applicable Warren County Biomass Energy Facility equipment.

Condition 2.4 defines the Stack B001.

Condition 2.5 defines the minimum and maximum operating loads for Source B001.

Condition 2.6 defines the startup and shutdown for Source B001.

Condition 2.7 defines biomass.

Condition 2.8 defines the primary fuel for Source B001.

Condition 2.9 defines NOx PSD emissions limit for Source B001.

Condition 2.10 defines filterable PM_{10} PSD emissions limits for Source B001.

Condition 2.11 defines total PM_{10} and total $PM_{2.5}$ PSD emissions limits for Source B001.

Condition 2.12 defines SO_2 PSD emissions limit for Source B001.

Condition 2.13 defines CO PSD emissions limit for Source B001.

Condition 2.14 defines filterable PM_{10} and total $PM_{2.5}$ PSD emissions limits for biomass fuel and handling processes.

Condition 2.15 defines filterable PM_{10} and total $PM_{2.5}$ PSD emissions limits for material storage silos.

Condition 2.16 defines opacity limits for biomass fuel and handling processes and material storage silos.

Condition 2.17 defines effectiveness of drift eliminators on the Cooling Tower CT01.

Condition 2.18 defines NOx PSD annual emissions limit for Source B001.

Condition 2.19 defines CO PSD annual emissions limit for Source B001.

Condition 2.20 defines SO_2 PSD annual emissions limit for Source B001.

Condition 2.21 defines individual and combined HAPS emissions limits for the entire facility. This limit (10/25 tpy) will ensure that the facility will remain a HAPS minor source. The facility will be classified as an area source under 40 CFR 63.

Condition 2.22 defines particulate matter emissions limits for all storage silos and biomass handling systems at the facility.

Condition 2.23 defines total hours of operation limits for Sources FP01 and FP02 per year.

Condition 2.24 defines visible emissions limits for Sources FP01 and FP02.

Condition 2.25 defines accumulated non-emergency service time limits for Sources FP01 and FP02 per year.

Condition 2.26 defines allowable sulfur contents of applicable fuels that can be fired in Sources, FP01 and FP02.

Condition 2.27 requires the facility to remove Longwood Mobile Chipper GRN3 from the facility within 12 months. This condition will ensure that the Mobile Chipper GRN3 is not subject to 40 CFR 60 Subpart IIII requirements per EPA guidance.

Condition 2.28 defines visible emissions limits for Source B001.

Condition 2.29 defines NOx 1-hour PSD emissions limit for Source B001.

Condition 2.30 defines SO_2 1-hour PSD emissions limit for Source B001.

Conditions 2.31 and 2.32 address the general applicability of 40 CFR 60, Subpart OOO to the sorbent storage silo and the operation of the sorbent milling process and associated conveying system at the facility.

Section 3.0: Fugitive Emissions

Conditions 3.1 and 3.2 incorporate Georgia Rule (n), which requires the facility to minimize fugitive dust emissions.

Section 4.0: Requirements for Control Equipment

Condition 4.1 requires the installation of SNCR on Stack B001. The facility application indicated that a 65% load is required to initiate the SNCR system; once the SNCR is active its usage can be maintained down to 40% load.

Condition 4.2 requires the installation of BHB1 on Stack B001. The facility application indicated that halfway through phase II of the startup, the fabric filter baghouse can be used.

Condition 4.3 requires the installation of DSI on Stack B001. The facility application indicated that halfway through phase II of the startup, the sorbent injection system can be used.

Condition 4.4 requires the installation of particulate matter control equipment on applicable fugitive and non-fugitive materials handling equipment.

Condition 4.5 requires the installation of drift eliminators on Source CT01.

Section 5.0: Monitoring

Condition 5.1 explains general requirements for the operation of a continuous monitoring system.

Condition 5.2 requires the installation of CEMS for NOx, SO_2, CO, and COMS on Stack B001.

Condition 5.3 requires a continuous indicator to determine the sorbent injection rate into DS1 for Source B001 and a continuous indicator to determine the heat input for Source B001.

Condition 5.4 requires the monitoring of fuel usage from Source B001.

Condition 5.5 requires verification of allowable sulfur contents of applicable fuels that can be fired in Sources FP01 and FP02.

Condition 5.6 requires verification of monitoring in Group BFPH and Group MSS via recordkeeping and periodic inspections to verify compliance with Condition 2.16.

Condition 5.7 requires the installation of monitoring devices to monitor the hours of operation during emergency service and the hours of operation in non-emergency service of Sources FP01 and FP02.

Condition 5.8 requires the facility to quarterly visible emissions for the Sorbent Storage Silo (Source Code: SSS).

Condition 5.9 requires visible emissions for all baghouses at the facility.

Condition 5.10 requires the facility to implement a Preventive Maintenance Program for baghouses.

Section 6.0: Performance Testing

Condition 6.1 defines general testing requirements.

Condition 6.2 lists the applicable testing method for applicable equipment.

Condition 6.3 discusses the requirements for applicable CEMS.

Condition 6.4 requires the facility to conduct performance tests for PM_{10} and $PM_{2.5}$ to demonstrate compliance with the PSD limits.

Condition 6.5 requires conducting performance tests to demonstrate compliance with the HCl emissions limit.

Condition 6.6 requires conducting performance tests to determine the Acrolein, Benzene and Formaldehyde emissions rate. Based on data collected through the performance testing, the Permittee shall use the results as approved emission factors (in lbs/MMBTU) for Acrolein, Benzene and Formaldehyde to calculate HAPs emissions in Condition 7.16.b.

The emission factors for HCl, Acrolein, Benzene and Formaldehyde from testing in Conditions 6.5 and 6.6 will be more accurate for this boiler than the AP42 emission factors. Emission factors for all other HAPs are included in Appendix C of the Permit Application No. 19121 (Volume I), dated October 2009. The facility mainly used AP-42 emission factors (Section 1.6) and vendor specific emissions factors in cases where none were available. Please refer to Table C-2 in Appendix C of the Permit Application.

Condition 6.7 defines the required performance testing and associated requirements for Biomass Fuel Preparation and Handling (BFPH Group).

Condition 6.8 defines the required performance testing and associated requirements for Material Storage Silos (MSS Group).

Condition 6.9 defines the required performance testing for the Sorbent Storage Silo (Source Code: SSS).

Section 7.0: Notification, Reporting and Record Keeping

Condition 7.1 defines the records maintenance schedule.

Condition 7.2 requires submitting the result of performance tests of PM emissions in accordance with 40 CFR 60, Subpart OOO requirements.

Condition 7.3 requires submittal of applicable records for the sorbent storage silo and the operation of the sorbent milling process and associated conveying system at the facility in accordance with 40 CFR 60, Subpart OOO.

Conditions 7.4 discuss record keeping and reporting associated with compliance demonstration for applicable limits for Sources B001, GRN3, FP01, and FP02.

Condition 7.5 describes 1-hour average, 30-day rolling average, and 12-month rolling total determination of NOx emissions from the Bubbling Fluidized Bed Boiler B001 and requires recordkeeping.

Condition 7.6 describes 1-hour average, 30-day rolling average, and 12-month rolling total determination of SO_2 emissions from the Bubbling Fluidized Bed Boiler B001 and requires recordkeeping.

Condition 7.7 describes 30-day rolling average and 12-month rolling total determination of CO emissions from the Bubbling Fluidized Bed Boiler B001 and requires recordkeeping.

Condition 7.8 discusses record keeping requirements for the cooling tower CT01.

Conditions 7.9 and 7.10 discuss record keeping and reporting associated with compliance demonstration for applicable limits for Source B001.

Condition 7.11 defines the timeline for which are records shall be kept.

Condition 7.12 requires reporting of any deviations and corrective actions taken.

Condition 7.13 requires quarterly reporting of excess emissions, exceedances and excursions associated with this permit.

Condition 7.14 requires record keeping of the operating hours for Sources FP01 and FP02

Condition 7.15 requires recordkeeping to demonstrate compliance with the NSPS Subpart IIII emission limits for Sources FP01 and FP02.

Conditions 7.16, 7.17 and 7.18 establish reporting thresholds and provide equations for determining monthly emissions for individual and combined HAPs from the Bubbling Fluidized Bed Boiler (Source Code: B001). Testing must be conducted for HCl, Acrolein, Formaldehyde and Benzene emissions. The facility will be required to use the emissions factors from testing required in accordance with Conditions 6.5 and 6.6 to determine HCl, Acrolein, Formaldehyde and Benzene emissions. Emission factors for all other HAPs are included in Appendix C of the Permit Application No. 19121 (Volume I) dated October 2009. These emission factors are approved by EPD. Unless otherwise, the facility will be required to use these approved emissions factors in the HAPs calculations in Condition 7.16.

Condition 7.19 requires certification for the biomass fuel combusted in the Bubbling Fluidized Bed Boiler B001.

Condition 7.20 discusses record keeping and reporting associated with compliance demonstration for applicable limits for Source B001.

Condition 7.21 defines excess emissions, exceedances and excursions associated with this permit.

Condition 7.22 requires the facility to notify the Division of the removal of the Longwood mobile chipper (Source Code: GRN3).

Section 8.0: Special Conditions

Condition 8.2 requires facility to pay an annual permit fee.

APPENDIX A - Draft SIP Construction Permit for Warren County Biomass Energy Facility
Warrenton (Warren County), Georgia

APPENDIX B - PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. 19121, dated August 6, 2009
2. Revised PSD Permit Application No. 19121, dated October 14, 2009
3. Additional Information Package, dated February 4, 2010
4. Additional Information Package, dated March 5, 2010
5. Additional Information Package, dated April 27, 2010
6. Additional Information Package, dated June 11, 2010
7. Additional Information Package, dated June 25, 2010
8. Additional Information Package, dated June 28, 2010
9. Additional Information Package, dated July 27, 2010

APPENDIX C - EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review

APPENDIX D - EPD BACT Comparison Spreadsheet for the Biomass Boiler B001